APPrO
ASSOCIATION OF
POWER PRODUCERS
OF ONTARIO

APPrO submission to the OEB consultation on Distributed Generation: Rates and Connection (EB-2007-0630)

August 28, 2007

Part 1: Context

Background on APPrO

APPrO is a non-profit organization representing electricity generators in Ontario. APPrO members produce nearly all the power generated in the province. Using facilities of many types including hydro-electric, natural gas-fired, nuclear and wind energy, APPrO is the leading association of its type in Canada. APPrO members collectively represent a very significant amount of capital invested in the provincial energy system, measured in the billions of dollars. In addition, APPrO members are involved in the development of new generation, and are thereby concerned about the conditions under which any potential future generation facilities would operate. The organization currently has more than 100 members, of which 89 are corporate members. In addition to generators, APPrO membership includes developers, equipment suppliers, service suppliers, consultants and individuals in a variety of professions and trades concerned with power generation.

The significance of the issue for APPrO

APPrO represents the interests of a customer group as customer is defined in the Distribution System Code ("DSC"). Generators pay for connection services from distributors and, when connections trigger network upgrades, are responsible for network upgrade costs. These costs are often significant to them, in part because, unlike distribution service costs, they are paid up-front in lump sum. APPrO has a particular and important interest in the timely and proper construction of distribution facilities in order that its members meet their current obligations pursuant to OPA contracts and otherwise.

APPrO's interest in this proceeding is in the development of distributed generation (DG), which will likely ultimately benefit consumers by lowering prices through increased supply, and facilitating savings in distribution and transmission infrastructure, reduced line losses, and increased energy efficiency.

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Benefits of distributed generation

It is APPrO's general view that the benefits of DG, although they may vary greatly depending on the circumstances, are significant and often under-recognized. To the extent that generation is located closer to load on a more consistent basis, there would be a significant reduction in line losses, and a major reduction in the need for additions to the grid infrastructure, along with other benefits to the system, including improved resiliency to disruption and often, reduced environmental impact.

A province-wide electrical system that has accommodated distributed generation would likely have greater numbers of renewable energy and high-efficiency power generation projects, and thereby contribute to meeting provincial and national objectives for environmental performance. Although distributed generation is not necessarily environmentally beneficial in every case, having a system that facilitates the development of distributed generation increases the opportunities for application of technologies that are inherently environmentally preferred, while also potentially reducing the size of the overall system and thereby its overall environmental impacts.

In addition, the smaller scale of distributed generation projects ensures that financial risks are distributed amongst more players. If a small scale project were to become financially non-viable, the impacts on the electrical system or on the energy-related financial community, whether public or private, will be relatively limited. In addition, because the impacts of financial failure in a given project will be concentrated on a small number of players, mostly private, distributed generation projects are unlikely to proceed at all, unless there are very strong assurances to its investors that risks are well-managed. Even where DG projects make use of centralized power supply contracts such as those from the OPA, the consumer and the province is protected financially because the generator is only paid if the project produces, and the pricing levels are predetermined.

Of course, it is generally understood that distributed generation projects, because of their relatively small scale, are usually more expensive on a dollars-per-kilowatt basis, compared to larger scale projects. However, the other benefits of DG, including infrastructure savings, will in many cases outweigh the higher unit capital cost.

To summarize, DG creates significant benefits for electricity consumers and for the province as a whole. These benefits, depending on the technology, can include:

1. low-cost power production,
2. high levels of energy efficiency,
3. a reduction in transmission and distribution system losses,
4. the ability to increase the usage of renewable fuels,
5. relatively rapid construction times,
6. the ability to defer new wires infrastructure, and
7. a low environmental footprint.

DG also has the added benefit of being able to reduce the demand on the T&D systems during peak hours, and to provide emergency back-up power during grid outages.

In light of these advantages, public policy should try to maximize the benefits available to the system from distributed generation within reasonable economic limits.

DG is not the answer to all of Ontario's electric system problems, but it does make many of the system's most important problems easier to deal with. DG is an adaptable and versatile way of addressing cost and security issues, while simultaneously meeting environmental and economic development objectives that are important to the province.

It is APPrO's view that DG will not replace centralized plants, but be complementary to them for the following reasons:

a) Benefits to DG Owner or Host – Energy cost savings through the operation of self-generation, a physical hedge on power prices, ability to employ high-efficiency cogeneration, improved security through provision of back-up power in an outage, avoided capital costs.

b) Benefits to Distributor – Reduced line losses, power factor correction, voltage stabilization & improvement, reduced/avoided/delayed capital expenditure on distribution equipment, potential for improved ability to respond to system-wide outages, potential ability to mitigate effects of local system disruptions due to equipment failure or other reasons, other system benefits of a technical nature, depending on specific circumstances.

c) Benefits to transmission system – reduced line losses, diversity of supply, power factor correction, voltage stabilization & improvement, reduced/avoided/delayed capital expenditure on transmission equipment, substations etc.

d) Benefits to the environment – Smaller environmental footprint in general, and in the case of cogeneration, generating power at the location of thermal loads will result in significant reduction (better than 25%) in overall fuel consumption when compared to the separate production of power and heat.

e) Benefits to customers in the area – Potential for increased local power reliability, security and quality; if purchasing some of the power there will likely be cost savings and reduced exposure to risk of market price variations; and normally there is job creation and economic development associated with the use of distributed generation, primarily because the thermal host typically employs many more people than the power project alone (e.g. Chrysler in Windsor, or Abitibi in Thorold).

