EB-2010-0132

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Hydro One Brampton Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2011.

BOARD STAFF

CROSS-EXAMINATION COMPENDIUM GREEN ENERGY PLAN

DECEMBER 6, 7 & 9, 2010

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Green Energy Act Cross-Examination Compendium
December 6, 2010

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hydro one Brampton

Hydro One Brampton Networks Inc.
Capital Expenditure - 2011

Project Title:	*Expansion for Renewable Generator Connections*	**Project Number:**	*2011-240*
Project Manager:	*Aldo Mastrofranceso*	**Project Technician:**	
Last Updated:	*Monday, June 14, 2010*	**Investment Category:**	*Other or Shared Services*
Type	*Green Energy Programs*	**Investment Driver:**	*Regulatory*

Description

This project is for the expansion of Hydro One Brampton's distribution system to facilitate the connection of "*Renewable Generators*"

Investment Scope

Construct new facilities to provide service connection capabilities between new "Renewable Generator" sites and Hydro One Brampton's existing distribution system.

Investment Results

To meet the obligations stipulated in the Distribution System Code to accommodate new Renewable Generators.

Cost & Timing

	2011	2012	2013	2014	2015
Capital Costs	$165,000.00	$168,000.00	$172,000.00	$175,000.00	$179,000.00
OM&A					
Gross Investment	$165,000.00	$168,000.00	$172,000.00	$175,000.00	$179,000.00
Recoverable	$0.00	$0.00	$0.00	$0.00	$0.00
Net Investment	$165,000.00	$168,000.00	$172,000.00	$175,000.00	$179,000.00

Project Start Date	
Project In-Service Date	

Business Case Justification

The Distribution System Code stipulates certain costs that Hydro One Brampton must bear in relation to constructing an expansion required to provide a point of connection for "Renewable Generator" sites.

Alternatives Considered

Hydro One Brampton Networks Inc.
Capital Expenditure - 2011

Project Title:	*Renewable Generator Enabling Improvements*	**Project Number:**	*2011-241*
Project Manager:	*Aldo Mastrofranceso*	**Project Technician:**	
Last Updated:	*Monday, June 14, 2010*	**Investment Category:**	*Other or Shared Services*
Type	*Green Energy Programs*	**Investment Driver:**	*Regulatory*

Description

This project is for the "non expansion" type works required to facilitate the connection of "Renewable Generators"

The Distribution System Code requires that specific changes to Hydro One Brampton's distribution system to allow it to accommodate renewable generation be classified as Renewable Enabling Improvements (REI).

Investment Scope

To install or modify;
> electrical protection equipment;
> voltage regulating transformer controls or station controls;
> protection against islanding (transfer trip or equivalent);
> bidirectional reclosers;
> tap-changer controls or relays;
> breaker protection relays;
> supervisory Control and Data Acquisition system design, construction and connection;
> equipment to allow for and accommodate 2-way electrical flows or reverse flows; and
> communication systems

to facilitate the connection of renewable energy generation facilities.

Investment Results

To remain compliant with the Distribution System Code.

Cost & Timing

	2011	2012	2013	2014	2015
Capital Costs	$83,000.00	$84,000.00	$86,000.00	$88,000.00	$89,000.00
OM&A					
Gross Investment	$83,000.00	$84,000.00	$86,000.00	$88,000.00	$89,000.00
Recoverable	$0.00	$0.00	$0.00	$0.00	$0.00
Net Investment	$83,000.00	$84,000.00	$86,000.00	$88,000.00	$89,000.00

Project Start Date	
Project In-Service Date	

Business Case Justification
The Distribution System Code stipulates certain costs that Hydro One Brampton must bear in relation to constructing facilities enabling connection for "Renewable Generator" sites.
Alternatives Considered

hydro one Brampton

Hydro One Brampton Networks Inc.
Capital Expenditure - 2011

Project Title:	*Smart Meter Technology*	**Project Number:**	*2011-242*
Project Manager:	*Aldo Mastrofranceso*	**Project Technician:**	
Last Updated:	*Monday, June 14, 2010*	**Investment Category:**	*Other or Shared Services*
Type	*Green Energy Programs*	**Investment Driver:**	*Regulatory*

Description

This project is for the purchase of software required to utilize smart meter technology and to leverage the functionality of the existing outage management system currently in operation at Hydro One Brampton.

Investment Scope

To implement Smart Meter Technology initiatives to integrate the Smart Meter system with the Outage Management System (OMS). Smart meter data will be transmitted from the Smart Meter system to the OMS system in real time, allowing the prediction engine in OMS to accurately pinpoint failed equipment on the distribution system. It will also identify when the meter is removed and will help identify theft of power or meter tampering issues.)

Investment Results

To have a fully functional smart meter interrogation program with data collection and data transfer capabilities integrated with the Outage Management System.

Cost & Timing

	2011	2012	2013	2014	2015
Capital Costs	$289,000.00	$295,000.00	$301,000.00	$307,000.00	$313,000.00
OM&A					
Gross Investment	$289,000.00	$295,000.00	$301,000.00	$307,000.00	$313,000.00
Recoverable	$0.00	$0.00	$0.00	$0.00	$0.00
Net Investment	$289,000.00	$295,000.00	$301,000.00	$307,000.00	$313,000.00

Project Start Date	
Project In-Service Date	

Business Case Justification

Subsequent to a requirement imposed by the Province in 2006 the company has since installed over125,000 smart meters. The company is now planning to capitalize on this investment and utilize the capabilities of this system.

Alternatives Considered

hydro one Brampton

Hydro One Brampton Networks Inc.
Capital Expenditure - 2011

Project Title:	*SCADA Mate Automation Switch Program*	**Project Number:**	*2011-243*
Project Manager:	*Aldo Mastrofranceso*	**Project Technician:**	
Last Updated:	*Monday, June 14, 2010*	**Investment Category:**	*Other or Shared Services*
Type	*Green Energy Programs*	**Investment Driver:**	*Regulatory*

Description

This project is designed to improve distribution system outage recovery times by introducing automated switching devices.

Investment Scope

Install automated Scada mate switching devices at key locations in the distribution system.

Investment Results

Increase feeder sectionalizing capabilities to improve fault restoration response time and to improve overall system reliability.

Cost & Timing

	2011	2012	2013	2014	2015
Capital Costs	$330,000.00	$337,000.00	$344,000.00	$351,000.00	$358,000.00
OM&A					
Gross Investment	$330,000.00	$337,000.00	$344,000.00	$351,000.00	$358,000.00
Recoverable	$0.00	$0.00	$0.00	$0.00	$0.00
Net Investment	$330,000.00	$337,000.00	$344,000.00	$351,000.00	$358,000.00

Project Start Date	
Project In-Service Date	

1. Executive Summary

The Hydro One Brampton Networks Inc. (HOBNI) Green Energy Plan (Plan) presents the Company's response to the *Green Energy and Green Economy Act, 2009* ("GEGEA") in alignment with HOBNI's corporate strategy. The Plan covers the five year period from 2011 to 2015 and includes the incorporation of renewable energy generation, development of HOBNI's Smart Grid and promotion of energy conservation. HOBNI considers this Plan to be a prudent and responsible. The Plan's~~e~~ development is based on the Company's experience with the implementation of renewable energy generation connections in Ontario since 2006, its Conservation and Demand Management ("CDM") programs since 2004, and a measured approach to Smart Grid investment focused on studies, demonstration projects, planning and training. The spending reflected in the Plan went through the same business planning and approval process as all other investments in our distribution system.

The total costs of investments contained in the Plan are summarized in the table below.

Green Energy Spending 2010 - 2015						
Description	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Generator Connections (Capital)	$300,000	$300,000	$306,000	$312,000	$318,000	$324,000
Smart Grid (Capital)	$733,000	$750,000	$765,000	$780,000	$795,000	$812,000
OM&A	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000
Less Generator Funded Costs	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000
Totals	**$1,033,000**	**$1,050,000**	**$1,072,000**	**$1,092,000**	**$1,113,000**	**$1,136,000**

Given the current uncertainty regarding the total demand for and location of the feeders, the Board does not wish its approval to result in a requirement that Hydro One expand or reinforce its system prematurely. The Board is therefore directing that the construction of the express feeders be deferred. Hydro One shall inform the Board when it has sufficient information regarding requests for connection underpinning the need for each feeder and the location of each feeder. The Board will then determine when and confirm how this expansion of Hydro One's distribution system should occur, which the Board may do with or without a hearing. However, the Board does authorize Hydro One to begin the necessary development and pre-construction work associated with the express feeders.

The revenue requirement amounts for each test year related to the express feeders will be split between Hydro One's ratepayers and provincial ratepayers. In its partial decision in this application, dated February 18, 2010, the Board provisionally approved, for rate setting purposes, the methodology proposed by Hydro One for the allocation of eligible investment costs in Hydro One's Green Energy Plan between Hydro One ratepayers and provincial ratepayers. The allocation methodology and the resulting responsibility for eligible investment costs for 2010 and 2011 will be subject to later revision to reflect the Board's final policy determination in EB-2009-0349. If the result of the Board's policy is to change the allocation that has been provisionally approved, Hydro One will be required to recalculate the assignment of costs, and implement a debit or credit to each ratepayer group.

5.3 REMAINING RENEWABLE GENERATION EXPENDITURES

Hydro One proposes to connect 3,500 MW of renewable generation to its system by the end of 2011. The capital required to connect this level of generation is projected to be $464 million over two years for connections, expansions and REI. The capital expenditures by cost responsibility category are summarized below:

Renewable Generation Capital Expenditures, 2010 and 2011
($ millions)

	Connection		Expansion		REI		Total	
	2010	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**
Generator Funded	13	27	0	0	0	0	13	27
Externally Funded	0	0	60	118	79	118	139	236
Hydro One Ratepayer Funded	0	0	12	25	4	8	16	34
Total Capital	13	27	72	143	83	127	168	296

One of the key assumptions in the capital budget is the expected number of renewable generation connections. Hydro One has assumed that a majority of these new connections will be from the Feed-in Tariff (“FIT”) program. However, when Hydro One’s capital expenditure forecast was developed, the actual results of the FIT program were not definitively known.

Hydro One also proposed that the renewable generation capital assets developed under the Green Energy Plan be depreciated on a straight line basis over a 20 year period. Hydro One argued that a 20-year depreciation period is appropriate because it equals the length of the underlying electricity contracts between the OPA and the renewable generators. Hydro One claimed that there is no guarantee that the assets will be used and useful beyond the life of those contracts and that the service life should match the period of time for which there is a benefit for provincial ratepayers. Board staff argued that the assets will still be used and useful when the initial contracts expire and notes that Hydro One has not provided any rationale for why this is not the case.

