**EB-2015-0003**

**PowerStream Inc.**

**Application for electricity distribution rates for the
period from January 1, 2016 to December 31, 2020**

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**SUBMISSION OF**

**BUILDING OWNERS AND MANAGERS ASSOCIATION, GREATER TORONTO
("BOMA")**

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January 14, 2016

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**Submission**

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1. **Compliance with the RRFE Principles**

The Board, in the Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (the "RRFE Report"), at p2, concluded that the following four outcomes were appropriate for distributors:

"*Customer Focus*: services are provided in a manner that responds to identified customer preferences;

*Operational Effectiveness*: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

*Public Policy Responsiveness*: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

*Financial Performance*: financial viability is maintained; and savings from operational effectiveness are sustainable."

These four outcomes are what the Board expects utilities to achieve regardless of the form of IRM the distributor chooses. In its recent Toronto Hydro decision (EB-2014-0116), at p4, the Board stated that:

"At the heart of the RRFE policy objectives are customer-focused outcomes and continuous performance improvement by distributors."

This Argument will focus on the extent to which the PowerStream proposal achieves these results.

BOMA will address the extent to which PowerStream achieves each of these outcomes, with special attention to those features which the Board has characterized as being at the heart of RRFE policy objectives, starting with Customer Focus Outcomes. BOMA will also address those features which the Board has stated in the RRFE are critical to a custom IR proposal.

These were set out at p13 of the RRFE, as follows:

"**Table 1: Rate-Setting Overview - Elements of Three Methods**

|  |  |  |  |
| --- | --- | --- | --- |
|  | **4th Generation IR** | **Custom IR** | **Annual IR Index** |
| **Setting of Rates** |
| **“Going in” Rates** | Determined in single forward test-year cost of service review | Determined in multi-year application review | No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism |
| **Form** | Price Cap Index | Custom Index | Price Cap Index |
| **Coverage**  | Comprehensive (i.e., Capital and OM&A) |
| **Annual Adjustment Mechanism** | **Inflation**  | Composite Index | Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor’s forecasts (revenue and costs, inflation, productivity); (2) the Board’s inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor’s forecasts | Composite Index |
| **Productivity** | Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor | Based on 4th Generation IR X-factors |
| **Role of Benchmarking** | To assess reasonableness of distributor cost forecasts and to assign stretch factor | n/a |
| **Sharing of Benefits** | Productivity factor |
| Stretch factor | Case-by-case | Highest 4th Generation IR stretch factor |
| **Term**  | 5 years (rebasing plus 4 years). | Minimum term of 5 years. | No fixed term. |
| **Incremental Capital Module** | On application | N/A | N/A |
| **Treatment of Unforeseen Events** | The Board’s policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors, will continue under all three menu options. |
| **Deferral and Variance** | Status quo | Status quo, plus as needed to track capital spending against plan | Disposition limited to Group 1 Separate application for Group 2 |
| **Performance Reporting and Monitoring** | A regulatory review may be initiated if a distributor’s annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels." |

These features are important because without them, or most of them, the purported custom IRM degenerates into a five-year cost of service plan, which is unacceptable. It is unacceptable because it is fundamentally at odds with the Board's RRFE policy, and because it is grossly unfair to ratepayers, in that it allows the utility to base its proposal solely on what it perceives to be its needs, without the annual scrutiny of a cost of service framework. The Board has already ruled that such multiyear cost of service proposals (in excess of two years) are unacceptable in the Toronto Hydro (2012) case.

1. **Early Rebasing**

In its letter of April 20, 2010, described in the RRFE, p15, the Board stated:

"a distributor that seeks to have its rates rebased earlier than scheduled must justify in its cost of service application why rebasing is required and why and how the distributor cannot adequately manage its resources and needs during the remainder of the fourth generation term plan."

PowerStream is proposing to exit its existing fourth generation IRM plan a year early by filing what is described as a custom IR plan. The effect of its filing is to stop the fourth generation 2016 rather than 2017. Even if the Board ultimately judges the five-year plan is to be a custom IRM plan, and not a cost of service plan, as stated in the above quotation, the fundamental point stated above remains the same; a utility that wishes to terminate an existing performance-based plan prematurely must explain why it cannot manage under the plan it is on. PowerStream is attempting an early termination of its fourth generation plan, which it is not permitted to do without a compelling rationale. The issue here is the premature termination of a plan, which an applicant cannot do unilaterally.

The company has not provided any detailed rationale on why it must rebase for 2016, a year earlier than normal. It is currently under fourth generation IRM and 2016 was to be the last year of the three-year plan (2014, 2015, 2016). Its last rebasing year was 2013. For example, the company has not explained why it has been unable to manage with a capital module. It simply states that it cannot do so (Tr1, p24).

However, that is the entirely foreseeable result of the company's increased capex and OM&A during the first three years of its current IRM program.

1. **Customer Focus**

BOMA is of the view that PowerStream rates proposal does not reflect customer needs and preferences. PowerStream's evidence is that it did not even begin its consultation with its customers until it had virtually completed its application (Tr2, p17), and further made no changes to its application as a result of the consultations (J2.1). It also acknowledged that it should have begun the consultation much earlier, in the Spring of 2014. Innovative Research Group ("Innovative" or the "Consultant"), the Consultant chosen by PowerStream to conduct the consultation, noted in the introduction to its report, that:

"While PowerStream engages customers in a number of ways to explore their needs, it has not done so in the context of its capital plan or rate application. This consultation sought to bring customers directly into the process of finding the right balance between cost and reliability in PowerStream's distribution system" (Exhibit G, Tab 2, Appendix F, p1) (our emphasis).

Unfortunately, the consultation was conducted too late, and was otherwise flawed.

More particularly, the focus groups, a telephone opinion survey, and the posting of its proposal on the PowerStream website (the "online primer"), the three methods used by the Consultant to determine customer preferences, were not undertaken until very late in 2014 and early in 2015. PowerStream stated that it began work on the plan in the Spring of 2014 and had substantially completed the proposals by December 2014. In that month, it filed the essence of its application with intervenors with a view to convening a "settlement conference" in early 2015, prior to filing its application with the Ontario Energy Board ("OEB"). PowerStream filed substantial financial and performance data in support of its application with those same intervenors in February 2015.

Given this sequence of events, PowerStream cannot claim to have represented customer identified consumer preferences in its application. It simply did not know what they were in time.

An example of the consequences of consulting after the rate proposal was complete was the disconnect between stated consumer preferences and the plan on the matter of "storm hardening" or preparation for extreme weather.

General Service and Residential Customers indicated to the Consultant that:

"Preparing for extreme weather is not seen as a priority for many customers. Because reliability is generally seen positively, many participants, both General Service and Residential, did not see preparing for extreme weather as a priority. These types of events are seen as unpredictable, and do not provide value to the overall system's viability." (Ibid, p49)

Notwithstanding the stated customer preference, PowerStream's proposal included a $150 million, five-year program on "system hardening" expenditures, much of which was, in fact, rear lot conversion of both primary and secondary lines.

