Development of a Standard Methodology for the Quantification of DG Benefits

Prepared for:

Ontario Energy Board

July 31, 2008

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Contents

Executive Summary

Power Advisory was engaged by Board staff to develop a standard methodology for quantifying certain "specific, readily quantifiable" system-wide benefits of distributed generation (DG). These benefits are reduced costs of operating transmission and distribution systems due to deferred or avoided capacity investments, reduced system losses and avoided voltage regulation investments.

Although not the focus of this study, the OEB could use such a methodology to provide credits to DG installations that contribute to lower system costs and serve as the basis for rate calculations. A "standard" methodology is preferred because it would be uneconomic to perform a special study for each DG application. Finally, proper reflection of system-wide benefits will send a price signal to the DG market to locate facilities where they provide the greatest benefit, a matter of particular concern in the early development stages of Ontario DG.

Power Advisory applied the following criteria to establish the methodologies for quantifying DG benefits. These criteria reflect guidance provided by OEB staff, the specific attributes of DG projects, and an underlying objective of securing stakeholder approval of the methodology for quantifying DG benefits. There are many trade-offs that must be considered in applying these criteria. The most basic trade-off is the conflict between the desire to be simple and minimize regulatory burdens and the objective to reflect technology and location attributes in the methodology.

1. Standard methodology that can be applied throughout Ontario and produce reliable results;

2. Methodology should be simple and measurable with an eye toward minimizing potential regulatory burdens on all stakeholders;

3. Methodology should distinguish between DG projects that are 10 MW or less and greater than 10 MW;

4. Methodology should reflect design and operating characteristics of different DG technologies, including renewable technologies;

5. Methodology should distinguish among DG for merchant generation, load displacement, and hybrid installations to the extent it has a meaningful impact on the calculation of benefits;

6. Methodology should capture diversity benefits (e.g., the value created if several DG installations occur in a constrained area);

7. Data sources should be identified, readily available, and viewed as reliable; and

8. Methodology should be structured to allow updates to calculations based on more recent and/or accurate information.

The recommended standard methodologies are described below. The methodologies for estimating the value of deferred capacity investments in transmission and distribution facilities may require adjustments to the process used to determine capital spending by utilities. However, the fact that there are existing processes provides a valuable starting point when considering how to reflect the potential for DG - if sited where capacity is needed. It is also relatively straightforward to calculate the system value of deferred investments using accepted revenue requirement models. With respect to deferred distribution investments, the recommended methodology also requires the OEB to oversee determinations as to locations where DG would appear to provide the greatest value.

The methodology for reflecting the benefit from reduced transmission losses benefits from considerable work done in Ontario on this issue. More specifically, the IESO already calculates marginal losses associated with all major generation resources. The IESO is considering changes these loss factors. One alternative that could be implemented are loss factors that reflect both location and time-of-day considerations. Power Advisory recommends that the basis for calculating the benefit of reduced transmission losses for DG resources reflect locational as well as temporal differences. Care should be taken, however, to avoid double-counting of this benefit given that it is reflected in the OPA’s Renewable Energy Standard Offer Program (RESOP) and Clean Energy Standard Offer Program (CESOP) pricing.

The development of standard methodologies for estimating the benefits of reduced distribution losses and avoidance or deferral of distribution regulation investments is much more difficult that the other benefits. This difficulty is attributable to the fact that the potential benefit depends on specific system design and load characteristics in very localized areas of the distribution network (on a feeder, for example). Power Advisory has developed a methodology, but defers to the OEB as to whether it is appropriate at this time, based on the current state of technology, to implement such a methodology.

Deferred Transmission Investments

The standard methodology for the benefits created by deferred transmission investments must reflect the local conditions incorporated in transmission planning processes. One complicating factor is the conflict between the need to plan major transmission additions several years in advance versus the relatively short planning horizon of DG developers. As a result it may not be possible to "rely" on DG being developed for system planning purposes. Power Advisory's recommendation assumes that there is a way to solve this planning dilemma through a five-step methodology:

1. Estimate the amount of DG capacity to be installed by adjusting Ontario-wide DG development estimates to reflect regional prospects

2. Estimate DG operating profiles, using economic drivers for dispatchable units and intermittent resources based on operating profiles

3. Reflect diversity of DG development (and reliability of the collection of DG resources) using equivalent availability factors

4. Calculate the deferral impact in years by dividing the available DG (MW) by the annual area load growth in MW.

5. The revenue impact from a deferral can be estimated by applying a fixed-charge factor to the deferred capital costs.

Deferred Distribution Investments

The methodology for calculating the value of deferred distribution investments requires that the OEB establish criteria for each LDC to apply annually to identify - and subsequently publicize - the areas of their system that have a potential for significant investments to be deferred due to DG development. Power Advisory recommends that the locations be defined as substations with any DG development behind the substation be considered as a contributor to a deferral benefit - assuming that enough DG is developed to defer the investment. The LDC would also report an estimated DG value expressed as the NPV $/kW of the cost of investments that would be made, absent DG. The DG deferral benefit or credit would be calculated as the product of this value and the capacity that can be relied upon during peak hours for each facility.

Reduced Transmission & Distribution Losses

As noted above, PowerAdvisory recommends that the IESO transmission loss factors be used to value transmission loss reduction benefits, but that these loss factors be modified to consider temporal differences in losses if the updated IESO loss factors don't reflect these differences.

With respect to distribution loss reduction benefits, LDCs currently calculate losses on an average system-wide basis for revenue requirements purposes, without regard to location. These loss factors are a good starting point for a standard methodology but adjustments must be made to account for location-specific conditions. This can be done in either of two ways: (1) identify distinct loss factors for primary and secondary feeders, or (2) reflect distance from a substation in adjusting the system-wide loss factor. In either case, DG that results in increased line loadings would not be eligible for a credit.

Improved Voltage Stability

As noted above, LDC determinations of areas of the system requiring investments to include the voltage profile (higher, but not too high, and flatter are preferred) is an extremely complex undertaking. There are some generalities that can be made to simplify the process, but these simplifications have an adverse impact on the validity of the approach. This simplified methodology is based on a few decision rules:

- If the DG technology does not produce reactive power, it has no value as voltage support;
- If the DG facility is greater than 10 MW, it must be subject to a special study; and
- If the DG facility is less than 10 MW and is connected to a low or medium-voltage feeder, then it is eligible for a credit. The credit is calculated as the product of the facility kW and an average value of avoided LDC voltage investment.

As described more fully in the report, these recommendations reflect a balancing of the sometimes conflicting evaluation criteria. The paramount goal has been to develop a standard methodology that is not overly burdensome to implement, but reflects the value of DG in different locations.

1. Introduction

1.1 Background and Context

The Ontario Energy Board (Board or OEB) has several consultation processes underway that directly address issues related to distributed generation. Connection cost responsibility, rate classification and standby rates, and revenue losses associated with load displacement generation were identified as issues in the Distributed Generation – Rates and Connection consultation (EB-2007-0630). Furthermore, the question of whether distributed generation should pay regulated "use of system" charges was an issue in the Rate Design for Electricity Distributors consultation (EB-2007-0031).

In its assessment of these issues, the Board also has found that an important element of the ratemaking for DG resources is the consideration of benefits that they may provide to the transmission and distribution network, often referred to as "system-wide" benefits. In the 2006 electricity distribution rate-setting process (RP-2005-0020/EB-2005-0529) the Board found that standby rates for distributed generation (DG) should consider system-wide benefits (and be cost-based) and "a standard methodology across all utilities is preferable, but notes that a standard methodology does not necessarily mean identical rates."[1] To address the issues associated with the system-wide benefits of DG, the Distributed Generation - Rates and Connection initiative has been refocused on the development of a standard methodology for quantifying specific benefits from the connection of distributed generation.

Power Advisory was engaged by Board staff to develop such a standard methodology for quantifying certain "specific, readily quantifiable" benefits of DG. This report frames this standard methodology for quantifying these identified benefits and reviews other methodologies that were considered, but not recommended. The report has been drafted with the understanding that stakeholders will have an opportunity to comment on the methodology.

1.2 DG Benefits Evaluated

DG projects can provide a broad range of benefits including customer benefits such as lower energy costs, enhanced reliability and high quality premium power as well as network benefits such as the deferral of the need for new generating, transmission and distribution capacity, increased transmission and distribution equipment operating life, reduced energy losses, and increased system reliability.

The RFP for consulting services issued by Board staff specified that the consultant should examine the following "readily quantifiable" benefits of DG: (1) reduced losses for both transmission and distribution; (2) deferred capacity/reinforcement investments for both transmission and distribution, and (3) deferred capital investments for voltage regulation improvements. The methodology outlined in this report focuses on these specified benefits and doesn't evaluate numerous other potential customer, system and societal

[1] P. 12.

benefits including avoided energy, capacity or emission benefits, avoided congestion costs, increased operating life of transmission and distribution assets, or increased system reliability.

As indicated above, the OEB's interest in a standard methodology for quantifying DG benefits is to assist with DG facility ratemaking (e.g., establishing standby rates) for LDCs. As such, the methodology should focus on benefits that will be realized by the customers of the respective LDCs that are experiencing DG development. Given Ontario's experience to date where DG projects have been concentrated in the service territories of a relatively limited number of LDCs, this is particularly important. As such, the focus is on actual DG benefits that the other customers of the LDC or transmission network realize.[2] This is consistent with standard ratemaking methodologies that design rates to recover costs from customers that are responsible for their cost incurrence. As applied to DG benefits, compensation for benefits should be funded by the customers that receive the benefits (e.g., to the other customers of the LDC if a DG facility creates system benefits that are restricted to that LDC). As such there is a need to distinguish between utility-specific, regional and province-wide benefits.

