ONTARIO ENERGY BOARD

STAFF SUBMISSION

2011 ELECTRICITY DISTRIBUTION RATES APPLICATION -

Board Staff Submission

Horizon Utilities Corporation

EB-2010-0131

PUBLIC REDACTED

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The following constitutes Board staff's submission on Horizon's application for rates effective January 1, 2011 based on a Cost of Service approach (the "Application"). This submission is a substantive review of all aspects of Horizon's application. There is a voluminous amount of information on the record, comprised of the original Application filed on August 26, 2010, interrogatories and submissions on the Preliminary Issue of Early Rebasing, interrogatories on the main application, updated evidence filed on March 14, 2011 and responses to interrogatories on the updated evidence. There was also a one day transcribed Technical Conference held on February 25, 2011. An oral hearing before the Board was conducted on April 7, 8, 11 and 14, 2011. Exhibits and Undertakings filed in or arising from the Technical Conference and the oral hearing are also part of the record. Staff notes that a total of 23 Undertaking responses were filed by Horizon during the oral hearing.

There are also numerous documents for which the Board determined that the material should be held in confidence, and portions of the Technical Conference and the oral hearing were conducted *in camera*.

While a facilitated Settlement Conference was conducted on March 8-9, 2011, and in which Board staff were in attendance, no settlement was reached as noted by Horizon's counsel at the beginning of the oral hearing.[1] In accordance with the Board's *Rules of Practice and Procedure*, any discussions in the Settlement Conference are privileged and do not form part of the record.

Board staff's submission covers Horizon's application in its entirety. The submission follows the order of exhibits in Horizon's application and as documented in the Board's *Filing Requirements for Transmission and Distribution Applications*, issued June 28, 2010 (the "Filing Requirements"). This order is as follows:

- The Nature of Horizon's Application
- Exhibit 1 – Administration
- Exhibit 2 – Rate Base and Capital Expenditures
- Exhibit 3 – Operating Revenues and Load Forecast

[1] Tr., Vol. 1, pg. 16/ll. 23-25

- Exhibit 4 – Operating Expenses
- Exhibit 5 – Cost of Capital
- Exhibit 6 – Revenue Requirement and Sufficiency/Deficiency
- Exhibit 7 – Cost Allocation
- Exhibit 8 – Rate Design
- Exhibit 9 – Deferral and Variance Accounts
- Other Matters

Within each section there may be sub-issues on various aspects of Horizon's Application and proposals.

The Nature of Horizon's Application

In accordance with the Board's Filing Requirements, Horizon has filed a Cost of Service application for a forward test year for 2011 rates. As such, the Application is based on a forecast of demand (both in terms of number of customers and consumption, either in kWh or kW depending on how the customer is billed), and on the necessary and prudent costs that the utility needs to expend to invest in and operate its distribution system safely and reliably to meet that demand within the same test year. The total costs needed for the test year are expressed as a revenue requirement, which is the sum of operating expenses and capital-related costs within the test year; these costs include a cost of capital commensurate with expected market conditions and the utility's business risk, and associated costs (i.e., taxes or PILs).

Rates are a unitized recovery of the annualized costs based on the demand. In other words, if the demand materializes as forecasted, then the total revenues recovered from the approved rates based on that demand will be fully compensatory for the operating and capital-related costs, including recovery of debt carrying costs and the opportunity to earn a market-based return on shareholders' equity, needed to service the forecasted level of demand.

Under the Incentive Regulatory Mechanism ("IRM") plan, the Cost of Service rebasing application also serves another purpose – of establishing rebased rates that, all else being equal, are representative of the demand-cost-revenue relationship for the subsequent IRM period and hence are a realistic basis on which rates in subsequent years will be adjusted by the IRM formula to allow for inflationary adjustments to costs less expected productivity improvements. This is not to say that the demand, costs and revenues are held constant, but that there is a relatively stable relationship.

It is Board staff's submission that Horizon's Application, as updated on March 14, 2011 and during the oral hearing, should be adjusted by the Board in its Decision in order to establish a reasonable level of rates to satisfy both requirements for the 2011 test year as well as establishing appropriate base rates for the subsequent IRM term.

For example, with the updated evidence, the load forecast does not appear to reflect 2011 actuals, particularly for the Large Use class. Given the timing of the update, Board staff submits that the actuals to date should be informative in determining an accurate forecast for the test period. With the updated evidence, Horizon has specifically zeroed the demand for one Large Use customer, even though there is load for the customer in at least the first three months of the year. Whether the reduced load forecast for the other specific Large Use customer is realistic for the 2011 test year remains unknown at this time.[2]

In response to Undertaking J3.3, Horizon has also updated its aggregate Load Forecast for other customer classes. This update was introduced on the last day of the oral hearing. As is discussed elsewhere in this application, Board staff has reservations concerning this update without further testing, something that was not possible given the timing of the update.

Further, Board staff is concerned that, in updating its load forecast, Horizon has not updated its costs. Ignoring any concerns that may exist over the quantum and justification for capital and operating cost increases that Horizon is proposing in this application, Board staff submits that it is unrealistic to materially change the forecasted demand without having some associated changes in costs. Board staff therefore submits that Horizon's application, as updated through the proceeding, does not realistically represent the demand/cost relationship for the

[2] While Horizon has proposed establishment of a deferral account to track revenues for load above the forecast for the two identified Large Use customers, Board staff makes submissions on this proposal later in this submission.

2011 test year and thus is not a realistic basis for setting 2011 rates without some adjustment.

Exhibit 1 – Administration

Alignment of Fiscal and Rate Years

Horizon has requested approval to align the rate year with the calendar fiscal year. Like most utilities, Horizon's rate year is currently from May 1 to April 30. However, some utilities have aligned the rate year and the fiscal year. Enbridge and Union Gas have calendar rate years, as does Hydro One Networks.

In a Decision regarding Enersource Hydro Mississauga's 2010 IRM application, the Board denied Enersource's proposal to align the rate and fiscal years, but stated:

> While the Board accepts Enersource's argument that aligning its rate year with its financial year would simplify reporting to the investment community and thus sees merit in the request, the Board believes that other distributors, particularly those that are reporting issuers, may also be interested in a change in rate year to January 1. The implications of such a change need to be examined more fully, in a Board policy context. The Board will initiate a brief consultation process in this matter in the near future. For purposes of this Decision, the 2010 rate year for Enersource shall commence May 1.[3]

In early 2010, the Board conducted a consultative process involving the industry and stakeholders[4]. In its letter documenting its findings from the consultation, the Board stated:

> All filings supported the idea that the Board allow each distributor the discretion to apply to align its rate year with the fiscal year as opposed to the Board prescribing a "generic" policy treatment. In addition, all filings suggested that any proposal for an alignment of

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[3] Decision with Reasons [EB-2009-0193], page 5, December 15, 2009
[4] EB-2009-0423, initiated January 10, 2010, http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Alignment+of+Rate+Year+with+Fiscal+Year

> the rate year with the fiscal year be made in a Cost of Service application. The Board concurs with these approaches.
>
> The Board has concluded that it is appropriate to consider the merits of an alignment of the rate year with the fiscal year for a distributor on a case-by-case basis upon receipt of an application for that purpose. Such an application shall form part of a distributor's Cost of Service rate application. Any distributor applying for an alignment to be effective on January 1, 2011 is requested to file that application as soon as possible.
>
> The Board expects the distributor to include an analysis of the benefits and ratemaking implications, if any, of the alignment as part of its application. To assist a distributor in this regard, the Board has included in Appendix B [of its letter] examples of the issues that should be addressed.[5]

Horizon, in its application, has requested alignment of the fiscal and rate years on this basis, and provided its reasons in support of the request.[6]

Board staff notes that the Standard & Poor's Report on Horizon Holdings Inc.[7] does not identify rate year alignment as an issue. In fact, the report states:

> The ratings (A/stable/-) on Horizon Holdings Inc. (HHI) reflect what Standard & Poor's Rating Services view as the excellent business risk profile of its key subsidiary, Horizon Utilities Corp. (Horizon of the utility; not rated), which the low-risk regulated monopoly electricity distribution (LDC) characterizes. … HHI's other investments are not material to the ratings.[8]

While Standard & Poor's noted the existence of regulatory lag, it is not seen as a major issue by the rating agency:

> The Ontario Energy Board's (OEB) regulatory framework supports the utility's cash flow stability. The framework allows for the recovery of prudent costs and the opportunity to earn a modest

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[5] Letter from the Board Re: Alignment of Rate Year with Fiscal Year for Electricity Distributors Board File No.: EB-2009-0423, April 15, 2010, pages 1-2
[6] Exhibit 1/Tab 2/Schedule 1/pp. 15-17. Further elaboration was also provided in the response to Board staff Technical Conference Question # 3.
[7] Exhibit 1/Tab 3/Schedule 4/Appendix 1-14. The date of the report is July 8, 2010.
[8] *Ibid*, page 2

> return. Regulatory cost recovery is generally predictable and timeliness is improving.[9]

Horizon's financial risk will be lessened but not eliminated by aligning the rate and fiscal years. As one matter, Board staff observes that the maturity dates of Horizon's debt is mid-year; this exposes Horizon to some unpredictability and risk as the cost of debt, when issued or renewed, will depend on rates at that time. In addition, Board staff notes that the Ontario natural gas sector uses a January 1 rate date and a four-quarter change in the GDP-IPI based on quarter 2 statistics in the previous year are used. Therefore, the Board has already adopted a methodology for determining GDP-IPI for use for rates effective January 1.

An effective date later than January 1 can also be useful for reflecting updated commodity and transmission rates. As Hydro One transmission does generally have a January 1 effective date, updated approved Uniform Transmission Rates can be known and reflected in Retail Transmission Rates and working capital allowances for May 1 effective dates, but not for January 1 implementation.

Board staff acknowledges that there could be benefits to the Board in balancing workload if some LDCs have rates effective May 1 and some January 1. The Board has acknowledged that it will consider alignment of the rate and fiscal year on a case-specific basis, and indeed approved a January 1 effective date for Hydro One Brampton recently.[10]

Board staff also notes that, while the impact on credit ratings does not appear to be material, Horizon did provide more information in support of its alignment of the rate and fiscal year than have most other utilities to date. Board staff therefore takes no issue with Horizon's proposal to align the rate and fiscal years.

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[9] *Ibid*. See also pages 6-7 and 10
[10] Decision for Hydro One Brampton Networks for 2011 rates (EB-2009-0132, April 4, 2011)

Effective Date for Rates

In its application, Horizon has requested an effective date for rates of January 1, 2011. In its decision[11] on this matter, the Board made Horizon's current rates interim pending a determination on this case.

Horizon's current approved rates were adjusted as a result of the Board's decision with respect to Horizon's separate application for an increased Smart Meter Funding Adder ("SMFA"), effective on an interim basis as of March 1, 2011.

Board staff submits that the effective date for rates should be subsequent to the Board's decision in this case, not January 1, 2011 as proposed by Horizon.

While Horizon requested January 1, 2011 for the effective date, it filed its application on August 26, 2010, only four months in advance of the proposed effective date. Normally, the Board's schedule assumes about 9 months for processing of a Cost of Service application.

Consideration of the preliminary issue of early rebasing required about 1.5 months of elapsed time. Horizon could not have known of the process by which the Board would consider this, as this was not known at the time of filing, and was subsequently established by the Board in the consideration first for a rates applications by Hydro Ottawa[12] and then in this proceeding.

Confidentiality of documents has been an ongoing matter throughout this proceeding which has added to the administrative and time requirements to process an application.

Late in the process, Horizon filed updated evidence on March 14, 2011. This was subsequent to interrogatories, the Technical Conference and the Settlement Conference, and barely three weeks before the oral hearing. The Board issued

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[11] Decision on the Preliminary Issue of Early Rebasing and Procedural Order No. 4, page 9, December 15, 2010
[12] EB-2010-0133

Procedural Order No. 7 to make allowance for an accelerated round of discovery with respect to the updated evidence. While parties largely complied by submitting interrogatories and Horizon filed its responses in accordance with the timelines, some updates were filed as late as April 6, 2011 and at the commencement of the oral hearing.

Board staff observes that there were 23 undertakings filed during the oral hearing. Many of these were filed just prior to the last day of the oral hearing. While the oral proceeding concluded as scheduled, the Board panel and staff and other parties have been challenged to deal with significant material filed late in the process.

In summary, Horizon filed in late August of 2010, which Board staff submits is too late for an effective date of January 1, 2011. While Horizon has had to respond to numerous interrogatories, undertakings, and questions, Board staff submits that these have been necessary to explore the issues raised in Horizon's application, and to seek necessary corrections and clarifications of the record.

In recent decisions on applications that were filed late, the Board has established effective dates subsequent to the release of the Board's decisions, and after the standard rate order process can be implemented. With the close of record scheduled for May 17, 2011, if the Board adopted a similar approach this would, in all likelihood, result in approval of an effective date no earlier than August 1, 2011.

Staff notes however, that the oral hearing was not delayed due to Horizon's updates. While staff will address the challenge of understanding the updates later in this submission, the Board may wish to consider an earlier effective date of May 1, 2011. This would be four months after January 1, 2011, and aligned with the normal effective date commensurate with the timing of the filing in August 2010.

Exhibit 2 – Rate Base and Capital Expenditures

Rate Base and Capital Expenditures

Subject to revisions for 2010 actuals and 2011 budgeted capital expenditures, Board staff has no issue with Horizon's in-service assets as a component of its rate base.

Horizon is proposing capital expenditures of $43,992,099[13] in 2011, a ~~78%~~ 27.7% increase over 2008 actual capital additions of ~~$24,731,529~~ $34,449,049.[14] It documents that the formal asset management approach that it has adopted beginning in 2008 has resulted in increased capital expenditures to address the age and condition of its network, particularly for certain assets. Horizon estimates that sustainable replacement of its network on a going-forward basis will require an increase of capex to about $45 million per year from 2015 onwards.

Horizon has not included any smart meter spending in rate base.

Generally, Board staff has no concerns with specific capital projects, save for one that will be noted below. However, Board staff does have concerns about the overall level of capital expenditures proposed, in light of the load forecast and considering other spending proposals in OM&A. Board staff will comment on this further below.

Horizon has relied extensively on the Asset Management Plan ("AMP") filed in its application to support its planned capital expenditures. In the oral hearing, Horizon noted that it conducted its AMP using internal staff. The purpose of the AMP was to get better data than had been done by an external consultant in the context of a merger being considered between Horizon and Guelph Hydro a few years ago. Horizon's AMP had improved information about the age and

[13] Of the $43,992,099 capital expenditures for 2011, Horizon documents that $34,783,221 are for "distribution system" and $9,208,878 are for "non-distribution system", as shown in Exhibit 2/Tab 2/Schedule 4/Table 2-14. In fact the $43.992 million is all within Horizon's regulated monopoly system. "Non-distribution system" expenditures are for general plant, such a buildings, IT hardware and software, etc. These are part of a utility's normal distribution rate base. Horizon's use of the term "non-distribution" is atypical and has caused some confusion on the record.
[14] Exhibit 2/Tab 2/Schedule 4/page 1/Table 2-14

condition of its assets. Horizon's evidence is that many of its assets are aging and in need of repair or replacement due to end-of-life. Horizon indicates that it has deferred some capital projects in 2009 and 2010 to cope with demand and revenue reductions, but states that continued deferment of capital investments to renew its infrastructure is unsustainable.

While Board staff concurs with this concept, there is no evidence that Horizon is "harvesting" its assets to the point of risking safety, quality and reliability of its system. Board staff also notes comments in the Standard & Poor's credit rating analysis:

> Nevertheless, HHI expects that it would have some flexibility to reduce dividends in times of financial stress. … We believe the LDC could also temporarily defer, for a year or so, a small portion (about C$5 million to C$7 million) of its maintenance capital expenditure without compromising service levels.[15]

This analysis was released on July 8, 2010, and so would also consider Horizon's financial and operational situation in 2009 to mid-2010. Horizon is in a better position to determine the condition of its assets and the need for and prioritization of capital investments, but the AMP is not definitive support for the magnitude of increases being sought by Horizon.

