hydro one

Stakeholder Consultation
2011/2012 Transmission Rate Application

March 2, 2010 Stakeholder Session
Meeting Notes

Sutton Place Hotel
Wellesley Room
955 Bay Street
Toronto

HAUSSMANN CONSULTING

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1. Background

Hydro One Networks Inc. is in the process of preparing its 2011/12 Transmission Rate Application for submission to the Ontario Energy Board (OEB) at the end of the first quarter of 2010 for rates effective January 1, 2011 and January 1, 2012.

Hydro One invited key stakeholders who participated in the previous Hydro One Networks transmission rate proceeding, other transmitters, IESO, OPA and OEB representatives to participate in two discussion sessions. The main objectives of this consultation program were to solicit stakeholder perspectives, ideas and concerns and to develop a shared understanding and prioritization of the key issues affecting the application, with an aim to resolving or reducing the scope of as many issues as possible prior to the OEB process. All consultation activities are carried out on a without prejudice basis.

Prior to engaging stakeholders in a discussion of the rate application, Hydro One sought stakeholder input at a consultation session held on November 16, 2009 regarding its response to the Ontario Energy Board (OEB) directive in its Decision With Reasons on Proceeding EB-2008-0272 (Hydro One's previous transmission rate application). This directive requires Hydro One to include in its next application:

1. A further analysis of the AMPCO "High Five" proposal on network charge determinants; and,
2. A suitable proposal for implementation for the Board's consideration in the event the Board decides to change the charge determinant.

This document reports on the second consultation session which took place on March 2, 2010. The overall goal was to inform stakeholders about the application, improve the quality and completeness of the pre-filed evidence, identify stakeholder issues and minimize the issues to be addressed at the OEB hearing.

1.1 Welcome and Introductions

Allan Cowan (Director, Transmission Applications) welcomed participants to the session and noted that the day's presentations would provide Hydro One's preliminary numbers for its 2011/2012 Transmission Rate Application which Hydro One intends to file with the OEB at the end of March 2010. Although there is always a possibility that these numbers will be adjusted in the course of finalizing the evidence and as a result of today's stakeholder input, what is being presented is indicative of the direction the filing will take. He noted that because the numbers are preliminary, hard copy handouts of presentations are not available during the session, but will be posted on Hydro One's web site subsequent to the meeting. Hydro One expects that oral hearings will take place late summer of 2010 and that the new rates will take effect in January of 2011 and 2012, using the OEB's latest cost of capital estimates and associated parameters. The filing will include a transmission Green Energy Plan.

Allan provided an update regarding stakeholder input at the November 16, 2009 session. After an extensive RFP process, a consulting contract will be awarded shortly to study AMPCO's "High Five" proposal on network charge determinants, as directed by the OEB. Hydro One expects that the consultant's study will be filed early summer 2010. In later discussion, it was noted that Hydro One expects to be able to file the consultant study in four months.

He provided an overview of the session agenda, thanked participants for their attendance and encouraged them to raise their concerns and questions and to provide their ideas. He then introduced Chris Haussmann as the facilitator for the session.

Chris Haussmann of Haussmann Consulting Inc. (HCI) asked participants to introduce themselves. In attendance were representatives from the Association of Major Power Consumers of Ontario, Association of Power Producers of Ontario, City of Toronto, Consumers Council of Canada, Energy Probe, Independent Electricity System Operator, Ontario Energy Board, Ontario Power Authority, Ontario Power Generation, Pollution Probe, Power Workers Union, Powerstream, Toronto Hydro, Union Gas, and Vulnerable Energy Consumers Coalition. Also present were Hydro One staff and the HCI facilitation team.

The full list of participants, together with the agenda, is provided in Attachment #1. Attachment #2 presents the more detailed questions and answers raised in the discussions that followed each of the presentations.

The following sections provide brief descriptions of the presentations made by Hydro One staff and a summary of the ensuing discussions. All meeting presentation slides are available on the Hydro One Regulatory Web site at: http://www.hydroone.com/RegulatoryAffairs/Pages/TxRates.aspx.

2. Transmission Green Energy Plan

Allan Cowan (Director, Transmission Applications) provided a brief overview of Hydro One's Transmission Green Energy Plan that will be filed with the 2011/12 Transmission Rate Application. The Plan will provide a strategic overview of Hydro One's response to the *Green Energy and Green Economy Act*, identify projects for which development work is currently underway and new projects that will be undertaken in 2011/2012, and address need determination for any projects that may require OEB approval to move ahead with construction. Hydro One's goal is to support the Ontario Government's green energy objectives by expediting the expansion of transmission capacity to facilitate renewable generation while providing responsible stewardship of ratepayer funds. Hydro One is considering requesting the inclusion of Construction Work In Progress (CWIP) in rate base treatment for four projects (Slide 7), following the guidelines set out in the OEB's January 2010 infrastructure investment report. Hydro One will provide the information required by the OEB to confirm the need for the projects and why CWIP treatment is being requested.

Randy Church (Manager, Major Project Co-ordination) then presented additional detail on Hydro One's Transmission Green Energy Plan. He pointed out that the development and construction timelines for major transmission projects are typically in the order of eight years – approximately five years for the planning and approvals phase and two to three years for construction (Slide 5). Given the lengthy timeline from identifying the need for a project and the in-service date, Hydro One has developed an aggressive Transmission Green Energy Plan as part of its filing. Based on information currently available and discussions with the Ontario Power Authority (OPA), Hydro One has identified priority projects for which development work has begun or is planned (Slides 6, 8). These include both stations and lines.

Naren Pattani (Manager, Transmission Planning) explained the need for the Toronto Short Circuit Uprate (Slide 6). The primary driver for the Hearn Station short circuit uprate is that Hearn has reached its end of life. In addition, its short circuit capability is not high enough to allow for the incorporation of distributed/renewable generation. Hydro One is therefore proposing to replace the Hearn Station with a Gas Insulated Station (GIS) that would be in service in 2012. The Leaside Station has circuit breakers that have reached their end of life and voltage transformers that need to be replaced, work which can be completed by the end of 2012. The Manby Station currently has spare short circuit capacity, but its circuit breakers are nearing their end of life and will be replaced by 2013.

2.1 Discussion Summary

Much of the discussion following this presentation focused on the planned distributed generation projects. It was clarified that:

- Distributed generation connection capacity in the Greater Toronto Area is limited to no more than 80 MW at this time. Uprating the Hearn and Leaside transformer stations would provide approximately 450 MW connection capacity in the eastern portion of Toronto. Completion of the Manby TS will provide an additional 270 MW connection capacity. Accelerating the uprating of these stations would be difficult.