1.2.1 Potential DG System-Wide Benefits Excluded from This Study

As noted above, there are a number of potential benefits from DG projects that are not reflected in the standard methodology presented in this report. One important system benefit that is related to design and operation of the transmission network is transmission congestion relief. A second system benefit that is related to the design of both transmission and distribution networks is the potential that DG will contribute to an increase in the operating life of transmission and distribution assets and in network reliability. These are briefly reviewed in this section, before concluding with a comment on avoided emissions benefits.[3]

Congestion Relief

In Ontario congestion is priced through congestion management settlement credits (CMSCs). Specifically, when a generator is required to be dispatched down or off as a result of transmission congestion, it receives the difference between HOEP and its offer. Conversely, when a generator is dispatched its "constrained on" payment is equal to the difference between its offer and the Hourly Ontario Energy Price (HOEP). These "constrained off" and "constrained on" payments are CMSC payments and are recovered from customers in the Wholesale Market Service Charges. To the degree that a DG project reduces loads on the transmission network it can reduce congestion and CMSC payments and provide a benefit that is shared by all customers. Conversely, more DG in areas that already have a surplus of generation and transmission congestion (e.g., Northwestern Ontario) can increase congestion costs on the system. CMSCs are a relatively small portion of total market costs,

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[2] In the Decision for RP-2005-0020 and EB-2005-0529, the Board noted that "The starting point for the development of the standard methodology would be the proper allocation of costs to those that cause the cost, as well as the quantification of the benefits."(p. 12). The corollary to this would be the proper allocation of costs to those that realize the benefits.

[3] There is general consensus that the value represented by these benefits is typically less than that of the transmission and distribution investment deferrals and avoided transmission and distribution loss benefits.

representing less than 2% of energy costs.[4] Furthermore, the vast majority of these congestion costs are incurred in Northwestern Ontario and on Ontario's interties. DG in southern Ontario would reduce this congestion to the degree that the decrease in market prices from the additional supply reduces the economic flows from these areas with transmission constraints. This is likely to be a negligible impact from DG and one that is difficult to measure. The IESO does produce shadow prices that reflect locational marginal pricing and the costs of congestion. While these are viewed by many as providing a more accurate price signal than Ontario's uniform price, Ontario has not implemented LMP. Furthermore, to the degree that new transmission projects are developed to reduce congestion costs then DG's ability to defer such investment will be considered when its ability to defer these facilities is evaluated.

Increased Asset Operating Life and Enhanced Network Reliability

To the degree that DG reduces loads on transmission and distribution equipment it can increase the operating life of this equipment. For example, DG can reduce the number of hours that a substation transformer operates at elevated temperatures and it is operation at elevated temperatures which has the most significant impact on decreasing operating life. Furthermore, failure of transformers and other transmission and distribution infrastructure often results in service interruptions. Reliability can also be enhanced by having generation resources closer to load such that service quality is less reliant on the transmission infrastructure. Evaluating these impacts and quantifying the resulting benefits is difficult. It requires that actual operating conditions be evaluated and then the impact of DG on these operating conditions be assessed and this change in operating conditions be expressed in terms of operating temperatures for the various transmission and distribution components with the resulting impact on their operating life assessed. This is beyond the scope of a standard methodology. It is likely that the impact is relatively small and well within the error of other estimates.

Avoided Emissions

Power Advisory expects most merchant DG projects to participate in the OPA's Renewable Energy Standard Offer Program (RESOP) and Clean Energy Standard Offer Program (CESOP) and the RESOP and CESOP prices reflect the energy and capacity value provided by these projects. Load displacement DG projects will enable the customer behind whose meter they reside to avoid energy prices and the Global Adjustment which is in essence a capacity price. With respect to the value of avoided emissions, these as well are largely reflected in the RESOP and CESOP pricing. Specifically, the Minister of Energy has established renewable energy targets in its Supply Mix Directive presumably based in part on the environmental benefits offered by these resources and these RESOP prices reflect the cost/value of acquiring this renewable energy and thus reflect the value of the avoided emissions. Economists may argue that damage estimates, willingness to pay or emission allowance markets are better reflection of this value. However, Ontario energy policymakers have demonstrated a preference for reflecting this value in terms of policy initiatives rather than formal quantitative economic estimates that appear to be more

[4] Derived from data provided in: Market Surveillance Panel, *Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2007-October 2007*, p. 37.

precise, but are subject to considerable uncertainty. As such, Power Advisory believes that the value of any avoided emissions already are embedded in the RESOP and CESOP prices paid to DG projects.

1.3 Distinguishing Among Different Types of DG Projects

The RFP requested that the methodologies distinguish between DG projects that are 10 MW or less and greater than 10 MW and merchant and load displacement DG. It also requested that differences between the generation technology and the diversity benefits be considered. This distinction is reflected in the recommended standard methodologies.

With respect to the distinction between load displacement and merchant DG projects, the RFP also noted that it may be appropriate to distinguish among:

- load displacement distributed generation comprises generation facilities that supply electricity to a specific load, displacing electricity supply that would otherwise be obtained from the local distribution system;
- merchant distributed generation comprises generation facilities that supply electricity to the local distribution system; and
- hybrid distributed generation comprises generation facilities that generate electricity in excess of the needs of the associated load and injects the surplus into the local distribution system.

To the degree that there are no standby charges, load displacement DG allows the customer behind whose meter the DG project is located to avoid LDC demand and energy charges.[5] Load displacement projects reduce losses and may defer transmission and distribution system reinforcement costs.

The benefits provided by merchant distributed generation projects are more location and generation technology specific.

1.4 Report Contents

This report contains six chapters, including this Introduction. The second chapter reviews the considerations for establishing methodologies to quantify these benefits. Chapter 3 outlines the methodology for quantifying the benefits attributable to DG projects from deferring transmission investments. Chapter 4 outlines the methodology for quantifying the benefits provided by DG from deferring distribution system investments. The next chapter reviews the methodology for quantifying avoided transmission and distribution losses and Chapter 6 reviews the methodology for deferring investments for voltage regulation improvements. Appendix A reviews the methodology for estimating the deferral impact of DG resources. Appendix B reviews the derivation of the fixed charge factor for transmission investments. An example of the transmission deferral benefit calculation is provided in Appendix C. A bibliography identifying the various sources cited is presented at the end of the report.

[5] The degree to which demand charges may be avoided will depend on whether there are demand ratchets, etc.

2. Selecting a Methodology for Quantifying DG Benefits

The OEB has identified several considerations that are to be reflected in the methodologies for quantifying system-wide benefits of DG. These criteria are reduced to a set of criteria presented in this chapter. After identifying these criteria, Power Advisory will note certain other cautions that should be kept in mind when selecting the respective methodologies.

2.1 Selection Criteria

Power Advisory applied the following criteria to establish the methodologies for quantifying DG benefits. These criteria reflect guidance provided by OEB staff, the specific attributes of DG projects, and an underlying objective of securing stakeholder approval of the methodology for quantifying DG benefits.

1. Standard methodology that can be applied throughout Ontario and produce reliable results;

2. Methodology should be simple and measurable with an eye toward minimizing potential regulatory burdens on all stakeholders;

3. Methodology should distinguish between DG projects that are 10 MW or less and greater than 10 MW;

4. Methodology should reflect design and operating characteristics of different DG technologies, including renewable technologies;

5. Methodology should distinguish among DG for merchant generation, load displacement, and hybrid installations to the extent it has a meaningful impact on the calculation of benefits;

6. Methodology should capture diversity benefits (e.g., the value created if several DG installations occur in a constrained area);

7. Data sources should be identified, readily available, and viewed as reliable; and

8. Methodology should be structured to allow updates to calculations based on more recent and/or accurate information.

2.2 Measurement Considerations

The focus of this study is system-wide benefits or the value of DG to non-participating customers. Focusing on the value to these customers ensures that the benefits that are considered are realized by all customers. This value can be measured in terms of reduced utility revenue requirements. DG can reduce utilities' revenue requirements by deferring capital expenditures for expansion of the transmission and distribution network and reducing transmission and distribution losses.

For example, if capital expenditures are deferred, increases in revenue requirements are deferred and the benefits to customers depend on the significance of the capital expenditures that are deferred and the duration of the deferral (i.e., the time value of money). With inflation the deferral would result in higher costs when the facilities are ultimately built. This impact needs to be considered when evaluating the deferral benefit. Calculating the change in revenue requirements on a present worth basis allows these different impacts to be compared and the net benefit to non-participating customers calculated.

These benefits cannot be measured precisely. Overstating value realized can harm non-participants by increasing system costs as a result of overpaying or under-collecting the costs of DG resources. As discussed earlier, to the degree that these DG benefits are used to establish credits for standby charges or lost revenues, then it will be a discrete group of LDC customers that bear the risk that benefits are overestimated. Understating value fails to realize the value offered by lower cost DG alternatives, resulting in higher costs.

Furthermore, the analysis needs to ensure that value isn't already reflected in an existing policy or pricing program and as a result double counted. For example, the RESOP pricing already reflects the benefit of avoided transmission losses. Therefore, it isn't appropriate to pay a RESOP project a premium based on these avoided transmission losses and then assert that this same benefit warrants that the project should be charged reduced standby charges that reflect the same assumed loss reduction. Alternatively, to the degree that the standard methodology outlined in this report employs a different value when estimating these benefits, the standard methodology can be modified to only consider the incremental/decremental benefit. Specifically, the benefit(s) that are already reflected in the RESOP or CESOP pricing could be removed from the benefit calculation or to the degree that there is a different benefit estimate the benefit considered in the standard methodology could be net of that reflected in the CESOP or RESOP pricing.

In addition, where transmission and distribution charges (as well as the Global Adjustment) are embedded in rates that a load displacement DG project would allow the customer to avoid, then consideration needs to be given to these avoided charges. The actual value of the avoided transmission or distribution investment is likely to be better reflected by marginal costs and rates are more likely to be based on average costs. As such, there may be a need to reconcile the difference between the marginal and average costs, if it is significant.

3. Methodology for Quantification of Benefits of Deferred Transmission Investments

3.1 Overview of Approach

This chapter focuses on the benefits of deferred transmission investments. These transmission investments include transmission lines, substations and voltage support equipment. DG facilities, depending on their location, can defer the need for investment in Ontario's transmission network. This section describes the circumstances that create these benefits and a methodology for estimating them. Transmission planning is a long-term process characterized by substantial public input that reflects the role that these facilities serve in reliably delivering generation to market areas and siting considerations that are of public interest.

Thus, to understand how transmission investment can be deferred by DG it is necessary to understand how transmitters plan for these investments.[6] Hydro One Network Inc's (HONI's) transmission planning process is outlined in its 2005 Transmission Plan[7]: "[p]ossible transmission solutions are developed when technical assessments based on load and generation forecasts identify a potential need for system modifications or new transmission facilities within a 10-year planning period. Potential solutions are then assessed on various criteria including cost, value, lead-time, and impacts on the environment and the local community."[8] HONI's transmission investments are driven by three considerations: (1) reliability; (2) security of supply; and (3) power quality.

