BORDEN
LADNER
GERVAIS

Borden Ladner Gervais LLP
Lawyers • Patent & Trade-mark Agents
World Exchange Plaza
100 Queen Street, Suite 1100
Ottawa ON K1P 1J9
tel.: (613) 237-5160 fax: (613) 230-8842
www.blgcanada.com

By electronic filing and by e-mail

February 5, 2010

PETER C.P. THOMPSON, Q.C.
direct tel.: (613) 787-3528
e-mail: pthompson@blgcanada.com

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th floor
Toronto, ON M4P 1E4

Dear Ms Walli,

Hydro One Networks Inc. ("Hydro One")
2010 and 2011 Distribution Revenue Requirement and Rate Application
Board File No.: EB-2009-0096
Our File No.: 339583-000044

Please find attached the Written Argument of Canadian Manufacturers & Exporters ("CME") in this proceeding.

Paper copies will follow shortly.

Yours very truly,

Peter C.P. Thompson, Q.C.

PCT\slc
enclosure
c. Hydro One
Paul Clipsham (CME)

OTT01\3933954\1

EB-2009-0096

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

AND IN THE MATTER OF a review of an application filed by Hydro One Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution for 2010 and 2011.

ARGUMENT OF
CANADIAN MANUFACTURERS & EXPORTERS ("CME")

February 5, 2010

Borden Ladner Gervais LLP
World Exchange Plaza
100 Queen Street
Suite 1100
Ottawa ON K1P 1J9

Peter C.P. Thompson, Q.C.
Vincent J. DeRose
Counsel for CME

TABLE OF CONTENTS

I. OVERVIEW AND CONTEXT 1

A. The Challenge facing the Board 1

1. Introduction 1

2. Balancing Conflicting Objectives 1

3. Need for a Disciplined and Integrated Approach 2

B. Responding to the Challenge 4

1. Adopt Economic Feasibility Criteria Suitable for the New Era 4

2. Empirically Determine a Measure of Affordability and Tolerance 6

3. Adopt Integrated Multi-Year Total Price and Bill Impact Analysis Rules 9

4. Apply Forward-Looking Integrated Multi-Year Total Price and Bill Impact Analysis to Constrain Spending within the Limits of Affordability and Tolerance 14

5. Monitor and Publish Multi-Year Rolling Total Price and Bill Impact Analysis 15

C. CME's Response to Hydro One's Application 16

II. CONSUMER IMPACTS AND REASONABLENESS OF REVENUE REQUIREMENT INCREASES IN 2010 AND 2011 17

III. GREEN ENERGY PLAN AND CRITERIA TO APPLY 32

IV. LOAD AND REVENUE FORECAST 37

1. Conservation and Demand Management Forecast 37

V. OPERATIONS, MAINTENANCE AND ADMINISTRATIVE ("OM&A") COSTS 38

1. Overview 38

2. Trend Analysis 39

3. Cost per Customer Benchmark 40

4. Cost per Circuit Km Benchmark 40

5. Inflation 41

6. Compensation 41

7. Vegetation Management 44

8. Other Concerns 45

9. Appropriate Ceiling for OM&A Expenses 45

VI. CAPITAL EXPENDITURES AND RATE BASE 47

1. Overview 47

2. Hydro One’s Proposed Capital Expenditures Materially Exceed Historic Spending 47

3. Other Concerns with Hydro One’s Capital Budgets 48

4. How Much Of Hydro One’s Capital Budget Should The Board Disallow? 49

VII. CAPITAL STRUCTURE AND COST OF CAPITAL 50

VIII. DEFERRAL AND VARIANCE ACCOUNTS 55

1. Disposition of Regulatory Assets 55

2. New Regulatory Asset Accounts 56

IX. COST ALLOCATION AND RATE DESIGN 57

1. Hopper Foundry 57
2. Cost Allocation and Density Relationship 60
X. IMPLEMENTATION DATE CHANGE 62
XI. COMMUNICATION OF DECISION 62
XII. HYDRO ONE'S DIRECT BENEFITS DETERMINATION PROCESS PROPOSAL 64
XIII. COSTS 64

I. OVERVIEW AND CONTEXT

A. The Challenge facing the Board

1. Introduction

1. The greening of Ontario's integrated power system exposes the Ontario economy to material risks if regulators do not carefully control the transition in an integrated manner. In the absence of appropriate spending constraints, there is a real risk of creating an overbuilt power system at an exorbitant cost. In combination with the very high prices that the Ontario Power Authority ("OPA") is agreeing to pay for renewable energy and the large amounts of money that are being directed towards conservation and demand management ("CDM"), an overbuilt power system will produce prices for electricity in Ontario at levels that will likely be intolerable for many consumers. Absent an integrated and disciplined approach to the greening of Ontario's integrated power system, there is a material risk of consequential and irreparable harm to Ontario's economy.

2. The Ontario Energy Board should control and regulate the greening of Ontario's electricity system in a way that minimizes the risk of irreparable harm to the Ontario economy. The challenge facing the Board is to establish criteria that can be applied to determine, from year-to-year, the level of combined traditional and *Green Energy and Green Economy Act* (the *"GEA"*) spending by utilities in a measured way so that the transition to an integrated power system that accommodates renewable generation does not materially contribute to economic turmoil.

2. Balancing Conflicting Objectives

3. There are five statutory objectives that guide the Board in carrying out its responsibilities under the *Ontario Energy Board Act, 1998*, as amended, (the *"OEB Act"*) and any other *Act* in relation to electricity. One of these objectives, added by the provisions of the *GEA*, is:

> *"To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission*

systems and distribution systems to accommodate the connection of renewable energy generation facilities."

Another is to exercise its regulatory authority in a way that protects the interests of consumers with respect to electricity prices. The Board's role in managing and minimizing the risk that the greening of Ontario's electricity system poses to the Ontario economy cannot be performed without according a high priority to this price protection statutory obligation. Because of the extraordinarily high costs associated with the greening of Ontario's integrated power system, the Board is faced with balancing these conflicting objectives in a manner that avoids harm to Ontario's economy.

3. Need for a Disciplined and Integrated Approach

4. To balance these conflicting objectives, the Board needs to develop and apply measures that will operate to constrain, within the limits of reasonableness, the system expansion, system enhancement, and embedded generation initiatives the Government of Ontario is striving to achieve through OEB regulated utilities, including the electricity utilities and other entities the Ontario government owns and controls, such as Hydro One, Ontario Power Generation Inc. ("OPG"), OPA, and the Independent Electricity System Operator ("IESO"). We submit that granting regulatory approvals for all of the transmission and distribution systems enhancements and expansions needed to accommodate all of the renewable energy potential that exists, including, for example, the possibility of solar panels on every roof in Ontario, will inevitably lead to intolerable electricity prices and a consequential economic crisis. Yet, that outcome is conceivable if the Board does not impose constraints to control and discipline spending on such measures.

5. In its December 18, 2009 Draft Filing Requirements for Distribution Plans under the *Green Energy Act*, the Board recognizes that an integrated approach is critical and that:

> *"Coordinated planning among distributors and transmitters and the Ontario Power Authority (the "OPA") will be essential in achieving the goals of the GEA in a timely and cost effective manner."* (emphasis added)

We wholeheartedly agree and submit that the regulation of these coordinated plans on an integrated basis is equally essential. In the absence of the regulation of these spending plans on an integrated basis, there is a real risk of creating an overbuilt power system at an exorbitant cost.

6. The need for controls on utility spending, in order to protect the interest of consumers with respect to electricity prices, is now more acute than it was previously because of the material price increases that result from applying the Board's recently issued Cost of Capital Guidelines. These Guidelines, as well as the approach the Board has adopted in its January 15, 2010 Report pertaining the regulatory treatment of infrastructure investment will operate to materially increase rates and electricity prices in those rate cases in which those guidelines are applied.

7. We submit that controls on spending are vital because those managing the utilities the Board regulates are essentially indifferent to the impact that their spending plans have on electricity consumers. The assertions by those who manage Hydro One that they have an acute sensitivity for the impact that utility spending plans have on electricity consumers are lacking in credibility. Actions speak louder than words, and the actions of those who manage Hydro One demonstrate an indifference to consumer impacts.[1]

8. An agency responsible for exercising its statutory authority in a manner that protects consumers with respect to electricity prices cannot discharge that obligation without monitoring the "all in" electricity prices that consumers pay. This is axiomatic and calls for the agency to monitor the effects of all factors that influence all elements of the "all

[1] According to its witnesses, Hydro One does not conduct "all in" electricity distribution, transmission and energy commodity charge increases that is likely to result from the connection of more and more renewable generation to its system upon which its spending plans are based. Apparently, neither its management nor its Board of Directors are aware of the likely outcome of the planned activities. This, coupled with its responses to the many emotional letters of comment the Board received in response to the Notice of Application in which Hydro One appears to attribute to responsibility for bill increases to the Board, demonstrates the indifference of Hydro One to consumer impacts; and
Transcript, Vol. 2, p. 153, line 21 to p. 154, line 17; p. 156, line 27 to p. 157, line 20; and
Board Staff Submissions, pp. 4 and 5.

in" prices. The fact that the Board may not control all of the elements of "all in" electricity prices does not relieve it from considering both the direct and indirect implications that its actions and the actions of others are likely to have on each of the elements of the "all in" price. The Board's price protection objective under section 1, paragraph 1 of the *OEB Act* cannot be achieved without the adoption of an integrated approach to total price and bill impact analysis.

B. Responding to the Challenge

1. Adopt Economic Feasibility Criteria Suitable for the New Era

9. In addition to considering traditional economic feasibility criteria, including need, cost benefit analysis and work force capability in the context of historic spending levels, the extraordinary spending related to the greening of Ontario's power system needs to be confined to spending levels that produce prospective annual and multi-year total price and bill increases that are affordable and tolerable. Spending levels that produce annual and multi-year total price and bill increases that are not affordable and are intolerable are neither economically feasible nor prudent. Accordingly, such spending levels should not be approved.

10. In this context, we submit that the Board needs to adopt a new regulatory tool to estimate and measure, on an integrated basis, the annual and multi-year total price and bill increases that are affordable and tolerable and unlikely to cause material harm to the Ontario economy. This measurement tool can then be applied to evaluate and, if necessary, constrain the annual spending plans of the entities the Board regulates and thereby minimize and ideally avoid the risk of irreparable harm to Ontario's economy.

11. The integrated multi-year total price and bill impact measurement tool we envisage should be applied to the various entities the Board regulates to evaluate the economic feasibility and prudence of their spending plans. This type of evaluation should be

applied in order to manage the pace of the transition to the integrated power system end-state the provincial government is attempting to achieve in a way that avoids material economic harm.

12. There are two critical elements in this economic feasibility and prudence criterion we envisage. The first is a determination of the sensitivity and tolerance of the Ontario economy to electricity price increases over 5, 10, 15 and 20 years. The second is the adoption of an integrated and forward looking multi-year total price and bill impact analysis that reflects all of the elements of the total price and bill that consumers of electricity currently receive.

13. This forward looking integrated multi-year total price and bill impact model should reflect the following:

    (a) The impact on regulated distribution and transmission charges of the annual and multi-year spending plans of the utilities the Board regulates;

    (b) The estimated impact on energy charges in the bill of the expected gradual transition to expensive electricity generated by the renewable generation resources contemplated by the plans the Board is asked to approve; and

    (c) Estimated changes in other energy charges in the bill that the Board either controls or influences, such as,

        (i) OPG regulated charges for electricity,

        (ii) Amounts charged by the OPA and IESO,

        (iii) The province-wide *GEA* charge,

        (iv) The special charge yet to be authorized calling for payments to the Ministry of Energy to fund its CDM programs.

14. The Board sets the regulated rates of OPG and, as a result, has access to prospective year and multi-year forward looking estimates of OPG's regulated charges. The Board

also regulates amounts that the OPA and the IESO charge for the services they provide.[2] In an exercise of that power, the Board can require the OPA and IESO to provide prospective year and multi-year forward looking information on the likely increases in energy charges that will occur as a result of the gradual acquisition of more and more electricity from renewable electricity generators who have been, and will likely be, connected to the power system by virtue of the Board's approval of spending plans presented by the transmission and distribution utilities it regulates. The OPA, IESO, distributors and transmitters are the parties that must engage in the coordinated planning that is essential to achieving the goals of the *GEA* in a timely and cost effective manner. Separately and in combination, these parties have the information in their possession that is needed to produce a reliable estimate of total price and bill impacts over the five year planning horizon.

15. Because of its authority over these parties, the Board is in a position to direct the preparation and presentation of information that is needed to complete an integrated multi-year total price and bill impact analysis covering all elements of the "all in" electricity prices consumers pay. If an integrated multi-year total price and bill impact analysis indicates that the limits of affordability and tolerance are being exceeded, then approvals for the total level of spending requested should not be granted. Approvals should only be granted for a total level of spending that falls within the limits of affordability and tolerance.

2. Empirically Determine a Measure of Affordability and Tolerance

(a) Tolerance under Existing Rules

16. In its 2006 Electricity Distribution Rate Handbook ("2006 Rate Handbook") Report dated May 11, 2005, the Board establishes 10% as the maximum total annual bill increase that

---

2 The IESO's proposed fees revenue requirements for 2010 are currently under consideration in EB-2009-0347. The OPA's proposed fees revenue requirements for 2010 are currently under consideration in EB-2009-0377.

is tolerable. This 10% tolerance limit appears to date back to the initial Rate Handbook the Board established on or about May 13, 2000. The rationale for determining that a 10% per annum total price and bill impact is the appropriate tolerance level is not specified in the 2006 Rate Handbook Report or the earlier Rate Handbook.