- Nine options are being considered for the North-South Transmission Expansion, all within the Essa-Barrie-Claireville corridor. No new green field corridors are being considered.

- CWIP treatment is being considered for four projects – Northwest Transmission Expansion, Goderich Area Enabler, Algoma to Sudbury Transmission Expansion and Toronto Short Circuit Uprate (Slide 7). These projects have significant cash flows requiring financing, and many are green field projects that entail a higher degree of risk.

3. Export Transmission Service (ETS) Tariff Study & Recommendations

Nicholas Ingman (Manager, Government and Regulatory Affairs, Independent Electricity System Operator) provided an overview of the Independent Electricity System Operator's (IESO) Export Transmission Service (ETS) Tariff Study and its recommendations for an appropriate ETS charge for Ontario, which were filed with the OEB in August 2009. Hydro One subsequently notified the OEB that it intends to make the study part of the 2011/12 Transmission Rate proceedings. The ETS tariff has not changed since its inception in 1999.

Four ETS design and rate options were considered during the study (Slide 3). These included maintaining the status quo, equivalent average embedded network rate ($/MWh), reciprocal tariff treatment (mutual elimination of all ETS tariffs between jurisdiction and reciprocal treatment based on average embedded network cost in each jurisdiction, except for New York where it was eliminated), and unilateral ETS tariff elimination by Ontario (all hours and off-peak hours only). Consideration of the latter option was requested by stakeholders. The study also included discussions with neighbouring jurisdictions regarding reciprocal treatment of ETS tariffs, including tariff elimination, which with the exception of New York was not seen as a priority.

The study examined the potential impacts of the options on Hourly Ontario Energy Price (HOEP), export revenues, export/import volumes, Ontario market efficiency, air emissions, surplus base-load generation (SBG) events, reliability, operability, and the regulatory and legal implications (NAFTA, GATT).

The study came to the conclusion that Option 2 (equivalent average embedded network rate - $/MWh) best met the principles of simplicity, consistency with neighbouring rates, fairness and net benefit. The IESO recommends that the current $1.00/MWh ETS tariff be continued as Ontario's electricity sector navigates the transformation that is underway as a result of factors such as the *Green Energy and Green Economy Act* and changing economic conditions, or unless reciprocal tariff elimination agreements are reached with neighbouring jurisdictions and approved by the OEB.

3.1 Discussion Summary

Following this presentation, the AMPCO representative went on record to indicate that AMPCO does not support the continuation of the current $1.00/MWh ETS tariff and would cross-examine on this matter at the hearing. It is anticipated that there will be a panel on this issue at the hearing.

4. Transmission OM&A and Capital

George Juhn (Director, Sustainment Investment Planning) provided stakeholders with an overview of Hydro One's proposed Transmission OM&A and Capital expenditures for its 2011/12 Transmission Rate Application. He reviewed Hydro One's existing transmission system, which includes 281 transmission stations, 3,784 km of 500 kV transmission lines, 13,824 km of 230 kV lines, 10,953 km of 115 kV lines, and 46 km and 221 km of 230 kV and 115 kV respectively of underground cable located primarily in Toronto, Hamilton and Ottawa.

The key transmission OM&A and capital investment drivers include public/employee safety, reliability, regulatory and environmental compliance, system growth, and the *Green Energy and Green Economy Act* including the OPA's Feed-in Tariff (FIT) program. Transmission program expenditures take place under the following categories: Sustaining, Development, Operations, Shared Services (between transmission and distribution) and property taxes.

Transmission OM&A expenditures, excluding Shared Services, are projected to increase from $377 M in 2010 by 6% to $401 M in 2011and by 3% to $413 M in 2012. Details of the expenditure increases are provided in the presentation.

The most significant increase in OM&A expenditures is in the Sustaining category, which is required to ensure that existing lines and stations continue to perform as originally designed. Within this category, stations expenditures are projected to increase from historic most due to aging assets, more stringent Environment Canada PCB regulations, new cyber security measures, and system growth. The increase in OM&A expenditures on lines is driven by aging assets, the 500 kV circuits coming from northern Ontario and the Aeolian vibration problem in south-western Ontario that is damaging Hydro One's conductors.

OM&A expenditures in the Development category fund activities such as research and development, new standards and large project development work (which is charged to a deferral account), including approvals, in response to the *Green Energy and Green Economy Act*.

OM&A Operations expenditures are required to fund the ongoing operation and management of transmission assets through the Ontario Grid Control Centre (OGCC), the maintenance of operational support tools and systems, the management of relationships with transmission-connected customers, and environmental, health and safety activities. OM&A operations expenditures are projected to increase from by 2% in 2011 and by 3% in 2012.

Transmission Sustaining, Development and Operations capital expenditures are projected to increase by 13% from $1,064 M in 2010 to $1,197 in 2011 M and by a further 1% to $1,208 M in 2012.

Sustaining capital expenditures are required to replace or refurbish existing station and line components to ensure that the transmission system reliably functions as originally designed. The most significant increase from historic in sustaining capital expenditures is in stations. These increases are related to factors such as the replacement of 230 kV transformers, end of life station replacements at Beck 1 and protection, control & monitoring systems, as well as the need for enhanced site security as a result of copper theft from stations. The increase in line expenditures results primarily from the replacement of two underground cables in Toronto.

Development capital expenditures are required to upgrade or enhance system capabilities to, for example, meet Customer Delivery Point Performance (CDPP) standards, provide reliable supply to local areas and customers, ensure inter-area network transfer capability to connect supply to load centres, and to connect generation and load customers to the transmission system. The top five projects (Slide 17) include the Bruce to Milton line, the Mississagi Static VAR (volt –ampere reactive) Compensator or SVC, the Hearn Station rebuild, the Leaside to Bridgman line, and the Leaside and Manby Station improvements.

Operations capital expenditures are anticipated to increase significantly by 69% in 2011 and by a further 29% in 2012. Operations capital expenditures are required to maintain, and if necessary modify and expand the infrastructure related to the Central Transmission Operations function operated from the Ontario Grid Control Centre. Key factors driving Operations capital expenditures include the replacement of network management system components and installation of a wide area network driven by the need for increased bandwidth.

