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January 15, 2016

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
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Dear Ms. Walli:

Re: Vulnerable Energy Consumers Coalition (VECC)
Final Submissions: EB-2015-0003
PowerStream Inc.
2016-2020 Electricity Distribution Rate Application

Please find enclosed the submissions of the Vulnerable Energy Consumers Coalition (VECC) in the above noted proceeding.

Yours truly,

Michael Janigan
Counsel for VECC

cc: Colin Macdonald, Senior Vice President, Regulatory Affairs & Customer Service
colin.macdonald@powerstream.ca

EB-2015-0003

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by PowerStream Inc. pursuant to section 78 of the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for electricity distribution to be effective January 1, 2016 to December 31, 2020.

FINAL SUBMISSIONS

ON BEHALF OF THE

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

January 15, 2016

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Vulnerable Energy Consumers Coalition (VECC)

Final Argument

PowerStream Inc. EB-2015-0003

Submission Summary

VECC has organized its detailed argument in accordance with the Board's issues list. With respect to its overall submission VECC argues for the following.

Denial of the 5 year CIR plan as proposed and substitution with:

- 1 or 2 year rate plan;
- reduction of 2016 OM&A $6 million with IRM adjustment thereafter;
- reduction of the approved capital plan for 2016 and 2017 (under a 2 year plan of between $20 and $27 million;
- cost of capital fixed at Board's 2016 values; and,
- earnings sharing with an asymmetrical dead band of 50 basis points accruing to the Company before sharing occurs.

1 Custom Application

1.1 Has PowerStream responded appropriately to all relevant OEB directions from previous proceedings, including commitments from prior settlement agreements?

1.1.1 In this proceeding, the applicant, Powerstream Inc. ("Powerstream") has filed a Custom IR application to determine rates for the period of 2016-2020. In this the Final Argument of the Vulnerable Energy Consumers Coalition ("VECC"), the principal issue to be first dealt with will be whether the application meets the criteria for the approval of a Custom IR application within the meaning of the RRFE and the subsequent decisions of the Board that have dealt with Custom IR applications of other distribution utilities. The discussion of the required elements of a Custom IR application as understood by VECC, will also be referenced both to draw a conclusion as to the merits Powerstream's filing as a Custom IR plan and to attempt fashion both an alternative rate setting option to what has been proposed and/or the setting of the base revenue requirement to plug in to the model that is chosen.

1.1.2 The Custom IR option was set out the Board's policy document "Renewed

Regulatory Framework for Electricity", (RRFE) released in late 2012[1]. In that document, the Board gave electric distribution utilities a choice of a regulatory framework which included an option of proposing a custom Incentive Regulation (IR) Plan. In the Custom IR method, rates are to be set based on a five year forecast of a distributor's revenue requirement and sales volumes. The Report provided the general policy direction for this rate-setting method, but the Board also expected that the specifics of how the costs approved by the Board would be recovered through rates over the term that would be determined in individual rate applications. It was noted that this rate-setting method was tailored to the circumstances of each applicant so that the terms might differ from plan to plan.[2]

1.1.3 Nevertheless, the Board also clearly indicated that the Custom IR method was not for all electric distribution utilities in all circumstances. It was most appropriate for distributors with "significantly large multi-year of variable investment commitments that exceed historical levels". Distributors in this category had to show "robust evidence" of their costs and revenues over a five year period, and "detailed infrastructure investment plans". There had to be evidence that a distributor could manage potential variances within the rates set.[3] With the exception of a 300 basis point off ramp, the Board's expectation, given the considerable time spent in preparation and adjudication of the application, was that the distributors would stick it out for the duration of the plan.

1.1.4 In the Hydro One Networks application in EB2013-0416/EB 2014-0247, the Board Decision set out the expectations associated with Custom IR that clearly went beyond simply incorporating future operational and capital plans into a five year envelope. In that Decision, Hydro One's Custom IR plan was rejected on the grounds that it failed to incorporate the central objective of measuring performance and providing incentives for continuous improvement[4]. The language associated with the rejection is instructive:

> "The OEB finds that Hydro One's proposed plan is deficient in this regard, as it includes limited prospects for continuous improvement, lacks any externally imposed improvement incentives, includes limited cost and productivity benchmarking support, and fails to demonstrate value to customers commensurate with the forecasted spending."[5]

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[1] Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" October 18, 2012
[2] RRFE Report p.18
[3] RRFE p. 19
[4] Ontario Energy Board Decision, "In the matter of an Application by Hydro One Networks for approval of Distribution Rates" 2015-2019, EB 2013-0416/EB 2014-0247, March 12, 2015 p.9
[5] Hydro One Decision, p. 14

The Board was specific in its criticism of the missing Custom IR elements:

> "The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses…"

1.1.5 However, Custom IR proceedings are intended to be framed more like performance inquiries resulting in multi-year outcome commitments and measures that facilitate year-over-year performance assessment. The productivity and efficiency elements allow the OEB to move away from detailed input cost assessment and focus more on utility performance. These factors provide utilities with strong incentives to continually seek efficiencies and share expected savings with ratepayers "up front" avoiding "after the fact" regulatory scrutiny.[6]"

1.1.6 On the subject of external benchmarking, the Board emphasized the importance of producing evidence that reinforced the goals of the RRFE:

> "The RRFE policy articulates the importance the OEB places on benchmarking. Benchmarking evidence, whether it compares a utility's performance to itself year-over-year, or to other utilities, is a critical input to the OEB's assessment of utility performance.
>
> Benchmarking, when used in combination with specific cost drivers and other sources of utility performance information, allows for an overall assessment of a utility's cost and outcome performance."[7]

