BEFORE THE ONTARIO ENERGY BOARD

Review of the Transmission System Code) **and Related Matters)**	**Docket No. RP-2002-0120**

EVIDENCE OF

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ON BEHALF OF

THE GREEN ENERGY COALITION

THE CANADIAN INSTITUTE FOR ENVIRONMENTAL LAW AND POLICY

THE ONTARIO SUSTAINABLE ENERGY ASSOCIATION

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Introduction

A societal-cost perspective that includes externalities should inform all decisions regarding transmission charges. Transmission charges should be set at levels that allow the development of societally cost-effective investments in generation and other resources. To the extent consistent with that goal, transmission charges should be used to minimize cost shifting.

Any reduction in recovery of fixed costs due to a customer action must be weighed against the societal benefit of that action. For example, minor reconfiguration of transmission and distribution facilities, to allow an *existing* generator to sell behind a distributor's meter, will rarely have any societal benefits; neither the generator nor the distributor should be able to avoid embedded transmission costs by such means. The same would be true of a customer that built a new connection to a transmission provider, abandoning an existing connection.

In general, network facilities should be presumed not to be abandoned by reductions in billed load, since the network will continue to serve many customers, including growing loads. Connections are more likely to be subject to abandonment since in many cases capacity on connection equipment freed up by one customer's action will not be useful for any other customer.

Similarly, any actions reconfiguring connections between existing generation and load is unlikely to have societal benefits. By contrast, new clean generation may result in tangible benefits but may be difficult to implement without some flexibility in the transmission code.

Many of the issues raised in these comments are especially important at distribution voltage, where most renewable generators will connect. The Board should convene a process to consider similar issues for distribution companies.

Many of these issues have been recognized by the U.S. Federal Energy Regulatory Commission in its Advance Notice of Proposed Rulemaking "Standardization of Small Generator Interconnection Agreements and Procedures" (Docket No. RM02-12-000, August 16, 2002). The FERC found that simplifying interconnection for small generators would

> enhance competition in the energy market. The Commission expects that, as a result of this rulemaking, an increasing number of new generation resources will participate in the market, thereby furthering customer choice of technologies and fuels, allowing more customer options in response to high generator prices, and facilitating development of non-polluting alternatives such as photovoltaics and small wind resources.

The FERC described its intention to "allow small generators to avoid unnecessary delay caused by interconnection studies and queues established for larger generators and their greater impact on the grid" through the development of "detailed, simplified procedures and agreements that allow for quick, inexpensive, and simple interconnection for small generators." The proposed rules would cover connections at both the transmission and distribution levels.

For example, the FERC rules, if adopted, would create a presumption that a small generator will have no impact if the total load of small generators on the line (net of on-site load) was less than 15% of the peak load on a radial line or 25% of the minimum load on a network link, so long as the generator's capability did not exceed 25% of the maximum short-circuit potential. So long as these conditions are met, the rules would require the transmission provider to justify any refusal to interconnect or require specific system upgrades. For small generators that exceed any of these limits, the transmission provider would perform simplified studies to determine whether upgrades are required.

In addition to the interconnection procedure and agreement for generators under 20 MW, the FERC proposal includes an even simpler procedure and agreement for generators smaller than 2 MW.

In the following sections, I list the Board questions from Appendix A to Procedural Order No. 1 in this proceeding, and respond on each point.

1. Transmission System Bypass

1.1. Permitting Bypass

> *1.1 What type of bypass should be permitted, and on what basis should it be permitted?*

First, it is important to be clear on what constitutes bypass and what does not. Reduction in load and increases in internal generation within a distributor (including generation connected to the distributor from outside its territory) are not bypass.[1] The effect of these actions is properly treated in transmission rates and has largely been addressed by the Board in its RP-1999-0044 Decision.

Second, true transmission bypass, in which a customer constructs new equipment to avoid paying the charges to the transmission provider, should be permitted where it is in the social interest. The balance of societal costs and benefits will be affected by the reduction in the transmission provider's costs, and by environmental and other externalities.

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[1]Generation within a distributor that causes power to flow back into the transmission system may incur connection charges, to the extent that it imposes incremental costs on the transmission provider. This is an incremental-cost issue, rather than an issue of bypass.

1.2. General or Specific Policies

> *1.2 Should the Code include a general policy governing bypass, or should each bypass proposal be decided on a case-by-case basis?*

The Code should include general principles, with decisions made (and if necessary, reviewed) on a case-by-case basis.

1.3. Contractual Provisions that Prevent Bypass

> *1.3 Should the Code prohibit contractual provisions that prevent bypass?*

Yes, except to the extent that those provisions are explicitly approved by Board order, in a contested case. Transmission providers should not be in a position to set the rules by which they will provide and charge for their monopoly service. The economic interest of the transmission provider is not the same as the societal perspective; the latter should guide decisions regarding the ability of customers to alter their transmission service.

