

Ontario Energy Board



EB-2011-0043

Board Staff Discussion Paper

**Regulatory Framework for Regional Planning for
Electricity Infrastructure**

November 8, 2011

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1 INTRODUCTION

1.1 Purpose and Objectives

On April 1, 2011, the Ontario Energy Board (the “Board”) issued a letter (the “[April 2011 Letter](#)”) initiating a consultation process aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters.

As indicated in the April 2011 Letter, this consultation is intended to develop a regulatory framework for regional planning in a manner that is consistent with the principles articulated in earlier [Transmission System Code \(“TSC”\)](#) consultations as well as the following:

- that an optimized solution is desirable as being the lowest cost in the long term;
- that a coordinated solution is desirable as allowing for a consideration of broader needs and for involvement by a larger set of stakeholders; and
- that cost responsibility for optimized solutions is attributed in an appropriate manner.

The purpose of this Board staff Discussion Paper is to set out staff’s proposals and options in relation to regional planning in Ontario for stakeholder consideration and comment. This Discussion Paper focuses on transmission Connection assets which comprise line connection facilities, commonly known as radial lines, and transformation facilities (transformer stations).¹

1.2 Background and Scope

In 2008, the Board initiated a consultation process (EB-2008-0003) – the Transmission Connection Cost Responsibility Review (“TCCRR”). As set out in the Board’s January 4, 2008 letter, the initial intent was to examine the issue of cost responsibility associated with the connection of both generation and load facilities. The primary trigger for the

¹ The transmission system also includes Network assets, which benefit and are therefore paid for by all Ontario ratepayers. For a more detailed discussion of the various transmission assets, please refer to [Appendix 2](#).

TCCRR consultation process was the Ontario Power Authority's ("OPA") initial Integrated Power System Plan ("IPSP"), which identified a significant amount of new renewable energy generation that would need to be connected to the transmission system. At that time, the Board felt that the decision to examine cost responsibility in relation to generation connections presented a good opportunity to do the same in regard to load connections. For example, it provided an opportunity to consider concerns expressed in relation to the Board's load connection policies during a separate proceeding relating to the connection procedures of Hydro One Networks Inc. ("Hydro One") and Great Lakes Power Limited ("GLP") discussed in Chapter 2. Among the concerns noted at the time was that the Board's cost responsibility policies may inhibit rather than facilitate the construction of facilities that are necessary to meet regional load growth and do not provide sufficient regulatory certainty for infrastructure planning and investment purposes. However, the Board subsequently decided the TCCRR consultation should focus on generation connections and noted that a separate staff Discussion Paper on issues pertaining to cost responsibility associated with load connections would be issued at a later date.²

Given the Board's cost responsibility policies in relation to load customer connections have not been examined for some time, as noted below, and the concerns discussed above related to the potential implications that those cost responsibility policies may have in relation to regional planning, Board staff has proceeded on the basis that the focus of this consultation process should be to examine the issue of cost responsibility and regional planning in relation to load customer connections. More specifically, the primary focus should be on distribution system connections, which themselves are affected by generation connections at the distribution level.

The last generic policy review of the cost responsibility and planning rules in the TSC that addressed load customers was completed in July 2005 following two successive consultation processes (RP-2002-0120 and RP-2004-0220). Since that time, a great deal has changed due to, among others, the amendments made to the *Ontario Energy Board Act, 1998* (the "OEB Act") and the *Electricity Act, 1998* (the "Electricity Act") by the *Green Energy and Green Economy Act, 2009* (the "GEA"). In 2005, the

² In its [July 8, 2008 letter](#) accompanying the release of a staff Discussion Paper on generation connections, the Board advised interested parties that it would address load and generation separately given the differences in concerns and the underlying issues. The EB-2008-0003 consultation process culminated in amendments to the TSC that addressed issues associated with "enabler facilities" that connect clusters of renewable generation facilities to the transmission grid, including how those facilities are identified and the allocation of cost responsibility for them.

transmission and distribution systems in Ontario were relatively distinct systems, with most distributors focusing almost exclusively on the delivery of electricity to load customers. The distribution system is now in the process of essentially evolving into an extension of the transmission system, with significant amounts of renewable energy generation connecting at the distribution level. Among other reasons, this has contributed to an increased need for coordinated planning between distributors and transmitters.

The Board recognized this need in its 2011-2014 Business Plan which identifies the following goal: *Optimizing Infrastructure Investment: Prudent and cost-effective investments in the electricity system by transmitters and distributors provide consumers with a reliable and sustainable supply of electricity at a reasonable cost.* In terms of transmitters, a specific objective for achieving this goal is that the expansion of the transmission system should proceed in an orderly and economically prudent manner. In fiscal year 2011, the Business Plan identifies that this will be addressed through, among others, the issuance of policy guidance setting out the Board's requirements for transmitters in respect of regional planning. In relation to distribution, a specific objective identified in the Business Plan for achieving the infrastructure optimization goal is that distributors prioritize distribution investments through local system and regional planning with regard to reliability and the total bill impact on consumers. The Business Plan calls for the Board to issue policy guidance in relation to regional planning by distributors, also in fiscal year 2011.


As indicated in the April 2011 Letter, this consultation is intended to focus on the development of regional planning requirements that will apply in circumstances where a localized geographic issue can be resolved through a number of different transmission and/or distribution solutions. It is not intended to be a broad integrated planning exercise that addresses solutions such as conservation and distributed generation as potential alternatives to infrastructure.


1.3 Links to Other Initiatives

There are linkages between this project and other initiatives that are both internal and external to the Board as set out below.

On October 27, 2010, the Board announced an initiative to develop a Renewed Regulatory Framework ("RRF") for electricity. The regional planning consultation is


most closely related to the *Distribution Network Investment Planning* (EB-2010-0377) component of the RRF. The EB-2010-0377 consultation is concerned with distribution system planning and prioritization. This regional planning consultation, for its part, will examine the more specific circumstance of how a particular infrastructure need can be addressed through regional planning among utilities. The Board referenced this regional planning initiative in the December 17, 2010 letter regarding the RRF, noting that “[T]he Board will also assess whether planning by distributors and transmitters might yield more efficient and effective outcomes if conducted on a more coordinated and regional basis.” The two consultations will be conducted in parallel, and will be managed with a view to ensuring that they result in a principled and cohesive framework.

On January 13, 2011, and further to a directive received from the Minister of Energy, the Board initiated a consultation on guidance to be provided to licensed electricity transmitters and distributors (among possible others) in relation to the implementation of a smart grid (EB-2011-0004). Among other things, the directive requires the Board to consult for the purpose of developing a regional or otherwise coordinated approach to the planning and implementation of smart grid activities. There will be some common ground between the *Smart Grid consultation* and this broader regional planning initiative which covers regional planning for purposes beyond smart grid implementation. It is expected that these two projects will be managed in a manner that results in a cohesive framework and optimizes the use of stakeholder resources. 

External to the Board, in its *IPSP Planning and Consultation Overview* report³ issued in May 2011, the OPA discusses its regional planning activities. The report explains that the OPA attempts to address local and regional supply adequacy and reliability needs through joint regional planning studies with distributors, transmitters, and the Independent Electricity System Operator (“IESO”). The OPA notes that these activities are conducted outside the IPSP as they require a high degree of coordination with distributors to develop integrated plans that potentially involve distributed generation, infrastructure investments, and conservation activity opportunities. The OPA’s regional planning projects that are currently active include: 

³ <http://www.powerauthority.on.ca/sites/default/files/page/IPSP%20Planning%20and%20Consultation%20Overview.pdf> (see p.5-5). The list of OPA regional planning activities set out in this Discussion Paper differs from the OPA IPSP document. The list was revised based on discussions with OPA staff after the IPSP document was issued.

- Kitchener-Waterloo-Cambridge-Guelph (“KWCG”) area
- Central-Downtown Toronto
- York Region
- Windsor-Essex
- Ottawa


Board staff’s understanding is that the OPA’s joint regional planning studies will identify options that distributors and transmitters may wish to pursue, and will be subject to consultation amongst a broader group of stakeholders before being finalized. Board staff also understands that the studies are relatively high level in nature, as the OP  does not engage in matters related to distribution system planning.

1.4 The Consultation Process

This consultation process is being conducted in stages.

The first stage was a stakeholder meeting which was held on May 12, 2011. The purpose of that meeting was to provide a forum for discussion on topics such as:

- objectives for regional planning;
- a status check on current practice;
- best practices for regional planning and examples of successful processes;
- cost responsibility for optimized, regional infrastructure projects; and
- the identification of any barriers to regional planning in the current regulatory framework and how these may best be addressed.

The stakeholder meeting was attended by representatives of transmitters, distributors, ratepayers, municipalities, the IESO and the OPA. Relatively detailed meeting notes that summarize stakeholder input at the meeting were posted on the Board’s website .

This Board staff Discussion Paper is the next step in this consultation process. In developing this Discussion Paper, Board staff has built on the input provided during the stakeholder meeting as well as on written comments provided by stakeholders in the


⁴ http://www.ontarioenergyboard.ca/OEB/ Documents/EB-2011-0043/StakeholderMeeting-Notes_RegionalPlanning_20110512.pdf

early stages of the TCCRR consultation on cost responsibility for load connections to transmission systems (EB-2008-0003) discussed above.⁵

The final stage in this consultation process will be consultations regarding proposed amendments to the Board's regulatory instruments that will embody the Board's policy on regional planning. The consultation process is discussed in more detail in the Board's cover letter related to this Discussion Paper.

The balance of this Discussion Paper is organized as follows:

- Chapter Two provides an overview of the current cost responsibility and planning framework in the TSC, discusses the underlying principles and identifies stakeholder concerns raised at the recent stakeholder meeting and during the TCCRR consultation process.
- Chapter Three discusses the potential reclassification of certain transmission assets and associated options.
- Chapter Four presents Board staff's proposed approach to facilitate regional planning as well as potential options to address barriers to regional planning that have been identified by stakeholders.

This Discussion Paper sets out questions in relation to which stakeholder input is specifically requested. [Appendix 1](#) provides a list of all of those questions. Participants should, however, feel free to comment on any aspect of this Discussion Paper. 

⁵ These comments can be found on the Board's website at:
<http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Transmission+Connection+Cost+Responsibility+Review/Transmission+Connection+Cost+Responsibility+--+Subs>

2 CURRENT REGULATORY FRAMEWORK: COST RESPONSIBILITY, PLANNING POLICY AND UNDERLYING PRINCIPLES

The TSC governs transmitters in relation to, among other things, planning and cost responsibility for new or modified assets. At a high level, the framework as set out in the TSC can be captured by the following four points:

- Treats all transmission load customers – industrial and distributor – the same in relation to cost responsibility. In the normal course, load customers (including distributors) would pay a capital contribution for Connection asset upgrades to the transmission system, which are triggered by the load customer.⁶ In the case of a distributor, this includes upgrades that are required as a result of the connection of renewable energy generation facilities to the distributor's distribution system;
- Requires a transmission capacity evaluation process to be undertaken when the available capacity on a Connection facility falls below a certain pre-set percentage of total normal supply capacity;
- Does not require transmission customers to pay a capital contribution for Connection asset upgrades that, at the relevant time, were 'otherwise planned' by the transmitter, except for any advancement costs; and
- Does not require transmission customers to pay a capital contribution in relation to upgrades to Network assets, which benefit all customers in Ontario, except in exceptional circumstances.

The remainder of this Chapter includes a discussion of the Board's principles underlying the current framework, followed by a more detailed discussion of the high level framework set out above.

⁶ An economic evaluation is performed and any shortfall is paid as a capital contribution, calculated as: the cost of the new investment (capital cost + present value (PV) of O&M costs for the study horizon) less the PV of the revenue received from the load customer over the same study horizon.

2.1 Principles Underlying the Current Framework

As noted in Chapter 1, this consultation is intended to assist the Board in developing a regulatory framework for regional planning in a manner that is consistent with the principles articulated in earlier consultations related to the TSC, as well as the principles listed in Chapter 1. Board staff therefore believes it would be beneficial to discuss the principles articulated by the Board in earlier consultations.

Also discussed below are stakeholder concerns and additional principles suggested at the stakeholder meeting and/or during the early stages of the TCCRR consultation.

2.1.1 Two Basic Principles: Cost Causality and “Beneficiary Pays”

The Board’s current cost responsibility policy, as reflected in the TSC, is generally based on two regulatory principles – cost causality and “beneficiary pays”. The following is a discussion of these principles and how they help shape the current cost responsibility policy contained in the TSC.

The cost causality principle is quite straightforward. The transmission customer(s) that cause(s) or trigger(s) the costs related to new or reinforced infrastructure should bear those costs. This principle, expressed in current cost responsibility rules, provides an incentive to transmission customers to seek new or reinforced infrastructure only when the benefits to them are greater than the costs they must incur. Under this principle and the associated cost responsibility rules, it will usually be the case that customers will pay their direct costs of connecting to the Network.⁷

Stakeholders have, however, noted that complications can arise when new or modified connection investments are made. In some cases, a connection to the transmission grid can result in beneficial effects to other parties that use the transmission system (e.g., increased reliability or reduced congestion). In other cases, a connection investment may trigger reinforcements to the Network that might impose costs on other customers. Sometimes both can happen. In such cases, a cost responsibility rule strictly based on cost causality will not necessarily achieve the most efficient outcomes from an overall system perspective. The connecting customer will consider only the

⁷ These direct costs are usually called “shallow costs” – the costs associated only with the customer’s physical connection to the transmission system. These costs are distinguished from “deep costs” – the costs of any upgrade to the Network that is needed as a result of the connection.

cost it has to pay and the benefits that it expects to receive – not the benefits and costs affecting other parties. In some cases, the costs and benefits to other parties could be significant.