Focusing on the transmission planning process is essential to establish the circumstances under which DG projects can either defer transmission investments or lead to a smaller-sized and less costly investment.[9] In the simplest terms, transmission projects can be deferred only if the need date for the investment can be deferred by DG. There are also a number of transmission system investments which are not driven by load growth. These include: (1) asset replacement; (2) interconnection upgrades; and (3) reliability driven investments. As such, these types of transmission system investments generally cannot be deferred by DG.[10]

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[6] The OPA's Integrated Power System Plan evaluates transmission investments that would enable and facilitate the Minister of Energy's Supply Mix Directive's specific supply mix goals (conservation, renewables, gas, nuclear, coal replacement) and promote system efficiency and congestion reduction.

[7] HONI accounts for over 90% of the transmission network in Ontario.

[8] *Transmission Solutions: A 10 Year Transmission Plan for the Province of Ontario 2005-2014*, 2005, p. 12.

[9] While DG facilities aren't likely to result in the resizing of a transmission line (e.g., from 230 kV to 115 kV), they could result in the installation of a smaller capacitor or other voltage support equipment.

[10] As discussed, DG can extend the operating life of transmission facilities. As a result, DG can affect asset replacement decisions if transmission planners are able to distinguish the impacts of DG on asset lives.

3.2 Two Approaches for Quantifying Transmission Capacity Deferral Benefits

There are two distinct approaches that can be used to quantify these benefits: (1) a long-run equilibrium approach that recognizes that facilities need to be replaced over time and; (2) an approach which focuses on the locations of near-term transmission investments.

The evaluation of these two basic approaches is driven in large part by data availability and, in particular, the information that is available regarding the costs of identified transmission system investments.

3.2.1 Option 1: Long-Run Equilibrium Approach

The long-run equilibrium approach reflects an environment where DG is planned and coordinated with transmission and distribution capacity. This approach was used in an Oak Ridge National Laboratory study[11] and relies on "[t]he premise … that in the long run, all distribution capacity must be replaced and/or upgraded. Therefore, any increase in DG capacity has the potential to avoid distribution capacity costs."[12] Although the citation refers to distribution costs, the concept applies equally to transmission investments.

In this approach DG benefits are estimated based on the changes in the embedded costs of transmission investments. Specifically, the increase in transmission costs over a several year period can be divided by the increase in transmission capacity over this same period to yield a $/kVA cost of transmission investment. These data are readily available in FERC Form 1 for US utilities, which greatly simplifies the analysis. These cost data also are provided in HONI's transmission rate filings.

The primary benefit of this long-run equilibrium approach is that it is easy to implement. However, it fails to consider that DG benefits are by their nature very location specific. While a case can be made that a long-run equilibrium approach is appropriate given the need to replace transmission or distribution facilities over time, in many instances, DG facilities are unlikely to affect this need or even the sizing of the required network facilities. As such, Power Advisory believes that a long-term equilibrium approach isn't appropriate given that it doesn't provide the appropriate locational price signals for DG.

3.2.2 Option 2: Locational Benefits Approach

The second approach is much more site-specific and recognizes that the benefits from DG projects are driven primarily by their location, the characteristics of the network on which they are installed and how the DG resources operate.[13] By definition, this approach is location and network-specific and as a result more resource intensive to apply. Furthermore, it is likely to be implemented by the local distribution

[11] S. W. Hadley, J. W. Van Dyke, W. P. Poore, III, and T. K. Stovall, *Quantitative Assessment Of Distributed Energy Resource Benefits*, ORNL/TM-2003/20, Oak Ridge National Laboratory, April 2003.

[12] Hadley, p. 31.

[13] See for example, Peter B. Evans, 2005. *Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energynet.* California Energy Commission, PIER Energy-Related Environmental Research.

companies to reflect site-specific conditions on their respective networks. As a result, it has the potential to conflict with the objective of not unduly increasing the regulatory burden.[14] The obvious offsetting benefit of this greater level of effort is greater precision regarding the benefits provided by DG resources in specific locations.

However, employing this approach is much less resource intensive when evaluating transmission than distribution investments given the limited number of transmission investments for which it would be employed.

The remainder of this chapter focuses on how this second option could be implemented in Ontario for transmission.

3.3 Implementation

Assuming that transmission investments that can be deferred by DG are driven by load growth, then it is reasonable to posit that in areas where there is no load growth there will be no transmission deferral benefits, other than to reduce existing congestion costs (e.g., in Northwestern Ontario). There is information available to establish the Ontario zones where no load growth is forecast to identify where there is not likely to be any transmission deferral benefits.[15] For example, declines in load are forecast over the next 10 years for the Northwest and Northeast zones.[16] (Figure 1 identifies the various Ontario zones.)Therefore, one can assume that there are no transmission deferral benefits in the Northwest or Northeast Ontario from DG.

One complicating factor for this methodology is that for a transmission project to be deferred, the DG impact must be sufficiently far enough in the future that the transmitter hasn't already committed to the reinforcement given the need to initiate permitting and seek construction approvals. HONI has indicated that with lead times for permitting and obtaining construction approvals it needs to commit to a project about three to seven years before the desired in-service date, depending on the specific permitting requirements. If an Environmental Assessment (EA) is required, the lead time is approximately seven years, whereas if no EA is required the lead time is approximately three years.

However, the potential seven-year lead time does not always correspond with the capital budgeting process, a factor that presents a challenge to applying the methodology. The capital budget identifies transmission investments that are needed in the next five years. While as part of its 10-year transmission planning process HONI distinguishes between the factors that are driving the potential transmission projects on the basis of four different "buckets": (1) status quo; (2) aging of assets (i.e., asset

[14] OEB staff noted the importance of this objective at the project kickoff meeting.

[15] The IPSP provides a summer peak forecast by zone. OPA, Integrated Power System Plan, EB-2007-0707, Exhibit D, Tab 1, Attachment 2, p. 7 of 11.

[16] The increase in load forecast for Niagara and Bruce is less than 25 MW over this period, suggesting that there is unlikely to be new transmission facilities proposed in these areas that could be deferred by DG. Interestingly, there are two major transmission projects targeted to these areas. However, these are being proposed for congestion relief and additional DG in these zones would not eliminate the need for these projects.

sustainment); (3) load growth; and (4) power quality, transmission projects are only conceptual at this point in the planning process. A need is identified only in general terms. Specific transmission solutions aren't necessarily identified. Depending on the requirement, the solution could vary significantly. Therefore, there is no cost estimate developed at this stage.[17]

Figure 1: Ontario Load Zones

Source: OPA

[17] One potentially complicating factor is that HONI has indicated that it doesn't distinguish between what is driving the investment. This can make it more difficult to identify which transmission investments can be avoided by DG. In comments in the OEB's Transmission Connection Cost Responsibility Review Proceeding, HONI noted "[w]hile it is relatively simple to compare the reliability impacts of different plans, it is difficult to determine objectively whether a plan is required for load growth as opposed to system reliability and integrity." Hydro One Networks, Initial Comments and Submission in EB-2008-0003, *OEB Review of Cost Responsibility for Connection to Electric Transmission Systems*, p. 6

3.3.1 Estimating the DG Impact

Assessing whether DG projects can defer a transmission investment and for what duration is a multiple step process. The first step is estimating the amount of DG capacity, the second the likely operating profile, the third the availability of this capacity, considering the diversity impact, the fourth the deferral impact, and the fifth the impact on revenue requirements. This approach is outlined below and the first four steps illustrated in Appendix A.

Step 1: Estimating the Amount of DG Capacity

Estimating the amount of DG that is likely to be developed can be a major undertaking. The starting point is establishing the geographic scope of the area served by the transmission facility to be deferred. This is the area where DG projects can be located to defer the transmission investment. The peak load of this area relative to the Ontario forecast peak indicates the proportion of the Ontario market served by the transmission facility.

Applying a market-based approach, DG penetration rates can be estimated based on payback, with higher paybacks resulting in higher adoption rates. The most significant challenge is establishing the number of potential DG applications to which this market penetration rate would be applied. Establishing a methodology to estimate this is beyond the scope of this analysis. An alternative approach is to use a general estimate of the DG potential in Ontario and then estimate a market adoption rate to determine the DG capacity likely to be installed. This approach is used as a starting point for the analysis. If better data become available the analysis framework can be updated.

Power Advisory wasn't able to find a recent reliable estimate of the achievable DG potential for Ontario.[18] Therefore, we used an estimate for the US and scaled it to the size of the Ontario market. This analysis produced an incremental DG potential estimate of 1,000 MW for Ontario.[19]

[18] There are a wide range of types of market potential estimates. Maximum technical potential estimates the largest possible impact assuming that all applications which are technically feasible given engineering considerations are implemented. Economic potential evaluates this maximum technical potential to determine what is economically feasible (i.e., cost-effective from a customer or societal perspective). Achievable potential evaluates the economic potential and recognizes real-world constraints on consumers such as limited capital availability and high initial costs for DG equipment, lack of information regarding the availability and performance of DG technologies, perceived risks associated with employing these technologies given that this isn't a primary area of business, and the relatively small portion of total costs represented by electricity which cause DG to be overlooked. Depending on how compelling the project economics and the magnitude of these barriers, achievable potential can be a relatively small percentage of economic potential.

[19] The US DG market potential estimate was 28,300 MW. With a US total peak load of about 760,000 MW, and Ontario peak load of about 26,000 MW, this would represent slightly less than 1,000 MW for Ontario. Power Advisory recognizes that the RESOP program has resulted in 1,300 MW of contracts executed as of April 30, 2008. While the resources developed under this program qualify as DG resources they aren't indicative of typical DG resources. As RESOP projects, they are driven by the RESOP program pricing and renewable resource potential. As such, they are sited to best capture the renewable resource potential. The concentration of RESOP projects in these locations, prevent them from providing many of the benefits quantified in this Report.

The second part of estimating the amount of DG capacity is estimating the market adoption rate for DG (i.e., the rate at which customers that have cost-effective DG development opportunities decide to install DG projects). The market adoption rate is likely to be influenced by the return offered, with higher returns increasing the rate at which DG projects are implemented. For this initial analysis, Power Advisory assumed a 10% per year market adoption rate, implying that within 10 years the full DG potential would be achieved.[20] This market adoption rate will be applied for each year for which the DG technology can defer the proposed transmission investment.[21]

Step 2: Estimating Operating Profile

The DG project's impact also needs to consider the operating profile of the specific DG generating technology. For a DG project to defer a transmission investment it must be operating at the time of system peak or of the circuit peak.

