Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5700
Fax: (416) 345-5870
Cell: (416) 258-9383
Susan.E.Frank@HydroOne.com

Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

September 9, 2009

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2009-0077 – Cost Responsibility for Connecting Generation Facilities – Hydro One Networks Supplemental Comments on the Board's Proposed Amendments to the DSC

In response to the Board's Notice of Proposal to Amend a Code issued June 5, 2009, Hydro One Networks' provided comments on June 30, 2009. Hydro One was requested to provide additional examples of what investments would qualify as "Connection Assets," "Expansion Assets" and "Renewable Enabling Improvements" based on the proposed amendments.

Once the FIT Program launches, it will be important for distributors and generators to have a common understanding of the cost responsibility principles in the DSC, and as a result, what work is to be paid for by generators and ratepayers, what work is contestable and who will own which assets after the connection work is completed. The attached document provides example scenarios and lists a number of equipment types to assist the Board in clarifying the proposed cost treatment.

Hydro One believes it is equally important for the Board to consider establishing a set of rules that determine what portion of the "eligible investments" distributors will make on Expansions and Renewable Enabling Improvements should be recovered from all ratepayers in Ontario and what portion of the total investments will be recovered from distributors' ratepayers.

Hydro One submits it will be necessary for the Board to provide this guidance to distributors, through further amendments to the DSC, prior to the generation connections that will be made after the launch of the FIT program so that common criteria are applied by all distributors.

Three paper copies of the attached document are being provided by courier to the Board and I have also attached proof of successful submission of these comments through the Board's Regulatory Electronic Submission System as directed in the Notice.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach. (1)

EB-2009-0077: Proposed Amendments to the DSC re Cost Responsibility for Generator Connections – Clarification on New Asset Categories

This document has two main purposes:

1. The purpose of Section 1 of this document is to seek clarification on the cost recovery principles for the three new asset categories defined in these proposed amendments to the DSC:

1) Connection assets
2) Expansion assets
3) Renewable Enabling Improvements

Once the FIT Program launches, it will be important for distributors and generators to have a common understanding of the cost responsibility principles in the DSC, and as a result, what work is to be paid for by generators and ratepayers, what work is contestable and who will own which assets after the connection work is completed.

2. The purpose of Section 2 of this document is to bring to the Board's attention the need for the Board to consider establishing a set of rules that determine what portion of the "eligible investments" distributors will make on Expansions and Renewable Enabling Improvements should be recovered from all ratepayers in Ontario and what portion of the total investments will be recovered from distributors' ratepayers.

Hydro One submits it will be necessary for the Board to provide this guidance to distributors, through further amendments to the DSC, prior to the generation connections that will be made after the launch of the FIT program so that common criteria are applied by all distributors.

Section 1:

1. Connection Assets – Issues for Clarification

In the proposed amendments, Connection Assets are described as "that portion of the distribution system used to connect a customer to the existing main distribution system, and consist of assets between the point of connection on a distributor's main distribution system and the ownership demarcation point with the customer."

Normally, the ownership demarcation point will be where the customer's line on private property connects to the distributor's system at the road allowance. The portion built on the road allowance as "connection assets" will become part of the distribution system and the portion that is built beyond the customer's ownership demarcation point on private property will be "customer assets." (See examples 1 & 2 below)

Similar to expansions in Section 3 of the current Code, the Generator will pay the full cost of "connection assets" and after construction the Generator would transfer ownership to the distributor for ongoing operation and maintenance as part of the expanded distribution system and therefore these assets must be designed and built to meet the distributor's standards. Clarification is needed that an Economic Evaluation would still be used, including construction costs and future O&M costs, plus support for the generator if any load revenues are forecast.

Customer assets beyond the demarcation point can be designed and built to the customer's standards as they will be owned and operated by the customer.

2. Expansion Assets – Issues for Clarification

In the proposed amendments, a number of examples of Expansion Assets are provided but they all involve rebuilding of existing lines to increase capacity, eg. single phase to three phase, larger conductor, higher poles to add circuits & conversion to higher voltage. Clarification is needed on what other modifications to accommodate a generator connection are to be considered as "expansion assets." For example, if a 15MVA transformer needs to be replaced by a 25MVA transformer to allow the generator to connect, would this be an Expansion asset. (See Examples 4 & 5 below)

In the description it also states that an expansion is "an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example by increasing the length of the distribution system." Confirmation is needed that if an extension of the distribution system is built to connect more than 1 customer it will be considered as an expansion. (See example 3 below)

Based on the above, for generator connections, Hydro One will use the number of CIA applications as the indication of more than one generator requiring a new line. The OPA plans to limit the issuance of FIT contracts to unique and independent projects and not projects that split into separate entities for gaming.

