Ontario Energy Board

EB-2009-0349

Report of the Board

Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09

June 10, 2010

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EXECUTIVE SUMMARY

The *Green Energy and Green Economy Act, 2009* (the "Green Energy Act") amended the *Ontario Energy Board Act, 1998* (the "Act") to introduce a mechanism under section 79.1 whereby some of the Board-approved costs incurred by a distributor to make an *eligible investment* for the purpose of connecting or enabling the connection of a renewable energy generation facility to its distribution system may be recovered from all provincial ratepayers rather than solely from the ratepayers of the distributor making the investment.

To enable this rate protection provision, the Government filed Ontario Regulation 330/09 ("O. Reg. 330/09") which sets out details related to the implementation of the cost recovery framework established in section 79.1. O. Reg. 330/09 sets out the following formula:

A = B - C, where:

A = the amount of *rate protection* to be provided to prescribed consumers in a distributor's service area,

B = *eligible investment costs* determined by the Board to be the responsibility of the distributor in accordance with the DSC, and

C = the amount the Board determines to represent the *direct benefits* that accrue to prescribed consumers as a result of all or part of the eligible investment made or planned to be made by the distributor.

The Board's first phase of determining cost responsibility (EB-2009-0077) was completed in October 2009 and determined the allocation of costs between generators and distributors.

Building on phase one, this Board framework allocates the non-generator costs between the ratepayers of the distributor making the investment and all provincial ratepayers. The direct benefits as determined by the Board will represent the allocation of costs to the ratepayers of the distributor making the investment.

The Board has identified two categories of direct benefits that accrue to the customers of the distributor making the investment to form the basis from which this allocation will be determined. Those direct benefits are comprised of:

1. surplus Network and Connection (renewable generation < 2 MW) transmission charges as well as surplus wholesale market service charges (WMSC); and
2. a portion of the Expansion and Renewable Enabling Improvement (REI) eligible investment costs.

For the first category of direct benefits, an *ex post* approach will apply to all distributors for the purpose of quantifying these benefits. Based on the actual production from qualifying renewable generation the previous year, the surplus transmission and WMSC charges collected by the distributor, as a consequence of new embedded renewable generation connected to eligible investments, will be determined to be a direct benefit that accrues to the customers of the distributor as a result of the eligible investments.

For the second category of direct benefits, the Board has adopted a two-pronged approach which recognizes the circumstances of distributors based on the amount of eligible investment. The Board will utilize the threshold in the Filing Requirements for Distribution System Plans (EB-2009-0397) to implement that two-pronged approach. Distributors that file a Basic GEA Plan will be permitted to undertake a basic (i.e., standardized) direct benefit assessment, while essentially all distributors required to file a Detailed GEA Plan will be required to undertake a detailed direct benefit assessment based on the principles and criteria set out in this Report. As such, in cases where there is relatively little incremental renewable generation connected, an approximation is justified based on a standardized approach, while a rigorous analysis is required where and when it is justified (i.e., disproportionate share of incremental renewable generation connections). For detailed direct benefit assessments, an *ex post* approach will also be the default for the purpose of quantifying this category of benefits.

The Board considers this approach to be transitional and evolutionary. A transitional approach that takes into account the following:

1. O. Reg. 330/09 which clarified the Board's responsibilities in this regard was issued relatively recently;
2. the relative magnitude of the eligible investment costs and, therefore, the associated direct benefits at this time[1]; and
3. the estimation of direct benefits in relation to such investments, for the purpose of establishing rates, is a new responsibility for the Board, particularly given the manner such generation will be connected which is unique to Ontario.[2] As a consequence, results from other jurisdictions cannot be directly applied to Ontario.

Over time, as material amounts of new renewable energy generation is connected across Ontario by different distributors, the Board expects there will be an opportunity to gain experience, in relation to quantifying the direct benefits, based on actual results. In doing so, as the Board, distributors and other participants in this consultation process

[1] The Rate Order for Hydro One Distribution (EB-2009-0096) sets out the approved amount to be provincially recovered in 2010 and it amounts to less than $0.46 million on a monthly basis from May 1, 2010 to December 31, 2010.

[2] In other jurisdictions (e.g., New Zealand), where benefits have been estimated, the local distribution companies were provided with more control over where distributed generation is connected and the type of generation (i.e., an appropriate balance between intermittent and non-intermittent generation) in a manner that allowed for the "optimization" of the network and the maximization of the benefits associated with distributed generation. In contrast, under the *Green Energy Act*, distributors will have an obligation to connect renewable generation facilities regardless of the location and type of generation.

attain a better understanding of the direct benefits (and costs), under the circumstances unique to Ontario, it should allow the Board to refine its approach in this regard.

The Board is of the view that the approach set out above strikes a reasonable balance between administrative burden and incremental precision.

1 INTRODUCTION

The *Green Energy and Green Economy Act, 2009* (the "Green Energy Act"), which received Royal Assent on May 14, 2009, made a number of amendments to the *Ontario Energy Board Act, 1998* (the "Act"). Among these amendments, the Board has, as a new objective, to *"promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities"* (paragraph 5 of subsection 1(1) of the Act).

Consistent with its new objective of promoting the use and generation of electricity from renewable energy sources, the Board has reviewed the cost responsibility policies with respect to the connection of renewable energy generation to distribution systems. As a consequence, in EB-2009-0077, the Board issued final amendments (on October 21, 2009) to the Distribution System Code (the "DSC") in relation to *Distribution Connection Cost Responsibility* (the "DCCR Amendments") to revise its approach to assigning cost responsibility between an electricity distributor and a generator. For the purposes of assigning cost responsibility, the Board decided that such investments be classified within three general categories:

1. Connection assets (*generator* responsibility);
2. Expansions (*shared* responsibility based on a cost cap or *distributor* responsibility if identified in a Board-approved investment plan); and
3. Renewable enabling improvements (*distributor* responsibility).

The consequences of these changes in cost responsibility will mean that some of the costs related to connecting renewable generators – previously the responsibility of the connecting generator – will shift to ratepayers.

Evidence from the Renewable Energy Standard Offer Program ("RESOP") suggests that distribution-connected renewable energy generation development will not be distributed evenly among the service territories of the electricity distributors. As a result, in the absence of a cost-sharing mechanism, the cost burden of distribution system investment to accommodate the renewable generation would not be shared equally amongst distributors (and their ratepayers).

The *Green Energy Act* recognizes that some portion of such investment costs incurred by individual distributors should be shared amongst the province's ratepayers. Specifically, the *Green Energy Act* amended the Act to introduce a mechanism under section 79.1 whereby some of the Board-approved costs incurred by a distributor to make an '*eligible investment*' for the purpose of connecting or enabling the connection of a renewable energy generation facility to its distribution system may be recovered from all provincial ratepayers rather than solely from the ratepayers of the distributor making the investment. (see Appendix 3 for full text of section 79.1). The structure of this rate protection provision closely resembles the provision in section 79 of the Act for Rural and Remote Rate Protection (“RRRP”).

To enable this rate protection provision, the Government filed Ontario Regulation 330/09 (“O. Reg. 330/09”) on September 9, 2009 which sets out details related to the implementation of the cost recovery framework established in section 79.1. That cost recovery framework establishes a process for the collection – by the Independent Electricity System Operator (“IESO”) – of the amounts that qualify for rate protection and a process for the IESO to make compensation payments to distributors based on the rate protection amounts as determined by the Board to which each distributor is entitled.[3] (see Appendix 4 for Regulation 330/09).

O. Reg. 330/09 sets out the following formula:

A = B - C, where:

A = the amount of *rate protection* to be provided to prescribed consumers in a distributor’s service area,

B = *eligible investment costs* determined by the Board to be the responsibility of the distributor in accordance with the DSC, and

C = the amount the Board determines to represent the *direct benefits* that accrue to prescribed consumers as a result of all or part of the eligible investment made or planned to be made by the distributor.