The possible complications discussed above are primarily the result of the “lumpiness” associated with certain infrastructure investments – infrastructure tends to come in only discrete sizes and tends not to be available in small percentage increments. This is particularly true for transmission lines in Ontario, which are generally limited to only three voltages: 115kV, 230kV, and 500kV. Allocating the costs of an upgrade to the party who has directly triggered the need for it at a given moment in time does not specifically account for earlier connections that have also cumulatively contributed to the need for the upgrade.

The “beneficiary pays” (or “user pay”) principle can help to correct problems that arise with a cost allocation rule derived solely from the cost causality principle. This principle states that those customers that benefit from a new or upgraded infrastructure investment should pay their share of the costs of that investment. Once operationalized into rules, the “beneficiary pays” principle can help support greater economic efficiency in several ways. One is by controlling free-riding – those who do not pay but use and benefit from the infrastructure investments once they are made. If these benefits to other parties are not identified and taken into account, and a strict rule derived from cost causality holds, then beneficial cost-effective investments might not get made. Such an outcome would be inconsistent with the Board’s goal for this initiative – optimized solutions in the long term.

One way the TSC currently strives to address the “lumpiness” of transmission investments discussed above is in section 6.2.24. Under that section, where a customer has made a capital contribution that includes the cost of capacity on a Connection facility that is not needed by that customer, the customer is entitled to a refund if that additional capacity is assigned to another load customer within the subsequent five years. However, if that assignment occurs after five years, there is no such reimbursement and subsequent customers that benefit from the Connection asset are able to avoid contributing to the cost. Section 6.3.9 of the TSC is of similar intent, as is section 6.3.17. The latter section is related to excess capacity that is included on the Connection facility in order to comply with facilities standards or good utility practice. Section 6.3.9 is related to capacity which is added for the purpose of any future customer(s) that the transmitter is aware of.

One concern raised by stakeholders is that the beneficiary pays principle essentially ceases to apply after expiry of the five year period. Another concern identified at the stakeholder meeting is that certain connection investments can have numerous beneficiaries, but these beneficiaries are often difficult to identify. As a consequence, costs cannot be allocated in a manner that appropriately takes into account all of the beneficiaries. Examples of such transmission assets that were identified by stakeholders include 230/115 kV auto-transformers and the associated switchgear. It was therefore suggested by some stakeholders that such assets should be reclassified as Network assets to facilitate these investments. This suggestion is further discussed in Chapter 3.

Board staff notes that the Board has recognized in the past that assets such as 230/115 kV auto-transformers are unique and the Board has identified that an adjustment to cost responsibility should be made for them where they are Connection assets.⁸ The Board also noted in that case that “the use of auto-transformers is seen as a means to optimize use of the transmission system, as a whole, in accommodating new loads safely and reliably and, most of all, in a timely manner”. However, a common theme at the stakeholder meeting was the concern that the Board decides on such adjustments to cost responsibility at the end of the process, as part of a leave to construct application, after the investment decisions must be made. According to these stakeholders, this uncertainty regarding the outcome may result in such investments not being made, even if desirable in terms of optimizing the use of the transmission system.



2.1.2 Efficient Transmission System Growth

If the cost causality and beneficiary pays principles together can jointly support efficient decision-making with respect to transmission system reinforcements and expansions, then an important regulatory goal would be achieved. This regulatory goal was expressed by the Board in its September 7, 2007 Decision and Order in a combined proceeding regarding the connection procedures of Hydro One and GLP (the [“Connection Procedures Decision”](#)) as follows:



“This structure is an expression of another key concept which underpins the Code. That principle is that the system should grow and be

⁸ The Board's September 7, 2007 Decision and Order in a combined proceeding regarding the connection procedures of Hydro One and GLP (EB-2006-0189 and EB-2006-0200), pages 24-25.

reinforced and enhanced in a planned and cost effective manner. This means that the transmitter needs to develop, in concert with other responsible agencies, an orderly and “right-sized” approach to system growth and reinforcement.


Where an individual customer has a pressing local requirement, which does not form part of a planned reinforcement, or which requires an advancement of a planned enhancement, the Code provides for a method to impose, in a manner that is fair to all of the competing interests, an appropriate capital contribution. In this way the “user-pay” and cost causality principle can be implemented in a manner that permits expansion of the system, but does not encourage overbuild. Those responsible for unplanned reinforcements must bear some responsibility for the costs associated with such projects.”⁹

An additional principle which was the focus of much discussion at the stakeholder meeting and relates to some of the stakeholder concerns discussed above was the need for greater “regulatory certainty” in relation to investments in the transmission system. Stakeholder emphasis on where “regulatory certainty” seemed to be lacking most was in relation to one specific provision in the TSC; specifically, section 6.3.6 – the “otherwise planned” provision. It is discussed in the next section below which describes the current TSC framework in more detail.

2.2 The Current TSC Framework and Stakeholder Concerns


2.2.1 “Otherwise Planned” Provision - Section 6.3.6 of the TSC

The most prominent concern amongst participants at the stakeholder meeting in relation to the TSC was related to section 6.3.6 of the TSC, which states:

A transmitter shall develop and maintain plans to meet load growth and maintain the reliability and integrity of its transmission system. The transmitter shall not require a customer to make a capital contribution for a connection facility that was otherwise planned by the transmitter, except for advancement costs. 


⁹ Connection Procedures Decision, page 22, paragraphs 1 and 2.

The rationale underlying section 6.3.6 of the TSC was described in the Connection Procedures Decision as follows:

“Section 6.3.6 of the Code is an expression of the concept that an individual customer ought not to bear any unique responsibility for projects within established plans for things such as additions or improvements to the system for **reliability and integrity improvements** which have been already identified and planned  by the transmitter, except for any additional costs associated with the advancement of the improvements at the request of the customer.”¹⁰
(emphasis added)

At the same time, the Board also acknowledged that there can be ambiguity in relation to the application of section 6.3.6:

“...[T]here can be ambiguity with respect to whether an enhancement of the system is one which is designed primarily to address system integrity and reliability issues as identified by the transmitter, on the one hand, and those which are primarily of benefit to one or a small group of customers who have a pressing local need, on the other.... That ambiguity is most easily resolved where the transmitter can demonstrate that the enhancement was identified as part of its planning process and not merely because a customer has requested it. To be clear, where planning involves joint studies between Hydro One and one or more distributor(s) to meet different timing and supply needs such as load growth, the Board views such plans as customer-driven, where a capital contribution would be required.”¹¹

The Connection Procedures Decision in effect holds that the distinction between “system needs” and “customer needs” can be operationalized by finding the former in plans developed by transmitters, independent of the requirements of a specific customer or a small group of customers within a local area (e.g., through a joint plan with distributors), for the purpose of maintaining system reliability and integrity. 

¹⁰ Connection Procedures Decision, page 21, paragraph 7.

¹¹ Connection Procedures Decision, page 22, paragraphs 3-4.

Some participants at the stakeholder meeting expressed the view, however, that joint regional plans/studies should constitute “a plan” for the purposes of section 6.3.6, and that a capital contribution should therefore not be required in such cases. These stakeholders noted that effective and efficient regional planning involves joint planning studies between a transmitter and more than one distributor, as such joint studies are needed to determine the optimal mix of transmission and distribution solutions. According to these stakeholders, the Board’s distinction between “system needs” and “customer needs” could therefore be viewed as a barrier to efficient planning and the achievement of the goals articulated by the Board for this regional planning initiative.

In the excerpt above from its Connection Procedures Decision, the Board noted the ambiguity can be easily resolved where the transmitter can demonstrate that the enhancement was identified as part of its planning process. However, a number of participants at the stakeholder meeting, including transmitters, also noted that there is a lack of clarity and certainty regarding what constitutes a transmitter’s plan for the purpose of section 6.3.6. It was also noted that the determination of what is ‘otherwise planned’ occurs too late in the process, and is left to be determined on a case-by-case basis. According to these participants, this lack of regulatory certainty can also present an additional barrier to optimal infrastructure investment decisions.

It was further noted by stakeholders that certain recent Board decisions related to section 6.3.6 can send the wrong signal to distributors. Specifically, these stakeholders noted that if the distributor *cooperates* in joint planning with the transmitter in clearly identifying its long term needs, the distributor (and hence its customers) may be *penalized* via the requirement to pay a capital contribution (because it was the “trigger”). On the other hand, if the distributor does *not cooperate* – intentionally understates its true transmission needs (to avoid being the “trigger”) – and makes short-term sub-optimal investments in the distribution system until such time as its needs are met in “a plan” of the transmitter, then the distributor (and hence its customers) may be *rewarded* by avoiding the capital contribution. However, no specific “real life” examples were identified by stakeholders to demonstrate that this is in fact occurring.

Board staff notes that some of these concerns are of relatively long-standing, having been raised in the context of the Connection Procedures Decision and subsequently in a motion to review (EB-2007-0797) related to that Decision. In its November 26, 2007 Decision and Order on the motion to review, the Board stated as follows:

“This panel also acknowledges that the Connection Procedures Decision has not eliminated all uncertainty with respect to the application of section 6.3.6 of the Code. However, the Connection Procedures Decision does provide parameters around what the Board might consider to be a transmission plan for purposes of that section of the Code and, in that regard, provides guidance where none existed before. In addition, the issue of cost responsibility remains subject to Board oversight in the context of leave to construct applications or rate applications, as the case may be depending on the nature of the facilities in question. Absent more prescriptive rules in the Code, certainty is not obtained until those processes have been completed.

...

The parties to this proceeding have raised, both now and during the Combined Proceeding, questions of transmission policy that are better addressed in a policy process than they are in a review hearing. The Board as a whole is aware of the issues, and it remains open to the Board to initiate such a process if it considers that to be necessary or desirable at this time.”

Board staff believes that this regional planning initiative is an opportune occasion to suggest that the Board consider re-examining this specific provision of the TSC. To that end, Board staff proposes potential changes to section 6.3.6 in Chapter 4 which strive to enhance regulatory predictability, increase consistency with the Board's beneficiary pays principle and facilitate achievement of the Board's objectives for this regional planning initiative.

2.2.2 The Available Capacity Procedure


A key aspect of the transmission planning process in Ontario in relation to Connection assets is a transmitter's available capacity procedure. The TSC requires each transmitter to have an available capacity procedure as part of its overall connection procedures. Sections 6.2.6 and 6.2.9 of the TSC require a transmitter to determine the total assigned capacity and monitor the available capacity on its Connection facilities, from time to time, as required. The *available capacity* of a Connection facility is the amount of new load (in MW) that could be served by that facility. As set out in section 6.2.7 of the TSC, it is equal to the *total normal supply capacity* of the Connection facility

minus the total *assigned capacity* on that facility (the capacity that has been assigned to the load customers that use the facility).

As load grows on a given Connection facility, assigned capacity will rise and available capacity will decline. When available capacity falls to 25% of total normal supply capacity, the transmitter must implement its available capacity procedure. This procedure must, among other things, identify the circumstances under which an expansion study will be carried out. As such, available capacity serves as an indicator to signal when a Connection facility may need to be upgraded.

A key step that a transmitter takes in order to determine whether there is a need for an expansion of a Connection facility is to estimate the potential capacity requirements of all customers that are connected or are expected to be connected to that facility, as set out in section 6.2.14 of the TSC. This element of the available capacity procedure helps facilitate transmission planning.

In order to assist the transmitter with planning, the standard form Connection Agreement for load customers – Appendix A to the TSC (section J.3.2) – requires that the customer notify the transmitter, by October 1st of each year, of any anticipated “material” increase or decrease in: (i) load in relation to each connection point during the following year; and (ii) the customer’s peak demand (winter or summer) for each delivery point.

A transmitter noted at the stakeholder meeting that it often currently must rely on obtaining municipal land use plans, where possible, for long term transmission planning purposes. This transmitter raised the following question. Municipalities undertake long term planning when new subdivisions are introduced for the purpose of making infrastructure investments in water and sewer systems. Why is it not the same for infrastructure investments in the electricity system under the Board’s rules related to  planning? Board staff were not able to answer that question and notes it is a relevant question since the three core infrastructure requirements of any new subdivision involve water, sewer and electricity.

A related concern noted at the stakeholder meeting is that the current regime tends to focus on short-term planning while optimal investments require long-term planning and there is a planning disconnect between transmission and distribution. For example, from a transmitter’s perspective, the size of a new line should be large enough to meet

the long-term future needs of all distributors in an area (such as a 230 kV line instead of a 115 kV line), which tends to be beyond the planning horizon and needs of most individual distributors.¹² Proceeding with the higher cost investment that meets the transmitter's longer-term horizon also raises an affordability problem for the distributors who must consider the bill impact on their residential and business consumers of a larger associated capital contribution, as the current cost responsibility rules for Connection lines require up-front recognition of a large portion of the costs.¹³ It was identified by multiple stakeholders that the ultimate result is planning discussions often being delayed because of the difficulties in dealing with affordability and "who pays" issues, with the latter related to section 6.3.6.