If one or more generators pay for part of an expansion above the expansion cost cap and then another generator or load customer wants to connect to the expansion facilities, does the first generator(s) get a rebate from the other generator or customer? Under the current Code, rebates are provided for line connection costs but not for enhancement costs. Distributors will need confirmation if an Economic Evaluation is to be used to reflect capital, future O&M costs and possibly support from load revenues.

3. Renewable Enabling Improvements – Issues for Clarification

Renewable Enabling Improvements are described as being similar to enhancements in the current Code but are meant to address system investments that are made to enhance the ability of a distribution system to accommodate increased levels of renewable generation, eg. to manage and control two way power flow, for electrical protection equipment, for voltage regulating equipment and for transfer trip or equivalent. Clarification is needed on whether this includes all replacements of regulating transformers to allow the connection. If a Regulating Transformer needed to be replaced, would the transformer replacement cost be an Expansion asset and the regulating controls would be a Renewable Enabling Improvement asset, or would the full cost be treated as a Renewable Enabling Improvement. Please note the cost to replace a Regulating transformer could be approx. $2.5M and could be triggered by a relatively small generator connection. (See example 5 below)

Planned enhancements to the distribution system to allow DG connections will be identified in distributors' Green Energy Plans or Dx Rate Applications and approved by the OEB in advance, however other renewable enabling improvements will be triggered by DG connection requests. There should be a common list for all distributors of the types of equipment replacement that would qualify as renewable enabling improvements.

The following example connection scenarios highlight the key issues that need clarification. Appendix A provides specific equipment types and questions to help further clarify the categories. It is not intended to be a comprehensive list.

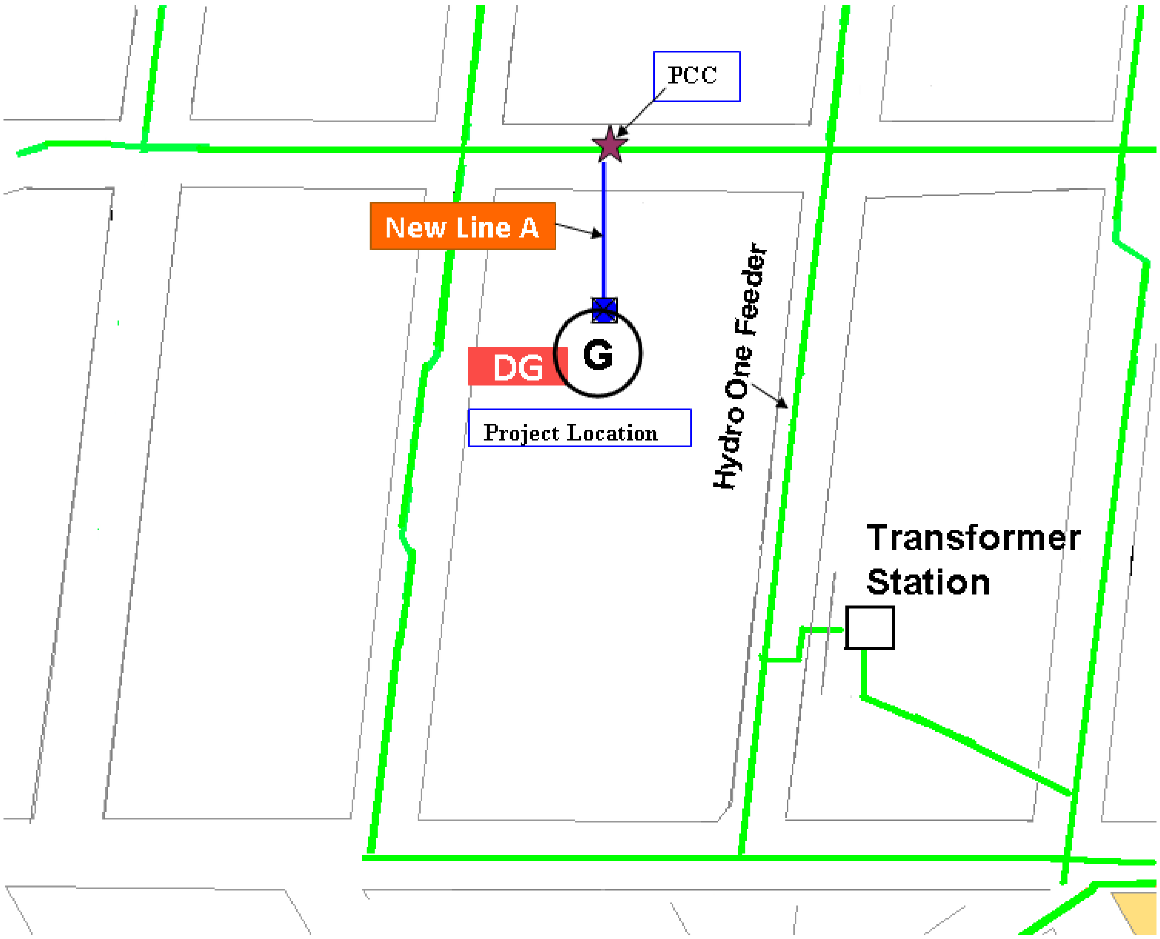
Example 1: Generator wants to connect from Generator Site on Private Property to the Main Dx System by building a new Line.