Hydro One's advocacy of internal performance measurements was given short shrift:

> "The OEB disagrees with Hydro One's assertion that external benchmarking will not assist the OEB in determining whether costs at Hydro One are reasonable. As stated earlier, benchmarking information is used in combination with specific cost drivers and other sources of utility performance information. Benchmarking evidence is expected to include an explanation of any significant divergence from the optimal benchmark."[8]

1.1.7 The lack of a plan for continuous improvement was also troubling for the Board.

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6 Hydro One Decision, p.15
7 Hydro One Decision p.15
8 Hydro One, p.16

Embedded cost savings based on cost avoidance without achieving higher efficiency was not envisioned by the Custom IR option:

> “The OEB expects distributors to embrace the principles of continuous improvement and to develop plans which provide benefits to customers. If the benefits are considered to be the ability to re-invest in additional work then the product of that additional work should be measurable desired outcomes.”[9]

The criteria of continuous improvement was applied by the Board later in the Decision, to evaluate the Operations and Maintenance elements of the proposed budget:

> “Arriving at an appropriate OM&A budget is critical in ensuring that Hydro One has sufficient funds to operate a safe and reliable system while at the same time considering the customer bill impacts so that any increase is fully justified and reasonable….In reviewing the OM&A budget, the OEB also considers Hydro One’s efforts in achieving efficiency gains (i.e. doing more work with fewer resources), implementing innovation and demonstrating continuous improvement in performance.”[10]

1.1.8 The Board was concerned that the objective of providing value for customers was more than simply making appropriate maintenance decisions. Instead, the targets had to have some relationship to outcomes valued by customers such as reduced outages:

> “A number of Hydro One’s measures are activity-based such as the number of substations refurbished, rather than being outcome-based whereby the number of outages avoided or length of outages reductions as a result of the substation refurbishment would be measured.”[11]

1.1.9 Measurable outcomes were thus important to the value proposition associated with distributor investment.[12] It appeared that general statements about improvements made had to fit in the context of RRFE objectives set out above.

1.1.10 In the Board’s Decision concerning the Oshawa PUC Networks Inc., application in EB 2014-0101[13], the Board once again was faced with measuring up the distribution utility’s application against the plans for a Custom IR rates option for

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[9] Hydro One, p.18
[10] Hydro One p.21
[11] Hydro One, p.19
[12] Hydro One p.20
[13] Oshawa PUC Networks Inc. “Application for electricity distribution rates and other charges beginning January 1, 2015 and for each following year through to December 31, 2019”, EB 2014-0101, November 12, 2015

a five year period. The Board set out the task as one which used the goals of enhancing efficiency in line with customer expectations:

> "The RRFE policy provides options for a distributor to apply for rates. The RRFE policy, as the title states, confirms a performance-based approach to regulation that supports the cost-effective planning and efficient operation of a distribution network. The OEB intends the policy to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price."[14]

1.1.11 The Board found that the Oshawa plan paid insufficient attention to the important aspect of the RRFE –designed Custom IR option, namely the assumption of risks associated with variances in revenue arising while maintaining rates set during the period. In doing so, the Board noted:

> "A distributor should not file a Custom IR unless it is prepared to take on risks, and manage those risks, throughout the five-year term."

Later in the Decision, the Board rejected the Company's attempt to insulate itself from risks that were expected to be assumed:

> "The OEB finds that the number and frequency of the proposed adjustments over the plan term is inconsistent with the risk management principles under the Custom IR model - to manage within rates set, given that actual costs and revenues will vary from forecast. It is the OEB's view that Oshawa PUC's annual adjustment proposal does not provide the appropriate allocation of risk between the distributor and its customers. It also reduces the incentive to seek efficiency improvements.
>
> Oshawa PUC selected the Custom IR option given its large and variable capital plan. However, as a relatively small distributor, Oshawa PUC does not have the diversity or breadth in its customer base and underlying infrastructure to readily manage the risk through trade-offs, deferrals and reprioritization, implicitly required in a Custom IR application."[15]

1.1.12 While the Board was not inclined to change the rates option for Oshawa, there was a solution found in terms of a mid- term review that required the filing of a new application by July 2017 to deal with a number of areas where Oshawa had proposed adjustments in the context of its Custom IR plan. These included issues such as capital expenditures dependent on new customer connections and updates to enable comparisons between Company forecasts and rates for

[14] Oshawa, p.1
[15] Oshawa Decision p.9

2018 and 2019 in the application and those projected at that time. The Board found that Oshawa lacked adequate tools for capital project prioritization and question capital estimates based on past practice and concerns about benchmarking. The fix, albeit one that met with the consent of Oshawa, clearly provided a mechanism to better align risks and benefits between ratepayers and the utility.

1.1.13 Other elements of the Oshawa Decision reinforced the previous approach of the Board to the measurement of outcomes. Oshawa was criticized for providing outcomes measurements that failed to demonstrate continuous improvement (other than outages) and were ordered to provide the same in the next rate application.[16] And while the Board found that some of the yardsticks contained in the OEB's yearbook compilation were favourable, there was a need to develop other external benchmarks.