The intervenors generally submitted that the amount of additional capacity needed and the timing of renewable generation connections are very uncertain. In addition, CCC questioned Hydro One’s capability to complete the work plan by 2011 in any event, given the significant level of expenditures for the overall capital program.

BOARD FINDINGS

With the exception of the proposal to construct the express feeders, the Board will not approve as prudent the expenditures for renewable generation at this time. In the Board’s view, the proposal is deficient due to the unsubstantiated magnitude of the forecast connections, and therefore total expenditures, and the lack of specificity as to projects to be undertaken.

Hydro One has provided little conclusive evidence regarding the timing and extent of renewable generation connections. The OPA's FIT program is in its very early stages and the most recent public information from the OPA suggests capacity renewable generation connections at 50% to 75% of Hydro One's estimate. While the Board recognizes that this is very preliminary information, there is little else to indicate the overall capacity required in 2010 and 2011. The Board also shares the concern expressed by CCC that Hydro One may not have the capability to complete such an ambitious program in any event.

Hydro One agreed that the Board's review of the plan should be consistent with the review normally done in a cost of service application in terms of testing the evidence. The level of detail for renewable generation expenditures, however, did not allow such a review to be conducted. The actual projects, their location and the specific needs to be addressed by each project were not set out in the Green Energy Plan.

The Board notes that considerable uncertainty remains regarding all the proposed green energy projects, despite Hydro One's efforts to work with all available information. The Board concludes that it is necessary to have greater detail and specificity regarding the projects to be undertaken before a finding of prudence and approval of the remaining expenditures can be made. In the past, expansion costs to serve a generator would be paid for by the generator and ratepayers faced minimum risk if the forecast was inaccurate. In today's environment for renewable generation, if the Board approves the expenditures, ratepayers are at risk for the entire cost of the expansions. It is therefore particularly important to have confidence that the investments become used and useful. In addition, given the still uncertain take-up and location of FIT generation, the Board is reluctant to make a finding which under section 70(2.1)3 of the Act, might require Hydro One to build the facilities approved in the plan even if it became unnecessary to do so.

Although the Board will not approve these renewable generation expenditures on the basis of the record in this application, the Board understands that Hydro One will likely need to undertake work in this area during 2010 and 2011 and should therefore have funding to undertake that work. The Board concludes that funding adders and deferral accounts should be used to support Hydro One's work, while managing the risk to ratepayers and Hydro One.

The Board finds that funding will be provided for 67% of the remaining capital and OM&A expenditures for renewable generation connection for 2010 and 2011. In the Board's view, this represents a more probable level of activity for 2010 and 2011. Actual expenditures will be captured in deferral accounts which will be subject to a prudence review and cleared as part of Hydro One's next distribution rate case. This clearance will be symmetrical. That is, if Hydro One has spent less than the amount collected through the funding adder, the difference will be returned to ratepayers, in addition to any costs found to be imprudently incurred. If Hydro One has prudently spent more than the amount collected through the funding adder, Hydro One will collect the difference through future rates.

Rate protection as prescribed under section 79.1 of the Act will apply to allow collection of a portion of the costs from provincial ratepayers, consistent with the allocation proposed by Hydro One. As explained in the previous section, this allocation is provisional and will be revisited once the Board's policy is determined through the EB-2009-0397 process.

Section 79.1(2) of the Act reads as follows:

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

In making an order permitting collection of amounts from provincial ratepayers in this case prior to a prudence review, the Board has taken a purposive approach to section 79.1 of the Act, using a regulatory approach that is consistent with the manner in which the Board sets rates in the normal course as well as one that will further the Board's objective of promoting the use and generation of electricity from renewable energy sources.

Under the Board's rate setting regime, rates are set based on a forecast of the revenue that will be required by the distributor in the test year. Rates are therefore largely set on the basis of costs that have not yet been incurred. In exercising its other powers under the Act, the Board should do so in a manner consistent with how the Board carries out its mandate to set just and reasonable rates under section 78 of the Act. In some instances in the past the Board has permitted the collection of funds from ratepayers, subject to a subsequent prudence review. This enables the utility to have a source of funding, while protecting ratepayer interests.

The Board, for the reasons cited above, cannot make a finding of prudence with respect to the remaining proposed expenditures for renewable generation connection in Hydro One's plan. However, when viewed in light of the way in which the Board sets rates, the Board is of the view that in the circumstances of this application, costs can be specifically approved for collection under section 79.1 even if not yet approved as prudent.

The Board is of the view that, ultimately, the liability of provincial ratepayers for the rate protection referred to in section 79.1 of the Act is limited to costs that have been determined by the Board to have been prudently incurred (net of any direct benefits). As such, where collection from provincial ratepayers is provided for by the Board on a provisional basis, it will be important to ensure that an appropriate mechanism is in place to allow for any necessary reconciliation. In this case, the Board has provided for a reconciliation between costs actually spent and costs prudently incurred, as well as between amounts provisionally collected from provincial ratepayers and costs that are determined to be their responsibility once the Board's policy on the calculation of direct benefits is finalized.

The Board's Guidelines created two deferral accounts for the recording of renewable connection expenditures: account 1531 for capital costs and account 1532 for OM&A costs. Hydro One should use these accounts to record actual expenditures related to renewable energy generation connections. In addition, in its *Filing Requirements for Distribution System Plans*, released March 25, 2010, the Board approved two deferral accounts for the recording of amounts collected through Green Energy Act related funding adders. Account 1533 should be used to record amounts collected through the funding adder. It will be necessary to use sub-accounts to separate collection from Hydro One ratepayers and provincial ratepayers (i.e. payments from the IESO).

Under the provisions of the DSC, if expansion and REI costs have not been previously approved by the Board, then any amounts over $90,000 per MW are the responsibility of the generator. If a plan or the specific expenditures are approved (found prudent) the cost responsibility for those expenditures shifts from the renewable generator to ratepayers. The Board understands, therefore, that its approval of a plan, or expenditures within a plan, has significant ramifications for renewable generators as well as ratepayers. The DSC does contemplate approval of expansion and REI work outside the context of a five year Green Energy Plan. When sufficient detail becomes available to allow Hydro One to demonstrate the prudence of the remaining renewable connection expenditures for the test period, Hydro One may apply for a determination of prudence and collection of those expenditures through a rate rider.

Depreciation for Renewable Generation Investments

The Board does not accept Hydro One's proposal to use a 20-year depreciation period at this time. The Board agrees with Board staff that Hydro One did not provide sufficient evidence to support a deviation from the standard treatment for depreciation. However, it would be appropriate for Hydro One to bring further evidence supporting its request for a shortened depreciation period when the Board considers the prudence of the expenditures. Until such a case is made and decided upon, Hydro One will use the normal depreciation periods for the assets in the plan, including the Express Feeders.

5.4 SMART GRID

Hydro One plans to spend $30 million in 2010 and $62 million in 2011 on Smart Grid capital investments. Hydro One proposes that the investments be included in rate base for the test years, arguing that the investments are necessary, used and useful, and sufficiently well defined to be included as part of its rate base. Smart Grid O&M costs of $10 million for each of 2010 and 2011 are also included in the Green Energy Plan.

The Smart Grid expenditure projection was developed following a three step process. The first step was to focus on integrating renewable energy generation, CDM, and system automation. Second, Hydro One formulated plans to utilize pilots to investigate new innovative technologies. The final step is the implementation of pilot projects. The capital expenditures on the smart grid program are summarized below:

Smart Grid Capital Expenditures, 2010 and 2011
($ million)

	2010	**2011**
Energy Storage	2	2
Smart Zone Pilot	13	42
PHEV Trials	1	1
Distribution System Innovation	5	5
Facilities/System Upgrades	7	10
Technology Work (GIS)	3	3
Total Smart Grid Capital	**30**	**62**

As shown above, a significant portion of the investments is related to the Smart Zone pilot project. The main objective of this project is to innovate, test and prove new and emerging technologies. Hydro One issued an RFP in 2009 related to research and development and other development work that will be undertaken in the Smart Zone pilot. The results are yet to be finalized.

In cross examination, the witnesses confirmed that until the RFP process is completed, the final costs may vary. However, Hydro One acknowledged that the final costs may vary, but argued that the estimates have been developed in a prudent manner and that the final costs will reflect the forecast.

Board staff argued that Smart Grid costs were of higher risk because of developing requirements for distribution grids and quickly evolving technology. Staff suggested the use of a rate adder and deferral account with a subsequent review for prudence.

CCC and CME both objected to the Smart Grid costs. CME argued that the total plan costs should be reduced by 67%, including the Smart Grid costs. CCC submitted that Hydro One's costs were uncertain since its RFP process was not finalized. CCC also argued that Hydro One had not met the Smart Grid guidelines because the company had not entered into joint participation agreements and that part of the RFP was for research and development. Hydro One responded that the forecast is reliable and maintained that the work does not include research and development but rather technical studies.

BOARD FINDINGS

Hydro One's Smart Grid plan includes many of the activities indentified in the Board's filing guidelines regarding smart grid. Generally, the Board finds that the activities identified in Hydro One's Smart Grid plan are consistent with the filing guidelines. Other than the submissions of CCC that Hydro One had not entered in a joint participation agreement and that the activities included research and development (which is prohibited under the guidelines), no party argued that the activities were inconsistent with the Board's guidelines. Parties were most concerned with the uncertainty of the costs.

Although the Board encourages utilities to jointly participate in Smart Grid studies, the Board accepts that Hydro One is uniquely positioned to move forward at this time with Smart Grid activities. The Board encourages Hydro One to share the results of its programs with other utilities where applicable.

The Board accepts Hydro One's evidence that the activities do not include research and development as contemplated in the Board's guidelines. The Board agrees with Hydro One that the RFP in question is very detailed and that Hydro One has the expertise to accurately forecast the cost.

Regarding Board staff's concern that Smart Grid functions are quickly evolving, the Board notes that it is the need to understand these changes which drives the requirement for Smart Grid studies. The development of renewable generation is dependent to a significant degree on technical enhancements to the system - smart grid capabilities. Given the unique role of Hydro One in the province, and the need to develop these capabilities, the Board considers it prudent to approve the Smart Grid aspects of the Green Energy Plan.

Therefore, the Board concludes that the costs as budgeted are prudent, and should be recovered in rates.