While an extensive AMP is corroborative support for a capital plan, it is not sufficient in and of itself. A utility must also consider its resources – time, money, and people – and decide what it can and must do, and with what priorities. Board staff submits that Horizon's evidence on this is limited. First, Horizon has proposed significant increases in operating and capital expenditures in the 2011 test year, even when faced with little growth in customers and possibly a decline in consumption. When faced with demand constraints, a profit-seeking corporation will consider options for productivity improvements and cost constraints. While distribution utilities face an obligation to serve, they also must make similar decisions of how to manage costs when faced with demand and

[15] Exhibit 1/Tab 3/Schedule 4/Appendix 1-14/pg. 10

revenue constraints. This was discussed during the oral hearing[16], but the evidence, in Board staff's view, is not definitive as to how Horizon has dealt with this in its 2011 capital and operating programs and budgets. In fact, Board staff submits that the misalignment between demand and capital plans is exacerbated by the load forecast updates where Horizon has reduced its load forecast but has not altered its 2011 capital program at all.

Board staff also submits that there is a disconnect between Horizon's proposed capital expenditures for 2011 and its resources. Horizon's workforce complement is dealt with later in this submission, where Board staff submits that Horizon's proposed FTE for 2011 is unsupported. [redacted]

This has several implications with respect to capital expenditures. First, as some portion of labour is capitalized (as it is directly attributable to capital programs), a reduction will reduce capital directly. Horizon has budgeted $13.25 million for capitalized labour in 2011, while Board staff's analysis suggests that a capitalized labour of $11.66 million may be more realistic based on the FTE reductions that will be recommended in the OM&A section below. Also, Board staff submits that this proposal aligns with historical amounts, as Table 4-25 updated for Undertaking J2.4 (and summarized later in this document) indicates that the 2010 budget for capitalized labour was $12 million while 2010 actuals were $9.2 million.

There also appears, to Board staff, to be some incongruities in Horizon's evidence and approach. As previously noted, Horizon conducted, using its own staff, an extensive AMP which has been filed in this Application. Horizon has noted the improved quality of the results of this study to support its capital plan. [redacted]

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[16] Tr., Vol. 1, pg. 94/l. 9 to pg. 96/l. 22
[17] [redacted]

[redacted]

In terms of specific capital projects, Board staff makes the following submissions.

Horizon has also stated that the data from the AMP was input into its GIS (geographic information system), part of its Enterprise Resource Planning ("ERP") system. The ERP is a significant multi-year capital program which was reviewed in Horizon's 2008 cost of service application (EB-2009-0697). Horizon's witnesses noted that the AMP data in the GIS was "data mined" to provide useful information on asset age and condition to develop its capital plan.

However, Horizon has also included a project called Enterprise Data Warehouse/Operational Data Store ("ODS"), with a 2011 capital cost of $350,000 for computer hardware and $990.494 for software in 2011. As Board staff interprets the description of this project, the purpose of this ODS system is to provide a single enterprise data warehouse integrating data from multiple applications (including GIS) for shared use across departments and for more effective planning both for operational and business planning decisions.[19]

During the oral hearing, Horizon's witness testified that the ODS is separate from and provided different functionality from the ERP, while acknowledging that ERP data, such as the GIS, was one source of the data for the ODS data warehouse.[20]

In Board staff's view, there appears to be some redundancy between the ODS and the current ERP/GIS systems which were analyzed to prepare the 2011 capital plan based on the AMP data. The ODS is, in part, another hardware and software tool for mining the data. Horizon may want to address this point in their reply argument.

18 [redacted]
19 Exhibit 2/Tab 3/Schedule 1/pp. 89-90
20 Tr., Vol. 1/pg. 66/l. 23 to pg. 70/l. 1

Board staff also expresses some concern with the fact that, even before it has implemented the results of the first AMP in renewing its system, it has redeployed staff to conduct another AMP in addition to implementing the ODS system. There seems, in Board staff's submission, redundancy and overlap. Board staff submits that it would have been more prudent and beneficial for Horizon to focus on carrying out action plans to address the results of the AMP for system maintenance and renewal before embarking on a second AMP. It also seems that the ODS does overlap Horizon's ERP/GIS system; as such Board staff questions the need for and prioritization of this project at this time, despite Horizon's assurances that it is expected to be in-service by the end of 2011. The Board may wish to consider a further reduction to Horizon's capital expenditures for the test year of $1.34 million.

Board staff also observes that, despite Horizon's insistence on the need to renew its aging infrastructure based on the results for the AMP, a significant amount of the 2011 capex is related to non-distribution[21] system projects, such as office renovations and IT systems. Table 2-14 indicates that $9.2 million of the $43 million proposed is for non-distribution system projects, such as IT hardware and software. The $9.2 million can be compared to 2008, when the ERP system was a significant component of Horizon's capex in that year. Table 2-14 indicates that 2009 and 2010 non-distribution capex are $5.4 million and $5.8 million respectively.

In light of this, Board staff submits that Horizon has overstated its 2011 capex, particularly for non-distribution capital expenditures. If Horizon is focussing on renewal of its distribution system in line with its AMP, Board staff submits that non-distribution capex should be reduced to a level more in line with recent actuals. In this case, Board staff submits that non-distribution capex of $6 million may be reasonable.

[21] Horizon's use of the term non-distribution capital is inconsistent with the *Accounting Procedures Handbook* which uses the term general plant for these types of assets.

Later, under Exhibit 4, Board staff submits that Horizon has overestimated its employee compensation, and Board staff submits that the 2011 capitalized labour should be $11.66 million, a reduction of about $1.59 million from the $13.25 million proposed by Horizon in Table 4-25 updated for Undertaking J2.4.

Board staff submits that an envelope reduction to 2011 capital expenditures of about $5.5 million may be reasonable; this is inclusive of the $1.6 million reduction in capitalized labour and a re-prioritization of 2011 capital projects, particularly for what Horizon terms as “non-distribution system”. While Board staff acknowledges the utility of these projects, the emphasis that Horizon has expressed about the results of its AMP indicating increased renewal of its aging distribution infrastructure suggests that Horizon should be more focussed on capital projects related to the distribution infrastructure itself. Horizon also needs to factor the reality of little customer growth and even a decline in demand to better determine the need for, prioritization and costs of its capital projects.

Lead-Lag Study

As directed by the Board in its decision on Horizon’s previous Cost of Service application for 2008 rates (EB-2007-0697), Horizon filed a lead-lag study to update its working capital requirements. The study, conducted by Navigant Consulting Inc. (“Navigant”), was filed in Exhibit 2/Tab 4/Schedule 1/Appendix 2-3 of Horizon’s original Application. The results of the lead-lag study are the basis for Horizon’s proposal that the Working Capital Allowance (“WCA”) be calculated as 14% of the sum of the Cost of Power plus controllable expenses; this is lower than the 15% factor that is commonly used in the electricity distribution sector. Some utilities have conducted individual lead-lag studies, typically in accordance with Board direction as is the case for Horizon. In the case of Hydro One Networks Inc. (“Hydro One”) and Toronto Hydro-Electric Systems Limited (“Toronto Hydro”), the WCA factors are 11.9% and 12.9% respectively. Recognizing the costs for a lead-lag study, the Board, has in recent cases identified the need for a generic process to review the working capital requirements for electricity distributors generally.

An update to the study was filed as part of Horizon's updated evidence on March 14, 2011. The updates do not result in material changes to the results of the lead-lag study.

Mr. Subbakrishna of Navigant testified on behalf of Horizon with respect to the lead-lag study.

Mr. Subbakrishna was questioned about the weighting factors used in calculating the revenue and expense leads and lags. In particular, Mr. Aiken questioned Horizon's witness about the customer-weighting of the service lag:

MR. AIKEN: Okay. I am thoroughly confused now.

The lag days for the service lag you have used are customer weighted. I am speaking to Horizon specifically. You are using the customer weighted service lag in the revenue lag; is that not correct?

MR. SUBBAKRISHNA: We use customer weighting in order to determine the time period between which a customer's billing cycle begins and the time the meter is read.

It is our belief that at that point in time, the issue of money hasn't arisen yet. The meter needs to be read. The bill needs to be generated. It needs to be sent to the customer.

There is a waiting period for the customer to pay. The payment needs to be processed, needs to be deposited into a bank, and then the funds are available to the customer.

Revenue weighting even before the meter is read we consider inappropriate, because at that point in time we don't even know how many kilowatt hours the customer has consumed.[22]

Board staff agrees that the power consumed is not relevant for customers that are on the same billing period (one month or two months), but notes that different customer classes are on different cycles. Residential and small commercial customers are on a bi-monthly cycle currently, while larger commercial customers are on a monthly cycle. Larger commercial customers consume more electricity and hence lagged revenues, but with a shorter service lag. Board staff submits that customer weighting overestimates the average service lag, and that revenue weighting for the service lag, as for other revenue and expense leads and lags is appropriate. As noted in the response to Undertaking J1.2, reducing the service lag from 30.5 days to 26.7 days would result in a WCA factor of about 13%, and reduce rate base by about $5.5M.

Board staff also notes some other assumptions of the lead-lag study. The Navigant study documents, under Billing Lag:

> A Billing Lag is the time period between the end of a customer's service period and meter read to the time that customer's bill is generated and dispatched. While customer consumption data was readily available subsequent to a meter read, interviews with the Company's Customer Service Department indicated that the key determinant of the Company's ability to dispatch a bill to its customer was the receipt of pricing data from the Ontario Independent System Operator ("IESO") which could take up to 11 or 12 business days. Taking this information into account, an overall Billing Lag of 17.35 calendar days was determined.[23]

It is clear that the IESO pricing data is necessary for billing of non-RPP customers. For RPP customers, it is not clear if waiting for the IESO pricing is a limitation of Horizon's CIS in order to determine settlement amounts and, if so, what the cost would be to change the system to bill RPP immediately after the meter read. This would improve Horizon's cash flow, lower the working capital

[22] Tr., Vol. 1 (April 7, 2011), page 49/ll. 9-28
[23] Exhibit 2/Tab 1/Schedule 4/Appendix 2-3, updated March 14, 2011, page 4

requirement and result in more timely billing to RPP customers. The Board may want to consider requiring Horizon to study this issue and report back at its next cost of service application.

Under cross-examination from Board staff counsel, Horizon's witnesses indicated that, with the implementation of smart meters and AMI, there could be a potential decrease in the billing lag. Horizon's witnesses also testified that they have reviewed the potential of monthly billing, and that this would not result in a decrease in costs.[24]

While the decreased factor of 14% is lower than the default 15%, the change is less than what Hydro One and Toronto Hydro have in identified in their updated lead-lag studies. Board staff also notes that Horizon's lead-lag study does not take into account operational efficiencies and changes in business processes that smart meters, remote reading and TOU data may allow for[25].

For this application, Board staff submits that the evidence does not support a factor of 14%. Board staff particularly is not persuaded that customer weighting for the service lag is appropriate. As a result, Board staff submits that a lower factor, around 13%, may be more reasonable for the 2011 test year and subsequent IRM period based on the above.

Exhibit 3 – Operating Revenues and Load Forecast

Load Forecast

Horizon has used an approach similar to that used by other distributors, with one significant exception. Horizon has used a commonly accepted approach for a regression-based load forecast for demand for all classes, in aggregate, excluding Large Users. It has then separately forecasted demand for the Large Use class.

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[24] Tr., Vol. 1 (April 7, 2011), page 73/l. 18 to page 75/l. 16
[25] The lead-lag studies of Hydro One and Toronto Hydro similarly represent pre-smart meter implementation.

The approach is intermediate between the class-specific modelling that Toronto Hydro has used in its 2011 Cost of Service application currently before the Board, and the one-model approach generally used by other distributors.

Board staff submits that Horizon’s approach is appropriate, given its circumstances. First, it has a distinct Large Use customer class, currently with 12 customers. These customers have unique load and demand characteristics. Horizon’s application for early rebasing is premised, in part, on the demand and revenue volatility of specific customers in this class. Board staff considers it reasonable for Horizon to forecast the demand for this class separately. Board staff also considers Horizon’s approach to model demand for other classes using a more standard regression approach as reasonable. That being said, Board staff makes submissions on each of these regression approaches, particularly in light of the updated forecasts that Horizon has made on the record.

Load Forecast for other than Large Use

Horizon has used a linear regression model that has evolved and been accepted by the Board in previous Cost of Service cases. The general approach is to regress monthly kWhs based on economic activity, days in the month, Heating Degree Days (“HDD”), Cooling Degree Days (“CDD”) Spring/Fall binary “flag”, CDM and other variables as necessary. This modelling approach attempts to estimate the influence of key determinants – such as customer base, economic activity, and seasonal and weather variations on realized demand. The estimated parameters are then used in the model along with forecasted exogenous variables for the test period to estimate a weather-normalized demand.

This aggregate demand is then apportioned within classes based on estimated per customer consumption patterns, and kW demand forecast for demand-billed customer classes are estimated through kW/kWh patterns or trends.

This regression-based approach has generally been preferred to a previous approach of Normalized Average Consumption (“NAC”), insofar that the regression approach tries to understand the determinants in a more substantive econometric model. However, there are caveats with this approach. While the aim of this regression-based approach is to produce a suitable forecast and not necessarily to understand the economic relationship of demand on various socioeconomic drivers, the suitability of the model and resulting forecast can be highly affected by the model specification, and the estimated parameters.

On the following two pages, Board staff has replicated the regression statistics from the Load Forecast regression model, both from the original application and the updated model filed as part of Undertaking J3.3. The regression outputs are contained in the Excel versions of the model but were not previously provided in hardcopy. These regression outputs were the subject of the cross-examination of Mr. Bacon by Mr. Shepherd on April 14, 2011, where the change in the CDM coefficient from -0.37 to -0.48 in the updated model was discussed.[26]

A significant amount of the cross-examination on the fourth day, April 14, 2011, was related to Undertaking J3.3 and the associated updated load forecast model. In Undertaking J3.3, Horizon confirmed that there had been a double-counting of 3rd tranche and OPA CDM savings. It had adjusted the CDM variable and then re-run the model. In J3.3, Horizon provided a summary indicating that the resulting revenue deficiency increased (in magnitude) from ($19,684,267) to ($20,721,653) – a change of over $1 million.

[26] Tr., Vol. 4, page 35/l. 18 to page 40/l. 8, partially replicated below.

Load Forecast (other than Large Use) – original application

Regression Statistics	
Multiple R	95.9%
R Square	91.9%
Adjusted R Square	91.3%
Standard Error	9,700,385
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	8.26673E+16	1.37779E+16	146.4214629	5.27815E-40
Residual	77	7.2455E+15	9.40975E+13		
Total	83	8.99128E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	(109,409,893)	72332297.31	(1.51)	0.134474796	-253441895.8	34622109.47	-253441895.8	34622109.47
Heating Degree Days	95,047	7571.622857	12.55	2.59882E-20	79969.98897	110124.0431	79969.98897	110124.0431
Cooling Degree Days	910,043	57530.20143	15.82	6.63961E-26	795485.322	1024599.851	795485.322	1024599.851
Number of Days in Month	8,780,815	1366982.439	6.42	1.0038E-08	6058805.323	11502824.81	6058805.323	11502824.81
Spring Fall Flag	(10,042,271)	3128996.165	(3.21)	0.001940057	-16272898.5	-3811643.966	-16272898.5	-3811643.966
CDM Activity	(0.37)	0.070389149	(5.19)	1.65819E-06	-0.505512056	-0.225186656	-0.505512056	-0.225186656
Ontario Real GDP Monthly %	1,331,306	449826.3092	2.96	0.004091755	435587.3356	2227024.538	435587.3356	2227024.538

Source: Appendix 3-2 (Excel spreadsheet model), Sheet “Purchased Power Model”, Cells N3 to V24

Load Forecast (other than Large Use) – Filed with Undertaking 3.3, April 13, 2011

Regression Statistics	
Multiple R	96%
R Square	92%
Adjusted R Square	92%
Standard Error	9,478,848
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	8.29945E+16	1.38324E+16	153.952549	8.9794E-41
Residual	77	6.91834E+15	8.98486E+13		
Total	83	8.99128E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	(45,152,289.61)	61136932.8	(0.74)	0.462429394	-166891473.8	76586894.6	-166891473.8	76586894.6
Heating Degree Days	94,926.45	7393.439202	12.84	7.97164E-21	80204.23127	109648.6674	80204.23127	109648.6674
Cooling Degree Days	912,669.72	56043.39423	16.29	1.17766E-26	801073.0709	1024266.378	801073.0709	1024266.378
Number of Days in Month	8,809,318.58	1335796.479	6.59	4.81265E-09	6149408.017	11469229.15	6149408.017	11469229.15
Spring Fall Flag	(9,886,988.56)	3051964.348	(3.24)	0.001768536	-15964225.89	-3809751.236	-15964225.89	-3809751.236
CDM Activity	(0.49)	0.086041519	(5.64)	2.64733E-07	-0.656956787	-0.314295687	-0.656956787	-0.314295687
Ontario Real GDP Monthly %	826,128.30	345707.5132	2.39	0.019309503	137736.7039	1514519.892	137736.7039	1514519.892

Source: Updated Load Forecast (Excel spreadsheet model) to Undertaking J3.3, Sheet “Purchased Power Model”, Cells M3 to U24

Messrs. Buonaguro and Shepherd attempted to understand the reason for this change that was apparently due to the updated load forecast. The following is an exchange between Mr. Shepherd and Mr. Bacon on this:

MR. BACON: That's assuming you use the same forecast.

