**TRANSMISSION SYSTEM CODE REVIEW PROCEEDING – RP-2002-0120**

**Facilitator's Report to the Board on the Results of the Settlement Conference**

## Introduction:

This is the Report of a Settlement Conference held September 9 - 16, 2003, in accordance with Procedural Order No. 4 dated July 30, 2003 in this Proceeding. The Report has been discussed with all parties who participated in the Settlement Conference, and the extent of parties' agreement with the various items in the Report is indicated under each issue.

Those participating in the Settlement Conference are listed in Appendix A to this Report, together with the abbreviations used for parties' names in this Report. The Report sets out each of the *seven issues* that the Board requested parties to consider, in the order the issues appear in Appendix "B" to Procedural Order No. 4, followed by a description of the outcome of the settlement discussions on that issue. Parties not listed under a particular issue take no position on the issue.

Detailed discussion of each of the issues remitted to the Conference by the Board produced considerable agreement on some of those issues, and produced a clarification of remaining differences among parties on others. It was, however, often difficult for parties to separate their views on these specific issues from their positions on other issues or propositions not yet decided by the Board, but not subject to these discussions. In some cases, those circumstances may have prevented more complete agreement. If the Board requires clarification of any portion of the Report, all parties are prepared to provide additional context in a one-day oral proceeding before the Board.

## The Issues and Outcome of Discussions:

**1.** ***Determination of the remaining value of an asset.*** *(reference: Principle #5, Proposition #3, Bypass, Proposition #8, Available Capacity)*

*What specific methodology can or should be used to determine when a connection facility such as a line or transformer station, has become fully depreciated?*

*Several parties have proposed that prohibiting customers from building connection facilities that duplicate a transmitter's existing transformation connection facilities (Principle #5) or prohibiting customers from transferring existing load (Proposition #3) off the transmitter's transformation connection facilities is not an appropriate solution. It would be more desirable to establish a methodology for determining fair and equitable compensation for any stranded assets. This would allow customers to make the best economic decisions for their particular situation while protecting the transmission system and its existing customers from the undesirable effects of stranded assets.*

*It is beneficial to explore details of possible methodologies for determining compensation for stranded assets. Parties are requested to recommend possible methodologies and explain how they would be used. Two possible alternatives have been proposed:*

*i) Net Book Value (NBV) at the time of stranding as this represents the accounting value of the asset incorporated into rate base.*

*ii) The principle of grossing load up by applying pertinent transmission connection rates for a period of time equal to the time required for the facility to become fully depreciated*

*Parties are requested to explain the advantages and disadvantages of each of these, or any other alternatives they propose.*

*It has been suggested that for the case of distributors that are transmission customers there may be a need for the Board to be directly involved. Parties are invited to propose approaches to enable the Board's oversight and screening prior to implementation of a licensed distributor's capital expenditures to build new transformation connection facilities. Parties are asked to specifically consider the event that such transformation connection facilities are designed to serve not only new loads but also existing loads that are currently supplied by a transmitter, thereby causing stranding of a transmitter's transformation connection assets.*

**<u>Outcome of Settlement Discussions</u>:**

The methodologies for the determination of the remaining value of an asset were discussed in the context of stranding. The subject of sale was not discussed. It was suggested by some parties that the methodologies considered should be viewed as resulting in compensation for stranded "value", as opposed to compensation for stranded "assets". Three alternatives were considered, with some parties supporting each. The alternatives do not address the method of collection, an important related issue which will need to be addressed by the Board.

**a) Net Book Value**: Discussions clarified that Net Book Value (NBV) includes a credit for salvage and the addition of removal costs. The following parties support the use of NBV as a basis for the determination of compensation for stranded value:

*AMPCO, Algoma, Imperial, ECAO, IPPSO, INCO, IBEW-CCO, TransAlta, Bruce Power, OPG and ECMI (for sole user situation only).*

They identify the following *advantages* to this option:

- NBV is used in rate base for both transmission and distribution utilities
- consistent with Minister's and Board's policy for sale of assets/businesses
- reflects asset value to be recovered in rates, avoiding over-recovery
- consistent with the Uniform System of Accounts (USOA)
- simple deterministic method which is robust against gaming
- encourages customers to take responsibility for their line and/or transformation connection(s) individually as stated in RP-1999-0044
- asset value is independent of its usage
- NBV is considered in business valuations
- reduces regulatory burden
- for shared facilities, proportioning NBV according to current load is simple and

deterministic and preserves advantages for both exiting and remaining customers.

- assigns environmental remediation cost responsibility correctly

The following *disadvantages* to this option were identified by opposing parties:

- results in bypass decisions that impact rates of pool customers
- leads to uneconomic bypass decisions
- does not fully reflect the basis on which rates are set (i.e. pool rates vs. specific asset cost)
- does not capture stranded costs
- based on historical accounting cost, unrelated to the economic value of assets
- does not form part of proper economic assessment and will lead to uneconomic investment decisions
- depreciation values are based on averages.  Bypass decisions are triggered by individual customer decisions based on customer's self interest, leading to "cherry-picking"
- "individualized" determination of NBV for specific assets is inconsistent with ratemaking and will encourage "cherry picking" of assets.
- Ignores cost responsibility for environmental remediation

Parties suggested the following ways to improve the acceptability of this option. Notwithstanding the fact that they do not support this option as the best alternative, the following parties believe it would be more acceptable if the remaining asset life were adjusted by Iowa curves or other appropriate annuity adjustments to reflect the changed life expectancy of the asset at the time the valuation is being undertaken.  NBV would then be adjusted based on the adjusted remaining asset life, and to include other non-capital costs, such as those for environmental remediation, directly attributable OM&A costs, etc.

*Hydro One, GLPL, CNPI.*

**b) Present Value of (Revenue from load displaced - avoidable costs)** over the **remaining useful life** as determined for the individual asset by the Transmitter

The following parties support the use of this calculation:

*Hydro One, VECC, CAC, GLPL, PWU, preferred alternative of Toronto Hydro / EDA.*

They identify the following *advantages* to this option:

- province wide economic (Macroeconomic) value captured
- ensures bypass does not result in increase of customer rates
- protects pool customers – rate neutrality/reduction – especially for multiple use facilities
- captures physical "used and useful" value
- consistent with current Board approved financial evaluation practices (TSC,DSC-new connections) and this option can be implemented in a similar fashion

- holds individual customers accountable for cost responsibilities/consequences of their investment decision
- consistent with utility economic planning process
- issue is duplication of assets, not transfer of assets.  This methodology is directly applicable to duplication issue.
- encourages rational and economic decision making, i.e. economic bypass decisions based on efficient asset use
- captures other non-avoidable costs apart from capital costs.

The following *disadvantages* to this option were identified by opposing parties:

- uncertainty and subjectivity of determination of useful life and the projected revenues and costs
- inherent conflict of interest in establishing stranded value – Hydro One is the party determining the value of the assets to the pool when they hold the responsibility to protect the pool
- asymmetry of information
- reliant on multiple forecasting assumptions (i.e. engineering and end of life) for exiting and remaining parties for shared facilities

*No opposing parties* suggested ways of improving the acceptability of this option.

**c) Present Value of (Revenue from load displaced - avoidable costs)** over the remaining life as determined **using depreciation schedules**. The remaining life is calculated by taking the weighted average by dollar value of the accounting residual life of the components of the asset. Recognizing that assets may have value beyond their accounting life, this option captures some of this value through the present value determination over the remaining accounting life.

The following parties support the use of this calculation:

*ECMI (for shared use facilities), OSEA, GEC.*

Parties suggested the following ways to improve the acceptability of this option.
As with option a), notwithstanding the fact that they do not support this option as the best alternative, the following parties believe it would be more acceptable if the remaining asset life were adjusted by Iowa curves or other appropriate annuity adjustments to reflect the changed life expectancy of the asset at the time the valuation is being undertaken OR the remaining asset life were adjusted to the point of next major infusion of capital investment.