A transmitter also noted that, for the most part, industrial customers do not give rise to the same issues in terms of the planning process. For example, industrial customers tend to be clear in relation to their future needs since they need to operate their businesses and electricity only represents a portion of their production costs.

2.2.3 Should All Transmission Customers Continue to be Treated the Same?

The load customers of transmitters are typically divided into two groups: directly connected distributors and directly connected industrial customers.



Currently, these two types of transmission customers are essentially treated in the same manner in the TSC. However, some stakeholders have suggested that these two groups should be treated differently from a transmission connection cost responsibility perspective. This section discusses the differences between distributors and industrial customers that could potentially justify differing cost responsibility treatment.

Stakeholders have pointed out that distribution systems grow in an "organic" fashion as the loads of individual customers grow within a distributor's service area and as new customers are connected. In addition, it was noted at the stakeholder meeting that distributors have much less control over their load growth since it depends on the actions of their end use customers. Furthermore, under amendments to the Electricity

¹² According to the OPA, a 230 kV line accommodates about 400 MW. Based on monthly data provided by the IESO (for the 12 month period from May 2010 to April 2011), 400 MW is greater than the maximum peak load of 87% of distributors in Ontario including distributors such as Kitchener-Wilmot Hydro, Burlington Hydro and Oakville Hydro.

¹³ Less the present value (PV) of revenues based on the additional loads served, if any, which can be a small amount compared to the capital investment.

Act made by the GEA, distributors have a statutory obligation to connect renewable generation facilities subject to applicable technical, economic and other requirements.¹⁴ Distributors are therefore now in the process of connecting large numbers of renewable energy generation facilities to their distribution systems as result of the operation of the OPA's Feed-in Tariff ("FIT") program. Experience to date is that this new generation is nearly all intermittent in nature (e.g., solar or wind) and is increasing distributor requirements for transmission connection capacity. Distributors can also upgrade their distribution systems to forestall the need for a transmission connection modification.

In contrast, industrial customers tend to experience discrete changes in energy demand, which are most often planned and over which they have full control as a result of business planning and investment decisions. These discrete, planned changes in energy demand are often "lumpy" in the same way that the transmission solutions tend to be. As such, the costs and benefits of the customer's transmission connection typically occur at the same time, are closely identified with each other, and are apparent in the customer's planning and business decision-making. In addition, if an industrial customer decides to invest in load displacement generation, it has a choice over the type and location of that generation. Board staff expects that an industrial customer would invest in generation that is not intermittent in nature in order to reduce its demand and therefore its requirements for transmission connection capacity. Unlike distributors, industrial customers can also choose where to locate their load facilities.

In addition, as noted above, the general message from the stakeholder meeting was that industrial customers do not present the same issues as distributors in relation to the transmission planning process.

In Board staff's view, for the reasons noted above, there is not a strong case to be made for changing the status quo in relation to industrial customers. The costs and benefits arising from industrial customer connections seem most likely to fall largely on the customers themselves, and thus efficient outcomes can continue to be expected under the status quo.

The remainder of this Discussion Paper will therefore focus primarily on potential changes and options that relate solely to distributor customers of transmitters. At the same time, Board staff recognizes the importance of ensuring that any proposed changes to the framework in relation to distributors do not have negative and/or

¹⁴ The same statutory obligation applies to transmitters.


unintended implications for industrial customers, who in some cases share Connection facilities with distributors. Certain changes to the current transmission cost responsibility regime in relation to industrial customers may therefore be desirable depending on the nature of any changes that the Board ultimately adopts in relation to distributors.

3 POTENTIAL RECLASSIFICATION OF CERTAIN LINE CONNECTION ASSETS

Prior to the discussion of Board staff's proposed approach to regional planning and potential cost responsibility options, Board staff believes it is important to also address another common concern raised at the stakeholder meeting. That is, the suggestion that certain transmission assets currently included in the Line Connection pool should be shifted to the Network pool because they perform Network functions and/or provide benefits to customers beyond those customers to whom the Connection assets are currently attributed. Stakeholders have noted that this is the case because, among other reasons, the transmission system is constantly evolving.

The example that best illustrates the evolution of the transmission system is related to certain Line Connection assets. During the days of Ontario Hydro, the 115 kV system, which is currently part of the Line Connection pool, formed the initial Network.

Board staff also notes that the attribution of transmission assets to the various pools was completed over a decade ago in the Board's RP-1999-0044 proceeding, and has not been re-examined on a generic basis since that time. This represents a relatively long period of time, and some stakeholders have also suggested that the initial attribution of certain assets was somewhat arbitrary.

Staff also notes that, based on stakeholder input, the current classification of certain Line Connection assets may provide distributors with a disincentive to fully cooperate in the regional planning process and an incentive to implement less costly alternative investments in their distribution systems that may be sub-optimal from an overall system perspective. To the extent this is the case, the outcome(s) would be contrary to the Board's goals for this regional planning initiative. 

Staff notes that stakeholder concerns regarding the classification of transmission assets were limited to certain assets in the Line Connection pool. As there appear to be no similar concerns in relation to assets in the Transformation Connection pool, the focus of the following discussion is on transmission assets included in the Line Connection pool.

[Appendix 2](#) provides a brief overview of the different types of transmission assets and includes a simplified graphic showing the transmission system. It provides useful context for the discussion that follows.

3.1 Connection Assets with Broad Beneficiaries

The concern identified by stakeholders is that the TSC does not include a provision to take into account the evolutionary nature of the transmission system and therefore the changing functions of certain Line Connection assets. Stakeholders also noted a concern related to the inconsistent treatment of certain transmission assets across Ontario.

One type of asset identified in this regard is 115/230 kV auto-transformers as previously discussed in section 2.1.1. An example is the four auto-transformers in the New Hamburg area which benefit customers throughout the entire Niagara region. Based on discussions with representatives of Hydro One, it would be virtually impossible to determine the relative benefits to the various transmission customers in that region associated with that Line Connection asset. Staff also notes that, if one distributor triggered the need for a fifth auto-transformer, that distributor (and hence its customers) would be required to pay the entire capital contribution (which would be quite significant)¹⁵ while the benefits of the new transmission asset would be realized by customers throughout the Niagara region which includes about 9 – 10 distributors and their respective customers. Stakeholders also identified the switchgear associated with the auto-transformers as a further example of a Line Connection pool asset that has numerous beneficiaries and that contributes to optimizing the use of the transmission system.¹⁶

Another consideration is that there is some inconsistency in relation to the allocation of assets into the different pools. For example, the 230/115 kV auto-transformer at the Hawthorne TS is the same size and performs the same transmission function as the 230/115 kV auto-transformers at New Hamburg but is currently defined as a Network

¹⁵ The cost of a new 230/115 kV auto-transformer is approximately \$10 million.

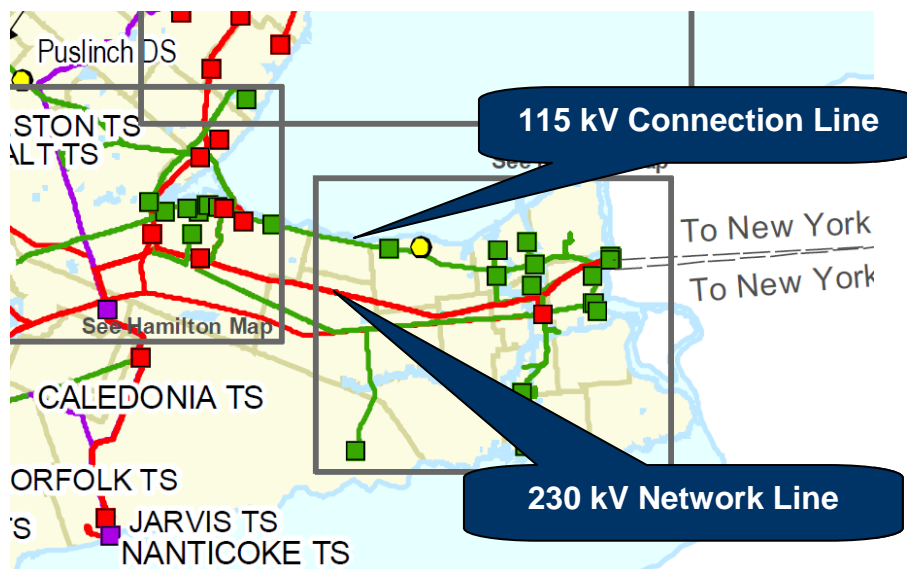
¹⁶ Switchgear is an integral part of the power system and refers to electrical facilities which allow the connection of multiple power system elements (e.g., lines, transformers, capacitors, etc.) to typically a common electrical point. Switchgear includes bus conductors, circuit breakers, switches, disconnects and associated monitoring and control facilities. It performs the switching (energization and de-energization) of power system elements for normal operations, maintenance and protection of equipment during electrical disturbances. Switchgear essentially acts as hubs throughout the power system that connect the various elements and permit the flow of power from one part of the system to another.

asset. As a result, if an upgrade were to be required to the Hawthorne auto-transformer, the relevant distributor (and hence its customers) would not be similarly required to provide a capital contribution.

According to representatives of Hydro One, there are approximately 90 such auto-transformers throughout the Hydro One system and almost half of the 230/115 kV auto-transformers are already categorized as Network assets while the other half are Connection assets.

3.2 115 kV Connection Lines that Provide Network Benefits

Stakeholders also noted that there are a number of very long 115 kV lines that are currently defined as Line Connection assets but often perform Network functions and therefore benefit many transmission customers. Board staff followed up with representatives of Hydro One regarding examples of such 115 kV lines. One example runs along the bottom of Lake Ontario from OPG's Beck generating station to Hamilton parallel to a 230 kV Network line (the green line in the map below denotes that 115 kV Connection line, while the red line running parallel is a Network line).



Hydro One staff noted that the 115 kV Connection line, in the map above, is configured to allow electricity to flow to customers in the rest of Ontario beyond the distributors connected to that 115 kV line when the 230 kV Network line is overloaded or maintenance is required. Other examples of such relatively long 115 kV Connection

lines include those connecting Niagara to London, Burlington to Kitchener and London to Sarnia.

Under the current cost responsibility rules, which tend to focus on cost causality (i.e., the “trigger”), if all of the capacity on such a 115 kV line has been assigned and a distributor requires incremental capacity, the line would either need to be upgraded or a second 115 kV line could be required. In such a case, as the “trigger” of that investment, the distributor would be required to provide a significant capital contribution, which would ultimately be borne by only its customers. Under such circumstances, Board staff believes that a distributor would have a strong disincentive to cooperate in transmission planning and may strive to implement less costly alternative investments in its distribution system – even if they are sub-optimal from an overall system perspective and less cost-effective in the longer term – to avoid a more costly capital contribution.

The following are options that may address such situations:

- a. Some utilities suggested that such Line Connection assets should be re-assigned to the Network pool in order to: facilitate cooperative and effective regional planning, to recognize that such transmission assets often serve to benefit customers beyond the customers of the distributors connected to them and to facilitate optimal use of the transmission system.
- b. An alternative option that was not discussed at the stakeholder meeting would involve the reclassification of such Line Connection assets as “Dual Function Lines”.¹⁷ This would recognize that, while sometimes they function as Network lines, they only benefit the distributors connected to the 115 kV line some of the time. This approach appears to be more consistent with the Board’s beneficiary pays principle than option (a) above.

Staff also notes that the Board has already defined certain transmission lines as Dual Function Lines.¹⁸ As such, this approach to reclassification would not

¹⁷ While OPA staff did not go into detail at the stakeholder meeting, OPA staff did suggest that the Board should make greater use of dual-function asset treatment. Board staff believes this option is consistent with that OPA suggestion.

¹⁸ The introduction of the concept of Dual Function Lines on a broad scale was approved by the Board in Hydro One’s EB-2006-0501 transmission rate proceeding. It addressed the Board’s concerns associated with the Line Connection pool in the RP-1999-0044 transmission rate proceeding where the Board had stated that it expected the definition of the Line Connection pool to be reconsidered in Hydro One’s next cost allocation and rate design proceeding.

represent a new concept in Ontario. However, staff is uncertain regarding how difficult it would be for the transmitter to determine with precision the extent to which such lines function as Network assets rather than as Connection assets. This would itself likely change from year to year for a variety of reasons including changes in system conditions. Staff is therefore uncertain of the degree of administrative burden this approach would impose on the transmitter.¹⁹

At the stakeholder meeting, it was also suggested that the option of reallocating certain Line Connection assets that currently perform Network functions from the Line Connection pool to the Network pool be taken a step further to also reallocate Line Connection assets that are not currently providing Network functions but are expected to do so sometime in the future. Board staff's concern with this proposal is that it may involve a great deal of speculation and could result in cost responsibility being attributed in a manner that departs from the underlying principles articulated by the Board as discussed in Chapter 2. Staff notes that it may be a more than a decade until the functionality of the asset changes or the functionality may never change in manner that is consistent with current expectations. During that time, the customers that benefit from those assets would be subsidized by customers that do not benefit. At the same time, Board staff acknowledges that the transmission system evolves over time in terms of functionality and agrees that it would be appropriate for the TSC to take this into account.