1.1.14 The proposed Controllable Capital Investment Efficiency Mechanism (CCEIM) was not approved. The mechanism was designed to control the cost of capital investment programs by allowing revenue requirement impacts of variances between forecast and actual capital investment for these programs to be tracked and shared between Oshawa PUC and its customers. Once again, while the Board was very much in favour of innovation in attempting to obtain efficiency improvements, this innovation was turned down presumably because it misaligned risks and benefits between ratepayers and the Company:

> "The OEB will not approve the CCIEIM as Oshawa PUC, like any distributor, should strive to find cost savings and provide its best forecast in the evidence supporting a proposed capital expenditure plan."[17]

1.1.15 The Board has approved innovations such as the Efficiency Adjustment, providing an incentive for the distributor not to slide into another productivity cohort during the Custom IR period in the recent Ottawa[18] and Kingston[19] cases, and capital variance accounts that track capital expenses in different asset categories and add to rate base when brought into service. As well asymmetric earnings sharing accounts have been approved in both of these cases that provide for no sharing of under- earnings and no dead band for sharing of over-earnings. While such earnings sharing provides a rather clear incentive for

[16] Oshawa Decision p.11
[17] Oshawa, p.13
[18] Application for electricity distribution rates for the period from January 1, 2016 to December 31, 2016 Hydro Ottawa Limited EB 2015-0115
[19] Application for electricity distribution rates for the period from January 1, 2016 to December 31, 2020, Kingston Hydro Corporation EB – 2015-0083

distributors to be efficient, the Board has been reluctant to institute such a measure without company consent. In Oshawa, no earnings sharing was imposed,[20] and in Toronto Hydro[21], earnings sharing was symmetrical with a dead band of 100 basis points accruing to the Company before sharing occurs.

1.1.16 The recent Toronto Hydro Decision provided an opportunity for the Board to elaborate on the application of the RRFE framework to the adjudication of the acceptability of a custom IR plan. In doing so, the Board reiterated the emphasis on outcomes rather than individual line items and its unwillingness to substitute its judgement for the company's in the management of operations. It is noted that it was the intent of the Decision was to provide guidance, so the principles developed in the RRFE Report and subsequent Decision are to be applied in a similar manner. However, there are still clearly findings of fact that must inform the regulatory approach beyond the emphasis on the outcomes in any Custom IR plan. For example, in examining the Capital C Factor plan, Toronto Hydro's attempt to match funding with the execution of the plan was approved as a customized solution but the spending levels to feed into the plan were found to be too high.[22]

1.1.17 In the Toronto Hydro Decision, there is once again the theme of the necessity for a plan to show continuous improvement, and that plan must have the individual features that create the incentives for the improvement to be achieved.[23]This, is in turn, must be coupled with the requirement that the outcomes of the plan are the ones that customers want. Thus while the overall Toronto Hydro plan is going forward with approval, the customer engagement approach must be one of a fully informed nature and must guide and inform planning not just confirm it.

> "The OEB has determined that it cannot fully rely on Toronto Hydro's approach to establishing its spending proposals in determining if the outcome of that spending is desirable for ratepayers. It is not clear that Toronto Hydro's proposals are necessarily aligned with the interests of its customers, as they are largely supported by an asset condition analysis rather than the impact of the proposed work on the reliability of the system. The approach used by Toronto Hydro does not give a clear indication of how the overall spending is related to customer experience such as reliability."[24]

1.1.18 As well, there is more to the Board's framework for approval capital expenses than a simple meshing of operational replenishment of assets with funding. There

[20] Oshawa Decision p.13
[21] Toronto Hydro Decision p.49
[22] Toronto Hydro Decision p.6
[23] Toronto Hydro Decision p.5
[24] Toronto Hydro Decision p. 6

must be some ability to show the relationship of those expenses with the continuous improvement previously described and the measurement of outcomes that will disclose the results of the investment.

> “There does not appear to be any measurement of units of activity and their costs that would allow for year over year assessment of improvement in Toronto Hydro’s proposed metrics. The OEB agrees with the parties which suggested that reporting measures such as specific performance improvements sought and achieved per asset class, tie-ins of capital program spending to the dollar value of OM&A savings achieved and how program spending specifically impacts the reliability and quality of service are desirable under the RRFE.”[25]

1.1.19 Similar to the approach to be used for overall capital expenditures, the setting of the overall base requirement for OM&A is not simply to involve plugging in the forecasts of the Company for the five year period but, at least in the case of Toronto Hydro, involves an examination of the historical record of these expenditures and an acceptance of the concept that the there is an interrelationship between capital and OM&A expense that sees the replacement acquisition of assets serve to diminish the need for maintenance.

> “While the OEB recognizes that the relationship between capital spending and OM&A is complex, the OEB finds that it is reasonable to expect that there will be some reductions in OM&A costs, particularly those related to maintenance, from the large capital expenditures, over many years, on system renewal, general plant, and system service. New assets should require less maintenance than old assets (at least in the corrective maintenance category) and underground assets should require less maintenance than overhead assets as there is no need for vegetation management, and no issue of animal interference.”[26]

1.1.20 Given the historical record, and the likelihood of reduced demand for “expensive corrective maintenance and the unplanned reactive maintenance” the increase sought by Toronto Hydro was reduced to an inflationary 2.1% subject to the annual adjustments.[27] It might be noted that rather large increase of 11.7% that was sought in this case for base year O&M might also been colourable by the Board as inappropriate.