*Hydro One, GLPL, CNPI, acceptable alternative to Toronto Hydro / EDA.*

With respect to the final paragraph of the issue, the following process has been proposed and is agreed to by parties as follows:

> Parties have discussed the need for Board "oversight and screening prior to implementation of a licensed distributor's capital expenditures to build new transformation connection facilities." It is agreed that, in the situation where a distributor is proposing to change transmission provider, where the former transmitter and the distributor have reached agreement, both the former transmitter and the distributor will confirm to the Board that agreement has been reached. As part of that confirmation, the distributor will include its proposal along with rationale for the need for new transformation assets including a load forecast, costs associated with stranded assets (either in the form of a payment to the Transmitter or a load guarantee on the remaining facilities), justification of the capital cost of the new assets and the impact its proposal will have on its customers' rates.

The Board may, if the distributor's new assets are to be deemed distribution assets, initiate a hearing to determine the prudence of the investment and adjust the distributor's rate base and distribution rates accordingly. If a separate transmission provider constructs and owns the assets, the Board will require the provider to obtain a transmission licence, and a rate order, which would involve a proceeding to consider the prudence of the investment and the setting of transformation rates.

Where the distributor and the former transmitter cannot agree, the following process will be followed:

1. All reasonable attempts should be made by the parties to resolve the matter prior to contacting the Board.
2. Notice will be issued to the Board by one of the parties, with a copy to the other, that a dispute exists, the nature of the dispute, and a description of the attempts that have been made to resolve it.
3. The Board will appoint a facilitator at the cost of the parties. The facilitator should produce a report to the Board in a period not exceeding 6 weeks from the date of the notice.
4. The facilitator's report will contain the facilitator's recommendations indicating either:
    a. That there is no remaining dispute, and that the parties will file the material as required above where there has been an agreement.
    b. That the dispute remains, in which case the facilitator will list, with or without the recommendations, the residual items in dispute.
5. The Board will initiate, within two weeks of its receipt of the facilitator's report of a dispute, a proceeding on the matters in dispute.
6. The Board will render a decision on the matter within 12 weeks of its receipt of the facilitator's report.
7. Each party will be responsible for its own costs in the process.

*2.* ***What constitutes Fully Allocated Costs*** *(reference: Proposition #5, Economic Evaluation & Proposition #2, Contestability)*

*In considering the question of what overheads a transmitter should apply to projects involving the construction of new or the upgrading of existing connection assets, it has been proposed that all direct overheads and a portion of the indirect overheads should be included. This proposal was made on the basis that a transmitter's business involves more than just construction of connection assets and that some of the indirect overheads are used to support these other aspects of a transmitter's business.*

*It has been proposed that the share of indirect overheads that a transmitter should include in the economic evaluation be determined by dividing the amount of the Net Book Value ("NBV") of the transmitter's connection assets by the NBV of the transmitter's total assets. The focus at the settlement conference should be to determine the appropriate <u>indirect</u> overheads.*

**<u>Outcome of Settlement Discussions</u>:**

With respect to the final paragraph in the Board's characterization of the issue, some parties, as shown below, endorse the following:

> It has been proposed that dividing Net Book Value of the transmitter's connection assets by the transmitter's total assets would provide an appropriate percentage base to allocate indirect overhead. Some parties disagree with this proposed methodology as it would not provide a measure reflective of the effort and costs associated with the design and construction process, and would tend to over-allocate overhead costs to connection assets. The assets in transmission connection asset pools (line connection and transformation connection) have been built up over many years in line with the development of the provincial transmission grid. With the transmission grid in place and new connection activity growing more slowly, this percentage overstates the current activity level in new transmission load connection assets as a share of the overall capital program.
>
> The above paragraph is agreed to by the following parties: *Hydro One*

Information was exchanged regarding Hydro One's indirect cost components that are attributable (and not attributable) to specific projects. See Appendix C attached.

With respect to the issue in general, there were two views, with some parties agreeing to each as indicated below:

<u>View I</u>

> This issue addresses the allocation of costs to transmitters' connection services for purposes of determining capital contribution requirements. Transmitters currently cost their connection services by incorporating costs that are uniquely attributable to a specific connection project. This does not include an allocation of corporate-wide costs that are not uniquely attributable to a specific connection activity, including human resources, regulatory affairs, treasury, tax, insurance, etc. This cost allocation approach applies whether or not the connection project may be funded by the pool funded option. For capitalization of transmission assets, including connection assets, these additional corporate-wide indirect costs that are not uniquely attributable to a specific connection activity are allocated to the assets of the rate base.
>
> One issue is whether this approach is appropriate in light of the Board's determination that the transmission connection market should be made contestable. Contestability in the context of connections means that transmission customers may choose to contract with any qualified contractor for the design and construction of any connection assets whether or not the connection facility is pool funded.
>
> This is consistent with the Board's first preliminary proposition under the heading Contestability" in Procedural Order No. 3 which states that 'The Code should allow transmission customers the choice of contracting with any qualified contractor for the design and construction of connection facilities, whether or not the connection facility is pool-funded'. If transmission customers are unable to hire non-Hydro One contractors to provide the pool funded option, then the connection market will not become competitive. This is because the pool funded option is designed to be more attractive than the "self build" option.

As a result, if the Code allows only Hydro One to provide the pool funded option, then the Code will be securing Hydro One's monopoly over connection services.

Three transmitters have provided information on their costing methodologies. The present proceeding does not include an evidentiary basis to determine the appropriateness of transmitters' current costing policies. In addition to the contestability issues referred to above, other issues that are impacted include intergenerational rate equity and the degree of consistency required in costing methodologies for different regulatory purposes. Parties to the TSC proceeding respectfully submit that, given the possibility that the next rate proceeding may be some years away, the Board convene a separate proceeding, prior to the next cost allocation and rate design hearing to determine the appropriate cost allocation methodology and its implementation.

As well, the parties note that, pending the outcome of the requested proceeding, the *status quo* costing methodologies will remain in place. If the cost allocation requires changes, any impact on the market place cannot be corrected retroactively.

The parties' proposed approach to this issue and the issue of defining line connection and network assets (Issue 5) should not be taken as a request for further delay. The relationship between these two issues was referred to by the Board as follows in RP-1999-0044:

> *'OHNC should not seek to monopolize the connection market. Rather, it should take steps to encourage competition. In this regard, the Board notes that the resolution of the dual function definition of network lines is critical to the development of the competitive market for line connection facilities.'*

There is urgency to resolving both of these interrelated issues.

The following parties support the above proposal: *AMPCO, ECAO, INCO, Algoma, IBEW-CCO, Toronto Hydro.*

<u>View II</u>

Some parties have noted the following factual errors in the above option:

- This cost allocation approach applies only to the pool funded option
- For capitalization of transmission assets, additional corporate-wide costs that are not uniquely attributable are allocated to current period costs as well as the rate base
- When a customer chooses the pool funded option, Hydro One would design and construct the connection facility. Otherwise, Hydro One is concerned that collective agreements and labour legislation would be violated. If the customer does not choose the pool funded option it may choose to contract with any qualified contractor for the design and construction of connection assets.

Some parties suggest that the Board provide for a stakeholder consultation just prior the next cost allocation and rate design hearing to consider this issue. This area is complicated and does not lend itself to resolution in an adversarial hearing review. The specific purpose of this consultation would be to determine the appropriate cost allocation methodology for contestable, pool funded and rate base work. This consultation would not review such areas as the quantification of costs or percentage allocation rates. The transmitter would take the output of this consultation into account for its cost of service filing. The ruling out of the cost of service hearing would implement the approved methodology.