1.4. Accommodating New Growth

> *1.4 What principles should apply where new load growth can be accommodated by either the transmitter's existing facilities or by new facilities built by a customer?*

The guiding standard for this question, as for all others, should be societal least cost, as determined by Board. If new customer-built connection facilities would reduce losses, avoid the need for new distribution facilities, and allow the distributor to more economically connect new clean generation, the Board should encourage such construction. In most cases, the transmitter's existing facilities will provide service as lowest societal cost.

2. Available Capacity

I have no comments on this point at this time.

3. Cost Responsibility

3.1. Network

3.1.1. Benefits of Network Reinforcement

3.1.1 For the purpose of determining cost responsibility should the Network component of a transmission system reinforcement be treated as:

(a) benefiting all transmission customers and therefore not attributable to the connecting party;

(b) benefiting the connecting party and therefore attributable to that party; or

(c) a combination of (a) and (b)?

Network reinforcements driven by load will be recovered from load through rates. Due to the nature of network service, attributing costs to specific customers, or even to specific regions, is generally not possible, and no locational signal appears appropriate at this time.

Network reinforcements driven by additions of large generation, on the other hand, should be paid for by the generation. Otherwise, generators would be free to site plants in areas that will force large network reinforcements without bearing any of the costs (since load pays for the network) and without receiving any locational signal. If an area with cheap land, good pipeline interconnections, and low electrical connection costs is also a very expensive place to inject more power, in terms of required network reinforcement, the failure to charge generators for their contribution to network upgrades could result in hundreds of millions in additional costs to Ontario electric customers.

These are not even necessarily just transfers of costs from generators to loads; they may be real increases in societal costs. A generator that picked a site to save $3 million in land costs might well increase societal costs by $30 million in network reinforcements.

3.1.2.1. When the Cost of the Network Component of a Reinforcement Is Attributed to a Connecting Party

3.1.2.1 If the cost of the Network component of a reinforcement is to be attributed to a connecting party:

(a) should power-carrying system elements such as bus works, breakers and transmission towers be treated differently from auxiliary equipment such as protection and control schemes and communication facilities; and

(b) should power-carrying system elements that behave in a radial fashion be treated differently from power-carrying system elements that interconnect network stations?

I am not aware of any reason to make these distinctions.

3.1.2.2. Principles for Attributing Costs to a Connecting Party

3.1.2.2 If any cost, in its entirety or in part, of the Network component of a reinforcement is to be attributed to any connecting party, what principles should apply to the attribution of that cost?

Customers should not be charged twice for the same service. If a customer is charged for an upgrade that is later beneficial to the network or to specific other customers, the costs should be prorated.

Customers should not be charged for network reinforcements if such charges would increase total societal costs. As I note elsewhere, it is appropriate for large conventional generators to pay the costs of network reinforcements they require.

Attribution of network reinforcements to small generators is inherently less certain than for large generators, since the same upgrades might well be required for currently unanticipated load or generators, or not required even with the small additional generator. The administrative costs of identifying, quantifying, and pricing network reinforcements due to a small generator are likely to be high, compared to the potential investments under study. On the other hand, the potential cost of discouraging small generators and losing their competitive role, diversity of fuel sources, and environmental benefits is quite high. The FERC has recognized these considerations and proposed that the potential network effects of small generators should be reviewed only in extraordinary circumstances.

3.2. Principles of Connection Reinforcements

3.2 What principles should apply to the attribution of cost responsibility with respect to the following types of line and transformation connection reinforcements:

(a) shared radial connection lines;

(b) breakers;

(c) disconnect switches?

The general considerations in the transmission code (load and distance) are appropriate for use in allocating shared costs between customers. Two aspects of the attribution of cost responsibility as currently described in the transmission code could impede the development of societally beneficial generation.

First, consider the example of development of multiple wind farms along the Bruce Peninsula. Hydro One might prudently determine that the appropriate interconnection for 100 MW of planned wind development along the Peninsula is a 115-kV line. If Hydro One built that line for the first 10-MW wind farm and charged the wind farm for the entire cost of that connection facility, the cost of that line might well dominate the economics of the facility for its early years. Indeed, construction of the first wind farm might be economically infeasible, since the developer would go broke paying for the transmission until subsequent plants came on line to share the cost. Hence, an economic and environmentally valuable resource might never be developed, since the rule for assignment of connection costs to new generators could render infeasible the development of the first of a series of dispersed generators. In addition to wind farms, similar problems could arise for other dispersed renewable generators that must be sited at the energy source, such as biomass-fueled plants (e.g., methane digesters at large livestock operations) or small hydraulics along a river, and perhaps some areas with opportunities for multiple high-efficiency cogeneration installations. This is an economic development problem distinct to specific groups of small generation customers. Similar problems are unlikely for large plants, especially those (such as gas combined-cycle) that can be sited to minimize connection costs.