As noted in the Discussion Paper, the Board has determined that Distributed Generation can yield system-wide benefits for every distributor in Ontario.

Summary of APPrO Issues

The following five issues are discussed in more depth below:
Issue 1: Alignment of regulatory procedure with provincial energy policy objectives
Issue 2: Assurance that utilities will be held harmless from volume reduction and stranded costs associated with DG / Codifying rules for recovery of system upgrade costs
Issue 3: Rationalizing stand by rates
Issue 4: Recognizing the need for different kinds of DG to be treated differently
Issue 5: Systematic recognition of system benefits resulting from DG

This submission will address each of these issues in later sections, following the responses to questions posed in the Board staff paper.

Part 2: APPrO responses to questions posed in the Staff Paper

<u>In the area of Standby rates, the Board staff paper asks the following questions:</u>

1. What might be a reasonable billing determinant for recovering demand-related costs? For example, the demand charge could be calculated on the basis of the annual contract demand, or alternatively be based on the maximum demand for back up service.

2. Should standby charges be further differentiated between backup, maintenance and supplemental services? As stated in the EESC Report, backup service is defined as electrical energy delivered by the electricity distributor during unscheduled outages of the customer's onsite generator, while maintenance service represents electrical energy delivered during a scheduled outage. Supplemental service is defined as electrical energy delivered by the electricity distributor when the output of the onsite generator is less than the customer's maximum demand.

3. Are there other issues that should be considered by the Board?

APPrO responses:

1. APPrO does not currently have a predetermined position on billing determinants in this context. However, when calculating the costs of providing standby services, the Board should consider incorporating factors into the calculation of costs of supplying standby

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services so as to reflect the system diversity characteristics and contingency facilities already available in most LDCs.

2. The three types of standby charges proposed have merit in principle and are worthy of closer consideration.

3. APPrO believes that the impact on the system (and therefore the costs) of a customer with behind-the-meter generation can only be determined on a net basis, meaning the net amount the customer actually withdraws from the system – setting aside any amount of the load that is supplied internally. From a system perspective, reduced load due to onsite generation is not fundamentally different from reduced load resulting from changes in internal usage or energy efficiency investments.

<u>In the area of Benefits, the Board staff paper asks the following questions:</u>

1. How should any distribution and transmission benefits provided by load displacement generation be identified and quantified?

2. Should a different approach be adopted depending on the size of the customer?

3. Should any benefit provided to customers with load displacement generation be recovered from all customers? If so, on what basis should this be done?

4. Are there other operational or implementation issues that should be considered by the Board?

APPrO responses to these questions are as follows:

1. APPrO does not have a predetermined view in this area, other than to say that it is important to capture the full value of all benefits, and that significant work is likely necessary to establish appropriate methodology. (See APPrO issue 5 below.)

2. It is inevitable that some forms of approximation will be used to estimate benefits. For smaller customers, a simpler model with more estimation (e.g. standardized values or a set of generic formulae for estimating benefits in various situations) is necessary. For larger customers, site specific impact on distribution facilities is more necessary and feasible to calculate.

3. It is common in electric system development to build assets which benefit a wide range of customers, and to put the costs of such assets into the general rate base. Investment in upstream facilities triggered by generation development is rarely customer-specific and is likely to have benefits to load customers broadly either directly because of increased

system capacity, or indirectly by virtue of increasing load customers' access to more options for supply. Given that generators must pay their own connection costs, it is unlikely that there will be any other investments to accommodate generation which would qualify as a benefit provided exclusively to generators, either individually or as a group. Experience in other jurisdictions has often resulted in treating such costs as benefits to all customers.

4. Please see "APPrO Issue #5" below, and the earlier sections of this paper for APPrO's views on the benefits of DG and how they should be recognized in rates and policies.

<u>With respect to rate classifications, the Board staff paper asks the following questions:</u>

1. Is a separate classification warranted and, if so, should it apply to all customers with load displacement generation, or to a subset of these customers as suggested in the EESC Report?

2. Are there other criteria that should be used to justify a separate rate classification for a subset of these customers?

3. What would be an appropriate threshold for a generator rate class?

APPrO responses to these questions are as follows:

1. Yes, in general a separate rate classification for generators is warranted since they cause different kinds of costs and benefits for the system than do load customers. The distinction proposed by EESC (for customers with generation capacity above 500 kW and generating more than 10% of the customer's total load) is worthy of closer consideration.

However, APPrO would be concerned about the potential for anomalous distribution of costs in some instances, if there were only one customer class for this purpose. APPrO therefore suggests holding open the option of establishing subclasses mirroring those in common use amongst distribution customers (for example, less than 50 kW, less than 1 MW, and over 1 MW). There should be no situation in which a load displacement customer would pay more distribution charges in total with generation than he or she would without generation.