This approach is consistent with the Settlement Agreement in RP2000-0023, where parties agreed that in order to facilitate full review of issues relating to external recoverable work, Hydro One agreed to provide related information in the context of a future cost of service rates hearing.

Furthermore, the Board stated in its decision in RP-1999-0044:

> *"The Board expects OHNC to report on these matters at its next cost allocation/rate design proceeding."*

Parties supporting View II are: *Hydro One, PWU.*

In addition, the following parties *support* the proposed *separate proceeding*, <u>without</u> agreeing to the arguments in either View 1 or View 2: *CAC, VECC, EDA, ECMI, GLPL.*

In addition to its support for View I, *Toronto Hydro* specifically supports the initiation of a separate process to address fully allocated cost issues.

### *3. Determination of O&M costs (reference: Proposition #6, Economic Evaluation)*

> *Parties are invited to consider the methodology they would propose to determine incremental O&M costs for various types of connection assets that might be associated with a new or upgraded customer connection and describe how these costs should be incorporated into the economic evaluation.*

**<u>Outcome of Settlement Discussions:</u>**

Parties agreed that the incremental O&M costs arising from new or upgraded connections assets will be determined on an average basis reflecting the circumstances of the Transmitter concerned. In the case of Hydro One, incremental O&M costs are based on the experience of the company in operating and maintaining transformation connection assets and line connection assets respectively. In the case of GLPL, O&M incremental unit cost will be estimated based on the experience of the Company in operating and maintaining similar equipment in similar environments.

In response to paragraph 1 of Appendix A (references Proposition #6, Cost Responsibility), the parties agree that there should, at the present time, be no allocation to generators of incremental O&M costs for new or modified connections, in view of the relatively small amounts involved.

The following parties support this resolution*: AMPCO, INCO, Algoma, VECC, CAC, Bruce Power, Toronto Hydro/EDA, GLPL, IPPSO, CNPI, ECMI, OPG, Hydro One.*

4. ***Definition of CATC*** *(reference: Proposition #3, Available Capacity) Capacity Allocated To a Customer ("CATC") is calculated on a per delivery point basis. For new load customers, CATC is defined on the basis of the customer's load forecast. For existing customers, there is no specific commitment associated with the CATC but some parties believe there should be a "baseline" CATC allocation which represents the minimum amount of allocation to that customer. For existing customers, CATC would be recalculated annually based on actual transmission usage using the average of three consecutive months of load. It was originally proposed that it would be calculated as the highest monthly peak load, over the past 5 years, or the capacity of a dedicated feeder position, whichever is greater. However, concerns were raised associated with a single peak load determinant in terms of gaming or anomalies such as emergency situations. One proposal that may address these concerns is to use the average of 3 consecutive months peak load over the most recent 5 years. While this annual CATC calculation would be made, a customer would always be assured of their "baseline" allocation of capacity. Parties are invited to review this approach for consideration at the settlement conference.*

**Outcome of Settlement Discussions:**

The Capacity Allocated To a Customer ("CATC") is defined ONLY for the purpose of allocating existing capacity among all Transmission Customers that are supplied from a common transmission connection facility in relation to an expansion project for that facility as required to determine Connection and Cost Recovery ("CCR"). The definition is the following: For new load customers, CATC is defined on the basis of the customer's load forecast contained in the construction agreement negotiated with the transmitter. For existing customers, CATC is calculated based on actual transmission usage using the average of 3 consecutive months of highest peak load (over the past 5 years) for the transformer station or feeder position(s) as appropriate.. Each CATC calculation will be made on a per delivery point basis. A customer will always be assured of its "baseline" allocation of capacity. Each customer's "baseline" will be determined using the most recent 5 years prior to the expansion study. CATC does not include temporarily anomalous situations such as temporary load transfers or emergency situations. Such anomalous situations will be backed-out of all CATC calculations. The CATC determinations will be made available to all parties connected to the common connection asset in question in a manner that is consistent with any confidentiality requirements.

The following parties agree to the above definition: *ECMI, VECC, CAC, Toronto Hydro/EDA, Hydro One.*

*5.* ***Definition of Line Connection / Network Assets***

*In the pre-filed evidence of RP-1999-0044 [Exh. A/Tab9/Sch. 1/p.9/definition of "Line Connection"], Line connection assets were defined as: "The radial lines of OHNC's high voltage system (115 kV and 230 kV) that are specifically dedicated to serving a single customer or group of customers".*

*An issue has been raised about the classification of certain lines commonly referred to as "local loops". These types of lines are generally characterized as starting at a Network station, terminating at a non-Network station and looping back uninterrupted to another Network station.*

*Parties are requested to comment on whether such lines should be classified as Connection or Network and what principles or references support that opinion. Parties are also requested to provide detailed criteria for classification of transmission lines into the two pools, Line Connection and Network.*

**Outcome of Settlement Discussions:**

Parties note that the Board in RP-1999-0044 accepted Hydro One Network Inc.'s definition of the proposed transmission pools (Network Pool, Line Connection Pool and Transformation Connection Pool), for the purpose of setting initial rates until the next cost allocation/rate design proceeding, at which time a set of criteria could be presented as the basis for the classification system (see Board Finding 2.2.24 of the Board's Decision in proceeding RP-1999-0044). Parties to this TSC proceeding respectfully submit that, given the possibility that the next rate proceeding may be some years away, the Board convene a separate proceeding as soon as possible, prior to the next cost allocation and rate design hearing, to deal with the classification of transmission assets. The classification definitions determined at such a proceeding would not form the basis of rates until the next rate proceeding. Hydro One has filed, in the present proceeding, a document outlining its proposed classification criteria that could form the basis of the proposed separate proceeding (see Appendix B). Parties agree that all the classification of assets of all licensed transmitters should be considered at the proposed proceeding, and that such issues as the appropriate treatment of customers who have contributed part, as opposed to all, of the cost of constructing Transformation Connection or Line Connection Assets would be included.

There are two proposals for the interim:

1. Until such time as rates are set based on thorough classification criteria developed through the proposed proceeding, parties agree that that existing local parallel loops that are reinforced and future local parallel loops that are built for the purpose of reinforcing the network shall be classified as network assets for the purpose of calculating capital cost contribution. This does not detract from the classification of such loops as transmission connection assets, and the loads connected to such connections shall pay the connection rates. Should the new classification system result in a change of the classification, any financial implications on parties as a result of reclassification of the "Local Loops" will have to re-evaluated. At that time any amounts owing to the transmitter, including interest will be settled. For clarity, this will not preclude the re-evaluation of financial impacts resulting from the reclassification of those local loops which are in existence at the date of this report.

   Parties supporting *interim measure 1*, above, are: *AMPCO, INCO, Algoma, IPPSO, VECC, CAC, Bruce Power.*

2. As an interim measure, until the Board has ruled on the appropriate treatment, the following parties agree that, where reinforcement of transmission lines in the future may result in the creation of new “local loops”, these reinforcements shall be treated following the proposed classification criteria set out by Hydro One (see Appendix B). Should the Board’s review result in a subsequent reclassification of these “local loops”, any financial implications on the parties shall be re-evaluated. At that time, any amounts owing, including interest, shall be settled between the parties.

   Parties supporting *interim measure 2*, above, are: *Hydro One, Toronto Hydro/EDA*

*GLPL and ECMI* support the introductory paragraph and take no position on the interim treatment of local loops.

*6.* ***Definition of Embedded Generation*** *(reference: Proposition # 1, Bypass)*

*Parties are requested to provide proposed definitions of embedded generation considering factors such as location.*

*It is proposed that ownership and voltage connection level not be criteria with respect to defining what constitutes embedded generation.*

**Outcome of Settlement Discussions:**

Parties explored a number of possible definitions, including for the purpose of determining when net load billing will be applicable for network charges by a particular rate-regulated transmitter. The parties had extensive discussions of the related issues and reviewed several schematic diagrams showing a variety of configurations. Two positions were eventually defined and are described below. Each position comprises a definition of embedded generation, and a discussion of the determinations, which will be required by the Board.