a. Category of Assets: Customer Assets. Line A would connect the generator on private property to the Dx system and the ownership demarcation point would be where the new line connects to the Dx System - normally at the road allowance.

b. Cost Responsibility: Generator

c. Contestability: Contestable Work

d. Ownership: Generator owns and maintains lines on private property



Example 2: One Generator wants to connect from Generator Site on Private Property to a New Line that has to be built on Road Allowance to connect to the Main Dx System

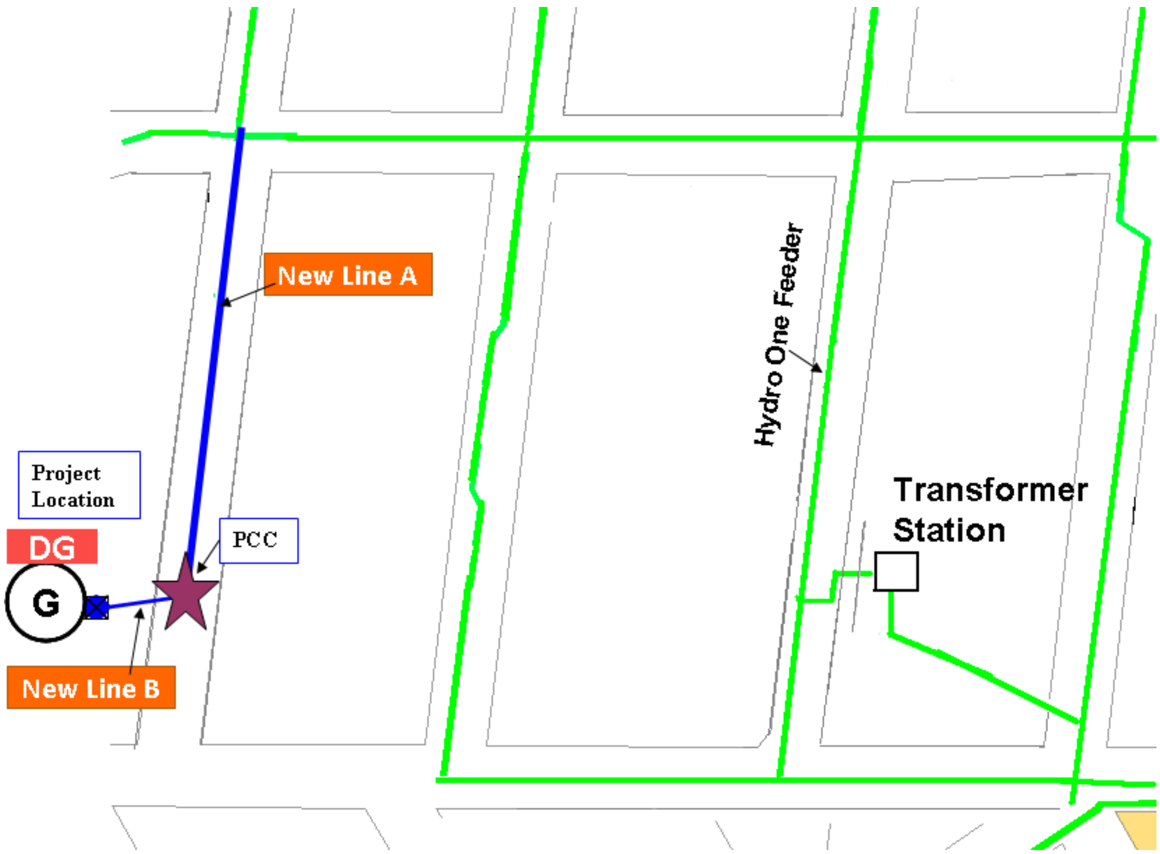
a. Category of Assets: Line A along the road allowance will be built as a connection between the main Dx system and the ownership demarcation point with the customer – this line is a "Connection Asset." Line B is on private property beyond the ownership demarcation point – this line will be a Customer Asset.