In the next Chapter, as part of Board staff's proposed approach, staff identifies its preferred approach in relation to reclassifying certain Line Connection assets, which includes recognition of the evolutionary nature of the transmission system on a going forward basis.

¹⁹ Existing Dual Function Line (DFL) costs are currently allocated based on the relative amount of the transmission customer's coincident peak (CP) load connected and the minimum capacity of the DFL. Specifically, it is calculated as: *Proportion Allocated to Line Connection portion of DFL = (Monthly DFL Customer CP Demand) divided by (Minimum DFL Capacity)*. This value (and therefore the allocation of costs between the Network and Line Connection pools) is updated each time a transmission rate application is filed and is calculated based on the forecast customer demand.

4 BOARD STAFF'S PROPOSED APPROACH AND POTENTIAL COST RESPONSIBILITY OPTIONS

This Chapter sets out Board staff's proposed approach to the implementation of regional planning, and a discussion of various options that staff believes will facilitate the achievement of the Board's goals in relation to establishing a framework for regional planning.

The primary focus of Board staff's proposed approach relates to the establishment of a framework for the implementation of regional planning. Following that is a discussion of various options that could address the potential barriers to regional planning in Ontario that have been identified by stakeholders. Those options include proposed changes to section 6.3.6 of the TSC, the potential reclassification of certain Line Connection assets as well as changes to the current cost responsibility rules in the TSC.

It is important to note that some of the options essentially represent alternative approaches that would result in similar outcomes. For example, if the Board were to proceed with the reclassification of certain Line Connection assets, there would appear to be little need to alter the costs responsibility rules that are currently set out in the TSC, aside from section 6.3.6 of the TSC. Similarly, if the Board were to adopt changes associated with certain options that would result in capital contributions no longer being required from distributors in relation to Line Connection investments included in a regional plan, the issues associated with section 6.3.6 of the TSC may no longer subsist as far as facilitation of regional planning is concerned.

Board staff's consideration of the current framework is discussed prior to the discussion of staff's proposed approach. Those considerations include some potential issues that were not specifically raised by stakeholders.


4.1 Board staff's Consideration of the Current Framework

Board staff agrees with the comments made by stakeholders to the effect that under the Board's rules:


- (a) distributors should not have an incentive to make less costly sub-optimal investments (from a longer-term perspective) in their distribution systems as an alternative to paying a capital contribution for a more optimal transmission connection upgrade; and
- (b) regulatory predictability (i.e., minimizing case-by-case determinations) is an important objective in order to facilitate a more efficient planning process and more optimal outcomes.

Staff notes that the current framework appears to place much of the planning burden solely on the transmitter. As previously discussed, in order to assist the transmitter with planning, the standard form Connection Agreement ("CA") for load customers requires that each customer (e.g., distributor) notify the transmitter of any anticipated "material" increase or decrease in load in relation to each connection point during the following year. Staff notes, however, that "material" is not defined in the TSC (including the CA) and is subjective in nature. It is therefore left largely to the discretion of the customer. A transmitter and its customers may therefore define "material" differently. In addition, in regard to a shared Connection facility (i.e., a number of transmission customers are connected to it), what may be immaterial from the perspective of each customer in isolation may be relatively material from the transmitter's perspective when collectively aggregated across all of the customers sharing that Connection facility.

Staff also notes that the requirement to provide information regarding material changes in load relates only to a one year period under the current CA requirement. Board staff suggests that information regarding changes in load over a longer period could better support longer term planning by the transmitter and the development of optimized solutions. Board staff is aware that, in some other jurisdictions, load customers are required to update transmission planners with near and long-term forecast information on a regular basis. The planning implications of the more limited forecasting obligation set out in the current CA are reflected in Hydro One's Board-approved Available Capacity Procedure in the following terms:


While the projection of future available capacity is intended to be helpful to Hydro One and to its customers, it must be noted that such estimates are not required under the Transmission System Code, and given the quality of the information 

used to prepare them, **they should not be relied upon for planning purposes.**²⁰ *(emphasis added)* 

In Board staff's view, when the current regime was put in place in 2005, placing the transmission planning burden largely on the transmitter would not have been a major issue. At that time, the transmission system was expanding in a relatively organic and predictable manner based on load growth. However, with the introduction of the GEA and the OPA's FIT program, distributors are now in the process of connecting significant amounts of intermittent renewable energy generation. This is increasing the transmission connection capacity requirements of distributors, as well as having other upstream impacts such as creating the need for increased short circuit capability. 

Board staff therefore believes that a coordinated joint planning approach between transmitters and distributors is desirable in relation to transmission planning in order to achieve the objectives articulated by the Board. Under such an approach, additional obligations would need to be placed on distributors, as set out in more detail below.

Based in part on stakeholder input, staff also believes that coordinated joint planning will be facilitated by ensuring that distributors have the appropriate incentives to fully cooperate with the transmitter by clearly identifying their longer term needs as well as any potential distribution solutions that may be more optimal and cost-effective than a transmission solution.

Staff believes that the achievement of the Board's goals for regional infrastructure planning would also be supported by increasing the emphasis on the beneficiary pay principle in terms of cost responsibility. As a consequence, there would be less emphasis placed on cost causality (i.e., the "trigger"). 

Board staff notes that a potential issue that was not raised at the stakeholder meeting is associated with the first come, first served approach to the allocation of available capacity in the TSC. The current approach may place too much emphasis on cost causality (i.e., "trigger" pays) and this has the potential to result in outcomes that are in conflict with the Board's principle of "beneficiary pay" (or "user pay"). The following simplified example is provided for illustrative purposes. In the example, two transmission customers (e.g., distributors) both require additional capacity and the remaining available capacity on the Line Connection facility that they share is about 40

²⁰ [Hydro One, Transmission Connection Procedures](#), page 17.

MW. Distributor A requires 3/4 of that available capacity (30 MW) and it is assigned to that distributor by the transmitter, leaving approximately 10 MW of unassigned capacity. Distributor B then advises the transmitter a short time later that it requires half as much additional capacity (15 MW). Under the current cost responsibility rules, Distributor B would be the “trigger” of the upgrade and would therefore be required to provide a capital contribution while a similar capital contribution would not be required from Distributor A. The costs associated with the capital contribution would be passed on to the customers of Distributor B, however, those customers would not be “benefitting” any more from the transmission system than the customers of Distributor A. In such a case, Distributor B may have an incentive to make short-term sub-optimal investments in its distribution system until such time as the transmitter has planned an expansion to the Connection facility and section 6.3.6 (“otherwise planned”) applies.


In the same vein, Board staff also suggests that section 6.3.6 of the TSC should be re-examined through the lens of an increased emphasis on the beneficiary pays principle in order to facilitate effective joint regional planning. For example, two distributors can have the exact same transmission connection needs. The transmitter may have “otherwise planned” a Connection asset upgrade that accommodates the needs of one distributor but may not have “otherwise planned” an upgrade that accommodates the needs of the other distributor. In such cases, the customers of the latter distributor would pay a capital contribution while the customers of the former distributor would not pay at all (other than advancement costs, if applicable). However, the customers of both distributors would benefit equally from the transmission system upgrades. In such a case, the latter distributor may have an incentive to make short-term sub-optimal investments in its distribution system.

Board staff’s proposed approach, as described below, therefore reflects a greater emphasis on the beneficiary pays (or user pays) principle and less emphasis on which transmission customer is the “trigger” of a Connection asset upgrade.²¹ In staff’s view, this approach can provide more appropriate incentives and better support the achievement of the goals articulated in the Board’s April 2011 Letter.


²¹ The U.S. Federal Energy Regulatory Commission (“FERC”) recently issued [Order No. 1000](#). The focus of that FERC Final Rule is also regional transmission planning and cost allocation. Placing greater emphasis on the “beneficiary pays” principle is consistent with FERC’s approach in that Final Rule. FERC identified six principles in Order No. 1000. FERC’s “Cost Allocation Principle 1” is “*Costs Allocated in a Way That is Roughly Commensurate With Benefits*” and “Cost Allocation Principle 2” is “*No Involuntary Allocation of Costs to Non-Beneficiaries*”.

4.2 Board staff's Proposed Approach: A Regional Planning Framework

This section sets out Board staff's proposed approach to joint regional planning, proposed changes to section 6.3.6 of the TSC and the potential reclassification of a relatively small subset of certain Connection assets. Section 4.3 discusses some potential options in relation to cost responsibility.

Staff proposes that a requirement be introduced that entails joint planning between distributors and transmitters in relation to distributor connections to the transmission system. Specifically, all licensed distributors and transmitters would be required to engage in joint planning exercises, share information regarding distributor connection issues, and identify optimal connection solutions among alternatives involving transmission and distribution investments.²² This obligation would be implemented on a regional basis, and given effect either through amendments to the DSC and TSC or via licence amendments. 

All distributors within a region would provide the transmitter with information related to their forecast transmission connection capacity needs at the same time. This would take into account both projections of load and the amount of generation expected to be connected to each distributor's system. On that basis, the transmitter would be able to assess the respective transmission needs of the distributors within a region collectively. Given that the information would be provided at the same time, it would also avoid the situation discussed above in section 4.1 involving the Distributor A and Distributor B example.

The information provided by the distributors to the transmitter would be in relation to both the near term (covering one year) and longer term (covering a minimum of five years), with the near term forecast more detailed in nature. The five-year horizon is consistent with the timeframe associated with the filing requirements for "GEA Plans" that the Board currently requires distributors to submit in relation to renewable energy generation connections and the development of the smart grid.²³ Some stakeholders suggested that 20-25 year load forecasts should be provided. However, staff notes two difficulties: (1) based on previous experience in Ontario with such forecasts, the 

²² These proposed requirements would not be limited to distributors that are transmission customers. It would also apply to embedded distributors as they can also contribute to the need for transmission connection upgrades.

²³ [Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence \(EB-2009-0397\)](#).

accuracy of such forecasts would be questionable; and (2) staff questions whether the incremental benefit for planning purposes would outweigh the burden placed on distributors associated with providing 20-25 year forecasts on a regular basis. Staff also notes that KPMG found that, within the context of distributor planning in Ontario, smaller distributors identified that it was difficult to predict load growth beyond five years and anything beyond that was not useful.²⁴ Staff further notes the proposed five year forecasts would represent a minimum time horizon (i.e., could be for a longer period of time) and they would supplement any 25 year forecasts that a distributor must provide to a transmitter for the purposes of conducting an economic evaluation in relation to new or modified Connection assets.

Regional plans would be required to take into account the relevant land use planning documents for the applicable five year period.²⁵ Those documents would typically include municipal “Official Plans” as well as supporting documents that identify expected future development (e.g., new subdivisions) and indicate the pace/probability at which that future development is likely to occur.²⁶ It would be the expectation that each distributor in the region would obtain such land use planning documents from the appropriate authority (typically the municipality) in its service area for the purpose of providing the pertinent information to the transmitter.²⁷

This joint infrastructure planning exercise would commence after the appropriate mix of generation, conservation and transmission/distribution infrastructure has been

²⁴ KPMG found that distributor planning in Ontario ranged from 5-15 years, with smaller distributors identifying it was difficult to predict load growth beyond 5 years and anything beyond 5 years was found not useful. KPMG also noted “*for large utilities, we would expect that high-level demand forecasts and capital plans be prepared with a time horizon of 15 or more years.*” KPMG Review of Asset Management Practices in the Ontario Electricity Distribution Sector, March 2009, page 10.

²⁵ At the stakeholder meeting, Hydro One discussed the value of land use plans for the purpose of transmission planning and their coordination with the Region of Peel which resulted in Peel setting aside the necessary land for a future transmission line.


²⁶ “Official Plans” are required to be prepared and adopted under the [Planning Act](#). An Official Plan must contain the “goals, objectives and policies established primarily to manage and direct physical change and the effects on the social, economic and natural environment of the municipality or part of it, or an area that is without municipal organization”. The *Planning Act* [section 26(1)] requires that, at least every five years, an Official Plan must be reviewed and revised as required.

²⁷ Staff has not proposed specific documents for the following reason. The specific nomenclature used by municipalities, regions, etc. across Ontario in relation to these supporting documents related to land use planning likely differs. For example, York Region has a “Master Plan” for water and sewage infrastructure. Board staff’s rationale for proposing such supporting documents is relying solely on the use of historical population and employment growth may suggest an increase in demand for electricity infrastructure that is overstated. For example, water or wastewater infrastructure may be nearing its current system capacity limits. As such, the required *actions* (e.g., infrastructure investments) and the *timing* of those actions to support the forecast future population and employment growth over the long term will be an important consideration. The York Region Master Plan discussed a “phased” approach.

determined, and would focus on the transmission/distribution infrastructure element of such an integrated plan. One basis for commencing joint planning could be the completion of a regional plan under the OPA's integrated regional planning activities. Alternatively, the joint infrastructure planning exercise could occur in conjunction with an OPA integrated regional planning activity to facilitate the process. However, in Board staff's view, completion of a regional plan under the OPA's integrated regional planning activities would not necessarily be a prerequisite. For example, staff expects there will be regional plans focusing on infrastructure needs in areas of the province where the OPA does not intend to initiate an integrated regional planning process. In addition, the appropriate mix of generation, conservation and infrastructure could be determined through other processes (e.g., IPSP).