The Board’s DCCR amendments process addressed the first part of the formula (see “**B**” above) by determining the “eligible investment costs” and those include *Expansion* and *Renewable Enabling Improvement* investments, as described above.

The focus of this new Board policy entails completing the framework for determining the amount of rate protection to be provided by specifying the “direct benefits” component of the regulation formula (see “**C**” above).

The purpose of this framework is therefore to identify:

1. the direct benefits that must be taken into account by distributors; and
2. a standard methodology to be used by distributors in calculating or quantifying those direct benefits.

[3] Once the Board establishes the Aggregate Rate Protection amount, the Board will establish a rate that would be applied to all Ontario electricity customers of distributors in a manner that is consistent with the cost recovery framework set out in O. Reg. 330/09. The rate set by the Board will be a function of the Aggregate Rate Protection Amount and an IESO load forecast (AQEW + Embedded Generation). Under O. Reg. 330/09, the fixed annual rate set by the Board (included in the WMSC) will only be applied by distributors. The IESO will collect the actual amounts of ‘rate protection’ each month from Market Participants, including distributors, as determined by the Board (and pay out the exact same amount in Monthly Compensation Payments to distributors based on their share as set out by the Board). The IESO will therefore charge a different “notional” rate to Market Participants that varies each month (i.e., not fixed) with fluctuations in market consumption.

1.1 Regulation 330/09

As a consequence of the determination of the direct benefits, the cost allocation associated with eligible investments between provincial ratepayers and the ratepayers of the individual distributor making the investment will be determined. There is therefore a relationship between the eligible investment costs and the associated direct benefits. As such, a clear understanding of what constitutes an eligible investment is necessary before discussing the related direct benefits. The Board therefore wishes to set out its interpretation of the following in relation to O. Reg. 330/09.

- "Eligible investment" costs, as set out in O. Reg. 330/09 and section 79.1 (5) of the Act, are not limited to only the initial capital investment costs but also includes the *up-front* OM&A costs necessary for the purpose of "enabling the connection of a qualifying generation facility". However, given that section 79.1 focuses solely on the initial investment, *ongoing* OM&A costs that are incurred by the distributor after the investment has been made will not be eligible for provincial recovery.

- The *Green Energy Act* focused on investments related to both the smart grid and the connection of renewable energy generation. However, O. Reg. 330/09 applies to only investments related to the connection of renewable energy generation in relation to being "eligible investments". As a result, unless a certain smart grid related investment has been identified in the DSC as a Renewable Enabling Improvement, such investments are not "eligible investments" for the purpose of the Act and the regulation.

- Not all investments made by a distributor to accommodate renewable generation will qualify as an "eligible investment". Investments to connect such generation that is contracted under the feed-in tariff ("FIT") program will be treated as an "eligible investment". However, similar investments to connect generation that was contracted under the RESOP program will not be treated as an "eligible investment". The important distinction is not between the two programs of the Ontario Power Authority (OPA). Instead, it is related to the Board's cost responsibility rules under the DSC and the timing of the recent DCCR amendments. RESOP generation was contracted before those DCCR amendments were made. As a consequence, investments to connect a RESOP generator remain the cost responsibility of the generator. In contrast, investments made by a distributor to connect FIT generators will occur after the Board issued its revised cost responsibility rules on October 21, 2009 and are therefore eligible for the provincial recovery mechanism.[4] As such, the "direct benefits" which are the focus of this Board framework only take into consideration

[4] Specifically, the Board's October 21, 2009 Notice of Amendment to the DSC (EB-2009-0077) identified that the new cost responsibility rules apply to investments associated with renewable generation projects for which an application to connect was made on or after October 21, 2009. Further details in relation to the date of application and a specific scenario are provided in that Board Notice.

those related to investments to connect renewable generation under the FIT program.[5] Such generation is referred to as 'qualifying' renewable generation in this report.

- Most *upstream* costs and benefits related to renewable generation connected in the distribution system will not be taken into account for the purpose of the Act and O. Reg. 330/09.

  - The Board's Notice (June 5, 2009) related to the DCCR Amendments (EB-2009-0077) states *"Some generation connections may trigger the need for upstream upgrades to the system of a host distributor or of a transmitter, in addition to triggering the need for the expansion of the distribution system to which the generation facility will be connected. Although the DSC is silent on the issue of cost responsibility for these upstream upgrades, the practice is for distributors to pass these costs on to the connecting generator. The Board does not propose to revise this approach at this time…".* Since such costs, which are related to another upstream entity, have been determined by the Board to be the responsibility of the generator, these investments would not be considered "eligible investments" under O. Reg. 330/09 and, as a consequence, would not be considered in determining the direct benefits.

  - Similarly, a potential *upstream* benefit often associated with distribution generation is related to the deferral or avoidance of certain transmission network investments. Such *upstream* benefits may be realized. However, these *upstream* benefits accrue to all provincial ratepayers – not only the customers of the distributor making the investment – and, therefore, will not be considered in this particular Board policy.

  - The only *upstream* benefits that will be taken into account for the purpose of the Act and O. Reg. 330/09 are in relation to transformers owned by the distributor undertaking the investment, as those benefits accrue to only the customers of the distributor making the investment.

1.2 The Consultation Process

The Board engaged stakeholders in a consultation to assist the Board in determining an appropriate framework for determining the direct benefits. To that end, the Board released a Staff Discussion Paper (the "Discussion Paper") for comment.

The Discussion Paper proposed the types of direct benefits to be taken into account as well as principles and criteria for the purpose of quantifying those direct benefits. The Discussion Paper also included a list of issues designed to elicit and facilitate comment.

[5] Any investment made by a distributor on or after October 21, 2009 to connect *merchant* renewable generation would also be considered an "eligible investment".

That list is set out in Appendix 1 to this Report. Among the issues the Discussion Paper identified were:

- whether the two types of direct benefits that were proposed are appropriate;
- whether any refinements should be made to the proposed criteria for the purpose of estimating the direct benefits;
- whether the Board should consider a certain standardized approach and, if so, what would an appropriate threshold be to determine which distributors could use the standardized approach and which distributors should be required to undertake a more rigorous assessment; and
- whether there are any information limitations that may prevent certain distributors from providing an assessment of any proposed criteria as described in the Discussion Paper.

As part of the initial comments, certain stakeholders expressed a desire for further discussion of the issues in advance of issuance of the Board's policy, as well as the opportunity for a second round of comments. The Board agreed that it would be beneficial to expand the scope of the consultation process to include further written comments and a Stakeholder Meeting to better inform that second round of comments.

The Board received written comments from the 13 stakeholders listed in Appendix 2 to this Report. Those stakeholders represent electricity distributors and ratepayers. The Board has benefited from these written comments in determining the framework set out in this Report, and thanks all stakeholders for their thoughtful input.

2 THE DISCUSSION PAPER AND OVERVIEW OF STAKEHOLDER COMMENTS

2.1 Types of Direct Benefits

The Discussion Paper proposed that the scope of the direct benefits be limited to those that meet the following criteria:

1. the benefit is directly attributable to only the customers of the distributor making the investment; and
2. the benefit is readily quantified in monetary terms.

On the basis of those criteria, the Discussion Paper also identified two types of direct benefits:

1. Reduced *Network* transmission charges and reduced wholesale market service charges (WMSC) realized by the distributor as a consequence of electricity production from new renewable generation connected by an eligible investment; and
2. Improved capabilities of the distribution system for load customers as a consequence of the eligible investments made by a distributor.