17. The ability of different sectors of the economy to tolerate total bill increase of 10% per annum likely varies. For example, in the difficult economic circumstances that currently prevail, the manufacturing sector is likely to be materially harmed if faced with total electricity bill increases over the next five years in an amount, on average, of 10% per annum. The manufacturing sector, which is critical to the economy, is very dependent on electricity and, as a result of the recession, is currently in an economically fragile state. Granting total bill increases at a level that causes material harm to Ontario's manufacturing sector will irreparably harm the Ontario economy. For these reasons, it should no longer be assumed that a total bill impact of 10% per annum is tolerable and affordable. Rather, the Board should either require the utilities it regulates to provide, or itself commission, empirical studies of the sensitivity of the Ontario economy to electricity price level increases so that the appropriateness of a 10% per year tolerance level can be properly tested and evaluated in a public hearing.

(b) <u>Study Sensitivity of Ontario Economy to Electricity Price Increases to Establish Realistic Tolerance and Affordability Limits</u>

18. We are unaware of any studies that demonstrate that a 10% per annum increase in the "all in" prices of electricity, or, put another way, a doubling of such prices over 10 years is either affordable or tolerable. We reiterate that a key factor in determining affordability and tolerance is a skilled empirical evaluation of the overall impacts on the Ontario economy of various levels of increases in the "all in" electricity price. Questions that should be considered in such studies include the following:

(a) What is the likely impact on the Ontario economy of a doubling of the "all in" price for electricity in 10 years or less?

(b) What is the likely impact on the Ontario economy of an "all in" electricity price increase that only doubles in 15 or 20 years?

19. Without having an appreciation of the sensitivity of the Ontario economy to various electricity price increase levels at 5 year intervals over the next 20 years, the Board cannot discharge its statutory obligation to protect consumers with respect to electricity prices.

20. We are aware that some studies of the dollar impacts of the greening of Ontario on electricity prices have already been done. For example, we are aware of a study released on April 30, 2009 by London Economics International LLC ("London Economics"), a firm that the Board has retained on a number of occasions for expert advice. This report indicates that *GEA* initiatives could cost up to $46B over the next 15 years.[3] Now that the spending plans by large distribution utilities, including Hydro One, and the transmission spending plans of Hydro One are more defined, these estimated costs have likely escalated. We say that because when one considers the measures recently adopted by the Board, such as increases in the allowances for equity and debt returns and apparent permission to now include Construction Work-In-Progress ("CWIP") in Rate Base and to accommodate other special investment measures, there is little doubt that cost estimates based on circumstances that existed in April 2009 will now be low.

21. Studies of the type we propose, tested on the public record, will provide an indication of the sensitivity of various sectors of the Ontario economy to the rapidly increasing

---

[3] See Study by clicking on link below.
http://www.londoneconomics.com/pdfs/Potential%20cost%20implications%20of%20Green%20Energy%20Act%20-%20final%20version.pdf

electricity prices that will result from the greening of Ontario's integrated power system. Such studies will reveal the sensitivity of the Ontario manufacturing sector to exponential increases in electricity prices that are implemented too quickly.

22. Armed with information pertaining to the probable economic impacts of various levels of increase in electricity prices, the Board can establish the tolerance and affordability level that is to be used in conjunction with the results of an integrated multi-year total price and bill impact analysis to maintain the levels of spending within affordable and tolerable limits and thereby prevent material harm to the Ontario economy.

3. <u>Adopt Integrated Multi-Year Total Price and Bill Impact Analysis Rules</u>

(a) <u>Deficiencies in Existing Rules</u>

23. The electricity pricing situation in Ontario has materially changed since the Board released its Rate Handbook Report in May 2005. The utility-specific total bill impact analysis rules contained in that Rate Handbook are no longer appropriate because they do not reflect the passage of the *GEA* and the many other government of Ontario initiatives that have occurred since 2005.

24. We consider existing total bill impact rules to be inappropriate because they evaluate price and bill impacts by only considering the requested increase for charges that comprise about 30% of the total bill. All other elements of the bill are held constant. For example, a 20% increase on 30% of a bill, with other elements thereof held constant, produces a so-called "total bill" increase of 6%. The phrase "total bill" to consumers means all elements charged in the bill. A bill analysis of 30% of the total bill, while holding other elements constant, is not a "total bill" analysis. It is a "partial bill" analysis.[4] When it is known that the other elements of the bill will not remain constant but will increase at a pace considerably greater than zero, it is misleading and inappropriate to

4 Transcript, Vol. 2, p. 155, line 18 to line 28.

characterize a "partial bill" analysis as a "total bill" analysis and to rely on the results of a partial bill analysis as if it were a "total bill" analysis. We submit that a prudent planner does not continue to apply rules and procedures when it is known that the results they are producing are misleading.

25. The elements of the bill that currently produces the "all in" prices that electricity consumers pay include the following:

(a) Regulated transmission charges;

(b) Regulated distribution charges;

(c) Energy charges that include a Global Adjustment/Provincial Benefit amount consisting of 4 items:

(i) OPA costs;

(ii) Ontario Financial Services Corporation ("OFSC") charges;

(iii) OPG's Regulated Energy Price; and

(iv) Market price/regulated energy price variance charge or credit;

(d) Regulated province-wide recovery charge related to the portions of the *GEA* planned costs of the distributors the Board regulates not directly of benefit to the customers of the particular distributor making the investment; and

(e) A special charge, yet to be authorized, that is intended to flow monies to the Ministry of Energy to fund its conservation programs.

26. When the Board's current total price and bill impact analysis rules were initially established, the Global Adjustment Mechanism ("GAM") was expected to be a price leveling mechanism – leading to oscillating positive and negative variances in the "all in" electricity price.[5] As a result of events that have taken place over the past several years,

[5] See para. 47 of this Argument quoting an excerpt from a recent Report describing the historic nature of the GAM and the manner in which it now currently operates.

the GAM is now significantly positive and is increasing exponentially. Events contributing to this result include the following:

(a) OPA procurement contracts and contracting commitments to pay long term fixed prices for electricity from renewable energy sources that are well in excess of prevailing electricity market prices, including commitments to pay premium prices for electricity that conceivably could be generated by a solar panel on every roof in Ontario[6]; and

(b) Passage of the *GEA* and further add on charges reflected therein such as the province-wide *GEA* charge and the special purpose charge to recover monies from ratepayers that will be flowed to the Ministry of Energy to fund CDM initiatives. The extent to which the implications of these measures will find their way into the "all in" electricity price consumers pay is to be either controlled by or influenced by regulatory approvals the Board grants.

27. As a result of changed circumstances, the total bill impact analysis required by the Board's current 2006 Rate Handbook is no longer an indicator of the change in the "all in" electricity prices consumers are likely to face as a result of the approvals the Board grants. Moreover, because the spending plans being presented to the Board by the utilities it regulates are multi-year plans and envisage exponential spending to respond to the government *GEA* initiatives, it is no longer appropriate to only consider immediate bill impacts. The multi-year impacts of the proposals on all elements of the "all in" price should be examined.

6 See para. 50 of this Argument quoting an excerpt from a recent Report that describes the impacts on GAM when higher priced electricity acquired from renewable generators displaces lower cost supplies.

28. In these circumstances, we submit that the Board's existing total bill impact rules need to be modified. The Board's current rules need to be changed to reflect the current and very costly realities of the greening of Ontario's integrated power system.[7]

(b) Development of Integrated Forward Looking Multi-year Total Price and Bill Impact Analysis

29. The misleading aspect of considering total bill impact analysis on a partial bill basis can be illustrated by the manner in which Hydro One proceeds in presenting its applications for rate relief. As a corporation, Hydro One concurrently presents to its Board of Directors for approval, its distribution and transmission spending plans. These spending plans are presented over a five year planning horizon. The information presented includes separate so-called total bill impacts for distribution and transmission. Notwithstanding that Hydro One's transmission spending plans can have a material impact on bills to distribution customers, and that, as a corporation, Hydro One prepares its distribution and transmission spending plans at the same time, in this case, as in previous applications for approval of distribution rates, Hydro One excludes the impact of Board approved increases in its transmission spending for 2010 and its proposed transmission spending for 2011 from the total bill impact analysis it presents to support its request for 2010 and 2011 distribution rate increases. This approach, in and of itself, understates bill impacts and, as a result, is misleading.

30. Moreover, as already noted, the utility spending Hydro One asks the Board to approve is based on the connection of renewable generators so that more and more electricity can be acquired from renewable generation sources. These spending plans, for which approval is requested, have an impact on the pace at which the acquisition of more and more expensive renewable generation is likely to displace cheaper supply. Add to this

[7] See Mr. Rogers' Argument at Transcript, Vol. 11, p. 16, lines 20 to 23 where these very costly realities are acknowledged.

the fact that a portion of the amounts Hydro One plans to spend on *GEA* initiatives is to be recoverable in the bills that other distributors charge and it becomes apparent that we have a situation that calls into question the continued appropriateness of conducting total bill analysis on the basis of an assumption that all elements of the bill, other than distribution charges, will remain constant. All components of the bill now need to be considered in a total price and bill impact analysis, and regardless of the fact that the OEB does not control all of the amounts that appear in the bill. We reiterate that, as an agency responsible for exercising its statutory authority in a manner that protects consumers with respect to electricity prices, the Board must consider and monitor the "all in" electricity prices that consumers pay to discharge its statutory responsibilities.[8]

31. Further, since the distribution and transmission charges in the bill will be increasing significantly during the greening of Ontario's integrated power system with a consequential exponential increase in the price of other elements in the bill, the total bill impact analysis should no longer be confined to the estimated test year total bill impact. The Board should require the utilities to present a total price and bill impact analysis of their spending plans over the duration of the five year planning horizon that each utility uses.

32. There is a critical need for a transparent mechanism that provides a current estimate and prospective forecast, on a rolling 5 year basis, of all elements of the total price and bill received by electricity consumers. This type of multi-year rolling total price and bill impact analysis is needed in order to enable the Board to manage the pace of the transition to the greening of Ontario end-state that the provincial government is attempting to achieve so that the risk of irreparable harm to Ontario's economy is minimized and ideally avoided.

[8] See para. 8 of this Argument.

33. The short, medium and long term greening end-state of Ontario's integrated power system is not currently a matter of public knowledge because public scrutiny of the Integrated Power System Plan ("IPSP") was suspended on or about October 2, 2008. We do not know when, if ever, the IPSP proceeding will be reconvened. In the absence of a Board-approved IPSP, the pace at which the greening of the integrated power system is planned to occur can only be gleaned from the five year plans presented to the Board by Hydro One and the other utilities involved in the coordinated planning that is essential to achieving the objectives of the *GEA* in a timely and cost-effective manner. The connection of renewable energy sources forecasted in these plans should be used to estimate the mix of costly supply from renewable generation sources that will displace cheaper supply and its consequential impacts on electricity prices. These increases in electricity prices should then be factored into the total bill impact estimates that need to be considered when evaluating the reasonableness of the total spending levels the utilities propose.

4. <u>Apply Forward-Looking Integrated Multi-Year Total Price and Bill Impact Analysis to Constrain Spending within the Limits of Affordability and Tolerance</u>

34. The integrated multi-year total price and bill impact analysis we are suggesting will indicate whether the utility-specific spending plans the Board is being asked to approve produce annual and multi-year total price and bill impacts that fall within the tolerance and affordability limits the Board establishes having regard to its consideration, at a hearing, of the likely economic impacts of various levels of "all in" electricity price increases over the next 5, 10, 15 and 20 years.

35. If the spending plans of a particular utility is proposing produce an annual or multi-year total price and bill impact that is intolerable, then approvals for the total amount of spending requested should not be granted. Spending in excess of such limits is neither prudent nor economically feasible. The measurement tool we advocate is to be applied

to determine prudence and economic feasibility and is a supplement to the existing criteria that are applied to determine economic feasibility such as need, cost benefit analysis, and work force capability in the context of historic spending levels.

36. The measurement tool we advocate should be applied to constrain excessive spending plans. It prevents the utility from overspending. In this context, we do not regard the measurement tool as a "mitigation" measure. To us, mitigation is a concept that applies to smooth out, over future years, an approved level of spending. The approved high level of spending in a particular year proceeds as planned, but recovery of some of the cost implications of that spending is postponed to future years. The measurement tool we advocate will be applied to prevent the high level of planned spending in the test year from taking place. The approval the Board grants is for a lower level of spending because the higher spending level the applicant proposes is neither prudent nor economically feasible because it is unaffordable and intolerable.

5. <u>Monitor and Publish Multi-Year Rolling Total Price and Bill Impact Analysis</u>

37. Currently, for each of the electricity distributors it regulates, the Board periodically publishes bill impact analyses prepared in accordance with its existing rate and total bill impact rules. As already noted, these utility specific total bill impact analyses do not realistically reflect the total "all in" electricity prices that consumers are likely to face as a result of the approvals the Board grants. Total bill impact analyses, prepared in accordance with current 2006 Rate Handbook rules, do not inform consumers of the realistic total bill impacts of the approvals the Board grants.