1.1.21 More puzzling perhaps is the Board’s pronouncement on the use of benchmarking in the Toronto Hydro case. It appears to still be a necessity, but what benchmarking drives and how to deal with inadequate or uninformative benchmarking is somewhat of a mystery:

[25] Toronto Hydro Decision p. 6
[26] Toronto Hydro Decision p.11
[27] Toronto Hydro Decision p.10

> "The OEB has emphasized in the RRFE and in previous cases the importance of benchmarking. It is an important input to the OEB's assessment of an application, but it is not the sole determining factor in setting rates. In the context of a Custom IR, the OEB will use benchmarking as a tool to inform its decisions, but will not use it as the method by which to determine rates."[28]

1.1.22 While VECC recognizes the problems of external objective measurements as the sole component of regulatory decisions,, the gathering of information and measurements without consequences is undesirable, as well as imparting of only precatory effect to filing requirements. VECC believes that if results for the operational efficiency of the Company and the need of the customers are the most important aspects of a Custom IR application, the lack of benchmarking or performance metrics should be a fact that informs a conclusion that the required framework has not been followed.

1.1.23 Extracting the appropriate principles from the foregoing, VECC would suggest that the following are the most important elements of a Custom IR plan that are relevant to the assessment of the Powerstream application:

1. **There must be a need for large and variable historical investments that exceed historical levels to justify the request for the custom IR option.**

2. **There must be comprehensive evidence of costs and revenues over a five year period together with detailed investment plans with the assurance that the risks of variability can be taken on by the distributor during that period without their assumption by ratepayers**

3. **A plan of continuous improvement must be shown that provides for the meeting of key benchmarks and performance metrics that meet customer expectations. These must be company specific and go beyond the formulaic adjustment of rates**

4. **A Custom IR plan must align the goals of maintenance of sustainable operations with the goal of providing needed and expected value for customers. This goal drives the setting of appropriate base case values for O&M and rate base.**

5. **Where there has been an inadequate incorporation of these key principles, there may be the necessity for altering the application**

[28] Toronto Hydro Decision, p.19

of the plans to allow for modifications to meet the RRFE principles.

1.1.24 VECC submits that the applicant Powerstream has fallen short of meeting the above noted criteria and its plan must be modified to meet the requisite objectives. VECC proposes to discuss the evidence that informs that conclusion, as well the alternatives to the Powerstream application approach following the order set out in paragraph 1.1.23.

1.2 What Actions should the OEB require PowerStream to take at or near the end of the 5-year rate term (e.g. rebasing, plan assessment, measurement of customer satisfaction)?

1.2.1 In VECC's submission the proposal for a 5 year-rate period should be denied. The Applicant does not meet the requirements established by the Board under the RRFE. As noted above the Board in prior decisions has made in clear what the requirements are for a custom incentive rate proposal to succeed.

1.3 Do any of PowerStream's proposed rates require rate smoothing or mitigation?

1.3.1 No, VECC proposes a maximum 2 year rate which under the reductions proposed would not have an inordinate rate impact.

2 Outcomes and Incentives

2.1 Does PowerStream's Custom IR Application promote and incent acceptable outcomes for existing and future customers (including for example, cost control, system reliability, service quality, and bill impacts)?

2.1.1 VECC has made its submissions with respect to customer engagement and incentive based rates elsewhere in this argument. With respect to system reliability and service quality we think the Applicant's plan to be deficient.

2.1.2 Like most electricity distribution companies regulated by the OEB, while there is reporting of system reliability under ambit of the SAIFI/SADI there is little, if no relationship between that reporting, actual outcomes and there are no results if outcome measure deviate from plan.

2.1.3 VECC also continues to argue that the over reliance on SAIFI/SAIDI indicators of reliability have little if any meaningful relationship to the capital or maintenance plans of utilities.

2.2 Does the Custom IR Application adequately incorporate and reflect the four outcomes identified in the RRFE Report: customer focus, operational effectiveness, public policy responsiveness and financial performance?

2.2.1 No, as noted by Board Staff in their argument PowerStream performed a customer engagement process *and then* reviewed those results against its Distribution System Plan.[29] It is clear from the evidence that customer engagement in the distribution system plan was an afterthought. In our submission this is counter to the intent of the RRFE which is to use the information garnered in such engagements to shape the capital plan.

2.2.2 PowerStream undertakes a number of initiatives to keep in contact with its customers. Many of these are useful, like the customer transaction surveys and key account meetings, because they provide meaningful data which can be used to modify service behaviour. However, others, like the Utility Pulse Surveys are of questionable value as they provide little more than generalities and impressions.

2.2.3 Like a number of other utilities PowerStream engaged Innovative Research Group ("Innovative") to justify its proposed distribution plan. VECC is generally critical of these surveys because they are leading in their questions making it appear to respondents that the alternative to approval of the utility's plan is degradation of service. We are especially critical because participating customers are not told that the utility has no proposed measures to judge the efficacy of its spending. These studies are expensive, the full cost of the work done by Innovative Research Inc. was $266,764.[30] Yet they provide no value in shaping the DSP of this Applicant.

2.2.4 The lack of any nexus between customer engagement and the plans of PowerStream are best illustrated by vegetation management and rear lot conversion. Vegetation management was not discussed as part of customer engagement and notwithstanding that tree canopies are undeniably a major consideration of residential customers[31]. With respect to back lot conversions the Innovative Study does mention this project. In a one page description it simply states that there are 49 projects with an average cost of conversion of $1.2 million. While it states that the capital work is required to address reliability, safety and customer concerns it does not say what these are, provide any

[29] Ex G, Tab 2, pg.8
[30] Section III/Tab1/Schedule 1/pg.79 May 22 2015
[31] Hearing TC Vol.3, pg.88

options for addressing any concerns or explain why plant which has been in back lots for as much as 65 years now requires to be put in the front. Nor does it explain that the option chosen to remedy the supposed problem should be the most expensive one[32].