Had PowerStream obtained the statement of customer preferences at the outset of the application process, they may have avoided including those proposed expenditures in its application, or at least reduced their amount.

Other parties will deal with the details of the proposed "hardening" expenditures. BOMA's point here is to note the disconnect between the initiative and stated customer preferences.

In addition, Innovative reported that:

"Before agreeing to a rate increase, many customers, both General Service and Residential, felt that every possible avenue of cost savings needs to be looked at. They felt that the magnitude of the rate increase required would require significant sacrifice on the part of customers – they wanted to see that the sacrifices were shared by PowerStream, even among management.

General Service customers were particularly interested in internal efficiencies related to employee salaries and managing assets. Many General Service customers argued that they could not increase costs so dramatically at their own business, and PowerStream shouldn't either" (Report, p49).

Had the information been available on time and been heeded, PowerStream may have been more aggressive in demonstrating productivity improvements, salary resets, and maintenance savings linked to growing capex.

BOMA also believes that the scope of the consultation was much too narrow.

Its questions on new technology did not probe deeply about the customers' preferences for CDM (including distributed generation under 10 MW), cogeneration, or renewables. Many of the larger commercial customers are actively examining the role CHP and distributed generation might play in their facilities; but the questions were very limited in these areas.

BOMA also has concerns with the accuracy of Innovative's reporting the results of its findings and how in its report. For example, Innovative states, at p8 of its Report:

"All stages of the consultation focus deeply on the question of outages, both under normal circumstances and due to unusual weather. In both cases, PowerStream customers were extremely satisfied with the utilities response" (our emphasis).

Yet, the two Tables in the Report immediately below that sentence, on which the Consultant relies, do not say that. The Tables are reproduced below.

"Satisfaction with Response to Unusual Weather Outages

|  |  |  |
| --- | --- | --- |
| Response | Directional(Focus Groups & Online Primer) | Generalizable(Telephone Surveys) |
| Residential Groups | GS under 50 kw Groups | Mid-Market Groups | Online Primer | General Service | Residential |
| Very satisfied | 11 | 11 | 8 | 41% | 25% | 33% |
| Somewhat satisfied | 7 | 13 | 8 | 41% | 41% | 40% |
| Somewhat dissatisfied | 3 | 0 | 0 | 8% | 4% | 7% |
| Very dissatisfied | 0 | 0 | 0 | 3% | 3% | 5% |
| Don't know / Refused | 0 | 0 | 1 | 7% | 25% | 13% |
| TOTAL | n=21 | n=23 | n=17 | n=1,553 | n=201 | n=1,001" |

"Satisfaction with Response to Normal Outages

|  |  |  |
| --- | --- | --- |
| Response | Directional(Focus Groups & Online Primer) | Generalizable(Telephone Surveys) |
| Residential Groups | GS under 50 kw Groups | Mid-Market Groups | Online Primer | General Service | Residential |
| Very satisfied | 11 | 12 | 5 | 42% | 38% | 42% |
| Somewhat satisfied | 9 | 12 | 8 | 42% | 43% | 44% |
| Somewhat dissatisfied | 0 | 0 | 1 | 8% | 8% | 5% |
| Very dissatisfied | 0 | 0 | 0 | 3% | 5% | 4% |
| Don't know / Refused | 1 | 1 | 2 | 5% | 6% | 6% |
| TOTAL | n=21 | n=25 | n=16 | n=1,012 | n=81 | n=462" |

(Exhibit G, Tab 2, Appendix F)
The tables above quantify the customer responses in the focus groups. In the focus group, the majority of all three categories of the customers are roughly divided between "very satisfied" and "somewhat satisfied". The same is true for the response to the online "primer" and the telephone surveys.

In this instance, the Consultant's statement is advocacy for the utility, rather than a balanced statement of how the customers responded to the question.

The focus group, the online primer, and the telephone surveys are the core methods used to determine customers' needs and preferences.

BOMA also notes that PowerStream's consultations carried out for its Customer Experience Plan were all internal, within the PowerStream organization. Oddly enough, customers were not consulted on the best way of developing a customer centric culture in the utility. This omission reflects a bureaucratic, rather than a customer centric culture.

Other examples of the Consultant's advocacy in place of unbalanced reporting, including placing customers' negative reaction percentages in a footnote, rather than listing them in the text itself (p40).

Furthermore, many of the question/response linkages are unclear. For example, in a question based on Figure 16 (p139) of the Report, customers are asked whether they agree with general direction of the Investment Plan. Fifty-eight percent (58%) said right direction, thirty-five percent (35%) said not sure. In the next question, Figure 17(a), they were asked "why do you feel that way", and answers are rank ordered; but the rank ordering was not done separately for those customers that answered positively, or uncertainly, to the previous question. The failure to do this creates confusion (p40).

Some questions are incomplete. For example, in Figure 12(b), p35, customers are asked how much they would value new technology, but they are not asked about the cost trade-off; 3 in 5 say investments in new technology should be a priority, while 2 in 5 say it is a luxury and should be a low priority. There were no questions on which new technologies were of the greatest interest to customers, for example, there were no questions on combined heat and power (cogeneration), distributed generation, assistance with behind the meter projects, customized enhanced reliability services, etc. Nor was there any attempt to quantify the new technology/cost trade-off or to bridge the apparent gap between the two customer camps.

With respect to the rate increase itself, 21 of 32 business customers in the customer meetings said they didn't like the rate increase plan, but think it necessary, and nine said they opposed it. None said the rate increase is reasonable and I support it.

With respect to "key accounts", which include many BOMA members, only one focus group was held, on December 10, 2014. With respect to that session, the Consultant reported that:

"Many participants are willing to accept the rate increases, however, they want to be assured that their reliability will be improved, otherwise it is difficult to justify the proposed rate increase".

The Consultant also reported that the key accounts' view was that:

"Regardless of the investments they (PowerStream) makes, the overall system's liability has to be improved in order to reduce the effect of an outage."

Notwithstanding this view, PowerStream did not commit to improving reliability in this application and forecast of only modest improvements.

The Report states that many general service customers are looking beyond PowerStream (i.e. investigating installing UPS technology or constructing their own generation) to improve their company's electricity reliability, often because they cannot afford to have any outages. PowerStream did not appear to appreciate the urgency of the matter.

The report also states (p95) that many key accounts felt:

"there was not a clear stream of information between PowerStream and themselves. Projected outage durations were a particular concern for many of the participants, who managed several properties or buildings".

BOMA is not clear how PowerStream is responding to the need for better communication with strategic accounts. Where is the plan? What about the key accounts suggestion that a separate line be established to provide a continued update in outage restoration time changes?

Several key account participants felt that investment in technology should bring a positive return (p96). PowerStream projects higher, not lower, costs as a result of the investment.

The general feeling among the general service participants was that the plan, with its attendant rate increases was unrealistic and further internal efficiencies could be achieved to reduce the overall percentage rate increase (p98). One participant stated: "I challenge them to revisit it".

Finally, the lack of consultation with customers was also apparent in PowerStream's approach to regional planning in York Region (Exhibit G, Tab 2, 5.2.2) (our emphasis).