38. Since one of the Board's statutory objectives is to protect consumers with respect to electricity prices, consumers have a right to know and, for planning purposes, need to know the "all in" price increases that are the likely result of the approvals the Board grants. The results of applying the integrated multi-year total price and bill impact

analysis that we suggest, should periodically be published by the Board because, without such information, consumers are unable to evaluate the extent to which they are being protected with respect to electricity prices. The transparent disclosure of such information is essential in order for the Board to discharge its responsibilities in accordance with its statutory objectives.

C. <u>CME's Response to Hydro One's Application</u>

39. In the submissions that follow and from the information available in this case, we develop a surrogate for the integrated total price and bill impact analysis concept that we urge the Board to adopt. The manner in which we develop this analysis is detailed in the section of this Argument that follows.

40. The percentage impacts that flow from this analysis indicate that the total price and bill impact of Hydro One's spending plans and its likely impacts on all other elements of the bill will lead to total bill increases over the next five years of about 74% or almost 15% per year.[9] Total bill increases in this magnitude are excessive. Hydro One is asking the Board to approve far too much for its proposed traditional and *GEA* spending in 2010 and 2011. As a result, we urge the Board to refrain from approving all of the spending Hydro One proposes.

41. In these submissions, we recommend spending levels that fall within the limits of affordability and tolerance. We also quantify, on an envelope basis, the global amounts of spending that we submit should not be approved. In addition, we identify some specific areas where costs should be disallowed in order to bring Hydro One's planned spending within the limits of affordability and economic feasibility.

---

[9] See the Table at page 18 of this Argument and para. 77 thereof on pages 29 and 30.

II. CONSUMER IMPACTS AND REASONABLENESS OF REVENUE REQUIREMENT INCREASES IN 2010 AND 2011

42. For the purposes of illustrating how we envisage an integrated multi-year total price and bill impact analysis should be used as a tool in evaluating the economic feasibility of the plans Hydro One Distribution asks the Board to approve in this case, we set out below a table that summarizes what we think illustrates the 2010, 2011 and 2012 to 2014 impacts on Hydro One Distribution customers of the spending plans of the utilities the Board regulates over the five year planning horizon. From this, we derive the percentage increase in the total price and bill over the five year planning horizon.

43. The table below contains our high level estimate of what an integrated multi-year total price and bill impact analysis should reveal. An analysis of this nature should be prepared and filed by the utilities the Board regulates in all future rate applications. The analysis should be based on the information in their possession and in the possession of those engaged in the coordinated planning exercise that is <u>essential</u> to achieving the goals of the *GEA* in a timely and effective manner. A prudent planner would prepare a careful analysis of the type we present, based on information gathered from all those engaged in the coordinated planning exercise. A prudent planner would prepare the analysis <u>before</u> determining the total level of increased spending that is economically feasible. The results of this type of analysis should be used as a tool to help evaluate the economic feasibility and prudence of the total level of all *GEA* and traditional spending proposals that the Board is asked to approve. The derivation of the numbers in the Table are described in the paragraphs of this submission that follow the Table.

Estimated Changes in "All In" Electricity Price 2009 to 2014					
Line		2009	2010	2011	2012 to 2014
		$M	$M	$M	$M
1	DISTRIBUTION CHARGES				
2	Base Revenue Requirement	1,000			
3	Incremental Revenue Requirement				
4	• Traditional Spending, including all *GEA* indirect costs but excluding *GEA* direct costs		166	99	300
5	• All *GEA* incremental revenue related to *GEA* direct costs		18	55	158
6	TRANSMISSION CHARGES				
7	Incremental Revenue Requirement attributable to Hydro One Dx		35	50	150
8	ENERGY/COMMODITY	2,416			
9	Components for Estimating Increments				
10	OPG 1,004		50	50	150
11	OEFC 370		–	–	–
12	OPA 632		253	253	759
13	PROVINCE-WIDE *GEA* CHARGES				
14	*GEA* Charge (Credit)	n/a	(11)	(35)	(100)
15	SPECIAL PURPOSE CHARGE				
16	Ministry CDM Costs	n/a	10	10	30
17	TOTAL "ALL IN" ELECTRICITY COSTS	3,416	521	482	1,447
18	CUMULATIVE TOTALS	3,416	3,937	4,419	5,866

44. Our starting point in developing this tool is an estimate of Hydro One's 2009 distribution system revenue requirement. At line 2 in the 2009 Column of the Table, we estimate this amount to be in the order of $1,000M. This estimate is derived from the rates

revenue requirement for 2008 of $986M shown in Table 2 of Exhibit E1, Tab 1, Schedule 1, page 3, plus $12M revenue requirement related to the 2009 IRM Decision, for a total of $998M which we rounded to $1,000M.

45. At line 8 of 2009 Column of the Table, we provide our estimate of the "all in" electricity prices Hydro One currently pay based on 2009 costs. For our estimate of the 2009 year end "all in" energy costs, we use the "All In Energy Costs" of about $65/MW hours shown on Slide 13 of the IESO December 2, 2009 Presentation to CME marked as Exhibit K2.6 (the "IESO Presentation"). Hydro One's Distribution customers consume about 25% of the total Ontario electricity consumption of 148,670M MWh.[10] This equates to about 37,169M MWh of consumption for Hydro One. Multiplying this amount of consumption by $65/MWh produces the amount of $2,416M shown at line 8 of the Column for the 2009 year.

46. At lines 10, 11 and 12 of the Table, we show three of the components in the GAM that are likely to cause the "all in" price to increase in the future. These three components of the GAM are shown in Slide 10 of the IESO Presentation. They consist of OPG regulated costs, OEFC costs, and OPA procurement and other costs.

47. The likelihood of the GAM leading to material increases in the "all in" price is discussed in the recent Electricity Market Monitoring Report issued by the Market Surveillance Panel and released by the Board on January 29, 2010 (the "Market Surveillance Report"). At page v of the Report, the historic and prospective nature of the GAM is described as follows:

> *"Historically, the Global Adjustment Mechanism represented a rebate from generators to consumers, then a small payment from consumers to generators. As more contracted generators have come online and as contract prices have increased, the Global Adjustment has become a more substantial component of the total effect of cost of energy. It is expected that as new generation under FIT contracts come online, they will put further downward pressure on HOEP and upward pressure on the Global Adjustment."*

[10] Exhibits J2.3 and H, Tab 13, Schedule 2, responses (a) and (h).

48. For the purposes of helping us quantify the current levels of these components of the total price and bill, we, once again, use the information, as of October 2009, shown on the IESO presentation to CME marked as Exhibit K2.6. This information indicates that, at that point in time, the total GAM was about $52/MWh and consisted of OPG charges of about $25/MWh, OEFC charges of about $10/MWh and OPA costs of about $17/MWh.

49. Using the 37,169,000 MWh of electricity consumption attributable to Hydro One's customers, these unit prices translate into about $1,003.6M for OPG charges, $370.2M for OEFC charges and $631.9M for OPA charges, for a total of about $2,005.7M within the $3.4B "all in" amount recovered from Hydro One Distribution customers in 2009. These numbers, rounded, for the OPG, OEFC and OPA components of GAM are shown in the first column of the Table at lines 10, 11 and 12, and they are used as a basis for estimating increments thereto that are likely to occur in the years 2010 to 2014.

50. We pause here to note that we have not included in our Table a line item for what we refer to in paragraph 25(c)(iv) as the "Market price/regulated energy price variance charge or credit". We recognize that the Hourly Ontario Electricity Price ("HOEP") is a component of the "all in" price and that it is likely to decline as more and more electricity from renewable resources displaces cheaper supply. However, such declines will be off-set to some extent by increases in the GAM. The reasons for this are described at page 5 of the Executive Summary in the Market Surveillance Report to which we refer in paragraph 47 of this Submission. The authors of the Report state as follows:

> *""The addition of large amounts of renewable energy will also impact HOEP and Global Adjustment. Most renewable generation is a marginal production cost in $0/mWh. Thus, whenever these generators produce energy, they displace generation offered above $0/mWh. This reduces HOEP everything else being equal. However, the reduced HOEP is accompanied by an increased Global Adjustment associated with contract payments to renew facilities under FIT contracts and other contracted facilities."*

For the purposes of our high level analysis, we have assumed that any declines in HOEP will be off-set by increases in the GAM. The parties engaged in the coordinated planning exercise that is essential to achieving the objectives of the *GEA*, including Hydro One, possess the information necessary to predict the likely effect that the gradual acquisition of more and more electricity from renewable generators is likely to have on HOEP and GAM. They can address this when they provide all of the information that is essential to measuring total price and bill impacts in the manner we propose.

51. At lines 17 and 18 in the 2009 Column of the Table, we show our estimate of the total "all in" amounts paid by Hydro One customers for electricity in 2009 at $3,416M, which is the sum of the Base Revenue Requirement at line 2 and the "all in" Energy Charges at line 9.

52. At lines 4 and 5 for the years 2010 and 2011, we provide the incremental revenue requirement related to two items, namely:

    (a) Hydro One's traditional spending, excluding *GEA* direct costs but including all *GEA* indirect costs; and

    (b) All *GEA* incremental revenue requirement related to *GEA* direct costs.

53. The incremental revenue requirement related to traditional spending but excluding *GEA* direct costs, updated for Cost of Capital, is $166M, being the rates revenue requirement shown in Table 2 of Exhibits J4.4 at page 2. For 2011, the amount in line 4 of $99M is the rates revenue requirement, updated for Cost of Capital, shown in Table 4 of Exhibits J4.4 at page 3. It is not immediately apparent to us why increases in the Cost of Capital operate to reduce the rates revenue requirement deficiency in 2011 from the amount initially filed in Exhibits J4.2 and J4.3 at page 2 of $109M to the updated and lower amount of $99M. We assume that there is a plausible explanation for this and use the $99M amount in our Table.

54. Because the numbers at line 4 exclude revenue requirement relating to all *GEA* direct costs, we add, at line 5, all *GEA* revenue-related requirement, including Smart Grid, updated for Cost of Capital, shown in Exhibit J2.2, at page 2. The amounts we add are $18M for 2010 and $55M for 2011. We use these figures because the figures on the previous page do not include Smart Grid *GEA* costs. The figures we use represent the full year revenue requirement impact in each year. We regard the full year revenue requirement calculation to be a more appropriate indicator of "all in" prices and because using the full year amount as a slight margin of safety for the benefit of consumers. These amounts we use were calculated using twenty (20) years depreciation. We use the twenty (20) year depreciation amounts because that is the approach Hydro One followed in developing its pre-filed evidence estimates of revenue requirement related to its *GEA* spending plans. The purpose of our Table is to determine what Hydro One proposes in its Application and thereafter, to use the "all in" electricity total price and bill impact results of these proposals to measure the economic feasibility, prudence and overall reasonableness of the total spending levels Hydro One asks the Board to approve.

55. For the purposes of estimating, at line 4, the incremental revenue requirement in the years 2012 to 2014 inclusive related to traditional spending on Distribution, but excluding all *GEA*-related direct costs, we assumed that incremental spending in each of those years would produce incremental revenue requirements at or about the same level of incremental revenue requirement increases experienced, on average, in 2010 and 2011. Updated for the Cost of Capital, the incremental revenue requirements for 2010 and 2011 are $166M and $99M respectively, for an average of about $132.5M. Before updating for the Cost of Capital, the incremental revenue requirements for 2010 and 2011 shown in Exhibits J4.2 and J4.3 were $101M and $109M and respectively, or an average of about $105M.

56. For the purposes of our analysis, we have assumed incremental revenue requirements in each of the years 2012 to 2014 of $100M per year which produces estimated total incremental spending of $300M for the three (3) years, 2012 to 2014. The Board can consider the reasonableness of our $300M incremental revenue requirement estimate for traditional distribution spending (excluding *GEA* direct spending) for these three (3) years by referring to Hydro One's Business Plans filed in confidence at Exhibit H, Tab 13, Schedule 1 in this proceeding. Because of sanctions on our use of confidential information in this particular case, we have not engaged in that exercise.

57. At line 5, we provide an estimate of $158M of all *GEA* incremental revenue requirement related to direct *GEA* costs for the period 2012 to 2014. This number is derived from the capital costs of $1,180,000 less the generator funded costs of $40M shown in Exhibit A, Tab 14, Schedule 2, page 1, for a net of $1,140 or, on average, $380,000 per year, for all incremental *GEA* expenditures in period 2012 to 2014.

58. To develop a high level estimate of the revenue requirement implications of $380M of *GEA* capital expenditures per year on a full year basis, we calculate a weighted pre-tax Return on Equity ("ROE") using a 40% equity ratio and a 9.75% ROE to get 3.9%; add to it the pre-tax estimated weighted cost of debt of 60% x 6% for 3.60%; add the 5% depreciation rate Hydro One uses in its proposals with respect to *GEA* capital spending and tax on the equity component which we conservatively included at 1%, to produce a Rate Base carrying cost, including depreciation, ROE, and debt, and taxes on equity in a total amount of about 12.5%. Once again, we use a five (5) year depreciation rate in deriving this percentage because that is the rate Hydro One proposes to use in its calculation of the *GEA* revenue requirement, most of which Hydro One proposes to recover in the province-wide *GEA* charges the Board determines.

59. Applying this percentage to the $380M of capital budgeting per year produces, on a full year basis, about $47.5M of carrying costs or $142.5M for three years. To this sum

should be added the incremental Operations, Maintenance and Administrative ("OM&A") costs over the three year period of $15M ($45M less $30M)[11] to generate a total amount of about $157.5M.