4.1 Discussion Summary

Discussion following this presentation clarified the following:

- CWIP treatment is being considered for the Hearn, Leaside and Manby projects and for the Bruce to Milton project.
- The Bruce to Milton project will contribute about 3.5% of the rate increase in 2011 and a lesser amount in 2012. It is proposed that this project be treated as if it were a partial in-service project whereby the full amount of dollars spent in 2010 plus half that spent in 2011would be in the 2011 rate base. 2012 rate base would include the full amount spent in 2011 and half of the amount spent in 2012.
- Hydro One purchasing decisions are driven by when materials or equipment are needed in place to meet in-service dates. With CWIP, Hydro One is taking a partial in service approach as is often done with staged projects where pieces of the same project are built, go into service, and provide a benefit at various intervals until the entire project is completed. This is not new; Hydro One is simply characterizing project elements as being partially in service, even though

technically they may not be functional. This is necessary because these are large projects that would strain Hydro One's borrowing capacity.

- CWIP treatment is similar to the notion of expensing interest, but recognizes that the Hydro One capital structure and investments are not 100% debt funded and therefore include an equity component.

- The Toronto short circuit uprate projects are reaching their end of life and would need to be replaced irrespective of a need for uprating.

- Projects with a capital requirement over $3M will be identified and an investment summary filed linking the project to benefits such as performance remedies.

- With Operations, Hydro One is currently at the high end of the capital spending cycle, much of which is driven by the wide-area network.

- The OM&A account includes R&D studies and standards development associated with normal development projects.

5. Preliminary Shared Services Costs

Stefanie Stocco (Manager, Regulatory Finance) provided an overview of Hydro One's Preliminary Shared Service Costs. Services shared across Hydro One's transmission and distribution businesses include Human Resources, Corporate Finance, General Counsel, Asset Management, Information Technology & Cornerstone, Facilities & Real Estate, Transport, Work & Service equipment, cost of sales related to external revenues, and other. Hydro One's shared services expenditures directly or indirectly support overall work program requirements and therefore generally tend to follow the same spending pattern. In general, the shared services OM&A and capital forecast expenditures for 2010 through to 2012 are consistent with the expenditures submitted in Hydro One's 2011/12 Distribution rate application.

Transmission shared services OM&A costs are projected to increase from $48 M in 2010 to $54 M in 2011 (Slide 3). The increase in facilities and real estate is driven by the need for field facilities, the requirement to secure leased office space in the GTA to support the increase in work programs and the need to make improvements at Hydro One's head office facilities, which are approaching their end of life. Common corporate functions and services are expected to increase to expand the HR work program to support additional hiring, enhanced graduate training and coaching programs driven by the growth in our core sustaining, development and operations (SDO) work programs and the rising number of retirements faced by Hydro One. The need to strengthen First Nations and Métis long-term relationship building, consultation processes and negotiation capabilities to support core SDO work programs and major green projects requested by our stakeholder are also driving these budget increases. The increased credits on the 'Other OM&A' line are consistent with the growth in Hydro One's capital program and reflect overheads capitalized/recovered.

Transmission shared services OM&A costs are projected to be $55 M in 2012 (Slide 3), essentially on par with the projected shared services OM&A costs in 2011. There is an increase in Common corporate functions and services in 2012, reflecting additional work requirements to support the major Green Energy Act projects requested by our shareholder. The increase also reflects new cost recovery charges from the National Energy Board. This is offset by a decrease in cost of sales in 2012. While trends from prior years are used to predict external work requests, the projected cost of sales in 2012 reflects the commitment of our internal resources to the execution of our growing work program.

Transmission shared services capital expenditures are projected to decline from $89 M in 2010 to $63 M in 2011 and $46 M in 2012 (Slide 4). The relatively high expenditures in 2010 reflect the growth in SDO work programs and our aging facilities infrastructure, which requires the acquisition, development or refurbishment of field facilities, and the planned improvement plan for Hydro One's head office facility, which is approaching its end of life.

Both the OM&A and capital shared services expenditures are generally consistent with those presented in Hydro One's recent Distribution application.

5.1 Discussion Summary

Two questions were addressed following the Shared Services presentation.

It was explained that Hydro One would be seeking alternative treatment as opposed to following International Financial Reporting Standards (IFRS), and as a result overheads would still be recovered in Rate Base.

With respect to the Hydro One pension, the Company is currently working with its actuaries and will be submitting a valuation prepared at December 31, 2009 to the Financial Services Commission of Ontario in September 2010. Accordingly, Hydro One will be seeking continuation of its pension differential deferral account as part of this application.

6. Preliminary Revenue Requirement

Stefanie Stocco (Manager, Regulatory Finance) provided an overview of Hydro One's Preliminary Transmission Revenue Requirement for 2011 and 2012 as well as the rate base and regulatory asset recovery calculations. For the 2011 test year (Slide 3), the cost of debt (60%) and equity (40%) is projected to be 5.51% and 10.16% respectively, resulting in a cost of capital of 7.37%. Applying the cost of capital against the rate base of $8,888 M yields a return on capital of $655 M. The cost of service includes $455 M in OM&A and $314 M in depreciation and amortization (Slide 5) and totals $769 M. Capital tax is being eliminated in 2010 and therefore is no longer included in OM&A. The preliminary revenue requirement is projected to be $1,512 M.

For the 2012 test year (Slide 4), the cost of debt (60%) and equity (40%) is projected to be 5.56% and 10.41% respectively, resulting in a cost of capital of 7.50%. Applying the cost of capital against the rate base of $9,876 M yields a return on capital of $741 M. The cost of service includes $470 M in OM&A and $345 M in depreciation and amortization (Slide 5) and totals $815 M. Capital tax is being eliminated in 2010 and therefore is no longer included in OM&A. The preliminary revenue requirement is projected to be $1,634 M.

The 2010 forecast (OEB approved) rate base is $7,636 M and is projected to increase 16% to $8,888M in 2011 and a further 11% to $9,876 M in 2012 due to work programs requiring asset growth and asset replacement (Slide 6). Growth in rate base is the primary driver of the revenue requirement in 2011 and 2012. The current forecast for the 2010 revenue requirement is $1,321 M , as compared to a preliminary revenue requirement of $1,512 M in 2011 (14% increase) and $1,634 M in 2012 (8% increase).

The rates revenue requirement (Slide 7) is derived by subtracting from the preliminary total revenue requirement the credits that accrue from external sources (export service credits, work performed for others, regulatory asset recovery) and adding the low voltage switch gear (LVSG) credit. This calculation results in a rates revenue requirement of $1,472 M for 2011 and $1,615 M for 2012.