The evidence suggests that a Working Group consisting of utilities, the OPA and the IESO was established in 2011. It produced an initial report in November 2012, entitled "Study of Needs and Options". In October 2013, a Technical Working Group was launched, again without customer representation. In April 2014, the Working Group met with the Planning Directors and Chief Administration Officers of the municipalities in the planning area. It is not clear from the evidence whether renewable and CDM options were considered at these stages of the planning work. The evidence in the case then stated that now, the planning process was moving to the next phase, involving community engagement (customers?) on the long-term needs and alternatives (our emphasis). BOMA questions why the engagement of customers is left to the latter part of the process. That process is not a customer-focused process which responds to customers' stated needs and preferences. As a study which provides context to ongoing and subsequent distributor's plans and operations, it should be.

BOMA believes that PowerStream did not consult on time. They did not obtain and reflect customers' preferences in its application. Accordingly, the Board should give little weight to the Innovative report. In BOMA's view, the proposed custom IRM is not customer-focused.

1. **Rate Impacts**

The Application calls for large annual increases for capital and OM&A over the plan term compared with the last ten years, which increases have resulted in untenable rate increases. The company's August 21, 2015 evidence update (Exhibit A, Tab 1, Schedule 1, p2), which includes the updated working capital (see J1.2) and the monthly billing effective in 2017, is approximately $1.158 billion, a five-year revenue requirement. The revenue requirement from each of the five plan years, before revenue offsets, in millions of dollars, is stated to be:

2016 $199.6

2017 $223.0

2018 $234.2

2019 $244.9

2020 $254.7

The corresponding cumulative revenue deficiency, in other words, the amount of new money the company has asked the Board to approve in rates, for the five-year custom IR is approximately $275 million. That number was set out at p16 of the SEC compendium for Panel 1 (general). The Company agreed with the number, subject to check (Tr1, p41).

The SEC compendium for Panel 1 (general) projects the cumulative revenue requirement over the five-year plan period is approximately $200 million higher than the deficiency that the revenue requirement would result from the application of fourth generation IRM method (absent a capital module) using a fourth generation Board-approved IRM annual escalator of 1.85% for each year but 2016 (the first year of the new plan) in which it assumed an increase of six percent (6%) over the 2015 rate was used (Tr1, p43). The $200 million difference highlights the very large increases over historical levels that the Company is seeking.

The very large increases are driven by historically large increases in both capital and OM&A expenses (see below). They result in very large increases in rates for almost all rate classes. For example, from 2006 to 2015, the company's residential rate increased an average of 1.38% compounded per year. Over the custom IR plan, it is forecast to increase by 5.66% per year compounded, an annual increase more than 400% larger than that over the previous ten years (Tr1, pp95-97).
For general service customers <50, the annual rate increase over the years 2006 to 2015 averaged 0.62% per year, while the proposed annual average increase for the plan period is 7.41%, a 1,200% increase over the historical annual increase in rates (Ibid).

For general service customers over fifty kw, the historical annual average rate increase was 1.10%; the proposal for the plan period 2015-2020 is an average of 8.15% per year, an increase of more than 700% over the historical rate increase (Ibid).

Moreover, the notion that PowerStream advanced the fact that in earlier years, rate base and depreciation were lower due to the fact that developers/home builders paid for the infrastructure in new subdivisions, which no longer is the case, somehow puts the utility at a disadvantage, does not hold up. The utility didn't pay for some or all of the assets used to supply the subdivision. It cannot, therefore, by longstanding regulatory law and policy, claim a depreciation or return on such assets.

These numbers are very large, and are not justified in the application. They will cause a real problem for customers. It is clear from responses to the Company's belated custom consultation that many customers, especially business customers, consider these increases excessive.

PowerStream's evidence is that the total electricity bill for a residential customer using 800 kwh/month and a general service customer using 2,000 kwh/month will use in 2016 over 2015 by 4.0% and 3.8%, respectively (S1, Tab 2, Schedule 1, p3). The impacts are not shown in the overview documents.

Not surprisingly, the rate impacts of the plan are much higher. The average rate increase for the York Region for all rate classes in 2016 over 2015, the first year of the five-year plan is 21.9%. The first year rate increase for general service > 50 customers in 2016 is 30.67%, almost a one-third increase, for general service < 50 customers, the increase is 17.4%, and for a residential customer 17.3% (Exhibit B, Tab 1, p3). These are increases in customers' payment for the service provided by PowerStream to those customers, and for which PowerStream, not other parties, are accountable. PowerStream's own efforts, or lack thereof, to control costs and provide value for money should not be camouflaged by comparing them with the total utility bill, especially as the increases or decreases in the other components of the bill are not shown. Such a selective presentation is misleading to customers. Moreover, almost any size increase in distribution rates can be made to look reasonable when compared to the customer's total electricity bill and defuses the utility's accountability for its activities. Conversely, the utility would have difficulty explaining an increase in its rates in percentage of the total bill if some other components of the bill, for example, the global adjustment or the commodity costs, were reduced.

1. **Relationship Between Capital and OM&A Expenditures**

The Board supports a comprehensive approach to ratemaking. When the Board speaks of the interrelationship between capital expenditures and OM&A, it means that as a general rule, increased capital expenditures, especially on system renewal and system service and general plant, should result in lower maintenance costs.

The Board reiterates this view in its recent Toronto Hydro decision (p6).

PowerStream has agreed that a newer plant should need less maintenance (Tr3, p124). This view is confirmed by the descriptions of a sample of PowerStream's three hundred and seventy-six (376) capital project sheets, for example, project 101012 and project 102730.

The Project Sheet for 101012 (a circuit breaker replacement) states:

"Replacement breakers will be more reliable and pose reduced risk to personnel. From a configuration perspective, this is a like-for-like replacement, but the replacement equipment will require reduced maintenance and parts will be readily available".

 The Project Sheet for 102730 (station switchgear replacement) states:

"From a configuration perspective, this is like-for-like but the replacement component is more technologically advanced requiring reduced maintenance and has an improved safety feature…".

While these savings are specified in many project sheets, they are never aggregated and shown as explicit reductions to the OM&A budget, nor are regimes put in place to measure them (Tr3, p149).

1. **Customer Focus Results and Increased Reliability**

The Company agrees that a major objective of the system renewal part of the capital program is to increase reliability (Tr3, p123). PowerStream's forecast improvement in SAIDI improvements over the period 2015-2020 is a reduction from 69.26 minutes to 59.97 minutes (our emphasis). These amounts include a declining controllable SAIDI and a flat uncontrollable SAIDI, a decline of about two to three percent (2-3%) per year (Exhibit G, Tab 2, p37).