b. Cost Responsibility: Line A – Generator. Line B - Generator

c. Contestability: Line A - Contestable Work. Line B – Contestable Work

d. Ownership: Line A – Distributor. Line B – Generator

The Distributor would take ownership of Line A on the road allowance which was built as an expansion of the main Dx system to be owned and maintained by the distributor and potentially to serve other customers. Therefore the line would have to be built to the distributor's design. If other customers connect to this line within 5 years, the generator would receive a rebate.
The generator would own and maintain Line B on private property.



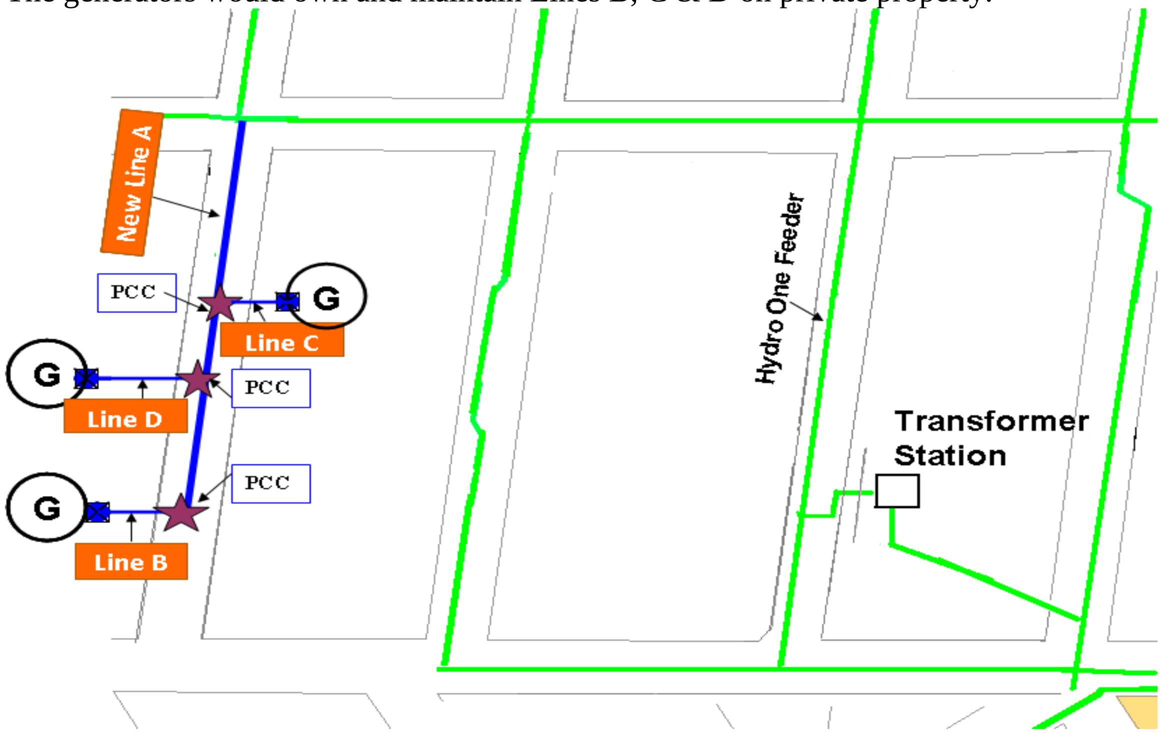
<u>Example 3: Several Generators want to connect from Generator Sites on Private Property to a New Line that has to be built on Road Allowance to connect to the Main Dx System</u>

a. Category of Assets: Line A along the road allowance will be built as a connection between the main Dx system and the ownership demarcation point with several generation customers – this line is an "Expansion Asset" as it is being built "in response to a request for additional customer connections that otherwise could not be made; for example by increasing the length of the distribution system." Hydro one will use CIA applications to determine if more than one generator requires the new line.
Lines B, C & D are on private property beyond each ownership demarcation point – these lines will be Customer Assets.