In regard to *Reduced Network Transmission and WMSC charges*, the Discussion Paper identified that, as additional renewable generation is connected to eligible investments within a distribution system and begins to produce power, it will reduce both the peak demand and the total quantity of energy withdrawn by the distributor. This, in turn, reduces these charges that must be *paid* by the distributor to the IESO. At the same time, there is no impact on the demand or quantity of energy consumed by that distributor's customers. As such, charges *collected* by the distributor do not decline. As a result, surplus network transmission and WMSC charges will be collected by the distributor which will be recorded in the distributor's applicable variance account and that surplus will ultimately be paid (i.e., disbursed) to only its customers.

In relation to the *Improved Capability of Distribution System for Load Customers*, the Discussion Paper identified that certain investments in the distribution system to accommodate additional renewable generation will also result in benefits for load customers of the distributor making the investment. Many of the eligible investments will convey energy to load customers as well as from renewable energy generation. For example, the investment may replace an asset that would have required replacement, in the near future, solely for the purpose of serving load customers.

Stakeholder comments on the Discussion Paper revealed general agreement in relation to the two criteria identified above for the purpose of determining the scope of direct benefits. There was, however, a clear difference of opinion between distributors and representatives of ratepayers in regard to whether the avoided charges should be included in the determination of the direct benefits. On the one hand, there was agreement that there would be a benefit to the customers of the distributor making the eligible investment (i.e., changes in revenue responsibility for these charges). On the other hand, ratepayer representatives believed that such avoided charges were a direct benefit and should be included, while distributors were of the view that the avoided charges were not a direct benefit within the context of O. Reg. 330/09. Some distributors therefore recommended that such benefits should, if the Board thought it necessary, be addressed in a separate Board proceeding.

A number of stakeholders also suggested that the avoided transmission charges should, in addition to the avoided Network charges, include avoided Connection charges associated with renewable generation under 2 MW. It was further suggested that the avoided charges related to microFIT generation should be excluded from the calculation given the administrative burden associated with tracking each microFIT project and the relatively small output.

2.2 Approach: Quantifying the Direct Benefits

For the first category of direct benefits, an *ex post* approach was proposed to apply to all distributors for quantifying these benefits. Based on the actual production from renewable generation the previous year, the surplus Network transmission and WMSC charges collected by the distributor, as a consequence of new embedded renewable generation connected to eligible investments, would be determined to be a direct benefit that accrues to the customers of the distributor as a result of the eligible investments.

For the second category of direct benefits, the Discussion Paper also proposed that a similar approach apply to all distributors at the outset. The methodology to derive those benefits would be based on the proposed principles and criteria discussed in section 3.3.2.1 of the Discussion Paper. The level of detail and analysis provided by a distributor would be commensurate with the circumstances of the distributor.

The Discussion Paper (section 3.3.2.2) also noted that the Board may wish to consider transitioning to a two-pronged approach with a less resource intensive standardized approach for certain distributors; specifically, in cases where there is relatively little incremental renewable generation connected, an approximation may be justified. The rationale in the Discussion Paper was the extreme diversity amongst the distributors in terms of the amount of generation capacity contracted in their territories under the RESOP program.[6] The Discussion Paper noted that, for the majority of distributors with a lower level of investment, undertaking a detailed analysis to estimate these benefits may result in administrative costs that represent a significant fraction of the benefit being estimated. However, the proposed standardized approach would be based on historical distributor results under the rigorous and detailed analysis associated with application of the principles and criteria discussed in section 3.3.2.1. The Discussion

[6] For example, under the RESOP program, 70% of the generation capacity was located in the territory of one distributor while 40 distributors each had less than 1% of the contracted capacity.

Paper therefore discussed the standardized approach within the context of a “Future Option” due to the fact that there were no historical results to draw upon. Within this context, the Discussion Paper also requested stakeholder input on a threshold to determine whether a distributor would be required to complete a detailed analysis or use the standardized approach.

Stakeholder comments on the Discussion Paper revealed general agreement that an *ex post* approach was appropriate, but that distributors should also have the option to use an *ex ante* approach if a variance account is used given all of the uncertainties associated with the timing and amount of renewable generation that will be connected under the OPA’s FIT program. One distributor supported a pure *ex ante* approach (i.e., no variance account). However, one stakeholder identified that the wording in O. Reg. 330/09 appeared to not permit such a pure *ex ante* approach.

In first round of comments, there was almost full agreement with the Discussion Paper that a standardized approach should only be considered after sufficient experience had been gained. Only one distributor representative supported a standardized approach at the outset. However, the views of some stakeholders changed following the Stakeholder Meeting once there was a better understanding that the information available to assess direct benefits with accuracy was more limited than previously expected. The Hydro One distribution rate proceeding, where this issue was addressed, had also been completed. For example, one ratepayer representative noted in the second round of comments that they had a “major change in our thinking” and therefore suggested as part of the initial implementation that “the Board establish a default percentage for smaller utilities with limited resources or eligible investments instead of doing an expensive analysis that might not make any material difference”.

In terms of a threshold, for determining whether a detailed analysis would be required or a standardized approach could be used, a ratepayer representative suggested adopting the threshold used by the Board in the Filing Requirements for when a Detailed GEA Plan is required (EB-2009-0397) and a distributor identified that it should be based on percentage of rate base to be consistent with other OEB guidelines.

2.3 Criteria Used to Assess Direct Benefits

While not explicitly stated in the Discussion Paper, the discussion of the criteria suggested project specific assessments would be necessary.

In terms of applying the criteria, one stakeholder noted that project specific assessments would be too costly and labour intensive and that a high-level approach should therefore be adopted. Another stakeholder acknowledged that, for certain distributors, a project specific approach could be somewhat onerous but, since most distributors will have a limited number of projects, a project specific approach should be readily applicable and that a cluster approach would yield a better estimate of direct benefits relative to a high level approach and reduce the level of detail required relative to project specific analysis for distributors with a large number of projects.

The criteria identified in the Discussion Paper for the purpose of estimating the direct benefits included the following:

1. Portion of Eligible Investments not used by Qualifying Generators
2. Customer Load Growth
3. Asset Condition
4. Size of Renewable Energy Generator(s)
5. Service Quality Improvement
6. Line Losses *(not included in assessment at outset)*
7. Alternative Criteria for Specific Investments *(optional)*

Of the stakeholders that commented on the following three criteria, there was general agreement that: (i) Line Loss impacts should be studied and not required at outset; (ii) Alternative Criteria for Specific Investments should be provided as an option that can be proposed by distributors; and (iii) Size of Renewable Energy Generator(s) should be eliminated as a separate criterion.

Distributors also identified information constraints in terms of three of the proposed criteria. With respect to the *Portion of Eligible Investments not used by Qualifying Generators* criterion and the *Service Quality Improvement* criterion, it was noted that no distributors have customer density information available at an area/regional level as proposed in the Discussion Paper. Similarly, in regard to the *Customer Load Growth* criterion, most distributors do not have such load growth information available at an area/regional level as proposed in the Discussion Paper.

The Service Quality Improvement criterion attracted the widest range of views including: it should be taken into account; it should only be taken into account for a couple of assets (SCADA for station automation and automated feeder reclosers); it should only be taken into account if it was already a planned investment for load customers of the distributors or if it was desired/wanted by the distributor’s customers; and it should not be taken into account at all. Stakeholders also expressed concerns regarding the difficulty and/or ability to quantify the value of improvements in service quality/reliability to load customers.

In regard to the Asset Condition Criterion, one stakeholder noted that the statement in the Discussion Paper that an asset replaced early in its service life would not provide as great a benefit appeared to overlook an important consideration. That consideration is the residual value since distributors could use certain assets that are in good condition as a system spare or in another station. As such, the avoided cost of purchasing such a new asset for these purposes should be a direct benefit.