The regulatory assets balances that Hydro One will request for recovery in 2011 and 2012 are based on regulatory assets as of December 31, 2009, plus forecasted interest (Slide 8). Regulatory asset categories that are taken into account include export service revenue, external revenue, pre-IPSP development costs and pension cost differential. The total regulatory asset value on December 31, 2009 is negative and represents a total customer refund of approximately $7 M. This value is driven primarily by credits for export services revenue ($5 M) and for external revenue ($8 M). These credits represent the excess (actual) above the OEB approved forecasts for these regulatory assets, as tracked in variance accounts. Pre-IPSP development costs and the pension cost differential were valued at $2 M and $3 M respectively. Hydro One is proposing a two year recovery period for the pre-IPSP development costs and the pension cost differential. However, for rate mitigation purposes and to minimize the impact of any rate increases on customers, Hydro One will be proposing that the export service revenue and external revenue credits be recovered in a single year (2011).

6.1 Discussion Summary

Following the presentation, questions resulted in the following additional information being provided:

- Transmission has a uniform province-wide rate unlike distribution, so no province-wide cost recovery mechanism is required;
- Hydro One is not seeking depreciation or amortization recovery on the CWIP of projects proposed to receive the CWIP treatment. The CWIP treatment results in recovery of the cost of capital only.
- 2010 base revenue requirement would be $1,257 M based on the Board's obsolete cost of capital methodology.

7. Transmission Cost Allocation and Rates

Mike Roger (Manager, Pricing) provided an overview of the major factors driving 2011 and 2012 rate increases, primary rate pools, asset and cost allocation, preliminary revenue requirement and charge determinants, and projected rates and their impacts. Details are found in the slide presentation on the Hydro One web site.

The major factors contributing to a 16.2% transmission rate increase in 2011 and a 9.8% increase in 2012 include a growth in assets, an escalation in OM&A costs, an increase in the cost of capital, a decline in load in both test years, and an increase in the Bruce to Milton line CWIP. Taxes decline and rate riders increase in both test years (Slide 3).

Hydro One's approach to cost allocation continues to use the four primary rate pools (Slide 4), as was the case in the 2009/2010 transmission filing. The network pool is paid by all transmission customers and includes the network portion of dual function lines and the generator portion of line and transformation. The line connection pool is paid by customers using transmission lines and related functions that are dedicated to one or a few customers, and includes the connection portion of dual function lines. The transformation connection pool is paid by customers using transmission station assets that step down voltage higher than 50 kV. The transmission meter pool is paid by customers who receive regulated meter service.

The gross book value (GBV) for Hydro One's transmission assets is allocated to the network, line connection, transformation connection and transmission meter pools. OM&A costs (excluding taxes) and depreciation costs are also allocated to the four rate pools (Slides 7 and 8).

"Other" revenue requirement costs (Slide 9) include asset removal costs (based on GBV), amortization (based on net book value), return on debt and equity (both based on rate base), taxes (based on rate base) and non-rate revenues (pro rated). These costs total $777 M and $875 M in 2011 and 2012 respectively. These costs are also allocated to the network, line connection, transformation connection and meter pools. This methodology is consistent with the approach taken in the 2009/2010 transmission rate filing.

Using Hydro One's proposed rates revenue requirement (Slide 10) and the 2011 and 2012 charge determinants for the four primary pools, and taking into account the revenue requirements and charge determinants of the other transmitters (Slides 11 to16), the projected uniform transmission rates (UTR) by rate pool are as follows (Slide 17): For Jan 1, 2010 (under motion), 2011 and 2012 the UTR is $3.13, $3.71 and $4.17 per kW/month respectively for the network pool; $0.77, $0.91 and $0.94 per kW/month for the line connection pool; $1.79, $1.95 and $2.08 per kW/month for the transformation connection pool; and, $7,000, $8,700 and $8,700 per meter point per year for the meter pool.

In order to project the impact of UTR by customer class (Slide 18), the commodity price and wholesale market service charge are assumed to be 6.2 cents/kWh (which includes the global adjustment) and 0.61 cents/kWh respectively (based on 2009 IESO data). As a result, and based on the 2010 UTR per the Hydro One motion before the Board, the projected 2011 UTR impacts on the transmission part of the bill are 18.3% 15.6% and 18.2% for directs, LDCs and generators respectively. For the total bill, the impacts are projected to be 1.5%, 2.0% and 2.0% respectively. The projected 2012 UTR impacts on the transmission part of the bill are 10.3%, 9.6% and 11.8% for directs, LDCs and generators respectively. On the total bill the impacts are projected to be 1.0%, 1.4% and 1.5% respectively.

7.1 Discussion Summary

The ensuing discussions elicited the following information.

- The transmission rate increase would be 22.3% for 2011 if Hydro One's motion for a revised return on equity is denied (i.e. based on an 8.39% ROE).

- Compared to the total preliminary Revenue Requirement of $1,512M, the preliminary rates Revenue Requirement of $1,472M includes a credit of $52M that accrues from external revenues and a low voltage switch gear (LVSG) charge of $12M for a combined credit of $40M. The same calculations apply to 2012.

- If Hydro One's ROE motion before the Board is not accepted, the 2010 UTR rates would be $2.97, $0.73 and $1.71 for network, line connection and transformation connection respectively (Slide 17). If the motion succeeds, Hydro One will seek to recover any increase over the balance of the year since January 15.

- The total bill impact of the UTR transmission rate increase on a residential customer would be approximately 1.2% in 2011 and 0.9% in 2012 (Slides 18 and 19).

A large part of the 1.4% increase built into the work programs is due to new regulatory requirements. And much of the 8.3% rate increase resulting from growth in rate base is in the development category, a large proportion of which have already received S.92 approval – their cash flows were seen in the last filing and many of these projects will come into service in 2011. Most of the increases depicted in Slide 3 are driven by external factors, such as load growth, green projects and the off-coal initiative directed by the Government.

8. Other Areas of Interest

Stakeholders were provided an opportunity to raise other issues at the end of the session.

8.1 Discussion Summary

The main issue discussed was the treatment of the Charge Determinants study to be filed later this year. It was determined that a likely course would be to hold a technical conference or entertain interrogatories on the study once it is filed, and before the rate application hearing. It was also noted that there may be a link between charge determinants and the revenue requirement, although this is unlikely for the 2011/2012 period.