b. Cost Responsibility: Line A – Distributor up to $90K/MW or full cost if included in approved Green Energy Plan. Lines B, C & D – Generator.

c. Contestability: Line A - Uncontestable Work. Line B,C & D – Contestable Work
In situations where generators have to contribute above the $90K/MW cap, it will normally be a small component of the total cost of the work paid for by the distributor so the work is uncontestable.

d. Ownership: Line A – Distributor. Line B – Generator
The Distributor would pay for and build Line A on the road allowance which was built as an expansion of the main Dx system to be owned and maintained by the distributor and potentially to serve other customers. If other customers connect to this line within 5 years they will be treated as lie along customers.
The generators would own and maintain Lines B, C & D on private property.



Example 4: One or More Generators want to connect from Generator Site(s) on Private Property to the Main Dx System and Existing Line A needs to be rebuilt to accommodate the connection

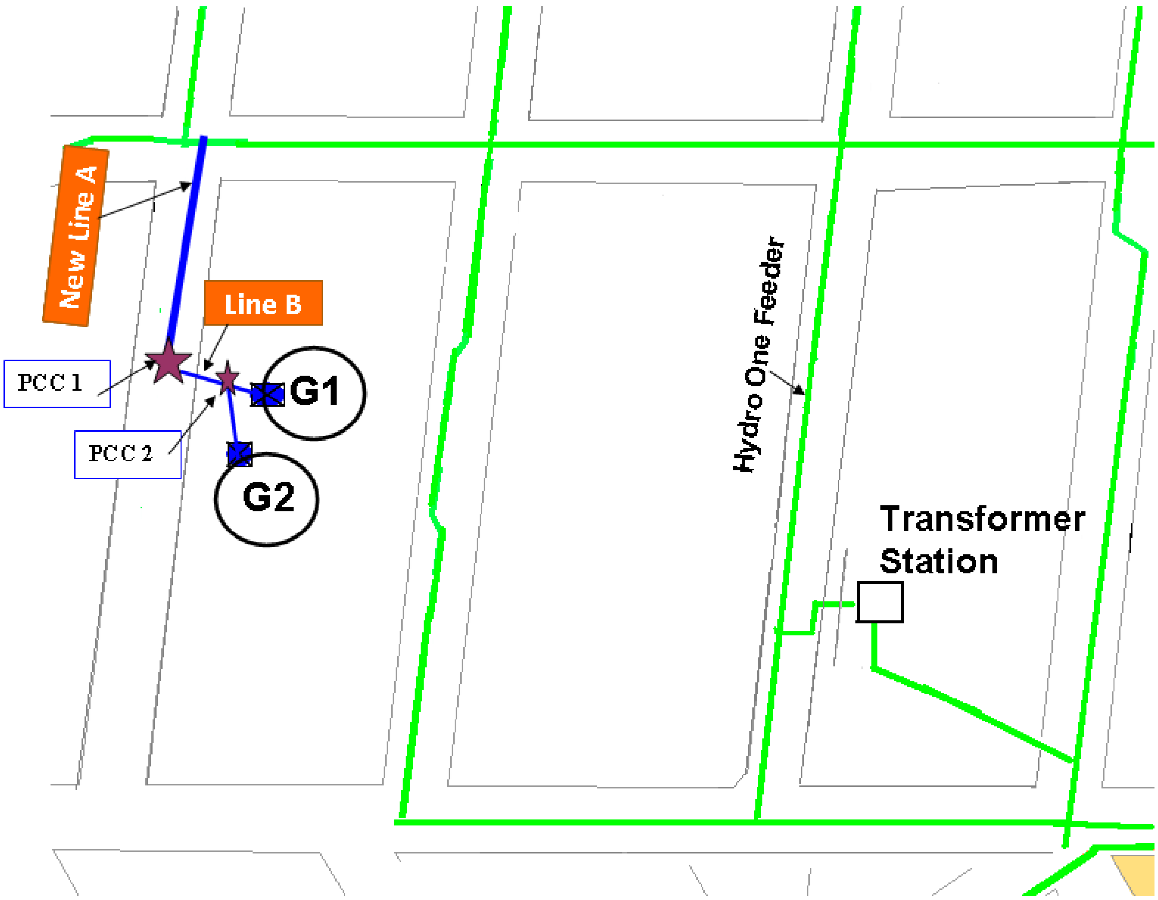
a. Category of Assets: Line A is part of the main Dx system and needs to be rebuilt/replaced – Line A is an "Expansion Asset."