60. At line 7, we estimate the incremental transmission revenue requirement attributable to Hydro One Distribution. For 2010, we derive the $35M from the increases Hydro One is seeking in its 2010 Transmission Rates on its Motion for Review. The 2009 Transmission Base revenue requirement approved by the Board in its June 30, 2009 Order in EB-2008-0272 is $1,179M. The 2010 Transmission Base revenue requirement Hydro One is seeking in its Motion for Review in EB-2008-0272 is $1,321M. Based on Hydro One's consumption of about 25% of the total electricity consumed in Ontario, we allocate 25% of $142M, or about $35M to Hydro One Distribution. That amount appears at line 7 in the 2010 Column of the Table.

61. For 2011 and 2012 to 2014, we assume that Hydro One Transmission's incremental spending in each year attributable to Hydro One Distribution will be about $50M per year. The five year plans for Hydro One Transmission for 2010 to 2014 inclusive are filed in confidence in these proceedings and estimates of the year-by-year revenue requirement impacts of those plans and the proportion allocable to Hydro One Transmission can be derived from that information. We have not performed that exercise because of the sanctions on our access to that information for the purposes of this particular case. The exercise we would conduct is to apply a carrying cost amount of about 11.0% consisting of the weighted cost of equity at 3.9%, the weighted cost of debt at 3.6%, tax at 1% and depreciation at 2.5% to the capital expenditures planned for each of the years 2010 to 2014 inclusive, and to that figure, add the incremental OM&A expenses planned for each of those years to produce an estimated total incremental

---

11 There is no incremental renewable generation OM&A expense for the years 2012 to 2014 in the Table at Exhibit A, Tab 14, Schedule 2, page 1. However, the $45M of OM&A Smart Grid expenses for the years 2012 to 2014 as shown in the Table exceed, by $15M, the total OM&A that would prevail if the $10M per year for 2010 and 2011 was the level of expenses for 2012 to 2014 inclusive.

transmission cost for each of the years. In this calculation, we use a lower depreciation rate of 2.5% because we understand that an economic life rate lower than 5% is used by Hydro One to calculate its transmission revenue requirement. Hydro One Distribution's share of these transmission costs is estimated to be 25% thereof, based on the fact that Hydro One's customers consume about 25% of the electricity energy used in Ontario.

62. We believe that our estimate of incremental transmission cost increases for Hydro One Distribution of $50M for the years 2011 to 2014 inclusive is reasonable and reiterate that the Board can assess the reasonableness of our estimate by considering Hydro One's Transmission spending plans for each of the five years ending in 2014 that were filed in confidence in this proceeding as Exhibit H1, Tab 13, Schedule 1. Having regard to the $168M Hydro One Transmission seeks permission to record in the deferral account the Board created in its EB-2008-0272 Decision for development planning, and the $2.3B of planned expenditures over the next three (3) years disclosed by Hydro One Transmission representatives at a meeting of Stakeholders on November 16, 2009, our estimate of incremental transmission cost increases for Hydro One Distribution of $50M per year for the years 2011 to 2014 inclusive may be conservative.

63. At line 10, we illustratively estimate Hydro One's share of OPG costs in each of the years 2010 and 2011 and for the three years 2012 to 2014 inclusive. To illustrate the approach, we assume that OPG's regulated costs will increase by an amount of about 5% or $50M in each year. The changes expected over the period 2010 to 2014 in OPG's regulated payment amounts are not currently a matter of public record. However, information about these plans will shortly be available to the Board and other Stakeholders. For 2010, OPG is operating under the auspices of deferral account protection. As in previous cases, it is expected that in its next Payments Application for the 2011 and 2012 test periods, OPG's five year business plans will be filed in confidence. The Board and participating Stakeholders will have all of the information

they need to consider an estimate of the implications of OPG's plans on the "all in" electricity price consumers pay.

64. At line 11, we assume that there will be no incremental OEFC charges in any of the years 2010 to 2014 inclusive.

65. At line 12, we provide an estimate of the extent to which OPA charges in the GAM are likely to increase. We are not privy to all information in the possession of the IESO, the OPA and the transmission and distribution utilities whose engagement in coordinated planning is essential to achieving the goals of the *GEA* in a timely and cost-effective manner with respect to the mix of renewable generation that is likely to come on line in the next five years and the precise prices being paid for such electricity. These parties, the Ministry of Energy and any others engaged in the coordinated planning process that is essential will have more precise information about these matters and can provide reliable estimates thereof for use in evaluating the economic feasibility and prudence of the total levels of expenditures that the Board is being asked to approve.

66. What we do know from our participation in the currently adjourned IPSP proceeding, is that the total resource requirement for Ontario over the five year planning period ranges between 30,000 and 40,000 MW. We also know from Exhibit K2.6 that 3,700 MW of OPA contracted capacity came on line in the twelve months prior to December 2009. We know that the spending plans of Hydro One Distribution for the period 2010 to 2014 are based on forecast additions of 3,500 MW of renewable energy in 2010 and 2011 and another 3,500 MW in the period 2012 to 2014. The sum of these amounts is 10,700 MW or between 25% and 33% of Ontario's total resource requirements of 30,000 MW to 40,000 MW. Based on this information, we conclude that Hydro One's spending plans contemplate that at the end of five years, there will be sufficient renewable generation available to satisfy about 25% to 30% of Ontario's resource requirements.

67. While other parties have more precise information about prices, we do know from the evidence in this proceeding that prices being paid by OPA for small solar are about 80¢/kW, large solar about 40¢/kW and for wind and other types of renewable generation, in the 12¢ to 14¢/kW range.[12] Small solar is some twenty (20) times more expensive than the lower prices for nuclear and other base load supplies. Large solar is about ten (10) times these lower priced supplies and other renewable sources are approximately three (3) times the lower prices for nuclear and other base load supplies that will be displaced.

68. In the context of this information, we perform a simple calculation to ascertain in a 25% displacement scenario, the extent to which the costs of 100 units of supply at $5 per unit will increase if units costing $5 are displaced as follows:

(a) By 5% or five units costing 20 times $5, or $100 per unit;

(b) By 5% or five units costing 10 times $5, or $50 per unit;

(c) By 15% or fifteen units costing 3 times $5, or $15 per unit; and

(d) The undisplaced 75 units continuing to cost $5 per unit.

69. This calculation represents an estimate of a 25% displacement scenario with a mix of 5% for small solar, 5% for big solar, 15% for wind and other. The results of this simple calculation reveal that the costs for the 100 units increase from $500 to $1,350, or a 270% increase in the level of costs being incurred prior to displacement.

70. If we assume the displacement occurs over five years, then the OPA component of GAM will, on average, increase by about 54% per annum (270% ÷ 5 = 54%). If we assume a slower transition, namely, over six years, then on average the increase in the OPA component of GAM reduces to about 45% per year (270% ÷ 6 = 45%). At seven years,

[12] Transcript, Vol. 2, p. 109, lines 4 to 17; and in line 4 "HOEP" should read "OPA".

the OPA component of GAM increases at about a rate of 39% on average (270% ÷ 7 = 39%).

71. Bearing in mind that some 3,700 MW of renewable capacity has come on stream in the twelve months prior to December 2009 and that Hydro One's budgets are based on a further 7,000 MW coming on stream in the next five years, the renewable generation implicit in Hydro One's budgets over the next ten years will be in the order of 10,000 MW. In these circumstances and in recognition of the possibility that the connection of 7,000 MW of renewable generation will take somewhat longer than five years, it seems reasonable to assume the 25% displacement scenario and a pace of displacement that is something slightly longer than that reflected in Hydro One's Business Plans.

72. We have assumed that the displacement will take place over the next six to seven years which results in the average OPA escalation based on the mixed calculation we have used to be an amount of about 40% per annum over the next five years. The application of this 40% ratio to the current OPA component of GAM of $632M produces the numbers of $253M at line 12 for 2010 and 2011, and $759M for the three years 2012 to 2014 inclusive.

73. As already noted, we have assumed that any declines in HOEP will be offset by increases in the market price adjustment paid to generators and recovered in GAM.

74. The province-wide *GEA* charge (credit) we calculate at line 14 is derived in the following manner. The "all in" *GEA* incremental revenue requirement related to *GEA* direct costs calculated at line 5 would be the amount recoverable from Hydro One customers, assuming every distributor proportionately spent exactly the same amounts on *GEA* initiatives as Hydro One. That is unlikely. The information to which Board Staff referred in its Discussion Paper pertaining to the proposed framework for determining the Direct Benefits accruing to customers of a distributor under O.Reg. 330/09 at page 3 implies

that total *GEA* spending by all distributors other than Hydro One is likely to be less than the amount Hydro One spends. We do not have the information that indicates what other distributors are planning to spend on *GEA* initiatives. For the purposes of our analysis, we have assumed that total *GEA* spending by all distributors other than Hydro One will be about 50% of Hydro One's planned spending.

75. If the revenue requirement of one distributor pertaining to the *GEA* costs is $100 and the revenue requirement pertaining to all other distributors combined is $50 and the total of $150 is to be collected province-wide from all distribution customers, then Hydro One's share of the total, based on its 25% portion of Ontario's load, is $37.50, leaving $62.50 to be recovered from other customers. On this basis, we show a *GEA* charge credit at line 14 being 63% of the amounts at line 5 to adjust for the portion of the revenue requirement related to Hydro One's *GEA* spending that will not be collected from Hydro One's customers.

76. At line 15, we show the yet to be implemented Special Purpose Charge that we understand will be used to recover monies paid by distributors to the Ministry to fund CDM costs. These amounts are unknown at the present time and, for the purposes of illustration, we assume that the incremental amounts recoverable from Hydro One Distribution customers in each year will be $10M per year. This assumption accounts for the entries in line 16. In the context of significant CDM-related reductions in load Hydro One forecasts[13] for 2010 and 2011, which will need to be funded through increased CDM allowances, the amounts that we have included in our Table may very well turn out to be quite conservative.

77. The totals and cumulative totals at lines 17 and 18 reveal that the total "all in" costs for Hydro One Distribution customers of about $3,400M in 2009 will increase to about $5,900M by 2014. This equates to $2.5M or a 74% increase over five years, or, on

[13] See our submissions on Hydro One's load forecast at paras. 98 to 101 of this Argument.

average, almost 15% per year. On the assumption that Hydro One's distribution load remains at or about its current level for the next five years, these calculations are a surrogate for the "all in" electricity price increases Hydro One Distribution customers face. The "no material change in load" assumption seems appropriate in the context of the load forecasts Hydro One presents in this case. Similarly, these calculations are reasonably representative of total bill impacts where no major changes to the customer base are anticipated over the next five years. That assumption seems reasonable over the next five years in the context of the economic situation that currently prevails in Ontario. Accordingly, we submit that the analysis we present is a reasonable indicator of the extent to which the total "all in" price for electricity for Hydro One's customers is likely to increase over the next five years.

78. We anticipate that, in its Reply Argument, Hydro One will criticize the total electricity price and bill impact analysis we have prepared. We accept that the analysis is very high level and that those engaged in the coordinated planning essential to achieving the *GEA* goals in a timely and cost-effective manner can provide a more reliable analysis. That said, it should be remembered that we attempted to obtain, by way of interrogatories and cross-examination,[14] better information pertaining to an analysis of the type we have presented. We were told by Hydro One that it had no information in its possession that was responsive to our inquiries. Hydro One's response to our information requests implies that no one engaged in the coordinated planning exercise that is essential for cost-effectively achieving the goals of the *GEA* is preparing the type of analysis that is required to evaluate the economic feasibility and prudence of the total spending levels Hydro One proposes. Hydro One's Board of Directors are not informed of the likely total "all in" electricity prices and total bill impacts that flow from the plans

[14] Exhibit H, Tab 13, Schedule 2(g) and (h); and Transcript, Vol. 2, p. 154, line 24 to p. 157, line 19.

they have approved because Hydro One management does not provide them with that type of analysis.

79. As a participant in this coordinated planning exercise that is essential, Hydro One either has in its possession or can obtain all of the information that is needed to prepare an integrated total price and bill impact analysis of the type we have illustrated. In these circumstances, the Board should be very wary of accepting any criticism that Hydro One makes of our analysis without a convincing demonstration from Hydro One that the "all in" increases in electricity prices and total bill that we estimate over the year five years of about 74% or, on average, about 15% per year are far too high. Without a convincing demonstration by Hydro One that our estimate of total electricity price increases of 74% over the next five years is materially high, it can be inferred that our overall conclusion is realistic, despite any deficiencies that relate to one or more of the line items that has led us to that overall conclusion. To be convincing, any criticisms Hydro One makes of the increase of 74% that we estimate for the five years ending in 2014 should be supported by information available to it as a major participant in the coordinated planning exercise that is essential to achieving the objectives of the *GEA*. Absent a convincing demonstration of this nature, our analysis indicating a 74% increase over five years should be utilized as a tool to evaluate the prudence and economic feasibility of the total levels of spending Hydro One asks the Board to approve.

80. Our analysis indicates that the total spending Hydro One proposes will lead to total price and bill increases of about 15% per year, on average, over the next five years. If total bill impact tolerance is 10% per annum, as reflected in the Board's existing 2006 Rate Handbook, then, at a high level, the total spending Hydro One proposes is excessive by a factor of approximately one third or 33%.

81. Total spending levels should fall within the limits of tolerance and affordability. To do this, the Board should refrain from approving more than 67% of the total capital and OM&A amounts Hydro One proposes in its application.