MR. SHEPHERD: Well, so that's what I'm getting at.

So I thought these were the only three changes. These are all changes that appear to me to increase your forecast. What else happened in your forecast?

MR. BACON: We re-ran the regression analysis, and it actually came up with a better fit, better R-squared, but putting that aside, we re-ran the regression analysis with the double-count out, having all the correct values in for the CDM activity variable from 2003 to 2009.

That regression analysis, in its wisdom, assigned a higher coefficient to the CDM activity variable of 0.49 compared to 0.37. And so what that -- that was an increase of 32 percent.

So the coefficient went up, the negative coefficient went up by 32 percent. The reduction in the CDM activity variable as a result of addressing all the double-counts and making sure there was -- the persistence was dealt with only reduced the variable by 13 percent.

So what happens is -- I know it's kind of a double negative, because it's an amount of subtraction, but actually the coefficient is bigger, being applied -- the coefficient of negative 49 is being applied -- negative 0.49 is being applied to a smaller number, but in total, it's a bigger number being reduced.

MR. SHEPHERD: Okay. So this sounds very black-boxy to me, and so perhaps you can help me out.

You understand, Mr. Bacon, we've dealt with each other a number of times. You know I know nothing from load forecasts; right?

To my simple mind, if you do three things that should each increase your load forecast, then your load forecast should increase. And so I haven't heard anything in what your answer was to tell me why that isn't the case, other than: It was a black box and we got a different coefficient.

So can you give me a more sort of "normal people can understand" explanation?

MR. BACON: Let me take you to...

Can I take you to Exhibit 3 of the original application? Exhibit 3, tab 2, schedule 2, page 15 of 17.

It's a picture. Would you be able to turn to it, so I could show it?

MR. SHEPHERD: Not and still make my 12:00 o'clock deadline.

MR. BACON: Oh, sorry. Okay.

MR. SHEPHERD: Just describe it.

MR. BACON: The picture shows the actual purchases and it shows the predicted purchases, but the critical point here is the actual purchases haven't changed. So the target hasn't changed, what you're trying to target to.

And now, you might think -- well, so the actual purchases that we have for each month for 2003 to 2009 hasn't changed. So the regression is still trying to target that number.

Does that make sense to you?

MR. SHEPHERD: Keep going.

MR. BACON: Okay. So the regression has various buckets that it uses. It has -- I call it a heating-degree bucket, and a cooling-degree bucket, and a number of days in the month, and spring/fall flag, and Ontario GDP, and CDM savings bucket.

MR. SHEPHERD: Yes.

MR. BACON: Okay? And it's still trying to target that purchase amount, which hasn't changed.

So you have buckets that are -- various buckets that are trying to target that. The only bucket that changed was the CDM savings or CDM activity variable. It went down.

MR. SHEPHERD: So in your past data for some of the years prior to 2011, your CDM assumption was lower because -- or that is, the actual data you had on CDM was lower because of these adjustments, but in order to get to the same number, you had to assume it had a bigger effect on the load forecast?

MR. BACON: In order to get to, conceptually, the same bucket, you have a lower number now because CDM went down. You have to multiply it by a bigger coefficient to get to the same bucket.[27]

The following table summarizes the two regressions, both estimated over the range from January 2003 to December 2009:

	Exhibit 3-2, original Application, August 26, 2010			**Updated Load Forecast filed with Undertaking J3.3, April 13, 2011**	
Regression statistics					
Multiple R	95.9%			96%	
R-squared 91.9%				92%	
Adjusted R-squared	91.3%			92%	
Standard Error	9,700,385			9,478,848	
Observations 84				84	
F-statistic 146.42	14629			153.952549	
Regression Coefficients					
Coeffici	ent	t-statistic		Coefficient	t-statistic
Intercept -109,4	09,893	-1.51		-45,152,289.61	-0.74
Heating Degree Days	95,047 12.55			94,926.45	12.84
Cooling Degree Days	910,043	15.82		912,669.72	16.29
Number of Days in the Month	8,780,815 6.42			8,809,318.59	6.59
Spring/Fall Flag	-10,042,271	-3.21		-9,886,988.56	-3.24
CDM Activity	-0.37	-5.19		-0.49	-5.64
Real Ontario GDP	1,331,306	2.96		826,128.30	2.39

The updated regression is marginally better than the original model in terms of R2 and F-statistics. What Board staff observes is the change in both the coefficient and the associated t-statistic for each of the intercept and the Real Ontario GDP variables, along with the change in the CDM activity. It is notable that the coefficients of other variables do not materially change (which may be suggestive that multicollinearity does not involve these variables).

[27] Tr., Vol. 4, page 35/l. 19 to page 38/l. 12

Board staff submits that the "CDM bucket" is not the only bucket that changed with the updated regression. In fact, the coefficient on economic activity decreased by nearly 38%. What this means is that, in addition to the increased impact of CDM due to the increased coefficient, the contribution of the income variable was much reduced with the updated model.

Board staff submits that all of this is symptomatic of multicollinearity in the data. Multicollinearity refers to linear relationships or correlationships amongst a number of variables. Its significance for regression analysis as is being used here is that the correlationships amongst the variables confounds the regression formulae to disentangle the independent relationship of each explanatory variable on the endogenous variable (in this case, purchased kWh). The impact is that, due to normal endogeneity in the data, one variable's coefficient may pick up some of the explanatory power of another variable that it is correlated with and whose coefficient may be similarly affected. The standard errors of the coefficients will be larger.

Mr. Bacon has stated that multicollinearity is not his area of expertise, and that he focuses on R^2, t-statistics and coefficients.[28] Ms. Butany-DeSousa also acknowledged that, while Mr. Bacon did run the regression model for the load forecast, he is not a load forecast expert.[29] However, Board staff notes Mr. Bacon's response to Mr. Buonaguro:

MR. BUONAGURO: All right. Are you aware of other applications where multicollinearity has been looked at and what the effects of those -- that study may have for these applications?

MR. BACON: No, I'm not aware of any applications with that term or feature in it.[30]

[28] Tr., Vol. 4, page 32/l. 17 to page 33/l. 7
[29] Tr., Vol. 4, page 40/ll. 5-8
[30] Tr., Vol. 4, page 33/ll. 8-13

In fact, concern over collinearity (or correlations) amongst exogenous regressor variables has been explored in previous applications. In particular, in several 2010 Cost of Service applications, the presence of unintuitive results, such as negative income/economic activity coefficients (i.e., implying lower demand with increased economic activity) was possibly indicative of multicollinearity amongst the variables. Board staff notes that Mr. Bacon was a consultant to both Cambridge & North Dumfries Hydro [EB-2009-0260] and Chatham-Kent Hydro [EB-2009-0261], and was aware of concerns expressed in regression models of demand regarding multicollinearity, particularly between income and CDM variables, and other possible issues with estimated models.

In some of those applications, correlation between economic activity and CDM activity was noted. While the situation here has not resulted in unintuitive coefficients, the volatility between the CDM and economic coefficients between the original and updated load forecasts is symptomatic of multicollinearity involving these variables. This is confirmed by calculating the simple correlation between the Real Ontario GDP and CDM activity variables filed in the updated regression model. The simple correlation statistic between these two variables for the data from January 2003 to January 2009 (i.e. the regression range of the model) is 0.785.

Mr. Bacon has noted that he focuses on t-statistics and R^2. In Board staff's submission, this is not enough.[31] With an aggregate demand model as is used here, it is easy to get a high R^2. Aggregate economic activity and demand are both correlated with population, and hence with each other; thus, it is easy to get a good fit to the model. That t-statistics are significant is only a test of the hypothesis that there is, based on the data and model, likely a non-zero relationship of the explanatory variable on the endogenous variable.

[31] This argument has also been raised in staff submissions in some other cases. Board staff's submission on the load forecasting model in Cambridge and North Dumfries Hydro (EB-2009-0260) extensively discussed the issue of perverse outcomes and the need for more sophisticated econometric modelling approaches to recognize and deal with issues such as multicollinearity and heteroskedasticity. The Board's findings are cited in following footnotes. In addition, the issue of collinearity between income and CDM variables was discussed between Board staff with Mr. Bacon and staff from Chatham-Kent Hydro during the Technical Conference for that utility's 2010 Cost of Service application – Tr., Technical Conference, EB-2009-0261, January 26, 2010, pg. 24/l. 27 to pg. 34/l. 4

In Board staff's submission, some more sophisticated approaches to modelling may be necessary, both in this case and generally. Econometric modelling is both a science and an art. There are available techniques to estimate these sorts of models, including different functional forms, and many diagnostic tests for heteroskedasticity, serial correlation, multicollinearity, etc., all of which may lessen the accuracy of model estimates and even be indicative of model misspecification.

The challenge is how far to go. The purpose of this approach is to develop reasonable forecasts for the test period; it is not a post-graduate understanding of price and income elasticities. However, there is still a need to get it "right enough". As the Board has stated elsewhere:

> The Board acknowledges that load forecasting is continuing to evolve. This is a highly technical area, and the move to more sophisticated econometric techniques make it more so. The Board agrees that regression techniques can, if properly applied, provide valuable insight to the utility and the Board. Misapplied, techniques can result in significant errors and material under- or over-recovery. The impacts of errors may be magnified, as the base rates determined through a cost of service hearing will impact the IRM formula until rebased in four years.[32]

However, the Board continued in that Decision:

> Much of this Decision and indeed the entire proceeding has been devoted to the 2009 and 2010 load forecasts. This "war" of econometric models has become the least attractive part of the process. It has consumed considerable time and costs, all of which will be borne by the ratepayer. In the end the Board was forced to declare a truce, and essentially split the difference between the two models.
>
> It is important to consider how the process can be improved in the future. The difficulties experienced in this case are not unique to

[32] Decision on Cambridge and North Dumfries Hydro's 2010 rates application, [EB-2009-0260], page 12, para. 49, April 20, 2010

> this proceeding, and have been repeated in a number of applications for other utilities.[33]

Board staff submits that Horizon's model exhibits symptoms similar to those of earlier models. However, these matters only have come to light with Undertaking J3.3 and the updated load forecast. Parties did not have adequate time to fully test even the corrected CDM variable, and the volatility of the model only become apparent at the last day of the oral hearing, and there is no viable alternative on the record. For Total System Purchases excluding Large Users, Horizon's 2011 weather-normalized forecast was 4,127.6 GWh[34]; in the updated model filed on April 13, 2011, the revised load forecast is 3,991.0 GWh.[35] 2009 actuals (non-weather-normalized) were 4,207.5 GWh, and historical actuals from 2003 to 2009 were in the range of 4,400 to 4,700 GWh. Comparisons between weather normalized and non-normalized results is difficult. However, it is easy to see that the original forecast, inclusive of CDM impacts, is lower than historical actuals, while the load forecast updated on the last day of the hearing has a further reduction of about 2.5%. This last update had a material impact and it is unfortunate that it could not be subjected to appropriate testing due to timing.

Board staff also observes that Horizon has also factored in the CDM targets that are now a condition of a distributor's licence into the 2011 weather-normalized load forecast. Horizon has done so by assuming that 25% of the target is achieved in the 2011 year. This assumption contrasts with the interpretation of the CDM target, with respect to kWh as being the cumulative savings to be achieved over the four year period. In other Cost of Service applications for 2011 rates, an approach of ramping up savings so that 100% of the target is achieved cumulatively over the four years (i.e. 10% in the first year, 20% in the second year, 30% in the third year and 40% in the fourth year, cumulating to 100%) is a more realistic approach that has been approved by the Board in rate applications for other utilities.

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[33] *Ibid*, page 15, paras. 58-59 (in part)
[34] Exhibit 3/Tab 2/Schedule 2/Table 3-9
[35] Load Forecast spreadsheet model filed with Undertaking J3.3

Board staff acknowledges that this is not a straightforward issue. The CDM license condition also has a kW target, and concurrently achieving the kWh and kW targets relies on assumptions about load profiles. Nonetheless, Board staff submits that Horizon's assumption of achieving 25% of the target in the 2011 rate year is an ambitious aim that further lowers the load forecast and hence puts upward pressure on rates. An adjustment to achieve the savings cumulatively as has been approved in other 2011 Cost of Service applications may be more realistic.

Overall, Board staff submits that the original 2011 weather-normalized Purchased Load Forecast of 4,127.6 GWh may be a more realistic forecast, despite the errors of the CDM variable in the regression model. Board staff has no confidence in the load forecast from the updated model filed on April 13, 2011, in the absence of adequate opportunity to test the model.

Large Use Load Forecast

As noted previously, Horizon has developed a separate Load Forecast for its Large Use customer class. As previously mentioned, Board staff considers Horizon's approach appropriate. These are heavy industrial customers; their energy demand, unique to each customer, will be sensitive to macroeconomic conditions and to weather and other influences much differently than for most other Horizon customers.

Board staff takes no issue with the general approach, but is concerned with the update filed on March 14, 2011. In this update, Horizon updated the load forecast for 2011 for the Large Use class in aggregate and for each of the current 12 Large Use customers. The updated forecast is provided in Table 3-24A. Board staff observes that the aggregate Large Use forecast for 2011 went from 3,044,901 kW to 2,417,347 kW. Historical actuals were 3,299,915 kW in 2008 and 2,433,218 kW in 2009.[36] Updated 2010 forecast in Table 3-23 was 2,853,449 kW.

[36] Exhibit 3/Tab 2/Schedule 2/Table 3-23 (original and revised March 14, 2011)

While the update showed altered demand for most of the Large Use customers, the major changes were with respect to the demand of two specific customers. For these two specific customers, the revisions are due to publicly known events – one, an announced closure of a plant, and for the other, a managed shutdown reducing demand. For the first customer, Horizon has zeroed out demand for all months in 2011, despite the fact that there has been actual demand in all months to date for that customer.

Board staff's concern is that Horizon's adjustments produce a forecast that is, in all likelihood, lower than what would otherwise be expected for 2011. Horizon has proposed an asymmetric deferral/variance sub-account of Account 1572 to address this situation; Board's staff's submissions on this proposal are dealt with elsewhere in this submission.

In large part, Horizon's revised forecast is to be more representative of what it considers to be the load in the next IRM period beyond the 2011 test year. This is premised on the assumption that there will be no new or replacement load, particularly for the two affected customers. Unfortunately, neither the Board not any other party can forecast what will – or is even likely to – happen at this time. The decisions are beyond Horizon's control.