However, in calculating SAIDI, PowerStream excludes Major Event Days ("MED") based on an IEEE formula that appears arbitrary (Tr3, p128). Pending the Board's development of an acceptable standard definition for MED, BOMA believes "MED outages" be included in SAIDI. Excluding such days from the calculation simply lowers the bar for the utility without any empirical data. Finally, the utility has introduced the category of a non-controllable outage which appears to contain a wide variety of events, which one would have thought the system should be sufficiently resilient to cope with, events other than loss of supply. The graph on p38 of Exhibit G, Tab 2 shows the amount at a constant 24.7 minutes over the six-year period, which causes it to increase from fifty percent (50%) of controllable SAIDI in 2015 to about seventy percent (70%) of controllable SAIDI in 2020, a very significant impact. Aside from loss of supply events, uncontrollable outages should be reclassified as controllable absent some compelling reason not to do so. The distinction again seems arbitrary and simply adds another layer of protection to the utility. What is left, aside from equipment failure? The definition of the controllable and uncontrollable categories should be established by the Board and be uniform across utilities.

More important, PowerStream refuses to commit to a reliability increase over the term of the plan, notwithstanding the fact that it proposes to spend approximately $250 million over the next five years (2016-2020) to renew aging infrastructure or infrastructure in poor condition. Its customers, especially its larger customers, have clearly asked for an increase in reliability and expect an increase in reliability in return for agreeing to a rate increase. As noted below, the proposed rate increases, especially for the general service >50 rate class, which, including many BOMA members, are substantial.

The Board has recently issued a Report in which it recommends mandatory reliability improvement targets for each distributor over a baseline which (baseline) is the average SAIDI and SAIFI numbers over the last five years. In BOMA's view, management should be accountable for achieving these targets, and there should be consequences for them if they are not achieved. Second, the new targets should be put in place during the IRM term as soon as possible once a Board decision has been made. BOMA recommends that the Board make the targets mandatory, and standardize what is to be included in the SAIDI and SAIFI calculations and milestones. However, given that the utility is seeking the Board's approval for large renewal capex, it should be prepared to commit now to improvements for reliability improvement targets. The previous policy of meeting the scorecard target by simply matching the average of the last three years is not sufficient. Reliability improvement is a customer focused result. It is what many customers think they are paying for.

1. **Capital and OM&A – The Customer Information Plan**

Another example of the disconnect between additional capital expenditures and maintenance and other OM&A savings was the company's evidence that the installation of a new customer information and billing system, at a cost of approximately $45 million, would generate additional operating costs (our emphasis).

The Company did not document any operating savings. It appears they did not attempt to make any analysis of likely cost reductions. They stated that they signed a long-term maintenance contract for the new system, but did not say whether they had conducted an RFP for that service. They also forecast an additional $1.4 million in training costs.

In fact, the evidence characterized the new CIS as a productivity initiative (Section III, Tab 1, Schedule 1, p65) which would enable more work to be done smarter, "more value for the same head count", but made no effort to quantify the additional value.

The Company states that they will need to adjust business practices to mirror the available system functionality. It is not clear why they chose a system that did not mirror the business practices that it was using.

The Company states that they have a baseline level of operation for each business unit, so that savings for productivity improvements can be demonstrated over the term of the plan. These baselines do not appear in the evidence (Section III, Tab 1, Schedule 1, p11 of 366).

The business case for the new CIS system, which was filed originally in EB-2012-0161, and refiled in this case at Section III, Tab 2, B-CCC-15, Appendix A, p2 of 14, stated:

"The CC&B system will provide customers with the ability to more easily access information and tools necessary to self-manage relationships and enable better energy decisions, thereby achieving two of the CIS project’s key objectives: to 1) reduce cost to serve by lowering the number of calls to the customer care center…" (our emphasis).

The evidence does not document the reduction in costs.

The business case also stated:

"The new system will reduce the need to increase future staff resources due to the inherent efficiencies and improved functionality built into the system. The CC&B system provides a platform where PowerStream can optimize core business processes and thereby supports the implementation of process improvement methodologies that drive efficiency and effectiveness of core CIS processes." (Ibid, p13 of 14)

Again, there are no details or quantification of the likely avoided staff costs over the plan term, or indication of what types of staff hires (jobs) will be avoided.

1. **Renewable Energy and CDM and Distributed Generation/Public Policy Responsiveness**

PowerStream has taken all of their initiatives to respond to provincial government policy, legislation and specific directives to the IESO and the OEB, and subsequent OEB CDM guidelines. Their performance in these areas is a measure of their responsiveness to public policy.

Renewables. PowerStream's evidence is that it has about 40 MW of solar and wind projects on stream with 76.5 MW forecast for 2020, and 671 MW of excess Transformer capacity to accommodate renewable energy projects (Exhibit G, Tab 2, p4). It is not clear to what extent PowerStream network of feeders have concomitant capacity to the station capacity, but PowerStream states that it will be able to handle whatever renewable energy demands there are.

PowerStream mentioned two potential "customer-side" constraints, namely insufficient pad mounted and pole mount transformer capacity (Ibid, p14). However, BOMA's understanding is that these constraints are remedied as necessary within the proposed plan and budget. PowerStream should clarify whether or not, and to what extent that these are constraints to additional Distributed Generation in their reply argument. If they represent restraints, PowerStream should indicate how it would remove them.

PowerStream noted a 1 MW per site limitation on connections to 44 kV lines in part of its northern region but didn't explain why. BOMA believes that PowerStream should explain why the limitation is in place, the extent to which it constrains renewable and distributed generation development in that region, and what measures it is taking to remedy the situation.

PowerStream has stated that while it has the procedures, the capacity, and the absence of system restraints, except in a few feeders, and two transmission stations (Ibid, pp13-14) to attach large amounts of distributed generation, including renewables, it has stated that "since it is a distributor, it does not promote distributed generation". However, the Minister's Conservation First directive to the OPA/IESO dated March 31, 2014 classified distributed generation under 10 MW or less as conservation initiatives and, therefore, eligible for CDM funding from the IESO. PowerStream does have an obligation to promote, implement and achieve prescribed CDM targets over the plan term, which nearly coincides with the six-year (2015-2020) Conservation First initiative. Distributed generation, including cogeneration, can make a contribution to meeting that conservation target, so PowerStream should make the same efforts to facilitate the introduction of distributed generation to its customers as it does for any other CDM measure.

PowerStream has said that it helps customers who show interest in distributed generation, either renewable or gas-fired. BOMA believes it must go further and promote distributed generation cases where it makes sense for customers.

1. **CDM/Customer Focus**

PowerStream's failure to deliver on the Customer Focus the Board has directed in its RRFE Report is further illustrated by the way it has dealt with CDM in its plan and rates application.

The Board will recall that in its March 31, 2014 Conservation First Directive to the OPA, the Ontario government established a six-year CDM plan for the province for the 2015-2020 period, which required 7 Twh of energy savings by 2020. The electricity distributors are responsible for implementing the plan, and each was assigned a pro rata portion of the target. The plan is to be funded by ratepayers through the global adjustment. The IESO/OEB allocated the total plan budget pro rata to each distributor. PowerStream's 2020 savings target is 535 MW; its share of the OPA's pending budget is $40.7 million.

The distributors were described in the directive as the face of electricity conservation to their customers in all sectors and are accountable for the achievement of the energy savings goals. The distributors are also expected to be innovative and customize general programs to the local circumstances.