82. Based on the foregoing, our responses to the questions contained in the Issues List to which submissions in this section of the Argument apply are as follows:

Issue 1.5: Is the overall increase in 2010 and 2011 revenue requirement reasonable given the impact on consumers?

Answer: No, for the reasons outlined in sections I and II of this Argument.

Issue 3.1: Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Answer: No, for the reasons outlined in sections I and II of this Argument.

Issue 4.1: Are the amounts proposed for Rate Base appropriate?

Answer: No, for the reasons outlined in sections I and II of this Argument.

83. We submit that the Ontario economy, as a whole, and in particular, its manufacturing sector, is likely to be materially harmed if the "all in" price of electricity and total bills increase, on average, by some 15% per year over the next five years. We submit that the indicated impacts of the extraordinarily high levels of spending Hydro One is proposing in conjunction with all of the other spending increases expected from other entities the Board regulates will, in combination with the acquisition of more and more renewable generation, create a real risk of serious economic harm.

III. GREEN ENERGY PLAN AND CRITERIA TO APPLY

84. It is not too early to determine the general criteria that the Board should apply when considering Hydro One's Green Energy Plan.[15] The Board's role with respect to

[15] At page 34 of their Submission, Board Staff suggests that it is too early to establish specific criteria for assessing Green Energy Plans and at page 37, urge the Board to refrain from making any findings with respect to prudence. We submit that findings with respect to economic feasibility, affordability and prudence cannot be postponed.

approving green energy plan proposals is the same as its role with respect to traditional utility expenditures. The Board's responsibility is to determine now whether the proposed spending plans are economically feasible and prudent. Now is the time to make findings with respect to these matters and not later, as Board Staff suggests.

85. Approved *GEA* plans lead to an approved *GEA* plan revenue requirement and charges or rates based thereon that will be recovered from customers of Hydro One and customers of other distributors. In these circumstances, any elements of *GEA* spending plans should be subject to the same degree of regulatory scrutiny that applies to traditional utility spending plans.

86. Accordingly, an applicant seeking approval of a proposed Green Energy Plan should objectively demonstrate that elements of the plan respond to a public interest need; that the benefits of the specific elements of the plan exceed their costs; and that the applicant has the capability to do the planned work having regard to, among other things, its historic spending levels.

87. Green Energy Plans that fail to objectively demonstrate that they satisfy the economic feasibility criteria the Board traditionally applies should not be approved. They are deficient.

88. Most importantly, and for the reasons already outlined in these submissions, the total spending associated with the combined Green Energy Plans and traditional utility spending plans must be shown by the applicant to be at a level that is tolerable and affordable and that the spending levels for which approvals are sought will not cause serious economy harm. We submit that the onus should be on the applicant to provide cogent evidence with respect to this critical component of economic feasibility.

89. Hydro One has not discharged the burden of demonstrating the economic feasibility of all of the *GEA* spending it asks the Board to approve. Quite apart from matters that

Board Staff discusses in their submission[16], such as the lack of sufficient detail and the probability that its generation connection forecast is overstated, we submit that Hydro One has failed to discharge the burden of establishing economic feasibility because there is no prospective analysis of total price and bill impacts on an integrated multi-year basis. We submit that such an analysis is fundamental to the coordinated planning exercise that is essential in achieving the goals of the *GEA* in a timely and cost-effective manner.

90. As already noted, Hydro One implies that no one engaged in this essential coordinated planning exercise measures the total price and bill impact of the activities they are planning on a realistic forward looking basis. If that is so, then everyone engaged in the essential coordinated planning exercise is behaving imprudently. We find this hard to accept. If everyone engaged in the coordinated planning exercise is planning for spending without any consideration of the ability of the economy to afford or tolerate the consequences of the planned activities, then they are planning with complete disregard for the economic consequences of their plans. This would be incredible.

91. We reiterate that, where all elements of the price billed to consumers will increase as a result of the implementation of plans for which approval is requested, it is inappropriate to evaluate price and bill impacts by only considering the requested increase for charges that comprise about 30% of the total price and bill and holding the other elements of the bill constant.

92. Integrated multi-year total price and bill impact analysis is an essential element of economic feasibility and prudence and is a criterion that needs to be applied to evaluate the affordability of the combined the *GEA* and traditional utility spending plans for which approval is requested.

---

16 Board Staff Submission, pp. 35 to 40.

93. We agree with Board Staff that there are a number of deficiencies in the Green Energy Plan submitted by Hydro One that separately and in combination should prompt the Board to refrain from approving the test year consequences of the Plan as presented.[17] We discuss some of these types of items below. We reiterate that a priority consideration should be a determination of the excessiveness of the total spending Hydro One proposes, based on a consideration of the integrated multi-year total price and bill impact analysis of the type we have presented and that total spending levels should fall within the limits of tolerance and affordability.

94. Using our total price and bill impact analysis as a guide and for the reasons already outlined, the total amounts the Board approves for capital and OM&A related to Hydro One's Green Energy Plan for 2010 and 2011 be limited to about 67% of the amounts Hydro One proposes. The approved ceilings could be higher if Hydro One can demonstrate with supporting information from those engaged in the coordinated planning process, that our 74% price increase over five years is materially high. To fall within the limits of tolerance and affordability, the approved total *GEA* capital spending should be no more than \$133M for 2010 and no more than \$240M for 2011, being 67% of the amounts proposed by Hydro One of \$198M in 2010 and \$358M in 2011. The *GEA* and OM&A costs for 2010 should be approved in an amount of no more than \$9M, being 67% of the OM&A costs of \$13M (excluding the CDM amounts) proposed by Hydro One in 2010 and 2011.

95. With respect to rate recovery, we agree with Board Staff that the deferral account approach outlined in the Board's June 16, 2009 Guidelines should be followed with respect to renewable generation expenditures and that the same rate recovery mechanism should apply to the Smart Grid expenditures Hydro One proposes.[18]

---

[17] Board Staff Submission, pp. 35 to 40.
[18] Board Staff Submission, pp. 41 to 43.

96. We also support Board Staff's suggestion that any allocation of Hydro One's Green Energy Plan revenue requirement to the province-wide rate recovery mechanism be provisional and subject to later adjustment.[19]

97. Based on the foregoing, our responses to questions contained in the Board's Issues List to which the submissions in this section apply are as follows:

Issue 3.1: Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Answer: No, the OM&A budgets in the Green Energy Plan are inappropriately high for the reasons we have outlined in sections I, II and III of this Argument.

Issue 4.1: Are the amounts proposed for Rate Base appropriate?

Answer: No, the portion of the Green Energy Plan capital expenditures that is proposed to be included in Hydro One Distribution Rate Base is excessive for the reasons outlined in sections I, II and III of this Argument.

Issue 9.4: To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?

Answer: The total expenditures relating to the Green Energy Plan in 2010 and 2011, as well as in the years 2012 to 2014, are excessive for the reasons described in sections I, II and III of this Argument. While the portion of the spending plans for 2012 to 2014 that is excessive need not be specifically determined in this case, the Board should, in its Decision, indicate to Hydro One that the currently planned amounts for 2012 to 2014 fall well outside the limits of economic feasibility and affordability. The Board should also confirm that it will apply a total price and bill impact analysis of the type we have suggested to evaluate the economic feasibility, affordability and prudence of spending levels for 2012 to 2014 inclusive when Hydro One asks the Board to specifically approve its spending plans for those years.

---

[19] Board Staff Submission, pp. 43 and 44.

Issue 9.5: ***What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?***

Answer: The Board's role and the criteria it should apply are described in paragraphs 84 to 88 of this Argument. The total impacts of the combined traditional and *GEA* spending are as described throughout this Argument and these impacts should prompt the Board to limit its approval of Green Energy Plan amounts as described in paragraph 94 of this Argument.

IV. LOAD AND REVENUE FORECAST

1. <u>Conservation and Demand Management ("CDM") Forecast</u>

98. Hydro One has projected the cumulative CDM impact in its distribution system load forecast as 1,325 gW hours in 2010 and 1,604 gW hours in 2011. These CDM impacts on Hydro One distribution loads for 2010 and 2011 are very significant increases from the 2008 CDM impact of 432 gW hours.

99. In cross-examination, Hydro One confirmed that every 100 gW hours of this CDM impact represents a $2M revenue impact.[20] This means that the forecast CDM impact on Hydro One's Distribution load for 2010 of 1,325 gW hours has a resulting revenue impact of $26M, and the forecast 1,604 gW hours for 2011 has a resulting revenue impact of $32M. By way of comparison, Hydro One's 2008 CDM impact was only 432 gW hours, which represented an $8M resulting revenue impact.

100. We are concerned that, to the extent that the forecast CDM impacts on Hydro One distribution load for 2010 and 2011 are less than projected, Hydro One's revenue requirement will be excessive. In this regard, we note that CDM programs will be planned and delivered through a number of agencies outside of Hydro One's control,

---

[20] Transcript, Vol. 9, p. 78.

including the OPA, IESO, federal and provincial governments, and other LDCs. Furthermore, Hydro One has based its CDM projections, in part, on recent CDM program results and analysis. The fact that Hydro One is projecting the CDM impact to increase from 432 gW hours in 2008 to 1,604 gW hours per year by 2011 leads us to conclude that recent program results may not be a strong indicator of what will occur in the next two years. In short, there exists a high level of uncertainty about the extent of the CDM impact on Hydro One distribution load.

101. Within this context, we believe that it would be appropriate for the Board to implement a variance account mechanism to track the actual CDM impact on Hydro One's distribution load for 2010 and 2011. To the extent that the impact is less than 1,325 gW hours in 2010 or 1,604 gW hours, the associated revenue collected for these years should be credited to ratepayers.

V. OPERATIONS, MAINTENANCE AND ADMINISTRATIVE ("OM&A") COSTS

1. Overview

102. Our integrated multi-year total price and bill impact analysis indicates that the total revenue requirement increases Hydro One asks the Board to approve in this application for 2010 and 2011 are excessive by about one third or 33%. In this section of our Argument, we provide additional rationale to support our contention that the increases in OM&A expenses that are a component of those excessive revenue requirement increase requests are in amounts that lie well beyond the limits of economic feasibility, affordability and reasonableness. We agree with Board Staff that in this time of slow economic growth, job losses, plant closings and reduced inflation, the OM&A increases requested by Hydro One should be significantly reduced.[21]

[21] Board Staff Submission, p. 9 .

103. The determination of the 2010 and 2011 OM&A costs to be recovered in rates is an exercise of judgment that the Board must make after considering all factors which it regards as relevant. In assessing the reasonableness of Hydro One's proposed OM&A costs, we urge the Board to consider three "indicators of reasonableness". First, the Board should compare Hydro One's overall OM&A budgets to previous years. Second, the Board should compare Hydro One's proposed 2010 and 1011 OM&A cost per customer to previous years. Finally, the Board should compare Hydro One's 2010 and 2011 OM&A cost per circuit km to previous years. We submit that these three "indicators of reasonableness" all support the conclusion that Hydro One's proposed OM&A costs for 2010 and 2011 are excessive.

2. Trend Analysis

104. With respect to the first indicator of reasonableness, we urge the Board to consider Hydro One's overall 2010 and 2011 OM&A budgets compared to its Board approved 2008 OM&A costs. In conducting this budget comparison, we also urge the Board to consider the five year increases since 2006.

105. The Board has previously recognized the appropriateness of assessing Hydro One's proposed OM&A budgets within historical norms. In Hydro One's 2006 distribution rates case[22], the Board did not rely upon a global or envelope assessment because, at that time, there did not exist a "solid historical baseline". The Board did, however, recognize that "global or envelope reductions to costs proposed by utility can be and have served as a practical tool".

106. In Hydro One's 2008 distribution rates case[23], the Board went on to recognize as follows:

> *"In considering any proposal for increases in spending, the Board attempts to place the company's current budget within historic norms. While sharp deviations may be justifiable on the basis that issues have arisen that require extraordinary attention, the Board considers that past spending is a useful guide in assessing spending proposals."*

[22] EB-2005-0020
[23] EB-2007-0681

107. The years 2006 and 2008 were both subject to full cost of service applications. In 2006, Hydro One's total distribution OM&A was $399.3M.[24] This was increased to $471.3M in 2008. That increase alone represented an 18% increase. Just two years later Hydro One seeks approval to further increase its OM&A budget to $560M for 2010 and $575.2M for 2011. This represents an 18.8% increase between 2008 and 2010, and 22% between 2008 and 2011. If the Board approves Hydro One's current application, Hydro One's OM&A five (5) year increase from 2006 to 2011 would be 44%.

3. Cost per Customer Benchmark

108. In previous cases, the Board has recognized that in assessing the reasonableness of OM&A costs on a global or envelope basis, it is appropriate to consider the OM&A cost per customer.[25] We submit that this is a measure that permits the Board to review cost levels and trends over time while taking into account customer growth.

109. In 2008, Hydro One's OM&A cost per customer was $394.9M. If approved, Hydro One's 2010 OM&A cost per customer would increase to $459.5M.[26] This represents a 16.4% increase in just two years.

110. In 2006, Hydro One's OM&A cost per customer was $341.1. If approved, Hydro One's 2011 OM&A cost per customer will be $467.3.[27] If approved, this would result in a 37% increase in just five years. We are concerned about the pressure which this continuing trend of large increases will have on Hydro One's customers. We urge the Board to consider this increased OM&A on a per customer basis as further evidence that Hydro One's proposed 2010 and 2011 OM&A budget is not within the limits of reasonableness.