There was also general agreement that where provincial ratepayers provided rate protection and the asset is not ultimately used by the distributor as an eligible investment, the amount of rate protection should be reduced accordingly going forward to reflect the use of the investment for other purposes. However, there was also agreement that it should not be reduced if the renewable generation does not materialize and the investment has not been used for other purposes.

3 THE BOARD'S APPROACH

The Board recognizes the need for a framework that recognizes the significant diversity of distributors in relation to the amount of renewable energy generation to be connected and the magnitude of the associated eligible investment. It also needs to recognize the current information limitations of distributors and strike a reasonable balance between administrative burden and incremental precision. The framework must be implemented in manner that is consistent with section 79.1 of the Act and O. Reg. 330/09, while protecting the interests of all ratepayers – ratepayers of the distributor making the investment and provincial ratepayers. The framework set out in this Report is therefore intended to be evolutionary in nature, with the expectation that the degree of precision will be enhanced in relation to quantifying the direct benefits as experience is gained and more information is acquired.

3.1 Identifying the Direct Benefits

As noted above, the Discussion Paper identified two criteria for the purpose of determining the scope of the direct benefits to be taken into account. The Board notes that those criteria are consistent with O. Reg. 330/09 as those criteria serve to exclude benefits which would accrue to all ratepayers across the province (e.g., environmental benefits) as well as *indirect* benefits such as local economic or fiscal impacts (e.g., additional local tax revenues).

The Board has therefore determined that the scope of the direct benefits will be limited to those that meet the following criteria:

1. the benefit is directly attributable to only the customers of the distributor making the investment; and
2. the benefit is readily quantified in monetary terms.

Based on those criteria, the Discussion Paper also identified two benefits to be used in determining the direct benefits that accrue to the prescribed customers of the distributor associated with eligible investments to connect new renewable energy generation.

The Board notes that, in terms of the types of benefits, the comments focused primarily on reduced network transmission charges and reduced wholesale market service charges (WMSC) realized by the distributor as a consequence of electricity production from qualifying renewable generation connected by an eligible investment.

The primary comment was to the effect that these reduced charges should not be considered a direct benefit under O. Reg. 330/09 as the focus should be on distribution costs or the distributor's revenue requirement. The Board notes that O. Reg. 330/09 makes no reference to distribution costs or revenue requirement and that there was agreement amongst all participants in this proceeding that there will be such a benefit to ratepayers of the distributor making the investment. The Board is of the view that, since provincial ratepayers will be required to pay some or all of the costs of the eligible investment needed to connect the qualifying renewable generation (from which this benefit is directly derived), it is appropriate that those provincial ratepayers should also share in the benefit that will be realized. In the absence of an eligible investment paid for by provincial ratepayers, this benefit would not exist. The Board is also of the view that this is the appropriate process to address this matter and that dealing with the issue in a separate Board process would be inefficient. The Board has therefore determined that these reduced charges will be included in the determination of the direct benefits that accrue to the prescribed customers of the distributor.

The Board also agrees with the comment that the reduced transmission charges should not be limited to Network charges. All charges that are subject to net load billing will result in a direct benefit. As such, a subset of Connection charges associated with renewable generation under 2 MW will also be taken into account.

The Board acknowledges the comment that microFIT generation should be excluded from the assessment of direct benefits for materiality reasons based on the relatively small output and the administrative burden associated with tracking each project. While the direct benefits associated with such generation will be immaterial at the individual project level, the Board believes there is the potential that it may become material over time at an aggregate level, particularly within the territories of certain distributors. The Board is therefore of the view that it is important to monitor microFIT generation at the outset in relation to its materiality and that period of time be used to ascertain whether a "rule of thumb" can be developed to minimize the administrative burden on distributors in the event the Board decides to include microFIT in the determination of direct benefits in the future.

The Board has therefore determined that the direct benefits to be taken into account by distributors are as follows:

1. Reduced *Network* and *Connection (renewable generation < 2 MW) transmission charges* as well as reduced *wholesale market service charges (WMSC)* realized by the distributor as a consequence of electricity production from new renewable generation connected by an eligible investment; and
2. Improved capabilities of the distribution system for load customers as a consequence of the eligible investments made by a distributor.

3.2 Quantifying the Direct Benefits

3.2.1 Reduced Network Transmission and WMSC Charges

The Discussion Paper identified two approaches – *ex ante* and *ex post* – for the purpose of estimating the direct benefits associated with reduced transmission and WMSC charges and proposed that an *ex post* approach be used by distributors.

The Board notes that section 3 of O. Reg. 330/09 refers to an eligible investment “made or planned to be made” by a distributor. This would support either an *ex post* or an *ex ante* approach. On the other hand, section 2 of O. Reg. 330/09 also describes the consumers eligible for rate protection as those served by a licensed distributor that has “incurred costs” to make an eligible investment that has been approved by the Board. This would clearly support an *ex post* approach. However, the Board believes that it would also support an *ex ante* approach, provided that the direct benefits are ultimately determined on the basis of costs that have been actually incurred. This is consistent with the approach taken by the Board in the proceeding to determine the 2010 and 2011 distribution rates for Hydro One (EB-2009-0096). Accordingly, while the Board believes that the *ex post* approach should be used by distributors, a distributor may use the *ex ante* approach on the condition that variance or deferral accounts are in place to allow for any reconciliation between forecast and actual benefits.

The Board acknowledges the concern expressed by distributors that the reduced charges will be difficult to track and that processes will need to be developed. The Board notes, however, that distributors are already required by the regulation pertaining to the Global Adjustment to submit production from embedded generation on a monthly basis to the IESO and that distributors will also be required to settle FIT contracts based on hourly data. The Board is therefore of the view that other processes are or will be in place to facilitate the calculation.

The Board also acknowledges the comment that the reduced allocated quantity of energy withdrawn (AQEW) of distributors from the grid due to embedded renewable generation will result in higher WMSC and transmission rates. However, the Board does not agree an expected higher rate should be used in the calculation of the direct benefits. To the extent these rates increase due to reduced withdrawals from the grid, it will equally affect all provincial ratepayers – not only the customers of the distributor making the investment. Distributors should therefore use the actual rates in place for the year the direct benefits are being determined.

The calculation of direct benefits in relation to reduced transmission and WMSC charges will be made by distributors based on the actual energy production from the qualifying renewable generation connected to eligible investments, and its contribution to reduced peak demand. Under the *ex post* approach, quantifying the annual benefits in this category for a given year will therefore be calculated by multiplying the actual rate (WMSC and transmission) by the actual renewable energy production from the *previous* year.

3.2.2 Improved Capability of Distribution System for Load Customers

3.2.2.1 Approach

The Discussion Paper proposed a framework for the estimation of the direct benefits related to this category. That framework was based on a number of principles and criteria to be taken into account by the distributor in estimating the benefits that will accrue to the customers of the distributor as a consequence of making the eligible investment(s). The Discussion Paper also proposed consideration of a less resource-intensive standardized approach for certain distributors. However, a standardized approach was only proposed as an option for implementation in the future due to the lack of historical results to use as a basis. Stakeholders generally agreed with this approach.

The Board believes that a two-pronged approach which recognizes the circumstances of distributors based on the amount of eligible investment is appropriate. However, the Board is of the view that, due to a number of factors, a standardized approach for certain distributors is appropriate at the outset of the implementation of this framework. The primary factor relates to the information limitations associated with the criteria identified in Discussion Paper that have come to the Board's attention during this consultation process. The Board has also recently issued a Partial Decision that addressed this matter in relation to Hydro One Distribution. As a consequence, the direct benefits cannot be estimated with the degree of precision previously expected and some historical results are now available as a basis for standardized approach that can be refined over time.