2.2.5 In our view such engagement is meaningless. Worse still is its unproven premise that there are reliability or safety issues in back lot service. What is presented as "evidence" is in fact speculation backed by a simplistic logic: rear lot service is hard to get to, there are trees in rear lots therefore we should move to underground front lot service. We would suggest that at a cost of potentially more than $18,000 per customers such investments would never be undertaken by a company if it were provided a guaranteed regulatory return.

2.2.6 PowerStream testified that it was currently putting together a strategy for future customer engagement[33] .

2.3 **Does the Custom IR Application adequately account for productivity and efficiency gains in its forecasts? Does the Custom IR Application adequately include expectations for productivity and efficiency gains relative to benchmarks that are external to the company**.

2.3.1 VECC has laid out the prior decisions of the Board which provide clarification as to the correct implementation of the RRFE under a customer IR plan. In our submission PowerStream fails on all critical factors.

2.3.2 As was the case in Hydro One rejected CIR filing, PowerStream has used "baked in" productivity savings in an attempt to show that the plan meets the intent of the RRFE of efficiency gains.

Table 2: Estimated Productivity Savings ($ Millions)[34]

	2014	2015	2016	2017	2018	2019	2020	Total
Capital		$3.8	$4.1	$4.5	$4.7	$5.0	$5.0	$27.1
OM&A	$2.5	($0.8)	($1.0)	$0.3	$1.2	$2.0	$3.0	$7.1
Total	**$2.5**	**$3.0**	**$3.1**	**$4.8**	**$5.9**	**$7.0**	**$8.0**	**$34.2**

2.3.3 As we have noted in section 1, the Board has repeatedly rejected this interpretation of incentive rate making. In our submission, this is correct since there are no incentives in such a plan. What are presented are in fact forecasts

[32] Section III/Tab 2/ G-SEC-29, Appendix B, DSP Review Primer, page 26
[33] TC transcript, Sept 9, 2015, page 138
[34] Exhibit F, Tab 1, page 4

of costs. All forecasts include assumptions. In this case PowerStream has labelled those assumptions which lower costs “productivity gains.” The assumptions which raise costs are simply noted as “inevitable.” Whether forecasts of lower or rising costs they remain just that – forecasts. If forecasts of lower costs are “productivity gains” then assumptions of higher costs are just as correctly called “productivity losses”. One simply nets the two to see what efficiencies are being forecast.

2.3.4 The fact is, under the Applicant’s proposal, it is forecasting that it become less efficient. This hardly provides an incentive for lowering costs, rather it is a recipe for higher costs. By definition incentives are devices to motivate management and employees to constantly look for new ways to reduce costs and improve service. The proposed plan is absent any such incentives.

2.3.5 The Board has consistently rejected “semantic incentives” such as those shown by PowerStream. In our submission it should do so again in this case as well.

2.4 Does the Custom IR Application adequately provide value to the customer (such as the X-Factor, Y-Factor and a shared earnings mechanism)?

2.4.1 There is considerable uncertainty as corporate future of a number of GTA utilities including PowerStream. It is clear to VECC that much of the OM&A and general plant category of capital investment is speculative. As such it would be unreasonable see rates rise considerably while costs decline in as considerable a fashion. Under such a scenario the Board will need to explain why its policies around “efficiency and incentives” consistently lead to rate increase above the rate of inflation. The plan lacks a commitment to carefully developed priorities in response to customer values and expectations. To be clear, it is not so much that PowerStream’s plans are fundamentally unworkable, but they require greater superintendence by the regulator as they haven’t achieved fulfillment of the criteria required for approval of a Custom IR plan.

2.4.2 To mitigate these risks VECC proposes that rates be set for no more than 2 years and that the Board require an asymmetrical earning sharing plan starting at 50 basis points above the regulated rate.

2.5 Does the Application adequately plan and prioritize capital expenditures?

2.5.1 VECC has made its submission on the capital plan under section 3.2

2.6 Is the monitoring and reporting of performance proposed by PowerStream adequate to demonstrate whether the planned outcomes are achieved?

2.6.1 Under VECC proposal of a 1-2 year rate plan no additional reporting is required.?

2.7 Are PowerStream's proposed off-ramps and annual adjustments appropriate? Has PowerStream demonstrated adequately its ability and commitment to manage within any rates set via this proceeding, given that actual costs and revenues will vary from those forecast?

2.7.1 VECC is proposing that PowerStream be put on a 1 or 2 year rate plan. Under a 2 year plan our view is that PowerStream would have the associated IRM adjustment to rates.

2.7.2 Under any rate plan PowerStream should make annual adjustments for RTS and LV rates and make DVA dispositions as an IRM filer.

2.7.3 VECC notes that the issue of the effects of the upcoming merger have been ruled out of scope in this proceeding by the Board and, as such, VECC has not engaged in any speculation herein concerning the likely effects of the merger and to what stakeholders, if any, the benefits of the merger may accrue.

3 Revenue Requirement

3.1 Is the rate base component of the revenue requirement, including the working capital allowance, for 2016 – 2020 as set out in the Custom IR Application appropriate?

3.1.1 VECC believes the Board should make adjustments in a number of areas to recognize the excessive costs related to PowerStream's CIS system. These are set out below

3.2 Are the Distribution System Plan, capital programmes and related expenditures, associated with the revenue requirement for 2016 – 2020, as set out in the Custom IR Application, appropriate and is the rationale for planning and prioritizing appropriate and adequately explained and supported ?