4. Cost per Circuit Km Benchmark

111. Another indicator of reasonableness that we urge the Board to consider is the increase of Hydro One's OM&A cost per circuit km. In 2008, Hydro One's OM&A cost per circuit

---

24 Exhibit C2, Tab 2, Schedule 1, page 2 of 2.
25 See EB-2005-0001.
26 Exhibit H, Tab 1, Schedule 15, page 1 of 2.
27 Exhibit H, Tab 1, Schedule 15, page 1 of 2.

km was $3,276.50. If approved, this will increase to $3,794.90 in 2010.[28] This represents a 16% increase between 2008 and 2010.

112. In 2006, Hydro One's OM&A cost per circuit km was $2,614.80. If approved, Hydro One's 2001 OM&A cost per circuit km will be $3,849.80 in 2011.[29] This represents a 35.3% increase in just five years. We submit that this third indicator of reasonableness also supports a conclusion that Hydro One has failed to maintain its OM&A costs within the limits of reasonableness.

5. Inflation

113. The extent to which these indicators demonstrate the excessiveness of Hydro One's proposed OM&A costs for 2010 and 2011 is further bolstered by also considering Ontario's CPI during the relevant time periods. Hydro One has provided the Ontario CPI forecast released by Global Insight in August 2009,[30] which confirms that inflation was 1.8% in 2006 and 2.3% in 2008. Global Insight has further forecast Ontario CPI to be 1.7% in 2010 and 2.0% in 2011. These low inflationary rates, compared to the substantial percentage increases for all three of the indicators of reasonableness set out above, further demonstrate the excessiveness of Hydro One's proposed OM&A costs for 2010 and 2011. When inflation is low, we would expect Hydro One to show a level of restraint that is absent from its proposed OM&A budgets for 2010 and 2011.

6. Compensation

114. In addition to these three indicators of reasonableness compared to Ontario CPI, we also have concerns about specific budgets. The first relates to Hydro One's proposed compensation and staffing costs.

115. In response to a Board directive made in EB-2006-0501, Hydro One engaged Mercer/Oliver Wyman to prepare an independent study on compensation costs and

28 Exhibit H, Tab 1, Schedule 15, page 1 of 2.
29 Exhibit H, Tab 1, Schedule 15, page 1 of 2.
30 Exhibit H, Tab 3, Schedule 1, page 2 of 2.

productivity for Hydro One and comparable companies.[31] This study, entitled "Compensation Cost Benchmarking", was submitted in evidence in Hydro One's transmission cost of service application for 2009 and 2010.[32]

116. The Mercer study concluded that on a weighted average basis for the positions reviewed, Hydro One's compensation is approximately 17% above the market median. In that case, Hydro One argued that its compensation levels should not be reduced because, *inter alia*, they were driven by legacy collective agreements, legacy pension and benefit programs, and the need for competitive salaries. The Board in EB-2008-0272 rejected Hydro One's argument and disallowed $4M in each of the test years. In making that finding, the Board concluded that, "this level of adjustment goes someway toward aligning Hydro One's costs with other comparable companies".

117. In this case, Hydro One has not reduced any of its compensation and staffing costs in response to the Mercer study or in response to the Board's previous disallowance in the Transmission case. In cross-examination, Hydro One acknowledged that the Board's disallowance of $4M was "very relevant". That said, Hydro One elected to not even acknowledge the Board's previous disallowance in its evidence. Hydro One's explanation for not addressing the $4M disallowance is as follows:

> *"What we are trying to do is provide fresh evidence to have the Board consider some other evidence when they render the decision in this case."*

118. We submit that Hydro One has failed to provide any compelling evidence that would justify the Board not making a disallowance in this case that is comparable to the disallowance made in the transmission case. Instead, Hydro One has acted as if its compensation costs had not been previously disallowed.

119. Hydro One has confirmed that a $9M per year reduction in distribution OM&A costs would be comparable to the $4M disallowance from the transmission case.[33]

---

[31] Exhibit C1, Tab 3, Schedule 2, page 10 of 18.
[32] EB-2008-0272

120. In the transmission case, Hydro One submitted that if they were to pay everyone at the market median, the impact would be $13M. The Board in the transmission case only reduced their compensation by $4M and not $13M.[34]

121. We submit that if Hydro One distribution were directed by the Board to pay everyone at the market median, the impact would be $29.25M per year. This amount is equivalent to the $13M calculated in the transmission case and then prorated in the same manner as the $4M to $9M.[35]

122. On the basis of the findings in the transmission case, we are of the view that the Board should reduce Hydro One's budget for compensation by <u>at least</u> $9M per year. Further, on the basis of the Mercer Report, the Board would be justified in reducing Hydro One's compensation in an amount up to $29M per year as this would bring Hydro One's compensation costs into the market median found by the Mercer Report.

123. On a final note, in its final argument in this case, Hydro One argued that:

> *"The message that you sent in the transmission case is well understood by my client, and I think in the industry. And I have no doubt it will play a significant role in the next collective bargaining process."*

124. In disallowing $4M in Hydro One's transmission, the Board was not merely sending a message. As it wrote in that case, "this level of adjustment goes someway toward aligning Hydro One's costs with other comparable companies". We submit that Hydro One's characterization of the previous disallowance as merely a "message" should cause the Board concern.

125. That said, even if the disallowance was meant to send a message, the evidence supports a conclusion that Hydro One has missed that that message. Had Hydro One actually received the message, it would have proactively reduced its compensation in this case. The fact that Hydro One distribution did not even acknowledge in its written

---

33 Exhibit H, Tab 10, Schedule 4, p. 2; and Vol. 7, pp. 59 to 60.
34 Transcript, Vol. 8, p. 123.
35 Transcript, Vol. 8, pp. 123 to 124.

evidence that the Board previously disallowed part of its compensation costs supports the conclusion that the message was either not received or ignored. If the Board wants to send a message, it should reduce Hydro One's budget by more than $9M. In this regard, we remind the Board that if Hydro One's compensation was at the median of the Mercer Report, that it would need to reduce its compensation by $29M. Under such circumstances, and in light of the overall increase of the OM&A budgets, it would not be unreasonable for the Board to reduce the compensation by more than $9M.

7. Vegetation Management

126. The second specific budget for which we have concerns is the vegetation management budget. Hydro One's vegetation management budget for 2008 was $118.2M. Hydro One is requesting an increase of the vegetation management budget to $133.2M.[36] This represents an increase of 12.7%. In assessing the reasonableness of the proposed increases, we urge the Board to also consider the five (5) year increase since 2006. The cost of vegetation management for Hydro One in 2006 was $89.1M. Hydro One is seeking a budget of $144.6M in 2011. If approved, this would represent a 62.3% increase from 2006 to 2011.

127. One of the cost drivers for proposed increases in the 2010 and 2011 budgets for vegetation management is Hydro One's proposal to reduce the vegetation management cycle from the current Board approved eight (8) year cycle to a seven (7) year cycle beginning in 2011. We have had the benefit of reviewing AMPCO's draft submissions on this issue. For the reasons set out by AMPCO, we urge the Board to direct Hydro One to continue the eight (8) year clearing cycle approved in Hydro One's 2008 distribution rates application,[37] instead of the seven (7) year cycle it has proposed in this application.

---

[36] Exhibit C1, Tab 2, Schedule 2, pp. 33 of 41.
[37] EB-2007-0681

8. Other Concerns

128. Finally, we have also had the benefit of reviewing the Submissions of Board Staff. In addition to the items previously addressed, we support Board Staff's identification of the following additional concerns which further support a conclusion that the proposed budgets for 2010 and 2011 are excessive:

(a) In a benchmarking study by First Quartile,[38] Hydro One was listed as the highest distribution substation OM&A expense per installed MVA, and for substation OM&A expense per asset was ranked in the middle of the pack;

(b) On a line-by-line analysis of Hydro One's OM&A budgets, there were significant increases;

(c) Rate impacts will be higher than originally forecast in the application and, as such, more weight should be given to the "customer satisfaction business value";

(d) Hydro One has not exhausted all avenues of cost sharing with the OPA for CDM expenditures or with other LDCs and ratepayers in the province with respect to Smart Grid development costs; and

(e) Other jurisdictions have taken into account the current economic situation when approving utility OM&A budgets by imposing "austerity based rate allowances".

129. We believe that these additional concerns, which are succinctly described in Board Staff's Submissions, further justify a global reduction of Hydro One's 2010 and 2011 OM&A budgets by the Board.

9. Appropriate Ceiling for OM&A Expenses

130. In its February 1, 2010 Submissions, Board Staff notes that at Exhibit H, Tab 1, Schedule 14, Hydro One was asked to address a scenario whereby the 2010 OM&A costs would be held to $494M. The $494M was calculated by inflating the 2008 Board approved OM&A budget of $466M 3% per year for 2009 and 2010. In this regard, we

[38] Exhibit H, Tab 1, Schedule 29 and Exhibit J6.8.

note that if an OM&A budget for 2010 of $494M were again inflated by 3%, this would produce a 2011 OM&A budget of $508.82M. As noted by Board Staff, Hydro One did not provide the requested scenario, but instead, simply stated that the scenario would increase the risks to its business values.

131. We believe that the scenario that Hydro One chose not to address in Exhibit, Tab 1, Schedule 14 provides a good basis for a reasonable disallowance in this case.

132. Board Staff has recommended that the Board reduce Hydro One's OM&A costs for 2010 to at least half of the "3% inflation scenario" set out in Exhibit H, Tab 1, Schedule 14. If accepted, this would result in a disallowance of $33M in OM&A costs for 2010, which would reduce Hydro One's proposed budget of $560M to $527M. In Board Staff's view, such a reduction should be achievable if Hydro One "sharpens its pencil" to operate as efficiently as possible.

133. In our view, it would be appropriate for the Board to reduce Hydro One's OM&A costs by the full amount contemplated in the scenario initially proposed in Exhibit H, Tab 1, Schedule 14. This scenario, which assumed a 3% inflationary increase, would result in a 2010 OM&A budget of $494M. This amount would still provide Hydro One with a budget that exceeds inflation. If the Board accepts this recommendation, then Hydro One's 2010 OM&A budget of $494M should be escalated by an additional 3% for 2011, producing a 2011 OM&A budget of 508.8M. If the Board accepts this recommendation and directs Hydro One to reduce the 2010 and 2011 OM&A budgets accordingly, then we agree with Board Staff that Hydro One should be free to reduce their cost envelope in the areas that they deem most appropriate.

VI. CAPITAL EXPENDITURES AND RATE BASE

1. Overview

134. In this section of our Argument, we provide rationale, that is in addition to the results of our integrated multi-year total price and bill analysis, to support approvals for total capital expenditures in 2010 and 2011 well below the levels Hydro One proposes.

135. The increases that Hydro One requests for its net distribution capital expenditures, including capitalized overheads and AFUDC are unreasonable and excessive. This is demonstrated by an analysis of the proposed increases compared to historical spending, as well as concerns with respect to specific the capital expenditures.

2. Hydro One's Proposed Capital Expenditures Materially Exceed Historic Spending

136. Hydro One requests a capital budget of $564.4M in 2010. This is an increase of $129.1M since Hydro One's last cost of service application for distribution rates in 2008. This increase, if approved, represents an increase of 29.6% over just two (2) years.[39]

137. For 2011, Hydro One requests a capital budget of $576.9M. If approved, this would represent a five (5) year increase since Hydro One's 2006 cost of service application for distribution rates of $198.4M. If approved, the 2011 budget which represents a five (5) year increase of 52.4%.[40] As with Hydro One's proposed OM&A budgets for 2010 and 2011, we are very concerned by this trend of massive increases over the past five (5) years.

138. These proposed capital budgets for 2010 and 2011 do not, however, represent all of the capital costs which Hydro One requests that the Board approve in this case. As set out in Exhibit A, Tab 14, Schedule 2, page 1 of 34, Hydro One is also seeking approval of externally funded *GEA* costs of $139M in 2010 and $236M in 2011 to be externally funded. If we add these additional externally funded *GEA* costs to the requested

---

39 Exhibit D1, Tab 3, Schedule 1.
40 Exhibit D1, Tab 3, Schedule 1.

budgets, Hydro One is requesting approval for a capital budget of $703.4M in 2010, and $812.9M in 2011.

139. If approved, the 2010 budget represents an increase of $268.1M since 2008, which would be a two (2) year increase of 61.5%. Similarly, if approved, the 2011 budget of $812.9M would represent an increase of $434.4M since 2006, which would be a five (5) year increase of 115%. We submit that increases of this magnitude constitute *prima facie* evidence that supports a finding that Hydro One has not reasonably controlled its capital spending

140. The excessiveness of the increases requested is further demonstrated by considering Hydro One's historic year-over-year average increase in capital spending compared to the proposed capital budgets for 2010 and 2011. As Board Staff confirms in its submissions, the average year-over-year increase in capital spending from 2006 to 2009 was approximately 6% compared to Hydro One's proposed 2010 annual capital spending increase of 25% compared to 2009. If the capital costs that Hydro One proposes to be funded by external ratepayers are included, then the proposed annual increase from 2009 to 2010 is 56%

141. This if further demonstrated by an analysis of Global Insight's distribution cost escalation for construction for the years 2006-2011.[41] The historic year-over-year average increase from 2006 to 2009 was 5.4%. For 2010 Global Insight forecasts a -0.1% cost escalation and for 2011 a marginal increase to 1.3%. We submit that this further supports the conclusion that Hydro One's proposed increases are unreasonable.