**Option 1,** supported by *Hydro One, PWU*

*VECC and CAC* support Option 1 except for the requirement under Part B where Board determination that a facility is embedded generation would lead to an automatic rate adjustment. Furthermore, while VECC and CAC accept the proposition that "the category of licence(s) held by transmission customer B is not relevant to the determination of embedded generation", this is based on the assumption that the existence of generation and other customers' loads are relevant factors in determining the requirement for licences.

Part A

For the purpose of determining when net load billing will be applicable for network charges from a particular rate-regulated transmitter:

> With respect to any rate-regulated transmitter "A" and transmission customer "B" (being a party that is directly connected to transmitter A's transmission system) generation is considered to be embedded if:

a) The generation is connected behind the point of connection between the facilities of transmitter A and the facilities of transmission customer B. The load facilities that comprise or connect to transmission customer B shall belong to no more than one entity within the meaning of the *Ontario Business Corporation Act*. In any case, the generator is not embedded with a load unless the load and generation are located on a single property that is contiguous and owned by the load or generator, and either

    a. The generation and load are connected to the same radial line (or a facility supplied there from), or

    b. The generation and load of a single entity as defined under the *Ontario Business Corporation Act* are connected on the same radial line (or a facility supplied there from) and the generation is renewable generation connected after October 31, 1998. Renewable generation includes generation from wind, water, solar, geothermal, tidal and landfill or waste gas.

b) The generator connects directly to the distribution system of a host LDC.

For clarity it is confirmed that:

- Common ownership of generation and load facilities and connection voltage level are not determinative in defining what constitutes embedded generation;

- The relative capacities of generation and load are not relevant to the determination of embedded generation (noting that generation can only be "embedded" up to the quantity of coincident load);

- The category of licence(s) held by transmission customer B is not relevant to the determination of embedded generation; and.

- The terms generator and generation refer to a generating station irrespective of the number of generating units.

Part B

The TSC should establish an OEB review process for application seeking embedded generation designation and transmission rate treatment for situations not covered by the definition for embedded generation in Part A, such as, for example:

- Generation and load connections that are *Local Interrelated Systems*[a]

- Any new connection between generation that existed prior to October 31, 1998 and load that existed prior to the same date

- Any new connection between generation that existed prior to October 31, 1998 and new load that comes into existence after the same date.

Such embedded generation applications will result in a Board determination on whether or not the facility subject to the application is designated as embedded generation. If the facility is ruled to be embedded generation, the Board will also approve the adjustment to the existing Provincial Transmission Rate Order based on the removal of the load for this case from the previously approved load forecast to calculate the new rates required to provide for transmission rate treatment in accordance with the embedded generation designation in this ruling.

Note (a):

The classification of a group of facilities as components of a *Local Interrelated System* requires that:

- a single party identifies itself as the transmission customer in respect of all such facilities, and

- there exists some degree of energy or process relationship between the generation source and the load(s).

This is modeled on the definition of the Alberta "Industrial System" and would require the Ontario Energy Board to make a final determination in accordance with criteria that would be modeled on those of the Alberta "Industrial System".

**Option 2,** supported by *IPPSO, AMPCO, INCO, Algoma, TransAlta, Bruce Power, OPG,* and *Imperial.* *GEC and OSEA* support this option with the caveat that the Part B Board approval process be required for new load connecting to existing generation as well as for new connections between existing load and generation.

PART A, DEFINITION OF EMBEDDED GENERATION

With respect to any rate-regulated transmitter "A", and transmission customer "B" (being a party that is directly connected to transmitter A's transmission system) generation is considered to be embedded if either:

a) The generation is connected behind the point of connection between the facilities of transmitter A and the facilities of transmission customer B or at the Low Voltage side of a transformation facility owned by transmitter A, or

b) The generation and load are connected to the same line connection facility (or interconnected group of such facilities) owned by transmitter A (or a facility supplied therefrom) and are approved by the Board as belonging to the same Local Interrelated System (defined below) in accordance with the process set out in Part B, or

c) The generation and load of a single transmission customer are connected to the same line connection facility (or interconnected group of such facilities) owned by transmitter A (or a facility supplied therefrom) and the generation is renewable generation. Renewable generation includes generation from wind, water, solar, geothermal and landfill or waste gas.

For clarity, it is confirmed that the following are not criteria in determining what constitutes embedded generation:

- common ownership of generation and load facilities, or of the land on which they are sited,
- operating control of the generation and/or load facilities
- contiguity of generation and load facilities,
- connection voltage level,
- contractual or financial arrangements (if any) associated with the output of the generator,
- the relative capacities of generation and load (noting that generation in excess of the load at any time is injected into the transmitter A's transmission system, and has no "embedded" effect), and
- the category of licence(s), if any, held by transmission customer B.

The classification of a group of facilities as components of a **Local Interrelated System** requires that:

- a single party identifies itself as the transmission customer in respect of all such facilities, and
- there exists some degree of energy or process relationship between the generation source and the load(s).

This is modeled after the definition of an "Industrial System" in Alberta and would require the Board to make a final determination in accordance with criteria that would be based on the statutory definition of "Industrial System" in Alberta.

In addition, the determination of embedded generation status arising from any material new connection (defined below) between generation that existed prior to October 31, 1998 and load that actually existed prior to the same date shall be subject to the approval of the Board in accordance with Part B below. Such determination is not required with respect to any connection to service new load, for which asset stranding is not an issue. New load is defined as any load to which service is initiated after October 31, 1998, and any increase in load to existing customers above that load which actually existed at that date.

PART B: BOARD PROCESS :

Classification as embedded generation shall be subject to Board approval in the case that either:

- Classification is sought under paragraph (b) above as a Local Interrelated System, or
- Both generation and the load in question were in existence prior to $31^{st}$ October 1998, but the interconnection is made after that date,

and the transmission system impact would be material. The transmission system impact is considered material only if the impact on yearly average net transmission charges determinant quantity is expected to exceed 20 MW.

The parties supporting Option 2 respectfully request that the Board establish and incorporate an appropriate process into the TSC, having due regard for the need to avoid delay and regulatory burden that would be inappropriate to the scale of the project or its impacts. The Board may wish to consider the relationship of this process and the dispute resolution process to be discussed under phase 2 of the present Transmission System Code proceeding.

The *IMO* did not participate in the discussion leading to the two options above. It has reviewed the proposed definitions for embedded generation and Market Rules definition, within the context of the Board's recent decisions in the Abitibi and Casco proceedings, and concludes that:

a) the emerging definition of embedded generation in these proceedings, for the purpose of transmission rates, is different than the definition in the Market Rules.

b) it appears impractical to reach a common definition of embedded generation for rate making, and reliability and connection purposes.

c) while a common definition is desirable, it appears that a different meaning would be adopted for Market Rules purposes.