2. There may be need for further sub-classifications as the number of generators grow, in order to ensure customers are charged for costs that are properly related to their effects on the system.

3. Further technical analysis and discussion with customers is needed to answer this question.

With respect to Revenue loss for distributors, the Board staff paper asks the following questions:

1. Has net revenue loss due to customers with load displacement generation been material?
2. How might net revenue loss be quantified?
3. How might the Board determine an appropriate method to compensate electricity distributors for such revenue loss? Consideration should be given to a consistent approach between revenue loss caused by customers with load displacement generation and revenue loss caused by other load customers due to factors such as economic conditions. In evaluating each of the options presented above, consideration should also be given to the incentive regulate framework under which electricity distributors are currently operating.

APPrO feels it would be inappropriate to answer these questions as they relate primarily to the experience of distributors. However, we note that in recent years, Hydro One distribution has made formal commitments to publish annual reports on the actual and projected amounts of distributed generation in its territory, and the costs it has incurred to accommodate distributed generation.

With respect to connection costs, the Board staff paper asks the following questions:

1. What alternatives to the status quo should be considered and what is the rationale for each of these options?

2. If connection costs are socialized, is there a risk of uneconomic DG projects going forward? If so, how can that risk be mitigated or avoided? Would this approach affect the incentive for distributors to design economic connections?

APPrO's response to these questions is as follows:

It is difficult to propose any concrete alternatives to the status quo for connection costs without a more complete body of data on the options and the impacts of each. Such data should be collected as part of a fundamental cost allocation and rate design process, which the Board is currently conducting. Without such data, fundamental change to the current design seems unlikely. Of course, APPrO would agree with the idea of allowing distributors to pay for and add to rate base reinforcement costs when the generation connection that triggered the reinforcement is an economic alternative to network investment.

APPrO agrees that generator siting decisions should be sensitive to location-related costs and benefits to the system. However, it is only in relatively unusual and extreme cases that socialization of upstream system reinforcement costs would lead to the construction of significant amounts of generation that would otherwise be considered uneconomic. Such cases would likely be distant from load, or mismatched with the size of load, and would not likely qualify as distributed generation in any case.

<u>With respect to other aspects, the Board staff paper asks the following questions:</u>

1. Are there other rate-related issues associated with DG that should be addressed, or that should be addressed more fully?
2. Is the experience in other jurisdictions on those issues relevant to the Ontario situation?
3. Are there unidentified barriers or is separate treatment required for embedded generation projects or for projects falling below the threshold of a new rate class?
4. What are the institutional or regulatory barriers to implementation of DG?
5. How might such barriers best be addressed?
6. Are there DG-related issues, other than those relating to the rate or connection cost treatment of DG facilities that need to be addressed?
7. Is the experience in other jurisdictions on those issues relevant to the Ontario situation?

APPrO's response to these questions is as follows:

1. As outlined in "Issue 2" below ("Assurance that utilities will be held harmless from volume reduction and stranded costs associated with DG / Codifying rules for recovery of system upgrade costs") it is important from APPrO's perspective that rules and procedures be established that will allow utilities to recover any properly incurred costs for accommodating distributed generation.

2. Yes.

3, 4 and 5. The barriers are numerous and are addressed in a number of related papers. However, given the existence of the Standard Offer and Net Metering programs, and the public policy that led to them, the primary barriers that can be addressed at a regulatory level are those concerning ratemaking and connection procedures.

6. The most critical unaddressed question is the development of a robust and stable system for identifying benefits of distributed generation projects, and in concert with that, a system for estimating their levels in specific instances without introducing undue complexity, combined with regulatory procedure that makes full use of the estimates in rate setting.

7. Yes.

Part 3: APPrO Issues of Concern

Issue 1: Alignment of Regulatory Procedure with Provincial Energy Policy Objectives

It is APPrO's view that there have been two significant developments in provincial policy which must be recognized by the regulator:

First, that the system will have to facilitate the development of relatively large amounts of new clean and renewable generation capacity, as stated in the Supply Mix Directive and the IPSP.

Second, that transmission and distribution infrastructure needs to be reinforced to accommodate such development, and to the extent possible, in advance of the generation being built.

There is little doubt that Ontario will need to acquire large amounts of generating capacity in each of the time frames foreseen by the preliminary Integrated Power System Plan (IPSP). It is as yet unclear how all the necessary capacity will be procured. Some will be acquired through centralized contracting activity of the Ontario Power Authority. Some will arise through natural market activity in which customers and other players such as distributors, develop capacity to serve needs that they perceive. Whatever form new development takes, it is important that the regulatory environment be conducive to a variety of forms of new generation, in order to ensure that supplies are adequate, and that investment options are subject to the discipline of competition.

It is with such principles in mind that the province has instituted its Standard Offer programs for renewable energy and clean energy. With the announcement of these procurement initiatives, the province has signalled that it places a high degree of importance on the process of adapting Ontario's regulatory system to facilitate the connection of relatively large numbers of qualifying small generation projects to distribution systems.