For dispatchable DG projects (e.g., reciprocating engines), the operating profile of these DG projects can be established by estimating when it would be economic for them to operate. For a merchant DG project, its operating profile could be established using historical price information to infer the anticipated project dispatch. For example, for a natural gas-fired DG project without a CESOP Contract with the OPA the operating profile will be based on historical HOEP, Dawn gas prices, plus gas delivery charges and an appropriate heat rate for the generation technology. This methodology will need to consider the CESOP pricing proposal which is still under development by the OPA. This methodology can be employed for the full range of possible dispatchable technologies.

For load displacement projects, all the charges that the project would enable the load customer to avoid would need to be considered (i.e., electricity, delivery and regulatory charges). There may be some load displacement projects that wouldn't avoid the HOEP given that the customer is on the Regulated Price Plan.[22] For these projects, dispatch assumptions should be based on the avoided prices. For dispatchable projects, it is reasonable to assume that the DG project will either be on or off (i.e., there won't be any operating at minimum or intermediate loads).

For renewable projects that operate based on the resource availability (e.g., wind and photovoltaics), a fixed operating schedule should be used based on actual operating data. For wind projects such an operating profile could be obtained from the IESO based on the composite output for Ontario wind

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[20] The market adoption rate needs to be consistent with the DG potential estimate. The market adoption assumption used assumes that the full market potential is implemented. As a result the market potential estimate needs to consider barriers to the adoption of DG projects as well as the potential for these barriers to be overcome.

[21] One consideration in this analysis is the period for which the transmission or distribution investment can be deferred and whether transmission and distribution planners will commit to deferring a project before the DG capacity has been committed (i.e., will these planners proceed with the development of the required transmission facilities if sufficient DG capacity has not been installed even if it is anticipated to be installed.)

[22] This would be a limited number of projects given the relatively low threshold for the RPP. As of May 1, 2009, customers must have average monthly demand of less than 50 kW per month or 250,000 kWh per year to be eligible for the RPP.

projects.[23] For photovoltaic (PV) projects, such an estimate likely can be obtained from an LDC that has several PV projects in its service territory.

Step 3: Reflecting the Diversity of DG Resources

The analysis also needs to consider the impact of multiple DG projects on the system, i.e., what is the impact on transmission line loadings of a fixed amount of DG capacity. This is an issue for estimating deferral benefits for both the transmission and distribution network. However, this is a more significant issue when assessing the impact on the distribution network given that there is less potential for diversity in a particular area on the distribution system. To the degree that there is more than one DG project then there will be a diversity benefit that reduces the consequences of any one project being unavailable. There are different approaches for quantifying the impact of this diversity.

One approach to evaluate the diversity effect of DG capacity is to establish an equivalent amount of transmission or distribution capacity that can be deferred that reflects the reliable amount of DG capacity. With a reliability criteria established, the maximum number of DG units that can be counted on to be available can be estimated based on the DG technologies' forced outage rate and the total number of DG units operating in the area. Assuming that the DG units are the same size and have the same forced outage rate, the reliable amount of DG capacity can be estimated using a formula.[24] To the degree that the DG facilities are of a different size, have different forced outage rates, or different operating patterns, then a Monte Carlo analysis may be the most straight forward approach to determine the deferred capacity amount. Given that the size, forced outage rates and operating profiles of DG units are likely to vary, this approach can require significant analytical complexity (i.e., it would require a Monte Carlo analysis). As such it cannot be viewed as minimizing the regulatory burden.

Furthermore, focusing exclusively on the reliability of the DG resources fails to consider the fact that the availability of this DG resource is just one of many planning uncertainties that affect network capacity and reliability. In essence, there is a portfolio of resources and the impact on the reliability of the portfolio should be considered. As New York State Energy Research and Development Administration study found the "[s]tandard utility planning analysis does not mandate that each transformer, pole, wire, or breaker meet a specific availability target, but rather that the distribution (or transmission) system as a whole meet a certain standard *for the proposed system as a whole.*"[25] An alternative approach is to use the equivalent availability factor of the DG technology and apply this to the unit's rated capacity to estimate the reliable capacity of the resource. With few DG resources, this approach will overstate the

[23] It is not clear that an intermittent resource such as wind can defer transmission investments given the uncertainty regarding the availability of the resource unless the loading on the transmission facilities to be deferred is highly correlated with wind project output and this wind project output actually reduces these line loadings.

[24] S. W. Hadley, et al., *Quantitative Assessment of Distributed Energy Resource Benefits,* p. 33.

[25] A Comprehensive Process Evaluation Of Early Experience Under New York's Pilot Program For Integration Of Distributed Generation In Utility System Planning Final Report 06-11, August 2006, p.69.

amount of reliable DG capacity.[26] However, as the number of DG resources increase this approach will yield a more accurate estimate of the amount of reliable DG capacity. Therefore, Power Advisory believes that using the equivalent availability factor of the DG resource to estimate the impact of DG resources on the need for the transmission or distribution resource appropriately balances the objectives of minimizing the regulatory burden of implementing the methodology and producing reliable results.

Step 4: Estimating the Cumulative Impact of DG

This estimate of DG capacity in the area served by this transmission facility then must be compared with the forecast load growth (MWs) for this area to estimate the deferral impact. The area load growth can be estimated by applying the appropriate OPA zonal load forecast growth rate to the peak load for the area.[27] The number of years that the proposed transmission facility would be deferred can be estimated by dividing the Available DG capacity by the annual area load growth. Once again, if the cumulative DG impact is less than one year's load growth then there would be no deferral benefit.

Step 5: Estimating Avoided Revenue Requirements

After the transmission investments that can be deferred have been estimated, the avoided revenue requirements can be estimated using the cost of capital for the transmitter and estimating the other ancillary charges that would be avoided. One generic cost of capital can be used for transmission companies. In the most recent HONI Transmission Rate the OEB noted that there didn't appear to be a significant difference in the cost of capital for distribution and transmission companies. For transmitters we propose to use Hydro One's capital structure, ROE and cost of debt approved by the OEB in HONI's 2007/08 Transmission Revenue Requirements and Rate Application (EB-2006-0501): debt/equity ratio of 60/40; an ROE of 8.35%; and cost of debt of 5.53%. This cost of debt was recognized to be higher than Hydro One's current issuance cost. This results in an after tax required rate of return of 6.66%.

In addition to the cost of capital the analysis should also consider other costs that would be deferred by the transmitter if the transmission investment is deferred. These other costs that would be deferred include maintenance, property taxes, insurance and depreciation. E21/EPRI suggested that the appropriate gross-up factor is 1.40. Alternatively, in the Hydro One Avoided Cost Study, a 1% of capital cost figure was used to estimate operating expenses associated with capital investment.

Power Advisory estimated the annual fixed charge by reviewing Hydro One's common corporate costs allocated to transmission, OM&A, property taxes, depreciation expenses, income tax expenses (payments in lieu of income taxes) and required rate of return. The worksheet for the derivation of this charge is included as Appendix B to the report. This analysis relied heavily on the information provided in

[26] This can be viewed as offsetting the fact that the standard methodology doesn't consider the potential benefit of increased operating life for transmission and distribution assets.

[27] The appropriateness of this OPA zonal load forecast growth rate depends on how representative the area served by the proposed transmission facility is relative to the broader OPA zone. Alternatively, LDC demand growth forecasts might be more accurate and reliable. Furthermore, it may be appropriate to establish a composite load growth rate if a transmission facility spans one or more zones. This could be done by establishing a weighted (by the proportion of total load located in each zone) average load growth rate.

HONI's 2007/08 Transmission Revenue Requirement and Rate Application regarding these various expense items. This fixed charge factor is .1849 and would be applied to the deferred capital expenditures to estimate the reduction in revenue requirements for that year.

Deferral benefit needs to recognize that the facilities would ultimately be built and the costs incurred. Deferral benefits are estimated based on the avoided costs in years for which facilities are deferred less the higher costs from inflation for the period when the facilities are in-service. Cumulative present worth of these costs and benefits is derived by discounting revenue requirements at the utility's cost of capital. Appendix C presents an example of the estimated DG benefits from the deferral of a transmission facility.

4. Methodology for Quantification of Benefits of Deferred Distribution Investments

4.1 Background

DG facilities, under certain circumstances and depending on their location, will defer the need for LDC investment in the distribution network. This section describes the circumstances that create these benefits and a methodology for estimating them.

The value of DG in deferring distribution investments depends on the ability of LDCs to incorporate DG into their planning and capital budget processes. To the extent that DG facilities, either individually or as part of a group of facilities, can be relied upon to provide distribution capacity when it is needed to meet localized system requirements, then it offsets distribution system investments that would otherwise have to be made for the LDC to satisfy its obligation to provide reliable service. DG that is located on customer premises, whether as an offset to customer requirements or as a source of local generation into the network, reduces the load requirements that distribution facilities must serve.

4.2. LDC Distribution Planning and Capital Budgeting

Investments in the distribution network are determined each year as part of an LDC's capital budgeting process. Distribution systems are designed to meet anticipated peak load conditions. Although the budget forecast can be a five-year outlook (similar to transmission forecasts), the lead times are not as significant and there is much greater emphasis placed on investments to be made in the upcoming year. Investments in the system are designed to relieve constraints and address reliability concerns but are generally sized to serve anticipated needs for several years. In most cases, DG will not eliminate the need for these investments but will defer the timing of the investments and/or reduce the capacity of new equipment. Both outcomes reduce an LDC's revenue requirements in the near term, creating an economic benefit.