3.2.1 VECC has had an opportunity to review the submissions of AMPCO and supports and endorses its compelling analysis and recommendations for reductions in the proposed capital budget. We believe the Board should pay special consideration to their analysis of pole replacements which clearly shows PowerStream to have an inflated and overly aggressive program to replace plant.

3.2.2 Below we show the proposed spending by category followed by the reliability metrics between 2011 and 2014.

Table 2: Annual Capital Spending – Rate Plan by OEB Category ($000)

CATEGORY	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Plan	TOTAL
System Access	21,007	19,888	17,030	26,641	24,145	108,711
System Renewal	11,527	16,974	22,254	39,802	42,388	132,946
System Service	22,885	13,770	34,780	18,229	27,322	116,987
General Plant	7,877	24,200	19,593	24,816	24,545	101,030
Total	**63,297**	**74,832**	**93,657**	**109,488**	**118,400**	**459,674**

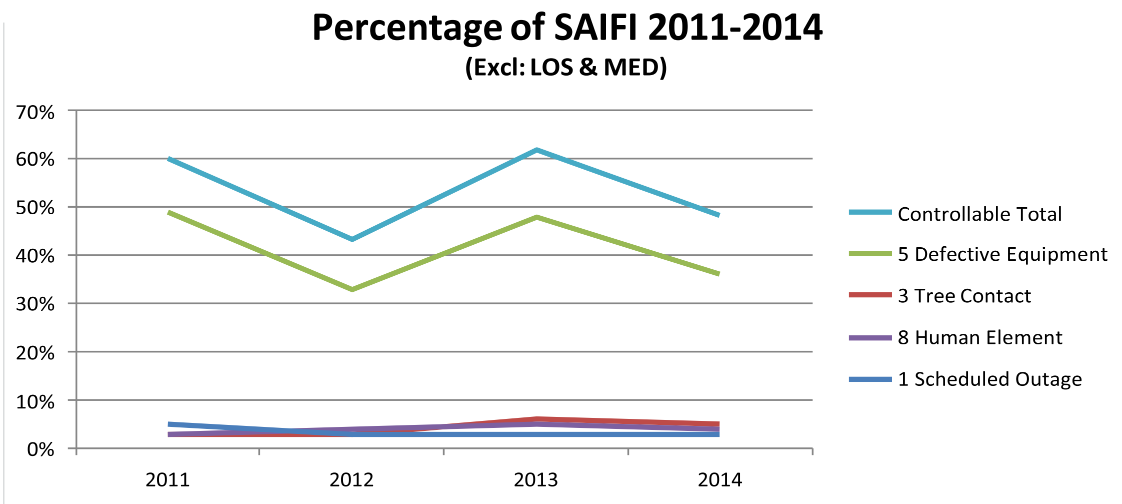
Table 3: Annual Capital Spending – Rate Plan by OEB Category ($000)

CATEGORY	2016 Plan	2017 Plan	2018 Plan	2019 Plan	2020 Plan	TOTAL
System Access	28,232	28,470	29,561	28,726	31,867	146,855
System Renewal	48,715	51,500	52,052	52,971	52,406	257,643
System Service	38,322	32,072	29,920	26,963	23,022	150,299
General Plant	17,631	19,558	13,967	16,840	18,206	86,202
Total	**132,900**	**131,600**	**125,500**	**125,500**	**125,500**	**641,000**

Source: Exhibit G, Tab 2, pgs.2-3

Table VECC 16.2, Figure VECC 16.2

Controllable SAIFI 2011-2014 (Excl: LOS & MED)								
Cause			Percentage of Total SAIFI					
	Cause Code	Description	2011	2012	2013	2014	2011-2014 Avg.
Controllable	1	Scheduled Outage	5%	3%	3%	3%	4%
	3	Tree Contact	3%	3%	6%	5%	4%
	5	Defective Equipment	49%	33%	48%	36%	42%
	8	Human Element	3%	4%	5%	4%	4%
	Controllable Total		60%	43%	62%	48%	53%



Source Section B, Tab 3, pg.7 VECC Interrogatory

3.2.3 What is clear from these charts is that the unprecedented capital program is not supported by any indication of degrading reliability. If anything outages due to defective equipment have been decreasing. This is not to argue that PowerStream should not have a capital budget, but it does question the reasons for extraordinary request. Reliability statistics are a lagging indicator yet there is no evidence that the much lower capital spending prior to 2015 have had a detrimental impact on the system.

3.2.4 Within system access projects VECC notes, as did AMPCO, that PowerStream has significantly inflated its forecast of unforeseen projects during the rate period. It hides the effect of this by showing a lower than average costs in 2016 ($600k) which rises to over $1 million during the rate period. We think this simply an example of padding budgets in order to protect itself from the uncertainty inherent in the 5 year rate plan it is proposing. As noted earlier, the Board has stressed the necessity for the utility under a Custom IR plan to manage risks and variability of results for the length of the plan without resort to adjustments or inflating budgets to provide insulation from those risks.

<u>Rear-Lot Remediation</u>

3.2.5 Within System Renewal the largest extraordinary capital project is PowerStream's back lot conversion program. Between 2016 and 20120 PowerStream is proposing to spend $37.5 million to move plant from rear lots to front lot underground. The option chosen is the most expensive approach to replacing this plant. Over the life of the program PowerStream intends to spend approximately $80-$90 million on this project.