At the same time as the IPSP has set aggressive targets for achieving significant increases in the amount of DG, the province has also indicated its belief that transmission facilities should be built at the same time as generation, to enable transmission from new generating facilities, rather than waiting until the generation is built to site new transmission. Although distributed generation does not generally affect transmission infrastructure, the principle of building wires infrastructure in advance of generation

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development, and in order to accommodate new generation, has much the same value at the distribution level as it does at the transmission level. This policy means that distribution companies need to take DG into account in their distribution system plan and DG developers need to give the distributors notice of their plans to build, as early as possible.

The Supply Mix Directive includes the following statements:

> "1. The goal for total peak demand reduction from conservation by 2025 is 6,300 MW. The plan should define programs and actions which aim to reduce projected peak demand by 1,350 MW by 2010 and by an additional 3,600 MW by 2025. The reduction of 1,350 and 2,600 MW are to be in addition to the 1,350 MW reduction set by the government as a target for achievement by 2007. The plan should assume conservation includes continued use by the government of vehicles such as ….small scale (10 MW or less) customer-based electricity generation, including small scale natural gas fired co-generation and tri-generation, and including generation encouraged by the recently finalized net metering regulation.
>
> 2. Increase Ontario's use of renewable energy such as hydroelectric, wind, solar and biomass for electricity generation. The plan should assist the government in meeting its target for 2010 of increasing the installed capacity of new renewable energy sources by 2700 MW from the 2003 base, and increase the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025.
> ….
> 6. Strengthen the transmission system to:
> - Enable the achievement of the supply mix goals set out in this directive;
> - Facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the province where the most significant development opportunities exist;
> - Promote system efficiency and congestion reduction and facilitate the integration of new supply, all in a manner consistent with the need to cost effectively maintain system reliability."
>
> - Excerpted from letter to Jan Carr, CEO of the OPA, from Ontario Energy Minster Dwight Duncan, June 13, 2006, known as the "Supply Mix Directive"
> http://www.energy.gov.on.ca/english/pdf/electricity/1870_IPSP-June132006.pdf

To summarize, APPrO believes that in order to ensure transmission and distribution facilities are adequate, it is important to take steps to align regulatory procedure with current provincial policy and plans.

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Issue 2: Assurance that utilities will be held harmless from volume reduction and stranded costs associated with DG / Codifying rules for recovery of system upgrade costs

APPrO believes that changes are warranted in the manner in which distribution reinforcement or extension costs associated with DG projects are allocated and recovered.

Distributors in Ontario are sometimes uneasy about accommodating new generation because there are numerous situations where new generation connection would trigger a requirement for investment in distribution infrastructure. Although the provincial Supply Mix Directive and the policy of transmission enabling generation suggest that infrastructure should be expanded to accommodate new generation, it is unclear whether and in which cases the costs of such infrastructure expansion will be socialized in any way. The DSC at present doesn't generally allow for such costs to be borne by the distributor, even temporarily. While it is clear that the cost of the connection itself, narrowly defined, is the responsibility of the generator, it is not so clear that other related costs can be collected by the distributor if they are not borne by the generator.

As a result, there is a gap between the amount of new generation targeted in the Supply Mix Directive, and the amount that is likely to be accommodated by distribution systems under present arrangements.

In fact, the Supply Mix will not likely be achieved unless changes are made to the system by which distributors recover certain costs. The reasons for making such a statement are as follows:
a) The traditional model of regulatory economics holds that costs should only be socialized among customers where those same customers are sure to earn an economic benefit from the generation in excess of their costs. However, the Supply Mix Directive mandates a new approach to generation investment. It requires that certain renewable and clean energy capacity targets be achieved, even if those capacity targets do not meet a traditional utility economics test of immediate profitability.
b) The DSC allocates the cost of system upgrade requirements to a new generator, based on the traditional model above. As a result, number of otherwise viable projects will be prevented from proceeding.
c) The results of this problem are already being demonstrated in the response to the Standard Offer Directive. Applications for the Standard Offer Program were filed in the amount of approximately 2800 MW. However, partly because of current DSC rules, only 500 MW have been contracted for.

The cost allocation rules under the DSC should therefore be reconsidered in light of the requirements of the Supply Mix Directive.

APPrO believes that both distributors and generators have a pressing need for clarification about which upstream costs distributors can be assured of collecting in this regard, even if there were no need to accommodate the Supply Mix Directive. In addition, given current government policy, it is important that distributors are encouraged in every reasonable way to prepare themselves to work with generation proponents significantly more than they have in the past.

Distributors should identify system reinforcement costs, indexing those triggered by DG, in their annual rate submissions or annual reports under incentive ratemaking regimes. More important, the DSC needs to be changed to allow distributors to pay for and put in rate-base any system expansion required as a result of a DG project that meets provincial standards for development. The appropriate analogy for such a change is the smart meter program in which the utilities' costs to implement smart meters are being placed in rate base and paid for by the distributors' customers. In both cases the ultimate beneficiaries are the distributors' customers. The same customers will of course benefit from reduced network transmission costs so there is a kind of automatic offsetting effect.