PowerStream acknowledged that it did not meet its energy demand targets for the predecessor 2011-2014 program. It did meet its energy target.

While the targets for the 2015-2020 Conservation First plan are energy targets only, the Directive also noted that distributors should also explore CDM alternatives to new infrastructure investment. In addition, the Board, in its recent Natural Gas DSM Guidelines, required distributors to consider DSM measures as part of infrastructure planning and investment.

PowerStream has taken no steps to integrate its CDM into its infrastructure planning in this way, and has no pilot project underway as, for example, the City of Toronto, and no full scale feeder by feeder programs to analyze CDM alternatives to new utility plant construction, such as the one at Consolidated Edison. PowerStream needs to embrace this approach, rather than maintaining its CDM program in a silo separate from the balance of its infrastructure planning. Such an approach is also consistent with the Board's directives on the use of IRRPs in regional planning.

PowerStream's overall business strategy "By 2020, we will build our core electricity distribution business to become Ontario's premier integrated energy service provider" is set out in a diagram at Exhibit G, Tab 2, 5.2.1. The diagram describes how the strategy will be implemented and the key priorities of the company. One of the four elements is Customer Focus. However, CDM activity is not included under that goal/characteristic, notwithstanding the fact that interaction with customers in all sectors on CDM projects is a major part of PowerStream's contact and collaboration with its customers, enhancing the perception of their offerings, and the customer receiving value for money. CDM delivery is also closely linked to one of the goals that is listed under Customer Focus which is "to deliver professional services and deliver an exceptional customer experience". Part of their experience would result from PowerStream tailoring general conservation programs to local conditions, and the creation of PowerStream programs to most customers' needs.

Instead, CDM is listed under the Growth and Sustainability objective, along with "pursue core business growth" and "develop new revenue streams", neither of which, conceptually or practically are closely linked to CDM. When asked about this, PowerStream's response was that CDM was listed where it was to balance the appearance of the table (Tr2, p50). This is not a sufficient answer, and it shows that PowerStream's conception of Customer Focus is bureaucratic rather than dynamic and is thought to be not much more than keeping the regulator at bay.

Finally, PowerStream has stated that in the CDM plan for 2015-2020 that it filed with the IESO, it expects to achieve about seventy-five percent (75%) of its 2020 CDM target. That includes six new programs that, as of February 24, 2015, were only in concept form, with details not developed, and not approved by the IESO. PowerStream, as part of its annual adjustment proceeding and as part of its annual reporting, should update the Board and parties on how it will close the expected performance shortfall. Without annual milestones, it is very hard for PowerStream, the Board, and interested stakeholders to measure progress. PowerStream should also provide annual earning savings targets, and report on variances from those targets.

1. **Earnings Sharing**

PowerStream does not include earnings sharing in its proposal. It does not provide a reason for not doing so, and does not discuss how refusing to share earnings reflects on customer-focused approach. When asked why it did not offer such a feature, it simply said it was a matter for argument.

BOMA is of the view that the Board should direct the company to enter into an earnings sharing proposal with its customers, similar to the one that the Board directed should be included in the EGD Custom IR plan (EB-2012-0459), and the one that it required Toronto Hydro to implement.

In the EGD case, the Board established an earnings sharing plan in which all over-earnings were shared fifty/fifty between shareholders and ratepayers, with no deadband. The Board noted the earnings sharing program would, inter alia, serve to offset the shortcomings of EGD's custom IR plan, which included, in its opinion, lack of total cost benchmarking and independent third party assessments of the reasonableness of capital and OM&A budgets, which result in a greater risk that costs have been over-forecast (p15). The Board went on to state that:

"a sharing ratio of 50-50 provides a suitable incentive level for the company while still ensuring significant benefits for ratepayers" (p15).

 PowerStream's proposal suffers from, among other things, the two shortcomings identified by the Board in the EGD case.

 Earnings sharing would help to compensate.

 Earnings sharing is one method by which the utility can share the benefits of enhanced productivity measures or innovation with its customers and provide a potential offset to increased rates. In other words, if the utility makes profits in excess of its allowed return (the ROE benchmark PowerStream has chosen for its application), it will share them with its customers.

In the recent Horizon Custom IRM decision, the Board, in approving a Settlement Agreement reached between the parties which included earnings sharing, commented that:

"The Board finds that there are several features in the Settlement Agreement that satisfy the RRFE's objective that the benefits of efficiency improvements would be shared with customers (our emphasis). The proposed earnings sharing mechanism and the capital expenditure variance account are examples of such features".

The Board directed Toronto Hydro to include an Earnings Sharing feature in its proposal, which provided for a symmetrical sharing, on a 50-50 basis, earnings above or below a 100 basis point deadband for the new capital related revenue requirement embedded in rates and the actual non-capital related revenue requirement. These features were suggested by Toronto Hydro in the event the Board directed that there should be an economic sharing feature to the proposal (p48).

In Toronto Hydro, the Board stated:

"The OEB is of the view that the establishment of the ESM will allow Toronto Hydro's customers to benefit from efficiency gains achieved during the course of the Custom IR Plan, and thereby alleviate the need for additional reporting requirements to track savings achieved during the term of the plan" (p49).

1. **Benchmarking**

BOMA expects, and suggests the Board expects an application for such large increases, to prioritize and pace capital expenditures, to demonstrate specific productivity measures, to demonstrate how cost increases are being controlled. Customer focused results including guaranteed reliability improvements, as well as continuous productivity improvements should be identified. The company's proposal contains none of these features.

In the RRFE, the Board stated that:

"Each [of the possible rate] methods will be supported by:

* the fundamental principles of good asset management
* co-ordinated, longer term optimized planning
* a common set of performance expectations
* benchmarking" (RRFE, p10).

The Board also noted that the more flexible approach to rate-setting will, among other things:

"help to manage the pace of rate increases for customers" (Ibid, p10).

The Board stated that the permissible rate increases over the plan term would be determined by consideration of:

"Distributor-specific rate trend for the plan term to be determined (1) by the Board, informed by the forecasts (revenue and costs, inflation, productivity); and (2) the Board's inflation and productivity analysis, and (3) benchmarking to assess the reasonableness of the Board's forecasts" (Ibid, p18).

The Board noted in the RRFE that expanded use of benchmarking will be necessary to support the Board's renewed regulatory framework, as follows:

"Benchmarking models will continue to be used to inform rate-setting. Benchmarking will also continue to be used to assess distributor performance".

PowerStream's rate application, including both its capital and OM&A components, was not reviewed for reasonableness by an independent, professional third party. While it did include in its evidence some studies on specific topics, such as storm hardening, it did not seek third party reviews of its own proposals as was done, for example, by Horizon and EGD, nor did it obtain third party assessment of its recent asset condition report as did Horizon and Toronto Hydro. It has not had an independent third party of the reasonableness of its capital budget since 2009. Since then, PowerStream has done its own asset condition reports. Moreover, its benchmarking effort was weak, and, contrary to its claim, did not follow the PEG model to its logical conclusion (see below).