The dilemma, from Board staff's perspective, is that the updated Large Use forecast for 2011 does not correspond with the reality in the 2011 test year. All else being equal, the zeroing of demand for the one customer means that the updated forecast is an under-forecast of 2011 demand for the Large Use class. The significance is that this will also impact on the cost allocation between classes and on the derived rates for the Large Use class. Specifically, an under-forecast for the Large Use demand will mean that, *ceteris paribus*, costs will be allocated to and recovered from some other classes and that the rates for the Large Use class (and, to a lesser extent because of the cost allocation, also for other classes) result in higher rates. This benefits Horizon in providing more certainty of cost recovery but does not, in Board staff's view, result in "just and reasonable rates".

The fact that Horizon, with the late update of the forecasts for both Large Use and other classes, has not adjusted costs when it has reduced its load forecast, exacerbates the situation, as has been commented on already.

Board staff submits that one option that might provide a more realistic view for 2011 would be for Horizon to develop an updated 2011 forecast for the Large Use class based on an extrapolation of actual demand to date in the class in its draft Rate Order. Some adjustment might have to be made for the shut down of the one user, but Board staff submits that assuming no demand for that customer where there is actual demand for at least one-third of the year is unrealistic. Horizon should provide sufficient documentation on this and parties should have opportunities to make submissions on this matter.

Other Revenues

In its Application, Horizon has forecasted Other Operating Revenues as $5,481,969 for the 2011 test year. There has been a trending reduction in Other Operating Revenues over time, from $7,292,436 in 2007, $7,344,652 in 2008, $6,083,647 in 2009, and $5,601,659 in 2010 bridge to the $5,481,969 for the 2011 test year.[37]

One area that was raised relates to Account 4390 – Miscellaneous Non-Operating Revenues. This is estimated at approximately $1.3 million per year from 2009 onwards. In 2008 the annual revenue was higher at $2.0 million. Horizon's evidence is that the reduction reflects, in part, a revised Service Level Agreement with Hamilton Utilities Corporation, effective May 1, 2009. Horizon notes that it shares and in fact provides certain corporate services with affiliated companies for certain administrative, financial, IT and other services. In part, this is based on allocated time for Horizon's executives, and units under them, to provide services to affiliates or on non-distribution activities. This was the subject of some cross-examination during the oral hearing. During the cross-examination, the practicality or reality of estimated time allocations for non-distribution activities for some of the Horizon witnesses were questioned, with

[37] Exhibit 3/Tab 3/Schedule 1/page 1/Table 3-25

Member Spoel pointing out that a 1% allocation would correspond to about 20 minutes per week.[38]

Board staff takes no issue with Horizon's proposal for Other Operating Revenue in this Application. However, in light of the above, Board staff submits that Horizon, in its next Cost of Service application, could be required to provide further detailed information on the actual time allocation of Horizon's executive, managers and staff involved in providing services to non-distribution affiliates. This information would be to better inform and assure the Board that there is no subsidization of the non-distribution activities of affiliates by Horizon's ratepayers.

Exhibit 4 – Operating Expenses

OM&A

In its original application, Horizon has applied for operating expenses for 2011 of $47,837,239. In the discovery phase, Horizon acknowledged a reduction of approximately $80,000, related to the amortization of regulatory expenses related to this application over four years (2011 and three years of IRM) as opposed to the three year amortization originally proposed.

The revised proposed OM&A of $47,757,439 represents an increase of $7.7 million or 19% over 2010 budget and $8.95 million or 23% over 2009 actuals.

In Board staff's submission, the increase in OM&A relative to 2009 actuals should be significantly reduced by about $5 million, resulting in a revised OM&A of $42,757,439. Board staff proposes this reduction for a number of reasons.

First, as is discussed later in this submission, Board staff considers that Horizon's 2011 staff complement is overstated. In a later section of this submission, Board staff has estimated a compensation budget of about $36.7 million, nearly $5 million lower than the $41.6 million proposed by Horizon. Of this, Board staff estimated expensed compensation of $25.0 million, compared to $28.3 million requested by Horizon, a difference of $3.3 million.

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[38] Tr., Vol. 2, pg. 92/l. 5 to pg. 95/l. 24

Second, and as explained later in this submission, Board staff also notes that Horizon has been unable to substantiate significant efficiencies in its capital and operating expenses. In fact, due to timing, in many cases, capital expenditures in 2011 will not result in significant efficiencies in the 2011 test year. However, Board staff submits that Horizon should have been able to document efficiencies from previous years and how these are reflected in its 2011 forecast.

Finally, Board staff is concerned about Horizon's estimates of inflationary pressures. As is noted on the record, labour agreement negotiations are ongoing. However, with respect even to non-labour inflationary pressures, Horizon seems to assume a high rate of inflation of at least 3%:

MR. SHEPHERD: Good. What I don't understand, then, is if revenues are lower, why would you ask this Board to increase your OM&A by 29 percent? I don't understand why, in those four years, with revenues dropping, you haven't been cutting your costs to match your revenues, spending what you can afford.

That is what I am trying to understand. That is what this is all about.

MR. BASILIO: We have been cutting costs in real terms. Costs between 2008 and 2010 have remained at approximately the same levels.

If you consider inflation, in real terms, costs have declined, and I would use 3 percent as probably an appropriate benchmark for inflation experienced by the utility but, you know, compounded, it is over 9 percent.

So costs have dropped in real terms.

But the simple fact is the level of activity that the utility needs to undertake to sustain itself -- which is the subject of the evidence -- is increasing and must increase.[39]

and:

[redacted]

[39] Tr., Vol. 1, p. 94/l. 14 to p. 95/l. 5

[redacted]

Horizon has provided no evidence in support of its contention that annual inflationary pressures on costs have been 3% per annum as a conservative estimate. Data from Statistics Canada suggest otherwise. GDP-IPI (Final Domestic Demand) is used as the inflation factor in the IRM plans for natural gas and electricity distributors, and the published annual growth factors have been 2.3%, 1.3% and 1.3% for 2009, 2010 and 2011 respectively.[41] GDP-IPI is a price deflator index, and not directly a measure of inflation, but its interpretation as a proxy for inflation in this context is commonly accepted.

The Consumer Price Index ("CPI") is a more common and direct measure of inflation. It measures inflationary pressures with respect to residential goods and services, and thus is not the best measure for business cost inflation. However, it can be a useful alternative measure. It is commonly understood that the Bank of Canada's current fiscal policy is to maintain inflation around a 2% target, and the commonly reported annual inflation rate of CPI has been maintained around that target for several years. The core CPI, which excludes certain volatile items, is even less. This is a trend in the data that has persisted for a number of years. Admittedly, certain international events may be putting upward pressure on inflation in Canada, but the fiscal policy is still a 2% target.

Board staff submits that, and in light of available Government statistics indicating a lower rate of inflation, Horizon's assumptions of 3% inflation for non-labour items as "conservative" is unsupported. Board staff notes that, in some other

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[redacted]

[41] From the Board's website, under Electricity Distribution Applications, the Board publishes, in early March, the annual percentage change in the GDP-IPI (FDD) for the previous calendar year, as published by Statistics Canada, for the final IRM rate adjustments.

Cost of Service cases, the GDP-IPI or some inflation adjustment closer to 2% is accepted as a measure of non-labour inflation.[42]

Taken together, Board staff submits that a reduction to the 2011 OM&A forecast of $5.0 million would be reasonable, giving a revised OM&A of $42,757,439. This $5.0 million reduction is inclusive of the $3.3 million reduction in expensed compensation, a lower non-labour inflation and of continued efficiency gains, and operational constraints that Horizon, like any business in similar circumstances, should consider in light of demand and revenue constraints. Board staff submits that Horizon should be able to operate within this OM&A envelope and is not suggesting specific reductions to OM&A.

Board staff notes that its proposal for an OM&A of $42.757 million is a 6.4% increase over the 2010 test year budget and 9.4% over the 2009 actuals. The Board has, in its decisions[43] in other proceedings, taken the 10% increase as a realistic cap on OM&A increases over a two-year period.[44]

Efficiencies

Horizon has documented little qualitative or quantitative support for productivity and efficiencies, and has indicated that operating and capital projects for 2011 currently result in little, if any, savings in the 2011 test year. [redacted][46]

Board staff submits that Horizon should be able to provide better support for operational efficiencies and productivity gains. Board staff views that Horizon's

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[42] Decision and Order, Hydro One Brampton Networks Inc., [EB-2010-0132], April 4, 2011, pg. 22 and Decision and Order (corrected), Kitchener-Wilmot Hydro Inc., [EB-2009-0267], April 7, 2010, pg. 13

[43] Decision with Reasons, Hydro One Networks Inc., [EB-2009-0096], April 9, 2010, pg. 14 and Decision and Order, Hydro One Brampton Networks Inc., [EB-2010-0132], April 4, 2011, pg. 23

[44] e.g., Decisions for Burlington Hydro for 2010 rates (EB-2009-0259, March 1, 2010) and Hydro [redacted]e Brampton Networks for 2011 rates (EB-2010-0132, April 4, 2011)

[redacted]

[46] [redacted] Tr., Vol. 3 (April 11, 2011), page 132/l. 19 to page 135/l. 12 and page 166/ll. 3-25

cost constraints in 2009 and 2010 contain examples of various efficiencies, and submits that Horizon should be able to continue productivity gains into 2011. Board staff thus interprets Horizon's evidence of limited productivity gains in the 2011 test year costs as indicating that the costs are overstated and that some downward adjustment is warranted. With the limited evidence in this regard, it is hard to quantify what these should be; however, Board staff has used this as one factor supporting its proposal for reductions to the operating expense increases being sought by Horizon.

While the production of Total Factor Productivity studies is not a requirement for cost of service applications, it is not unrealistic for parties to expect such evidence in circumstances where an uncharacteristically high increase (as compared to the historical trend) is requested by an applicant, as is the case in this Application. Therefore, if in subsequent Cost of Service proceedings Horizon continues to make requests that are much higher than its historical actuals, Horizon should be expected to provide better support for the productivity gains it has realized historically, and what and how efficiency gains are reflected in its test year operating and capital costs.

Employee Complement and Compensation

Horizon has forecasted a staff complement of 428 for the 2011 test year, including an increase of 27 new positions in 2011 alone. As became apparent during the oral hearing, this does not include students.

The primary evidence revolves around Table 4-25 and Table 4-26. Table 4-25 is the spreadsheet showing historical actuals and bridge and test year forecasts for number of employees (as Full-time Equivalents or FTEs), wages and salaries, incentives and benefits, and is part of the Board's Filing Requirements (Appendix 2-K, as it was frequently referred to during the oral hearing).

Table 4-26 was a tabulation of incremental new staffing positions by year and the actual or budgeted date of hire. Table 4-26 also included the actual or budgeted starting salary for each position, and was filed in confidence.

Tables 4-25 and 4-26 were updated throughout the discovery process, with the last versions filed as Undertaking J2.4. Undertaking JX2.4 is the confidential version of this undertaking. Board staff's submission only relies on the public redacted versions of the tables.

A summary of Table 4-25 as updated in Undertaking J2.4 is provided on the following page. Board staff has added lines showing the percentage of compensation capitalized and the percentage increases in FTEs and compensation (based on year-end actuals except for 2011 budget; the annual increases for the 2011 budget are now compared to the 2010 actuals that were filed on the record during the oral hearing).

While Horizon had budgeted for a staff of 395 and 401 employees in each of 2009 and 2010, the year-end staffing headcount[47] is 386. As Table 4-26 indicates that all incremental positions were filled in each year, this implies that Horizon had several vacancies at the end of each year.

[47] Confusion over head-count versus FTEs was discussed in the oral hearing, primarily with Panel 2 on Day 2 (April 8, 2011) and again on Day 4 (April 14, 2011) with respect to Undertaking J2.4. Board staff submits that the confusion that resulted during the oral hearing on this is due to Horizon not adequately documenting its evidence.

Summary of Table 4-25 (Public Redacted) as updated in Undertaking J2.4

		Last Rebasing Year - 1 2007 - Actual	Last Rebasing Year 2008 - Actual	Historical Year 2009 - Actual	2009 Budget	Bridge Year 2010 - Budget	2010 - Actual	FTE Equivalencies for all vacancies 2010	Test Year 2011 - Budget
Number of Full-Time employees ²									
Executive	(1)	5	5	7	5	7	7	0	7
Directors	(2)	10	10	10	9	10	10	0.92	11
Management	(3)	42	43	51	44	55	49	3.75	59
Non-Union	(4)	26	26	34	39	38	37	3.67	47
Union	(5)	284	284	284	298	291	283	3.67	304
Total	**(6)**	**367**	**368**	**386**	**395**	**401**	**386**	**12.01**	**428**
Number of Part-Time Employees									
Union	(7)	2	2	2	2	2	2		2
Total	(8)	2	2	2	2	2	2		2
Total Compensation (Salaries, Eages & Benefits)									
Total	(9)	29619888	30857057	32297935	34824058	37512325	35091915		41642494
Total Charged to OM&A	(10)	21934873	23641363	24670977	26600571	25453376	25861986		28395948
Total Capitalized	(11)	7685015	7215694	7626958	8223487	12058949	9229929		13246546
Percentage of Labour capitalized (11)/(9)	(12)	25.9%	23.4%	23.6%	23.6%	32.1%	26.3%		31.8%
Annual Percentage Increases									
Number of Full-time employees (YE actuals except for 2011)			0.3%	4.9%			0.0%		10.9%
Total Compensation			4.2%	4.7%			8.7%		18.7%

Table 4-26, as updated in Undertaking J2.4, is revealing insofar that Horizon's budget plans for hew hires exceeds actual hiring. For 2011, Horizon has budgeted for 27 new positions. However, as updated in Undertaking J2.4 on April 13, 2011, only 3 new positions had been filled. Of the remaining 24 positions, 3 were budgeted for in April or September of 2011. This means that 21 positions that Horizon is planning for – and which 2011 costs from the planned date of hiring are included in the proposed revenue requirement – had not been filled as of mid-April.

Board staff, also observes that Table 4-26 only pertains to new positions in each year. Vacancies in incumbent positions in Horizon are excluded. While it is necessary and prudent for Horizon to plan for and actualize new hiring, particularly for succession planning with an aging workforce, it must also temper its plans with what it can actualize. Also, as has been noted during cross-examination, many of the new positions are supervisory or back office/head office positions and not directly related to front line operations to maintain and replace Horizon's distribution infrastructure. Position titles such as "Manager, Documents & Records", "Capital Projects Financial Analyst", "Financial Advisor", "IFS Subject Matter Expert", "Data Warehouse Specialist" and "Specialist, Commodity Management" would be in line with many of these positions being related to capital and operations projects that are beyond core distribution functions.

While Horizon has commented that it has deferred projects, and that new staff are needed for projects to increase capital spending to refurbish its aging infrastructure, Horizon has to date managed its operations with a staff complement similar to that which it currently has been able to fill. As noted above, the evidence filed indicates that Horizon has had a number of vacancies at any point in time. There is no indication that this will not continue, particularly with the proposed increase of 27 new positions in 2011 alone. Board submits that a more reasonable approach is to include an allowance for vacancies in the compensation forecast.

It is not clear how Horizon has prioritized the utilization of its staff complement in the 2011 budget, particularly to avoid overlap and redundancies. [redacted]

[redacted] It is not clear to Board staff how Horizon is optimizing its utilization of staff. First, having conducting its AMP recently, the need to go out and re-assess the infrastructure assets intensively in another AMP is not clear. Second, if Horizon has utilized the data from the AMP, which data Horizon states resides in a GIS database as part of its Enterprise Resource Planning, to be able to identify and prioritize capital projects, it is not clear what incremental benefit the Operation Data Warehouse 2011 capital project brings.

Therefore, Board staff submits that the proposed 2011 headcount of 428, and associated compensation, is unsupported. Board staff submits that, in light of no significant increase in customer counts and demand, Horizon should look for operational efficiencies.

Given that Horizon had no change in year-end headcount from 2009 to 2010, Board staff considers the 8.7% increase in total compensation from 2009 to 2010 to be surprising; while inflation and progression would account for annual increases, how COLA and progression (with a significant mature workforce) could account for an increase that high is not clear. Board staff would submit that an increase in wages and salaries of 4.5% (itself based on the annual increases of 4.2% and 4.7% in 2008 and 2009) should be adequate. An increase of 4.5% over 2010 actuals of $35,091,915 would be $36,671,051. This is a reduction of $4,971,143 from the 2011 budget of $41,642,494. Horizon has proposed an increase in the capitalization of labour from 26.3% in 2010 to 31.8% in 2011. Accepting Horizon's estimate would give capitalized labour costs of $11,661,394 and expensed labour of $25,009,657. Board staff notes that the reductions proposed here are implicitly contained within the envelope of the overall reductions proposed for capex and opex.