While the Board accepts that the cost forecast for the Smart Zone pilot is reasonable, the Board is concerned that the funds may well not be spent in the 2010 and 2011, because the RFP has not yet been finalized. Given this uncertainty regarding the timing of this significant portion of the Smart Grid budget, the Board directs that Smart Grid costs will be recovered through a rate rider, and will be subject to further review, not for prudence, but to determine if the amounts were actually spent in the period. Therefore,

Technical Conference Exhibit JT 1.21

To provide management analysis, presentation, or some document which provides reasoning as to how those percentages were arrived at for SCADA, renewable energy investments, and expansions.

Response:

The following is the analysis used to determine the Cost Allocation Percentages as shown in the Table below:

HOBNI Green Energy Investment	Allocation of Cost Responsibility		
	Generator	**Provincial Ratepayers**	**HOBNI Customers**
Expansions (up to threshold)	-	81.25%	18.75%
Renewable Enabling Improvements	-	100%	0%
Smart Grid (SCADA Only)	-	50%	50%

The criteria used for the purpose of estimating the direct benefits included the following:

1. New Assets to accommodate Renewable Generators
    a. Portion of Assets used by Load Customer
    b. Portion of Asset used by Generator
2. Asset Replacement to accommodate Renewable Generators
    a. Age of Assets
    b. Asset Condition
    c. Asset Depreciation/Remaining life
3. Size of FIT Generators
4. Quantity of potential Generator Connections
5. Customer Load Growth
6. Service Life Improvements
7. Current Design of the Distribution System
8. Operating Practice

Analysis

Projects:

Criteria Question	Expansion	Renewable Enabling Improvements	SCADA
Are New Assets Required to Accommodate	Yes – New transformers will accommodate generator connections.	Yes – Monitoring and communication equipment.	Yes – these SCADA installations are chosen primarily based on generator connections.

Generators?			
Are existing Assets being replaced to Accommodate Generators?	Yes – Existing transformers which served only load customers are required to be upgraded to accommodate the generators.	No	No
Sizes of Generations?	250-500 kW	>249 kW	>75 kW
Quantity of Generators?	Density in some areas of 5-7 generators on one feeder.	Requirement on all generators >249 kW	Density in some areas of 5-7 generators on one feeder.
Load Growth?	<1%	N/A	Feeder loading is a factor for prioritizing.
Service Life Improvements?	Yes	N/A	Yes
Current Design of System?	N/A	N/A	We already have a well developed SCADA system.
Operating Practice?	N/A	N/A	To ensure we can provide maintenance to load customers while still having the generators supply power.
Analysis	The transformers are upgraded because of the generators. Investment is seen to benefit both load customer and generators. The transformers being replaced have an average in-service life of 15 years. The normal service life of a transformer is 40 years.	Monitoring and communication system to be installed on all generator connections which are greater than 249 kW. This is a requirement from the Provincial Transmitter.	These SCADA installations are to allow for proper connection and operation of Generators. These installs are initiated due to generators; however they do benefit load customers from an Operational/Reliability side.
Direct Benefit	A. New assets that	1. New assets -	A. New assets that

Percentage Calculations	benefit both the generators and load customers, investment will be shared equally. B. Replacements of assets, in this case 15 year old transformers being replaced before their time will have a benefit to the load customer = 15/40 = 37.5%. C. Therefore, Direct Benefit to Load Customers is A*B = 50% * 37.5% = **18.75%**	Monitoring & Communication system benefits the generator 100% of the time. This asset offers no benefit to load customers. 2. No replacement of existing assets. 3. Therefore, Direct Benefit to Load Customers is = **0%**	benefit both the generators and the load customers, this investment should be shared equally. B. No replacement of existing assets. C. Therefore, Direct Benefit to Load Customers = **50%**

Hydro One Brampton Networks Inc.
EB-2010-0132
Exhibit KT
Tab 1
Schedule 2.0
Filed: 18 October 2010

Technical Conference Exhibit KT 1.2

HOBNI Green Energy Investment 2010	Allocation of Cost Responsibility		
	Generator	Provincial Ratepayers	HOBNI Customers
OM&A	$250K	-	-
Expansions (up to threshold)	-	-	-
Renewable Enabling Improvements	-	$251K	-
Smart Grid (SCADA Only)	-	$294.5K	$294.5K
Smart Grid (Other)			$16K

Technical Conference Exhibit KT 1.3

TABLE IN REFERENCE TO VECC IR NO.28

Allocation of Cost Responsibility															
HOBNI Green Energy Investment	**2011**			**2012**			**2013**			**2014**			**2015**		
	Gen	**Prov**	**HOB**	**Gen**	**Prov**	**HOB**	**Gen**	**Prov**	**HOB**	**Gen**	**Prov**	**HOB**	**Gen**	**Prov**	**HOB**
OM&A	$250k	-	-	$250k	-	-	$250k	-	-	$250k	-	-	$250k	-	-
Expansions (up to threshold)	-	$134k	$31k	-	$137	$32k	-	$140k	$32k	-	$142k	$33k	-	$145k	$34k
Renewable Enabling Improvements	-	$83k	-	-	$84k	-	-	$86k	-	-	$88k	-	-	$89k	-
Smart Grid (SCADA Only)	-	$165k	$165k	-	$169k	$169k	-	$172k	$172k	-	$176k	$176k	-	$179k	$179k
Smart Grid (Other)	-	-	$330k	-	-	$337k	-	-	$344k	-	-	$351k	-	-	$358k

GEA Fixed Asset Continuity

For Accounting

		Opening Balance	Forecast 2010 Additions	Forecast Amortization For 2010	2010 Net Book Value	2010 Average NBV
Transmission Station Equipment - 1815	40	-	-	-	-	-
Supervisory Control Equipment - 1980	15	-	-	-	-	-
Poles, Towers & Fixtures -1830	25	-	1,003,000	20,060	982,940	491,470
Distribution Meters-1860	15	-	-	-	-	-
		-	1,003,000	20,060	982,940	491,470

		Opening Balance	Forecast 2011 Additions	Forecast Amortization For 2011	2011 Net Book Value	2011 Average NBV
Transmission Station Equipment - 1815	40	-	293,000	3,663	289,338	144,669
Supervisory Control Equipment - 1980	15	-	341,000	11,367	329,633	164,817
Poles, Towers & Fixtures -1830	42	982,940	-	23,881	959,059	971,000
Distribution Meters-1860	15	-	390,000	13,000	377,000	188,500
		982,940	1,024,000	51,910	1,955,030	1,468,985

Smart Meter Fixed Asset Continuity

For Tax Purposes

	CCA Class	CCA Rate	Opening UCC Balance	2010 Forecast Additions	CCA For Opening UCC	CCA For 2010 Additions	Total CCA - 2010	Closing UCC Balance
Transmission Station Equipment - 1815	Class 47	8%	-	-	-	-	-	-
Supervisory Control Equipment - 1980	Class 47	8%	-	-	-	-	-	-
Poles, Towers & Fixtures -1830	Class 47	8%	-	1,003,000	-	40,120	40,120	962,880
Distribution Meters-1860	Class 47	8%	-	-	-	-	-	-
			-	1,003,000	-	40,120	40,120	962,880

	CCA Class	CCA Rate	Opening UCC Balance	2011 Forecast Additions	CCA For Opening UCC	CCA For 2011 Additions	Total CCA - 2011	Closing UCC Balance
Transmission Station Equipment - 1815	Class 47	8%	-	293,000	-	11,720	11,720	281,280
Supervisory Control Equipment - 1980	Class 47	8%	-	341,000	-	13,640	13,640	327,360
Poles, Towers & Fixtures -1830	Class 47	8%	962,880	-	77,030	-	77,030	885,850
Distribution Meters-1860	Class 47	8%	-	390,000	-	15,600	15,600	374,400
			962,880	1,024,000	77,030	40,960	117,990	1,868,890

Hydro One Brampton Networks Inc.
EB-2010-
2011 GEA Rate Rider Application
Revenue Requirement Calculations

	Forecast 2010			Forecast 2011		
Average Fixed Asset Values						
Transmission Station Equipment - 1815	$ -			$ 144,669		
Supervisory Control Equipment - 1980	$ -			$ 164,817		
Poles, Towers & Fixtures -1830	$ 491,470			$ 971,000		
Distribution Meters-1860	$ -	$ 491,470		$ 188,500	$ 1,468,985	
Working Capital						
Operation Expense	$ -			-		
15% Working Capital	$ -	$ -		$ -	$ -	
GEA Fixed Assets in Rate Base		$ 491,470			$ 1,468,985	
Return on Rate Base						
Deemed Debt - Long Term	60.0%	$ 294,882		56.0%	$ 822,632	
Deemed Debt - Short Term		$ -		4.0%	$ 58,759	
Deemed Equity	40.0%	$ 196,588		40.0%	$ 587,594	
		$ 491,470			$ 1,468,985	
Weighted Debt Rate - Long Term	6.85%	$ 20,199		6.76%	$ 55,619	
Short Term Debt Rate		$ -		2.07%	$ 1,216	
Equity Rate	9.00%	$ 17,693		9.92%	$ 58,289	
Return on Rate Base		$ 37,892	$ 37,892		$ 115,125	$ 115,125
Operating Expenses						
Incremental Operating Expenses			$ -			$ -
Amortization Expenses			$ 20,060			$ 51,910
Revenue Requirement before PILs			$ 57,952			$ 167,035
Calculation of Taxable Income						
Incremental Operating Expenses			$ -			$ -
Depreciation Expense			$ (20,060)			$ (51,910)
Interest Expense			$ (20,199)			$ (56,835)
Taxable Income for PILs			$ 17,693			$ 58,289
Grossed up PILs			(818)			(3,068)
Revenue Requirement before PILs			57,952			167,035
Grossed up PILs			(818)			(3,068)
Revenue Requirement for GEA			57,135			163,967
GEA Rate Adder						
Revenue Requirement for GEA			57,135			163,967
Total Metered Customers			132,427			133,888
Annualized amount required per metered customer			0.43			1.22
Number of months in year			12			12
GEA Rate Adder			0.04			0.10
GEA Deferral Account Balance - PILs Calculation						
Income Tax						
Net Income	17,693			58,289		
Amortization	20,060			51,910		
CCA	- 40,120			- 117,990		
Revised Taxable Income	- 2,367			- 7,791		
Tax Rate	31.00%			28.25%		
Income Taxes Payable	- 734			- 2,201		
Ontario Capital Tax						
GEA Related Fixed Assets	982,940			1,955,030		
Less: Exemption	-			-		
Deemed Taxable Capital	982,940			1,955,030		
Ontario Capital Tax Rate	0.075%			0.000%		
NET OCT Amount	246			-		
	PILs Payable	**Gross Up**	**Grossed Up PILs**	**PILs Payable**	**Gross Up**	**Grossed Up PILs**
Change in Income Taxes Payable	- 734	31.00%	- 1,063	- 2,201	28.25%	- 3,068
Change in OCT	246		246	-		-
PILs	- 488		- 818	- 2,201		- 3,068