3.2.2.2 Threshold

On March 25, 2010, the Board issued its "Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence" (EB-2009-0397).[7] The Filing Requirements require that distributors file either a Detailed GEA Plan or a Basic GEA Plan depending on the materiality of planned system investments related to the connection of renewable generation or the development of a smart grid. Those Filing Requirements identify that such GEA Plans must be filed as part of a distributor's cost of service rate application for 2012 and subsequent rate years unless the Board directs otherwise. The Filing Requirements note that "the Board will issue a Report setting out a policy with respect to the calculation or quantification of direct benefits, and these Filing Requirements require that distributors provide information pertaining to direct benefits in a manner consistent with that policy".

For the purpose of this policy, the Board will adopt the threshold in the Filing Requirements for Distribution System Plans that is used to determine whether a distributor is required to file a Detailed or Basic GEA Plan.[8] As such, distributors that file a Basic GEA Plan will be permitted to undertake a basic (i.e., standardized) direct

[7] Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence (EB-2009-0397), March 25, 2010.

[8] Specifically, the materiality threshold currently set out in the Filing Requirements is:

1. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid in any one year:
    - Are more than $100,000 and exceed 3% of the distributor's distribution rate base; or
    - Exceed $5,000,000.
2. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid over five years:
    - Are more than $100,000 and exceed 6% of the distributor's distribution rate base; or
    - Exceed $10,000,000.

benefit assessment as explained below, while essentially all distributors required to file a Detailed GEA Plan will be required to undertake a detailed direct benefit assessment. However, if a distributor that files a Detailed GEA Plan falls below the threshold once all Smart Grid capital costs are excluded, that distributor will be permitted to use the standardized approach since Smart Grid costs are not relevant for the purpose of this framework.

Any distributor that is permitted to use the standardized approach will be provided with the option to undertake a detailed direct benefit assessment.

3.2.2.3 Basic Benefit Assessments for Basic GEA Plans

The Board will use an ongoing weighted average of actual direct benefits (relative to total eligible investment costs) associated with all distributors that have completed a detailed direct benefit assessment. As this is an evolutionary framework, it is the intent of the Board that the percentage used in the standardized approach will be refined over time as experience is gained and more distributors complete a detailed benefit assessment. For example, this may take the form of different percentages for different investments in the future.

At this time, only Hydro One Distribution has completed a detailed direct benefit assessment. The Board agrees with the comment that the Hydro One estimates of the direct benefits have an empirical basis and are based on a large number of projects, and therefore can be used as a transitional step in this evolutionary framework for distributors permitted to use the standardized approach. However, the Board does not believe the suggested use of a single percentage (i.e., 15%) for all eligible investments would be appropriate. The percentages of direct benefits differ for Expansion and Renewable Enabling Improvement (REI) investments, as Expansion investments tend to benefit load customers more than REI investments.[9] In addition, distributors will have different relative proportions of such investments. As such, separate percentages for Expansion and REI investments will be utilized to provide a more accurate estimate of the direct benefits.

Absent the information limitations identified during the consultation process, the Board would have been hesitant to use the Hydro One Distribution percentages of direct benefits in relation to REI and Expansion investments for other distributors. However, aside from the number of projects, the characteristic that differentiated Hydro One Distribution most from other distributors is customer density and it was learned in this consultation process that no distributors, including Hydro One, have such information specific to different areas in their service territories. The number of projects is also not a factor at all in the determination of direct benefits associated with an investment. As such, the Board is of the view that the percentages that are ultimately approved for

[9] For example, based on the provisionally approved methodology and allocation (i.e., dollar amounts) proposed by Hydro One as part of its 2010 and 2011 distribution rates application, those dollar amounts represent 6% for REI investments and 17% for Expansion investments.

Hydro One Distribution[10] in relation to Expansion and REI investments should provide a reasonable estimate for other distributors until more distributors complete detailed benefit assessments and a rolling weighted average can be used, particularly given the limited amount of eligible investments expected in Basic GEA Plans.

The Board has only approved the allocation of costs proposed by Hydro One, on a provisional basis, at this time. The Board's Partial Decision notes that "the allocation methodology and the resulting responsibility for Green Energy Plan costs for 2010 and 2011 will be subject to later revision to reflect the Board's final policy determination in EB-2009-0349." As such, the percentages that are initially to be used by distributors undertaking a basic benefit assessment will be the percentages based on the methodology and allocation that are approved by the Board on a final basis subsequent to the issuance of this Board Report. Those revised percentages will be communicated by the Board when they become available.

As noted above, in the future, the Board will use an ongoing weighted average of actual direct benefits associated with all distributors that have completed a detailed direct benefit assessment. As the percentages are updated to reflect changes in this ongoing weighted average, the updated percentages will only apply to incremental eligible investments for which the Board has not yet determined the direct benefits. In other words, the Board will not make future adjustments to previous calculations of direct benefits that have already been approved by the Board to reflect changes in the weighted average.

Consistent with the Board's interpretation of O. Reg. 330/09 above, the calculation of this category of direct benefits will also be on either an *ex post* basis or on an *ex ante* basis with a variance or deferral account.

3.2.2.4 Detailed Benefit Assessments for Detailed GEA Plans

As noted above, distributors required to file a Detailed GEA Plan will be expected to undertake a detailed direct benefit assessment based on the principles and criteria set out below unless the total capital costs in the plan are below the threshold once all Smart Grid capital costs have been excluded.

<u>Guiding Principles</u>

The Board generally agrees with the principles that were identified in the Discussion Paper with some modifications to reflect certain stakeholder comments.

In relation to the first principle, the Board agrees with the comment that it is important to clarify "load" customers and "eligible" investments.

In regard to the second principle, a number of stakeholders commented that the circumstances of the distributor should not be related to the size of the distributor in

[10] EB-2009-0096.

determining the level of detail and analysis to be provided. The Board is of the same view and has therefore clarified that it will be the circumstances of the distributor in terms of the amount of qualifying renewable energy generation to be connected and the magnitude of the associated eligible investment.

The Discussion Paper identified in the fourth principle that if any asset is replaced to accommodate qualifying renewable generation, customers of the distributor making the investment would realize a direct benefit of some magnitude. A stakeholder comment noted that there are certain specific assets (e.g., conductors, pole-mount transformers) where this would not be the case. This will need to be determined by the Board in a hearing on an application. As such, the Board has clarified that a direct benefit is expected in such cases unless it can be demonstrated otherwise.

The other principles that were set out in the Discussion Paper remain unchanged.

The Board has therefore determined that the following guiding principles will provide the basis for the more detailed discussion of the criteria that follow.

1) The benefit is directly attributable to only the load customers of the distributor making the eligible investment (i.e., limited to distribution system investments) and the benefit is readily quantified in monetary terms.

2) The level of detail and analysis provided by a distributor underlying the estimation of the direct benefits should be commensurate with the circumstances of the distributor in terms of the amount of qualifying renewable generation to be connected and the magnitude of the associated eligible investment.

3) Portions of certain eligible investments may not ultimately be used by only qualifying renewable generation facilities to which the Board’s new cost responsibility policies apply. Consistent with O. Reg. 330/09, to the extent the investment is used for other purposes (e.g., connect a large load customer), that portion of the investment would not be recovered through the provincial recovery mechanism.

4) Where any existing distribution asset is replaced to accommodate qualifying renewable generation, customers of the distributor making the investment will realize a direct benefit of some magnitude and therefore a certain portion of the costs should not be recovered through provincial recovery mechanism unless it can be demonstrated otherwise.

5) To the extent certain eligible investments (e.g., Renewable Enabling Improvements) that accommodate qualifying renewable generation are expected to improve service quality for the load customers of the distributor making the investment, such service quality improvements will represent a direct benefit to only the customers of that distributor (i.e., not paid for under the provincial recovery mechanism).

6) Distributors should not be required to estimate certain benefits (e.g., line losses) that may, in theory, sometimes be associated with distributed generation in a generic sense, but do not take into consideration the practical circumstances unique to Ontario under the *Green Energy Act*.