With respect to the numbers presented today, there may be some minor adjustments related to the CWIP treatment, but this wouldn't have a major impact on the revenue requirement. There are very large capital expenditures for various projects, but many of these have already received S.92 approval. Green projects actually have very little impact on rate increases in the two test years, but eventually the impacts will be felt whether through a rate rider for development costs or a variance account.

9. Closing Remarks

Allan Cowan acknowledged that Hydro One had presented a very expensive work program and is sensitive to concern about rate increases. He noted that if the OEB does not approve the proposed program or cuts a program, Hydro One will not do the work and will reassess its priorities.

Hydro One will file its application on March 31. Allan thanked stakeholders for their participation and input, and noted that the presentations will be posted to the web site as soon as possible.

Chris Haussmann reminded participants to complete their Consultation Evaluation Form

The meeting adjourned at approximately 1 p.m.

10. Consultation Evaluation

Four completed Consultation Evaluation forms were submitted. A compilation of the results is found in Appendix 3.

In general, participants reported that:

- the consultation met their expectations;
- the presentations were clear;
- there was adequate opportunity to share their views; and,
- Hydro One was responsive to the issues raised and the questions asked.

Comments received also indicated that participants found the notes of the November 16 session to be thorough and true to the discussions that transpired.

Individual comments noted included:

- The presentations were well done
- Hydro One seemed to be well prepared
- Easier to track notes on slide handouts if given in advance
- It will be nice to see this on the web site
- Shared services presentation was a bit quick – may need more emphasis on rate drivers
- It shouldn’t take 3.5 months to issue and award and RFP
- Good meeting facilities

APPENDIX 1

AGENDA AND LIST OF PARTICIPANTS

Agenda
Stakeholder Consultation Meeting #2
Tuesday, March 2, 2010
Sutton Place Hotel (Wellesley Room)
955 Bay Street, Toronto

Registration and Continental Breakfast starting at 8:30 a.m.

AGENDA

9:00 a.m.	Introductions and Agenda	Chris Haussmann, Facilitator, Haussmann Consulting Inc.
9:15 a.m.	Opening Comments and Timelines	Allan Cowan, Director, Transmission Applications
9:30 a.m.	Green Energy Act Projects	Allan Cowan/Randy Church, Manager, Major Project Coordination
10:00 a.m.	IESO Export Transmission Service Rate	Nicholas Ingman, IESO, Manager, Government and Regulatory Affairs
10:30 a.m.	**BREAK**	
10:45 a.m.	OM &A Capital Expenditures	George Juhn, Director, Sustainment Investment Planning
11:45 a.m.	Shared Services	Stefanie Stocco, Manager Regulatory Finance
12:00 p.m.	**LUNCH**	
12:45 p.m.	Revenue Requirement	Stefanie Stocco, Manager Regulatory Finance
1:15 p.m.	Transmission Cost Allocation and Charge Determinants	Mike Roger, Manager, Pricing
2:00 p.m.	Other areas of interest	All
2:30 p.m.	Wrap-Up	Allan Cowan
3:00 p.m.	Adjourn	

LIST OF PARTICIPANTS

LIST OF PARTICIPANTS	Affiliation
Barr, David	Ontario Power Generation Inc.
Brooks, Jake	Association of Power Producers of Ontario
Burrell, Carl	Independent Electricity System Operator
Chow, Bob	Ontario Power Authority
Codd, Chris	Ontario Power Authority
Clark, Wayne	Association of Major Power Consumers of Ontario
Dade, Christine	PowerStream Inc.
Dubeski, Phil	Toronto Hydro-Electric System Ltd.
Gibbons, Jack	Pollution Probe
Girvan, Julie	Consumer Council of Canada
Grice, Shelley	Association of Major Power Consumers of Ontario
Harper, Bill	Vulnerable Energy Consumers Coalition
Ingman, Nicholas	Independent Electricity System Operator
Kwik, Judy	Power Workers' Union
MacIntosh, David	Energy Probe
McOuat, Martha	Ontario Power Authority
McMahon, Pat	Union Gas
Pasternack, Scott	City of Toronto
Richmond, David	Ontario Energy Board
Thiessen, Harold	Ontario Energy Board
White, Adam	Association of Major Power Consumers of Ontario
Winn, Glenn	Toronto Hydro-Electric System Ltd.
Young, Terry	Independent Electricity System Operator
HYDRO ONE	
Boland, Mike	Manager, Station Sustainment
But, Stanley	Manager, Economics and Load Forecasting
Cancilla, Enza	Manager, Public Affairs
Church, Randy	Manager, Major Project Co-ordination
Cowan, Allan	Director, Transmission Applications
Dumka, Bohdan	Senior Regulatory Advisor
Frank, Susan	Vice President and Chief Regulatory Officer
Juhn, George	Director, Sustainment Investment Planning
Malenfant, Jim	Senior Regulatory Advisor
Pattani, Naren	Manager, Transmission Planning
Power, Vicki	Advisor, Regulatory Affairs
Roger, Michael	Manager, Pricing
Stadnyk, Alexandra	Community Relations Officer
Stocco, Stefanie	Manager, Regulatory Finance
Vegh, George	McCarthy Tétrault LLP

APPENDIX 2

FACILITATED DISCUSSIONS

QUESTIONS AND ANSWERS

Answers are presented in italics

Transmission Green Energy Plan - Discussion

- According to the Navigant study filed at the recent Toronto Hydro hearing, only 80 MW of distributed generation can be installed in downtown and central Toronto due to short circuit constraints at Hydro One's Toronto stations. Is 80 MW the best case scenario?

  I can't vouch for the 80 MW. It is likely the best case scenario as long as the 80 MW are distributed properly around Toronto in the distribution system. (Naren Pattani)

- How much additional distributed generation beyond the 80 MW can be supported in downtown and central Toronto once the new Hearn Gas Insulated Station (GIS) is in service in 2012?

  Provided that Hearn and Leaside are both uprated, and remember we are talking about the east side of Toronto, we should be able to accommodate approximately 300 MVA to 500 MVA (up to about 450 MW assuming a 0.9 power factor) of new generation, depending on the type of generation, where the generation is connected, how close it is to the station, etc. (Naren Pattani)

- And how much additional distributed generation can be supported once the circuit breakers are replaced at the Manby Station in 2013?

  Approximately 200 MVA to 300 MVA (up to about 270 MW), depending on type of generation and where the generation is located. (Naren Pattani)

- Could Hydro One speed up the work at the Hearn, Leaside and Manby stations?