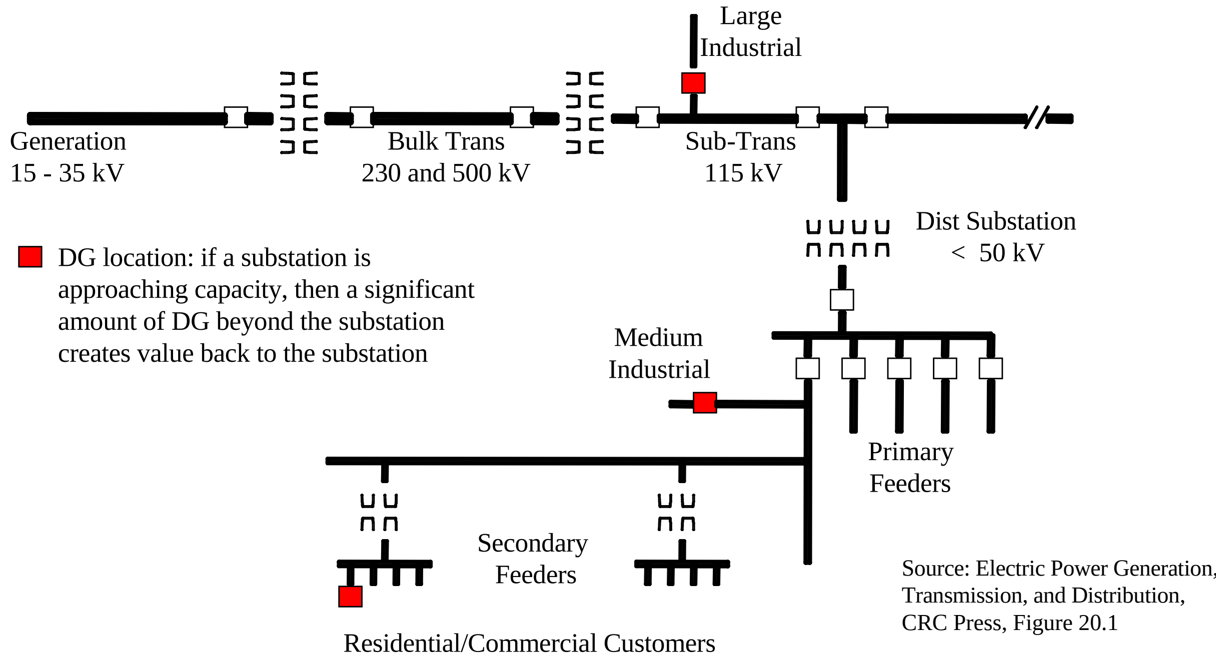
Distribution planners examine the entire LDC system to assess performance but recommend specific localized investments in substations, feeders and other distribution system equipment when developing a proposed capital budget. They take several factors into account when deciding the specific investments that are needed including anticipated load growth, projected substation and feeder line loadings, recent outage history, and investments that may have been deferred from the prior year for financial reasons. For alternatives that require more detailed analysis, distribution planners will apply sophisticated power flow models to assess the reliability of the network under a range of potential conditions. In general, potential investments are prioritized based on a set of specified criteria and decisions are made as part of the annual capital budgeting process. The contribution of DG facilities in deferring distribution system investments is enhanced to the degree that its potential capacity contribution can be reflected in this prioritization calculus.

As shown in Figure 2, potential deferral benefits are localized. In other words, the value of DG depends on its specific location, the facilities that it is connected to (e.g., a primary or secondary feeder) and the current and projected loading of those facilities which in turn is influenced by the cumulative amount of

DG connected to the feeder. Distributed generation facilities may be located directly off of the transmission network or at customer locations served off of primary and secondary feeders. The deferral value created by DG depends on their location relative to constraints that will require investments in order for LDCs to continue to provide reliable service. DG facilities that are located in an area of the distribution system that does not face any anticipated capacity needs for several years has little or no deferral value. This may occur if the area is no longer experiencing load growth, if substantial capacity additions have been made in recent years, or if there is a substantial amount DG already installed such that the flows on the feeder increase with the installation of additional DG.

Except in the case of large DG facilities, the distribution deferral value also depends on the number and size of DG facilities that an LDC can rely upon when conducting planning studies. This "diversity" factor will be discussed further below.

Figure 2: DG and Distribution Investment Deferral



Distribution planners examine all areas of the distribution network on at least an annual basis, focusing most intently on areas that are known to be approaching capacity or experiencing unusual levels of outages. In some cases, referring to Figure 1, capacity may be constrained at the substation location with adequate capacity in the feeders behind that substation. DG located anywhere behind that substation will contribute to an easing of this constraint. In other instances, a substation may have adequate capacity, but an individual feeder may be constrained and under consideration for an upgrade. In this case, only DG located on this particular feeder will provide capacity deferral value.

From their perspective, to the extent that DG offsets load growth and provides power during peak periods, it may provide lower cost solutions than system capacity upgrades. Stated another way, DG located in the right place can effectively increase distribution capacity by deferring the need for capacity investments that are designed to relieve capacity constraints including expansions to distribution substations that serve a broad area and more localized distribution system investments including primary and secondary feeder capacity. However, the LDC must be able to rely upon DG being available during peak periods.[28]

4.3 Methodological Considerations

The challenge in developing a standard methodology for estimating the deferral value of DG is reflected in the tradeoff between the ideal of reflecting the sophisticated modeling of the distribution network at a localized level (e.g., substations and feeders) to precisely determine the impact on DG on needed investments and the practical reality represented by the number and relatively small size of many DG facilities. At the same time, ignoring localized impacts and estimating the deferral benefit of DG across a broad geographic area will yield results that have limited value at best, and lead to DG being compensated for deferral benefits and sited in areas where it provides no deferral value at all. Clearly, it is appropriate to strike a balance between a desire to reflect localized distribution system conditions and needs and the desire to develop a standard methodology that can be applied by Ontario's LDCs without an undue regulatory burden.

In striking this balance, it is appropriate to take into account the following considerations or "principles":

1. the distribution system deferral benefits calculation should reflect the power engineering realities that underpin the design of the distribution system and planning for new investments;

2. DG deferral benefits are localized and depend on local conditions including customer loads, the configuration of the distribution network in that area, the specific DG equipment that is connected to the distribution system in that area, and the amount of DG connected in an area;

3. the calculation should reflect any impact that particular DG technologies may have on the need for new facilities;

4. the value of DG in the distribution planning process can be increased through contractual commitments of utility control of the equipment;

5. ideally, deferred distribution investments from DG should be incorporated into utilities' prioritization of the capital budget along with other characteristics used to prioritize investments (regulatory compliance, safety, environmental considerations, and customer satisfaction); and

6. the length (and value) of the deferral is dependent on the amount of incremental DG relative to the extent of the capacity situation.

[28] DG that can be controlled by the LDC has the greatest value.

Each of these factors help determine where the balance should be struck. A recommendation is presented in the following subsection.

4.4 Recommendation

The range of deferral benefit calculations can be represented as a spectrum with an estimate of the benefit calculated for each DG facility on one end of the spectrum and the deferral benefit calculated on an Ontario-wide basis at the other end. Judgment is required to draw the line at a reasonable point, based on the considerations noted above.

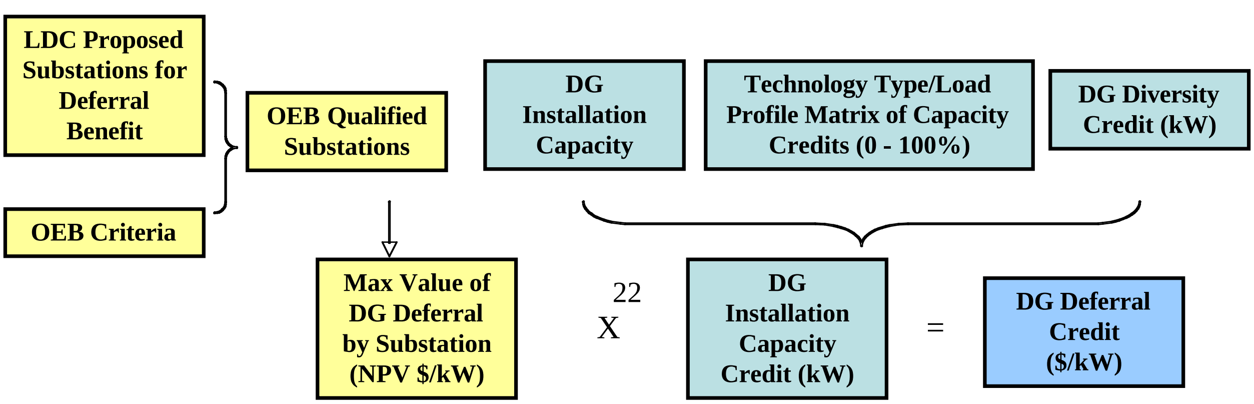
Power Advisory recommends that the OEB implement a two-pronged approach. The first element is to calculate the deferral benefit on a facility-specific basis for the largest DG facilities. This reflects the fact that larger facilities will have a proportionately greater impact on the design of local distribution facilities that must be subject to a specific study. We recommend further that the size cut-off be set at 10 MW to correspond to the limit established for the conduct of transmission system studies under the IESO's Connection Assessment and Approval process.

With respect to all other DG facilities, Power Advisory recommends that deferral benefits be applied to DG facilities that are located behind substations that are being considered for an upgrade or expansion, or in areas where a new substation is already under consideration.   By drawing the investment decision line at the substation, consideration is given to localized impacts within an LDC, increasing the likelihood that DG facilities will be located where they provide deferral benefits. As depicted in Figure 2 below, the LDCs would be required to identify and publicize "qualified" substations based on their distribution system planning analyses.

As shown in this figure, the LDC must reveal the substations that are being considered for upgrades as well as an estimate of the costs per kW for the upgrade. This effectively represents the costs that can be avoided if sufficient DG capacity is attracted behind the identified substation. The right half of the diagram depicts the calculations necessary to determine the kW of DG capacity that provides deferral value. It is based on the capacity of individual DG applications as well as an adjustment to reflect diversity value from multiple installations in the area.

One significant shortcoming of this approach is that it will not capture situations in which a substation may have adequate capacity but there are constrained feeders supported by that substation. Therefore, one option to this approach is to allow LDCs to refine the methodology to include the identification of specific feeders that would benefit from DG installations.

Figure 3: Overview of Distribution Deferral Methodology



This methodology requires the OEB to adopt a monitoring and complaint resolution role after publishing a list of criteria that LDCs should apply when identifying substations (or in the alternative, feeders) that would benefit from DG. The regulatory burden on the OEB and other parties of taking this approach will be far less than an approach that requires a litigated outcome for each substation. The OEB would also provide the methodology used to calculate the DG deferral value on a net present value (NPV) $ per kW basis. As an additional regulatory check, the OEB could require the LDC to demonstrate that it had pursued and considered the capacity contribution of DG when seeking to reflect new substation investments in rates.