To avoid these unfortunate situations, the Board should prescribe a solution that allows for incremental development of small generators (e.g., less than 20 MW) at reasonable costs. A reasonable rule of thumb would be that no generator may be charged for connection capacity in excess of twice its rated capacity. Any difference between the cost of equipment that is prudently installed (which may be sized in anticipation of future development, or to standardize system design) and the price cap would be recovered as part of the connection pool, until the additional capacity is utilized by additional generation or load.

Prospective customers should have the right to seek, through a simple and expedited process, a Board order for the transmitter to provide facilities to be shared in future, under the price cap above.

Second, see the comments on "economic evaluation horizon" in question 4.1.a, below.

3.3. Costs of Delay

3.3 What principles should apply with respect to the attribution of additional costs resulting from a customer's or transmitter's actions or delay?

If the customer damages the transmitter's system, as through interconnection of generation equipment that exceeds the announced ratings, the customer should be liable for that damage. Similarly, damage to the customer's equipment due to negligence on the part of the transmitter should be subject to compensation. All such disputes should be resolved by the Board.

It is difficult to imagine a customer imposing costs on the transmitter through delay. In contrast, the transmitter can increase the costs and reduce the viability of generation projects, especially small ones, through unreasonable delay. In such cases, the transmitter should compensate the customer for the delay.

While it is important to maintain the option of providing compensation for customers whose opportunity to connect to the system is delayed by the transmission provider, the Board should concentrate its efforts on reducing delays and other unnecessary friction in the interactions between transmission providers and customers. To that end, the Board should establish an inexpensive and responsive process to receive and resolve disputes and complaints regarding provision of information, negotiation, proposed charges, construction, and billing.

3.4. Third-Party Effects

3.4 A new or modified connection proposal may have impacts, such as increased fault levels, on parties beyond the connecting customer and the transmitter. These third parties may be the transmitter's existing customers or an adjacent transmitter and its customers. In such a situation, what principles ought to apply to the assessment of the impacts, the implementation of the measures required to mitigate the impacts, and attribution of the resulting costs?

All societal costs imposed by new generation should be included in the evaluation of the connection. If the generation provides little or no additional societal benefit, it should pay for any costs it creates. If the generation provides special environmental or other societal benefits, those benefits should be credited against any societal costs it may impose on other parties. To the extent that the extra costs flow through general transmission rates, borne by most electricity users in Ontario, the incidence of the costs will naturally match general environmental benefits reasonably well. If the extra costs fall on a small group of customers, and the benefits are more-widely distributed, some reallocation of costs to a broader group of customers may be appropriate.

3.5. Attribution of O&M Costs

3.5 What principles should apply to the attribution to a customer of:

(a) operating and maintenance costs for a transmitter's facilities paid for by that customer;

(b) cost responsibility for any requirement to carry out monitoring and testing that has been specified by the transmitter; and

(c) cost responsibility for performing switching operations outside of normal business hours.

In computing the "excess" interconnection cost to be assessed to new customers, above the costs that will be collected through rates, the current transmission code (Appendix 5, §6.1(a)) appears to estimate that charges as the incremental investment, minus any revenues projected for the new customer, plus

Annual(Wires)O&M = Customer Additions × Annual Marginal(Wires)O&MCost/customer

The description of the terms is not completely clear, but I read this formula as adding the following to the capital cost of the interconnection:

- the number of customers to be served by the interconnection, times
- the annual O&M cost for interconnections, averaged over all customers.

If I am correct, the formula charges every new customer the average incremental connection cost of the system, in dollars per customer. Thus, a 10-MW wind farm would be assessed the same average cost as Toronto Hydro or Bruce Generating. That results would be clearly inefficient and inequitable; this formula should be replaced by a reasonable forecast of the O&M costs of the particular interconnection.

3.6. Principles for Re-Connections

3.6 To what extent should the principles that apply to new or modified connections apply to re-connections?

I have no position on this issue at this time.

4. Economic Evaluation

4.1. Payment Principles

4.1 What are the principles that should apply to the determination and calculation of costs to be attributed to a customer in relation to:

(a) the transmitter's approach to the recognition, treatment and matching of costs and revenues in the economic evaluation used to determine costs to be attributed to a customer;

See comments in questions 3.2 and 3.5 above.