b. Cost Responsibility: Line A – Distributor up to $90K/MW or full cost if included in approved Green Energy Plan.

c. Contestability: Line A - Uncontestable Work as it is work "involving existing distributor assets."

d. Ownership: Line A – Distributor. The Distributor would continue to own and maintain Line A as an expansion of the main Dx system. If other customers connect to this line within 5 years they will be treated as lie along. If a generator paid a contribution to the expansion work as the cost was > $90K/MW, and new customers connect to the line within 5 years, would the generator receive a rebate? If it is another generator or load customer who would have also required the expanded facility (eg 3 phase power vs single phase) should they pay a rebate? If it is a smaller customer who could have connected to the older, smaller facility as a lie along, should they pay a rebate?

If a new generator G2 connects to the line of G1, the above provisions would still apply and the distributor would act accordingly. The two generators would negotiate the sharing of part of line B as a commercial matter between themselves.



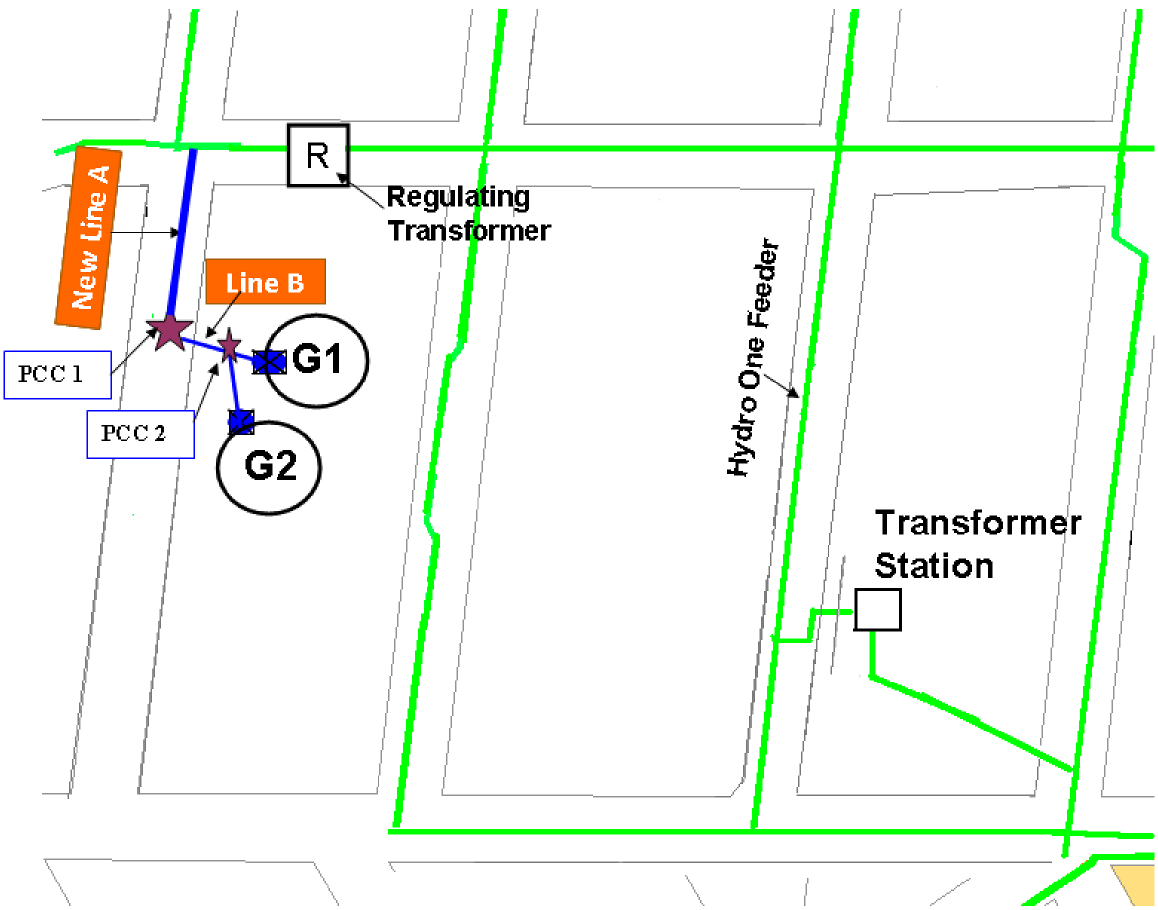
Example 5: One or More Generators want to connect from Generator Site(s) on Private Property to the Main Dx System and a Regulating Transformer needs to be replaced with a larger Regulating Transformer A to accommodate the connection