  With respect to Hearn, property and legal issues need to be addressed, which we believe will take six to twelve months to settle amicably. Building the new GIS station will take a minimum of two years to construct. So two and a half years is the best case scenario, and this would be quite a challenging and aggressive timeline. (Naren Pattani)

- I thought Hydro One owns the Hearn Station. So what are the legal issues?

  The intent is to continue operating the existing Hearn Station while we build the new GIS station on the adjacent property, which we do not yet own. There is goodwill among all the involved parties, so we do not anticipate great difficulty. (Naren Pattani)

- For which projects, and why, will Hydro One be seeking rate base treatment for projects under construction?

  Hydro One is considering requesting the inclusion of Construction Work In Progress (CWIP) in rate base treatment for four projects – Northwest Transmission Expansion, Goderich Area Enabler, Algoma to Sudbury Transmission Expansion and Toronto Short Circuit Uprate (Slide 7). We are looking at several options but a final decision has not yet been made, which is one of the reasons the numbers we are presenting today are preliminary. This issue is important because *some of these projects require financing significant cash flows, and some are green field projects and therefore are higher risk. (Allan Cowan)*

- With respect to the North-South line, how many transmission corridors are you considering from Barrie to the GTA?

  Nine options are being considered, but they are all in the existing corridor. We may widen the existing corridor, or put a new line between two existing lines, but there is only one corridor. We are not going to a green field corridor. (Naren Pattani)

- Is there not a corridor from Barrie to the Holland Junction Transformer Station?

  The primary corridor is from Essa to Barrie and from Barrie to Claireville, and does not pass through Holland Junction, which is a 230 kV junction on the 230 kV line from Claireville to Minden. So in terms of the corridors we are discussing for the planned activity for 500 kV North-South reinforcement, Holland Junction does not come into play. (Naren Pattani)

- But am I not correct in saying that you have a corridor from Barrie to Holland Junction?

  Yes we do, but that corridor is not capable of accommodating a new 500 kV line. (Naren Pattani)

- Could the Barrie to Holland Junction corridor be upgraded?

  It would require a lot of extension. We are not looking at this corridor as an option for the 500 kV corridor. (Naren Pattani)

- Have you considered going under Lake Ontario to feed Toronto?

  We are talking about bringing power from the north. So we are not considering lines under Lake Ontario. The lines are all overhead. (Naren Pattani)

Export Transmission Service (ETS) Tariff Study & Recommendations – Discussion

- AMPCO does not support the continuation of this subsidy – the continuation of the current $1.00/MWh ETS tariff. Expect cross-examination on this matter at the hearing.

- The study was undertaken by the IESO and received by Hydro One. What will the role of IESO and Hydro One be at the hearing with regard to the study? Will the IESO be participating on a witness panel?

  We will need to identify whether the study and its recommendations are an issue at this particular proceeding. Obviously the IESO will be prepared to support Hydro One in the submission of this particular piece of evidence. (Nicholas Ingman)

We anticipate there will be a panel to address this issue. (Allan Cowan)

Transmission OM&A and Capital – Discussion

- Are any of the projects on Slide 17 green? (Susan Frank)

  The Hearn, Leaside and Manby projects are green. (George Juhn)

- Is there CWIP treatment for these projects? (Susan Frank)

  We are considering the Hearn, Leaside and Manby projects for CWIP treatment. In addition, we are going to be requesting CWIP treatment for the Bruce to Milton project. (Allan Cowan)

- Isn't the Bruce to Milton project supposed to be in service in late 2012?

  That's correct. December 2012 is the latest projected in service date. But there are always issues when constructing a project of this size. We have never done a project like this in recent years. (Allan Cowan)

- When will we see the impact of the Bruce to Milton project on rates?

  The impact will be explained in more detail in Mike Roger's presentation, but about a 3.5% of the rate increase in 2011 will be driven by the Bruce to Milton project and a much smaller amount from a CWIP point of view in 2012. (Allan Cowan)

  We are going to request that what we spend on the Bruce to Milton project up to December 2010 be treated as if it were all in service at the end of the year – in other words, CWIP treatment. So 100% of those dollars would be in the 2011 rate year. We would also take half of the 2011 spend and include that in the 2011 rate year. So we are treating CWIP as if it was a partial in service type treatment. For the 2012 rate year we would include everything we spent in 2011 and half of what we spend in 2012. Bruce to Milton is the largest of our CWIP treatments even though it is not a green project although it has many of the same characteristics as green projects.

  We have been told to make sure this project is in service as soon as possible (originally 2011 and now 2012) so that when the new generation at Bruce comes online the transmission capacity is available to move the power. We are still waiting for some approvals (Niagara Escarpment), a significant risk factor. We entered into construction contracts and have pre-ordered and taken delivery of equipment and materials over the past 18 months so that we would be ready when we get all the necessary approvals. We took these initiatives because we thought we would start construction a year ago and as a result we have incurred and accumulated significant interest costs. CWIP allows us to put a stop to this. We expect to start construction in May on some of the parcels of land that we have acquired, which we can do even if the Niagara Escarpment approvals are not yet available. (Susan Frank)

- Does Hydro One plan to propose specific criteria for CWIP, for example the inclusion of prepayment for materials or equipment? As an intervenor I would want to be assured that Hydro One wasn't engaging in prepayments simply to get things on the books.

  We manage our projects in a prudent fashion and certainly don't do prepayments to increase the size of the rate base. Our purchasing decisions are driven by when we need to have materials or equipment in place to meet in service dates. We are taking a partial in service approach to CWIP – as if we had put in service what we have spent to date. It is a partial in service model, as is often done with staged projects where pieces of the same project are built, go into service, and provide a benefit at various intervals until the entire project is completed. So we are not proposing anything that is new or unusual or different from what is normally done with in service. We are simply characterizing project elements as being partially in service, even though technically they may not be functional. (Susan Frank)

- Have you considered alternatives to CWIP to help get you through the funding problem?

  Firstly, these are large programs and projects and would strain even Hydro One's borrowing capacity. Simply put, we need the cash. The OEB came up with the idea that there are ways of getting a bit more cash to help fund the infrastructure. Accelerated depreciation is a possibility, but we believe CWIP works best. (Susan Frank)

- The process of capitalizing interest ultimately hurts everybody. The reverse option of expensing interest has today's customers paying the interest, which may provide some relief.