[redacted]

Depreciation

In its Application, Horizon states that it has followed the Accounting for Municipal Electric Utilities in Ontario and the *2006 Electricity Distribution Rate Handbook*.[49] It has estimated a depreciation expense of $27,371,137 in the updated RRWF filed on April 15, 2011.

Board staff submits that Horizon's methodology for calculating depreciation expense is consistent with Board policy and practice. Board staff notes that on July 8, 2010, the Board issued a covering letter and the final report of Kinectrics Inc., a consulting firm retained by the Board, regarding the need for utilities to conduct updated depreciation studies in compliance with the adoption of IFRS. Given the timing of Horizon shortly thereafter filing its application in late August, and the fact that Horizon's application follows CGAAP and not IFRS, Board staff takes no issue with Horizon retaining its current depreciation rates for this application.

Board staff notes that the depreciation expense for the 2011 test year may need to be revised in accordance with any adjustments to rate base and capital expenditures as determined by the Board. In any draft Rate Order filing in compliance of the Board's decision, Horizon should file sufficient evidence, such as an updated Capital Asset Continuity Schedule to allow for confirmation of any updated depreciation expense.

PILs

In its original application, Horizon proposed a grossed-up PILs expense allowance of $6,058,643. This amount was subject to adjustment for the updated cost of capital, in addition to changes in capital and operating expenses, and possibly other factors, as determined by the Board in its decision.

In response to interrogatories and questions from the Technical Conference, Horizon amended its PILs allowance to reflect corrections to the calculations of taxes/PILs, to reflect:

[49] Exhibit 4/Tab 1/Schedule 13

- Correct classification of certain Class 52 computer hardware assets effective January 1, 2011. This in turn results in a different Capital Cost Allowance for these assets in the 2011 test year.
- Adjustments to reflect tax credits available. These tax credits include the Ontario Small Business Tax Credit as well as Federal and Provincial Apprenticeship Training Tax Credits.

Horizon also has accepted a tax reduction of $36,250 due to the availability of an Ontario surtax clawback on the first $500,000 of taxable income, as documented in its response to Undertaking J2.2, and confirmed that it will reflect that in the calculation of the revenue requirement resulting from the Board's decision.

In the updated Revenue Requirement Work Form ("RRWF") filed on April 15, 2011, Horizon has documented a grossed-up PILs expense of $5,904,367.

Board staff takes no further issue with the methodology, as amended through discovery, used by Horizon to calculate its tax/PILs allowance for 2011, and submits that Horizon should use this approach to calculate any updated tax/PILs allowance to reflect the Board's decision.

Green Energy Act

Horizon submitted its Green Energy Act Plan ("GEA Plan") as part of its original application on August 26, 2010. Horizon requested GEA Plan capital and operating expenditures as set out in the table below:

GEA plan amounts requested for prudence and recovery

Year	Operating Expenditures	Capital Expenditures
2011	$530,000	nil
2012	$640,000	$156,000
2013	$640,000	$192,000
2014	$590,000	$1,682,000
Total	$2,400,000	$2,030,000

The nature of the expenditures over the term of the plan include: renewable connections, renewable connection enablers, smart grid investigations, customer engagement & communication, and feeder & substation automation projects.

Horizon did not propose the use of a funding adder. Instead, and in the absence of capital expenditures in 2011, all operating expenditures in 2011 would be recovered through its revenue requirement. Horizon indicated that it was not seeking to recover any portion of the GEA Plan amounts through the provincial recovery mechanism. Horizon clarified at the oral hearing that it was seeking a finding of prudence with respect to all amounts from 2011 through 2014 included in its GEA plan, in keeping with the years that Horizon expects to be subject to the Board's incentive rate setting process ("IRM").[50] As has been noted elsewhere in this document, Horizon's next scheduled Cost of Service application would be for 2015 rates.

As part of the *Filing Requirements on Distribution System Plans* (EB-2009-0397) (the "DSP Filing Requirements"), the Board outlined mechanisms to address funding for expenditures proposed in a GEA Plan. The DSP Filing Requirements state that the nature of the mechanism used will depend on whether the Board is able to properly assess prudence of the proposed expenditures based on the evidence filed in the application. These two mechanisms are generally a combination of a rate rider and variance account, or a funding adder and deferral account.

The Board indicated that an account to track variances from budget may be established in conjunction with a rider, but did not assign a specific account number in its report. However, the Board established a series of accounts of Capital and OM&A Deferral Accounts for the purposes of administering an adder and deferral account recovery mechanism.[51] Complete descriptions of these accounts are listed below:

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[50] Tr. Vol. 2, Oral Hearing, p. 55/l. 16 to p. 56/l.1
[51] *Filing Requirements: Distribution System Plans Filing under Deemed Conditions of Licence* (EB-2009-0397), pp. 22-25

Smart Grid and GEA Plan accounts

Account # (USoA)	**Account Name**	**Type**
1531	Renewable Generation Connection Capital Deferral Account	Capital
1534	Smart Grid Capital Deferral Account	Capital
1532	Renewable Generation Connection OM&A Deferral Account	OM&A
1535	Smart Grid OM&A Deferral Account	OM&A
1533	Renewable Generation Connection Funding Adder Deferral Account	Funding Adder
1536	Smart Grid Funding Adder Deferral Account	Funding Adder

With respect to direct benefits and provincial recovery of GEA Plan amounts, *O.Reg. 330/09* set out details related to the implementation of the cost recovery framework. This cost recovery framework establishes a process for the IESO to collect the qualified rate protection amount through the Wholesale Market Service Charges and to make payment to the eligible distributor.

The Report of the Board (EB-2009-0349)[52] indicated that eligible investments would attract ratepayer recovery of 6% for Renewable Enabling Investments and 17% for Expansion Investments.[53]

On April 9, 2010, the Board issued a decision in the Hydro One Networks proceeding for 2010 and 2011 distribution rates setting out an amount for recovery from provincial ratepayers with respect to its GEA spending on a provisional basis.[54] Subsequently, the Board issued a Decision with Reasons[55] on July 22, 2010 which established Hydro One Networks' Renewable Generation Connection Rate Protection Compensation Amount ("RGCRP") for 2010, based on the utility's provisionally approved amounts and direct benefit percentages.[56] The Board issued a similar decision with respect to Hydro One Networks' RGCRP Amount for 2011 on December 21, 2010.[57]

[52] *Report of the Board: Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09*, EB-2009-0349, dated June 15, 2010.
[53] *Ibid*, page 15, footnote 9
[54] Decision with Reasons, EB-2009-0096, Hydro One Networks Inc, dated April 9, 2010.
[55] Decision with Reasons, EB-2009-0191, Hydro One Networks Inc, dated July 22, 2010.
[56] Decision with Reasons, EB-2010-0132, Hydro One Brampton Networks Inc, dated April 4, 2011.
[57] Decision with Reasons, EB-2009-0191, Hydro One Networks Inc, dated December 21, 2010.

Board staff has organized this submission on the issues in this proceeding along the following key areas of interest:

1. Prudence of Expenditures (2011-2014)
2. Appropriateness of the Recovery Methodology
3. Direct Benefits Percentages
4. Upfront vs. Ongoing Costs

Prudence of Expenditures (2011-2014)

Horizon has requested a finding of prudence with respect to GEA plan expenditures from 2011-2014[58], as set out in the table above. Board staff notes that total expenditures fall far short of the materiality threshold of 3% of rate base or $10 million in any one year of the GEA plan, as set out in the DSP Filing Requirements[59].

In light of other issues in the proceeding, parties have not focussed significant attention on testing the reasonableness of amounts proposed by Horizon in its GEA Plan. Board staff pursued a limited line of interrogatories and cross-examination to clarify the record, and took little issue with the type of expenditures proposed. No party to the proceeding actively challenged prudence of Horizon's proposed GEA plan expenditures at the oral hearing.[60]

The amounts requested in the GEA plan appear to support permitted initiatives as contemplated in the *DSP Filing Requirements*. However, given the evolutionary nature of the *Green Energy Act* plan and initiatives, Board staff submits that it may be more appropriate for the Board to allow for recovery of GEA plan amounts through the implementation of a rate rider for 2011, and a rate adder and deferral account mechanism for GEA costs forecast to be incurred in the period 2012 to 2014. The effect of a finding of prudence by the

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[58] Tr., Vol. 2, pg. 55/ll. 20 to 28

[59] *Filing Requirements: Distribution System Plans Filing under Deemed Conditions of Licence* (EB-2009-0397), p.4

[60] As a minor exception, Board staff questioned the inclusion of ongoing OM&A costs in Horizon's GEA plan.

Board for the four years of the plan (2011-2014) would commit Horizon to make certain outlays in respect to its GEA initiatives, whether or not there are material changes to Horizon's plan prior to its next rebasing application. A rate adder and deferral account mechanism would allow the Board to revisit and approve disposition of deferral accounts when it has better information at its disposal with respect to forecast and actual amounts spent with respect to the GEA plan.

Appropriateness of the Recovery Methodology

Horizon has applied to the Board for prudence of expenditures with respect to its GEA plan operating expenditures in 2011, as well as prudence of capital and operating expenditures from 2012-2014. Horizon intends to recover amounts through its 2011 revenue requirement and through inclusion in rate base of capital expenditures in the years 2012-2014. Board staff asked clarifying questions regarding Horizon's recovery methodology for GEA plan expenditures at the oral hearing.

The Board examined GEA expenditures previously as part of its decision on Hydro One Distribution's application for 2010 and 2011 rates. In that proceeding, the Board concluded that it could not approve all expenditures in Hydro One Networks' GEA plan. For those expenditures that the Board was able to deem prudent, it provided approval.[61] However, concerns of over-recovery may be lessened as the amounts for which Horizon is requesting recovery are well below the materiality threshold which would necessitate a Detailed GEA plan filing.

Reiterating earlier submissions, Board staff submits that Horizon should make use of the deferral and funding adder accounts described by the Board in its EB-2009-0397 Filing Requirements (*Distribution System Plans – Filing under Deemed Conditions of Licence*) to record GEA Plan costs and revenues, and the Board should defer making a finding of prudence for certain expenditures until Horizon's next cost-of-service rebasing proceeding, when better information is available.

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[61] Decision with Reasons, EB-2009-0096, Hydro One Networks Inc., Distribution, April 9, 2010, page 33.

Board staff submits that Horizon should clearly outline its proposed recovery mechanism, indicative of the Board's finding in its Decision on this proceeding, when it submits its draft Rate Order, and a calculation or derivation to provide the Board with the revenue requirement figures necessary to facilitate collection of RGCRP amounts from the IESO, if the Board should so decide.[62]

Direct Benefit Percentages

The *Green Energy and Green Economy Act* amended the *OEB Act* to introduce a mechanism under section 79.1 of the OEB Act, whereby some of the Board-approved costs incurred by a distributor to make an eligible investment for the purpose of connecting or enabling the connection of a renewable energy generation facility to its distribution system may be recovered from all provincial ratepayers rather than solely from the ratepayers of the distributor making the investment. Under this process, direct benefits are those that are attributable to only the customers of the distributor making the investment and where the benefit is readily quantified in monetary terms. Amounts deemed to benefit the province are collected via monies collected by the IESO, and paid out to eligible distributors.

The Board approved for Hydro One provisional percentages to be paid by its ratepayers as 17% for expansions, and 6% for Renewable Enabling Improvements. On April 4, 2011, the Board made a similar finding in Hydro One Brampton Networks Inc. 2011 rates case (EB-2010-0132), applying the Hydro One default direct benefit percentages for its Basic GEA plan.[63]

In evidence, Horizon indicated that: "[it] chose not to adopt such [default Hydro One Networks'] percentages, and instead wait for the Board to provide final direction on the issue."[64] During the Oral Hearing, Horizon offered further reasoning on why it proposed not to adopt default percentages, stating that: "Under the current calculations, the direct benefit--provincial benefit numbers are

[62] Including the scenario where the Board makes a finding requiring Horizon to apply direct benefit percentages to its GEA plan.
[63] Decision and Order, Hydro One Brampton, (EB-2010-0132, April 4, 2011)
[64] Response to Board staff interrogatory number 36, p. 3/ll. 19 to 21

quite small […] In 2011, we have calculated a zero benefit, and in 2012, $135,000."[65] However, Horizon indicated that it would not object to implementing and tracking direct benefits, should the Board make such a finding[66], and provided a hypothetical calculation to assist this purpose.[67]

Horizon provided reasoning why it chose not to adopt direct benefit percentages, chiefly because of the materiality of amounts involved, and the lack of a final Board decision on direct benefits. Nonetheless, Board staff submits that the *Report of the Board on Direct Benefits* (EB-2009-0349) indicates that Basic GEA plans attract default percentages, and made no provision for alternative treatment in the case of amounts claimed to be immaterial.

Board staff submits that the default direct benefit percentages set in Hydro One Networks' case would be the most appropriate to apply to Horizon[68], and also encourages a consistent framework and regulatory predictability for other distributors, and their respective GEA plans. Board staff submits that it may well be that a number of distributors will have small amounts to be socialized; however, over the coming years, amounts collected by the IESO under *O.Reg. 330/09* when taken in aggregate will likely be significant. Board staff also notes that the amounts proposed by Hydro One Brampton were also immaterial, but the Board decided to apply the default percentages.

Upfront vs. Ongoing Costs

Board staff is concerned about *ongoing* costs included in the GEA plan which may be more appropriately included in general OM&A. "Eligible investment" costs, as set out in O. Reg. 330/09 and section 79.1 (5) of the OEB Act, are not limited to only the initial capital investment costs but also includes the *up-front* OM&A costs necessary for the purpose of "enabling the connection of a qualifying generation facility". However, given that section 79.1 focuses solely on

[65] Tr., Vol. 2, p. 57/ll. 16 to 21
[66] Tr., Vol. 2, p. 57/ll. 11 to 19
[67] Response to Board staff interrogatory number 36(b), pp. 4-6
[68] 17% for expansion investments and 6% for renewable enabling investments.

the initial investment, *ongoing* OM&A costs that are incurred by the distributor after the investment has been made will not be eligible for provincial recovery.[69]

Horizon outlined costs for consulting and permanent staff additions in evidence.[70, 71] Horizon confirmed in cross-examination that it did not contemplate the distinction between upfront and ongoing costs when it prepared its GEA plan[72], and as a result, Board staff submits that some amounts may have been inappropriately included in the GEA Plan.

Board staff submits that consulting costs, and staff contributions that address *upfront* work should be included in the GEA plan. In the case of *ongoing* costs, particularly with respect to the full-time staff additions, Board staff submits that these ongoing costs should be removed from its GEA plan, and recovered through Horizon's normal distribution OM&A expenses. Board staff submits that the Board policy indicates that ongoing costs should not attract provincial recovery. Board staff estimates that these ongoing costs fall with a range of $100K to $300K. Horizon should confirm the exact amount in its reply argument.

LEAP

Horizon has not included any costs associated with LEAP in its application although it understands that LEAP will be recommenced by the Board pursuant to Ministerial Directive.[73] Horizon confirmed this in response to an interrogatory[74], and also indicated that an expense amount for LEAP should be included, equal to 0.12% of 2011 distribution revenues dependent on the Board's decision. Based on the original application, this would be an amount of $130,450. Horizon also noted that it had included in 2011 an amount of $55,000 for Winter Warmth programs, which will now be replaced by the LEAP program.

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[69] *Report of the Board, Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09,* EB-2009-0349, dated June 10, 2010, p.3
[70] Responses to Board staff interrogatories # 38 and 39
[71] Tr., Vol.2, p. 60/l. 8 to p. 61/l. 3
[72] Tr. Vol. 2, p. 59/ll.19 to 27
[73] Exhibit 4/Tab 2/Schedule 6/page 33
[74] Response to Board staff IR # 24

In accordance with Board policy and practice, Board staff submits than an expense for LEAP equal to 0.12% of approved distribution revenues, should be included in allowed operating expenses. The forecasted donation of $55,000 for Winter Warmth programs for 2011 should correspondingly be removed from 2011 operating expenses and hence revenue requirement.