**7.** ***Proposals for True-up Requirements*** *(reference: Proposition # 2, Economic Evaluation)* *It has been proposed that there should be specific rules defined for the true-up process.*

*It has been proposed that any true-up process should be a two way process so that the results of the true-up calculation could benefit either the customer or the transmitter.*

*It is proposed that regardless of the length of the study period there should always be a defined true-up application period of 10 years. For high risk customers this is beyond the defined study period. For low risk customers, true-ups would be terminated before the end of the study period. The defined true-up requirements might be as follows:*

> ***high risk*** *true-ups every 2 years for 10 years or as long as the customer remains connected*
>
> ***medium risk*** *true-ups at 3, 5 & 10 years or as long as the customer remains connected*
>
> ***Low risk*** *true-ups at 5 and 10 years or as long as the customer remains connected*

*Parties are requested to comment on the above proposals or to make additional proposals for dealing with true up requirements.*

**Outcome of Settlement Discussions:**

Proposal 1:

In each case, true-ups will be calculated over the appropriate time. At each point of true-up, if it is determined that a customer has not met its obligations to load a connection facility, then the customer would remit an additional contribution to the transmitter, with applicable interest, to compensate the pool. Similarly, if at the end of the true up period it is determined that a customer has exceeded its obligation to load a connection facility, then the Transmitter will remit the excess to the customer, up to a maximum of the customers initial capital contribution, with applicable interest. In the case of high-risk and medium- risk customers, the remittance by the Transmitter will occur at the end of the Economic Study Horizon. In the case of a low-risk customer with an Economic Study Horizon of 25 years, the true-up process will only occur at 5 years and 10 years, and not beyond, except in the case where there is a material shortfall, as noted below. For administrative ease, bands should be set at a material level to trigger the true-up.

The defined true-up requirements should be based on the following:

> **High Risk:** true-ups on an annual basis over the Economic Study Horizon of 5 years.
>
> **Medium Risk:** true-ups at 3, 5, & 10 years.

For medium and high risk, at each point of true-up, if it is determined that a customer has not met its obligations to load a connection facility, then the customer would remit an additional contribution to the transmitter, with any applicable interest, to compensate the pool. Similarly, if at the point of true-up it is determined that a customer has exceeded its obligation to load a connection facility, then the Transmitter will record the excess payment in a <u>notional account</u> on behalf of the customer, and remit any accumulated balance to the customer, with applicable interest, at the end of their respective Economic Study Horizons – 5 years (high) and 10 years (medium).

**Low Risk:** true-ups at 5 and 10 years but not beyond, except where the actual average load falls materially below or rises materially above the forecast (20%). At each point of true-up, if it is determined that a customer has not met its obligations to load a connection facility, then the customer would remit an additional contribution to the transmitter, with any applicable interest, to compensate the pool. Similarly, if at the end of the last true-up period it is determined that a customer has exceeded its obligation to load a connection facility, then the Transmitter will remit the excess payment to the customer, with any applicable interest. In the event that during the most recent true up period average actual load falls materially below or rises materially above the forecast (20%), then an additional true-up period will be added, to be calculated 5 years later.

When the economic evaluation has determined that there is no capital contribution, true up shall occur every 5 years based on a combination of actual and jointly agreed revised load forecast.

A and B are applicable to the low risk category for distributors only.

A. Where no lump sum Capital In Aid of Construction (CIAC) is required, that the forecast(s) in the original economic evaluation calculation be constrained such that the forecast(s) to which the customer(s) is (are) held for true-up purposes is not greater than the load required to support (fund) each customer’s original economic evaluation pro rata share of the incremental cost.

B. Where a lump sum CIAC is required, that the forecast(s) be constrained to the lesser of the available capacity or the amount(s) required to support (fund) each customer(s’) economic evaluation incremental cost(s). Further, that the potential rebate of each customer’s share of the lump sum CIAC be expanded to the full forecast true-up period (10 years).

The above proposal is agreed to by the following parties: *Hydro One, VECC, CAC, Toronto Hydro/EDA, GLPL, CNPI, ECMI*

<u>Proposal 2:</u>

Modify the introductory paragraph as follows, dealing with High and Medium Risk customers (changes in italics)

In each case, true-ups will be calculated over the appropriate time. At each point of true-up, if it is determined that a customer has not met its obligations to load a connection facility, then the customer would remit an additional contribution to the transmitter, with applicable interest, to compensate the pool. Similarly it is determined that a customer has exceeded its obligation to load a connection facility, then the Transmitter will remit the excess to the customer, up to a maximum of the customers initial capital contribution, with applicable interest. *In the case of high-risk customers, the remittance by the Transmitter will occur at the end of years 3 and 5. In the case of medium- risk customers, the remittance by the Transmitter will occur at the end of years, 3,5, and 10.* In the case of a low-risk customer with an Economic Study Horizon of 25 years, the true-up process will only occur at 5 years and 10 years, and not beyond, except in the case where there is a material shortfall, as noted below. For administrative ease, bands should be set at a material level to trigger the true-up.

Replace the paragraphs dealing with High and Medium Risk customers with the following (changes in italics)

**High Risk:** true-ups *at 3 and 5 years* over the Economic Study Horizon of 5 years**.**

**Medium Risk:** true-ups at 3, 5, & 10 years.

For medium and high risk, at each point of true-up, if it is determined that a customer has not met its obligations to load a connection facility in that year, then the customer would remit an additional contribution to the transmitter, to compensate the pool. *Similarly, if at the point of true-up it is determined that customer has exceeded its obligation to load a connection facility, then the Transmitter will remit any accumulated balance to the customer, with applicable interest.*

**Low Risk:** true-ups at 5 and 10 years but not beyond, except where the actual average load falls materially below the forecast (20%). At each point of true-up, if it is determined that a customer has not met its obligations to load a connection facility, then the customer would remit an additional contribution to the transmitter, with any applicable interest, to compensate the pool. Similarly, if at the end of the last true-up period it is determined that a customer has exceeded its obligation to load a connection facility, then the Transmitter will remit the excess payment to the customer, with any applicable interest. In the event that during the most recent true up period average actual load falls materially (20%) below the forecast, then an additional true-up period will be added, to be calculated 5 years later.

A and B are applicable to the low risk category for distributors only (see A & B, under Option 1 above, for discussion of A & B).

The following parties agree to Proposal 2: *AMPCO, INCO, Algoma*

*GEC and OSEA* accept proposal 1 or 2, based on the assumption that true-up will be on the basis of forecasts updated to reflect the factors addressed in paragraph 75 of Procedural Order # 3 in this proceeding.

In addition to the above proposals, some parties support the addition of the following proposal, with limited application as indicated:

This recommendation will apply to the low risk category for distributors only.

Where material capital costs are incurred subsequent to 1999 associated specific asset the forecast (after any adjustment required under Recommendation No.1) used for true-up should be adjusted downwards for:

A material distributor’s end-use customer going *out of business* and,
the addition of embedded *clean generation* and,
the success of a bona fide *energy efficiency program* within the distributor’s service area.

Supporting parties identified the following *benefits* to this option:

- Consistent with normal *Force Majeure* implications (i.e. the going out of business is outside of the control of the distributor).
- Consistent with network charges being a flow through for distributors (variance account).
- Limits the creation of new risk for distributors and their customers. Limits the transfer of risk from the transmitter to the distributor.
- For distributors with one delivery facility recognizes, to a small degree, that distributors are demand takers.
- Properly assigns transmission system revenue risk for this low probability, low risk, but potentially high end use customer rate impact situation.
- Limits small community end use customer bill impact associated with transmission system rates resulting from customers in that community going out of business.
- Is consistent with a separation of transmitter and distributor risk (i.e., the distributor accepts distribution system losses in these situations and the transmitter should accept transmission system losses in these situations).
- Encourages the introduction of *bona fide* energy conservation initiatives and the introduction of clean generation.

The following *disadvantages* have been identified:

- Distributor has control over investment decision and should bear responsibility
- Investment decision based on Distributor's forecast
- If distributor so vulnerable to one large customer should probably be classified as "high risk"
- *Force majeure* is not intended to apply to economic failure
- Inconsistent with treatment of Network charges. Network charges are payable by the distributors. Variance accounts attract differences.

Parties supporting this additional proposal are as follows: *ECMI*. *Toronto Hydro/EDA* support the additional proposal related only to energy efficiency programs and embedded clean generation.