3. <u>Other Concerns with Hydro One's Capital Budgets</u>

142. We have had the benefit of reviewing Board Staff's final submissions and AMPCO's draft submissions. We share the concerns of AMPCO and Board Staff with respect to wood pole replacements, development capital, and shared services & other capital. We

---

[41] Exhibit H, Tab 3, Schedule 1.

submit that the concerns raised by Board Staff and AMPCO further support a material reduction in Hydro One's proposed capital budgets for 2010 and 2011.

4. <u>How Much Of Hydro One's Capital Budget Should The Board Disallow?</u>

143. At Exhibit H, Tab 7, Schedule 39, page 2 of 4, Hydro One set out, on a line-by-line basis, the minimal level of capital spending identified in the preliminary capital spending proposed by management. We submit that the Board should impose this minimum level of capital spending on Hydro One for 2010 and 2011.

144. If the Board were to adopt this minimum level of capital spending, then for 2010 the sustaining budget would be reduced from $185.8M to $156.4M, the development budget would be reduced from $205.7M to $184.9M, the operations budget would be reduced from $8.1M to $6.2M, and the shared services and other capital budget would be reduced from $164.8M to $139.9M. On a global basis, the total proposed 2010 capital budget of $564.4M would be reduced to $487.4M. If the Board approved a capital budget of $487.4M for 2010, this would still represent an annual increase of 8.2%, which exceeds the year-over-year average of 6% since 2006.

145. For 2011, the sustaining budget would be reduced from $202.6M to $173.8M, the development budget would be reduced from $252.4M to $217.2M, the operations budget would be reduced from $11.2M to $8.7M, and the shared services and other capital budget would be reduced from $110.8M to $95M. The total capital budget for 2011 would be reduced from $576.9M to $494.7M.

146. We acknowledge Hydro One's qualification in Exhibit H, Tab 7, schedule 39 that this minimum level of investment is neither a sustainable or desirable investment over the medium term, but may be unavoidable because of constraints in the short term. We submit that in light of the current economic crisis facing Ontario Ratepayers, the enormous budget increases which Hydro One seeks in this application cries out for

imposition of short term constraints. While this level of constrained investment may not be sustainable over the medium term, it would be sustainable for 2010 and 2011.

147. In considering whether to impose these reductions, we urge to Board to pay special attention to Board Staff's Submission that the minimal level funding described in Exhibit H, Tab 7, Schedule 39, by definition is intended to mitigate unacceptable risk. Therefore, The Board may proceed with confidence that Hydro One has the ability to maintain reliability and safety with a capital budget of $487.4M in 2010 and $494.7M in 2011.

VII. CAPITAL STRUCTURE AND COST OF CAPITAL

148. In its December 13, 2009 Cost of Capital Report EB-2009-0084, at page 13, the Board confirmed that the consultative process that led to the Report was not a hearing process that produces rates. The Board acknowledged that specific evidence in a rate case could lead Board Panels considering individual rate applications to refrain from applying the policy set out in the Report. Specifically, the Board stated:

> *"This was not a hearing process, and it does not – indeed cannot – set rates. The Board's refreshed cost of capital policies will be considered through rate hearings for the individual utilities, at which it is possible that specific evidence may be proffered and tested before the Board. Board panels assigned to these cases will look to the report for guidance in how the cost of capital should be determined. Board panels considering individual rate applications, however, are not bound by the Board's policy, and where justified by specific circumstances, may choose not to apply the policy (or a part of the policy)".*

149. At page 25 of the Report, the Board addressed the utility ownership issue upon which it had invited comment from Stakeholders. The Board stated as follows:

> *"In Ontario, utilities regulated by the Board in the gas and electricity sectors are structured to operate as commercial entities. As such, the rate setting methodologies used by the Board apply uniformly to all rate-regulated entities regardless of ownership. The determination of rate-regulated entities' cost of capital is no exception. It follows that the opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Board sees no compelling reason*

> *to adopt different methods of determining the cost of capital based on ownership."*

150. In summarizing its view on the fair return standard, at pages 15 to 20 of the Report, the Board emphasized that equity return is recoverable where it is a real cost. In particular, the Board adopted the Decision of the Federal Court of Appeal with respect to TransCanada PipeLines Ltd. ("TCPL"), a privately owned utility that does actually access equity in the equity capital markets. That Court emphasized the need for utilities to recover their real costs. The passage to this effect from the Federal Court of Appeal Decision is cited at page 16 of the Report as follows:

> *"Second, the Federal Court of Appeal also stated*
>
> > *… even though cost of capital may be more difficult to estimate than some other costs, it is a real cost that the utility must be able to recover through its revenues. If the… [Board] does not permit the utility to recover its cost of capital, the utility will be unable to raise new capital or engage in refinancing as it will be unable to offer investors the same rate of return as other investments of similar risk. As well, existing shareholders will insist that retained earnings not be reinvested in the utility."*

151. The Board emphasized the real cost point later at page 20 of its Report as follows:

> *"Further, the Board reiterates that an allowed ROE is a cost and is not the same concept as a profit, which is an accounting term for what is left from earnings after all expenses have been provided for. The Board notes that while cost of capital and profit are often used interchangeably from a managerial or operational perspective, the concepts are not interchangeable from a regulatory perspective."*

152. The fact that brings Hydro One within the parameters of the special circumstances exception principle espoused by the Board at page 13 of its Report is that Hydro One does not raise equity in the capital markets. Hydro One does not incur any actual "costs" for equity. The source of funds invested in Hydro One's equity is not equity capital raised in the markets. It is either taxes that the Ontario government imposes on taxpayers or monies the government borrows in the debt markets.

153. The Board has long held that taxes as a source of capital for privately owned utilities do not attract an equity return. For regulatory purposes, funds sourced from taxes are

treated either as debt or zero cost capital.[42] We reiterate that neither Hydro One, nor the Ontario government either raise or attract equity capital. The source of Hydro One's equity is either provincial taxes or debt, or both. This is not an ownership issue. This is a source of funds issue.

154. We request that the Board acknowledge in its Decision with Reasons in this case that Hydro One does not raise equity in the capital markets and that it does not incur any actual costs of equity. We request that the Board acknowledge, in this case, that taxes and/or debt are the sources of Hydro One's equity capital. We request that the Board acknowledge in this case that, as a matter of regulatory policy and principle, privately owned utilities holding equity capital attributable to government taxes are not allowed to earn a full equity return thereon and that, for regulatory purposes, funds sourced from taxes are either treated as debt or as zero cost capital. We reiterate that this principle should apply to Hydro One just as it applies to privately owned utilities with the result that Hydro One should not be allowed a full equity return on the equity component of its capital structure.

155. We submit that the Board's December 11, 2009 Cost of Capital Report does not address either the source of funds issue with respect to Hydro One's equity capital, or the principle that, for regulatory purposes, funds sourced from taxes are treated either as debt or as zero cost capital. These matters are relevant to a determination of whether the equity returns Hydro One asks the Board to approve are appropriate.

156. We accept that Hydro One is entitled to recover the prudently incurred costs of capital that it actually incurs, as the Federal Court has ruled. However, neither the Federal

---

42 See for example Reasons for Decision in E.B.R.O. 380 dated September 14, 1981, at pages 61 and 62 where the Board found that capital sourced from taxes should be deducted from Rate Base so that no return is awarded thereon. That practice was followed by the Board consistently after that Decision. See also National Energy Board Decision in RH-1-78 duly July 1978 to the same effect, where capital sourced from taxes is deducted from Rate Base and thereby accorded a zero return. In prior OEB cases, such as E.B.R.O. 343-1 Reasons for Decision Phase I dated June 30, 1976, the return allowed on funds sourced from taxes was the difference between the overall rate of return and an imputed interest rate on a deferred tax balance. A Decision in E.B.R.O. 367-1 Phase I dated July 7, 1978, at page 48 indicates that capital sourced from taxes should be regarded as an interest-free loan from income tax authorities.

Court Decision, nor the Board's traditional approach to treating utility capital that is sourced from taxes as zero cost capital, support the proposition that utilities the Board regulates are entitled to recover costs of capital that they do not incur.

157. The actual cost recovery rationale applied by the Federal Court of Appeal in TCPL's case does not apply to Hydro One's claim to recover "notional" costs of equity from its ratepayers.

158. We submit that counsel for Hydro One's argument[43] that Hydro One is entitled to full equity return because it is a cost Hydro One actually incurs is incorrect because Hydro One does not raise equity in the capital markets.

159. We submit that the source of funds principle brings Hydro One into the special circumstances exemption in the Board's Report. The return on equity claims and related taxes Hydro One seeks to recover in this case should be reduced to reflect a consistent application of that source of funds principle to both privately owned and government owned utilities.

160. Hydro One's contention that a full equity return is required to enable it to maintain debt ratings is incompatible with a acknowledgement made by the government of Ontario years ago when Ontario Hydro was restructured. At that time, the government indicated that a ROE sufficient to recover the cost of government debt, then assumed to be the source of funds for the equity components of the capital structures of OPG and Hydro One, would operate to maintain favourable debt ratings for these utilities.[44]

161. The extent to which Hydro One's revenue requirement could be reduced by applying these principles can be derived from Exhibit B1, Tab 1, Schedule 1, page 4, Table 1 and Exhibit H, Tab 13, Schedule 2, page 7 updated for the December 11, 2009 Cost of

---

43 Transcript, Vol. 11, p. 39, lines 26 to p. 40, line 1.

44 Backgrounder dated February 23, 2005, entitled "Ontario Government Announces Prices on Electricity From Ontario Power Generation" filed as Exhibit J1.1. This, we submit, is an acknowledgement that a return on funds sourced from government debt that covers the cost of that debt is appropriate. This Backgrounder was filed as Exhibit J1.1 in OPG's First Payments Application EB-2007-0905 and is accessible by this link: http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/40771/view/

Capital Report. Total equity return for 2010 at 9.75% on so-called equity capital of $1,934.2M is $188.5M. PILS for 2010 updated for the Cost of Capital is $26.8M for a total of $215.3M.

162. Total equity return for 2011 at 9.75% on $2,058.3M of so-called equity capital, which excludes most of the proposed *GEA* capital expenditures, is $200.68M. 100% of PILS for 2011 (assuming all *GEA* capital is included) is $48.8M for a total of $249.48M.

163. We submit that the source of funds for Hydro One's equity capital is either debt or taxes or both. If the source is all taxes, then a zero return would reduce 2010 revenue requirement by $215.3M and 2011 by $249.48M. There would be an additional reduction in the *GEA* revenue requirement amount which we have not calculated.

164. If the source of funds is debt having a cost of approximately 6%, then the reduction in 2010 at 3.75% of "equity capital" is about $75.53M and for 2011, is about $77.19M. Capital sourced from debt does not attract taxes so that the PILS amounts for 2009 and 2010 would also not be recoverable.

165. We submit that, upon an application of the source of funds principle, the maximum amount Hydro One can recover for so-called equity return should be an amount that reflects reductions in their claims for 2009 and 2010 of $75.53M and $77.19M plus applicable PILS in each year.

VIII. DEFERRAL AND VARIANCE ACCOUNTS

1. Disposition of Regulatory Assets

166. Hydro One has requested approval to refund, over a two (2) year period, a total Regulatory Asset balance of $(25.8)M, or $(12.9)M per year.[45] This balance includes the audited Regulatory Asset balances as of December 31, 2008, and the unaudited forecast Regulatory Asset balances From January 1, 2009 up to December 31, 2009.

167. As set out in Board Staff's submissions, the usual practice of the Board in the electricity sector is to rely on the most up-to-date audited balances, plus forecast of carrying charges to start the new rate year on those balances. Hydro One's audited Regulatory Asset balance as of December 31, 2008 is $(39.3)M.

168. While applying the Board's usual practice would result in a larger credit to customers at this time, it will also likely result in a future charge of approximately $13.5M once the 2009 Regulatory Asset balances have been subject to an audit.

169. Hydro One provided the following explanation for the difference in Regulatory Asset balances for 2008 and 2009:

> *"MR. ROGER: That's correct, but another reason that the balances are changing is the RTSR variance account, the RSVA for RTSR. The uniform transmission rates were reduced substantially in the uniform transmission rates in 2007 up to 2008. But we could only implement the associated retail transmission service rates on February 2009. So we know that that variance that had been accumulated up to the end of 2008 will gradually disappear as the RTSR we are charging customers now reflect more appropriately the uniform transmission rates they were getting charged. And that's the reason that the audited results have a higher credit to customers than what expect to happen by the end of 2009. So we could give a larger credit to customers now, based on the audited results, but we know that eventually that balance of the account is going to change and we'll need to collect from customers in the future, then."*[46]

170. In light of Hydro One's evidence that the 2009 Forecast Regulatory asset balances are reasonably predictable, coupled with the fact that clearing both the audited and unaudited amounts will avoid the a large customer charge once the 2009 balances have

---

45 Exhibit F1, Tab 2, Schedule 1, page 1 of 2
46 Transcript, Vol. 9, pp. 164-165

been subject to an audit, we support Hydro One's proposal to clear both the audited Regulatory Asset balances as of December 31, 2008, and the unaudited forecast Regulatory Asset balances up to December 31, 2009. The unaudited forecast Regulatory Asset balances should, however, be subject to a true-up process after the 2009 audit is complete.