The third party reasonableness reviews and benchmarking provide a degree of comfort for ratepayers in assessing a five-year custom IR plan. They do not exist in this case. What the Board and intervenors are left with is, in essence, a five-year cost of service proposal, one which requires five-year forecasts with their attendant uncertainties, without opportunity for timely prudence reviews, and detailed scrutiny of annual costs and benefits, as would be the case under five one-year cost of service plans. Prudence reviews are difficult to complete several years after the expenditures in question were incurred. Too much has happened in the intervening years which muddies the waters. People have left the utility or changed positions, intervenor personnel have changed, and generally, memories have faded, documents are hard to find, and so on.

The reasonableness of the total proposed capital and OM&A spending proposals is what must be decided by the Board in this case and the Board looks to third party assessments and the application of the Board's accepted PEG benchmarking methodology by a professionally qualified consultant to support the chosen levels.

In 2014, the most recent year for which PowerStream has actual results its actual Total Costs (capital plus OM&A) were about $900,000 less than its cost as predicted by the PEG model (in other words, its benchmark). By 2018, four years later, the forecast costs were almost $24 million higher than the benchmark, a deterioration of about $25 million.

For the five years 2016 to 2020, the company forecast costs are $100 million over its benchmark.

In order to implement the conclusion in the RRFE Report, the OEB retained PEG in 2013 to report on Productivity and Benchmarking Research in support of Incentive Rate-Setting in Ontario. PEG submitted its final report, Productivity and Benchmarking Research in Support of Maintaining Rate Setting in Ontario, Final Report to the Ontario Energy Board, November 2013 ("Productivity and Benchmarking Report") in November 2013. PEG has since updated the relevant data.

PEG outlined its benchmarking approach as follows.

"PEG developed an econometric model to benchmark distributors' total cost performance. PEG's recommended model finds that there is a statistically significant relationship between a distributor's total costs and five business condition variables:

(1) the number of customers served

(2) kwh deliveries

(3) system peak capacity

(4) average km of distribution over the sample period

(5) the percentage of customers added in the last ten years (proxy for newness of the system).

PEG used the cost model to generate econometric evaluations of the cost performance of distributors by inserting values for each distributor's business condition variables that is "fitted" with estimated coefficients for the business condition variable. This process yields a value for the predicted or expected costs for each distributor in the sample given the exact business condition variables faced by that distributor. The model also generates confidence intervals around the cost prediction" (Productivity and Benchmarking Report, p56, p61).

These five business condition variables are the only five business conditions that PEG found to be statistically significant drivers of total costs (Ibid, p60). They are the five conditions which are inserted into the econometric model to establish the expected costs of a distributor, to which that distributor's achieved and forecast costs can be compared.

PowerStream provides in its evidence a table which shows PowerStream's Predicted Total Costs developed using the PEG model, versus Actual Total Cost/Forecast Total Cost from 2010 to 2020 (EP-9, T2, p84 of 363). The table shows a marked deterioration in its performance relative to its benchmark from 2016 to 2020, relative to its historical performance, where its costs were below benchmark. For the five-year plan period 2016-2020, on a cumulative basis, the forecast amount exceeds the benchmark by approximately $111 million. However, PowerStream continued to use GAAP to record actual costs per GAAP even after it had changed to IFRS in 2012. J1.3 shows the forecast numbers from 2012 to 2020, using IFRS accounting, which is the proper comparison, the actual over benchmark is more like $130 million. This analysis suggests that PowerStream's proposed total costs are unreasonable. The Board should reduce its costs to approximately its benchmark value, a reduction of $110 million over five years, in combined capital and OM&A costs.

PowerStream's explanation for the deterioration misses the mark as both its answer to part (c) of the above Energy Probe IR and in its discussion with SEC (Tr1, pp72-75), when it suggested it was the change in the business condition variables that caused the poor performance. The PowerStream witnesses seemed confused about the difference between the business conditions (PEG/Dr. Kaufman) found to be the significant determinants of cost and its own "need" to spend more (Tr1, pp72-74). The business conditions determined to drive costs utilized by Dr. Kaufman (PEG) in the derivation of the costs predicted by the econometric model have not changed; they are the same five conditions. They include a condition that, in PEG's view, is a proxy for the age of the utility's plant, which is the percentage of customers added in the last ten years. What has changed is that PowerStream is proposing to spend a lot more money on capital and OM&A than it did prior to 2015. But, as noted above, it has not justified a level of spending that, inter alia, brings them far above their benchmark.

PowerStream has proposed in essence a five-year cost of service program rather than a customized IRM program, and a five-year cost of service application is not an option under current Board policy. The Board has made it very clear in the RRFE and in subsequent decision on custom IR cases, including EGD, Hydro One, and Toronto Hydro, that, while a custom IRM application has features in common with a cost of service plan, for example a robust forecast of costs and revenues for the plan term, it is fundamentally different from a cost of service plan; it is a performance-based program. The application must, therefore, include all or most of:

* credible third party affirmation of reasonableness of the proposed capital and OM&A;
* total cost benchmarking to establish the reasonableness of the proposal;
* evidence of forecast productivity gains and continuous performance improvements over the term of the plan, such gains and improvements to be identifiable, discrete, and quantified, not simply claimed to be embedded in the proposed capital and OM&A budgets;
* evidence that the company can and will manage within its forecasted costs and revenues, and revenue requirement, without requiring annual adjustments other than for approved Z-factors, without reliance on deferral accounts for overspending;
* evidence which demonstrates value for money for ratepayers by such features as a capital tracker account to record any underspending relative to forecast to ensure ratepayers are not paying for "phantom" assets, earnings sharing, and evidence that the company has attempted to pace its capital expenditures and OM&A increases to lessen the impact on customers;
* evidence that demonstrates that customers should be able to receive measurable benefits in return for the increased rates, such as increased reliability, better service, and the like. Finally, rate and bill impacts should both be reasonable, and unavoidable increases should be mitigated to avoid sudden large increases.

Whether mitigation is necessary or not should be determined by examining the bill impact, not the rate impact.

PowerStream's application includes very few, if any, of these features.

1. **Pacing Capital Expenditures**

As noted above, the Board has stated that under Custom IR, the applicant must submit evidence showing that it has paced and prioritized its proposed capital expenditures to avoid unreasonable rate increases. Given that PowerStream states it needs to spend more capital than can be raised through a fourth generation IRM plan is the principal reason why PowerStream has chosen to submit a custom IRM, this requirement is very important.

All parties and the Board recognize that not all capital is equal in several respects, including the degree to which expenditures are mandated by law, and the degree to which they directly respond to customers' preferences and needs in the short and medium term. The Board requires that capital be categorized as System Access, System Service, System Renewal, or General Plant. The approximate amounts of each type of capital in the application are:

System Access $141,000,000
System Service $180,000,000
System Renewal $257,000,000
General Plant $87,000,000 (Exhibit I, Tab 3, Schedule 1, p7)

System Access expenditures are largely required by law. They are driven by municipality and provincial demands to reroute roads and rapid transit lines, etc. In some cases, cost sharing is determined by legislation, such as in the Utilities on Public Property Act. In other cases, the parties must negotiate a division of costs. Some system service capital is required to connect new customers, in a timely manner by the Distribution System Code, and general system expansion infrastructure, such as the proposed new Vaughan transformer station. But other expenditures are more discretionary, for example, storm hardening.