As facilitator in these discussions, I would like to express to the Board my appreciation of the courtesy and diligence of parties throughout the process. In my view, there was an effort on the part of all parties to understand the concerns of others with differing views, and all parties benefited from the careful examination of these issues. I would also like to express my thanks to

Board staff for their support and assistance throughout the discussions. Although I was disappointed that further agreement could not be reached, I hope that the alternatives presented will assist the Board to some degree.

Respectfully submitted,

Gail Morrison, facilitator.

## APPENDIX A

## TRANSMISSION SERVICE CODE
## RP-2002-0120
## LIST OF PARTICIPANTS

| | Party | Representative(s) |
|---|---|---|
| 1. | Hydro One Networks Inc. (Hydro One) | David Curtis<br>Oded Hubert<br>Ian Innis<br>Donald Rogers, Counsel |
| 2. | Association of Major Power Consumers in Ontario (AMPCO) | James E. Fisher, Counsel<br>Bruce Bacon |
| 3. | Algoma Steel Inc. (Algoma) | Mark Rodger, Counsel |
| 4. | Brighton Beach Power L.P. | Wayne Symington |
| 5. | Bruce Power | Corinne Draesner |
| 6. | Canadian Niagara Power (CNPI) | Douglas Bradbury |
| 7. | Consumers' Association of Canada (CAC) | Julie Girvan |
| 8. | Electrical Contractors Association of Ontario (ECAO) | George Vegh, Counsel |
| 9. | Electricity Distribution Association (EDA) | Maurice Tucci<br>Romano Sironi |
| 10. | Energy Cost Management Inc. (ECMI) Coalition[1] | Roger White<br>Andy Bateman |
| 11. | Green Energy Coalition (GEC) &<br>Ontario Sustainable Energy Association (OSEA) | David Poch, Counsel |
| 12. | Great Lakes Power Limited (GLPL) | Charles Keizer, Counsel<br>Bud Carruthers |
| 13. | Independent Electricity Market Operator (IMO) | Carl Burrell |
| 14. | INCO | James C. Sidlofsky, Counsel |
| 15. | Independent Power Producers' Society of Ontario (IPPSO) | Thomas Brett<br>Robert Cary |
| 16. | International Brotherhood of Electrical Workers Construction Council of Ontario (IBEW-CCO), and The IBEW Electrical Power Council of Ontario | Jack Dowding<br>Graham Williamson, Counsel |
| 17. | International Transmission Company (ITC) | Kristi Sebalj (Power Budd) |
| 18. | Imperial Oil Limited (IOL) | George Vegh, Counsel |

[1] *ECMI coalition*: Brant County Power, Clinton Power, COLLUS Power, Gravenhurst Hydro Electric, Halidmand County Hydro, Hearst Power Distribution, Peninsula West Utilities, St. Thomas Energy, Wasaga Distribution

| | Party | Representative(s) |
|---|---|---|
| 19. | Ontario Power Generation (OPG) | Andrew Barrett<br>Anthony Petrella |
| 20. | Power Workers Union (PWU) | Richard Stephenson, Counsel |
| 21. | Toronto Hydro-Electric System Ltd. (Toronto Hydro) | Colin McLorg<br>Romano Sironi |
| 22. | TransAlta Energy Corporation (TransAlta) | Dick Way<br>Richard King, Counsel |
| 23. | Vulnerable Energy Consumers Coalition (VECC) | William Harper |

## APPENDIX B

## PROPOSED CRITERIA FOR CLASSIFICATION OF TRANSMISSION ASSETS INTO NETWORK AND LINE CONNECTION

**Note: Extracts from Hydro One's response to Procedural Order No. 4 on the TSC Review (RP-2002-0120)**

**Hydro One's Submission:**

HON Inc. contends that transmission lines that are "local loops", are all encompassed in the broader classification of Urban Parallel Circuits. HON Inc. submits that the primary purpose of Urban Parallel Circuits and "local loops" is to improve local reliability for connected customers. Given that these investments are determined on this basis and not for the purpose of enhancing the transfer capability or reliability of the Network, 'Local Loops" should be categorized as Line Connection Assets. Criteria identifying Dual Function Line assets should also be set by the Board in the TSC review to complete the set of criteria for assigning line assets.

**Criteria for Assigning Transmission Assets To Network, Dual Function Line, and Line Connection Categories**

- **Network Assets**

  The transmission facilities that are used for the benefit of all or many customers in the province are categorized as Network Assets. Thus, Network assets comprise the following "back-bone" transmission facilities that ensure reliability of the interconnected system and that enhance overall electricity market efficiency:

- All 500 kV circuits and 500/230 kV Auto-Transformer facilities
- All 230 kV circuits that are not tapped[2] to supply load and that are normally operated in parallel with 500 kV circuits; such parallel circuits may be circuit(s) that form a series of transmission circuits that together normally operate in parallel with the 500 kV circuit(s).
- All 230 kV and 345 kV "interconnecting circuits" which connect HON Inc. transmission system to the transmitter systems owned by other transmitters in Ontario and to the power system(s) in the neighboring jurisdictions.
- All 230 kV circuits that are not tapped to supply load and that are normally operated in such a manner that they connect the "interconnecting circuits", directly or through a series of transmission circuits, to any of the 500 kV and 230 kV network circuits noted above.
- All 115 kV circuits that are not tapped to supply load and that are normally operated in parallel with network circuits noted above, with the exception of 115 Urban Parallel Circuits that operate in parallel with network circuits solely to enhance reliability of supply for one or few transmission customers.

– If necessary, the determination that parallel 115 circuits are not Network circuits shall be based on system studies to identify whether or not splitting of the 115 kV parallel would

[2] A "tap" is defined as a connection to a transmission circuit where that particular circuit is *not* connected to any other circuit(s) by a set of circuit breakers at the location of the tap connection.

materially reduce the transmission interface capability between two 500 kV or 230 kV Network stations.

- If necessary, the determination that parallel 115 circuits are not Network circuits shall be based on system studies to identify whether or not splitting of the 115 kV parallel would materially reduce the transmission interface capability between two 500 kV or 230 kV Network stations.
- If the splitting of the parallel 115 kV path[3] decreases the 500 kV or 230 kV transmission interface capacity, measured at both the outgoing and incoming buses, by more than 10 %, then the parallel 115 kV circuits shall be classified Network circuits or Dual Function Lines as described below. If the impact on the network interface capability is 10 % or less, the parallel 115 kV circuits will be categorized Line Connection.

▪ The 230/115 kV AutoTransformer facilities normally connecting the 230 kV and 115 kV network circuits noted above and/or the Dual Function Lines described below.

▪ The specific sections of 115 kV circuits that interconnect with transmitter systems owned by other transmitters in Ontario and the neighboring jurisdictions, beginning from the junction or station from/at which Ontario customer load is supplied up to the border with neighbouring State or Province.

▪ The transformation or switching stations, or portions thereof, that include circuit breakers that switch the network circuits and the Dual Function Lines described below.

▪ The capacitor banks located in high voltage Transformer Stations and Switching Stations.

♦ **Dual Function Line Assets**

The transmission circuits connecting two Network Stations are categorized as Dual Function Line assets if they are used for both, the common benefit of all transmission customers and for providing a tap connection between the Network Stations and load supply point(s) for one or few customers[4].

Specifically, the transmission circuits comprising the following types of electrical assets are Dual Function Line assets and include:

▪ All 230 kV circuits that are tapped to supply load and that are normally operated in parallel with 500 kV circuits.

▪ All 115 kV circuits that are tapped to supply load and that are normally operated in parallel with network circuits or 230 kV Dual Function Lines noted above, with the exception of 115 kV Urban Parallel Circuits that form a parallel path to primarily serve, or provide security of supply for, one or few customers as noted above.

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[3] For determination of the network interface capability, the location of the split of the 115 kV subsystem shall be the point(s) on the subsystem that result in a load balance within the split subsystem that is consistent with the continuous capacity of the elements of the split subsystem.