	2015	2016	2017	2018	2019	2020
System Renewal	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
i. UG Lines - Planned Asset Replacement	20,687	21,601	22,862	23,781	24,666	25,186
ii. Distribution Lines - Emergency/Reactive Replac	8,416	8,636	8,730	8,888	8,925	8,504
iii. Overhead Lines - Planned Asset Replacement	7,698	7,907	9,082	8,558	9,144	9,022
iv. Storm Hardening& Rear Lot Conversion	3,500	7,900	8,000	7,500	6,900	7,200
v. Stations/P&C - Asset Replacement	2,087	2,671	2,827	3,325	3,336	2,493
Total System Renewal	42,388	48,715	51,500	52,052	52,971	52,406

3.2.6 Over a fifteen years PowerStream is proposing somewhere between $84 and $90 million on converting rear lot services to front lot underground. The actual costs are uncertain because PowerStream has not undertaken any detailed study of the cost of rear lot conversions. Its current its estimates were derived by using the number of customers in each of the subdivisions and multiplying through based on the figures.[35] The cost per customer conversion is somewhere above $18,000 per customer. This estimate is based on not moving meters which are currently located for rear lot service.

> MR. JANIGAN: Okay. So it's 14 years at 16 million -- sorry, 6 million times 14, that's 84 million, plus the 3.5 million in 2015, so that's the total cost to complete this project?
>
> MS. CUNNINGHAM: That's correct.
>
> MR. JANIGAN: Okay. And is that for the 4,760 customers that are described in AMPCO 28 on page 5?
>
> MS. CUNNINGHAM: Yes, that's correct.
>
> MR. JANIGAN: Okay. And if my math is correct, that works out to about $18,382 and change per customer. Is that about correct?

[35] Hearing TC Vol. 3 pg.67

MS. CUNNINGHAM: That's correct.

…...

MR. JANIGAN: Okay. And I wonder if you could turn up page 23 of my compendium. In the 2015 report that is Table 1 and the rear lot priority list for 2015 to 2019 is shown, and that table lists projects by year, with both the current 2015 and future dollar impacts. Can you explain to me how these estimates were derived?

MS. CUNNINGHAM: So my recollection is that these estimates were derived by using the number of customers in each of the subdivisions and multiplying through based on the figures. The -- with respect to this particular program, certainly the costs are based on an estimate. We've not completed work -- or are just in the midst of completing work at the moment, and because we've not actually done it, the cost could in fact be different.

MR. JANIGAN: So there are some detailed studies that have to be undertaken in relation to these?

MS. CUNNINGHAM: I wouldn't say detailed studies; I would say more actual experience. [36]

3.3 What drives the need for this project? First of all, the project did not come about as a result of the ice storm:

While MR. JANIGAN: Now, I take it from the evidence and from your discussion today with Ms. Helt that the ice storm wasn't the genesis of the rear lot conversion program, but it changed the program.

MS. CUNNINGHAM: That's correct.

The Company states that their plans for the project were changed as a result of the ice storm, it is less clear that the project choice was the most efficient fix. Initially, the current plans were not the recommended solution.

MS. CUNNINGHAM: Yes, as we've stated before, our original plan with the rear lot was to do the hybrid option. When the storm came along, reflecting on the storm is when we moved to the full underground option out front.

. The Navigant ice-storm studies provide no analysis on the damage to rear-lot plant in relation to other distribution service types. It does anecdotally note that restoration time for rear lots was longer, but again there is not analysis to explain why this might be the case. In fact there are reliability advantages to rear lot services which PowerStream has simply ignored.

MR. JANIGAN: And we'll be getting to that. Is there any sort of measurement, in any kind of empirical form, of the difference between the advantages associated with the, with rear lot services and front lot services?

In other words, all of these factors have some kind of cost associated with them,

[36] Hearing Vol. 3 pp.66, 67

or some kind of reliability factor associated with them. Has there been any sort of study that compares these two?[37]

MS. CUNNINGHAM: We've not done that analysis.

3.4 Nor does the CIMA Report relied upon by PowerStream as the additional input for their current plans actually recommend rear lot conversion. Rather it seems to simply acknowledge the course of action being taken by PowerStream..

3.4.1 If one looks to PowerStream's own internal reports there is a changing view but which is unexplained. In November of 2012, this is what the PowerStream's Engineer of Asset Condition Assessment had to say[38]:

> This report reviews the existing rear lot supply system at PowerStream. It summarizes the extent, configuration, condition, advantages/disadvantages, and managing options of rear lot supply.
>
> There are disadvantages and operating concerns regarding rear lot supply. However, many of the issues can be mitigated through regular maintenance practices, effective customer communication and customer compliance with the Electrical Safety Code and easement terms.
>
> At the system level, a system-wide conversion program from rear lot to front lot is not justifiable and not recommended. On the cash flow and capital budget stand point, the initial installation cost ranging from $31,232,363 (Option 2) - $76,483,373 (Option 5) is not affordable. On the reliability stand point, the reliability impact of rear lot supply is modest and manageable.

3.4.2 Without explanation as to what has changed this is what the same author writes in the 2015 Report authored just before this application was filed:

> There are many operating, safety, reliability and customer service issues that need to be addressed. Through external consulting firm report (CIMA report "Hardening the Distribution System against severe storms") and PowerStream staff and management discussions, it was confirmed that PowerStream must implement a Rear Lot Supply Remediation Program to convert existing rear lot overhead supply system to front lot underground supply system[39].