In APPrO's view this issue has risen in importance in recent years, largely because of the two Standard Offer programs, and it now warrants high level consideration. A resolution in this area could ensure that generators and distributors are working on the same set of assumptions, and that less time is spent on issues of how to manage queues, exclusion zones and applications below the red line on a given transformer, in which new generation projects can not presently be accommodated, even when the projects are attractive in all other respects.

In general, distributors should be held harmless from all additional costs they incur to accommodate the growth of DG, including network expansion or reinforcement costs, stranded costs, and incremental generating costs, and loss margins due to DG. The latter is much like the LRAM program, which compensates distributors for lost margins due to energy efficiency investments.

Issue 3: Rationalizing Standby Rates

APPrO has taken the position that standby rates should be based on a generic methodology across the province and be cost-based. APPrO has opposed charges based on a gross billing model, and supported the principle that that LDCs should be kept whole for any properly incurred costs to accommodate DG. However, APPrO has also stressed that rates applicable to DG can not be properly designed unless there is a systematic analysis of the benefits created by DG, along with a means of quantifying those benefits and recognizing them in rates.

For more information, see APPrO's submission from January 2006: Generic Issues

Proceeding - RP-2005-0020/EB-2005-0529 (attached).

Issue 4: The Need For Distinct Treatment Options To Be Available For The Different Kinds Of Distributed Generation

APPrO sees three major options for structuring distributed generation projects. The three options have different commercial implications and therefore tend to require distinct regulatory treatments, appropriate to the option chosen. These options are:

1. New Generation connected to the LDC facilities but not directly connected to a load.

2. New Generation connected behind the meter with a new customer as a Load Displacement Generator (with or without the ability to sell excess generation to the grid)

3. New Generation connected behind the meter with an existing customer as a Load Displacement Generator (with or without the ability to sell excess generation to the grid)

Of course, projects may sometimes involve a combination of these three options, in which case a combination of regulatory treatments may be required. Option 2 creates no direct revenue issues for distributors, but would require measures to allow the distributor to recover the potential cost of system upgrades. Options 1 and 3 result in lost revenue for the distributor, and need to be associated with a lost revenue adjustment mechanism similar to that being developed for CDM projects hosted by distributors if distributors are to be kept whole and not dis-incented to facilitate DG. Option 1 and 3 will also need to be associated with recovery mechanisms for system upgrade costs.

APPrO notes that Board Staff and EESC have acknowledged in their respective papers the wide variations that can exist between different kinds of DG. If rates and policies are to be economic and cost based, they will certainly need to take into account the distinct circumstances and cost issues associated with different kinds of DG. This would include, potentially, distinct approaches to standby rates, different service options, and provision for interruptible rates (where customers have different needs/value for reliability; and where there is no need for upstream capacity for curtailable service; hence, causal costs will be very low).

Issue 5: Systematic Recognition in Rates of System Benefits Due to DG

APPrO agrees with Board Staff and the EES that standby rates should be designed to reflect the costs to the distributor of DG, net of any offsetting benefits. APPrO believes rates should reflect the type of utility service being offered, for example, back-up power, planned outage protection, or interruptible power. The Board recognized the potential benefits of DG in its decision on the Generic EDR proceeding. Board staff noted the absence of any applied methodology used to quantify the benefits of DG.

APPrO urges the Board to commission consultants to determine the benefits to both the distribution and transmission systems from load displacement generation. The studies should address whether there is a need to distinguish between larger and smaller projects. Whatever the size of the project, APPrO is of the view that some specific Board guidelines are required, in order to give the distributors and the generators guidance to calculate the actual amount of benefits in individual cases. It may be that for smaller projects, rules of thumb could be developed as suggested by EES, and these potential rules of thumb should be addressed. Once the study is complete, the Board should convene a stakeholder group to review the proposed solutions, and, if necessary, conduct further proceedings.

APPrO believes that, like in the case of smart meters, the "benefits" of DG should be collected from all customers on the same basis as the costs are collected.

The benefits of DG will increase and its costs will decline as the density of DG nodes increases in any given area. Forward looking analysis of the benefits and costs will help prepare participants in Ontario's electricity market for circumstances they are likely to face in the future. For this reason, APPrO believes the economic analysis of accommodating DG should be based on long run benefits and costs.

Of course, the rate structure currently provides distribution customers the savings associated with reduced use of the provincial transmission network, where DG is in operation. However, only in the case of load displacement are these savings passed through directly to the customer who creates the savings, i.e. the load displacement customer. There should be no barrier to the quantification of the present financial benefit, and its application to DG customers, in excess of load displacement. These savings, and any other transmission benefits of DG, would be most properly considered in the context of the transmission tariff itself, in order to confirm the expectations with respect to distributors passing the benefits on to DG customers. However, pending such review in a transmission rate proceeding, interim measures to confer the upstream benefits of DG on its local hosts may be appropriate.

In the meantime, distributors' rates for standby generation should remain interim.