[4] Such circuits jointly provide both Network and Line Connection functions and, depending on the Cost Allocation methodology approved by the Ontario Energy Board, the costs for such lines may be allocated to the Network and Line Connection functions.

- All 230 kV circuits that are tapped to supply load and that are normally operated in such a manner that they connect the "interconnecting circuits", directly or through a series of transmission circuits, to any of the 500 kV and 230 kV network circuits noted above.

♦ **Line Connection Assets**

The transmission circuits and intermediate 230 kV / 115 kV radial stations[5] which are used to serve, and to enhance reliability for, one or a few transmission customers are categorized Line Connection assets. Thus, the transmission lines or stations comprising the following type of electrical assets are defined Line Connection assets and include:

- The Transmission circuits that are radial (i.e. circuit sections that are not categorized as being Network circuits or Dual Function Lines).
- The 115 kV Urban Parallel Circuits that operate in parallel with Network circuits or Dual Function Lines without materially reinforcing the transmission interface capability of the "back-bone" transmission network that is commonly shared by a large portion of, or entire, province.
- The intermediate radial Transformer Stations, or portions thereof, dropping power from 230 kV to 115 kV are also categorized as a Line Connection assets if they are not already categorized as a Network asset as per the guidelines above. (They cannot be assigned to the Transformation Connection Pool, since they do not "drop the voltage from above 50 kV to below 50 kV", and they cannot be always assigned to the Network Pool because, in many instances, they serve dedicated or few customers).

**Background**

The discussions and deliberations about the definition of Line Connection assets evolved considerably during the Proceeding RP-1999-0044 from the simplified definition included in the pre-filed submission at Exh. A/Tab 9/ Sch. 1/ p. 9 dated November 24, 1999.

In response to a Board staff interrogatory under the above proceeding, HON Inc. provided relatively detailed guidelines for the allocation of transmission assets to cost pools. These guidelines are available under Appendix E-1-12: A of Exh. E/Tab 1/Sch. 12 filed on December 22, 1999 and they were accepted by the Board as per Board Decision with Reasons dated May 26, 2000 for Proceeding RP-1999-0044.

The discussions provided below address the issues around the classification of Network and Line Connection assets, in particular the 115 kV circuits that, although they are in parallel with sections of 230 kV network lines, are installed solely for the benefit of a Local Distribution Company (LDC). This discussion introduces the term 115 kV Urban Parallel Circuits to describe circuits, such as and including the "local loop", that are operated in parallel with network circuits yet they primarily serve the function of providing security of supply within a LDC. The discussion also addresses the issue of Dual Function Lines that are essentially

[5] The intermediate 230 / 115 kV radial stations that serve one or few customers are also included as Line Connection assets in order to simplify the transmission rate structure.

Network circuits with load tapped to them in-between two Network stations. The background pertaining to these two terms and related issues is summarized below.

115 kV Urban Parallel Circuits (Including Local Loops)

The issue of local loops is likely to manifest itself even more significantly over the next few years when different types of local loop facilities may be placed in service to ensure reliability of supply within urban centers in Ontario[6]. Hence it is necessary to deal with this issue under a broader category of 115 kV Urban Parallel Circuits so that the issue is addressed comprehensively and definitively at this time during the review of the TSC.

As noted in the Procedural Order #4, this issue has been raised following a recent proceeding in which a "local loop"[7] that serves a LDC was classified Line Connection for the purpose of calculating the capital contribution requirement to reinforce that loop.

For technical reasons, 230 kV circuits are not likely to be connected in a manner similar to the 115 "local loop" that precipitated the review of the asset categorization under the current TSC proceeding. Further, the 230 kV circuits in Ontario that operate in parallel with other network circuits always increase the transfer capacity between two or more Network stations. The issue of Parallel Urban Circuits is not germane to 230 kV lines.

The issue of categorization of 115 kV Urban Parallel Circuits, including local loops, into Line Connection pool is important in the immediate term in two contexts. These are: (1) The obligation for the payment of Line Connection Service charges by the LDC connected to, and benefiting from, these parallel circuits; and (2) the obligation to make contribution for new investments in these parallel loops by the LDC benefiting from these loops. In the longer term, when the transmission rates are recalculated for the next transmission rate filing, the manner in which this issue is resolved at that time will determine how the costs associated with the 115 kV Urban Parallel Circuits are allocated to the Network and Line Connection Pools.

If the wording "parallel to Network" were strictly observed to categorize the Network / Line Connection assets, then the existing and newly-formed 115 kV Urban Parallel Circuits would have to be re-categorized as Network facilities, instead of Line Connection facilities, when a 115 kV parallel path is formed for local reliability reasons. Thus, in the case of a new line being installed to form a parallel path for local reliability reasons, the circuits in this path may include existing Line Connection Circuits as well as the new circuit installed to close the parallel loop. Therefore, some of the existing as well as the new line connections will have to be categorized

[6] The IMO's March 31, 2003 report "10-year Outlook" anticipates that, in the foreseeable future, there will be a requirement for transmission investments in several urban areas in order to maintain security of supply within these areas. The options that can be considered for reinforcing the security of supply in these areas are likely to include new 115 kV transmission circuits that may result in many, if not most, of the existing Line Connection circuits in some urban areas becoming parallel with circuits classified as Network.

[7] The local loop that led the issue being raised in the Procedural Order comprises a 115 kV line originating at "Network" station, supplying four delivery points of a LDC, and terminating as a tap on a separate Network circuit that connects the first Network Station with another Network station. This local loop therefore does not increase the transfer capacity between two Network stations.

Network even if the 115 kV parallel path does *not* benefit any entity other than the LDC that is connected to the 115 kV parallel path.

Dual Function Lines

Currently, in accordance with Board decision under Proceeding RP-1999-0044, the Dual Function Lines are included in the Network Pool. It is proposed that this treatment should also be continued. As noted above, the Dual Function Line category is included in the stated criteria for Board consideration in order to complete the set of criteria for assignment of transmission line assets. The rate design considerations for Dual Function Lines should be considered among the options for cost allocation and rate design during the next transmission rate filing.

It is proposed that the discussion of the Network and Line Connection assets during the TSC Review should also include the matter of Dual Function Lines.

At the conclusion of Proceeding RP-1999-0044, the Board accepted the guidelines proposed by HON Inc. to assign assets into the Network and Line Connection Pool for initial transmission rates (effective upon Open Access). However, the Board also made the finding that further consideration was required in the matter of customers supplied by taps to Network circuits, and whether or not these customers should pay Line Connection service charges. The Board ruled that a modified definition to deal with the tapped Network circuits lines should be brought back for review in a future proceeding. This finding was based on concerns expressed by some stakeholders that the transmission customers tapped to Network lines, which may also be called "Dual Function Lines", should not have to pay Line Connection Service charges.

**Rationale**

The criteria described above indicate that the 115 kV Urban Parallel Circuits that do not increase the transfer capacity of the 230 kV and 500 kV network should be categorized Line Connection, and not Network, even if these circuits are in parallel with the network circuits. This approach of treating the 115 kV Urban Parallel Circuits can be justified on the basis of cost causality; fairness and equitable treatment of customers; and providing signals for new investments, as summarized below.

(a) Cost Causality

The role of the 115 kV Urban Parallel Circuits is primarily to increase the security of supply within the specific urban areas where these circuits are located. In most cases, these Urban Parallel Circuits would allow the distribution system load within an urban centre to be served even when one of the connections between the LDC and the network is severed due to a forced or maintenance outage of 115 kV circuits. For the most part, the 115 kV Urban Parallel Circuits do not materially enhance the throughput capacity[8] of 230 kV or 500 kV network interfaces that serve transmission customers throughout the province.