Board staff proposes that the basis upon which optimal transmission and distribution solution(s) would be determined would entail the combination of transmission and distribution solution(s) with the highest Net Present Value (NPV).²⁸ This would result in the solution(s) that meet(s) the need(s) of the distributors within a region at the lowest overall system cost over the long term.

Board staff proposes that Filing Requirements be developed for the regional plans. It is proposed that the Filing Requirements mandate that the regional plans would include all of the transmission and distribution solutions that were considered and evaluated, as well as the solution(s) that was selected as the optimal solution(s). Transmitters and distributors would be required to submit the regional plan as supporting evidence when they submit a leave to construct application or certain cost of service applications to the Board. Distributors would only be required to submit the regional plan as part of a cost of service application where one or more distribution solution(s) were identified in the distributor's service territory as the optimal solution(s) as part of the regional plan.²⁹

If a regional plan would trigger the allocation of costs to generators that are connect  or are in the process of connecting to a distribution system, it is proposed by staff that the applicable generators would be consulted before the regional plan is finalized.

²⁸ The NPV approach was suggested at the stakeholder meeting. This approach is consistent with the Board's current approach in relation leave to construct applications, as identified in [Filing Requirements for Transmission and Distribution Applications, Chapter 5, page 35](#).

²⁹ Where applicable, distributors would also be required submit such a regional plan as supporting evidence when they submit a capital module as part of an IRM application.

Staff proposes that an updated forecast of load and generation – both near term and long term as set out above – be provided by distributors to the transmitter at least every five years. Each distributor would also provide the relevant land use planning documents to the transmitter if they have been updated or revised by the applicable authority in the distributor’s service area. Following the completion of an initial regional plan, staff also proposes that the regional plan be reviewed at least once every five years for the purpose of determining if the plan needs to be updated. This proposed approach is not intended to mean that a regional plan could not be updated on a more frequent basis, if necessary (i.e., a transmission connection upgrade triggered by an unforeseen increase in load connecting to a distributor such as a large industrial customer). Nor is it intended to mean that an updated forecast of load and generation could not be provided to the transmitter on a more frequent basis.

A potential scenario that may arise under the process outlined above is that it may be determined by the Board that a regional plan filed by one utility, but involving a number of distributors as well as the transmitter, needs to be revised. For example, revision may be necessary if the plan was not completed in accordance with the Filing Requirements or it is determined that the option(s) selected in the regional plan is/are not the optimal solution(s) (i.e., lowest overall system cost in the long term). As a consequence, under such a scenario, the processes related to rate applications and/or leave to construct applications involving a number of regulated entities could be delayed until the regional plan is revised and the concerns have been addressed.

An option that may assist in reducing the likelihood of such an outcome is if the entities involved in the development of the plan were to consult more broadly before a regional plan is finalized. The focus would be on the regional plan and would occur in advance of the filing of any rate application or leave to construct application to which the plan is relevant. This would provide an opportunity for other parties to raise any major concerns they may have and to explore the merits of the plan. Consistent with the scope of these regional plans any such consultation would not delve into alternatives to the infrastructure investments identified in the plan (e.g., CDM, distributed generation).

Issue for Comment:

- 1) Staff requests general feedback on the proposed approach discussed above.
- 2) Staff has proposed that an obligation be placed on distributors to provide the transmitter with an updated forecast and the relevant land use planning documents (where applicable) at least every five years and for a period covering at least five years. In relation to the provision of the relevant information, should it be more frequent? Should the forecast cover a longer minimum period of time than five years (e.g., 10, 15 years)?
- 3) In cases where a transmitter is requested by distributors to be involved in the development of multiple regional plans at the same time, what criteria should be used by the transmitter for determining the prioritization of the regional plans in the event of transmitter resource constraints?
- 4) Do distributors foresee any problems in relation to obtaining the relevant land use planning documents from the applicable authority in their service area for the purpose of providing those plans to the transmitter? If so, please explain.

4.2.1 How should “Regions” be Determined? 

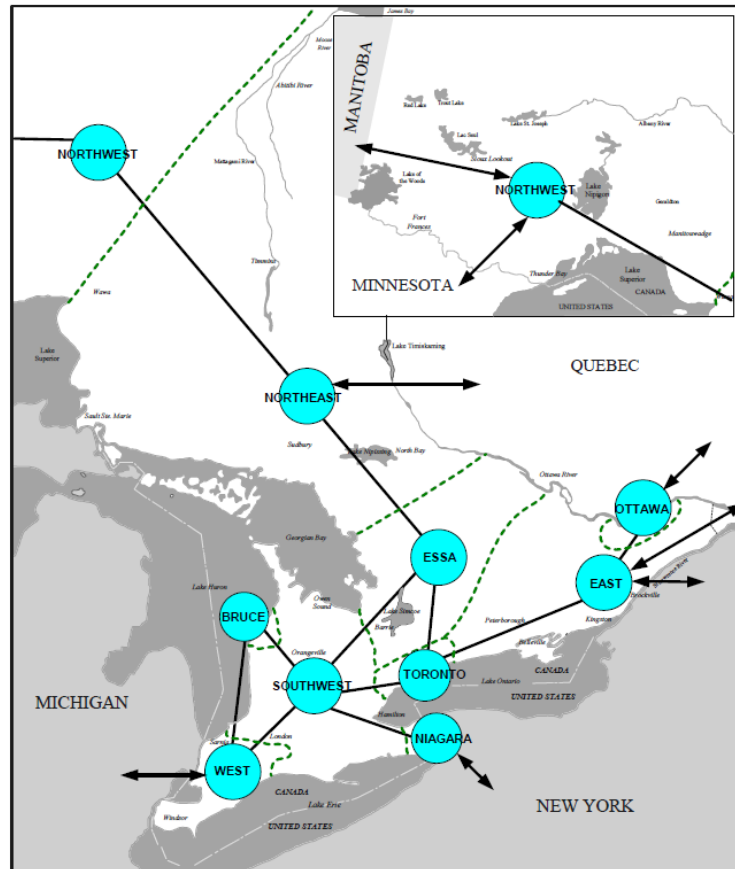
Implementation of a regional planning approach will ultimately require the determination of appropriate regions in Ontario. There are numerous ways in which regions could be defined for the purpose of this regional planning initiative. Regions could range from being quite broad to relatively small. Various potential approaches are discussed below, with Board staff’s preferred approach being discussed last.

Board staff agrees with the common view expressed at the stakeholder meeting which was that regions should be determined based upon transmission asset functionality as opposed to individual distributor service area boundaries. Staff notes that this approach will result in certain distributors potentially being included in more than one region. This appears to be unavoidable, regardless of the approach taken, given some of the distributor mergers/amalgamations that have been completed and resulted in a distributor serving a relatively large non-contiguous geographical area; e.g., Veridian Connections (Durham, Gravenhurst), Horizon Utilities (Hamilton, St. Catharines), etc.

Comments of Kitchener-Waterloo-Cambridge-Guelph (“KWCG”) at the stakeholder meeting seemed to suggest that the regions may need to be relatively broad. KWCG is currently the focus of one of the OPA’s integrated regional planning initiatives and one of the KWCG representatives appeared to indicate that the infrastructure requirements went beyond the distributors involved in that planning exercise.

There are few documents related to Ontario’s electricity system that break down Ontario into regions. One is the “Ontario Transmission System” documents that are issued by the IESO, as a complement to the transmission assessments contained in the IESO’s 18-Month and Ontario Reliability Outlooks. The “Ontario Transmission System” documents divide the Ontario transmission system into ten zones, with zonal boundaries chosen to correspond with major interfaces. The resulting map is reproduced below.³⁰ Based on discussions with IESO staff, these zones are largely based on electricity flows and serve as a demarcation for purposes of monitoring and measuring the reliability of the transmission system.


³⁰ [IESO, “Ontario Transmission System”, May 24, 2011.](#)




Board staff recognizes that the zones identified in the IESO “Ontario Transmission System” reports, as set out in the map above, are used more for the purpose of planning the bulk Network system and may be too broad in some cases for the purposes of this regional planning initiative. This is particularly the case for northern Ontario. Board staff suggests that the regional demarcations identified by the IESO may nonetheless provide a relevant starting point for determining appropriate regions (some likely smaller than the ones used by the IESO) in the context of this initiative given the direct relationship to transmission system reliability.

Another possible approach would be to determine the regions on the basis of regional municipality/county/district boundaries in Ontario (e.g., Peel, York, Simcoe, Parry Sound, etc.).³¹ This may facilitate the integration of the land use planning and electricity infrastructure planning exercises, which Board staff believes to be a desirable outcome. It would ultimately require coordination between the distributor(s) and the municipality or other applicable authority. As the Board noted in its April 2011 Letter, “a

³¹ A full list of all the regions, districts and counties in Ontario can be found on the website of the Association of Municipalities of Ontario (AMO) at: <http://www.amo.on.ca/YLG/yhg/ontario.html>.


coordinated solution is desirable as allowing for a consideration of broader needs and for involvement by a larger set of stakeholders”. While the Board cannot require a municipality to take into account a regional plan related to electricity infrastructure, Board staff believes it would be beneficial if the municipality did so in order to ensure infrastructure investments are coordinated and to ensure electricity can be supplied to the businesses and residents within the municipality over the long term. Under this approach, however, the regions would likely not be based on transmission asset functionality. 

An alternative approach would be to avoid predefining regions for the purpose of determining regions for this regional planning initiative and, instead, rely on the future electricity infrastructure needs of more than one distributor being identified as the trigger for the development of a regional plan, as the needs arise. This ad hoc approach, which essentially represents the status quo, would allow for greater flexibility, but seems somewhat reactive and unstructured. In Board staff’s view, a proactive and more structured long term planning regime would likely be more appropriate.

A potential hybrid approach, and the one preferred by Board staff, would involve the establishment of relatively broad ‘predefined’ regions across Ontario. These regions would be determined by the Board for the purpose of distributors providing the necessary information to the transmitter related to their expected transmission infrastructure needs as proposed above in section 4.2. Some distributors within a ‘predefined’ region will identify future transmission needs while other distributors may not. The development of a regional plan would then entail involvement of the subset of distributors that identified a future need working with the transmitter in the planning process. As such, the sole purpose for determining ‘predefined’ regions would be for the flow of information from distributors to the transmitter. Under such an approach, there could be multiple regional plans within a broad ‘predefined’ region. An example of where this may be the case is if the service territories of the distributors within a broad ‘predefined’ region that identified a future need were not contiguous. An option for the ‘predefined’ regions in relation to this transmission planning initiative could be the zones identified by the IESO above since they are directly related to reliability of the transmission system. Staff believes this approach would bring some structure to the regional planning process while maintaining flexibility. 

It is important to note that the manner in which a region is defined is not necessarily linked to cost responsibility (i.e., regional pricing).

Issues for Comment:

- 
- 5) Are any of the approaches discussed above appropriate for determining suitable regions for the purpose of regional planning? Why or why not?
 - 6) In relation to the approaches discussed above, are there any proposed modifications that would enhance their suitability?
 - 7) Are there any other criteria, beyond transmission asset functionality, that should be used in the determination of appropriate regions within Ontario for regional planning purposes?
 - 8) Are there other alternative approaches that could be used to determine appropriate regions? If so, please identify the proposed regional structure and explain the rationale and benefits associated with the proposed approach including reasons why it may be more suitable than Board staff's preferred approach.

4.2.2 Proposed Reclassification of Certain Connection Assets

In relation to the proposal of a number of participants at the stakeholder meeting that certain Connection assets be reclassified as discussed in Chapter 3, staff agrees that the reclassification of assets such as 230/115 kV auto-transformers and the associated switchgear is desirable in order to optimize use of the transmission system. Such reclassification involving assets where there are multiple beneficiaries would be consistent with the beneficiary pays principle and support achievement of the Board's goal of optimal investments for this regional planning initiative.

Staff notes that, in its Connection Procedures Decision the Board recognized the unique function of such assets. The Board noted:

"These unique system elements in some instances accommodate loads that are beyond a customer's requirement (e.g., autotransformers connecting the 230 kV transmission system to the 115 kV transmission system) In particular, use of autotransformers is seen as a means to optimize use of the transmission system

as a whole in accommodating new loads safely and reliably and, most of all, in a timely manner.”³²


Given the relatively significant cost of a 230/115 kV auto-transformer for a single distributor,³³ continuing to define such transmission assets as Line Connection could create incentives for distributors to make less costly short term investments in their distribution systems to avoid a significant capital contribution, even though the distribution investment is sub-optimal within the context of the overall system.

4.2.2.1 Reallocation of Assets with Broad Beneficiaries to the Network Pool

Board staff believes that reallocating a small subset of Connection assets to the Network pool will: (i) support the Board’s goal of achieving optimal transmission and distribution solutions over the long term; (ii) more appropriately recognize the broader group of beneficiaries of those assets and thus better reflect the beneficiary pays principle; and (iii) address the issue identified by stakeholders related to the inconsistent treatment of certain transmission assets in the province (e.g., treated as Network assets in about 50% of the cases and as Line Connection assets in the other 50%). The capital contributions provided by distributors, where they are currently Line Connection assets, are ultimately recovered from only their end use consumers.