Other comments

There is a need to define what is included under DG for regulatory purposes. There are a number of options for refining the definition, but one option would be to say that DG includes the following:

- Generation located close to load, of any size and fuel that meets current environmental standards, connected at the distribution system (voltages below 50 kV).

It is worth considering whether some flexibility could be provided for LDCs and DG customers to negotiate a rate adder that would enable the LDC to recover its costs over the term of a service contract rather than in the form of a lump sum charge. The pricing could reflect contract specific terms and conditions such as the LDC's right to interrupt the customers, with notice, in periods where there is insufficient distribution capacity to serve the DG customer's load and all customers. For example, a DG customer that requires backup service only could agree to be interrupted if necessary to maintain system reliability. An interruption would occur only if backup service was required during a high demand period. Other possible contract terms might be the right for the LDCs to call on the power generated by a DG customer that is self-generating as backup power for the LDC or certain customers. In essence, the contract would involve the mutual provision of backup service. Clearly, these types of arrangements would be situation specific and would best be handled through a negotiated rate, and would have to conform to principles set by the regulator.

All of which is respectfully submitted.

August 28, 2007

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Abbreviations used in this paper are defined as follows:

APPrO: Association of Power Producers of Ontario
DG: Distributed Generation
DSC: Distribution System Code
IPSP: Integrated Power System Plan
LDC: Local Distribution Company or electricity distributor
OPA: Ontario Power Authority

Note to reader: The comments above represent the general view of most participants in a discussion process led by APPrO, but they may not represent the specific positions of every individual involved in APPrO or of their respective organizations. It is a general consensus and should be seen as the collected wisdom of many people engaged in the industry after serious reflection and group discussion.

For more information on this submission or on APPrO's work in the area, please contact:
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Appendix 1: APPrO submission on standby rates from Generic Proceeding, January 2006

GENERIC ISSUES PROCEEDING - RP-2005-0020/EB-2005-0529
SUBMISSIONS ON STANDBY RATES
BY THE ASSOCIATION OF POWER PRODUCERS OF ONTARIO ("APPRO")

INTRODUCTION

1. APPrO represents over 98% of the electricity generators in Ontario, including many smaller generators who develop and operate distributed generation projects, and others that are interested in doing so.

2. These projects are both load displacement projects behind the metre at a particular load, or projects which are connected to the distribution system but are not sited at a load.

Some of the distributed generation projects are cogeneration projects in that they produce heat or cooling (or both) in one form or another.

The projects vary in both size and fuel type and range from smaller projects less than a megawatt to projects such as the GTAA cogeneration project with forecast capacity of over 120 megawatts.

THE PROCEEDING

On November 2, 2005, the Board launched its own motion to deal with certain generic issues raised by the applications of the electricity distribution companies for distribution rates to be effective as of May 1, 2006. The Board established an Issues List for the proceeding, which included the following issues:

> "**3. Generalized Standby Rates for Load Displacement Generation**
> **Background**
> The importance of standby rates will increase as the adoption of load displacement generation increases. For many utilities, it will be impractical to calculate customer-specific standby rates due to the number of customers and the difficulty of isolating costs. Generalized or standard rates could be developed but different utilities could take different approaches in the absence of policy guidelines.
> **Issues**
> Should the Board develop a standardized methodology for stand-by rates?
> Should the Board permit utility-specific approaches to the design of stand-by rates?
> If so, what should that design basis be?

2.2 Revenue Losses Attributable to Unforecasted Distributed Generation

Background

Concerns have been raised regarding the load and revenue effects of the accelerating adoption of distributed generation, the effects of which may be material and are difficult to forecast, and therefore warrant subsequent disposition by way of a deferral account.

Issues

Should utilities be permitted to record in a deferral account foregone revenue amounts attributable to unforecasted load losses arising from distributed generation."

APPrO's submission will address mainly issue 3, but will touch on issue 2.2 as well.

GOVERNMENT POLICY

The current Government of Ontario has consistently supported distributed generation. In a major speech to the Empire Club of Canada on April 15, 2004, Energy Minister Duncan stated:

> "Distributed generation, which is also attractive from a security perspective, holds significant promise for the environment, as it suggests an electricity system that minimizes massive transmission networks, and focuses resources only where they are absolutely necessary. Our desire is to help Ontarians unlock the potential for efficient electricity generation that is around them, and we will remove barriers, free up resources and bring new thinking and new ideas to the challenges that lie before us. ….."

During the Third Reading of the Electrical Restructuring Act, 2004 ("Bill 100") the Minister stated:

> "Where possible and economically feasible, it is desirable that Ontario move to a more distributed system of electricity generation, where clean generation capacity is situated close to the consumers who require the power."

The Ontario Ministry of Energy, in its December 21, 2004 discussion paper, "Electricity Transmission and Distribution – a Look Ahead", indicated that

> "the government recognized that the development of a diversified, clean, and renewable energy portfolio in Ontario lends itself to the development of distributed generation facilities."