Criteria

The Board generally agrees with most of the criteria that were identified in the Discussion Paper. Some criteria have been changed to reflect the information limitations mentioned above while other changes have been made to reflect certain comments from stakeholders. One criterion has also been added – Avoided Asset Upgrades – and one criterion that was identified in the Discussion Paper has been removed as explained below.

As noted above, the Discussion Paper suggested project specific assessments would be necessary. The Board acknowledges the comment that project specific assessments could be costly and labour intensive to implement under certain circumstances. However, the Board agrees that a project specific approach should be readily applicable since most distributors will have a limited number of projects and that, for distributors with a large number of projects, a cluster approach would yield a better estimate of direct benefits relative to a high level approach and reduce the level of detail required relative to project specific analysis. As such, the distributor should, in its Distribution GEA Plan, use project specific assessments in the application of the criteria set out below as the default approach. However, where a distributor has a significant number of projects, that distributor will be permitted to use a cluster approach.

In relation to the criterion identified as “Size of Renewable Energy Generator(s)” in the Discussion Paper, the Board agrees with the comment that it is taken into account in the assessment of other criteria. As such, the Board has removed it as a separate criterion.

The Discussion Paper also identified a “Line Losses” criterion in noting that distributors should *not* be required to take this criterion into account in estimating the direct benefits at this time because, depending on the circumstances, line losses can either be reduced or increase due to distributed generation and the outcome is not certain in Ontario. The Board notes that Ontario’s circumstances differ from most other jurisdictions as generators – not distributors – will be determining the point of connection and the distributor will therefore have no control in relation to the impact of the generator on line losses. The Board is therefore of the view that the impact on line losses is too uncertain at this time and that it will be in a better position to determine if such a criterion can be incorporated into the direct benefit assessment framework, with relative certainty and accuracy, once some experience has been gained in Ontario. The Board will consider carrying out a study in this regard once there is a material amount of distributed renewable generation in operation.

Given the above, the Board has determined that distributors should assess the direct benefits based on the first five criteria set out below. The sixth criterion is optional. A distributor should, in its Distribution GEA Plan, explain how they took each applicable criterion into account. Some of the criteria are only applicable to certain investments or certain circumstances.

1) Portion of Eligible Investments not used by Qualifying Generators

The Discussion Paper noted and the Board agrees that, to the extent this criterion is not appropriately taken into account, the distributor would derive two revenue streams for the same asset via distribution revenues or a capital contribution from its customers as well as ’compensation payments’ for ’rate protection’ purposes from provincial ratepayers. The Board is of the view that such an outcome would not be acceptable.

The Board notes that due to the fact that distributors do not have customer density information available at the area/regional level, customer density will not be taken into consideration in the assessment of this criterion as proposed in the Discussion Paper.

The distributor should, in its Distribution GEA Plan, estimate to what degree (i.e., share) the investment will be used by *load customers* (relative to qualifying renewable generators). The distributor should also estimate the portion of the investment that will be utilized by *non-qualifying generators*. This is not limited to non-renewable distributed generation that may be connected. It also includes renewable generation that has proceeded under a RESOP contract, as different cost responsibility rules apply under which the majority of the costs remain the responsibility of the connecting generator.

The Board acknowledges that the Discussion Paper did not specify a basis for determining the relative use of the eligible investment and that a common parameter should be used by all distributors. Various potential parameters were identified in the comments such as peak kW of output vs. peak kW of load (i.e., capacity), kWh of output vs. kWh of load (i.e., energy), etc. The Board also acknowledges that either energy or capacity could be used. However, the Board is of the view that capacity should be used by distributors. Investments are typically made on the basis of capacity and the use of energy would appear to entail greater complexity. The Board does not believe there would be incremental benefits or advantages that would flow from an alternative methodology that are sufficient to outweigh the added complexity.

There may be instances where the Board has determined an investment to be an eligible investment but circumstances resulted in the distributor subsequently utilizing the asset for other purposes (e.g., to connect load customers and/or non-qualifying generators). In such cases, the distributor should bring this to the attention of the Board and any direct benefits, which were not previously taken into account in an appropriate manner, should be applied by the distributor as a direct benefit to reduce future eligible investment costs of that distributor. The amount of rate protection will accordingly be reduced by the Board going forward. This may include the value of any rebates that are received by the distributor as proposed in the Board's March 11, 2010 Notice in relation to the EB-2009-0077 consultation process.[11] The Board notes, in cases where it is simply a matter that planned renewable generation has not been connected and the distributor has not used the asset for other purposes, there would be no direct benefits to take into account (i.e., no adjustments to rate protection would be necessary).

2) Customer Load Growth

The distributor should also estimate the extent to which an eligible investment might replace an investment that would otherwise be required to accommodate load growth. For example, in relation to an Expansion-related eligible investment involving new assets (e.g., a new distribution line), where load growth is relatively high, an expansion would have been required in the future even if there was not a new renewable generator to connect.

In applying this criterion, the load growth used should be as specific as the distributor has available to the area/region where the qualifying renewable generation will connect. This is most applicable to distributors with large service territories or distributors that have two or more non-contiguous regions included in its service area. The Board acknowledges that some distributors do not have load growth information available on an area/regional basis. In such cases, the distributor should use its system-wide load growth to estimate the direct benefits.

3) Asset Condition

Where an eligible investment is a replacement asset, the direct benefit to load customers of the distributor will depend on the condition and remaining useful life associated with the asset it replaces.

The Discussion Paper used the example of a 15 MVA transformer that may need to be upgraded to a 25 MVA transformer to accommodate qualifying renewable generation. The benefits to the customers of the distributor will depend, in part, on the remaining useful life of the 15 MVA transformer that was replaced. The Discussion Paper noted that, where the transformer would have required replacement in the near future, the direct benefits to the distributor's customers would be relatively significant. On the other hand, if the existing transformer was in good operating condition and was expected to have many years of service

[11] The Board's Notice (March 11, 2010) noted "Under the Proposed Rebate Amendments, there could be cases where a distributor obtains a rebate from an unforecasted customer after having already received compensation for the associated connection costs from consumers throughout the Province. Where the unforecasted customer is a non-renewable generator, for example, there is potential for the distributor to be compensated twice for the same cost. The Board expects to address this issue as part of its consultation on Rate Protection and the Determination of Direct Benefits under Ontario Regulation 330/09 (EB-2009-0349)."

remaining, the direct benefits would be expected to be relatively minor in most cases. However, a stakeholder noted and the Board agrees that where such an asset is in good operating condition, the distributor may be able to redeploy the asset as a system spare or use it in another location in its distribution system and therefore would avoid the cost of acquiring a new transformer in this example for such purposes. In such cases, the direct benefits would not be expected to be relatively minor.

The distributor should, in its Distribution GEA Plan, estimate the remaining useful life of the asset being replaced and therefore the extent it has deferred the need for future investment. The distributor should also estimate the avoided costs where the replaced asset can be redeployed.

Unless it can be demonstrated otherwise, where an asset is replaced, the Board expects that a certain portion of the costs would be allocated to the distributor's own customers, as a replacement asset will almost always extend the timeframe over which the asset would have needed to be replaced anyway and therefore represent a direct benefit.

4) Service Quality Improvements

Renewable Enabling Improvement investments can improve service quality to a distributor's load customers.

The Board notes that due to the fact that distributors do not have customer density information available at the area/regional level, customer density will <u>not</u> be taken into consideration in the assessment of this criterion as proposed in the Discussion Paper.

The Board acknowledges the comment that, if an investment results in an improvement in reliability or service quality, it should not be considered a direct benefit unless it was already a planned investment of the distributor for its load customers. However, the Board notes that O. Reg. 330/09 does not qualify the term direct benefit in any way. The Board is also of the view that it would not be appropriate to require provincial ratepayers to pay for any benefit that accrues to only ratepayers of the distributor making the investment.