However, System Renewal, the largest category of capital expenditures, is to replace aging or failing assets, and in system renewal, as in the general plant, and part of system service, the utility has more discretion.

BOMA believes the system renewal, system service, and general plant expenditures are too large and are unsupported by any "top down" benchmarking, and/or other credible third party confirmation and support. PowerStream defended the large amounts and the large increases from the previous revenue requirement IR plan amounts, in part on the basis that in the past, it had no depreciation expenses, because the costs of new subdivision expenditures were paid by developers (and passed on to house purchasers). This argument is fallacious. PowerStream had little or no depreciation because it did not make the capital expenditures. It could hardly put assets it did not pay for in rate base.

A key question that must be answered in a custom IR proposal is what is the appropriate level of capital expenditures over the plan term? To answer this question, the company must do much more than simply list the projects it claims to need in declining order of importance or urgency. Of course, it must prioritize projects one against the other, but first and foremost, it must choose a suitable amount of capital to spend during the term of the Custom IRM. However, it is clear while the optimization exercise conducted by PowerStream on its capital plan (DSP) does rank the cost benefit of spending proposals one against the other, it does not justify any particular level of capital expenditure (Tr3, p151). And it must pace the chosen capital outlay over the term. In other words, what amount of capital expenditure is appropriate in each year of the plan and over the five-year term altogether. What is the appropriate amount of capex over the five-year term? That is the key question. The company agrees that its "optimization tool" is useful for comparing its 376 projects one against another, but does not deal with the question of the appropriate overall level of expenditure (Tr3, p151). Zero-based budgeting could help but was not done in this case. Zero-based budgeting asks: what existing expenditures can be discontinued to make room for new types of expenditures?

While some expenditures are required by law, such as the connection of new customers with time period prescribed by the Distribution System Code and changes in location of assets to accommodate road rerouting and other municipal/provincial requirements, most capital expenditures are not mandated by law, especially system capital renewed, general plant capital, and system service capital. These expenditures are made to replace assets in poor condition, to provide greater reliability and provide higher levels of service to customers.

BOMA is of the view that if the Board decides to accept the application as a custom IR, it should reduce capital expenditures by $20-$25 million per year.

1. **Annual Adjustment Process**

It is important that there be an annual proceeding as part of the annual adjustment process, just as there is an annual proceeding to approve annual adjustments in a fourth generation IRM/multiyear plan. It need not be onerous but should deal with the following matters, in addition to the calculations proposed by the applicant.

As part of its Annual Adjustment Process, PowerStream plants to file a summary of the annual updated revenue requirement and the difference between the estimated actual preliminary revenue requirement, the revenue requirement which underpins the proposed "test year rates" and rates that are approved in this application (J1.8).

In addition, while PowerStream proposes to use the rate base approved in the current application as the starting point for calculating the year two rate base, BOMA is of the view that, consistent with its proposal for a capital tracker account, similar to that approved in Toronto Hydro, any underspend of the first year, which results in a lower than forecast rate base should be captured in a deferral account, in order to ensure customers are not paying for a utility underspending over the plan term.

A capital tracker deferral account should be established and should operate on the "Horizon model".

Contrary to PowerStream's proposal (J1.8, p1, par 2), load forecasts should be updated as part of the adjustment process. Load forecasts five years out are too arbitrary to base rates on.

Any overages or underspends should be placed in the deferral account for clearance at the end of the term, with the following caveats:

(1) the revenue requirement impact, if any, or any excess in rate base over that forecast over the five-year term should be for the account of the shareholder, since one of the key features of the custom IR ratemaking option is that the applicant must manage its affairs within its forecast capital and OM&A expenditures;

(2) the rates in any given year should be based on the original forecast rate base for that year, taking into account the impacts of other proposals BOMA makes in this submission;

(3) any underspend at the end of the five-year plan should be credited to ratepayers.

The first (2017) adjustment proceeding should also include a prudency review of the capital and operating expenditures for the customer care and billing system (see discussion of prudency below), in the event the Board does not decide the issue in this case.

BOMA is of the view that the Board should apply its existing Z-factor policy with respect to unexpected events that cause a material change in PowerStream's costs.

The Board's Z-factor should apply as it currently exists, in lieu of the "illustrative" list of changes proposed by PowerStream (Exhibit A, Tab 1, pp6-7). If any of these changes or events not on the illustrative list were to occur, should trigger changes to the rates would depend on whether they fit within the Board's Z-factor policy. That policy was most recently stated in EB-2012-0459 (the EGD custom IRM case), and endorsed by the Board in its Toronto Hydro decision (EB-2014-0116).

There, the Board stated:

"The Board will adopt Board's staff's proposed wording as it is sufficiently similar to the criteria for Union Gas and for electricity distributors and transmitters. The criteria will be as follows:

(i) Causation: The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event.

(ii) Materiality: The cost at issue must be an increase or decrease from amounts included within the Allowed Revenue amounts upon which rates were derived. The cost increase or decrease must meet a materiality threshold, in that its effect on the gas utility's revenue requirement in a fiscal year must be equal to or greater than $1.5 million.

(iii) Management Control: The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management could not reasonably control or prevent through the exercise of due diligence.

(iv) Prudence: The cost subject to an increase or decrease must have been prudently incurred."

1. **Capital Plan/Capital Expenditures, and Productivity Improvements**

BOMA's comments on the proposed capital expenditures also apply to the company's proposed capital plan. The capital plan reflects a forty percent (40%) increase in internal construction-related expenditures over the plan period, compared to the 2012-2014 period (Tr2, p7) (excluding payments to contractors who did certain projects, like the Vaughan transformer, and underground work). The company was asked to justify the increase and to demonstrate that productivity increased over the plan term. In response, the company referred to the increasing amount of work put out to contractors (Tr2, pp6-7). That answer was not acceptable; first, it conflated two separate issues, the internal expenditures per employee, and the percentage of work contracted out, and second, the fact that work has been contracted out to the market is not in itself evidence of improving productivity. The company's evidence was that only some of the contracts were fixed price. The structure of the contract, eg. do the contracts, similar to some of Union Gas contracts, allow for sharing of savings between the parties in the event contracts are completed under budget, the competitiveness of the bids, the number of change orders, and the manner in which the contracts were administered, and the frequency and the extent of the need to repeat work, and the amount of capital maintenance, and the profit margins claimed by the contractors, all need to be taken into account. More generally, work placed with outside contracts will need to include an amount in respect of contractor profits, which due to the unregulated nature of, and higher risk inherent in their business relative to a regulated utility, will be higher, that is the contractors' return on capital, will need to be higher than that of the utility. The company did not provide detailed evidence to support the proposition that contracting work out automatically must improve productivity. The Board took a similar view in the Toronto Hydro decision. There it stated:

"The OEB is not satisfied that bidding 81% of work to a competitive market is sufficient to ensure continuous productivity improvement. While Toronto Hydro provided some evidence on cost containment in respect of negotiated labour rates and performance tracking of its internal staff, it relies heavily on external contractors to achieve productivity improvements. Many parties argued that that Toronto Hydro was lagging in productivity, especially when benchmarked against other utilities. Based on the benchmarking results, the OEB does not accept that there are no further productivity gains that can be made over the next five years. The OEB finds that Toronto Hydro must place more emphasis on productivity gains and that Toronto Hydro must find efficiencies over the five years of the capital plan" (EB-2014-0116 Decision, pp25-26).