On August 18, 2005 the then Minister of Energy, Dwight Duncan, wrote to the Ontario Energy Board and the Ontario Power Authority as follows:

> "I am requesting that the Ontario Energy Board and the Ontario Power Authority cooperate in developing the terms and conditions for a standard offer program for small generators embedded in the distribution system that use clean or renewable resources."

The letter noted, in assigning responsibilities to the two agencies, that

> "The Ontario Energy Board, in accordance with its authority over connection policies and delivery obligations of distributors, will focus on the necessary changes to codes and connection requirements, and on <u>ensuring non-discriminatory access to the electricity system.</u>" (our emphasis).

The letter closed with the exhortation

> "Please begin this work immediately and report to me by the end of 2005 on your findings, recommendations and proposed implementation plan."

In late 2004, the Government of Ontario established the OPA to help alleviate a severe shortage of generation. In its recent Supply Mix Advice Report to the Minister of Energy, the OPA recommended:

- A "smart gas" strategy that would emphasize the use of gas in cogeneration, combined heat and power, and distributed generation, and result in the construction of another 1500 MW of gas-fired generation, in addition to existing planned procurements.

- 500 MW of biomass-powered generation, with 470 MW in addition to current procurements (including methane from municipal landfills and wastewater plants and gasification of municipal solid waste).

- 1,500 MW of additional waterpower resources by 2025, with 1,350 MW in addition to procurements under way.

- 5,000 MW of wind-powered generation by 2025, with 3,600 MW in addition to procurements already under way.

(Supply Mix Advice Report, Volume 1, pp. 62-63)

A substantial part of these proposed new generation facilities will be connected to the distribution system. Implementation of these facilities in a timely manner will require rates, instruments and practices on the part of the LDCs, and the OPA itself, that incent rather than deter, distributed generation.

The Energy Conservation & Supply Task Force, the recommendations of which formed the basis of much of the current government's energy policy, recommended as part of its action plan "a diverse supply and demand mix, including renewables, distributed generation, and conservation" (p. 86). In discussing distributed generation, it listed some of the benefits of distributed generation, as follows:

> "By supplying power near load, it is possible to avoid or defer transmission and distribution investments that would otherwise be needed to supply electricity to the load. Reductions in transmission and distribution line losses may also occur due to reduced transmission and distribution distances At times of system stress DG can enhance system reliability.
>
> Distributed generation projects are generally smaller, and require less capital than larger, centralized plants. Being easier to finance means more generation developers could undertake such projects, leading to the inherent benefits of competition.
>
> Distributed generation projects can generally be permitted and constructed faster than larger installations.
>
> Natural gas and some renewables are well suited to serve as distributed generation capacity. Distributed generation also allows more scope for use of innovative fuels." (p. 54)

It recommended, inter alia, that

> "Ontario should move towards a market with rules that promote investment in distributed generation. (p. 71)
>
> Distributed generation facilities should be able to compete on a level playing field with other supply and demand side initiatives. The level playing field should include consideration of system benefits including security of local supply, energy efficiency and emission reductions, and local commercial and industrial competitiveness. (p.72)
>
> The OEB should issue guidelines that encourage the timely and economic connection of distributed generation facilities. Any resulting stranded transmission and distribution costs should be recovered from the ratepayers." (p. 82)

STANDARD METHODOLOGY FOR RATES

APPrO recommends that the Board institute a proceeding to develop a standardized methodology for stand-by rates and a regulatory framework for distributed generation, for several reasons.

First, at the moment 16 of 95 LDCs in Ontario have stand-by rates, and, as noted in the Board staff's recent Discussion Paper on the Standard Offer Program for Eligible Distributed Generation, they incorporate many different approaches and a variety of charge determinants, including actual or anticipated maximum demand, per KW reserved, capacity reserved, KVA rating, manufacturer's rated output of the co-generator, various measure of demand, or a monthly service charge. Some of these rates were established long ago, prior to the restructuring of the market, are no longer appropriate, and need to be reviewed. The same is true for the proposals some utilities have made for new standby rates in this case.

Moreover, some utilities which do not now have stand-by rates have proposed stand-by rates in this proceeding which in effect "gross bill" the load, in other words, charge the same rate for stand-by as they would if they were actually supplying the electricity to the load. This approach is unacceptable to APPrO as it is not demonstrably cost based, conflicts with the Board's net billing decision with respect to transmission network rates (RP-1999-0044), and does not take into account the benefits distributed generation provides for distributors in the view of most objective observers, which benefits are not now allocated in whole or in part to those generators. Under current conditions, such rates are clearly significant disincentives to investment in distributed generation and run counter to current government energy policy to incent additional generation as a first priority through all available means, including the creation of a standard offer contract for distributed generation (which should be available within a few weeks).

Third, introducing a stand-by rate now is premature, as any such rate should be developed in the context of the utility's other distribution rates, which in turn should be based on a comprehensive cost allocation analysis now being conducted by the Board. Any generic stand-by rate should be developed as part of the standard cost allocation methodology proceeding now under way. APPrO notes that Hydro One shares its view on this matter [OEB Staff Interrogatory of Hydro One #2, p. 1 of 1]. Any stand-by rate should also be informed by the upcoming OPA Standard Offer for green and clean generation, in particular the degree to which the price it offers for distributed generation reflects the benefits of distributed generation to the electricity system.