Board staff therefore proposes that all 230/115 kV auto-transformers and the associated switchgear be classified as Network assets.³⁴

4.2.2.2 Reclassification of 115 kV lines

In relation to the stakeholder proposal that certain relatively long 115 kV Connection  lines that perform a Network function also be reclassified, as discussed in Chapter 3, staff agrees that it would be appropriate to make the necessary changes at this time that would facilitate the appropriate classification of new 115 kV lines or reclassification

³² Connection Procedures Decision, page 24-25.

³³ As noted earlier, the cost of a 230/115 kV auto-transformer is approximately \$10 million.

³⁴ If the Board were to consider such a change to be desirable, the Board could commence a proceeding to amend the rate order of each transmitter following this consultation process to implement this change. This would be similar to the process previously used by the Board to implement a policy decision in the last broad review of the TSC (RP-2002-0120) related to increasing the qualifying limit for exemption from gross billing for renewable generation from 1 MW to 2 MW per unit. In that instance, the policy decision was made in the [Phase I Policy Decision](#) (page 43) and the Board subsequently identified in its [Notice of Proposal](#) to issue a revised TSC (Dec. 17, 2004) that it would be implemented by means of an amendment to the applicable transmission rate order.

of existing Line Connection assets that begin to provide Network functions in the future through periodic reviews as discussed in more detail below. In addition to the benefits noted in section 3.3.1, this approach should also result in more equitable treatment across distributors (and hence end use consumers across Ontario). For example, some distributors in Ontario have a relatively straightforward and short radial connection to the transmission Network and do not also have cost responsibility for long lines such as those previously identified.

However, in terms of existing 115 kV lines that currently provide Network functions, Board staff does not believe that this consultation is the appropriate process in which to address their reclassification. Board staff believes that a more appropriate process would be a generic rate proceeding focused specifically on this issue.³⁵ Staff notes that the RP-1999-0044 proceeding was a rate proceeding where the transmission assets of Hydro One were initially allocated to the different pools. At the present time, Board staff is only aware of a limited number of such lines, and suggests that the reclassification of assets in an appropriate manner would require a comprehensive review of all 115 kV Connection lines to ascertain which ones across the province also provide Network functions and therefore should be reclassified. As such, Board staff is proposing that the Board consider making a policy decision in this consultation process in relation to reclassifying existing Connection lines that can be demonstrated to provide Network functions. Staff further proposes that the purpose of the generic rate proceeding would then be related to the implementation of that policy decision (i.e., comprehensive review and determination of the specific existing Connection lines that provide both functions and are to be reclassified).

In terms of how the relevant 115 kV lines should be reclassified, of the two options discussed in Chapter 3, Board staff believes the more appropriate approach is to classify such lines as Dual Function Lines where they perform both a Connection and a Network function.³⁶ The costs would therefore be allocated to both the Line Connection and Network pools based on the extent each relevant asset is used for Connection vs. Network purposes. While reclassifying such 115 kV lines as Network assets would be simpler from an administrative perspective, Board staff believes that the Dual Function Line approach is more consistent with the Board's principles and with past practice in defining transmission assets.

³⁵ Reclassification could also be addressed through the next cost of service application of each transmitter.

³⁶ As previously noted, Board staff believes the preferred approach is consistent with input provided by the OPA in relation to making greater use of dual-function asset treatment.

To recognize the evolutionary nature of transmission systems on a going forward basis, Board staff suggests that provisions be incorporated in the TSC (or another Board regulatory instrument) to provide for periodic reviews of the operation of Line Connection assets.³⁷ For example, the Board could conduct a review every five years to ascertain if a 115 kV Connection line is providing Network benefits at that time and should be reclassified from Line Connection to a Dual Function Line.³⁸ Alternatively, transmitters could propose the reclassification of specific Line Connection assets in each transmission rate application, if and where appropriate.

In supporting the proposal of stakeholders to reclassify certain Line Connection assets, Board staff believes that reclassification will facilitate more optimal planning and investment decisions. Reclassifying certain Line Connection assets should also place distributors (and therefore all Ontario ratepayers) on a more level playing field in terms of cost responsibility. Staff believes that this has the potential to provide a stronger foundation on which to build in relation to establishing a framework for regional planning.

³⁷ Staff is proposing this approach rather than the one suggested by certain stakeholders under which Connection assets would be classified now based on the expectation that they will perform a Network function some time in the future.

³⁸ To the extent it is demonstrated that certain Line Connections should be reclassified, the reclassification would need to be implemented through a transmission rate proceeding following such a review.

Issues for Comment:

- 9) Do stakeholders agree that assets such as *230/115 kV auto-transformers* and the associated *switchgear* should be reallocated to the Network pool? If not, why not and what other approaches might be considered to achieve consistency across Ontario?
- 10) Do stakeholders believe that *115 kV lines* should be classified as Dual Function Lines or as Network lines where they perform both a Connection and a Network function? Please explain the rationale for the approach supported.
- 11) Should the Board consider reclassifying any other Line Connection assets beyond *115/230 kV auto-transformers*, the associated switchgear and certain *115kV lines* for the purpose of facilitating regional planning? If so, please identify those assets and explain why the current classification could present a barrier to regional planning.

4.2.3 Proposed Changes to Section 6.3.6

This section discusses Board staff's proposed changes to section 6.3.6 of the TSC, which involves limiting the circumstances in which that section would apply and providing a more objective basis for its application.

Section 6.3.6 presently reads as follows:

6.3.6 A transmitter shall develop and maintain plans to meet load growth and maintain the reliability and integrity of its transmission system. The transmitter shall not require a customer to make a capital contribution for a connection facility that was otherwise planned by the transmitter, except for advancement costs.

As articulated by the Board in its Connection Procedures Decision, a focus of section 6.3.6 is cost responsibility for projects within established plans that address the maintenance of reliability and system integrity. Board staff believes the uncertainty arising from this section of the TSC results largely from the reference to "load growth". As such, Board staff is proposing that the reference to "load growth" be removed from

section 6.3.6, which staff believes would enhance regulatory predictability while retaining the focus on planning to maintain reliability and system integrity.³⁹ In addition, staff notes that this change would also recognize that circumstances have changed since 2005, with transmission Connection asset upgrades required by distributors also being driven by the connection of renewable energy generation facilities at the distribution level (i.e., no longer limited to only load growth).

At the same time, as demonstrated in a number of leave to construct cases, there can often be a great deal of debate regarding which investments are needed for reliability and system integrity purposes. In order to further enhance regulatory predictability, Board staff also proposes consideration of the following options:

- i. Section 6.3.6 be limited to transmission Connection investments that are necessary to satisfy the reliability requirements set out in the IESO's [Ontario Resource and Transmission Assessment Criteria](#) document. That document identifies the technical criteria for use in the assessments of the adequacy and security of the IESO-controlled grid and clarifies how the IESO will apply relevant reliability standards and implement them in Ontario. Section 5 of that IESO document sets out "*Transmission Connection Criteria*" and specifically requires that "*new or modified facilities must satisfy all NERC standards, Regional Reliability Council Criteria, and the requirements of the OEB's "Transmission System Code", the "Market Rules" and associated standards, policies, and procedures*"; and
- ii. A change to section 6.3.6 comprised of listing all the specific circumstances in the TSC under which section 6.3.6 would apply (e.g., change in NERC standards applicable to Connection facilities).

Board staff expects that the implementation of a regional planning regime in Ontario comprised of coordinated infrastructure planning between transmitters and distributors across the province should result in a material reduction in the need for transmitters to "otherwise plan" transmission investments (i.e., plan Connection investments in the absence of any input from distributors). As a consequence, both options discussed

³⁹ As noted above, in the Connection Procedures Decision the Board stated that section 6.3.6 of the TSC is "an expression of the concept that an individual customer ought not to bear any unique responsibility for projects within established plans for things such as additions or improvements for reliability and integrity improvements which have been already identified and planned for..."

above are intended to result in section 6.3.6 only being triggered under limited or exceptional circumstances.⁴⁰

Issue for Comment:


- 12) Of Board staff's proposed changes to section 6.3.6 discussed above, which would better achieve the intended goal of resulting in greater regulatory predictability? If the latter option (ii), please propose the list of specific circumstances.
- 13) Are there other alternative changes to section 6.3.6 that the Board should consider? If so, please explain the change in detail and identify the benefits.
- 14) What would the advantages and disadvantages be associated with removing section 6.3.6 from the TSC altogether, as an alternative to the options Board staff proposed above? If section 6.3.6 were to be removed, would other changes to the TSC also be required as a consequence?

4.3 Cost Responsibility Options

This section considers several options for cost responsibility policies in relation to load connections, and evaluates each in terms of the extent to which they promote the following three objectives: (1) economic efficiency; (2) the protection of consumer interests; and (3) regulatory predictability and administrative efficiency.

4.3.1 Objectives

Economic Efficiency

Economic efficiency is one of the Board's guiding objectives under the OEB Act  Specifically, item 2 of section 1(1) of the OEB Act states that the Board is to be guided

⁴⁰ This proposed approach is consistent with the views expressed by the Board in its Connection Procedures Decision in relation to section 6.3.6. On page 21 of that Decision, the Board described the application of section 6.3.6 (i.e., not requiring a capital contribution) as a "qualified exception" and noted "It is clear that, taken as a whole, section 6.3 of the Code ... provides that in almost all cases where the transmitter is enhancing its equipment to accommodate the needs of a line connection, a capital contribution will be required from the ... customers who benefit from the enhancement."

by the following objective: “to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry”.

The key way in which load connection cost responsibility policy options will be assessed in relation to enhancing economic efficiency in the use and expansion of transmission is the extent that they promote effective joint regional planning by distributors and transmitters and optimal approaches to load connection issues.



Protection of Consumer Interests

Protection of consumer interests is another one of the Board’s guiding objectives under the OEB Act. Specifically, item 1 of section 1(1) of the OEB Act states that the Board is to be guided by the following objective: “To protect the interests of consumers with respect to prices, and the adequacy, reliability, and quality of electricity service.”

In some ways, this objective overlaps with the economic efficiency objective. However, one way it can take on a distinct meaning in the context of load connection cost responsibility is to move further towards the beneficiary pays (or “user pays”) principle under which, to the extent practicable, the costs of new and/or upgraded connections to the Network should be paid by the customers that benefit (i.e., enhance allocative efficiency). As such, it is proposed that less emphasis would be placed on cost causality, which allocates the costs based on the customer that “triggers” an upgrade, but which does not necessarily reflect the degree to which various customers use or benefit from the upgrade.

In relation to protecting the interests of consumers, Board staff believes that the equitable treatment of end use consumers across Ontario is an important objective. Within the context of transmission connection cost responsibility, the focus tends to be on the costs allocated to the distributor. Often lost in the discussion, with the focus on the distributor as the transmission customer, is that the costs allocated to distributors are ultimately passed on to their end use consumers.

Regulatory Predictability and Administrative Efficiency

Regulatory predictability relates to the ability of stakeholders to understand how and the basis upon which regulatory decisions are likely to be made. It can be influenced by the number of regulatory determinations or proceedings that are required in relation to a given issue. In the case of load customer connections, a clear rule on cost

responsibility that limits the need for case-by-case determinations can enhance regulatory predictability. However, there is also a risk that highly prescriptive rules could lack sufficient flexibility to handle varying fact situations. In Board staff's view, the most appropriate approach will likely focus on what works best for the majority of distributors while maintaining some flexibility to address exceptions.

Administrative efficiency relates to the level of effort required from the perspective of proponents and other interested parties for effective participation in the Board's processes.

Regulatory predictability and administrative efficiency facilitate investment, planning and decision-making by project proponents and helps them to better manage project risks.

Issues for Comment:

- 15) Are there any other criteria that should be used in addition to the above for the evaluation of approaches in relation to load connection cost responsibility?

4.3.2 Analysis of Cost Responsibility Options

Board staff have identified three broad approaches to load connection cost responsibility, as well as two sub-options. These approaches are as follows:

- Status quo
 - Status quo sub-option: Smoothing option
- Full Pooling option
 - Pooling sub-option: Basic service option
- Hybrid option


Staff notes that no concerns were raised in relation to cost responsibility for Transformation Connection assets. It was noted at the stakeholder meeting that the problems of cost scale and multi-party benefits do not relate as much to transformation stations because they can be more easily sized and up-sized to meet the needs of the specific transmission customer. As such, all of the approaches to cost responsibility

discussed below are intended to be limited to the Line Connection assets, including the Full Pooling option.

4.3.2.1 Status quo

The status quo is included as a benchmark against which other options can be compared. Under the status quo, cost responsibility for load connections resides with the customer (e.g., distributors), subject to the section 6.3.6 “otherwise planned” exception.

Strengths

- Provides maximum scope for conservation and demand management (“CDM”) and demand response approaches, as it does not incent a potentially inefficient high recourse to rely on infrastructure solutions. 

Weaknesses

- As discussed earlier in this Discussion Paper, some stakeholders have expressed concern that the status quo would hinder rather than promote effective long term planning between distributors and transmitters. Therefore, it may not promote the optimal choice of solutions between distribution and transmission. As such, it may also not result in economically efficient outcomes.
- The concern of some stakeholders regarding the lack of regulatory predictability associated with section 6.3.6 discussed earlier in this Discussion Paper would remain.


The weaknesses discussed above assume that none of the other potential changes previously set out in this Discussion Paper are implemented (e.g., changes to section 6.3.6, reclassification of certain Line Connection assets, etc.).