Some stakeholders also identified that it is either very difficult or not possible to quantify the value associated with specific service quality improvements to load customers. The Board agrees that this would be too complex and would require a standard methodology that does not currently exist.

Until a more precise approach can be established, the Board believes that a relatively straightforward approach based on an estimate of the extent that load customers will use the investment relative to qualifying renewable generators should provide a reasonable estimate. The Board notes that there appears to be general agreement that the applicable REI investments are relatively limited. Two examples identified by stakeholders were SCADA for Distribution Station automation and automated feeder reclosers. As an example, Hydro One took such an approach in its application in relation to SCADA for Distribution Station automation. Hydro One estimated the percentage of Distribution Stations to be modified to accommodate renewable generation that should be monitored regardless of the generation and then applied an equal sharing to that subset of Distribution Stations between load customers and renewable generation to estimate the direct benefit.

The Board notes that, in cases where an investment is needed to prevent deterioration in reliability or service quality due to the connection of renewable generation, it should not be considered a direct benefit.

5) Avoided Asset Upgrades

The Board notes that the Discussion Paper focused on transmission assets in stating that upstream assets are not applicable to this policy. A stakeholder pointed out and the Board agrees that the injection of generation within a distributor's system can forestall the need to increase capacity at existing distributor-owned transformation stations. As a result, the distributor may avoid capital and OM&A costs associated with a larger transformation station and the value of such avoided costs should be considered as a direct benefit.

The distributor should, in its Distribution GEA Plan, estimate the avoided capital and OM&A costs in cases where such asset upgrades are avoided.

6) Alternative Criteria for Specific Investments

While the Board expects applying the applicable general criteria above in a similar manner to all eligible investments to be the most practical approach for distributors, certain selected asset investments may be more amenable to a benefit evaluation based on an alternative criterion (i.e., may not take any of the above criteria in account). If a distributor feels that another criterion would result in a more accurate estimate of the benefits, the distributor may propose such a criterion. The Board expects that this would be the exception rather than rule and that the distributor would explain why the alternative criterion was more appropriate in that particular instance.

Appendix 1: *Consultation – List of Issues*
Appendix 2: *List of Stakeholders*
Appendix 3: *Section 79.1 - Ontario Energy Board Act, 1998*
Appendix 4: *Full Text of Ontario Regulation 330/09*

Appendix 1:

Consultation – List of Issues

Section		Issues for Comment
3.2	**Identifying the Direct Benefits**	1) In addition to the two types of direct benefits identified above (i.e., reduced transmission and WMSC charges, improved capability of the distribution system), should the Board take into account any other direct benefits that accrue to customers of the distributor making the investment?
3.3	**Quantifying the Direct Benefits**	**Reduced Network Transmission and WMSC Charges** 2) Are there any circumstances under which a distributor should be permitted to deviate from the proposed *ex-post* approach and use an *ex-ante* (i.e., forwarding looking forecast) approach?
		Improved Capability of the Distribution System for Load Customers *Proposed Guiding Principles* 3) Are there any potential refinements to the proposed Guiding Principles discussed above? 4) Should any additional Guiding Principles be considered by the Board?
		Proposed Criteria 5) Are there any potential refinements to the proposed criteria discussed above for the purpose of estimating the direct benefits? 6) Are there any other criteria that the Board should potentially take into consideration or should certain criterion listed above not be taken into account? In proposing the addition and/or elimination of certain criteria, a solid business case should be made for the Board to consider the merits. 7) Is a ranking or weighting of the criteria above necessary? If so, please propose an appropriate ranking or weighting, from most to least applicable, and provide a supporting justification. 8) Are there any information limitations that may prevent certain distributors from providing an assessment of any criteria above?

Section		Issues for Comment
3.3	**Quantifying the Direct Benefits (cont'd)**	*Proposed Criteria (cont'd)* 9) In the absence of having the best available information possible (e.g., recently completed study), are there any factors above for which a distributor would not be able to provide a reasonable estimate? 10) What information should all distributors already have on hand (e.g., for distribution planning) that would allow for a reasonable estimate that is specific to certain areas of a distributor's territory of: (1) load growth; and (2) customer density? 11) Where provincial ratepayers have provided rate protection and the asset is not ultimately used by the distributor as an eligible investment, Board staff proposed that the amount of rate protection should be reduced accordingly going forward to reflect the use of the investment for other purposes. In such cases, are there any circumstances under which the amount of rate protection provided by provincial ratepayers should not be reduced? If so, please explain.
		Potential Future Option 12) Should the Board consider a certain standardized approach? If so, how should the approach be standardized? 13) Would a certain percentage of expansion investments and a certain percentage of REI investments (using a historical "baseline" specific to each distributor) provide a reasonable estimate on a go forward basis? 14) If the Board decided a standardized approach would be appropriate for certain distributors: (i) What *timeframe* would be suitable for implementation? (ii) What would an appropriate *threshold* be to determine which distributors could proceed under a standardized approach and which distributors should be required to continue under the more rigorous assessment discussed in section 3.3.2.1?

Appendix 2:

List of Stakeholders

The December 14, 2010 Staff Discussion Paper (“Discussion Paper”) on the *Proposed Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09* is available on the Board’s web site at:

http://www.oeb.gov.on.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Rate+Protection+-+Determination+of+Direct+Benefits

Below is the list of stakeholders that provided written comments on the Discussion Paper. Both rounds of comments can be found on the same web page as the Discussion Paper.

- Association of Major Power Consumers in Ontario (AMPCO)
- Coalition of Large Distributors (CLD)
- Canadian Manufacturers & Exporters (CME)
- Consumers Council of Canada (CCC)
- Electricity Distributors Association (EDA)
- Energy Probe
- Enwin
- Federation of Ontario Cottagers’ Association (FOCA)
- Hydro One Networks
- London Property Management Association (LPMA)
- Power Workers Union (PWU)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition (VECC)

Appendix 3:

Section 79.1: Ontario Energy Board Act, 1998

Cost recovery, connecting generation facilities
79.1 (1) The Board, in approving just and reasonable rates for a distributor that incurs costs to make an eligible investment for the purpose of connecting or enabling the connection of a qualifying generation facility to its distribution system, shall provide rate protection for prescribed consumers or classes of consumers in the distributor's service area by reducing the rates that would otherwise apply in accordance with the prescribed rules.

Distributor entitled to compensation re lost revenue
(2) A distributor is entitled to be compensated for lost revenue resulting from the rate reduction provided under subsection (1) that is associated with costs that have been approved by the Board and incurred by the distributor to make an eligible investment referred to in subsection (1).

Consumers' contributions
(3) All consumers are required to contribute towards the amount of any compensation required under subsection (2) in accordance with the regulations.

Regulations
(4) The Lieutenant Governor in Council may make regulations,

- (a) prescribing consumers or classes of consumers eligible for rate protection under this section;
- (b) prescribing criteria to be met by a qualifying generation facility;
- (c) prescribing the criteria to be satisfied for an in-vestment to be an eligible investment;
- (d) prescribing rules for the calculation of the amount of the rate reduction;
- (e) prescribing maximum amounts of the total annual value of rate protection that may be provided under this section;
- (f) prescribing rules respecting the amounts that must be collected to compensate distributors, including rules,
  - (i) respecting the calculation of those amounts,
  - (ii) establishing the time and manner of collection,
  - (iii) requiring the amounts to be paid in instalments and requiring the payment of interest or penalties on late payments,
  - (iv) prescribing methods of ensuring that the amounts required cannot be bypassed, and
  - (v) respecting the distribution of the amounts collected;
- (g) prescribing the powers and duties of the Board in relation to the calculation of amounts to be collected and the time and manner of collection and distribution;

Definitions
(5) In this section,

"eligible investment" means an investment in the construction, expansion or reinforcement of a distribution line, transformer, plant or equipment used for conveying electricity at voltages of 50 kilovolts or less that meets the criteria prescribed by regulation;

"qualifying generation facility" means a generation facility that meets the criteria prescribed by regulation.