2011 GEA Rate Adder Application

Ongoing Funder Rider

Revenue Requirement:

2011 Rate Year Entitlement	163,967
	163,967
Smart Meter Costs for Recovery	163,967
Forecasted Number of Customers	133,888
Number of Months	12
Rate Adder	0.1021

	2010	2011
Capital	1,003,000	1,024,000
OM&A	-	
	1,005,010	1,026,011
Revenue Requirement		

	2010	**2011**
Capital	1,003,000	1,024,000
OM&A	-	-
Total Capital & OM&A	1,003,000	1,024,000
Revenue Requirement		163,967
Number of Customers		133,888
Number of months		12
Rate Adder		**0.10**

Further details regarding the revenue requirement adjustments in this filing are as follows:

1) PST adjustments - Hydro One Brampton made adjustments to its revenue deficiency in relation to cost reductions relating to PST savings for both Capital and Operating expenditures for 2010 & 2011. Although the PST cost savings were taken into consideration for some expenditures in 2011, not all the PST savings were reflected for each year. For 2011, Revenue Requirement was reduced by $133K attributable to reductions in OM&A costs of $105K, depreciation expense of $9K, Capital Expenditures of $103K in 2010 and Capital Expenditures of $411K in 2011.

2) Low Income Energy Assistance Program – On October 20th the OEB issued a letter providing guidance to distributors filing cost of service applications for 2011 rates. This letter stated that distributors should include the LEAP amount as part of their OM&A expenses. Hydro One Brampton has made an adjustment increasing its OM&A expenses by $75K and increasing its revenue deficiency by $76K in this submission.

3) Green Energy Act – Hydro One Brampton was made aware that adjustments were required to its revenue deficiency in relation to capital costs pertaining to the GEA. Given the uncertainty relating to the amounts that Hydro One Brampton will recover for GEA, Hydro One Brampton has removed GEA capital expenditures for both 2010 and 2011 and is requesting a rate rider and permission to establish a variance account for GEA expenditures. Hydro One Brampton has increased its revenue deficiency by $163K and removed $1.0 Million in 2010 and $1.0 Million in 2011 for GEA capital expenditures. Hydro One Brampton requests a rate rider of $0.10/Customer/Month to recover the revenue requirement associated with its GEA expenditures. In addition, Hydro One Brampton requests permission to establish a variance account to capture the difference in the proposed revenue requirement entitlement and the revenue requirement collected by way of the rate rider.

In addition, Hydro One Brampton also submits an updated revenue requirement work form supporting the revised revenue requirement, and the GEA rate rider computations.

Respectfully submitted,

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The Board further indicated that Board staff would include its proposal with its submissions (4 days prior to the deadline for intervenor submissions), and parties would be expected to comment on the appropriateness of staff's proposal. Hydro One was invited to respond in its reply argument.

In Board staff's February 1, 2010, submission, staff submitted that the Board could set the allocation between provincial ratepayers and Hydro One ratepayers on a provisional basis. Board staff explained this alternative as follows:

> In this scenario, the Board would establish a deferral account in which the applicant would record amounts collected from its own ratepayers. A parallel account would be established to record recovery from provincial ratepayers.
>
> When the Board makes its final determination of the percentage of direct benefits to Hydro One's ratepayers of [Green Energy] Plan expenditures in 2010 and 2011 (which may not be until the next rates case) the Hydro One ratepayer account can be credited or debited, and any over or under-collection from provincial ratepayers can be taken into account in setting the amount to be collected in subsequent years.
>
> Staff further submits that if this approach is adopted, the Board need not reconvene the hearing at this time to determine the amount of direct benefits to Hydro One ratepayers. The Board could choose to adopt Hydro One's proposal or a different percentage allocation, for example, 15%, as a default allocation to Hydro One's ratepayers. The final allocation would be determined in a subsequent proceeding.

VECC, SEC, and CME generally agreed with the Board staff proposals. AMPCO agreed with the Board staff proposals but wanted an opportunity to cross examine the witness panel. The PWU supported the original Hydro One proposal on the issue.

Hydro One, in its February 12, 2010 reply argument, indicated that the Board staff approach was acceptable but made some specific comments on the design and clearance of the related variance accounts.

Decision

projects and costs proposed in a GEA Plan to similar scrutiny as any other cost proposed to be included in rates.

The Board will assess the prudence of the activities and costs to the extent permitted by the level of detail provided. The GEA Plan should contain sufficient evidence to allow the Board to conduct this examination. Issues of need, project selection, project budget and prioritization of expenditures that are addressed through the GEA Plan approval process in sufficient detail will not be revisited in subsequent proceedings. As described below, if recovery of approved expenditures is to occur through a rate rider, an account to track variances from budgeted costs may be established.

The Board will approve only those portions of a GEA Plan which it finds to have been appropriately supported by evidence, and it may attach conditions to its approval of a GEA Plan or any portion of a GEA Plan.

Availability of additional funding for expenditures proposed in a GEA Plan

In general, rates approved as part of a cost of service application will include only costs from year one of a GEA Plan. An exception to this general rule could occur if the Board is considering an application based on two test years, and finds the information in the GEA Plan sufficiently detailed and robust to approve for both test years.

The Board recognizes that distributors may need additional funding for expenditures proposed in a GEA Plan between cost of service applications, and will consider applications for suitable funding mechanisms. The nature of the mechanism used will depend on whether the Board is able to properly assess prudence of the proposed expenditures based on the evidence filed in the application.

A rate rider is a tool to allow recovery of expenditures that have been examined as part of an application, found to be prudent, and approved for recovery by the Board. An account to track variances from budget may be established in conjunction with a rate rider.

In contrast, the costs collected through a funding adder (sometimes referred to as a rate adder) are not subjected to a prudence review before the adder is approved. The costs will be subject to a prudence review in the first cost of service application following the implementation of the adder. The Board will require the distributor to refund to ratepayers costs already collected through the adder, but found to be imprudent.

Where costs recorded in a deferral account have not been subjected to a prudence review, recovery of these costs may be denied at the time the Board considers an application to dispose of the balances in the account.

"Single issue" rate hearings do not allow a complete and balanced consideration of all aspects of a distributor's operations that influence rates. Applications to increase base rates between cost of service applications for expenditures proposed in a GEA Plan are not encouraged by the Board.

VII. Capital and OM&A Deferral Accounts for Renewable Generation Connection or Smart Grid Development

In its Guidelines released June 16, 2009, the Board created four new deferral accounts in the Uniform System of Accounts to allow distributors to begin recording expenditures for certain activities relating to the connection of renewable generation or the development of a smart grid. These deferral accounts were authorized to be used to record the qualifying incremental capital investments or OM&A expenses which are described below. In this context, incremental means that an investment was not included in previous capital plans approved by the Board or is not funded through current rates.

In addition, the Board is creating, in these Filing Requirements, two additional deferral accounts for the recording of amounts collected from ratepayers through any funding adder the Board may approve relating to the connection of renewable generation or the development of a smart grid.

Renewable Generation Connection Deferral Accounts

Account 1531: Renewable Generation Connection Capital Deferral Account

Investments associated with expansions to connect renewable generation facilities and renewable enabling improvements, both as defined in the DSC, will be recorded in this capital deferral account. In addition, the capital cost of changes to a distributor's Customer Information System to enable the automated settlement of FIT or microFIT contracts may be included in this account.

The distributor's normal capitalization policies from its last cost of service proceeding should be followed in identifying fixed asset expenditures.

Account 1532: Renewable Generation Connection OM&A Deferral Account

Incremental operating, maintenance, amortization and administrative expenses directly related to expansions to connect renewable generation facilities, and renewable enabling improvements, both as defined in the DSC, will be recorded in this operating deferral account. In addition, costs that can be recorded in this account include expenses associated with preparing a GEA Plan and expenses associated with changes to a distributor's Customer Information System to enable the automated settlement of FIT or microFIT contracts.

Distributors should not record in this account any allocation of general expenses that are not specifically related to the investments that can be recorded in Account 1531.

Account 1533: Renewable Generation Connection Funding Adder Deferral Account

This account will record the revenues collected through a funding adder approved by the Board related to renewable generation connection projects. Separate sub-accounts shall be used to record any amounts collected from a distributor's ratepayers and any amounts received from the IESO (pursuant to the provincial pooling mechanism set out in 79.1 of the OEB Act) in respect of the projects.

Smart Grid Development Deferral Accounts

At the present time, the legislative and regulatory framework regarding the development and establishment of the smart grid is still under development. Most importantly, the objectives, interoperability requirements and technology standards for the smart grid are not currently known. For that reason, the Board will continue to limit amounts that can be recorded in the "Smart Grid Capital Deferral Account" and the "Smart Grid OM&A Deferral Account" to expenditures associated with the following activities:

- smart grid demonstration projects;
- smart grid studies and planning exercises; and
- smart grid education and training.

Expenditures for smart meter-related investments and activities, including advanced metering infrastructure, are adequately addressed through existing mechanisms and may not be recorded in these deferral accounts.

Account 1534: Smart Grid Capital Deferral Account

Investments related to smart grid demonstration projects will be recorded in this capital deferral account. This account will also be used to record the cost of smart grid investments that are undertaken as part of a project to accommodate renewable generation.

The distributor's normal capitalization policies from its last cost of service proceeding should be followed in identifying fixed asset expenditures.

Account 1535: Smart Grid OM&A Deferral Account

Operating, maintenance, amortization and administrative expenses directly related to the following smart grid development activities will be recorded in this operating deferral account:

- smart grid demonstration projects;
- smart grid studies and planning exercises; and
- smart grid education and training.

This includes expenses associated with preparing the smart grid portion of a GEA Plan.

Distributors should not record in this account any allocation of general expenses that are not specifically related to the investments that can be recorded in Account 1534.

The Board recognizes that an investment in a renewable enabling improvement, as defined in the DSC, may incorporate what the distributor believes to be smart grid technologies. In such cases, distributors should allocate any costs associated with the incorporation of smart grid technologies to the smart grid deferral accounts, with the balance of the costs going to the renewable generation connection deferral accounts.