As described in the transmission deferral section, the avoided capacity costs would be converted to a revenue requirements savings by applying the respective LDC's most recently approved capital costs and capital structure. Again, consistent with the approach to transmission deferrals, the methodology would reflect costs that would be deferred by the transmitter if transmission investment is deferred including maintenance, property taxes, insurance and depreciation. A similar annual carrying charge formula will need to be developed for LDCs, using a consistent methodology, but different data sources. In addition to identification of substations, the LDC will provide the calculation, including documentation, of this DG deferral value.

The deferral value is applied to DG installed capacity that is a function of the capacity of the installed unit and the likelihood that the unit will be available at peak periods.[29] Power Advisory proposes that generic Ontario-wide load characteristics be applied for each technology type in order to streamline the calculation, following Step 2 outlined in the Transmission Deferral Benefits discussion. The final step in the calculation is to determine if there are sufficient DG installations in a given area to warrant a credit to reflect diversity. This credit would capture the benefit in the form or an increased likelihood that capacity would be available to serve peak requirements as the number of DG installations increases. This methodology was described in the transmission deferral section but may be less statistically reliable to implement at the distribution level as there will be fewer DG installations within a given area (i.e., behind a specific substation), than behind a major transmission facility. This will decrease the potential contribution of diversity at the more localized level.

4.5 Summary

The application of this proposed methodology, particularly if accurately reflected in standby rates, will result in DG developers receiving an accurate price signal for the deferral benefit. As a consequence, this will increase the likelihood that DG will be located where it provides a benefit to the distribution system. The identification of areas requiring such support is made by distribution planners at the LDCs, who then must share this information with the market in order for DG developers to respond appropriately. The deferral credit is also based on the costs of specific investment alternatives that are being considered by the LDC.

[29] As discussed, if the DG causes loads on the feeder to increase then it will not lead to the deferral of distribution facilities.

5. Methodology for Quantification of Benefits of Avoided Losses

5.1 Introduction to Loss Analysis

One potential benefit of distributed generation is reduced transmission and distribution losses. The cost of losses is paid by customers. Therefore, if DG projects reduce losses then customers realize a benefit which should be considered in the standard methodology.

Losses are measured as the difference between supply delivered to and loads taken off the network. Losses are heat dissipation from current passing through conductors and magnetic losses in transformers. Conductor losses depend on resistance and current. Losses are proportional to the electrical resistance of the conductor and to the square of the current flowing through the wires; and increase with higher line loadings. As a result, losses typically are higher during peak periods. Losses also increase proportionally with the distance over which the power is transmitted.

However, DG projects can only reduce losses where they reduce line loadings. In areas where there is already a significant amount of generation from other DG projects (e.g., areas with a high penetration of RESOP projects) increases in line loadings from additional DG projects will increase, not decrease losses.

Losses can be modeled or measured. Modeling of the reduction in losses from DG requires a relatively detailed representation of the electric network. As a result, modeling of DG loss benefits is likely to be too resource intensive given the wide range of locations for DG. The impact of DG on losses is a marginal calculation (i.e., need to evaluate system losses with and without the DG resource) and marginal losses can be multiples of average losses for remote locations. Therefore, there are a limited number of potential sources for loss estimates.

The potential data sources for transmission loss estimates and implications for the methodology are outlined below. After this methodologies for considering distribution losses are reviewed.

5.2 Transmission Losses

There are two obvious sources for transmission losses. Both are generated by the IESO as part of its responsibilities administering Ontario's wholesale power market which clears hourly. Transmission losses are embedded in the IESO's hourly uplift settlement charges which are a component of the wholesale market service charges that are assessed all wholesale customers. These transmission losses are the system average and don't reflect locational differences. With transmission customers charged the actual costs of losses, changes in loss levels from DG flow through directly to customers.

The transmission loss estimate embedded in the hourly uplift settlement charges can be used to estimate loss reduction benefits from DG. Such data were used in the HONI avoided cost analysis performed by Navigant Consulting.[30] A review of these loss estimates helps assess their reasonableness and appropriateness for estimating the benefits of DG projects.

[30] Navigant Consulting Ltd., *Avoided Cost Analysis for the Evaluation of CDM Measures*, June 14, 2005, p. 19.

The marginal losses used in this study vary from 4.6% for the shoulder off-peak period to 12.3% for the shoulder mid-peak period.[31] The higher marginal losses in the Shoulder Mid-Peak Period are counter-intuitive. These were explained by the IESO as potentially reflecting the increased output of hydroelectric units in the North which would lead to higher losses given the distance from load centres and increased exports in this period. The explanation offered and the fact that the shoulder period has the highest marginal losses suggests that locational considerations should be given greater weight than temporal considerations when estimating losses.

The second possible source of transmission losses are the loss penalty factors used by the IESO in the Dispatch Scheduling Optimizer (DSO) that produces the pre-dispatch and real-time constrained schedules and prices in the IESO administered real-time market. The loss penalty factor (loss factor) for a resource is the amount of additional power that needs to be generated/consumed at the resource bus in order to supply/consume one additional MW at the reference bus.[32] The loss factors are intended to represent transmission losses associated with each resource and are the incremental transmission losses based on the location of the resource with respect to the reference bus and the flow of power on the grid. These loss factors allow the DSO to account for the incremental change in system losses as a result of the change in resource output. The IESO uses loss penalty factors to estimate the marginal losses associated with a resource.

The initial programming of the DSO was based on the use of dynamic loss factors where incremental losses were estimated based on actual system conditions and varied with each five-minute dispatch interval. This contributed to volatility in the market and erratic dispatch instructions so that the DSO was modified to contain static loss factors. Static loss factors continue to be used in the DSO.

A review of IESO loss factors indicates that the variation in losses among locations is significantly greater than over time (i.e., there is greater variation in marginal losses across Ontario than marginal losses throughout the year). This indicates reflecting the variation in losses across locations is likely to provide a more efficient price signal regarding the relative value of losses than focusing on the variation across time.

These loss factors could be used as a measure of avoided transmission losses. Their primary benefit is that they are estimated based on actual system incremental losses and vary by location reflecting the significant differences in losses across the Province.

The IESO has a stakeholder process underway to review alternatives to these static loss factors. Loss factors are being recalculated based on the current grid configuration and have been distributed to market participants for discussion. The IESO is considering options for adjusting the loss factors and stakeholder input secured. The stakeholder comments offered to date have expressed concern with the use of dynamic loss factors given the difficulty of establishing an offer strategy that accounts for these loss factors. As

[31] The shoulder period is the months of April, May, October and November and the shoulder mid-peak period is from 7 am to 10 pm and the off-peak period from 10 pm to 7 am. *Ibid*, p. 19.

[32] IESO, *Loss Penalty Factors*, April 10, 2007, p. 1, http://www.ieso.ca/imoweb/pubs/consult/se40/se40-20070430-Loss-Penalty-Factors.pdf. The reference bus is Richview which is located in the West GTA.

such, it does not appear that the IESO is likely to implement a dynamic loss factor alternative. One possibility would be static locational loss factors that also vary by time of day. This approach would reflect temporal differences in losses which are important, but would provide stability in loss factors which is needed by generators to establish their offer strategies.

Loss factors are estimated for interties, generators, dispatchable and non-dispatchable loads. There aren't separate loss factors for the LDCs. Therefore, the loss factors for generators and dispatchable loads would need to be mapped and adjusted for individual LDCs. Given the extent of HONI's distribution network, different loss zones are likely to be appropriate for different portions of its service territory.

While IESO data evaluates losses on the basis of either locational versus temporal differences it would be possible to integrate these data series to produce locational loss estimates that vary by time of day assuming that the updated IESO loss factors don't adequately reflect differences in losses by time of day. Specifically, these loss factors could be modified based on actual changes in these loss factors over time, assuming that the IESO were willing to make available this locational loss factor data.

As discussed, Power Advisory believes that the IESO is likely to modify its loss factors to reflect temporal variations. If this occurs, Power Advisory recommends that these be used to reflect transmission losses in the standard methodology. If temporal differences aren't reflected in these loss factors, Power Advisory recommends that these locational loss factors be modified using marginal hourly loss estimates for on-peak, mid-peak and off-peak periods based on data provided by the IESO.

5.3 Distribution Losses

LDCs calculate distribution loss adjustment factors as part of the process of setting distribution rates.[33] These loss adjustment factors reflect historical loss levels. Given their use, these distribution loss adjustment factors are constant across each LDC's service territory. Furthermore, the loss adjustment factor is based on average not marginal losses. As such, the use of this loss adjustment factor does not accurately reflect the impact of DG on distribution losses.

Equally important, the loss reduction benefit is likely to vary depending on the location of the DG resource on the distribution network. For example, DG resources that are located in areas with significant load are likely to result in reduced losses. However, if the DG resource is located in an area where there are already net injections of power into the distribution network given the preponderance of DG resources then additional DG may actually contribute to higher losses. As such care needs to be taken when estimating the loss benefit. This suggests that using one loss impact estimate for an entire LDC isn't appropriate.

The impact of a DG project on distribution losses could be estimated based on the rating of the distribution line to which the generator is connected, the line loadings and whether the DG project results

[33] Ontario Energy Board, 2006 Distribution Rate Handbook, Schedule 10-5: Determination of Loss Adjustment Factors.

in reduced or increased line loadings. This approach would result in a reasonably accurate estimate of the loss benefit assuming that network conditions were accurately reflected. However, gathering the required data and performing the necessary calculations could be overly burdensome for the LDC performing the analysis. This approach is a simplification of the modeling approach which was rejected earlier as overly burdensome.

A simpler alternative would be to use the LDC's loss adjustment factor and adjust it based on the network operating conditions. The average LDC loss adjustment factor could serve as the starting point for the estimate, with adjustments made based on system operating conditions. DG projects located near the end of long radial lines would have a higher loss reduction estimate whereas DG projects closer to substation would have a lower loss reduction estimate.   One possibility would be for LDC to estimate the mean load adjusted distance from the substation and to establish factors that could be used to modify the loss adjustment factor to account for the locations of the DG project relative to this.