[8] Throughput transfer capacity between two Network Stations is the lower of the maximum transfer out of one of these stations and the transfer into the other station. The throughput transfer between the two Network stations cannot exceed this throughput transfer capacity.

From the perspective of cost causality, the 115 kV Urban Parallel Circuits are no different than the radial circuits that serve one or few transmission customers. Just as the radial circuits do not benefit the transmission customers outside the local area where these circuits are located, the 115 kV Urban Parallel Circuits do not serve transmission customers other than the distribution system in the area in which these parallel circuits are located.

(b) Fairness and Equitable Treatment of Customers

According to the rules for the application of transmission rates, in accordance with the Board decision under Proceeding RP-1999-0044, transmission customers do not have to pay Line Connection Service charges if they are not connected to Line Connection assets or if they are not tapped to Network circuits.

If the 115 kV Urban Parallel Circuits were classified Network assets, then the load for LDCs supplied by these circuits would not have to pay Line Connection Service charges. In other words, under this approach, even though the Urban Parallel Circuits are primarily to serve only the local load, and not provincial load, the local load would escape Line Connection Service charges because of the existence of Urban Parallel Circuits.

Meanwhile, other transmission customers – including load in rural areas and in less dense urban areas where similar parallel circuits are non-existent– would still have to pay Line Connection Service charges and the Network service charges which would include the costs associated with the Urban Parallel Circuits. Indeed, the rural customers would have to pay higher Line Connection Service charges, compared to the current situation in which local loops are considered Line Connection, if the urban customers were to escape the Line Connection charges as a result of the local loops being considered Network assets.

In addition, if the Urban Parallel Circuits were included in the Network pool, the Network Service rate would also increase; thereby disadvantaging the rural customers even more compared to the urban customers.

(c) Signals for New Investments

There is also a concern that wrong investment signals will exist if the local loops and other Urban Parallel Circuits were treated as Network assets.

In this context, some transmission customers may cause actions that result in reinforcement of their reliability of supply – sometimes beyond the historical level - by forming local loops because of the additional incentive that these loops will also allow them to escape Line Connection Service charges. The inclusion of the Urban Parallel Circuits and local loops in the Network category will also limit competition in the provision of transmission connections.

**APPENDIX C**

September 12, 2003

TSC Review (RP-2002-0120)
Settlement Conference

Issue # 2: What Constitutes Fully Allocated Costs

**Hydro One**
**Fully Allocated Costing of Connection Assets**

## Costing of "Pool Funded" Connection Assets

The cost of this connection work is determined by reviewing the scope/deliverable of the project under consideration, identifying the optimal design and construction alternative, and estimating the labour, material and equipment costs necessary to complete the work.

Labour costs are a function of estimated staff time to be directly charged to the project and the standard labour rate. The standard labour rate is applied based on occupation code.

The standard labour rate which is applied comprises the base pay of the occupation performing the work, as well as a full set of overhead costs incurred in support of staff directly working on the project. These overheads include:

- company benefits (e.g. medical, dental)
- government obligations (e.g CPP, EI, EHT)
- vacation and statutory holiday time
- payroll allowances (e.g. payments per collective agreement)
- sickness and accident time
- safety meeting and training time
- supervision and management
- clerical support
- facilities costs
- telecommunications

The above overheads are calculated as part of the annual budget process and are added to the base labour rate to arrive at a standard labour rate for each occupation code (e.g., design engineer, scheduler, mechanical maintainer, electrical maintainer, regional line maintainer,…). On average, the standard labour rate is about 2x the base labour rate.

Equipment costs are estimated using the number of hours a piece of equipment is needed, multiplied by the standard "rental" rate for that specific piece of equipment. As part of the annual budget process, standard rates are developed for each type of equipment. These standard rates are set to recover lease costs (or depreciation), operating costs, repair costs and administration costs of managing equipment use.

Material costs are estimated and materials are acquired following standard Hydro One procurement and supply chain management practices. A material surcharge is added to the cost of materials to reflect the costs of the procurement function used to support the purchase.

In addition to the above labour, equipment and material costs, attributable overhead costs that are specifically related to new connection work are added to the estimate. This overhead reflects the cost of support provided by the following functions for the connection asset:

- Investment Planning – transmission planning staff for lines, stations, etc
- Program Execution – staff who monitor the work and its costs
- Customer Relations – staff who negotiate, execute and maintain the agreements with customers
- Finance – staff who support the economic evaluations and analysis
- Legal – work in support of the agreements
- Operations – work to ensure that the assets are incorporated appropriately into the Hydro One operating base.

As part of the discounted cash flow calculation, operations costs over the life of the asset are also considered. These costs are based on operating experience and reflect costs associated with preventative and corrective maintenance, asset management, infrastructure and auxiliary maintenance. These OM&A costs are calculated using the standard costing practices and rates for labour, equipment and materials.

An illustrative example demonstrating how a cost estimate is derived is provided as follows:

| | |
|---|---|
| Labour: | Occupation Code #1 (Standard Labour Rate) x Direct Hours Charged = L1 |
| | Occupation Code #2 (Standard Labour Rate) x Direct Hours Charged = L2 |
| | Occupation Code #3 (Standard Labour Rate) x Direct Hours Charged = L3 |
| Equipment: | Type Class #1 (Equipment Rate) x # hours charged = E1 |
| | Type Class #2 (Equipment Rate) x # hours charged = E2 |
| Material: | Invoice #1 x Material Surcharge = M1 |
| | Invoice #2 x Material Surcharge = M2 |

Attributable Overhead Costs: AOC

OM&A Cost: OMA

Cost of Project: L1+L2+L3+E1+E2+M1+M2+AOC + pv(OMA)

Issue # 2: What Constitutes Fully Allocated Costs

**Hydro One**
**Fully Allocated Costing of Connection Assets**

**Additional Information per September 12, 2003 Request**

**1. List the costs that are not included in estimates for pool funded new connection work.**

Some corporate costs are excluded from the pool funded new connection cost estimate. These excluded costs relate to functions supporting corporate services and asset management that are not deemed attributable to new connections.

Excluded corporate services costs relate to the following functions:
- Regulatory affairs
- Executive office
- Corporate development
- Treasury
- Human resources
- Finance (except portion specifically attributable to connections)
- Law (except portion specifically attributable to connections)
- Tax
- Audit
- Insurance
- Rate design
- Environment (re. Corporate policy/strategy)

Excluded asset management costs relate to the following functions:
- Investment planning (except portion specifically attributable to connections)
- Program execution (except portion specifically attributable to connections)
- Network strategy
- Business integration
- Customer relations (except portion specifically attributable to connections)
- Operations (except portion specifically attributable to connections)

**2. Outline the methodology followed for capital overhead capitalization.**

The Hydro One capitalization process applies a general allocation approach and attributes a portion of corporate costs to capital work in order to fairly apportion costs between OM&A and capital work.  This is important for regulatory accounting purposes in order to appropriately attribute costs to current and future customers and to maintain intergenerational equity.

Hydro One attributes a portion of asset management and corporate services costs (as identified above) to capital projects.  The capital overhead rate is determined based on this portion of capitalizable costs divided by the total cost of the capital work program (excluding non-overhead bearing costs such as interest and minor fixed assets).

All capital and OM&A costs are approved as part of the annual budget process.   The budget for asset management and corporate services and the portion attributable to capital are developed during this budget process.  The capital overhead rate reflects an average of costs over the planning period. The portion of asset management costs attributable to capital is determined based on the proportion of effort spent in support of capital projects.  Corporate services costs are attributed to the capital "pool" based on the proportion of capital program expenditures relative to total work program expenditures.

An example of how the rate is calculated follows:

Asset manager capitalizable costs = $X
Corporate services capitalizable costs = $Y

$$\frac{\$X+\$Y}{\text{Capital Work Program Base}} \boxed{= \text{Capital Overhead Rate \%}}$$