a. Category of Assets: Regulating Transformer A is part of the main Dx system and needs to be replaced to allow two way power flow and still maintain voltage stability – Clarification is needed whether Regulating Transformer A is a "Renewable Enabling Improvement" (REI) asset or an "Expansion Asset."

b. Cost Responsibility: Replacing Regulating Transformer A – Distributor if REI or if included in approved Green Energy Plan as REI or Expansion. Distributor up to $90K/MW if Expansion and not in the Plan.

c. Contestability: Replace Regulating Transformer A - Uncontestable Work as it is work "involving existing distributor assets."

e. Ownership: Regulating Transformer A – Distributor. The Distributor would continue to own and maintain Regulating Transformer A as part of the main Dx system.
 If a new generator G2 connects to the line of G1, the two generators would negotiate the sharing of part of line B as a commercial matter between themselves.



Section 2:

In the Notice to these proposed amendments, the Board notes that the GEGEA "will introduce a mechanism whereby Board-approved costs incurred by a distributor to make an "eligible investment" for the purpose of connecting or enabling the connection of a "qualifying generation facility" to its distribution system may be recovered through contributions payable by all consumers throughout the Province (section 79.1 of the Act)."

The purpose of Section 2 of this document is to alert the Board to the need for consideration of how costs of the "eligible investments" distributors will make on Expansions and Renewable Enabling Improvements could be allocated between all consumers in Ontario and the incumbent distributors' ratepayers. It is Hydro One's view that such investments will undoubtedly provide some benefits to local customers served by the investing distributor and so a methodology is needed that would allocate cost responsibility in a consistent and transparent manner irrespective of which distributor is making a submission in this respect. Hydro One believes that the Board is in the best position to establish those rules.

Hydro One suggests some potential decision criteria that could be applied to Expansion and Renewable Enabling Improvement investments. The following three possible decision criteria would involve allocation of costs based on the relative benefit of the investment to the distributor's ratepayers for improvements to the distribution system versus the benefits to all consumers of facilitating more renewable generation on the grid. The intent is to provide some simplified options that generally match costs to benefits in a practical way for efficiency purposes. More detailed methods could be suggested but we do not believe the precision is worth the added cost.

The three criteria proposed below are:

1. Age of Assets Being Replaced
2. System Load Growth
3. Customer Density

1. Age of Assets Being Replaced

For Expansions that involve the need to replace existing assets, the amount of benefit to the distributors' customers will vary based on the age of the assets being replaced. Although the generator connection triggers the need to replace the asset, an old asset would have required replacement at the distributor's cost in the near future. Conversely, the newer an asset that is being replaced, the less benefit to the distributors' ratepayers and the more the benefit is to all consumers in the Province. Using the example of a transformer that is being replaced, a possible method to guide the allocation of costs could be as follows:

i. If the asset age is greater than 40 years old, then 75% of the investment is attributable to the distributor's customers and 25% is attributable to all consumers,

ii. If asset age is between 20 and 40 years old, then 50% of the investment is attributable to the distributor's customers and 50% is attributable to all consumers, and

iii. If asset age is less than 20 years old, then 25% of the investment is attributable to the distributor's customers and 75% is attributable to all consumers.

2. System Load Growth

For Expansions that involve new assets to add capacity to the system, eg a new line or a new DS, the higher the load growth in that part of the distribution system the more benefit there is to the distributors' ratepayers as the capacity expansion would have been required in the near future. Alternatively, the less load growth in that part of the system, the more the costs are incurred for the benefit of all consumers in Ontario. A possible method to allocate the costs of the investment is as follows:

i. If load growth is less than 1%, then 100% of the investment is attributable to all consumers,

ii. If load growth is between 1% and 3%, then 50% of the investment is attributable to the distributor's customers and 50% is attributable to all consumers and

iii. If load growth is greater than 3%, 75% of the investment is attributable to the distributor's customers and 25% is attributable to all consumers.