Horizon, when filing its draft rate order in accordance with the Board's decision on this Application, should provide appropriate documentation on the calculation of this LEAP expense and its inclusion in its Board-approved revenue requirement, along with the removal of the winter warmth programs.

Exhibit 5 – Cost of Capital

In its original application, Horizon used an estimated Cost of Capital of 7.27%, based on a deemed capital structure of 60% debt (56% long-term debt and 4% short-term debt) and 40% equity. It used the then-current ROE of 9.85% and deemed short-term debt rate of 2.07%, which were the Cost of Capital parameters for 2010 applications with May 1, 2010 effective dates as announced in the Board's letter of February 24, 2010. Horizon acknowledged that these parameters would be updated with data three months in advance of the effective date for its new rates, proposed to be January 1, 2011, in accordance with the methodology documented in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009 (the "Cost of Capital Report").

Through discovery, Horizon has updated the cost of the new debt of $40 million in 2010, with a rate of 4.89%, compared to the 4.92% originally proposed. Horizon has reflected this in updated calculations of the revenue requirement.

On November 15, 2010, the Board issued a letter documenting updated Cost of Capital parameters for rates effective January 1, 2011. The updated Cost of Capital parameters are:

Cost of Capital Parameter	Rate
Return on Equity	9.66%
Deemed Short-term Debt	2.43%
Deemed Long-Term Debt	5.48%

With its update to VECC IR # 37 filed on April 6, 2011, Horizon has reflected the updated Cost of Capital parameters in calculating its revenue requirement. With the updated rate of the $40 million affiliated debt and the updated ROE and short-term debt rates, the weighted average cost of capital becomes 7.20%.

During the oral hearing, when cross-examined by Ms. Helt, Horizon acknowledged that the Cost of Capital parameters should be updated based on data three months in advance of the effective date, in accordance with the methodologies in the Cost of Capital Report, should the Board determine an effective date other than January 1, 2011.[75] The issue of the effective date for 2011 rates has been discussed earlier in this submission.

With the exception of Horizon's proposed treatment for the update of its long-term debt in 2012 discussed below, Board staff submits that Horizon's proposal for its Cost of Capital complies with the Cost of Capital Report and with Board policy and practice.

Long-term debt

Horizon used a long-term debt rate of 6.10% on a long-term debt note of $116 million payable to an affiliate, Hamilton Utilities Corporation. While the actual debt rate is 7.0%, the 6.10% corresponds to what the Board approved as the allowed rate for this affiliated debt in Horizon's 2008 Cost of Service application (EB-2007-0697). Horizon also had new debt of $40 million in 2010; this new debt is also due to an affiliated party (Horizon Utilities Corporation), and Horizon assumed a debt rate of 4.92% for the new debt. The weighted average cost of long-term debt in 2011 was 5.80%.

[75] Tr., Vol. 3, pg. 135/l. 14 to pg. 136/l. 23

The debt note of $116 million matures on July 31, 2012. This is outside of the 2011 test year. In its application, Horizon stated:

> … It is Horizon Utilities' intention to refinance such note at that time through the issuance of a promissory note to HHI ("Future HHI Note"). HHI is expected to finance the Future HHI Note through the issuance of a debenture obligation under its Trust Indenture ("Future HHI Debenture"). The terms of the Future HHI Note would be identical, *mutatis mutandis*, to the terms of the Future HHI Debenture. Horizon Utilities requests that, effective with the time of such refinancing of the $116MM HUC Note in its next scheduled incentive rate mechanism adjustment, its Long-Term Debt rate be adjusted based on the above analysis by substituting the rate on the $116MM HUC Note with the Future HHI Note.[76]

In response to questions concerning this debt instrument at the oral hearing, parties explored the possibility of imputing an update of the debt rate of this note into base rates during the IRM plan term. In its Application, Horizon did not make a specific proposal of how the Cost of Capital would be updated at the time of its next IRM application. However, it did provide certain options in response to SEC IR # 33. Its proposal was also discussed in the oral hearing, where Horizon qualified that it would not be finalizing the rate before July 31, 2012 and so the IRM application for which the debt rate update would occur would be for 2013 rates. Horizon's witness suggested that a deferral account could be used to track the difference between the 6.10% and the rate of the renewed debt during the IRM period; the approach would be symmetric (i.e. it would apply whether the rate was higher or lower than 6.10%).[77]

Board staff does not support the option discussed by Horizon. The maturation and replacement of the existing note is outside of the 2011 test year. The 6.10% rate used is the appropriate debt rate for the 2011 test year for this debt instrument and is a reasonable proxy setting the base rates for the IRM plan term.

[76] E5/T1/S1/pg. 3
[77] Tr., Vol. 3/pg. 84/l. 3 to pg. 85/l. 7

The option identified by Horizon for the adjustment runs counter to and even undermines the concept of incentive regulation. Under the third-generation Incentive Regulation Mechanism ("IRM") plan, there is no direct means of adjusting for the Cost of Capital. There is also no real need to do so. The Implicit Price Index for the Gross Domestic Product (Final Domestic Demand) (the "GDP-IPI") used as the price inflator in the Board's IRM plan implicitly captures changes in the cost of capital (in debt, bond and equity markets) year over year. This concept is well understood by regulatory practitioners worldwide, and the Board has acknowledged this principle in its Board Reports on both the 2nd- and 3rd-Generation IRM plans.[78]

As acknowledged under cross-examination by Mr. Aiken, any adjustment under IRM would not occur until 2013 even though the debt will be renewed at the end of July 2012.

While a deferral account approach would obviate the need for a specific adjustment to the IRM model, Board staff submits that the need for deferral account treatment is not warranted. While a separate approach, its existence reduces the risk and the regulatory "power" of IRM. Board staff is also concerned of this proposal serving as a precedent for other applications, particularly as Horizon has suggested that the proposal would be symmetric.

Debt renewal is a normal aspect of business, and is one that the utility is expected to manage under IRM. The Board does not adjust for debt renewal during the IRM for other electricity and gas utilities. Board staff submits that there should be no adjustment in this case and that the rate of 6.10% is a reasonable proxy rate of this debt instrument on which to set just and reasonable base rates for the IRM period.

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[78] The exception to this was the use of the K-factor in 2nd-generation and 3rd-generation IRM to effect the transition to the common deemed capital structure of 60% debt and 40% equity. This was a structural change to electricity distributors' costs of capital that was not occurring generally in the market and would not be reflected implicitly in the economy-wide GDP-IPI. While an adjustment analogous to the K-factor would be a possibility for Horizon's proposal, Board staff observes that this would be a "one-off" design for Horizon's application. Also, as the GDP-IPI would reflect debt rate movements in the economy in 2012, there is a conceptual concern that the change in debt would be double-counted in the IRM adjustment – once through the GDP-IPI and then through any specific adjustment.

Exhibit 6 – Revenue Sufficiency/Deficiency

In its original Application, Horizon calculated a revenue deficiency for the 2011 test year of $19,560,006. In the updated evidence filed on March 14, 2011, Horizon calculated a new revenue deficiency of $19,769,373. At the close of the oral proceeding, in the update filed on April 15, 2011 reflecting the updated load forecast filed in Undertaking J3.3, Horizon has revised the revenue deficiency to $20,721,655.

The drivers for the revenue deficiency are, of course, the load forecast, the rate base and capital expenditures and the operating expenses for the 2011 test year. Certain other factors, such as changes in the commodity prices affecting the Cost of Power and hence the Working Capital Allowance, also influence changes in the revenue deficiency.

Board staff has made submissions with respect to Horizon's rate base and capital expenditures, operating expenses and load forecasts elsewhere in this submission. Board staff estimates that the proposals made in this submission would reduce the revenue requirement to approximately $102.5 million and the revenue deficiency to approximately $15 million for the test period.

With respect to the methodology, Horizon has adhered to the Board's policy and practice, and employed the RRWF which forms part of the Board's Filing Requirements. Further, Horizon, in its April 15, 2011 filing has employed the RRWF correctly to show both the original Application and the revenue requirement as updated through the proceeding. Horizon agreed to this approach during the Oral Proceeding.[79] Board staff takes no issue with respect to Horizon's methodology for calculating the revenue requirement and revenue sufficiency/deficiency.

[79] Tr., Vol. 3, pg. 136/l. 24 to pg. 138/l. 21

Exhibit 7 – Cost Allocation

For this Application, Horizon has conducted an updated Cost Allocation study, which was subsequently updated throughout the course of this proceeding. Horizon's most current proposal for cost allocation between all customer classes is as follows:[80]

Revised Table 7-1 - Revenue to Cost Ratios - 2008 Board Approved and 2011 Proposed

Customer Class	Low	High	2008 Approved	2009 and 2010 Actual	2011 Cost Allocation	2011 Proposed
Residential	85.0%	115.0%	111.6%	106.4%	110.7%	104.0%
General Service < 50 kW	80.0%	120.0%	92.5%	88.1%	102.8%	102.7%
General Service > 50 kW	80.0%	180.0%	86.3%	98.0%	84.8%	91.2%
Large Use	85.0%	115.0%	92.1%	95.2%	63.9%	91.2%
Streetlighting	70.0%	120.0%	43.0%	70.0%	62.4%	91.2%
Sentinel Lighting	70.0%	120.0%	70.0%	72.3%	75.6%	91.2%
Unmetered Scattered Load	80.0%	120.0%	80.0%	62.0%	129.8%	120.0%

As Horizon clarified during cross-examination, its approach is to move classes towards unity. In this Application, Horizon decided to move the Residential class towards unity, moving from a revenue-to-cost ("R/C") ratio of over 110% to 104% ("approximately half-way")[81], and then adjusting other classes; classes outside of the thresholds were to move to the minimum/maximum, as applicable, and some adjustments were made for classes within the range for that class.[82] Horizon has also indicated its desire to move the R/C ratios for all classes towards unity, but is not seeking approval for further adjustments at this time.

Horizon's proposal deviates from usual Board policy and practice in that it proposes a common R/C ratio of 91.3% for GS > 50 kW, Large Use, Streetlighting, Sentinel Lighting and Standby Power classes, beyond the floor of the applicable range for the class. However, Board staff does not oppose Horizon's proposed R/C ratios and cost allocation as proposed in this Application, but makes the following submissions.

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[80] Exhibit 7/Tab 1/Schedule 1/pg. 3/Table 7-1 (updated March 14, 2011), revised to reflect Table 7-1 in response to VECC IR # 44 (April 1, 2011)
[81] In fact, the adjustment of 7.0 percentage points out of 11.0 percentage points to unity (100%) is a 63.6% movement.
[82] Tr., Vol. 3, pg. 147/l. 22 to pg. 155/l. 23. See also Undertaking J3.7

First, as has been documented in Volumes 3 and 4 of the oral hearing, and documented in Undertaking J3.7, there may be further adjustments as a result of the Board's decision in this application. Updating of allowed costs or of the load forecast may alter the cost allocation results. Board staff believes that Horizon has appropriately reflected the Board's current policy and practice, and submits that a formulaic updating of the cost allocation study reflecting the Board's decision is appropriate.

While Board staff takes no issue with Horizon's proposed cost allocation and R/C ratios as applied for and updated, Board staff cautions against further movement toward unity. Horizon's intentions assume that the cost allocation methodology is exact. In reality, like load forecasting and other econometric and economic aspects of rate regulation, cost allocation is an imprecise science. Informed assumptions are made as to suitable allocators for various costs – and even these allocators may be proxies for the real but unknown drivers. Also, as has been seen since 2006, cost allocation has become enhanced due to improvements in data and methodologies. And this will likely continue into the future, particularly as TOU data becomes available for residential and small GS customers and as utilities, including Horizon, use improved asset record and accounting databases in their studies.

The Board has acknowledged the (relative) imprecision of the cost allocation approach in its guidelines and in numerous decisions. While it has supported movement of R/C ratios to at least class boundaries, further movement when within the range is, in Board staff's submission, more cautiously treated.

Board staff also observes that the Board has conducted a consultation on limited enhancements to its Cost Allocation approach for electricity distributors, and the Report of the Board was issued on March 31, 2011.[83] Board staff submits that any further movement towards unity in R/C ratios should only be taken after the results of further consultations on the Cost Allocation methodology are

[83] *Report of the Board on the Review of Electricity Distribution Cost Allocation Policy*. EB-2010-0219, March 31, 2011, http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0219/Board_Report_CA_Policy_for_Distributors_20110331.pdf

completed. Also, Board staff submits that any such proposal would be considered in the context of a subsequent Cost of Service proceeding where an updated cost allocation study is filed and can be tested.

Exhibit 8 – Rate Design

Fixed/Variable Split

With the exception of the Large Use class, Horizon has proposed to retain the existing fixed/variable split for other customer classes.

For the Large Use class, Horizon has proposed to make the fixed component 49.4% instead of the existing 34.3%. The fixed component would be equal to that for the GS 50-4999 kW class.[84] Horizon's reasons for its proposal are largely based on the revenue volatility, the fact that most costs are fixed and invariant to the customer's demand once the capital assets have been invested in, and the revenue decoupling process that was underway at the time that Horizon filed its application. However, Horizon has provided no other analytical support for why the Large Use fixed ratio should equal the GS 50-4999 kW class.

During the oral hearing, Horizon's witness commented on revenue volatility due to volumetric rates. Horizon's witness also noted that the fixed charge recovers a much larger percentage of class revenues in other classes than is the case for the Large Use class. The fixed rate recovers 62.3% of residential class distribution revenues.[85]

Board staff conducted a consultation on revenue decoupling in 2010, in which the Board's consultant in that case noted that Ontario distributors, in many cases, have relatively higher fixed charges compared to many other North American jurisdictions.[86] As a result, any benefits from revenue decoupling (including

[84] Exhibit 8/Tab 1/Schedule 1/pp. 1-8
[85] Tr., Vol. 3, pg. 106/l. 21 to pg. 113/l. 19
[86] *Review of Distribution Revenue Decoupling Mechanisms*, Mark Newton Lowry and Matt Makos, Pacific Economics Group Research LLC, 19 March 2010, pg. 111
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0060/Report_Revenue_Decoupling_20100322.pdf

100% fixed charges) are lessened, at least relative to some other jurisdictions in North America.

Board staff also observes that increasing the fixed component as a means of reducing revenue volatility will also reduce the business risk of the utility. As a result, the Cost of Capital may need to be commensurately reduced.

Board staff submits that having an appropriate variable component for the Large Use class is important for allocating costs within the class. A 100% fixed charge would mean that all customers in the class would pay the same distribution charges. However, as is apparent from the historical and forecasted demand for each of the 12 customers in the Large Use class, there is a great deal of variability in the demand level between customers. Board staff submits that it is possible – and indeed likely – that Horizon has different costs to provide distribution services to customers with disparate loads within this Large Use class. Horizon may have different and higher cost investments to serve a Large Use customer with, for example, 25,000 kW of monthly demand compared to one with only 7500 kW of demand. It is only through the volumetric rate that cost differences can be apportioned to these customers.

Therefore, in light of work done on revenue decoupling, and on the Board's policy and practice with respect to rate design, Board staff submits that further movement to increase the fixed portion of rates should only be granted when supported by quantitative evidence. Board staff submits that Horizon has not provided evidence to quantitatively support its proposed alignment of the fixed/variable split of the Large Use class with that of the GS 50-4999 kW class.

However, Board staff acknowledges that the lower percentage for the fixed charge recovery for the Large Use class is, in part, a consideration in the revenue volatility and shortfall in this class. One option would be for the Board to allow for the fixed charge to move to halfway towards that of the GS 50-4999 kW class, i.e. (34.3% + 0.5 X (49.4% - 34.3%)) = 41.85%. This would increase the fixed component and increase revenue stability within the Large Use class, but without the magnitude of distribution rate increases proposed. However, should Horizon wish for any further increase in the fixed ratio for the Large Use class, staff submits that Horizon should file a detailed study supporting any such proposal in a subsequent Cost of Service application.