Account 1536: Smart Grid Funding Adder Deferral Account

This account will record the revenue collected through a funding adder approved by the Board related to smart grid development.

Interest Charges and Other Matters Relating to the Deferral Accounts

Interest carrying charges will apply to the monthly opening balances in the above accounts using the Board's prescribed interest rates in effect for the relevant quarterly period.

The Board may issue further instructions regarding these deferral accounts, including in relation to reporting, as required.

The recording of amounts into the deferral accounts described above does not guarantee final recovery of those amounts. Recovery of any expenditures recorded will be subject to a prudence review at the appropriate time. This will generally occur during a proceeding to set the distributor's rates, but could also occur at the time the Board approves a project to which the amounts relate, or in such other circumstances as the Board may determine.

VIII. Reporting

Implementation of Detailed GEA Plans

The Board will require that distributors file annual status reports on the implementation of their approved Detailed GEA Plans. These reports should provide the current status of projects and explain any material deviations from the Detailed GEA Plan as approved. At a later date, the Board will provide further direction as to the time and the manner of reporting.

Smart Grid Development Activities

In respect of smart grid development activities a distributor chooses to include in its GEA Plan, the Board will require distributors to provide evaluations of the outcome of such activities to ensure that the benefits of experience are shared. These reports should include:

- a description of the activity;
- the specific technologies tested or demonstrated, where applicable;
- activity costs;
- the performance of the demonstrated technologies, where applicable;
- the benefits of the activity, quantified where appropriate or otherwise presented on a qualitative basis; and
- recommendations and lessons learned from the project.

Smart grid study and demonstration project reports will be maintained by the Board in an on-line repository.

Where a report contains information that the distributor believes to be confidential, the distributor should notify the Board, and proceed in the manner described in the Board's *Practice Direction on Confidential Filings*.

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

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

3.2.2.3 Basic Benefit Assessments for Basic GEA Plans

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

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

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

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

1.1 Regulation 330/09

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

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

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

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

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

factors earlier today, right? We talked about our system being more urbanized than Hydro One's. We see our system being more intelligent. We have more protection, more SCADA on our system. Our feeders are shorter. Theirs is longer. Our age of assets, our operating practices, they all differ, and that all factors in, in all of this.

MR. COONEY: Okay. I don't have it here, but my part (c) of that question would be with respect to the 50/50 split for the SCADA systems, between provincial ratepayers and Brampton. I think that is provided in table -- in the table that is on Board Staff 34.

MR. MASTROFRANCESCO: Yes.

MR. COONEY: Could you shed light on, like, reasoning specifically for that case, why and what led you to the 50/50 split between --

MR. MASTROFRANCESCO: Sorry. The SCADA projects are basically projects that we are going to implement in areas where generation was going to go into.

Like I said earlier, we are fairly mature in the SCADA area. So to help enable generation, we thought it would be ideal if we could have additional SCADA where generation was going into so that, you know, we can work on our system while still having the generators pump power into the system.

I think that would be an ideal situation.

MR. COONEY: Okay. So --

MR. MILLER: Sorry, if I can, just to expand on that a little bit, with regards to our SCADA system, Hydro One

Brampton has had a SCADA system in place for many years. It is part of our system, and we use the data for this for planning purposes and so on.

So the addition of SCADA equipment on this is really nothing new to Brampton, other than the fact that not only will this help us collect data from other areas, but it also will help in generation, which is why we are proposing the 50/50 split.

MR. COONEY: Okay. There is also one other question I had come up with when I was listening to, I think, VECC in the morning, on some of their questions.

But more generally now, is there a reason why the SCADA investments, I think you just said they're nothing new? Is there a reason why they would be included under green energy investment as opposed to under the ambit of business as usual sort of work that you would undertake?

MR. MASTROFRANCESCO: Again, we see these projects as enabling generation. We are pretty much set up SCADA-wise for a lesser --

MR. COONEY: Sorry. So in the absence of this additional generation, you would sort of state that additional spending on SCADA is a direct result of this generation coming in through the FIT and microFIT?

MR. MASTROFRANCESCO: That's correct.

MR. COONEY: Okay. Thank you.

Just a moment.

Just one follow up question under the Board's Report on 330/09: Can Hydro One Brampton confirm that that sort of activity to invest in SCADA is covered in that report? Is Hydro One Brampton confident that is covered?

MR. MASTROFRANCESCO: We believe it is, yes. I think it does make mention that if SCADA is used for the purpose of enabling generation, it is an eligible investment.

MR. COONEY: Okay. Thank you.

So moving on to my next question, which is TC3, it is in reference to Board Staff IR No. 29, which is the letter of comment from the OPA.

I think that is located at -- I have it as appendix N. I am not sure if it is AN or BN, but anyhow...

So the main quote that I would look to here is that:

> “Hydro One Brampton plans on connecting over 40 megawatts of renewable generation per year for the next five years. The number of connections in the forecast includes 25 microFIT and 75 FIT projects per year."

It is further stated by the OPA there that:

> “Due to the challenges that FIT proponents encounter in finalizing development and connection details, not all applications will necessarily materialize or be awarded a contract. The 40 megawatts per year estimated by Hydro One Brampton may therefore be high."

So my first question here is could you -- could Hydro One Brampton provide comments on the OPA's assessment?

MR. MASTROFRANCESCO: We think the OPA's assessment is conservative. We feel that we have a more intimate, first-going on here, the OEB staff interrogatory had broken -- had indicated three different types of cost responsibility; it was a generator, provincial ratepayers, or Hydro One Brampton Networks customers. And we just asked if we could take the various initiatives that were identified in VECC No. 17, and indicate how they broke down between those three different funding areas.

I think this may actually answer number (c) as well, because -- no. Actually, it is number (c) comes up later on. But I was curious to make sure that, from my mind, because you indicated that the $251,000 of renewable enabling improvement expenditure was going to be funded by all of the provincial ratepayers, and I was just wanting to confirm that that amount had not been included in your 2011 rate base.

[Witness panel confers.]

MR. MASTROFRANCESCO: It is included in the rate base.

MR. HARPER: So that would have to be taken out of the rate base for purposes of setting your rates, then?

MR. MASTROFRANCESCO: An adjustment would have to be made, yes.

MR. HARPER: Right. Okay. Fine. Then in part (d), I guess when I was reading -- I think you have answered in your table you provided here -- but in part (d) I asked about the fact that it appeared that in VECC No. 21, the enabling improvements was the only capital spending where all or part of it was going to be funded through the -- through all provincial ratepayers, whereas in response to

DISTRIBUTION AUTOMATION PLAN 2010

Hydro One Brampton's Distribution Automation Plan is included for reference as part of this Exhibit on the following pages as **Appendix H.**

APPENDIX H

Distribution Automation Plan
2010

PROTECTION & CONTROL DEPARTMENT

May 10, 2010

Table of Contents

1. History

Hydro One Brampton Networks Inc. (HOBNI) began the distribution automation plan in the early 1980's starting with the installation of a Motorola PDP-11 Supervisory Control and Data Acquisition (SCADA) master system and Motorola DATRAC Remote Terminal Units (RTU) at several municipal substations (MS). This gave our Operators access to real time feeder data and allowed for control of Municipal Substation (MS) feeder breakers and reclosers. This initiative was then expanded to include the automation of several switch installations along our distribution feeders using Motorola DAS 100 RTUs connected through leased Bell communication circuits. This provided fault indicator data as well as remote control of our critical switches, allowing for faster feeder restoration and improved outage times.

This phase of the implementation continued for several years, and by 1991 there were 12 municipal substations as well as 67 remotely operable pole top switch locations on line.

2. System Expansion and Innovation

2.1. New SCADA Master Equipment

In 1992, coinciding with our relocation to 175 Sandalwood Parkway West, HOBNI installed new Quindar VMS based SCADA master station hardware and software. This new equipment replaced the legacy Motorola PDP-11 system. This allowed for communication line expansion as well as the use of multiple communication protocols. At this time new communication equipment was also installed that allowed for expansion of the number RTUs connected to the system.

2.2. New Communication Initiatives

The installation of the new SCADA master equipment allowed for the expansion of our SCADA communication network. Previously all communication was achieved through leased Bell lines. This mode of communication became expensive and unreliable.

New technologies were investigated and a Motorola licensed 900 MHZ data radio system was installed. This system allowed for easy system expansion and multiple MS and pole-top RTU locations were connected. After it became clear that the 900 MHZ licensed system was nearing capacity, we began to investigate other communication solutions. This led to the installation of several 900 MHZ spread spectrum radio installations, the installation of 2.4 GHZ spread spectrum system, as well as the introduction of our self healing fibre optic communication rings in the East and West areas of the city.

These systems became the backbone of our SCADA communication network and allowed for increased system expansion. Over the next few years we were able to connect all MSs to our SCADA system and expand our pole-top SCADA installations to over 125 fully controllable sites.

3. Current System Configuration

3.1. SCADA Master Equipment

HOBNI is currently using a Survalent Worldview based master station system on dual redundant WinServ 2003 hosts. There are two Windows XP based operator stations in the Control Room as well as multiple user client work stations located throughout the facility. These are connected via a secure connection to our corporate Local Area Network (LAN).

The master station equipment connects to field equipment through redundant master terminal servers allowing for a total of 64 independent communication lines speaking multiple protocols.