3. Customer Density

If the investment is a Renewable Enabling Improvement to manage two way power flow, install protection devices, bidirectional reclosers or voltage regulation equipment, the improvement in service quality to the distributor's existing customers as a result of the investment will vary based on the customer density in that part of the system. In general, the higher the customer density per given length of distribution feeder, the greater the benefit to the distributors' ratepayers. Possible allocation criteria could be as follows:

i. If density is greater than 30 customers per km of distribution feeder then 75% of the investment is attributable to the distributor's customers and 25% is attributable to all consumers,

ii. If density is between 10 and 30 customers per km of distribution feeder, then 50% of the investment is attributable to the distributor's customers and 50% is attributable to all consumers and

iii. If density is less than 10 customers per km of distribution feeder, then 25% of the investment is attributable to the distributor's customers and 75% is attributable to all consumers.

Other Comments

Hydro One encourages the Board to consider the matter of cost allocation and develop appropriate rules that will result in consistent and fair cost allocation to the different ratepayer groups involved. Good decision criteria in this area will also result in distributors and generators being motivated to ensure that connection projects are carried out in a cost effective way.

Hydro One would be glad to work with Board staff and other distributors to develop these concepts further.

Appendix A

Examples (E) and Questions (Q) of Equipment Types and in what Asset Category they will be included.

Connection Assets:

E. A new line that will benefit only one generator

Q. Would equipment on the new line (eg switches, reclosers, lightning arrestors) be included as line costs and part of the "connection assets" or not?
Q. Should distributors assume all equipment that is upstream of the new line (eg transformers, reclosers, switches) are not "connection assets?"
Q. If other customers connect to the new line within 5 years, do rebates apply for the first generator? Distributors will need direction on whether the calculation for a rebate from another generator would be based on distance and size of the generator, or only on distance.

Expansion Assets:

E. A new line built to serve multiple customers
E. Replacement of an existing line to increase capacity, eg. single phase to three phase, larger conductor, higher poles to add circuits & conversion to higher voltage
E. Replacement of a transformer to a larger MVA transformer
E. Upgrading a Regulating Station transformer to a larger MVA size should be considered an expansion, as it is not required to enable flow in the reverse direction but does increase the capacity of the system. Putting the new controls on the Regulating Station transformer that enable reverse flow should be an REI.
E. Installing or upgrading a TS circuit breaker should be considered an expansion. The breaker would be a Tx asset inside the transmitters fence – but costs should be charged to the distributor. Currently distributors pay for new circuit breakers at the TS when they are required to serve new load.
E. Buswork or station work needed so as to build a new line to serve multiple customers (e.g. there may be a need to extend the bus or do other work to prepare the station for the new breaker position)
E. Addition or upgrade of capacitor banks should be Expansion assets.

Q. For any cost portion over and above the $90K/MW Expansion cap do rebates apply?

Renewable Enabling Improvement (REI) Assets:

E. Bidirectional reclosers.
E. SCADA system design, construction and connection to allow two way power flow.
E. Feeder protection upgrades.
E. Tap-changer controls or relays that need to be changed to perform correctly in cases of reverse flow or frequent changes in the direction of flow.

E. Costs of making feeder metering or TS voltage regulating equipment reverse compatible.
E. Costs to replace breaker protection relays to provide transfer trip or be directional protection capable.
E. Neutral Grounding Reactors installed at supply stations.
E. Capacitor bank controls. The addition of a control does not add capacity to the system, but improves the controllability of the VAR flow, which in turn can enable more generation.
E. A LAN or other communication system that will facilitate SCADA for DG but not intended for Smart Grid.
E. Transfer Trip. This would require a charge to distributors for these assets which are typically inside a transmission station.

Q. Clarification is needed on telecommunication equipment to operate transfer trip.
Q. Should feeder coordination studies and protection setting studies be paid for separately by the generator or included as REI?
Q. If a study is needed to examine whether new assets are required to accomodate further renewable generation (eg this may be required to ensure a certain type of equipment can tolerate a certain level of DG's on the feeder) should it be paid for separately by the generator or included as REI?