  CWIP treatment is similar to the notion of expensing interest, but recognizes that our capital structure and investments are not 100% debt funded. Our (interrupted) Niagara Reinforcement build is becoming an issue. The direction we got was to expense the interest, which we are doing, but there is $100M sitting there and waiting, and this is also funded with equity. Only getting interest hurts our overall capital structure. So only having interest recovered is not appropriate, particularly when the solutions take many years. (Susan Frank)

- Is the Leaside to Bridgman line new or an upgrade? (Slide 17)

  It is to increase capacity. (George Juhn)

- Would you have to do the Toronto short circuit uprate projects anyway at some point in the future and with things like the North-South Bruce to Milton line coming in anyway?

  These Toronto stations are reaching their end of life so even if there wasn't a short circuit uprate issue, we would still need to replace these assets. The main driver for a short circuit uprate is the proximity of generation in the immediate area. So the North-South line does not drive these projects. (Naren Pattani)

- As was the case in your previous application, will there be a section in this filing that speaks to transmission business performance and how you identify outliers in terms of reliability, linked to descriptions of the projects that are proposed to address the outliers?

  Yes we will. The projects we will identify are those over $3M in cost. (George Juhn)

- Are you saying that if you have outliers in performance, it will cost you more than $3M to fix the problem?

  In some cases it can be very expensive. In others, we can fix the problem with sustainment type projects which may not cost that much, so these wouldn't make the threshold. (George Juhn)

- The operations capital expenditures increase more than eleven fold between 2007 and 2012 (Slide 19). Will this rate of increase continue after 2012?

  The Ontario Grid Control Centre was built in the late 1990s. The network management system was replaced in 2008 to 2010 and associated equipment now requires upgrading. Communication and bandwidth requirements have also increased. We are at the high end of the spending pattern, a key part of which is the wide area network. (George Juhn)

- You mentioned transformer failures earlier. Were these 230 kV transformers?

  They were 230 kV. (George Juhn)

Preliminary Shared Service Costs – Discussion

- There was no mention in your presentation of the International Financial Reporting Standards (IFRS). Does IFRS have any impact on your 2011 and 2012 capitalization projections?

  Our intent is to request alternative treatment when we file the transmission application. That means the status quo for this filing – you still will see overheads capitalized. (Stefanie Stocco)

- When does your next pension valuation take place and get reflected in the revenue requirement?

  We are working with our actuaries right now to perform a pension fund valuation as of December 31, 2009. We expect to go to our Board in August 2010 with the final valuation, following which it will be sent to the provincial authorities [Financial Services Commission of Ontario] in September 2010. In terms of treatment in our rate application, we intend to request a continuation of the pension differential deferral account. (Stefanie Stocco)

Preliminary Revenue Requirement – Discussion

- Is there a provincial cost recovery mechanism analogous to what happened in the distribution case?

Transmission already has a province-wide uniform rate. (Allan Cowan)

- Have you adjusted for CWIP in the cost of service depreciation and amortization number (Slide 4)?

  No. CWIP would be reflected in the rate base. We are not seeking any depreciation recovery on CWIP. CWIP treatment is just for cost of capital. The OEB has indicated it is not expecting any depreciation or amortization on CWIP. (Stefanie Stocco, Allan Cowan, Bohdan Dumka, Susan Frank)

- You show your current forecast for the 2010 revenue requirement as $1,321M in Slide 7. What would the 2010 revenue requirement be if you had used the OEB approved value based on your last rate proceeding?

  It would be $1,257, M based on the old (November 2009) return on equity. (Stefanie Stocco, Mike Roger)

Transmission Cost Allocation and Rates – Discussion

- Are you talking about rates or revenue requirement in Slide 3?

  This slide refers to the increase in rates over 2010 and assumes a return on equity (ROE) of 9.75% in 2010, and 10.16% and 10.41% in 2011 and 2012 respectively. The ROE will be adjusted as we get closer to implementing rates, consistent with OEB policy. (Mike Roger, Allan Cowan)

- Have you calculated what the percentage rate increase would be for 2011 if you don't get your motion?

  It would be 22.3% for 2011 versus the current approved revenue requirement, which was based on 8.39% ROE. (Mike Roger, Allan Cowan)

- Has your cost allocation changed at all?

  No it has not. We have updated the values but we continue to use the same methodology as in our 2009/2010 transmission filing. (Mike Roger)

- *Slide 10 shows a preliminary rates revenue requirement of $1,472.1 M in 2011. Slide 3 in the previous presentation Stefanie Stocco on preliminary revenue requirement shows a revenue requirement of $1,512 M for 2011. Please explain the difference. (Susan Frank)*

  Stefanie's Slide 3 shows a revenue requirement of $1,512 M for 2011. Her Slide 8 starts with this same number and then subtracts a $52 M credit that accrues from external sources (export service credits, work performed for others, regulatory asset recovery) and adds the low voltage switch gear (LVSG) credit of $12 M. This calculation results in a rates revenue *requirement of $1,472 M, which is the same number as on Slide 10. The same calculations apply to 2012. (Mike Roger, Stefanie Stocco)*

- Can you give us the numbers if the motion fails?

  If the motion fails, the values would be $2.97, $0.73 and $1.71 for network, line and transformation respectively. (Mike Roger)

- What is the impact on end use residential customers (Slide 18 and 19)?

  The total bill impact on a residential customer would be approximately 1.2% in 2011 and 0.9% in 2012. (Mike Roger)

- Please go back to Slide 3 on major contributors to the rate increase. How many of these factors are driven by an existing OEB decision or other requirements? In other words, how many of these factors have any flexibility? (Susan Frank)

  In terms of the OM&A, very little is flexible. A large part of the 1.4% increase built into our work programs is attributed to new work programs, e.g., PCBs. (George Juhn)

  Much of the 8.3% growth in assets is in the development category and 95% of these projects have already received S.92 approval – their cash flows were seen in the last filing and many of these projects will come into service in 2011. (Naren Pattani)

  Much of what you see on Slide 3 is driven by external factors and not within Hydro One's control – for example, changes in load growth, the off-coal initiative, etc. (Debra Vines)

Other Areas of Interest – Discussion

- If the motion is passed, will you take the balance of the increase over this year?

  Yes, part of the OEB decision declared the rates as interim as of January 15, so we will be seeking to recover any increase over the remainder of the year. (Allan Cowan)

- You said you expect to file March 31. When do you expect to file the results of the charge determinants study ("High Five")?