4.3.2.2 Status quo sub-option: Smoothing option

This option would be similar in every way to the status quo except distributors would no longer be required to provide an upfront capital contribution. Instead, the amount that would have been recovered through a capital contribution would be recovered by the transmitter over a period of 20 years from the applicable distributor(s) through a rate rider. This is similar to an option recently proposed by the Alberta Electric System Operator (“AESO”) in relation to distributors.⁴¹

⁴¹ The Alberta Utilities Commission (“AUC”) recently initiated a new proceeding entitled “[Electric Transmission Contribution Policy Proceeding](#)”. One of the primary objectives identified in the AUC letter

Strengths

- Same as status quo, except it would smooth cost recovery over time (i.e., avoid large lump sum capital contributions by distributors).
- It would be more equitable from an intergenerational equity perspective since cost recovery would more closely match the life of the asset 

Weaknesses

- Same as status quo, except additional administrative burden for the transmitter due to the need to administer multiple rate riders.

4.3.2.3 Full Pooling option 

This option was suggested by certain distributors at the stakeholder meeting. It would fully eliminate capital contributions by distributors for all new or modified Line Connections, including where a distributor is the sole beneficiary of a Line Connection. As a result, all Line Connection costs would be shifted to the Network pool and be recovered from all Ontario ratepayers through transmission rates.⁴²

A pooling sub-option referred to as the “*Basic Service option*” is discussed further below.


Strengths

- Enhances regulatory predictability and administrative efficiency given the lack of a need for regulatory determinations regarding the appropriate cost allocation.
- Facilitates a joint regional planning process, as there would be no adverse cost consequences for a distributor as a result of clearly identifying its needs.
- Avoids the issues identified in relation to section 6.3.6 of the TSC – no determination of whether a connection investment is “otherwise planned” would be needed as all costs would be recovered on pooled basis anyway.
- Avoids the potential need to reclassify Connection assets as Network or Dual Function assets (as discussed in section 4.2.2).


is to: “*Examine the underlying principles that create a requirement for customers to contribute capital, and specifically how the application of that principle should be used to determine contributions between two regulated utilities which already have underlying obligations to provide service*”. The option proposed by the AESO is part of that proceeding.

⁴² This would not include Line Connection upgrades triggered solely by a generation connection(s) at the distribution level. These costs would be recovered from the applicable generator(s) through a capital contribution.

Weaknesses

- A potentially inefficient high recourse to rely on transmission solutions. A distributor would have a disincentive to investigate solutions within its distribution system even if they may be more optimal, since the cost of a transmission solution would be spread across ratepayers throughout the province rather than being passed through to customers in the distributor's service area.
- Less emphasis on CDM initiatives due to greater reliance on transmission solutions. 
- Largely incompatible with the Board's cost causality and beneficiary pays principles.
- Inconsistent with the Board's goal of facilitating contestability in relation to Connection assets, as the transmitter would likely be responsible for building all Line Connection assets.
- Some distributors may desire "premium" connections (e.g., underground) while others would opt for less costly connections (e.g., overhead). The customers of the latter distributors would subsidize the former.
- Shifts in cost burdens from faster growing to slower growing regions (e.g., from southern Ontario to northern Ontario regions).
- Greater reliance on regulatory proceedings as the main avenue for cost discipline in relation to Line Connection assets.
- Would likely necessitate a separate Line Connection pool for industrial / commercial customers to avoid cross-subsidization, since industrial customers would still pay capital contributions while distributors would not.

As discussed previously in section 2.2.1, another option was suggested at the stakeholder meeting that would have a somewhat similar outcome to the Full Pooling option. That is, in cases where the investment or investments are contained in a regional plan, the investment(s) would be deemed to qualify as "otherwise planned" under section 6.3.6. As such, all of the Line Connection costs associated with the distributors involved in the regional plan would be paid by ratepayers across the province through the Network rate. This approach would appear to have all of the same strengths and weaknesses discussed above within the context of the Full Pooling option. An additional potential "weakness" associated with this approach is that all distributors involved in a regional plan would avoid capital contributions for Line Connections included in the regional plan, while all distributors not involved in a regional plan would still pay a capital contribution where a Line Connection upgrade is needed.

This approach therefore has the potential to result in the inequitable treatment of distributors (and therefore their end use customers) across Ontario. Given this approach would result in cost recovery from all provincial ratepayers (i.e., non-  beneficiaries) of all Line Connection investments included in plans and it would also result in a greater reliance on regulatory proceedings as the main avenue for cost discipline in relation to those investments, this approach may necessitate formal Board approval of all regional plans.

4.3.2.4 Pooling sub-option: Basic service option

The “Basic Service option” was originally proposed by Hydro One as a possible option in the early stages of the TCCR consultation.⁴³

In this option, a basic level of connection service would be available to all distributors on a pooled basis. The basic level of service would be determined based on criteria such as maximum distance to the grid and single circuit supply. This approach is similar to the current approach in the DSC, where the costs of a basic connection are (residential customers) or can be (non-residential customers) recovered through rates, whereas “above basic” connection costs are recovered by means of a variable charge levied on the connecting customer.

This approach would take into account the possibility that some distributors may desire a higher standard and more costly connection (e.g., underground connection), while other distributors may opt for a less costly solution. As such, distributors desiring to have a higher standard of connection (or “Premium Service”) would be required to provide a capital contribution to cover any costs that exceed the cost of the basic level of service.

Strengths

- Similar to those for the Full Pooling option, whenever basic service applies.
- Would avoid cross-subsidization in cases such as the underground example discussed above. Therefore, more equitable across consumers than the Full Pooling option.
- Relative to the Full Pooling option, the reliance on regulatory proceedings for cost discipline is reduced by the fact that pooling only applies to the least cost approach (i.e., basic level of service).

⁴³ EB-2008-0003 – [Hydro One Networks' Initial Comments and Submissions](#), February 11, 2008, p.6-7.

Weaknesses

- Not as simple in terms of cost allocation relative to the Full Pooling option.
- Similar to those for the Full Pooling option whenever basic service applies (except as noted above), but to a lesser degree as only part of the cost is pooled.

4.3.2.5 Hybrid option

Board staff has identified a further option that was not discussed at the stakeholder meeting nor has it been proposed in an earlier consultation. This “hybrid” option represents a middle ground between the status quo and the Full Pooling option discussed above.

Under the hybrid option, a distributor would only be required to provide a capital contribution for the radial lines that connect its system to the transmission system, whether that is a connection to a 230 kV Network line or another 115 kV Connection line. A distributor would also be required to provide a capital contribution for a Connection line that is not necessarily a radial line but where it is evident that the distributor is the sole user of the line. The costs associated with upgrades to the remaining 115 kV Connection lines that provide Network functions would be recovered through transmission rates on a pooled basis via the Line Connection pool.⁴⁴ The fact that the costs are recovered through the Line Connection pool rather than the Network pool or both pools distinguishes this approach from the options related to the reclassification of assets described in section 4.2.2. Otherwise, the connection cost responsibility impact or effect of the two proposals is the same.

Under this approach, to clarify how it would work, in considering the Niagara region example discussed in section 3.2, distributors in that region would no longer be required to provide a capital contribution in relation to upgrades to the long 115 kV line that extends from the Beck hydroelectric station to the Hamilton area and provides a Network function. In other words, capital contributions would only apply to upgrades to the radial lines that connect distributors to that long 115 kV line.

In cases involving a shared radial Line Connection, any capital contributions that are required would be shared on a pro rata basis based on the respective peak load forecasts of the relevant distributors over the planning horizon. Under staff’s proposed approach for regional planning described above in section 4.2, all distributors within a region would be required to submit an updated forecast of their transmission connection

⁴⁴ Where applicable, this would apply to new transmission lines as well as upgrades to existing lines.

capacity requirements at the same time. As such, the outcome associated with the scenario discussed above in which one distributor pays a capital contribution and the other does not because one distributor contacted the transmitter shortly before the other would be avoided.

Board staff is also proposing the elimination of the provision that limits the need for a capital contribution/rebate to five years as currently set out in section 6.2.24 of the TSC. In other words, a rebate would instead need to be provided to the initial load customer regardless of the timeframe within which the transmitter assigns capacity to another load customer. As discussed above, some stakeholders have noted that the current five year limitation related to the need to provide a rebate could be viewed as relatively arbitrary. In staff's view, the limitation could also create inappropriate incentives and the elimination of that limitation would better support the Board's desired goal of promoting the long term cost-effective development of electricity infrastructure. For example, this provision could create an incentive for a distributor to make investments in its distribution system that are sub-optimal (from an overall system perspective) until the five year period has expired. Staff is also concerned distributors may not be forthcoming regarding potential cost-effective distribution solutions as part of the planning process, since the cost of the distribution solution would be recovered from their customers while the cost of a potentially less optimal transmission solution would be recovered from all ratepayers in Ontario after the five year period expires. It was noted at the stakeholder meeting that transmission lines have a life of about 40-60 years. As such, with the current five year provision in place, a distributor can benefit from a new line for 35-55 years at no cost. Staff notes that this proposed change could accompany other cost responsibility approaches that may be selected by the Board (including the status quo), except for the Full Pooling option since no capital contributions would be provided at all under that option.

Strengths

- It would place all distributors on a more level playing field from a cost responsibility perspective since capital contributions would only be required for lines where the distributor is the sole user and/or the line is used solely for connection purposes on a shared basis (i.e., lines that never provide Network functions). It would therefore result in more equitable treatment of end use customers across Ontario than under the status quo.
- Recognizes that certain 115 kV lines have broader beneficiaries and therefore more consistent with the beneficiary pays principle than the status quo.

- Relative to the Full Pooling option, provides greater incentives for a distributor to be forthcoming in relation to potential distribution investment solutions. Similarly, avoids the incentive to rely on transmission solutions at the potential expense of fully exploiting cost-effective CDM alternatives. It should therefore result in more efficient outcomes.
- Recovery on a pooled basis through the Line Connection rate may be more appropriate than recovery through the Network rate, as this approach recognizes that the 115 kV lines in question do not perform Network functions all of the time.
- Avoid potential rate shock for ratepayers of distributors where capital contributions may be required under the status quo in respect of upgrades to long 115 kV lines that provide Network functions.

Weaknesses


- Increase the administrative burden for transmitters in terms of the identification of lines for which the costs would be recovered on a pooled basis. It appears to result in essentially the same administrative burden as that involved in reclassifying certain 115 kV Connection lines as previously discussed.
- It would be less precise relative to reclassifying the relevant Connection lines as Dual Function Lines in terms of cost allocation. The Dual Function Line approach would recognize that these assets are still used to some degree as Connection assets.

Not all of the cost responsibility options discussed above are intended to be mutually exclusive. For example, the Hybrid option could be combined with the Smoothing option. Also, as previously noted, the elimination of the provision that limits a capital contribution rebate to five years could accompany other cost responsibility approaches discussed above.

Issues for Comment:


- 16) Which approach among the cost responsibility options identified above would best achieve the Board's stated goals in relation to this initiative?
- 17) Are there other cost responsibility options that should be considered by the Board? Participants that wish to put forward alternative proposals for consideration in terms of cost responsibility are encouraged to include in their comments not only a detailed description of each proposal, but also the underlying rationale and principles that support the proposal.
- 18) If the Board were to: (i) adopt Board staff's proposed changes to section 6.3.6 of the TSC; (ii) eliminate the five year sunset period for capital contribution rebates; and (iii) reclassify certain Connection assets, all as discussed above, would it be appropriate to retain the status quo cost responsibility regime?
- 19) Which approach would be more appropriate in relation to the 115 kV Connection lines that perform Network functions – the Hybrid cost responsibility option discussed above (recovery via the Line Connection rate) or reclassification as Network assets (recovery via the Network rate) or reclassification as Dual Function Lines (recovery via both the Network and Line Connection rates) as discussed above? Please provide a detailed rationale for your preferred approach.

4.4 Other Proposed Changes

Board staff suggests that the Board may wish to use this consultation process as an  opportunity to codify one element of its connection cost responsibility policy in relation to generation connections at the distribution level.

Specifically, in the Board's June 5, 2009 [Notice of Proposal](#) related to amendments to the connection cost responsibility provisions of the DSC (EB-2009-0077), the Board stated the following:

*“Some generation connections may trigger the need for upstream upgrades to the system of a host distributor or of a transmitter, in addition to triggering the need for the expansion of the distribution system to which the generation facility will be connected. Although the DSC is silent on the issue of cost responsibility for these upstream upgrades, the practice is for distributors to pass these costs on to the connecting generator. The Board does not propose to revise this approach at this time...”*⁴⁵

Staff believes that codifying the above policy of the Board in the DSC, as part of this  consultation process, would contribute to achieving the desired goal amongst stakeholders for greater regulatory certainty.⁴⁶

Issues for Comment:

- 20) Are there any specific circumstances where generators should not be responsible for the costs related to an upstream upgrade that they triggered? If so, please identify those circumstances and the reasons why the generators should not be responsible for those costs.

⁴⁵ See page 7 of the June 5th Notice of Proposal.


⁴⁶ This is also consistent with what the Board decided in a recent [Decision \(EB-2010-0002\)](#) in relation to Hydro One’s most recent transmission rate application. In its application, Hydro One requested that the cost of certain Protection and Control upgrades on Connection assets be recovered from all ratepayers. The Board denied that request. Instead, the applicable generator(s) necessitating the upstream investments are to be held responsible for the costs. See page 41.