Fourth, the Board's generic methodology may need to accommodate generator projects of different sizes. It may be easier for example for a utility to identify incremental costs occasioned with a large 100 MW generator on its system than identifying such costs for a host of smaller generators scattered on various feeders throughout its system. More assumptions may need to be made in the latter case.

Fifth, one of the options that should be considered in the proposed proceeding is not to have a stand-by rate at all.

UTILITY BENEFITS OR AVOIDED COSTS FROM DISTRIBUTED GENERATION

While a stand-by rate, if one is deemed appropriate, should be viewed in the context of the utilities' rate structures and cost allocation generally, the decision whether to have a stand-by rate at all should take into account the fact that generators, whether sited at loads or embedded "at large" within a distributor's system, also create benefits to the distributors and their customers, which are not now recognized in the financial arrangements between them. These benefits need to be taken into account in the establishment of, and the size of, any stand-by rate.

The Distributed Generation Task Force, a group that includes many distributors, has summarized these benefits to distributors as follows:

> "Benefits to Distributors" - Reduced line losses, power factor correction, voltage stabilization and improvement, reduced/avoided/delayed capital expenditure on distribution equipment, potential for improved ability to respond to system-wide outages, in other words, improved reliability, other system benefits of a technical nature, depending on specific circumstances."

In addition, distributed generation reduces utilities' transmission charges, the benefits from which currently flow through to all utility ratepayers and not to the distributed generators that caused them. Distributed generation can also reduce transmission congestion.

In designing stand-by rates, including deciding whether to have one at all, these benefits need to be considered. It is well accepted that distributed generators can in some circumstances be an alternative to additional distribution or transmission assets, whether they be additional feeder lines, capacity banks, transformer stations or the like, particularly in a growing utility. For example, Hydro One has estimated the value of avoided distribution capacity on its system due to Conservation and Demand Management to be $6.50 per year per KW of avoided demand (RP-2004-0203/EB-2004-0533, June 15, 2005 letter to the OEB) [Greater Toronto Airport Submission, December 8, 2005, RP-2005-0020]. And it is well recognized that distribution system losses, while different from one utility to another, are substantial, and average about 4%.

These benefits, or avoided costs, are a reality and, subject to what has been done to date, the utilities should be required to develop estimates of the avoided costs of each type which arise from generation projects being installed on their systems.

To the extent that the OPA and the Board have not already done so in their report to the government on the standing offer program, the Board should determine the manner in which each of these benefits or avoided costs should be calculated. The Board should also gain a clear understanding of how utilities will and should take distributed generation into account in their system planning, including the diversity benefit.

At the same time, APPrO recognizes that the utilities will lose revenue as a result of the installation of load displacement distributed generation in their service territory. Distributed generation investments have a similar impact on utility revenues as conservation and demand management investments. However, the CDM investments provide some, but not nearly all, of the benefits to utilities that distributed generation does. The current regulatory framework holds gas and electric utilities whole against lost revenue due to customers' CDM activities caused by utility programs by way of a Lost Revenue Adjustment Mechanism. The OEB should implement some comparable method to hold utilities whole with respect to their revenues, but this relief should take into account the benefits (or avoided costs) utilities receive from distributed generation, to the degree that those benefits are not recognized in the OPA's Standard Offer.

Once the Board has adopted a standardized methodology for stand-by rates, utilities should apply that methodology to their own circumstances. A utility that wished to depart from the Board approved methodology would have to fully justify its choice, unlike some applicants in this case who have summarily dismissed the Board's proposed cost-based model in the Distribution Rate Handbook (Chapter 10.6) as unsuitable.

Some distributed generators do not displace load, but rather simply supply power to the distribution system. At the moment those generators must pay Hydro One a monthly administration fee of between $56.94 and $273.22 for the life of the project, say 25 years, over and above the original connection fee. Each such facility has a miniscule "station load", and its output to the distribution grid is normally at least one hundred times larger. It should not, therefore, be charged such a substantial on-going fee in light of the benefits it provides the distributor, as discussed above. Hydro One has proposed a reduction to the monthly administration fee in this proceeding. For small generators, the charge is a significant financial burden.

CONCLUSIONS

In APPrO's view, the Board should have a proceeding to develop a generic methodology for the calculation of stand-by rates that is informed by the work of its ongoing cost allocation proceeding.

The proceeding should also address the benefits the LDCs receive from distributed generation, the nature of a mechanism to hold the LDCs whole against loss of revenues due to the installation of on-site distributed generation and, in light of such benefits and such a mechanism, and the degree to which the benefits have been recognized in the standard offer, whether there is a need for a stand-by charge at all.

Pending the outcome of that proceeding, the Board should

- decline to approve any of the proposed new stand-by rates or amendments to existing rates; and

- suspend any existing LDC rate that operates on "gross billing" basis.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

January 9, 2006

Tom Brett
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