Alternatively, there could be one loss factor for DG on primary feeders (e.g., 1.5x the average loss factor) and another loss factor for DG on secondary feeders (e.g., 2x the average loss factor).[34] If the DG project would result in increased line loadings on the feeder, then there would be no distribution line loss benefit reflected. Power Advisory recommends that this methodology be employed to reflect the impact of DG projects on distribution losses.

[34] These loss factor adjustments are placeholders. These adjustment factors should be based on further analysis.

6. Methodology for Quantification of Voltage-Related Benefits

6.1 Introduction to Voltage Support Analysis

In commissioning this report, the Board included deferred capital investments for voltage regulation equipment as one of the readily quantifiable benefits of DG.[35] Voltage-related benefits also include the value that reactive power from DG installations can provide to the operation of the distribution and transmission network. It is worth noting at the outset, that the measurement of voltage-related benefits and the development of a standard methodology to be applied is more challenging than for the other benefits that are the subject of this report.

While this section focuses primarily on distribution system benefits, DG can also serve as a source of power for the transmission network. This has value particularly at times when transmission facilities are most heavily loaded as transmission operators rely on reactive power from central generation stations to maintain voltage levels. This factor could be reflected in the transmission system capital budgeting process described in Chapter 3.

In fact, DG can have a significant impact on the power flow, voltage profile, stability, continuity and quality of power supply. However, a reliable measurement of the impact is a technical exercise that requires the application of sophisticated power flow modeling tools. These tools are used to construct representations of localized distribution system and load attributes and conditions and they tend to be data-intensive and the results location-specific. As a result, developing a standard methodology for estimating the benefits provided by DG to voltage support is particularly challenging.

In order to address this challenge, Power Advisory will first attempt to reduce certain of the technical considerations to more easily understood language, reaching certain general conclusions along the way. Second, we will propose a simplified methodology to estimate the deferred capacity value that certain DG facilities provide in voltage support.

6.2 The Impact of DG on Distribution System Voltage

Certain DG technologies can provide voltage support by injecting reactive power that helps improve the voltage profile of the localized distribution network. By doing so, DG can also improve power quality and lower distribution system losses. In general, a higher and flatter voltage profile is preferred as long as voltage level does not exceed specified operating design parameters. To the extent that DG contributes to a flatter voltage profile, it improves the stability of the network. A stable network contributes to power quality that is necessary to meet appliance (including computers) operating requirements. In contrast, an unstable localized network can damage or even destroy connected appliances, including computers. LDCs design the distribution network to maintain the voltage profile within acceptable bounds. For these

[35] Ontario Energy Board, Request for Proposals For Identification and Quantification of Specific, Readily Quantifiable Benefits of Distributed Generation, February 11, 2008, p. 6.

reasons, the network system design includes certain equipment that is specifically designed to help maintain voltage levels including voltage regulators, voltage controlled capacitor banks, and automatic load tap changers (LTCs) on transformers.

Improved voltage profiles provide benefits to the overall network as well. They can enable the distribution network to support greater loading, serving as a source of incremental capacity. By doing so, they contribute the deferral of distribution system investments that are discussed above.

It is not always the case that DG will provide voltage-related benefits. In fact, some larger DG reactive power injections can cause a voltage profile on a feeder to exceed the maximum allowed voltage level and should not be operated under these conditions. For example, HONI and the IESO found that a number of the transformer stations that had a reverse flow greater than 10 MW as a result of a concentration of RESOP projects required some form of reactive compensation. Specifically, dynamic reactive compensation devices with costs in the tens of millions of dollars were identified as a possible solution. Clearly, a concentration of DG projects can result in an increase in costs for reactive compensation.[36]

Smaller DG generally avoids this issue, but its contribution to voltage support is limited by its size. In all cases, the ability to control DG for this purpose increases its value, particularly if integrated with the distribution planning process. However, many smaller technology applications do not have voltage regulation control capabilities.

The value of DG as a provider of voltage support is dependent on the design, loads and local generation on individual feeders. Voltage support benefits can be more costly to measure because of this localized aspect. However, some generalizations may help in constructing a methodology for estimating voltage-related benefits. For distribution systems that have been designed and operated as radial systems (including the design of voltage support equipment), voltage generally drops toward the end of feeders. Thus, one generalization is that DG located toward the end of these feeders has greater value as voltage support. Second, remote areas that suffer from low voltage conditions benefit from DG that provides reactive power. Third, the value of DG to improve voltage profiles is typically greatest on low and medium voltage feeders where there is less likely to be any voltage support equipment and as a result there is a greater need to raise the voltage level.

The specific DG technology is a determining factor in measuring the contributions of DG to voltage support. The voltage stability value provided by DG is related to the ability of DG equipment to provide reactive power, in relationship to its ability to provide real power into the system. Thus, benefits depend on generator type (reactive production capability) and unit operational characteristics. Synchronous DG with the ability to supply and control reactive power can increase the voltage stability of the distribution system. Only certain DG technologies are capable of providing reactive power (and therefore voltage support). These include gas turbines, large CHP, solar PV and certain wind technologies.

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[36] "Distributed Generation & Reverse Flow", OPA Technical Session III, July 17, 2008, p. 16. http://www.powerauthority.on.ca/SOP/Storage/78/7344_Presentation_RESOP_Technical_Session_3.pdf

In addition, and as noted above, smaller DG installations may not have sophisticated control systems necessary to maximize their value as voltage support and may, in fact, be tripped off in response to system voltage conditions. Moreover, the exact output of some DG such as photovoltaic energy converters and wind turbines depends on the weather and cannot be anticipated accurately.

Furthermore, generators are interested in operating to maximize their generation revenues. This can result in generator operation that is in conflict with the voltage control requirements of the distribution system. Finally, in some instances for a generator to provide reliable voltage-related benefits, it would have to invest significantly more in equipment and be willing to give up some operating control.

As suggested above, the most accurate method for quantifying the impact of DG on voltage is to run sophisticated power flow models[37] to estimate losses and benefits of reactive power injection by DGs, but the validity of the results depends on the conditions that are modeled and actual conditions will vary as loading conditions change. In theory it is possible to use these tools to identify where DG might provided the greatest voltage support value. It is not practical to apply modeling to smaller DG installations and it may be necessary to model the larger installations to ensure that they do not lead to over-voltage conditions.

6.3 Implications on the Development of a Standard Methodology for Quantifying Voltage-Related Benefits

For certain larger DG installations, it is appropriate to perform modeling in order to accurately assess their impact on voltage, and more specifically, on the deferral of investments that would otherwise be required to address voltage conditions. Power Advisory recommends that DG installations that are larger than 10 MW be subject to study, in order to be consistent with the methodologies used to estimate deferred capacity benefits.

With respect to installations below the 10 MW threshold, it is not practical to run sophisticated power flow models for smaller installations, even for those that appear to offer the greatest value as voltage support. Only certain DG technologies are capable of providing reactive power (and therefore voltage support). As noted above, these include gas turbines, large CHP, solar PV and certain wind technologies. It is also appropriate to reflect feeder loading conditions when assessing the value of DG as voltage support – long low and medium voltage feeders are the best prospects for voltage support. To the extent that DG offers such voltage support, it acts as a substitute for other equipment that a distribution system would need to stabilize the system including voltage regulators, voltage controlled capacitor banks, and automatic LTCs, and reconductoring of overhead wires to reduce voltage drop. To the extent that DG voltage support increases the capacity of feeders, it provides additional deferral capacity value, but this is likely to be captured by the distribution deferral benefit.

[37] One such model is AEMPFAST®, or Advanced Energy Management & Power Flow Analysis System Technology, licensed by Optimal Technologies. The AEMPFAST® brochure can be found at www.otii.com/pdf/AEMPFAST_E-Brochure-071126.pdf

Figure 4 on the following page presents a simplified methodology that takes these general factors into account. It is organized as a decision-tree format that could be incorporated into the DG connection applications process that is performed by LDCs.

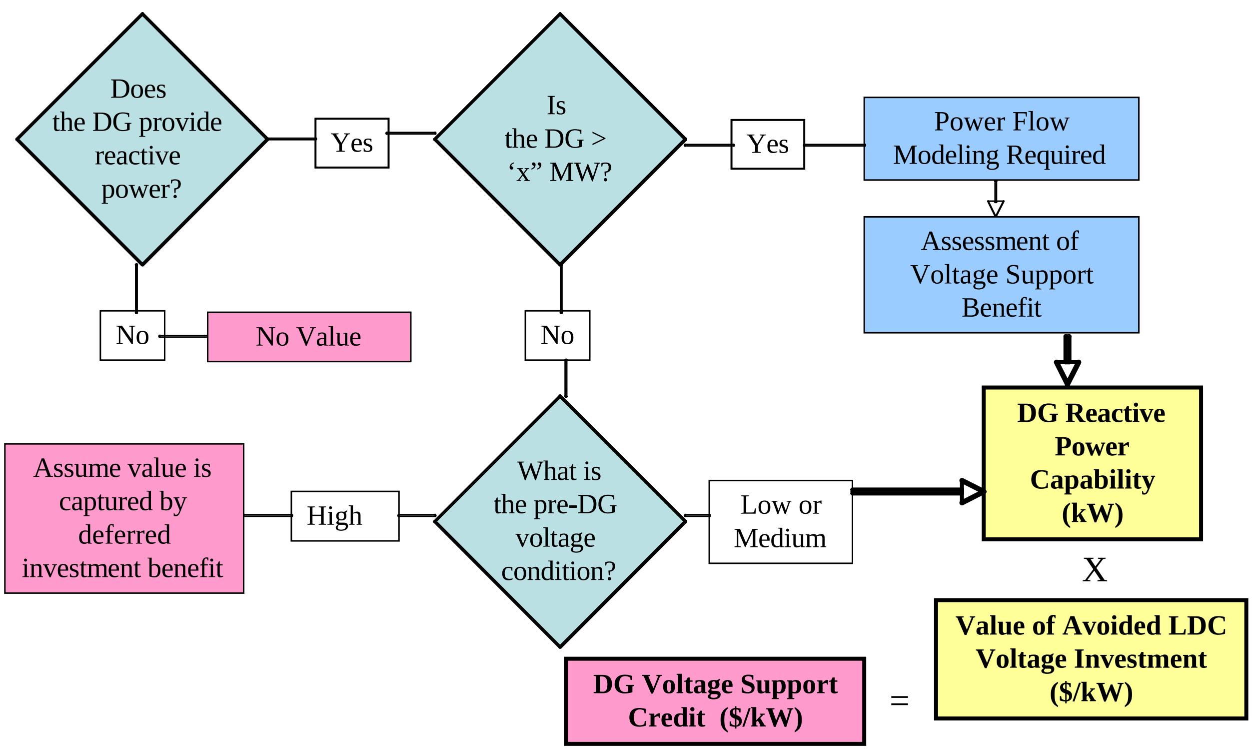
6.4 Implementation

There are several steps that must be taken in order to implement this simplified methodology. First, as noted above, a decision must be made regarding the size cut-off for power flow modeling. To the extent that power flow modeling is required for the larger installations, it is appropriate for stakeholders to engage in technical discussions in order to arrive at agreement on the process for conducting such modeling. This will lower the costs of conducting modeling and eliminate the prospect that the OEB will be asked to moderate disputes that arise in the area.