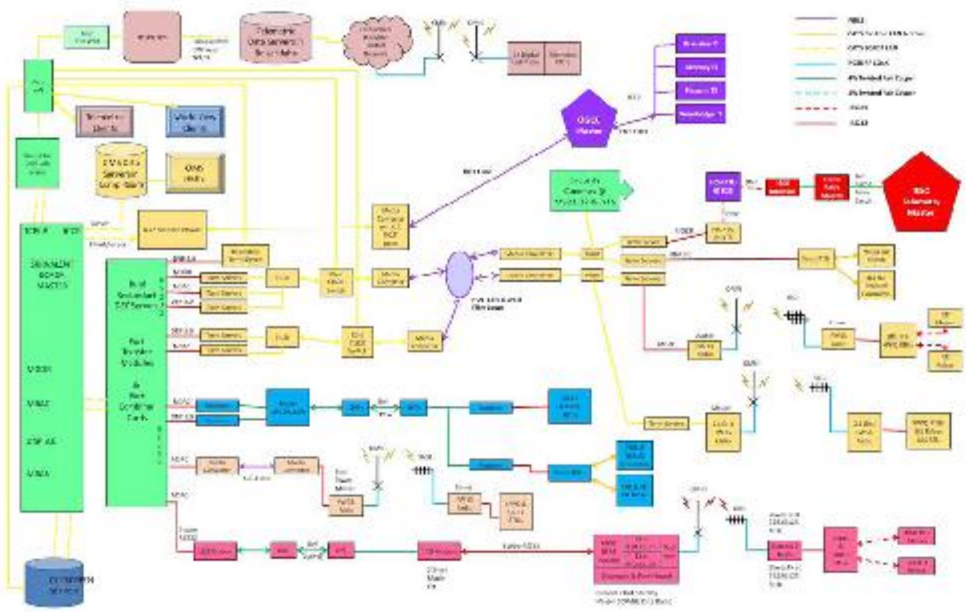
3.2. Remote RTU Communication

HOBNI currently has three bridged four-wire Bell leased communication lines connecting 17 RTUs to our Master system. There are also three individual four-wire communication lines connecting three Municipal Stations. Bell costs have decreased by two thirds since 1991 due to migration away from Bell communication.

The licensed 900MHZ master radio is located on a 20 storey building in central Brampton. It is connected to the SCADA master by a leased four-wire Bell line and communicates to 11 pole top RTUs as well as one MS. The Radio Frequency footprint of this installation covers the entire city of Brampton.

There are currently nine separate spread spectrum communication nodes located throughout the city providing communication the majority of our RTUs. Eight of the nodes are running at 900 MHZ while one is running at 2.4 GHZ. The master radios connect back to the SCADA master via our self healing fibre Wide Area Network (WAN).

Telemetric communication equipment connects to our SCADA master via a terminal server / internet link from the Telemetric data servers in Idaho. This communication equipment uses cellular data channels and can reach any location that has 1X coverage.



Block diagram outlining our various communication systems:

3.3. Remote RTU Equipment

HOBNI has RTU equipment installed at 13 MSs and one TS location, as well as three large customer substations. There are also RTUs installed at 98 overhead switches, 22 pad mounted switches and eight Gas Insulated Switchgear (GIS) auto transfer switchgear.

There are currently RTUs located at seven co-generation sites within Brampton.

Telemetric RTUs are located at more than 50 radio fault indicator locations. This equipment is also used at three overhead switch locations, five spot network vault locations and at two auto-transfer locations.

The SCADA master communicates to several IEDs including EIG NEXUS 1250 meters, PML ION meters, SEL 351R recloser controllers, various ABB and SEL protection relays, S&C intelligent motor operators as well as Schneider 44 KV current / fault sensing installations. This is accomplished by communicating directly to the IED or by using an RTU as a data concentrator.

4. Moving Forward

4.1. Smart Meter Integration with OMS (2011)

In 2011, HOBNI plans on integrating the Smart Meter system with the Outage Management System (OMS). 'Last gasp' smart meter data will be transmitted from the Smart Meter system to the OMS in real time, allowing the prediction engine in OMS to accurately pinpoint equipment on the distribution system.

4.2. Feeder Automation Equipment

HOBNI continues to investigate and install automation equipment on its distribution feeders. There are currently three auto transfer systems installed in Brampton.

In 2010 three new 46 KV Joslyn VBM switches will be installed at MS 19 as a pilot project. These remotely operable switches will replace existing air insulated manual equipment.

In 2011 new solid dielectric, remotely operable, sectionalizing switches will be installed at two underground vault installations in the downtown core. These units will allow for dynamic system load control as well as allow switching to be done safely above grade.

In 2011 solid dielectric recloser equipment is to be installed on a distribution feeder to allow for automatic feeder sectionalizing during faults. One unit will be tested and several more installed in the near future depending on the success of the project. This same equipment can be 'repackaged' into pad mounted form for installation at existing pad mounted switch gear installations.

4.3. Distributed Generation

New province wide green energy initiatives require HOBNI to monitor distributed generation installations with capacities greater than 250 KW. There are currently 40 installations of this type in the planning stages in Brampton.

Investigation has begun on how best to collect all required metering and SCADA data at these locations. Investigation is currently underway with hopes that a single metering / SCADA solution can be utilized.

In 2010 equipment from PML will be investigated for suitability. This equipment is to communicate to the SCADA master via Bell I/P modems in real time. This data will then be utilized by our Control Centre as well as sent to Hydro One Networks via our fibre based ICCP master-to-master link.

4.4. Safety / Security

In 2009 an MS security initiative was implemented. I/P based cameras were installed at three MSs and have proven to work well. These installations bring back real time video to the HOBNI Control Room. In 2010 this initiative is being expanded to increase the number of locations being monitored.

MS21 camera screen shot:

4.5. Communications Expansion

Communication to field devices is the backbone that all feeder automation relies on. As the need arises for more distribution automation, our communication networks will be required to expand. This expansion will involve expanding our fibre optic network, increasing the number of spread spectrum radio nodes (both 900 MHZ and 2.4 GHZ) as well as investigating new communication technologies. These new technologies may include secure I/P over the cellular network or Wi-Max solutions.

GREEN ENERGY ACT EXPENDITURES

The OEB requires that LDCs submit their Green Energy Plan to the OPA for review. After review, the OPA then provides a letter of comment to the LDC. HOBNI is currently in the process of submitting their Green Energy Plan to the OPA. Once the OPA provides a letter of comment, it will be made available and included in HOBNI's Green Energy Plan.

Hydro One Brampton's 2011 - 2015 Green Energy Plan is included for reference as part of this Exhibit on the following pages as **Appendix G**.

APPENDIX G

Green Energy Plan

2011 - 2015

ENGINEERING DEPARTMENT

May 13, 2010

Table of Contents

1. Executive Summary

The Hydro One Brampton Networks Inc. (HOBNI) Green Energy Plan (Plan) presents the Company's response to the *Green Energy and Green Economy Act, 2009* ("GEGEA") in alignment with HOBNI's corporate strategy. The Plan covers the five year period from 2011 to 2015 and includes the incorporation of renewable energy generation, development of HOBNI's Smart Grid and promotion of energy conservation. HOBNI considers this Plan to be a prudent and responsible. The Plan'ss development is based on the Company's experience with the implementation of renewable energy generation connections in Ontario since 2006, its Conservation and Demand Management ("CDM") programs since 2004, and a measured approach to Smart Grid investment focused on studies, demonstration projects, planning and training. The spending reflected in the Plan went through the same business planning and approval process as all other investments in our distribution system.

The total costs of investments contained in the Plan are summarized in the table below.

Green Energy Spending 2010 - 2015						
Description	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Generator Connections (Capital)	$300,000	$300,000	$306,000	$312,000	$318,000	$324,000
Smart Grid (Capital)	$733,000	$750,000	$765,000	$780,000	$795,000	$812,000
OM&A	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000
Less Generator Funded Costs	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000
Totals	**$1,033,000**	**$1,050,000**	**$1,072,000**	**$1,092,000**	**$1,113,000**	**$1,136,000**

The available capacity on HOBNI's Distribution system to accommodate renewable generation connection is approximately 720 MW. The distribution system has 166 MW available on the 44kV system and 555 MW available on the 27.6kV system.

Approximately 80% of the HOBNI distribution system will accommodate connections to generation without the need for expansion of new lines. However, as the number of generator connections increase, the short circuit fault levels also increase on the distribution system. Currently the only known constraint on HOBNI's distribution system is the fault level on the EZ Bus at Bramalea TS. There will be no generators allowed to connect to any feeders that are supplied by the EZ Bus at Bramalea TS. HOBNI's feeders that are affected by this constraint are the Bramalea M43, M44, M47 and M48.

The evolution of HOBNI's system into a Smart Grid offers value to both HOBNI's generation and load customers. A smarter distribution system will enhance the reliability, security and power quality of the system through automation and enablement of increased amounts of cleaner, renewable distributed generation; it will allow for new conservation and demand management programs by improving load management and overall understanding of customer load profiles through innovative two way communication; and it will improve asset condition monitoring and trouble call responses with more accurate data and enhanced system controls.

HOBNI proposes projects that would involve research and pilots into such technologies as real time monitoring, control devices, remediate faults and outage management & restoration systems. Several projects in the next 5 years include:

- ***Smart Meter Integration with OMS***

  In 2011, HOBNI plans on integrating the Smart Meter system with the Outage Management System (OMS). Smart meter data will be transmitted from the Smart Meter system to the OMS system in real time, allowing the prediction engine in OMS to accurately pinpoint failed equipment on the distribution system. It will also identify when the meter is removed and will help identify theft of power or meter tampering issues.

- ***Feeder Automation Equipment***

  HOBNI continues to investigate and install automation equipment on our distribution feeders. These remotely operable switches will replace existing air insulated manual equipment. In 2011 new solid dielectric, remotely operable, sectionalizing switches will be installed; these units will allow for dynamic system load control. Also, in 2011 solid dielectric recloser equipment will be installed to allow for automatic feeder sectionalizing during faults.

- ***Distributed Generation***

  HOBNI is required to monitor distributed generation installations with capacities that are greater than 250 kW. Exploratory work has been initiated on how best to collect all required metering and Supervisory Control and Data Acquisition (SCADA) data, with hopes that a single metering / SCADA solution can be utilized. In 2010 equipment from PML will be investigated for suitability. This equipment is to communicate to the SCADA master via Bell I/P modems in real time. This data will then be utilized by our Control Centre as well as sent to Hydro One Networks via our fibre based ICCP master to master link.

- ***Safety / Security***

  In 2009 a Municipal Substation (MS) security initiative was implemented. I/P based cameras were installed at three MSs and have proven to work well. These installations bring back real time video to the HOBNI Control Room. In 2010 this initiative is being expanded to increase the number of locations being monitored.

- ***Communications Expansion***

  As distribution automation increases on the system, HOBNI's communication network will require expansion. This work will involve expanding our fibre optic network, increasing the number of spread spectrum radio nodes (both 900 MHZ and 2.4 GHZ) as well as investigating new communication technologies. These new technologies may include secure I/P over the cellular network or Wi-Max solutions.