In addition, Appendix 4 to the transmission code allows the transmission provider to charge larger interconnection fees to customers with poorer (or no) credit ratings. This will obviously be a serious problem for many new small developers of renewable facilities. The higher fees are based on the assumption that customers with poor credit ratings will default and leave the transmission provider with no cash flow to support the investment. This appears to be a fallacious assumption. Whether the transmission provider has income from the connection facility or not depends more on the nature of the generation or load than on the financial qualification of the developer.

Once a wind farm (or a hydraulic site) is developed, it is likely to continue operating, and paying its transmission bills, under one owner or another, for the useful life of the equipment. These renewable generators with zero fuel cost impose little default risk on the transmission provider, regardless of their owner's finances. The "economic evaluation horizon" used in section 6.1 of Appendix 4 for these renewable facilities should be 25 years.

> *(b) the transmitter's approach to minimum payment obligations and the related commercial terms;*

Any large financial obligations imposed by transmitters on small renewable projects may discourage development of such projects. It is not clear that any such charges are anticipated, other than the excessive connection charges discussed in the section 4.1(a).

> *(c) the transmitter's treatment of certain network costs as non-pooled costs;*
>
> *(d) the transmitter's practice of performing an economic evaluation of the costs and revenues associated with the transformation and line connection pools, on a separate, rather than combined basis;*
>
> *(e) the transmitter's approach to adjustments and true-ups for the purpose of cost recovery, continuing prudential requirements and load guarantees, over the duration of the economic evaluation study period;*

As noted above, any large financial obligations imposed by transmitters on small renewable projects may discourage development of such projects. Requirements for financial guarantees of continued operation are generally unnecessary (see part (a)) and should not be imposed for generators of less than 20 MW.

> *(f) the transmitter's establishment of a minimum incremental load triggering mechanism;*

> (g) *the transmitter's recognition of revenues from overloaded connection facilities serving a customer, prior to construction of a new connection facility for the same customer, to offset the underutilization of the new facility, where the existing facilities continue to be operated on an overloaded basis?*

I have no comments on parts f and g at this time.

5. Contestability

5.1. Principles of Contestability for Connections

> *5.1 What principles should apply to the contestability of any work related to a connection proposal?*

To the extent that this question asks whether customers should have the option of building their own facilities, rather than paying for facilities built by the transmitter, the answer is that customers should always have the option of building their own connection facilities, whether at transmission or distribution voltages.

The opposite problem appears in Hydro One's "Customer Connections Process," §§5.1 and 9.1.1 of the Transmission Code. These documents suggest that the *generator* is responsible for building a connection to the transmitter's system. This would obviously be infeasible for the wind farms on the Bruce Peninsula, in the example discussed above. An exception should thus be made for locationally inflexible generators (wind, hydraulic, biomass, and high-efficiency cogeneration) of less than 100 MW, with the transmitter obligated to extend its system to allow for interconnection.

To the extent that this question asks about contesting the transmitter's cost assessment there should be a right of streamlined recourse to the Board in all such disputes. The Board should establish processes to ensure that Board resolution of disputes imposes only minimal costs and delays for small generators (e.g., less than

20 MW). Most of these facilities will be connected to the distribution system, so this issue is particularly important for distribution utilities, but issues may arise at transmission voltage for some smaller units as well.

Appendix 1:
Professional Experience of Paul Chernick

Paul L. Chernick, president of Resource Insight, has twenty-two years of experience in the electric and gas utility field. He has consulted and testified extensively on utility and insurance economics. His current and recent activities include assessing prudence of power-planning investment decisions, for power plants, transmission lines, and contracts; reviewing electric utility cost allocation and rate design; assessing energy-conservation and renewable-energy opportunities, particularly in conjunction with transmission and distribution planning; designing performance-based ratemaking mechanisms to promote reliable least-cost utility service; reviewing proposed sales of electric generation capacity and distribution assets; estimating the market value of power plants and purchase contracts; and reviewing the effects of utility mergers on ratepayers. He has been a leader in designing and evaluating electric, natural gas, and water utility conservation programs, including mechanisms for the recovery of conservation costs.

Mr. Chernick's experience includes three years on the staff of the Massachusetts Attorney General's utility division and thirteen years as principal and president of his own consulting firm. Mr. Chernick has testified in more than one hundred sixty regulatory and court proceedings and has performed a wide variety of studies for public agencies, nonprofit organizations, and corporations. His clients have included regulators, public advocates, energy utilities, non-utility power producers, environmental advocates, and municipal governments. He is author of more than 35 published papers on utility regulation and ratemaking, has provided training to public advocates and regulatory staffs, and has advised regulatory commissions in least-cost planning, rate design, and cost allocation.

Mr. Chernick holds an SM from the Technology and Policy Program and an SB in civil engineering from Massachusetts Institute of Technology. He is a member of Chi Epsilon, Tau Beta Pi, and Sigma Xi honorary societies, and received an Institute of Public Utilities Institute Award.