The blended work unit cost index used PowerStream's internal staff rate to forecast costs. The choice of "benchmark" for unit cost increases may not be accurate if a good deal of the work is done by contractors.

The company was asked about large increase in cost per km of cable replacement between three percent (3%) and ten percent (10%) per year (11-2.Staff.71). The answer was that material costs fluctuate, but that answer did not explain the steady increase of the forecast cost of cable replacement (our emphasis).

1. **OM&A Expenses**

The Board's July 17, 2014 decision in EB-2012-0459, on EGD's five-year Custom IR proposal, has some useful guidelines for the treatment of proposed OM&A increases. In that decision, the Board recognized that:

"It was appropriate that EGD looked to the RRFE Report for guidance in developing its plan" (p5);

and went on to state:

"This initial Custom IR application by Enbridge [the first of its kind since the Board issued the RRFE Report] has been a significant learning experience for all parties and for the Board as it works to implement its new policy framework. It is the Board’s expectation that this decision will provide further guidance on the interpretation and implementation of the Board’s rate-setting policies" (p5).

In making its decision, the Board noted that the RRFE framework required that an applicant provide:

"robust benchmarking analysis to demonstrate that the company had achieved a significant level of efficiency and if there was external expert analysis of the budgets themselves" (p50).

The Board noted that EGD did neither.

Accordingly, the Board allowed EGD a one percent (1%) increase in OM&A (excluding those components of OM&A that had been established separately from general OM&A in earlier decisions), for example DSM. EGD had proposed an increase of about three to four percent (3-4%) over the Custom IR term.

The company is seeking $519 million in OM&A over the plan term. The increases on an annual basis were 2016 – 4%, 2017 – 5.8%, 2018 – 1.9%, 2019 – 2.3%, 2020 – 2% (Tr3, p114), an average of about 3.2% per year. In the two years prior to the IRM plan years, the increase was 14% (Ibid). The average increase from 2014 through 2020 was 4.4% (Ibid, p16).

For the plan period only 0.2% of the average annual increase was due to customer growth (Tr3, p120).

The company's proposed five-year average annual increase of 3.2% is over three (3) times the one percent (1%) increase the company proposed in its initial budget (T3, p130) and much more than forecast inflation. The numbers are excessive, especially in light of the large capital expenditures, which should reduce OM&A and the other items discussed above, a point with which the Board agreed in the Toronto Hydro case (EB-2014-0116). The creation of a project management group to greater continue improvements over the term to determine what might be eliminated, and that the ramp up of the tree trimming does not appear to be a customer preference.

BOMA suggests that the Board allow an annual average OM&A increase of one percent (1%) per year, similar to what was done in the EGD case.

1. **Prudency**

In the EB-2013-0166 Settlement Agreement (February 4, 2014, p8 of 14), PowerStream agreed that a "true-up" process would be required in the next cost of service or custom IR application that will take into account active spending, in-service dates and prudence (our emphasis).

Given that agreement, BOMA is of the view that it is appropriate at this point in time to determine the prudency of PowerStream's acquisition and implementation of its new Billing Customer Service computer system.

BOMA is of the view that PowerStream acted imprudently in this matter and the Board should disallow approximately $10 million of the project costs.

PowerStream proposed the new customer billing/US system in EB-2012-0161 (Exhibit A2, Tab 1, Schedule 1, p6).

The proposed budget was $34,495,000 (B-CCC-15, p1). The business plan prepared at that time was filed in this proceeding as Appendix 1 to B-CCC-15. It stated that the project was to be constructed over the 2014-2014 period. The project consisted of approximately $33.2 million in capital and $35.2 million in OM&A.

In fact, the project was not completed until early 2015, at a cost of $45.8 million, approximately $11,379,000 over budget and two years behind schedule. Cost overruns in project components included $3.7 million in internal labour, $8.5 million in consulting, $2.2 million for the system integrator. The rate base impact of $42.8 million of capital costs is proposed to be included in 2016 rate base.

PowerStream's prefiled evidence (IR responses) stated that:

"Total project costs of $45.9 Million are $11.4 million higher than the initial plan primarily due to the original project plan being aggressive and only able to absorb a limited number of change requests and schedule slippages. The project took longer than expected to complete due to challenges and complexities associated with system interfaces and testing."

The company stated in response to cross-examination that:

"There's a theme through all of these different factors (increases) that are -- there are two main issues that took place. One issue was that in 2012, when the original estimate was put forward in our rate case then, there was just a lot we did not know about this project and the complexities.

 The second is that this project took longer than we planned."

Their evidence is that they did not have (Tr2, p44) on turnkey contractor responsible financially for the project. They had seven different contracts for the project. Four of seven were not fixed price, including the Oracle contract for the core of the system.

Based on the above information, BOMA is of the view that PowerStream was imprudent in the manner in which it managed the implementation of the major new system because:

* they did not take sufficient time at the outset, or consult with knowledgeable experts to scope out the project and identify key issues and milestones;
* they did not acquire a single tracking contractor to take overall responsibility for the project and be financially accountable, with a fixed price, or new fixed price contract;
* the contracts, notwithstanding very large legal costs, did not appear to allow them sufficient latitude to make necessary on course corrections;
* they had too many consultants with contracts with PowerStream, most of which were cost plans;
* they did not appear to have an internal project team to properly manage the project.
1. **Conclusion**

1. BOMA is of the view that the application does not offer the results that the Board requires from a custom IR process for the reasons outlined in this Submission. BOMA is also of the view that PowerStream has not made a sufficient case for the early termination of its existing fourth generation IR program. BOMA, therefore, recommends that the Board not accept this application as proposed and directs that PowerStream continue under its existing Fourth Generation IRM program for 2016.

2. If the Board wishes to accept this application as a custom IRM proposal, PS suggests at least the following modifications:

* a reduction in capital expenditure in the range of $100-$125 million;
* OM&A increases of 1% annually;
* reliability targets for the plan term should be set at the first annual update of the plan and be effective January 1, 2017;
* an earnings sharing program be established as proposed in this Submission;
* a capital tracker variance account be established as proposed in this Submission;
* specific performance improvements to be achieved over the plan term including full descriptions, and their dollar amounts, be filed with the Board as part of a first annual update to the plan;
* an outline of OM&A savings, including the amounts and sources that result from capital expenditures, should be provided for the plan term at the first annual update of the plan;
* all other recommendations contained in this Submission.

All of which is respectfully submitted, this 14th day of January, 2016.

*Original signed on behalf of Tom Brett*

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**Tom Brett**,
Counsel for BOMA

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