Appendix 4:

Full Text of Ontario Regulation 330/09

Definitions and interpretation

1. (1) In this Regulation,

"consumer" has the same meaning as in the *Electricity Act, 1998*;

"embedded distributor" means a licensed distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a licensed distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a licensed distributor who is a market participant and who distributes electricity to another licensed distributor who is not a market participant;

"licensed distributor" means a distributor who is licensed under Part V of the Act;

"qualified distributor" means a distributor serving consumers or classes of consumers that are being provided rate protection pursuant to subsection 79.1 (1) of the Act in accordance with this Regulation;

"rate protection" means rate protection under section 79.1 of the Act.

(2) The prescribed criterion for falling within the definition of an "eligible investment" under subsection 79.1 (5) of the Act is that the costs associated with the investment are determined to be the responsibility of the distributor in accordance with the Board's Distribution System Code.

(3) The prescribed criterion for falling within the definition of a "qualifying generation facility" under subsection 79.1 (5) of the Act is that the generation facility satisfies the criteria necessary to be a renewable energy generation facility under the *Electricity Act, 1998*.

Consumers eligible for rate protection

2. Consumers or classes of consumers are prescribed consumers or classes of consumers for the purposes of subsection 79.1 (4) of the Act if they are served by a licensed distributor that has incurred costs to make an eligible investment that has been approved by an order of the Board.

Calculation of rate protection

3. (1) The Board shall calculate the annual amount of rate protection to be provided to prescribed consumers or classes of consumers using the following formula:

$$A = B – C$$

where,

A is the amount of rate protection to be provided to prescribed consumers or classes of consumers in a distributor's service area,

B is the costs associated with the eligible investment described in subsection 1 (2), and

C is the amount that the Board determines to represent the direct benefits that accrue to prescribed consumers or classes of consumers as a result of all or part of the eligible investment made or planned to be made by the distributor.

(2) The Board shall calculate a monthly amount of compensation, referred to as the distributor's monthly compensation amount, to which each qualifying distributor is entitled, which amount shall be based on the amount calculated under subsection (1).

(3) Where the Board provides rate protection for a qualified distributor's prescribed consumers or classes of consumers, the Board shall, as often as is necessary and no less frequently than annually, calculate an aggregate monthly compensation amount by aggregating the amounts calculated under subsection (2) for each qualified distributor for each month for which collection is required.

(4) The Board shall, as often as is necessary and no less frequently than annually, calculate the monthly amount to be collected by the IESO under subsection 4 (2), such that the total amount that is to be collected is equal to the total amount of rate protection that is to be provided.

(5) The Board shall, as often as is necessary and no less frequently than annually, calculate the amount of the charge to be collected by each distributor under subsection 4 (3) for each kilowatt hour of electricity that is distributed to a consumer or embedded distributor, such that the total forecasted amount that is to be collected is equal to the total amount of rate protection that is to be provided.

(6) In any year, if the amounts collected by distributors in accordance with subsection (5) are greater or less than the amounts calculated under subsection (3), the excess or shortfall shall be considered by the Board in calculating the amount of the charge that is to be collected by distributors under subsection (5) for the following year.

(7) Qualified distributors and persons to whom this Regulation applies shall provide the information relating to this Regulation that the Board requires, in a form and within the time specified by the Board.

IESO calculation of proportional share

4. (1) On a monthly basis, the IESO shall collect from market participants the amount calculated by the Board under subsection 3 (4) based on each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid, as determined in accordance with the Market Rules, where the electricity is for the use of consumers within Ontario.

(2) For the purposes of subsection (1), the IESO shall proportionately charge market participants based on the total of the net volume of electricity withdrawn by the market participants from the IESO-controlled grid during the month and, if the market participant is a licensed distributor, the sum of,

(a) the total volume of electricity supplied by embedded generators during the month to the market participant, adjusted for losses as required by the Retail Settlement Code; and

(b) the total volume of electricity supplied by embedded generators during the month to all embedded distributors for whom the market participant is the host distributor, adjusted for losses as required by the Retail Settlement Code.

(3) On a monthly basis, each distributor shall collect from each consumer in its service area and from each embedded distributor to which it distributes electricity an amount proportionate to the volume of electricity distributed to the consumer or to the embedded distributor, including the total volume of electricity supplied by embedded generators to embedded distributors in the host distributor's service areas in the manner described in clause (2) (b).

(4) A distributor who bills a consumer from whom the distributor must collect an amount in accordance with subsection (3) shall aggregate the amount that the consumer is required to contribute to the compensation required under subsection 79.1 (2) of the Act and this Regulation with the amount otherwise payable by the consumer in respect of the wholesale market service rate described in the Electricity Distribution Rate Handbook issued by the Board, as it read on May 11, 2005.

IESO, monthly payments

5. (1) The IESO shall make a monthly payment to each qualified distributor that is equal to the monthly compensation amount determined by the Board under subsection 3 (2), including any payments for an embedded distributor to which the distributor delivers electricity.

(2) On a monthly basis, a host distributor shall, for each embedded distributor to which the host distributor distributes electricity, adjust the accounts between the host distributor and the embedded distributor by crediting the amount calculated by the Board under subsection 3 (2) to the embedded distributor.

(3) Payments required by this Regulation between licensed distributors and the IESO may be made, at the option of the IESO, by way of set off in the accounts maintained by the IESO.

(4) Payments required by this Regulation between an embedded distributor and its host distributor may be made, at the option of the host distributor, by way of set off in the accounts maintained by the host distributor.

IESO to provide certain information

6. (1) For the purpose of calculating the amounts referred to in subsection 3 (5), at least 60 days before the end of each calendar year the IESO shall submit to the Board,

(a) a forecast of the number of net kilowatt hours of electricity that are expected to be withdrawn from the IESO-controlled grid, as determined in accordance with the market rules, for use by consumers within Ontario during the IESO’s next fiscal year;

(b) a forecast of the total volume of electricity that is expected to be supplied to distributors and embedded distributors by embedded generators;

(c) documentation supporting the forecasts referred to in clauses (a) and (b);

(d) a calculation of the total amount of excess or shortfall held in variance accounts maintained by distributors resulting from the difference between the amounts charged to distributors by the IESO and the amounts collected from consumers by distributors;

(e) documentation supporting the calculation referred to in clause (d); and

(f) such other information as the Board may require for the purposes of this Regulation, in the form specified by the Board and before the expiry of the period specified by the Board.

(2) The forecast referred to in clause (1) (a) shall be derived from information submitted to the Board by the IESO pursuant to section 19 of the *Electricity Act, 1998* in respect of the IESO’s next fiscal year.

(3) At the end of each calendar year, the IESO shall submit to the Board the figures for the total amount of the monthly compensation that was paid out to each qualified distributor for each month of the year.

(4) Each distributor who is a market participant shall give the IESO such information as the IESO may require from the distributor for the purposes of this Regulation and shall do so in the

form specified by the IESO before the expiry of the period specified by the IESO. O. Reg. 330/09, s. 6 (4).

(5) Each embedded distributor shall give its host distributor such information as the IESO may require from the host distributor for the purposes of this Regulation and shall do so in a form specified by the host distributor before the expiry of the period specified by the host distributor.

Reliance on information

7. (1) For the purposes of this Regulation, the IESO shall rely on the information provided to it by each distributor who is a market participant.

(2) For the purposes of this Regulation, host distributors shall rely on the information provided to them by their embedded distributors.