5. CONCLUSION

The introduction of the GEA and OPA's FIT program has increased the need for a new framework to facilitate the most optimal and cost-effective infrastructure solutions. The current framework was developed at a time when distributors were focused principally on the delivery of electricity to load customers. As new load customers were added to the distribution systems of distributors, there was increased utilization of transmission connection assets. As a consequence, to the extent a capital upgrade was necessary in relation to a transmission connection asset, increased revenues from new load customers offset all or most of the impact of capital contributions and kept rates relatively stable. In contrast, there is now a significant amount of generation connecting to distribution systems which is similarly contributing to an increase in the transmission needs of distributors. However, unlike load customers of distributors, the FIT generators do not pay rates to help offset the impact of a capital contribution provided by a distributor nor do they provide a capital contribution in some cases (i.e., do not pay to use the system but use up transfer capability). As such, Board staff believes the need to strive to ensure infrastructure solutions are the most cost-effective has never been greater. That is the Board's primary objective for this initiative

A goal of Board staff in proposing some of the changes and/or options is to strive to place all distributors (and therefore their end use customers) on a more level playing field in relation to transmission cost responsibility. Staff believes that this is an important first step in establishing a consistent and effective framework for regional planning that can be applied to all distributors. It also contributes to enhancing fairness and providing the appropriate incentives to distributors. As the Board noted in its Synopsis that explained the TSC amendments issued in July 2005 when the cost responsibility rules were last revised in relation to load customers, "all customers must pay their fair share".⁴⁷ The Board put into place cost responsibility rules to achieve that end. However, it appears that goal of the Board may not have been achieved due, in part, to the current classification of certain transmission assets across the province. An example previously discussed was consumers in southern Ontario being responsible for the costs associated with 115/230 kV auto-transformers (Line Connection asset), while consumers in eastern Ontario are not responsible for such costs associated with the same transmission asset performing the same function (Network asset).

⁴⁷ [Synopsis of Changes to the Transmission System Code, July 2005.](#)

Board staff believes that achievement of the Board's goal – optimal infrastructure investment – will be facilitated by increased regulatory predictability. Staff believes some of the proposed changes in the Discussion Paper would provide greater regulatory predictability, such as the proposed changes to section 6.3.6. 

Stakeholder comments on this Board staff Discussion Paper will be used as input by the Board in the subsequent stages of this consultation process. In providing those comments, staff requests that participants take into account that some of the options related to cost responsibility and the reclassification of certain Line Connection assets (i.e., 115 kV lines) are alternative approaches that would essentially achieve the same outcome, as discussed at the beginning of Chapter 4.⁴⁸

Appendix 1: Compilation of Issues for Comment

Appendix 2: Overview of Different Types of Transmission Assets

⁴⁸ For example, it would not be practical to implement both the Full Pooling cost responsibility option and reclassify Line Connection assets as Network assets. Implementation of the former would make implementation of the latter redundant.

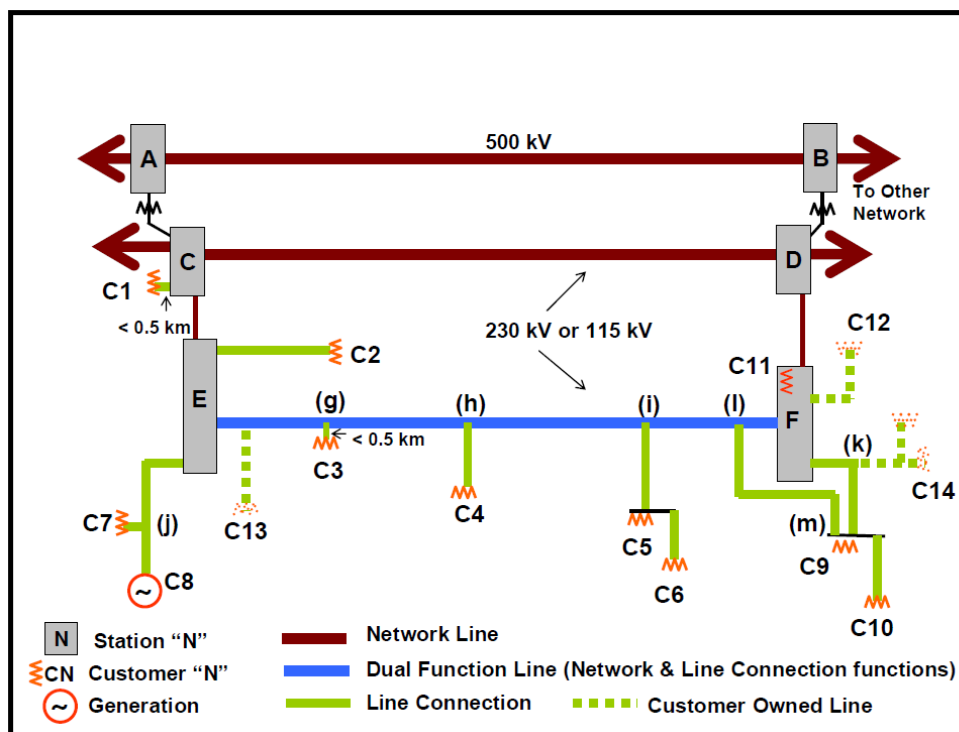
Appendix 1:

Compilation of Issues for Comment

Section	Issues for Comment
4.2	<p>Board staff's Proposed Approach: A Regional Planning Framework</p> <ol style="list-style-type: none"> 1) Staff requests general feedback on the proposed approach discussed above. 2) Staff has proposed that an obligation be placed on distributors to provide the transmitter with an updated forecast and the relevant land use planning documents (where applicable) <u>at least</u> every five years and for a period covering <u>at least</u> five years. In relation to the provision of the relevant information, should it be more frequent? Should the forecast cover a longer <u>minimum</u> period of time than five years (e.g., 10, 15 years)? 3) In cases where a transmitter is requested by distributors to be involved in the development of multiple regional plans at the same time, what criteria should be used by the transmitter for determining the prioritization of the regional plans in the event of transmitter resource constraints? 4) Do distributors foresee any problems in relation to obtaining the relevant land use planning documents from the applicable authority in their service area for the purpose of providing those plans to the transmitter? If so, please explain.
4.2.1	<p>How should "Regions" be Determined?</p> <ol style="list-style-type: none"> 5) Are any of the approaches discussed above appropriate for determining suitable regions for the purpose of regional planning? Why or why not? 6) In relation to the approaches discussed above, are there any proposed modifications that would enhance their suitability? 7) Are there any other criteria, beyond transmission asset functionality, that should be used in the determination of appropriate regions within Ontario for regional planning purposes? 8) Are there other alternative approaches that could be used to determine appropriate regions? If so, please identify the proposed regional structure and explain the rationale and benefits associated with the proposed approach including reasons why it may be more suitable than Board staff's preferred approach.
4.2.2	<p>Proposed Reclassification of Certain Connection Assets</p> <ol style="list-style-type: none"> 9) Do stakeholders agree that assets such as <i>230/115 kV auto-transformers</i> and the associated <i>switchgear</i> should be reallocated to the Network pool? If not, why not and what other approaches might be considered to achieve consistency across Ontario? 10) Do stakeholders believe that <i>115 kV lines</i> should be classified as Dual Function Lines or as Network lines where they perform both a Connection and a Network function? Please explain the rationale for the approach supported. 11) Should the Board consider reclassifying any other Line Connection assets beyond <i>115/230 kV auto-transformers</i>, the associated switchgear and certain <i>115kV lines</i> for the purpose of facilitating regional planning? If so, please identify those assets and explain why the current classification could present a barrier to regional planning.

Section	Issues for Comment
4.2.3	<p>Proposed Changes to Section 6.3.6</p> <p>12) Of Board staff's proposed changes to section 6.3.6 discussed above, which would better achieve the intended goal of resulting in greater regulatory predictability? If the latter option (ii), please propose the list of specific circumstances.</p> <p>13) Are there other alternative changes to section 6.3.6 that the Board should consider? If so, please explain the change in detail and identify the benefits.</p> <p>14) What would the advantages and disadvantages be associated with removing section 6.3.6 from the TSC altogether, as an alternative to the options Board staff proposed above? If section 6.3.6 were to be removed, would other changes to the TSC also be required as a consequence?</p>
4.3.1	<p>Cost Responsibility Options: Objectives</p> <p>15) Are there any other criteria that should be used in addition to the above for the evaluation of approaches in relation to load connection cost responsibility?</p>
4.3.2	<p>Analysis of Cost Responsibility Options</p> <p>16) Which approach among the cost responsibility options identified above would best achieve the Board's stated goals in relation to this initiative?</p> <p>17) Are there other cost responsibility options that should be considered by the Board? Participants that wish to put forward alternative proposals for consideration in terms of cost responsibility are encouraged to include in their comments not only a detailed description of each proposal, but also the underlying rationale and principles that support the proposal.</p> <p>18) If the Board were to: (i) adopt Board staff's proposed changes to section 6.3.6 of the TSC; (ii) eliminate the five year sunset period for capital contribution rebates; and (iii) reclassify certain Connection assets, all as discussed above, would it be appropriate to retain the status quo cost responsibility regime?</p> <p>19) Which approach would be more appropriate in relation to the 115 kV Connection lines that perform Network functions – the Hybrid cost responsibility option discussed above (recovery via the Line Connection rate) <u>or</u> reclassification as Network assets (recovery via the Network rate) <u>or</u> reclassification as Dual Function Lines (recovery via both the Network and Line Connection rates) as discussed above? Please provide a detailed rationale for your preferred approach.</p>
4.4	<p>Other Proposed Changes</p> <p>20) Are there any specific circumstances where generators should not be responsible for the costs related to an upstream upgrade that they triggered? If so, please identify those circumstances and the reasons why the generators should not be responsible for those costs.</p>

Appendix 2: Overview of Different Types of Transmission Assets



Source: Hydro One Networks (EB-2010-0002, G1-T3-S1).

Above is a simplified depiction of the transmission system setting out the different types of transmission lines – Network, Dual Function and Connection. It also shows different ways in which transmission customers are connected to the Network. Below is a description of each type of transmission asset, including Transformation Connection assets.

Network Assets

These are transmission facilities that are shared by all customers in Ontario, such as the **500 kV line between stations "A" and "B"** and the **230 kV or 115 kV line between stations "C" and "D"**. In general, these assets link Network stations around major sources of generation and major load centers. They include:

- All 500 kV lines and 500/230 kV auto-transformer facilities;
- All 230 kV and 115 kV lines that are not tapped to supply load customers and that are normally operated in parallel with Network lines;

- All 230 kV and 345 kV interconnections between transmitters in Ontario and those that provide a link to the electricity systems in neighboring jurisdictions;
- 230/115 kV auto-transformer facilities normally connecting the 230 kV and 115 kV Network lines noted above and/or the Dual Function Lines described below; and
- Specific sections of 115 kV circuits that interconnect with transmitter systems owned by different transmitters in Ontario and neighboring jurisdictions.

Dual Function Line Assets

These are transmission lines that perform both Network and Connection functions, such as the **Dual Function Line between stations “E” and “F”**. The costs are therefore split between the Network and Line Connection pools. They include:

- All 230 kV and 115 kV lines that are tapped to supply specific load customers and that are normally operated in parallel with Network lines; and
- *Local Loops*: An existing Line Connection that is reconfigured to create a local loop is considered to provide a Network function only if that loop creates a new independent delivery path emanating from one Network Station and ending uninterrupted at another Network Station, and would normally increase the transfer capacity between these two existing Network stations. Under this condition, the local loop would be classified as a Dual Function Line, which provides both a Network function and a Line Connection function for local customers.

Line Connection Assets

These are radial transmission lines operating at 230 kV or 115 kV that are used to provide a connection between a Network line/station or a Dual Function Line and supply point(s) for one or more customers and/or one or more generating stations. Line Connection assets do not, under normal operating conditions, connect Network stations.

The radial lines from stations “C”, “E”, and “F” connect one or more transmission customers. These lines can vary in length from a few 100 meters to over 100 km. Since these lines serve only one or a few customers, they are classified as Line Connection. Some of these are fully owned by the customer as shown by the dotted lines (e.g., C12, C13, C14).

Line Connection assets include the following:

- Transmission lines that are radial and connect (directly or indirectly via other connection circuits) to a Network station or Dual Function Line as described above. Line Connection assets are not intended to reinforce the transmission Network that is commonly shared by all customers in Ontario.
- Line Connection circuits that are used to provide a connection to only one Transmission Delivery Point, which is the transformation station that steps down the voltage from above 50 kV to below 50 kV.
- *Local Loops*: If the local loop, as described above, does not increase the transfer capability along the full length of the transmission interface between two existing Network stations, then such a local loop would be classified as Line Connection. Intermediate radial stations (or portions of them) dropping voltage from 230 kV to 115 kV are also categorized as a Line Connection asset if they are not already categorized as a Network asset as per above. They cannot be assigned to the Transformation Connection Pool, since they do not step down the voltage from above 50 kV to below 50 kV.

Transformation Connection Assets

A transformer station is a facility that is tapped off a transmission system and steps down voltages from transmission levels (above 50 kV) to distribution levels (50 kV or less).

Source: TSC and Hydro One Networks application (EB-2010-0002, G1-T3-S1).