171. However, we do not agree with Hydro One's proposal that the regulatory assets be refunded over a two (2) year period. We agree with Board Staff's position that clearing these balances (which are credits to customers) over a shorter time period will reduce rate impacts in 2010, and therefore, it would be appropriate for these balances to be cleared over a one (1) year period rather the two (2) year period requested by Hydro One.

2. New Regulatory Asset Accounts

172. Two of the new accounts for which Hydro One seeks approval have been previously rejected by the Board. We do not believe that Hydro One has provided fresh evidence that justifies the creation of either the OEB Cost Differential account or the Impact of Change in IFRS account

173. In Hydro One's 2008 distribution rate case, the Board denied Hydro One's request for approval of the OEB Cost Differential Account. Hydro One has not established new circumstances that would justify the establishment of this previously rejected account in this case.

174. Similarly, as Board Staff points out in its Written Submissions, the Board has considered and rejected the creation of an Impact for Changes in IFRS account. This was done in the Board's July 28, 2009 "Transition to International Financial Reporting Standards" Report.[47] Again, we submit that Hydro One has not justified the establishment of the impact for changes in IFRS account, particularly in light of the Board's recent Decision.

[47] EB-2008-0408

IX. COST ALLOCATION AND RATE DESIGN

1. Hopper Foundry

175. The Hopper Foundry is a small family owned foundry in the Town of Forest, Ontario. It dates back to a blacksmith's shop that was opened in 1861. Beginning with the installation of its first electric induction furnace in 1981, the Hopper Foundry has been offered restricted hour rates.[48]

176. In EB-2004-0457, the Board approved a request by Hydro One to implement a pilot program for distribution time of use ("TOU") rates for customers whose off-peak demand consumption (KW) was at least twice their peak demand consumption. Since that time, the Hopper Foundry's restricted hour rate has operated within the auspices of that pilot program.

177. In EB-2007-0681, the Board ordered that Hydro One continue the existing TOU rates for the Rate Year terminating on April 30, 2010 for the Hopper Foundry. In this proceeding, Hopper Foundry confirmed that the Board's Decision in EB-2007-0681 allowed Hopper Foundry to stay in business.

178. Since the Board's Decision in EB-2007-0681, Hydro One and Hopper Foundry have had several meetings and phone conversations in which they explored possible options.

179. One option, which is explained at Exhibit G1, Tab 9, Schedule 1, is to treat end use customers in a similar manner to embedded distributors being supplied below 13.8 kV in the Sub-Transmission ("ST") class. If this option were accepted by the Board, customers with average demands above 500 kW, that own their own transformation and are supplied at voltages below 13.8 kV, would be included in the ST class. There are 14 existing customers, including Hopper Foundry, that would meet this criteria.

---

[48] Exhibit K7.5, Tabs 1, 2 and 3

180. On the basis of the evidentiary record in this case, we submit that there are three options available for the Board to approve with respect to the applicable rate for Hopper Foundry. They are as follows:

(a) The Board could direct that Hopper be served under the General Service Demand rate applicable to Forest customers. This is the approach that was rejected by the Board in EB-2007-0681;

(b) The Board could approve the continuation of the existing interim TOU rate that was approved in EB-2007-0681. Hydro One confirmed in cross-examination that so long as it is permitted to recover $60,000 associated with the continuation of that existing TOU rate, they would have no objection to continuing on this basis;[49] or

(c) The Board could approve the option described in Hydro One's evidence at Exhibit G1, Tab 9, Sch. 1, which would result in Hopper Foundry being treated in the same manner that Hydro One treats embedded distributors being supplied below 13.8 kV in the ST class.

181. In our view, the first option should be rejected for three reasons. First, the General Service Demand Rate is premised on the assumption that Hydro One has the ability to meet the peak period demand for any customer, at any time, during the 24 hours in each day. As confirmed in an email from Hydro One to Hopper foundry dated November 26, 2009,[50] "it is possible that shifting load to daytime operations may cause problems for other customers". Hydro One is not able to provide any type of assurance that such disturbances would not occur,[51] and confirmed that Hopper Foundry could be required to take corrective actions as indicated in Section 2.3.3 of the electrical disturbances of Hydro One's conditions of service. If this occurred, the costs of the corrective action

---

49 Transcript, Vol. 7, p. 84
50 Exhibit K9.2
51 Transcript, Vol. 7, p. 82

would be paid for by Hopper Foundry and not Hydro One. Until such time as Hydro One can assure Hopper Foundry that its peak demands can be met 24 hours a day, the General Service Rate remains inappropriate.

182. Second, forcing Hopper Foundry into the General Service Demand rate for Forest without any TOU component would result in an excessive increase in Hopper Foundry's annual bill. Hydro One has estimated the resulting increases as ranging from 152%[52] to 190%.[53] We submit that, if imposed upon Hopper Foundry, this level of rate increase should be subject to mitigation measures. Hydro One confirmed, however, that they have not considered any mitigation measures with respect to transitioning Hopper Foundry from its existing TOU rate to the General Service Demand rate.[54]

183. Finally, Hopper Foundry's willingness to operate at off peak periods is the type of conservation behaviour that should be promoted by Hydro One. We submit that imposing a rate on Hopper Foundry that is premised on the provision of peak period demand 24 hours a day would be contrary to the "culture of conservation" that the Province of Ontario has directed the Board to promote, and would be contrary to the spirit of the *GEA*.

184. In its Submission of February 1, 2010, Board Staff suggests that a more detailed analysis of the costs in Hydro One's large system may warrant a larger number of rate classes or subclasses in the current approved tariff structure. In this regard, Board Staff submitted that Hydro One should determine whether a rate could be developed that would be more favourable to Hopper Foundry and similar customers, and would be consistent with cost allocation principles. One alternative identified was to include the cost of Hydro One's distribution facilities in some voltage range below 13.8 kV, along with the cost of its sub-transmission facilities for the purpose of cost allocation.

---

52 Exhibit K7.5
53 H-13-1
54 Transcript, Vol. 9, p. 88

185. We agree with Board Staff that the Board should direct Hydro One to prepare a cost allocation study or studies focusing on this aspect of the system, and present a report on its analysis with its next cost of service application. This cost allocation study or studies should provide the Board with the evidence necessary to properly determine the most appropriate rate treatment for Hopper Foundry and similar customers.

186. We do not agree, however, with Board Staff's proposed interim solution that Hydro One charge Hopper Foundry the General Service Demand rate. In our view, the interim solution should, to the greatest extent possible, maintain the status quo. Therefore, we urge the Board to direct Hydro One, as an interim solution, to continue to apply the TOU rate to the Hopper Foundry. This would be the simplest solution. The status quo would be preserved and only $60,000 would need to be collected from other ratepayers.[55]

187. If this is not acceptable to the Board, then we urge the Board to direct Hydro One to treat end use customers in a similar manner to embedded distributors being supplied below 13.8 kV in the Sub-Transmission ("ST") class. This would result in Hopper Foundry experiencing a bill increase of approximately 22.3%, and would produce a $1M shortfall in revenues from those customers that would need to be recovered from other ratepayers. Unlike the $60,000 associated with maintaining the status quo, however, we are concerned that, depending upon how it is allocated, the $1M shortfall could have a material impact on other customers.

2. Cost Allocation and Density Relationship

188. In Hydro One's 2008 distribution rates case, we raise concerns that the acquired utilities were generally located in more urban communities, and as such, could exhibit lower costs than Hydro One's legacy customers that were primarily rural. In its Decision with Reasons, the Board acknowledged that there may be factors that make it less costly to serve the acquired distributor territories than legacy systems, but that such a conclusion

[55] Transcript, Vol. 9, p. 89

could not be reached on the basis of the cost allocation information provided by Hydro One in that case.

189. The Board, however, explicitly agreed with Intervenors that Hydro One had not established that there are no significant differences in serving residential customers of acquired distributors compared to the legacy customers. On this basis, the Board directed Hydro One as follows:

> *"Accordingly, the Board directs Hydro One to provide a more detailed analysis on the relationship between density and cost allocation to the Board. This should consider whether the number of Residential and General Service customer classes in the new class structure is adequate, and whether the customer class demarcations approved in this Decision offer the best reflection of cost causation. The study should include consideration of alternative density weightings, with descriptions and criteria for comparing alternatives. Comparisons with the costs of distributors similar in size and location to Acquired Distributors would also be useful. The Board requires that Hydro One submit this information in its next cost of service application.*
>
> *[…] However, as is indicated above, the Board expects Hydro One to provide comparative analysis to allow the Board to better assess cost differences between the Legacy and Acquired customers."*

190. Instead of implementing this Board directive, Hydro One organized a Stakeholders' meeting and, on the basis of what the majority of the Stakeholders suggested, implemented a "staged approach". Hydro One has acknowledged that in adopting this "staged approach", it did not fully comply with the Board's directive.[56] In our view, the directive provided to Hydro One by the Board in the 2008 distribution case was not optional. The fact that some stakeholder's agreed with Hydro One's "staged approach" does not justify Hydro One's failure to respect the Board's directive. Hydro One should not be permitted to pick and choose which Board Directions it follows.

191. Because of Hydro One's failure to respect the Board's directive, interested parties and the Board remain in the same position they were in 2008. While there is evidence submitted by both Hydro One and SEC addressing whether Hydro One's current density based rates should be replaced by rate design premised on municipal boundaries, the

[56] Transcript, Vol. 10, p. 50

information needed to fully and adequately assess which is most appropriate remains missing. In short, had Hydro One followed the Board's directive, then the parties would have been in a much better position to assess this evidence.

192. Under the circumstances, we urge the Board to direct Hydro One to immediately comply with the directive previously given in the EB-2007-0681. To the greatest extent possible, the report should be provided to interested parties prior to the next cost of service hearing.

X. IMPLEMENTATION DATE CHANGE

193. In its initial application, Hydro One asked for rate implementation dates of January 1, 2010 and January 1, 2011, respectively. If approved, this implementation date change would have a revenue impact of $44.3M.[57]

194. On January 21, 2010, the Board initiated a consultative process to review the need for and the implications of a potential alignment of the rate year with the fiscal year for electricity distributors. In our view, it would be inappropriate for the Board to approve the alignment of Hydro One's rate year with the fiscal year prior to the conclusion of that consultative. The implications of aligning the rate year with the fiscal year for electricity distributors should be fully examined within the context of the Board consultative, and not in the context of this particular rate case. For these reasons, we submit that aligning Hydro One's rate year with the fiscal year in this case would be inappropriate.

XI. COMMUNICATION OF DECISION

195. In dismissing the Consumers Council of Canada ("CCC")'s Motion on January 14, 2010, the Board invited parties to provide suggestions for improving the communication of the results of its Decision to the public.

[57] Exhibit H, Tab 1, Schedule 7, page 1 of 1

196. The Board stated as follows:

> *"Although the motion is denied, the discussion which has taken place in the course of intervenor submissions has heightened the Board's awareness of the importance of clear communication of its final decision in this rates proceeding. The Board will seek to ensure that ratepayers understand the elements that drive rate changes resulting from this case and will also seek to ensure that, as much as possible, these changes are put into context for ratepayers.*
>
> *So in that regard, the Board asks that parties include in their final arguments any proposals they may have that would assist the Board in designing appropriate, transparent communication of the final decision of this proceeding."*

197. In this regard, we urge the Board to adopt an integrated total price and bill impact approach when both notifying the public of the results of its decisions and when providing the public with advance notice of the relief being requested by an applicant.

198. If the Board accepts our recommendations and modifies the Filing Requirements in its 2006 Rate Handbook and the Draft Filing Requirements pertaining to *GEA* plans to require utilities to provide the integrated multi-year price and bill impact information we describe in these submissions and in our prior letters of comment to the Board, then the Board will have the information it needs to prepare notices of applications that will contain realistic total price and bill impact information.

199. For example, the notice of application or report on a hearing that we envisage would read something to the following effect:

> *"Hydro One is requesting [was granted] an increase in the regulated distribution component of the prices that appear in its bill. Along with pending requests for increases in transmission costs and likely increases in the components of the energy and other charges that appear on your bill, the total price and bill impacts in 2011 are expected to be approximately ____% for average residential customers, _____% for average general service customers and _____% for large customers."*

200. Pending the provision by Hydro One and the other parties engaged in the coordinated planning that is essential to achieving the *GEA* objectives in a timely and cost-effective manner of an aggregated multi-year total price and bill impact analysis of the type we have suggested, we urge the Board to report the results of its Decision in this case and

its likely impact on total bills in a manner that does not assume that all other elements of the bill, other than Hydro One's distribution charges, will remain constant.

201. We suggest that it would be more appropriate to assume that increases in the other components of the bill will be in the same order of magnitude as the combined percentage increase in the bill that flows from the Distribution revenue requirement the Board approves for Hydro One in this case, and from the portion of the Transmission revenue requirement for 2010 that will be paid by Hydro One Distribution customers. If, for example, the combined effect of those increases is 20%, then a figure in that order of magnitude should be reported as the approximate total bill impact of the relief that has been granted. The practice of reporting partial bill impacts as if they were total bill impacts is misleading and, for the reasons outlined in this Argument, should be discontinued.

XII. HYDRO ONE'S DIRECT BENEFITS DETERMINATION PROCESS PROPOSAL

202. We support Board Staff's suggestion that a provisional allocation be made, subject to later adjustment.

XIII. COSTS

203. CME requests that it be awarded 100% of its reasonably incurred costs in connection with this matter.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 5th day of February, 2010.

Peter C.P. Thompson, Q.C.
Vincent J. DeRose
Counsel for CME

OTT01\3933262\1