Second, this methodology requires LDCs to identify their "low" and "medium" loaded feeders, a step that should flow directly from their distribution planning efforts.

Third, it will be necessary for DG developers to specify the reactive power contribution per kW as part of their applications.

Figure 4: Methodology for Estimating Voltage Support Benefits



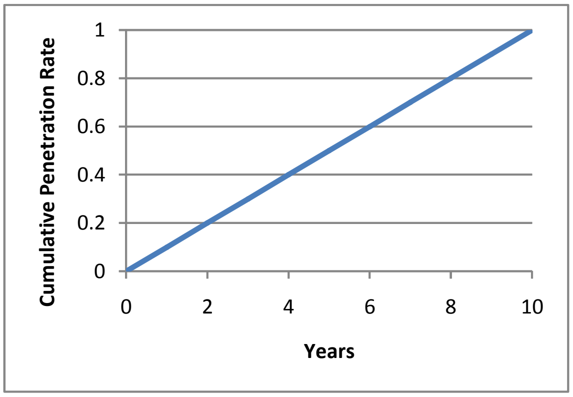
Finally, it is necessary to determination of value of avoided LDC voltage support investments, for those applications that fall below the MW-threshold.

Appendix A: Review of Methodology for Estimating the DG Impact

$$\frac{\text{Load of Area}}{\text{Ontario Load}} \quad X \quad 1{,}000\ \text{MW} \quad = \quad \text{DG Potential for Area}$$

Market Adoption Assumption

DG Potential for Area X



x Number of Years* = Total DG Installed

Total DG Installed x Operating Profile x Equivalent Availability Factor = Available DG

Available DG / (Load of Area x Area Load Forecast Growth Rate) = Deferral Years

* Number of Years is the period over which DG can be installed before the transmitter must commit to construction of the transmission facilities.

Appendix B: Review of Transmission Annual Fixed Charge Factor Derivation

The Exhibit below shows how the transmission annual fixed charge factor was developed along with the data sources. The methodology was outlined in a US Department of Energy study.[38] Where actual project specific estimates for the "overhead" costs are available these should be used and the fixed charge component removed from the methodology.

The weighted average cost of capital was based on Hydro One's approved cost of capital in its most recent transmission rate case. Corporate overhead costs were estimated based on the cost information presented by HONI in its most recent rate case application (EB-2006-0501) and reflect the common corporate costs allocated to transmission divided by total net book value of transmission. This same approach was used for sustaining O&MA, operations OM&A, and shared services and other OM&A and property taxes. Power Advisory did not include Development OM&A expenses because it believed that these wouldn't be affected by DG installations.[39] The depreciation charge was derived using a sinking fund methodology. It is essentially an annuity (i.e., a fixed charge) that recognizes the time value of money. The composite income tax factor is based on a similar concept.

	Percent	Cost	Weighted Average	
Equity	**40%**	**8.35%**	**3.34%**	**EB-2006-0501, p.73**
Debt	**60%**	**5.53%**	**3.32%**	**EB-2006-0501, p.68, 74**
Total	**100%**		**6.66%**	
Weighted Average Cost of Capital	**6.66%**			
Common Corporate Costs Allocated to Transmission(2007)	**$ 162**			**HONI Common Corporate Costs and Cost Allocation Methodology, EB-2006-0501, Exhibit C1, Tab 5, Sch. 1, p.5**
Total Net Book Value of Transmission	**$ 5,628**			**Hydro One, 2006 AR, p. 53**
Annual Average Overhead Charge (a)	**0.0288**			
Various OM&A Accounts				
Sustaining OM&A for Transmission (2006)	**$ 179**			**HONI Sustaining OM&A Expense for 2006, EB-2006-0501, Exhibit C1, Tab 2, Sch. 2, p. 7 .**
Operations (2006)	**$ 43**			**HONI Operations Expense for 2006, EB-2006-0501, Exhibit C1, Tab 2, Sch. 4, p. 3.**
Shared Services and other OM&A (2006)	**$ 76**			**HONI Shared Services and other OM&A Expense for 2006, EB-2006-0501, Exhibit C1, Tab 2, Sch. 5, p. 3.**
Total OM&A Expenses	**$ 298**			**Total of three OM&A expenses identified above**
Total Net Book Value of Transmission	**$ 5,628**			**Hydro One, 2006 AR, p. 53**
Annual Average OM&A Expense (b)	**0.0529**			
Property Taxes (2006)	**$ 69**			**HONI Property Tax Expenses, EB-2006-0501, Exhibit C1, Tab 2, Sch. 6**
Total Net Book Value of Transmission	**$ 5,628**			**Hydro One, 2006 AR, p. 53**
Annual Average Property Tax Expense (c)	**0.0122**			
Total Depreciation Expense (1) (2006)	**$ 219**			**HONI Depreciation & Transmission Expenses, EB-2006-0501, Exhibit C2, Tab 5, Sch. 1**
Total Net Book Value of Transmission	**$ 5,628**			**Hydro One, 2006 AR, p. 53**
Straight Line Depreciation	**0.038895**			
Average Transmission Asset Life	**55**			**Average Estimated Transmission Asset Service Life, Hydro One, 2006 AR, p. 53**
Depreciable Years "n"	**25.7**			
ROR	**6.66%**			
Depreciation Rate	**1.82%**			
Annual Average Depreciation Expense (d)	**0.014**			**[ROR/(1+ROR)^Depreciable Years -1]**
(1) Excludes amortization expenses.				
Corporate Income Tax	**34.50%**			
Gross Up Factor	**65.50%**			
Composite Income Tax Factor (e)	**0.0109**			
Total Fixed Charge Rate (a)+(b)+(c)+(d)+(e)	**0.1849**			

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[38] The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede its Expansion, 2007, p, A-8.

[39] HONI defines Development OM&A expenses as activities that "enable Hydro One to identify and implement solutions for asset management. This is accomplished through Research and Development projects that investigate the use of new technologies and/or practices that, if proven feasible, may be utilized by Hydro One to improve sustainment and/or development of its transmission system."(EB-2006-0501, Exhibit C1, Tab 2, Sch. 3, p. 1.)

Appendix C: Example Transmission Deferral Benefit Calculation

Presented below is an example transmission deferral benefit calculation. The number of years reflects the period over which DG facilities can be installed to defer the transmission investment. This is estimated by determining when the transmitter would likely need to commit to building the proposed facilities. In this example, we assumed a two year period covering preparation of construction bid documents, the tendering process for award of the construction contract and the construction period. This assumes that permitting would already have been started. The annual load growth is the estimated load growth for the area where the transmission facilities are being proposed.

The Available DG estimate assumes that the DG resources are dispatchable and would be operating and a .94 equivalent availability factor was used.

The assumed cost of the facilities that are deferred is $40 million, with an annual carrying charge of .1849. This represents a cost savings of $7.4 million in 2014. Inflation causes the cost of the facilities to increase by $1.0 million. This results in an annual increases in facility costs of 160 thousand for the 26 year assumed useful life of the facilities.[40] The net present value of these deferral benefits is $5.14 million over this period. Dividing this by the 19.1 MW of Total DG installed which is required to realize this deferral benefit results in a $/kW benefit in 2008$ of $182.91/kW. This demonstrates the significant leverage offered by DG if sited in the proper location.

This assumes that there isn't more or less DG than estimated. Power Advisory believes that it is probably reasonable to apply a gross up to the DG capacity to reflect the uncertainty that the DG target will be achieved.

[40] This useful life is consistent with that used in the derivation of the carrying charge. The useful life of a transmission line is likely to be significantly longer.

Load of Area (Essa) 2008	1,253	IPSP, Exhibit D, Tab 1, Schedule 1, Attachment 2, p. 4
Load of Area (Essa) 2014	1,330	IPSP, Exhibit D, Tab 1, Schedule 1, Attachment 2, p. 4
Ontario Load in 2014	27,873	IPSP, Exhibit D, Tab 1, Schedule 1, Attachment 2, p. 1
Number of Years	4	
Investment Commitment Year	2012	
Current Year	2008	
Area Load Growth %	1.0%	
Annual Area Load Growth (MW)	13.3	

Load of Area/Ontario Load in 2014	4.8%	x	1,000	47.72	=DG Potential for Area
DG Potential for Area x 10%/year x 4 years	47.72	x	40%	19.1	= Total Installed DG
Total Installed DG x Operating Profile x EAF***	19.1	x	94%	17.9	= Available DG
Available DG/Annual Area Load Growth (MW)	1.4	deferral years			

Year	2014	2015	2016	2017	2018	2019	2020
Capital Cost of Transmission Investment	$ 40.00						
Deferral Benefit*	$ 7.40						
Increase in Capital Cost given 1 year Deferral**		$ 1.00					
Increase Annual Costs given 1 year Deferral		$ 0.18	$ 0.18	$ 0.18	$ 0.18	$ 0.18	$ 0.18
Annual Savings (Cost)	$ 7.40	$ (0.18)	$ (0.18)	$ (0.18)	$ (0.18)	$ (0.18)	$ (0.18)
Present Value of Annual Savings (Cost)	$ 7.40	$ (0.17)	$ (0.16)	$ (0.15)	$ (0.14)	$ (0.13)	$ (0.13)
Net Present Value Benefit	$ 5.14						
$/kW Benefit in 2014$	$ 269.28						
$/kW Benefit in 2008$	$ 182.91						

* Deferral Benefit = Capital Cost x Carrying Charge
** Assumes 2.5% inflation rate
*** EAF = Equivalent Availability Factor

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