Streetlighting Revenue-to-Cost Ratio

In its updated evidence of March 14, 2011, Horizon has requested that it be allowed to update its revenue-to-cost ratio for streetlighting in a subsequent hearing, in all likelihood its 2012 (or maybe 2013) IRM application:

> Horizon Utilities has recently become aware of the approach taken by Kitchener-Wilmot Hydro ("Kitchener") in its 2010EDR Cost of Service Application in which it based street light rates on connections as opposed to luminaires for assessment of charges. Horizon Utilities understands that this approach was accepted by the Board. The Board currently has a Cost Allocation proceeding underway (EB-2010-0219) and Horizon Utilities understands that the Board is in receipt of a letter from the Association of Municipalities of Ontario ("AMO"), dated December 1, 2010, which references and supports the Kitchener approach.
>
> Horizon Utilities submits that this is an issue that has wide application for every municipality and deals with a public good (i.e. the illumination of roadways). Horizon Utilities is supportive of the approach taken by Kitchener. In fact, in its 2008EDR Cost of Service Application and in this Application, Horizon Utilities had divided the number of street lights by a factor of 2. Such is not a proxy for the more precise methodology noted above. In order to adopt this methodology, Horizon Utilities submits that it would need to: (a) in concert with its municipalities, determine how many luminaires are connected directly to the distribution system and how many luminaires are connected in a series or in a "daisy chain"; and (b) have that determination reviewed and accepted by the Board as such applies to cost allocation and, ultimately, Horizon Utilities' rates.
>
> Horizon Utilities submits that while the identification of such approach does not constitute an amendment to this Application, Horizon Utilities requests that it be granted leave to revise its cost allocation and rates for street lighting at the first opportunity for a

> rate adjustment following the completion of the street lighting study noted above, potentially in its 2012 3GIRM Application.[87]

Board staff observes that Kitchener-Wilmot's approach was on the record from when that utility filed its application in late August of 2009. The Board's Decision on that application was issued on April 7, 2010.[88]

As noted by Horizon, it has not conducted the necessary study in this Application and it is too late to update the ratios for 2011 rates. Horizon instead proposes to update the ratios in a subsequent application, likely its 2012 or possibly 2013 IRM application.

As noted earlier, the Board has recently issued its report on an updated Cost Allocation policy.[89] That Board Report states that a consultation will be initiated to consult on the methodology for the proper treatment of streetlighting for cost allocation.[90] The outcome of this consultation will, in all likelihood, result in changes to the Board's Cost Allocation model.

In light of the Board Report, Board staff submits that it is premature for Horizon to consider updating the Revenue-to-Cost ratio for the streetlighting class in its next IRM application. Instead, Horizon should await the outcome of the announced consultative process.

Even in the Board Report, there is a premise that updated cost allocation occurs as part of a Cost of Service application. Horizon has proposed that the update occur in a subsequent IRM application, given that its next scheduled Cost of Service application would be for 2015 rates.

[87] Exhibit 7/Tab 1/Schedule 1/page 4/ll. 4-25, updated March 14, 2011.
[88] Board staff observes that Waterloo North Hydro was aware of and used the Kitchener-Wilmot Hydro approach in its 2011 Cost of Service application (EB-2010-0144) which was filed on August 27, 2010. The Board issued its Decision on Waterloo North Hydro's application on April 26, 2011.
[89] *Report of the Board on the Review of Electricity Distribution Cost Allocation Policy,* EB-2010-0219, previously cited.
[90] *Ibid*., page 39

Board staff is concerned about what may be a selective Cost Allocation update. An update along the lines of Kitchener-Wilmot Hydro's approach will also affect the allocated distribution revenues to other classes, although the magnitude of any re-allocation is likely to be relatively small. However, Board staff observes that Horizon should also have updated evidence on its costs and demand, particularly with respect to the Large User class. With the implementation of smart meters and TOU rates, there will also be additional data on the demand for other classes.

Board staff submits that would be inappropriate to update the Cost Allocation for only the streetlighting class. A full and proper Cost Allocation study is best examined in the context of a Cost of Service application. In the meantime, Horizon should await the outcome of the consultation process announced by the Board.

Retail Transmission Service Rates

In its Application[91], Horizon filed for adjusted Retail Transmission Service Rates ("RTSRs") based on the Board's Guideline G-2008-0001: Electricity Distribution Retail Transmission Rates, based on an analysis of historical trends/patterns for over- or under-collection in the RSVAs. The proposed RTSRs are also based on the approved Retail Transmission Rates for Hydro One Networks Inc. effective January 1, 2010.

However, Horizon acknowledged that Hydro One Networks' Retail Transmission Rates were subject to adjustment, in accordance with the Board's Decision on Hydro One Networks' 2011/2012 Uniform Transmission Rate Adjustment Application. The Board approved new Retail Transmission Rates for Hydro One effective January 1, 2011 in its decision[92] issued December 23, 2010.

Board staff submits that Horizon's RTSRs for 2011 rates should be updated now to reflect Hydro One Network's approved 2011 Retail Transmission Rates.

[91] Exhibit 8/tab 1/Schedule 3/pp. 1-5
[92] File No. EB-2010-0002

Horizon should file information similar to that filed in Exhibit 8/Tab 1/Schedule 3 to allow the Board to confirm the derivation of updated RTSRs.

Loss Factor

In its Application[93], Horizon has proposed updates to its Board-approved loss factors as follows:

Description	Loss Adjustment Factor
Supply Facility Loss Factor	1.0078
Distribution Loss Factors	
Secondary Metered Customer < 5000 kW	1.0407
Secondary Metered Customer > 5000 kW	1.0179
Primary Metered Customer < 5000 kW	1.0303
Primary Metered Customer > 5000 kW	1.0078

For a Secondary Metered Customer with demand < 5000 kW, the current Board-approved Total Loss Factor is 1.0421.

Board staff considers that Horizon's methodology for updating its Loss Factors complies with Board policy and practice, and takes no issue with its proposal on this matter.

Specific Service Charges

Board staff observes that Horizon is proposing no changes to its Board-approved Specific Service Charges. Board staff takes no issue with Horizon's proposal.

Low Voltage Rate Riders

Horizon has proposed updated Low Voltage ("LV") Rate Riders in its original Application,[94], and has used Hydro One Networks' LV rates approved by the Board effective May 1, 2010 to derive its proposed LV rate riders that would be applicable to Horizon's ratepayers.

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[93] Exhibit 8/Tab 1/Schedule 3/pp. 6-7
[94] Exhibit 8/Tab 1/Schedule 1/pp. 10-11

Board staff observes that Hydro One Networks' has approved updated LV rates effective January 1, 2011. Analogous to the update for the RTSRs, Board staff submits that Horizon's LV Rate Riders should be updated to reflect Hydro One Networks' current approved LV rates for 2011. Horizon should provide documentation analogous to that contained in the Application to allow for checking of the derivation of updated LV rate riders.

Standby Rate Application

In its application, Horizon is proposing a change to the method by which the standby rate is applied to applicable customers.[95] Currently, the application of standby power is based on the generator name plate rating for the customer-owned generation equipment. In its application, Horizon proposes that the standby charge be based on the amount of load displaced, so that the customer is only billed on the reserved capacity to supply its gross load. Further information was provided in response to Board staff interrogatory # 16.

Board staff observes that Horizon's proposal is analogous to the situation applicable for some other distributors whereby the standby charge is applied based on a contracted amount, which may differ from the name plate rating of the customer's equipment.

Board staff observes that the standby charge is approved on an interim basis for Horizon as well as for a large majority of other Ontario distributors and Horizon has not requested to make these rates final.

Board staff takes no issue with Horizon's proposal to change the application method for the standby charge and the resulting change to the charge itself, but submits that any new standby charge should continue to be approved on an interim basis. Interim approval would continue until such time as the Board has reviewed the rate methodology for standby charges generically for all Ontario distributors.

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[95] Exhibit 3/Tab 2/Schedule 2/page 14

Exhibit 9 – Deferral and Variance Accounts

In its Application, as updated on March 14, 2011, Horizon has documented the following for its deferral and variance ("D/V") account balances:

E9/T1/S2/Tables 9-5 and 9-6
Interest Calculation to December 31, 2010 on Deferral and Variance Account Balances

Account Description	Account Number	Principal Amounts as of Dec-31 2009	Interest to Dec31-09	Interest Jan-1 to Dec31-10	Total
Accounts Proposed for Disposition					
Group 1 Accounts					
Low Voltage	1550	$68,685	$230	$495	$69,410
RSVA - Wholesale Market Service Charge	1580	($1,995,239)	($6,745)	($14,366)	($2,016,350)
RSVA - Retail Transmission Network Charge	1584	$907,196	$5,355	$6,532	$919,083
RSVA - Retail Transmission Connection Charge	1586	($324,102)	($555)	($2,334)	($326,991)
RSVA - Power	1588	($1,406,215)	$4,213	($10,125)	($1,412,127)
Group 1 sub-total not including Global Adjustment		**($2,749,675)**	**$2,498**	**($19,798)**	**($2,766,975)**
RSVA - Power Global Adjustment sub-account	1588	$5,253,200	$24,291	$37,823	$5,315,314
Total Group 1 including Global Adjustment		**$2,503,525**	**$26,789**	**$18,025**	**$2,548,339**
Group 2 Accounts					
Other Regulatory Assets Deferred IFRS Transition Costs	1508	$560,752	$690	$4,037	$565,479
Other Regulatory Assets Incremental Capital Costs	1508	$10,017	$3	$72	$10,092
Other Regulatory Assets CDM Costs	1508	$442,504	$0	$3,186	$445,690
Retail Cost Variance Account - Retail	1518	$310,336	($11,025)	$2,234	$301,545
Retail Cost Variance Account - STR	1548	$57,079	$1,670	$411	$59,160
Total Group 2		**$1,380,688**	**($8,662)**	**$9,940**	**$1,381,966**
Total for Disposition		**$3,884,213**	**$18,127**	**$27,965**	**$3,930,305**
Accounts Excluded from Disposition					
Other Regulatory Assets - Sub-account - 2008 LRAM/SSM	1508	$517,823	$10,903		$528,726
Other Regulatory Assets - Sub-account - 2009 LRAM/SSM	1508	$551,394	$721		$552,115
Smart Meter Capital and Recovery Offset Variance Capital	1555	$21,903,307	$489,836		$22,393,143
Smart Meter Capital and Recovery Offset Variance - Sub-account - Recoveries	1555	($7,451,996)	($9,842)		($7,461,838)
Sub-total Account 1555 - Smart Meter Capital	1555	$14,451,311	$479,994	$0	$14,931,305
Smart Meter OM&A Variance	1556	$5,190,956	$132,658		$5,323,614
Deferred Payments in Lieu of Taxes	1562	($4,476,650)	$833,592		($3,643,058)
Disposition and Recovery of Regulatory Balances	1595	($3,731,348)	($1,094,156)		($4,825,504)
Totals for D/V Accounts not to be disposed		**$12,503,486**	**$363,712**	**$0**	**$12,867,198**
Total D/V Account Balances		**$16,387,699**	**$381,839**	**$27,965**	**$16,797,503**

The amounts (December 31, 2009 principals plus carrying charges to December 31, 2010) for which Horizon is seeking disposition are:

- ($2,766,975) for Group 1 accounts excluding Account 1588 RSVA Global Adjustment sub-account;

- $5,315,314 for Account 1588 Global Adjustment sub-account, applicable to non-RPP customers; and
- $1,381,966 for Group 2 accounts for which Horizon is seeking disposition.[96]

In its original Application, Horizon also requested approval for the following new D/V accounts and sub-accounts:

- Account 1595 – Disposition of Regulatory Asset Balances. New sub-account to record D/V account balances approved in this application and subsequent cost recovery and carrying charges.
- New D/V account to record charges from the Smart Meter Entity ("SME") (the IESO) for Provincial MDM/R charges once these are established beginning in 2011. This D/V account is sought regardless of whether the issue is dealt with in this application or by way of a generic hearing.
- New D/V account to track OMERS pension contribution increases for 2011-2012.
- New D/V account to track payments for the Late Payment Penalty ("LPP") Charges and recovery for customers. Horizon's amount of the Late LPP is $1,107,863. Again, the D/V account is sought regardless of whether the issue is dealt with in this application or generically.

With the updated evidence filed on March 14, 2011, Horizon removed its request for the D/V accounts to track the LPP, as this has been dealt with by the Board in a separate generic proceeding (EB-2010-0295) and the tracking of SME MDM/R charges, as no charges have been applied for or approved by the Board.

Horizon has proposed that the D/V account balance to be disposed be recovered or refunded to customers over a one-year period.

With the exceptions of:

- Disposition of balances for Account 1508 – Other Regulatory Assets CDM Costs and Account 1508 – Other Regulatory Assets Incremental Capital Costs; and

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[96] Exhibit 9/Tab 1/Schedule 2/Table 9-5

- Inclusion of Account 1592 in the amounts to be disposed, as discussed later in this submission;

Board staff takes no issue with respect to Horizon's proposed disposition of D/V account balances.

Board staff notes that Account 1508 – Other Regulatory Assets CDM Costs, with a December 31, 2009 principal of $442,504, and Account 1508 – Other Regulatory Assets Incremental Capital Costs, with a December 31, 2009 principal of $$10,017, were not tested in any detail for prudence during the proceeding. Board staff submits that Horizon may wish to:

- clarify the nature of each of these sub-accounts;
- identify the Board decision or accounting order approving the establishment and use of these sub-accounts in Account 1508 – Other Regulatory assets. In particular, Horizon should confirm if Account 1508 – Other Regulatory Assets sub-account CDM costs pertains to $265,000 of CDM expenses ordered to be tracked in the Board's Decision with respect to Horizon's 2008 rates application[97]; and
- identify evidence on the record supporting the prudence of the amounts recorded in these two sub-accounts.

Board staff submits that Horizon's proposal to dispose of the account balances over a one-year period is consistent with Board policy and practice and should not have a material impact on the rate changes that Horizon's customers will face.

Board staff submits that a sub-account of Account 1595 to track the recovery of amounts disposed in this application is reasonable. Board staff notes that this request is consistent with the practice as documented in the Accounting

[97] Decision and Order, Horizon Utilities Corporation, (EB-2007-0697), October 3, 2008, pp. 29-31

Procedures Handbook FAQ issued in December 2010 with respect to D/V account dispositions approved for 2010 rate applications.[98]

OMERS Variance Account

In its Application, Horizon has requested a D/V account to track increases in the Ontario Municipal Employees Retirement System ("OMERS") pension contribution increases announced and which will be implemented in 2011, 2012 and 2013. Horizon notes that the contributions are an expense item and hence only the 2011 amounts are factored into its revenue requirement. The requested D/V account would track the incremental increases in 2012 and 2013. Horizon submits that its proposed approach is analogous to the manner in which the Board handled the cessation of the OMERS contribution holiday on December 31, 2002.

Board staff posed an interrogatory to Horizon asking about using a "normalized" OMERs expense increment from 2011 to 2014.[99] In its response, Horizon stated that it was open to the suggestion subject to the amount being subject to true-up at the end for any over- or under-collection. Any true-up approach would require a D/V account.

Board staff is of the view that known increases in the 2011 to 2014 period should be amortized over the rebasing year and IRM period and embedded in base rates with no true-up, similar to how other forecasted OM&A costs in some areas, such as regulatory costs, are treated.

[98] http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/APH_FAQs_December2010.pdf, Q. 6 and Q. 7

[99] Board staff IR # 52

Account 1592

Account 1592 - PILs and Tax Variances for 2006 and Subsequent Years is documented in the Accounting Procedures Handbook for Electricity Distributors as follows:[100]

1592 PILs and Tax Variances for 2006 and Subsequent Years

A) For the period starting May 1, 2006, the distributor shall use this account to record the tax impact of any of the following differences:
1. any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model
2. any differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities.
3. any differences in 2006 PILs that result in changes in a distributor's "opening" 2006 balances for tax accounts due to changes in debits and credits to those accounts arising from a tax re-assessment:
   a) received by the distributor after its 2006 rate application is filed, and before May 1, 2007; or
   b) relating to any tax year ending prior to May 1, 2006.