  Assuming that we are able to engage a consultant in the next week or so, we expect it will take about three months to carry out the study, followed by a couple of weeks to prepare draft and final reports. So we expect it will be about four months from now that we file the study. (Mike Roger)

- Sounds like you will be crossing over into the interrogatory phase. You may have to allow for some supplementary interrogatories (IRs) on the report.

We may, but the study deals with charge determinants and doesn't affect the revenue requirement, which can be dealt with independent of this study. We would like to deal with both items at the same time, but we don't want to rush the consultant and want him to take the time to do the proper analysis. (Mike Roger)

In terms of process, do you think you will need more IRs or perhaps a technical conference? (Susan Frank)

- It might be a bit of both. If we get a report during the interrogatory phase or just after, a technical conference and maybe a short opportunity for written interrogatories may be needed. We don't expect it will be a huge body of evidence, so it won't take weeks to generate interrogatories. Given the effort everyone has put into this, we will want a wholesome process. So we will have to entertain something.

What is the OEB's normal approach in this kind of situation? (Susan Frank)

- It depends. What is being suggested seems a reasonable approach. You want to give intervenors a reasonable chance to look at the study and get questions answered. Perhaps that can be done through a transcribed technical conference. If more detailed questions and answers are required, perhaps interrogatories are more appropriate. Until we see the study, it is hard to know what the best solution is.

- I'm not sure you can say that charge determinants are completely severable from the revenue requirement. It depends on the rationale for changing the billing determinants, which leads back to the rationale for investment decisions.

For 2011 and 2012, I doubt that we would see any changes in the work program based on a change in the charge determinants. I don't think they are linked in the period we are talking about in this filing. (Susan Frank)

- I am simply saying that you shouldn't preclude that there may be some link between charge determinants and revenue requirement. If the recommendation were that there is a link why not test the link with people that do the investment planning.

In terms of the capital plan for 2011/12, it is difficult to see how any change in charge determinants would have an impact. Most of the projects we have presented today have either already received OEB approval or are already underway. (Naren Pattani)

- Hydro One has presented preliminary numbers today. When can stakeholders expect to see these presentations on the Hydro One web site, and are they likely to see any changes from the numbers presented today? (Chris Haussmann)

There may be some minor adjustments in certain areas, largely with respect to how we decide to proceed with CWIP treatment. This wouldn't have a major impact. As the presentations have *indicated, there are very large capital expenditures for various projects which for the most part have already received S.92 approval. Green projects actually have very little impact on rate increases in the two test years. Even if we were to request full CWIP recovery, the impact on rates would be relatively small. And we are looking at methodologies that may reduce this increase even further. (Allan Cowan)*

- Will Hydro One post preliminary or final numbers on its web site for stakeholders, and by when? (Chris Haussmann)

  We can post the preliminary numbers if stakeholders are happy with that, or final numbers but that depends on how soon stakeholders want it. (Allan Cowan)

- What would stakeholders prefer? (Chris Haussmann)

  The preliminary numbers are close enough, so the sooner the better.

- So sometime later this week? (Chris Haussmann)

  Yes. (Allan Cowan, Enza Cancilla)

- *The expenditures on green development costs are proposed to go into a deferral account, so there will be no rate impact in the two test years. That will be coming in the subsequent years when we seek recovery. The only development-related expenditure we will be seeking recovery for is $2 M in pre-IPSP development costs. (Allan Cowan)*

- With respect to all the deferral accounts, the total is significant – perhaps over $30 M. You might want to consider variance accounts to avoid or at least minimize rate impacts and rate shock in future years.

  Either way, it is just a matter of timing as to when the impact is felt. Another option would be to use a variance account and request a rider for development costs. (Susan Frank, Allan Cowan)

- When development costs were discussed in the presentation on Transmission OM&A and Capital presentation (Slide 9), where did non-green, development costs for "normal" projects get allocated? They aren't going into a deferral account and I don't see them in OM&A, which seems to be all about standards and admin.

  The OM&A account includes R&D, studies and standards development associated with normal development projects. The shared services account includes asset management related to normal development projects. The design and specifics around the projects get charged to the project. (George Juhn)

APPENDIX 3

CONSULTATION EVALUATIONS

2010/2011 Distribution Rate Application Consultation Session # 2 Stakeholder Feedback

The data below represents the number of participants that circled the corresponding response. The total number of surveys returned was 4.

1. The information presented was clear:	Strongly Agree	Agree	Disagree	Strongly Disagree	Not Applicable/ No Response
Green Energy Act Projects	2	2			
IESO Export Transmission Service Rate	1	3			
OM&A and Capital Expenditures	3	1			
Shared Services & Revenue Requirement	3				1
Transmission Cost Allocation & Charge Determinants	2	1			1

2. I had adequate opportunity during this session to share my views with Hydro One on:	Strongly Agree	Agree	Disagree	Strongly Disagree	Not Applicable/ No Response
Green Energy Act Projects	1	3			
IESO Export Transmission Service Rate	1	3			
OM&A and Capital Expenditures	1	3			
Shared Services & Revenue Requirement		4			
Transmission Cost Allocation & Charge Determinants	1	3			
COMMENT	Overall numbers (aggregate) were skipped over rather quickly.				

3. Hydro One responded to the issues and recommendations I raised about:	Strongly Agree	Agree	Disagree	Strongly Disagree	Not Applicable/ No Response
Green Energy Act Projects	2	2			
IESO Export Transmission Service Rate	2	2			
OM&A and Capital Expenditures	2	2			
Shared Services & Revenue Requirement	2	2			
Transmission Cost Allocation & Charge Determinants	2	2			

4. Overall, this consultation session met my expectations:	Strongly Agree	Agree	Disagree	Strongly Disagree	Not Applicable/ No Response
Responses	2	2			

5. The notes of the first meeting held November 16, 2009 were thorough and captured the essence of the discussions:	Strongly Agree	Agree	Disagree	Strongly Disagree	Not Applicable/ No Response
Network Charge Determinants	2	1			1
Northwest Transmission Expansion	2	1			1

Additional Comments:

- It will be nice to see this on the web site. I would also have liked a handout of the presentation as I could have made notes directly on the slides that were applicable
- Easier to track notes on slide handouts if given in advance
- Shared services presentation was a bit quick – may need more emphasis on rate drivers
- Good meeting facilities
- It shouldn't take 3.5 months to issue and award and RFP
- Generally, presentations were well done and Hydro One seemed to be well prepared.