2. Generator Connections Current & Future Outlook

2.1. Planning Criteria for Generator Connection

The planning criteria used to evaluate Generator Connections to HOBNI's system are listed below:

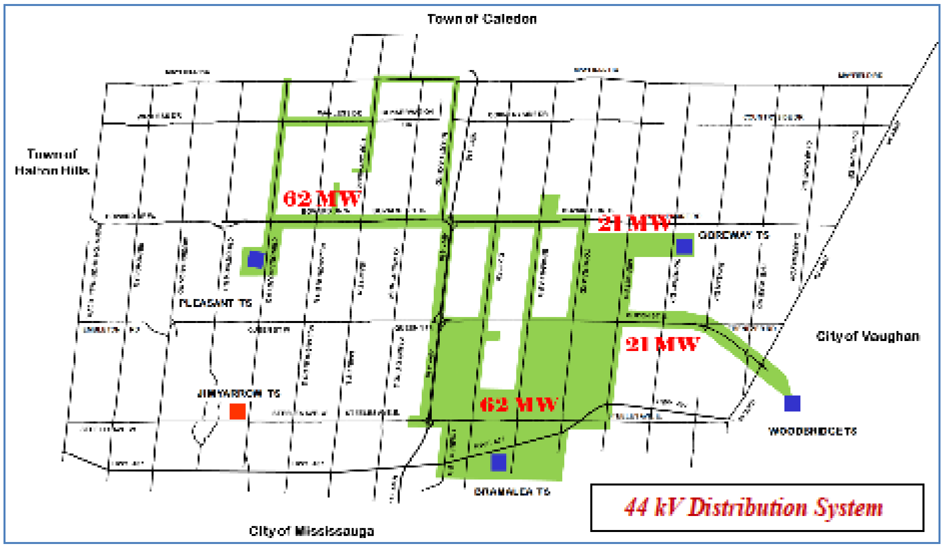
- Bus voltages should vary between 0.95 p.u and 1.05 p.u during normal and contingency situation.
- Bus voltage swing should not exceed 5.0% during switching operation.
- Line loading should not exceed 50% of thermal rating.
  - 50% Feeder rating for 44 kV is 300 A = 20.6 MW
  - 50% Feeder rating for 27.6 kV is 300 A = 12.9 MW
  - 50% Feeder rating for 13.8 kV is 155 A = 3.3 MW
  - 8.32 kV system – Not allowed to connect, will become obsolete
  - 4.16 kV system - Not allowed to connect, plan is to convert to 27.6 kV over the next 7 years.
- Reverse Power flow through HOBNI transformers should not exceed 50% of rated KVA.
- Short circuit values should be less than 20 kA at Hydro One Networks Inc. (HONI) 44 kV & 27.6 kV bus.
- Short circuit values should be less than 20 kA for the 27.6 kV bus at HOBNI's Jim Yarrow Transmission Station.
- Short circuit values should be less than 20 kA for HOBNI's Municipal Substation bus.
- Short circuit values should be less than 16 kA at HOBNI's load modules and customer breakers.

2.2. Available Feeder Capacities for Generation Connection

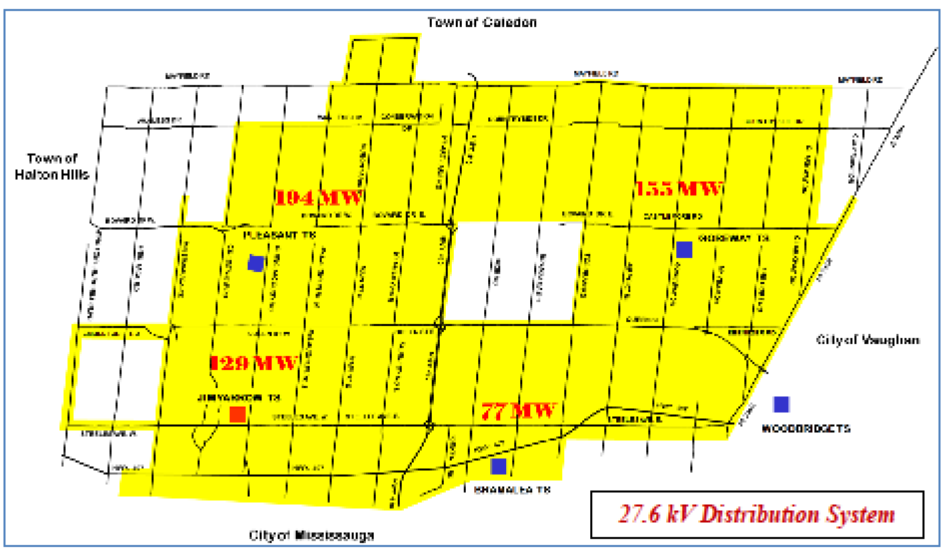
The following table breaks down the total capacity on HOBNI's distribution system for generation connection:

Table 1 – HOBNI Feeder Capacity

Station/Feeders	Available MW for Generation Connection	Notes
Woodbridge TS – 44 kV (M16)	20.6	
Bramalea TS – 44 kV (M26, M27, M28, M43, M44,M47,M48)	61.8	M43, M44, M47 and M48 are on the EZ Bus which is limited due to short circuit fault levels – therefore no connection to these feeders.
Bramalea TS – 27.6 kV (M2, M3, M4, M5, M6, M10)	77.4	
Goreway TS – 44 kV (M36)	20.6	
Goreway TS – 27.6 kV (M41, M42, M43, M44, M45, M46, M47, M48, M49, M50, M51, M52)	154.8	
Pleasant TS – 44 kV (M21, M22, M24, M26)	61.8	M21 has not been taken out of the station - therefore no connection to this feeder
Pleasant TS – 27.6 kV (M9, M10, M11, M12, M13, M14, M43, M44, M45, M46, M47, M48, M66, M67, M68)	193.5	
Jim Yarrow TS – 27.6 kV (M1, M3, M4, M5, M6, M7, M8, M10, M11, M13)	129	
Totals:	**719.5 MW**	



The available capacity on HOBNI's Distribution system to accommodate generation connection is approximately 720 MW. The distribution system has 166 MW available on the 44kV system (pictured above) and 555 MW available on the 27.6kV system (pictured below).



2.3. Connection & Fault Level Constraints

Approximately 80% of HOBNI's distribution system will accommodate connection to generation without the need for expansion of new lines. Generators wanting to connect in the 20% of un-served areas would be connected per Ontario Energy Board's (OEB's) Distribution System Code (DSC).

HOBNI does have plans to expand into the un-served areas of the City. The new 27.6 kV yards at Pleasant TS and Goreway TS will allow new feeders to service the north-west and north-east corners of the City. Current tentative plans include the following expansions:

- 2010 – two (2) 27.6 kV feeders out of Goreway TS
- 2011 to 2014 – one (1) 27.6 kV feeder per year out of Goreway TS
- 2011 to 2014 – one (1) 27.6 kV feeder per year out of Pleasant TS

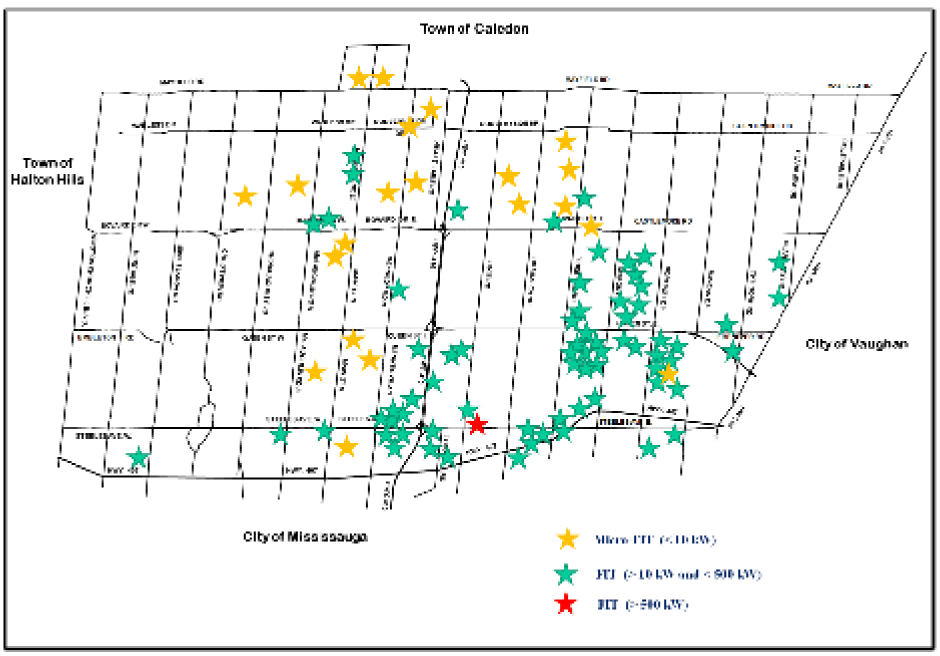
If the expansions are executed according to plan, HOBNI will have an additional 103 MW of capacity for generator connection by the year 2014.

As generator connections increase, the short circuit fault levels also increase on the distribution system. Currently the only known constraint on HOBNI's distribution system is the fault level on the EZ Bus at Bramalea TS. There will be no generators allowed to connect to any feeders that are connected to the EZ Bus at Bramalea TS. The HOBNI's feeders that are affected by this constraint are the M43, M44, M47 and M48.

2.4. Current Connections and Outlook

Since the official start of the FIT & Micro-FIT programs back on November 2009, HOBNI currently has applications for the following:

- 70 FIT applications totaling approximately 23.8 MW
  - All but one under 500 kW
  - Only one over 500 kW – 3.2 MW Biomass Unit
- 28 Micro-FIT applications totaling approximately 208.1 kW
  - 8 commercial solar
  - 20 residential solar



Renewable Generator Connection Applications

HOBNI's goal is to support the enablement of renewable generation in Ontario. However, areas remain in which the connection of renewable generation is not currently feasible due to existing system constraints. Under the Green Energy Act, distributors are obligated to respond to the potential for additional connections where these are deemed economic. Therefore, connection requests that are in excess of existing available system capacity will be assessed with respect to whether they can be enabled with economic additions to wires facilities. The Ontario Power Authority (OPA) will do this assessment for transmission; HOBNI will do the assessment of distribution enabling investments. In both cases, the assessments will be guided by OEB's direction with respect to cost allocation and the degree of risk that expected generation projects will not proceed. HOBNI is also working with the OPA to ensure the availability of distribution capacity is considered in the processes related to issuing and managing FIT contracts.

HOBNI notes that the incorporation of large amounts of renewable energy generation into its system will be an extensive and time consuming process. Under the proposed FIT application framework, HOBNI will continue to track and monitor the connection requests that have capacity allocations and make adjustments to its system expansion and enhancement plans according to changing conditions that would provide opportunity for these applicants to obtain a FIT contract.