B. Carrying charge amounts shall be calculated using simple interest applied to the monthly opening debit or credit balances in the account (exclusive of accumulated interest) and recorded in a separate sub-account of this account. Effective May 1, 2006, the rate of interest shall be the rate prescribed by the Board for the respective quarterly period.

C. Records shall be maintained at a detail level to support entries in this account. Disposition of the account balance will be subject to Board review.

Account 1592 is a Group 2 account per the EDVARR guidelines and is disposed at the time of a Cost of Service application.

In its original Application, Horizon did not propose disposition of this account. The account balance has not previously been disposed, as the method for disposing of this account and of account 1562, which tracks variances in PILs and taxes from October 1, 2001 to April 30, 2006, had yet to be dealt with. The Board has commenced a proceeding to deal with the disposition of account 1562, and this matter is before the Board. However, there are differences in the treatment of the accounts. In particular, account 1592 is simpler to deal with as

[100] Accounting Procedures Handbook, revised July 2007, page 37, http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/Accounting_Procedures_Handbook.pdf

there is no final "true-up" as applied to taxes or PILs paid prior to May 1, 2006. Thus, in certain cost of service applications for electricity distributors, disposition of account 1592 balances is being sought and approved. Board staff submits that disposition of the Account 1592 balance as of December 31, 2009 plus carrying charges is appropriate in this Application.

In response to Board staff IR # 54, Horizon concurred with the disposition of 1592. Horizon documented a December 31, 2009 audited balance of ($992,956.45), consisting of a principal of ($877,121) and carrying charges of ($45,835). This corresponds with Horizon's 2009 RRR filing 2.1.7 for its Trial Balance.

In response to Board staff IR # 55, Horizon provided an updated detailed derivation of the account 1592 balance to December 31, 2009 of ($1,089,186). In part d) of the interrogatory response, Horizon stated that it had followed the Board's guidance in the July 2007 FAQ to the APH, but, due to changes in staffing, is unable to reconcile the updated entries and balances to the 2009 audited information and RRR filing. In the oral hearing, Horizon's witness, Mr. Basilio, in his role as CFO of the utility, testified that the updated principal balance of $1,017,175 is an audited amount, made as a post-closing adjustment to its 2009 audited financial statements.[101] Board staff accepts this explanation and has no concerns with disposing of what is a higher credit to customers.

In part f) of the interrogatory response, Horizon responded that, should the Board determine that the account 1592 balance be disposed, distribution revenues should be used to allocate the amounts between customer classes, the refund period should be one year consistent with the proposed recovery/refund period for other D/V accounts, and the billing determinant for the rate rider for each customer class would be number of customers or connections, as appropriate.

Board staff takes no issue with Horizon's proposal, and submits that the Account 1592 balance be disposed along with the Group 1 and Group 2 D/V account balances for which Horizon has requested disposition.

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[101] Tr., Vol. 3, pg. 141/l. 21 to pg. 143/l. 9

HST

In its 2010 EDR IRM application (EB-2009-228), Horizon was directed to record in account 1592, Subaccount HST/OVAT Input Tax Credits (ITCs), any ITCs it receives beginning July 1, 2010. There is no audited balance as of December 31, 2009, so no disposition is sought in this application. In response to an interrogatory from Board staff, Horizon documented that the impacts of savings (from ITCs) are reflected directly in capital and operating costs for the 2011 test year.[102]

Account 1572

In its revised evidence of March 14, 2011, Horizon has requested approval to track in a subaccount of account 1572 – Extraordinary Event Losses any distribution revenues received for demand above the revised load forecast for two specific Large Use customers. Horizon proposed that any balance recorded in the sub-account, upon disposition, be shared 50:50 with its Large Use customers. Horizon proposed that the account be asymmetric and that any downside risk be borne by Horizon and its shareholder.

Horizon was queried regarding its proposal in interrogatories posed on the revised evidence. In particular, in response to Board staff supplemental IR # 3 c), Horizon stated:

> Horizon Utilities identified one approach to the disposition of any variances that are tracked in Account 1572. Since the volatility in load and related revenues stems from the Large Use customer class, Horizon Utilities submitted that this customer class alone should receive the benefit of positive variances. However, Horizon Utilities acknowledges that this is not the only approach that may be employed and that other approaches may be relevant. Further, the disposition of any balances will be a matter to be dealt with in a future application and proceeding.

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[102] Board staff IR # 57

The proposal was the subject of cross-examination, specifically with Panel 3 on April 7, 2011. In cross-examination, Horizon concurred that its proposal was one approach. Horizon's witness, Ms. Butany-DeSousa, clarified that the tracking would be with respect to 2011 and subsequent years[103], until Horizon next rebases. Further, Ms. Butany-DeSousa indicated that a full run of the cost allocation model indicated that the lower load forecast has impacts for other customer classes, with respect to the allocation of costs.[104]

When cross-examined by Board staff, Horizon concurred that, due to timing, the 2014 balance would not be known or audited if disposition would be sought as part of Horizon's next Cost of Service application, scheduled for 2015. In such case, the 2014 balance would persist until a subsequent application.[105]

Board staff makes submissions on a number of aspects with respect to Horizon's proposal:

- Determination of disposition methodology deferred to subsequent hearing;
- Asymmetry and risk of Horizon's proposal;
- Proposed method of disposition; and
- Disposition at Horizon's next Cost of Service application; and
- Is a Deferral Account Approach even Necessary or Reasonable?

Determination of Disposition Methodology Deferred to a Subsequent Hearing

While the exact approach to dispose of the deferral account balance could be deferred to a subsequent application, Board staff submits that the current panel, in being asked to approve the requested account and how the amounts should be recorded. The current panel can not bind a Board panel in a subsequent application for disposition, but it can provide useful instruction and documentation on what was its intention based on the evidence when it did establish a deferral account. In reality, the current panel is being asked for an accounting order.

[103] Tr. Vol. 3, pg. 73/ll. 19-24, April 11, 2011
[104] Tr. Vol. 3, pg. 74/l. 26 to pg, 75/l. 9, April 11, 2011
[105] Tr. Vol. 3, pg. 140/l. 28 to pg. 141/l. 19, April 11, 2011

With that in mind, Board staff submits that this Board panel can and should turn its mind as to what should be the purpose of this account based on the evidence in this Application.

Asymmetry and risk of Horizon's Proposal

While Horizon's proposal for asymmetrical treatment (Horizon's shareholder assumes 100% of downside risk with a 50:50 sharing of upside revenues), Board staff submits that the downside risk is minimal.

First, the proposal is only with respect to the load forecasts of two specified Large Users. Variances from the (updated) forecast for the other ten Large Use customers are exogenous to this proposal.

Second, in its updated Large Use forecast of March 14, 2011, Horizon has assumed no demand (i.e., 0 kW) for all months in 2011 for one of the specified customers. Demand can not go below zero, so there is no downside risk for this customer. In fact, in the oral hearing, Horizon confirmed that there has been demand for this customer in all months in 2011 to date; this was to be expected as the announced closure did not occur until April of this year. As a result, if the Board were to approve Horizon's approach, there will in fact be a positive variance in the account due to any actual demand by this customer beginning with its January 2011 demand.

The only downside risk that Horizon is assuming is with respect to the demand for the other customer, where Horizon's updated load forecast for this other customer is about 50% of its original forecast.

Board staff observes that both of the specified customers are not Horizon's largest customers in the Large Use class and, in any event, only correspond to about 20% of its Large Use demand. Horizon will still earn significant distribution revenues from its other customers in this class.

Proposed Method of Disposition

Horizon has proposed a 50:50 sharing between itself and its Large Use customers. As discussed above, Horizon has acknowledged that this is not the only approach, and has acknowledged that there are impacts of the updated Large Use forecast on other Customer Classes due to the re-allocation of costs through the Cost Allocation model. However, some of the impacts may be smaller.

This is to be expected from the Cost Allocation methodology. kW demand is not the only allocator for demand-rated customer classes. The major impact of re-allocation will primarily be within the Large Use class and will have a smaller impact on costs re-allocated to other classes.

Board staff opposes Horizon's proposal to retain 50% of any net revenues from demand overages for the two specified Large Use customers, and submits that this amounts to a windfall for Horizon and its shareholder. There are several reasons for this.

First, as noted above, Horizon's downside risk is minimal.

Second, Horizon is not adjusting its rate base, capital expenditures or operating expenses for the Large Use class, even with the updated Large Use load forecast. This results in higher rates, both fixed and volumetric, to recover the costs with a smaller demand forecast. In other words, the resulting higher rates are compensatory for Horizon's existing rate base and 2011 capital and operating costs, including the cost of capital and capital-related expenses such as depreciation and PILs, to serve this class; any additional distribution revenues due to increased load are basically "costless" to the utility.[106]

Board staff submits that a more reasonable sharing may be: 5% to Horizon, 75% to other Large Users and 20% to all other customer classes, based on the following. First, the 5% sharing to Horizon is intended to compensate them for

[106] This is particularly the case for Large Use customers where the costs of serving are largely for the capital infrastructure and are demand-invariant.

any demand-related additional operating expenses that might be related to increased demand, as well as to provide for some profit on the incremental demand and revenues from these customers. Second, the 75% sharing to other Large Use customers and remaining 20% to all other classes is arbitrary but intended to reflect the cost allocation impact discussed above. Most of the load forecast impact is on the rates for the Large Use Class itself, and there is a lesser impact on the allocation of costs and revenue requirement to other classes.

Disposition at Horizon's next Cost of Service Application

If approved, the deferral account/sub-account will track incremental distribution revenues for demand on the two specified customers until Horizon next rebases. Assuming that Horizon next rebases for 2015 rates, it will file sometime in 2014. At best, audited balances up to December 31, 2013 would be available for disposition. The account would only track amounts up to December 31, 2014, but would not be disposed until the following Cost of Service application (which would be for 2019 rates under the current four-year schedule).

The account would not need to track amounts beginning January 1, 2015 as the actual forecasted load of these specific customers (or their successors) will be known and can be reflected in the load forecast for 2015 rates.

Is a Deferral Account Approach even Necessary or Reasonable?

The above discussion points out the difficulties with Horizon's proposed deferral account. The panel must consider what approach is justified. The points discussed above indicate that there will be an administrative burden and costs for the utility to track the amounts, and also costs for the Board to review and dispose any balances. The account will also have some longevity, likely persisting until at least 2018 or 2019.

As identified in the evidence, the deferral account is specific to the load for the two specific customers, and is unaffected by load or revenue variances (up or down) for other Large Use customers. And, as previously noted, the two specified customers are not the largest customers in the class.

Board staff also notes that other complexities, such as the reclassification of either of the specified customers to another customer class due to load reductions, has not been considered in the proposal.

Board staff therefore submits that the issues discussed and the administrative cost and burden should be considered by the Board as to whether Horizon's proposed deferral account is even necessary.

On the other side, the need for the account is largely justified by the updated reduced Large Use Forecast filed in Horizon's March 14, 2011 evidence, which assumes zero demand for one of the specified customers. If a deferral account approach is rejected, the concern is that the zero demand for this customer in 2011 is inaccurate. Horizon's forecast should be adjusted if the proposal for this account is rejected; otherwise, Horizon is in fact retaining 100% of any incremental revenues while the increased Large Use rates are compensatory for the rate base and capital and operating expenses to serve the customers.

Smart Meters

As is noted on the record, Horizon's separate application for an increase to its Smart Meter Funding Adder ("SMFA") was dealt with separately, under File. No. EB-2010-0292. In the Board's decision in that case, Horizon was approved an increased SMFA of $2.14 per month per metered customer, effective from March 1, 2011 to April 30, 2012.

Board staff expects Horizon to file a stand-alone application for a prudence review of costs for its entire smart meter deployment at the earliest opportunity.

Other Matters

Late Payment Penalty Rate Rider

In its Application, Horizon requested the recovery of a one time expense of $1,107,863 related to the late payment penalty ("LPP") costs and damages resulting from a court settlement that addressed litigation against many of the former municipal electricity utilities in Ontario.

On October 29, 2010 the Board commenced a generic proceeding on its own motion to determine whether Affected Electricity Distributors[107], including Horizon, should be allowed to recover from their ratepayers the costs and damages incurred as a result of the Minutes of Settlement approved on April 21, 2010 by the Honourable Mr. Justice Cumming of the Ontario Superior Court of Justice (Court File No. 94-CQ-r0878) and as amended by addenda dated July 7, 2010 and July 8 (the "Minutes of Settlement") in the late payment penalty class action and, if so, the form and timing of such recovery. This proceeding was assigned File No. EB-2010-0295.

On February 22, 2011 the Board issued its Decision and Order in the LPP Generic Hearing (the "LPP Decision") and determined that it was appropriate for the Affected Electricity Distributors to be eligible to recover the costs and damages associated with the LPP class action in rates. The LPP Decision listed Horizon as an Affected Electricity Distributor and approved Horizon's share of the class action costs. The Board directed Affected Electricity Distributors such as Horizon to file with the Board detailed calculations including supporting documentation, outlining the derivation of the rate riders based on the methodology outlined in the LPP Decision, and noted that the rate riders submitted would be verified in each Affected Electricity Distributor's IRM or cost of service application, as applicable. Horizon has elected to recover the amount approved in the LPP proceeding and accordingly filed the associated rate riders on February 28, 2011.

Board staff has reviewed the rate riders and has no concerns.

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[107] As defined in the Board's Decision and Order EB-2010-0295

IFRS

Horizon has filed its Application in accordance with Canadian GAAP. At the time of filing in August 2011, Horizon assumed that it would convert to IFRS effective January 1, 2011; it has subsequently altered the changeover to January 1, 2012.

The Application was based on there being no further “transition” costs in 2011 assuming a January 1, 2011 changeover to IFRS, but there are costs for IFRS with respect to employees, systems and training factored into the 2011 operating and capital budgets. Horizon has included an amount of $560,752 as the December 31, 2009 balance of Account 1508 – Other Regulatory Assets – sub-account Deferred IFRS Costs in the D/V accounts for which it is seeking disposition.[108]

Staff notes that in its submission on Toronto Hydro-Electric System’s 2011 cost of service application (EB-2010-0142) filed on April 18, 2011, staff noted that the amount of IFRS costs claimed for recovery by Toronto Hydro is the highest that has been sought for recovery by an applicant to date. Staff noted that this was demonstrated during cross examination by the Schools Energy Coalition, during which IFRS costs proposed for recovery by other applicants were cited and the highest number found by SEC was $3,861,300 by Enbridge Gas Distribution. The highest number for an electricity distributor was Horizon Utilities Limited’s amount of $565,479.[109]

Staff further noted that Toronto Hydro’s request for recovery of this amount represents the first time the Board has been asked to approve the disposition of IFRS costs recorded in account 1508. Staff submitted in this context that before making a determination on the appropriateness of the cost recovery requested by Toronto Hydro, it would be helpful for the Board to see other claims for recovery in order to assist it in assessing the reasonableness of Toronto Hydro’s claim. Accordingly, staff submitted that the Board should consider allowing Toronto Hydro to recover 50% of the amount of these costs at the present time with the

[108] Response to Board staff IR # 58
[109] Page 12, Board Staff Submission, EB-2010-0142

remainder to remain in the deferral account and be assessed for recovery in a future proceeding. Board staff was of the view that carrying charges on the remaining balance should continue to apply.

Given the very short time frame between the staff submission filed on the Toronto Hydro case and this submission on Horizon's case, and the size of the quantum proposed by Horizon, Board staff is of the view that similar treatment should be afforded to Horizon's deferral account disposition. Presumably, Horizon will have further costs recorded to December 31, 2010 and may, with the delay in conversion to IFRS, have further transition costs in the 2011 test year.

Board staff does not directly address staffing and operating and capital costs related to IFRS, but these are implicitly captured in the capital and operating cost reduction envelopes that Board staff has addressed elsewhere in this staff submission.

– All of which is respectfully submitted –