2.5. OPA's Letter of Comment

In this section of the Plan, the distributor must include the letter of comment on the Plan provided by the OPA.

3. Renewable Generation Connection Information

3.1. HOBNI FIT Application Process

Phase	Purpose	Owner	Estimated Turnaround Time
Pre-FIT Consultation	Assist proponent to gather information necessary to apply for FIT, such as preliminary transmission and distribution testing, broad cost-estimates, etc.	HOBNI	5 days upon the receipt of a completed Form A - Pre-FIT Consultation Application.
FIT Contract Application	A process that is managed by the OPA for assessing applications and issuing contracts for FIT Allocation Exempt or Non Allocation Exempt. DAT & TAT.	OPA	60 days upon completed OPA FIT application.
Connection Impact Assessment (CIA)	After the FIT contract has been awarded, the applicant files a CIA with Hydro One Brampton for a more formal assessment of the impact of connecting the generator to the system. A System Impact Assessment (SIA) must be completed by the IESO for projects >10MW. A very high-level connect cost assessment will be provided as part of the CIA package back to the applicant.	HOBNI/IESO	60 days upon the receipt of a completed Form B - Connection Impact Assessment (CIA) Application. Longer than 60 days if projects involve other LDC(s).
Connection Cost Estimate (CCE)	If the applicant requires a detailed connection cost assessment, the applicant can complete a CCE.	HOBNI	90 days upon the receipt of a completed CCE study agreement by the generator. The CCE study agreement and cost are included as part of the CIA package.
Connection Cost Agreement (CCA)	Once agreement of the scope and cost are reached, the generator is required to sign a Connection Cost Agreement to recover the costs Hydro One Brampton will incur to connect the project to the distribution system.	HOBNI	6 months from the time the CIA is completed. The generator is required to complete a CCA study agreement along with payment in order to initiate the CCA process. The CCA study agreement and payment information will be included as part of the CIA package.
Engineering, Procurement and Construction	After submitting the CCA and payment, detailed design and construction may begin. The project in-service date will be set. Once all of the required work and approvals are completed, the Distribution Connection Agreement, signed by Hydro One Brampton and the generator, provides an outline of the connection as well as the roles and responsibilities of each party.	HOBNI	The project in-service day will be determined at the project kick-off meeting which will take place no later than 45 days after CCA execution.

3.2. Costing of Projects & Activities

HOBNI plans on connecting over 40 MW of renewable generation per year for the next five years. The numbers of connections in the forecast include 25 MicroFIT and 75 FIT projects per year.

Generator Connection Spending 2010 - 2015						
Description	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Expansions (capital)	-	$200,000	$204,000	$208,000	$212,000	$216,000
Enabling Improvements (Capital)	$300,000	$100,000	$102,000	$104,000	$106,000	$108,000
OM&A	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000
Less Recoverable	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000
Totals	**$300,000**	**$300,000**	**$306,000**	**$312,000**	**$318,000**	**$324,000**

The sections below describe the activities and investments that HOBNI will undertake to facilitate the achievement of these targets in a timely and prudent manner.

<u>OM&A</u> – HOBNI's costs included in this Plan cover Development work related to generation connections. Investments in this area allow HOBNI to undertake further research and development to understand and address the complexities associated with generation connections and the development of new standards for generation connections. Investments in this area will also address the increasing need to interface with generator connection proponents as a result of the forecasted increases in connection volumes.

Connection Assets – HOBNI has assumed that this investment only covers the work associated with providing isolating devices or other assets required for the specific generator's connection to HOBNI's system. Consistent with the Distribution System Code, HOBNI does not include the expansion costs associated with? its main distribution system to build a new line to the ownership demarcation point serving one or more generation customers as a Connection Asset. Generators are responsible for all costs associated with Connection Assets. As such, the costs associated with work on the main distribution system to physically connect and isolate Connection Assets are covered by capital contributions from customers and result in no net capital additions to HOBNI's rate base, and no impact on distribution rates.

Expansion - HOBNI has based this Plan on its assumption that Expansion of the distribution system to connect renewable energy generation includes the following types of investments carried out to serve one or more renewable energy generation facilities:

- Expand or build out the distribution system to the ownership demarcation point of the renewable energy generation facility;
- Rebuilding a single-phase line to three-phase;
- Rebuilding an existing line with a larger size conductor;
- Rebuilding or overbuilding an existing line to provide an additional circuit;
- Converting a lower voltage line to operate at higher voltage;
- Replacing a transformer to a larger MVA size;
- Upgrading a voltage regulating transformer or station to a larger MVA size;
- Building new express feeders to connect renewable energy generation;
- Providing new Municipal Stations and/or additional capacity at existing Municipal Stations.

These capital investments modify/upgrade the distribution lines and stations to allow the connection of one or more renewable energy generation facilities to HOBNI's system while preserving reliability and power quality. The costs associated with expansion investments required to connect all anticipated renewable generation facilities in 2010 are assumed to be covered by the funding requested in this Plan. For expansion investments beyond the work covered in this Plan HOBNI will contribute up to the maximum expansion cost cap of $90,000 per MW of connecting generator capacity established under the Distribution System Code. Any incremental expansion costs beyond the proposed cap are to be borne by the generator(s).

<u>Renewable Enabling Improvements</u> – these investments address modifications or additions to the main distribution system in order to accommodate increased levels of renewable energy generation. Renewable Enabling Improvement investments include the following:

- Modifications or additions to manage and control 2-way electrical flows or reverse flows (e.g. bidirectional reclosers, tap changer controls or relays, replacing breaker protection relays)
- Modifications to, or the addition of, electrical protection equipment.
- Modifications to, or the addition of, voltage regulating transformer or station controls.
- Provision of protection against islanding (transfer trip or equivalent).
- Design and installation of SCADA systems and telecommunication equipment.

Implementation of these Renewable Enabling Improvement investments will facilitate and streamline the connection of renewable energy generators by eliminating some of the technical limitations to the connection of new generation. In addition, Renewable Enabling Improvement investments will also dovetail with the development of the Smart Grid and this will ensure proper protection, automation and control measures are in place to facilitate the connection and operation of renewable energy generation.

4. Smart Grid Development

4.1. Smart Grid Strategy

HOBNI is taking a diligent and prudent approach towards its investment plans for Smart Grid. This is particularly important given the substantial cost and expert resources required to implement this relatively new concept using systems that have not been previously deployed. Additional complexities also arise due to the requirement that the Smart Grid enables the distribution system to accommodate larger volumes of distributed generation.

HOBNI has established five value drivers for the Smart Grid work:

1. Increased reliability,
2. Increased operations effectiveness,
3. Faster restoration,
4. Customer enhancement using smart meter/analytical tools to effect conservation and
5. Lower carbon footprint.

HOBNI's Smart Grid plan builds on the Ontario Government mandated foundations of an intelligent smart meter infrastructure, conservation and demand management ("CDM") implementation needs and the integration of renewable distributed generation into the distribution system.

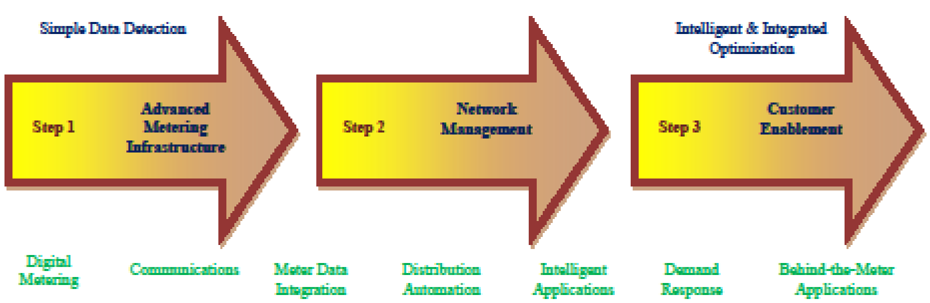
In order to understand how these smart grid value drivers can best be achieved, HOBNI will proceed with research and pilot projects to test new technologies and systems prior to recommending a corporate-wide deployment. The main objective of these initiatives is to innovate, test and prove new and emerging technologies. This will permit HOBNI to proactively define and implement measures that will eventually transform the current distribution system into a Smart Grid by making appropriate capital investments, asset solutions, standards and/or replacement strategies.

4.2. Smart Grid Planning

The evolution of HOBNI's system into a Smart Grid offers value to both HOBNI's generation and load customers. A smarter distribution system will enhance the reliability, security and power quality of the system through automation and enablement of increased amounts of cleaner, renewable distributed generation; it will allow for new conservation and demand management programs by improving load management and overall understanding of customer load profiles through innovative two way communication; and it will improve asset condition monitoring and trouble call responses with more accurate data and enhanced system controls.

HOBNI will be following a three step process to develop the Smart Grid long-term plan. The first step was to focus on system automation by leveraging the new communication infrastructure put into place for Smart Meters. The second step involves formulating plans to investigate, understand and prepare for new innovative technologies in the area of Network Management. The final step of the long-term plan will target studies in the area of green energy technologies such as automated home energy networks that will help in the enabling of the Smart Grid.

Evolution of the Smart Grid



4.3. Smart Grid Projects

4.3.1. Smart Meter Integration with OMS (2011)

In 2011, HOBNI plans on integrating the Smart Meter system with the OMS system. 'Last gasp' smart meter data will be transmitted from the Smart Meter system to the OMS system in real time, allowing the prediction engine in OMS to accurately pinpoint failed equipment on the distribution system. It will also allow the monitoring of meters and immediately advise HOBNI when tampering is occurring at the meter thereby reducing theft of power losses.

4.3.2. Feeder Automation Equipment

HOBNI continues to investigate and install automation equipment on our distribution feeders. We currently have auto transfer systems installed at the Bramalea City Centre, Shopper's World and in the downtown core.

In 2010 three new 46 KV Joslyn VBM switches will be installed at MS 19 as a pilot project. These remotely operable switches will replace existing air insulated manual equipment.

In 2011 new solid dielectric, remotely operable, sectionalizing switches will be installed at two underground vault installations in the downtown core. These units will allow for dynamic system load control as well as allow switching to be done safely above grade.

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4.4. Smart Grid Budget

Smart Grid Spending 2010 - 2015						
Description	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Smart Grid	$733,000	$750,000	$765,000	$780,000	$795,000	$812,000
Totals	**$733,000**	**$750,000**	**$765,000**	**$780,000**	**$795,000**	**$812,000**

Spending on the Smart Grid program is forecasted to 2015 and shown in the above table.

Appendices