3.4.3 In fact there is no such confirmation either in the CIMA or Ice-Storm Reports. A third internal report completed in August of 2014 was not filed until requested at the hearing. This report contains a change in the recommendation without

[37] Ibid pg.72
[38] Rear Lot Supply Review, November 2012, II-2-Staff-45
[39] Rear Lot Supply Remediation Program March 31, 2015; II-2-Staff-45

explanation. A number of advantages of rear lot are removed and the disadvantages increase. The once preferred option seems to have been given short-shrift, and the central fix of increased reliability is never quantified:

> MR. JANIGAN: Okay. Now, are you saying that the -- that CIMA -- I take it the CIMA report contained options for you to move forward on, and that it wasn't a direct recommendation that you replace the rear lot services with front underground services. Would you agree with that?
>
> MS. CUNNINGHAM: That's correct.
>
> MR. JANIGAN: Okay. And in the Navigant ice-storm report there didn't seem to be any specific information on the number or duration of outages during the storm attributable to rear lot services. And I didn't find any information on the durability of rear lot service………
> Do you have any study of that to understand whether or not there were any material differences in the outages in adjoining neighbourhoods with different types of service?
>
> MR. SHEOGOBIND: So there is not a specific study that addressed that issue[40].

3.4.4 It is instructive to look at the recommendation of PowerStream's own engineer made over three consecutive reports in the report provided at the hearing this recommendation is made as late as August of 2014:[41]

It is recommended that:

1. System Planning monitors the performance of existing rear lot locations.
2. Should assets in a rear lot location become end-of-life and require replacement, System Planning will conduct a detailed analysis and recommend the preferred remediation option for implementation. Inputs from Lines, Control Room, and Customer Services will be taken into consideration
3. Lines Department develop contingency plan for high risk locations (i.e. locations that are planned
4. Start the remediation capital program in 2015 as indicated in the plan.

3.4.5 What started as a plan with an emphasis on maintenance and further study of the costs and benefits over the course of 3 years has turned into a plan to replace all the rear lot assets. This is without a detailed study of the costs and benefits and prior to end-of plant life.

3.4.6 PowerStream has chosen the most expensive option to replace rear lots. The cost is twice to three times the cost of the overhead option.[42] There are no

[40] Hearing Vol 3 pg.76
[41] J3.5
[42] "In general, overhead systems are less expensive than underground systems. For example, in the Romfield Phase 3 project (more details in Section 6), the

detailed reports supporting the project, no analysis of the cost and benefits which shows reliability savings and no customer engagement asking whether customers are willing to pay $9,000 extra for front lot underground.

> MR. JANIGAN: You did a number of customer surveys with respect to your DSP as part of this application. Did you talk about the rear lot project on those surveys?
>
> MR. KLAJMAN: Yes, that was part of the presentations that we did to our customers.
>
> MR. JANIGAN: And in those surveys, did you ask what options PowerStream thought they should choose?
>
> MR. KLAJMAN: No, we did not.

3.4.7 Finally, in what can only be described as "belt and suspenders" planning PowerStream is proposing to increase the trimming cycle (and cost) for rear lots over the next five years! The cost of this is $300,000 per year[43].

3.4.8 In VECC's submission, there is insufficient evidence to approve the rear-lot replacement plan. The plan is extremely costly. The utility has not entered into serious negotiations with the municipalities over the cost of new underground in areas served by overhead. No meaningful customer consultation has been undertaken which explains the costs or alternative. We doubt if customers were required to pay the premium that front lot service would be chosen. Finally there is no certainty as to the final costs. The front underground is partly chosen to address the issue of back lot meters. If this turns out not work and meters (bases) have to be repositioned the cost of the project could exceed $100 million. This will be for less than 5,000 customers. In our view, PowerStream should be required to have an independent study of the feasibility of this project and, in particular, whether the efficiencies and service quality to be gained merits the expenditure. Such a study should identify and quantify the benefits of rear-lot conversion, address the question of early asset retirement and price out the options to address any problems identified with the current form of service.

Overall Reductions

3.4.9 VECC notes that notwithstanding the extraordinary capital program the costs categorized as emergency replacement are unaffected. In our submission this is

installation cost of the overhead option is $1,362,279 compared to $3,336,017 for the underground option" November 2012, op. cit.

[43] J3.6

unrealistic. Should the Board accept the Applicant's proposal in substance then this amount should be reduced significantly.

3.4.10 In VECC's submission the Rear lot remediation program should be removed from the current budget until such time as a proper justification and costing of the program is brought forward. There can be no confidence that this expensive program aligns with the goals and expectations of the customers that PowerStream serves. This project is the poster child for the necessity to show customer commitment to costs at this level to achieve clearly researched results as required under Custom IR as set out in the RRFE Report.

3.4.11 With respect to the remainder of the proposed capital budget VECC endorses and adopts the thorough and comprehensive analysis submitted by AMPCO in its argument herein. In general we submit that in addition to the rear lot program PowerStream eliminate a minimum of $20 million per year of its capital budget. .

3.5 Is the taxes / PILs component of the revenue requirement appropriate?

No submissions

3.6 Are the OM&A programmes set out in the Custom IR Application appropriate and is the rationale for planning choices appropriate and adequately explained and supported?

3.6.1 The Table below sets out PowerStream's proposed OM&A costs.

	2012 Actuals	Last Board-Approved Rebasing 2013	Last Rebasing Year 2013 Actuals	2014 Actuals	2015 Bridge Year	2016 TEST YEAR 1	2017 TEST YEAR 2	2018 TEST YEAR 3	2019 TEST YEAR 4	2020 TEST YEAR 5
Operations	12,468	12,773	12,240	13,211	13,955	14,797	15,369	15,750	16,128	16,346
Maintenance	19,409	19,091	20,030	20,167	21,450	22,601	23,558	24,402	25,209	26,161
Billing and Collecting	13,315	14,124	13,642	16,089	16,711	17,282	20,441	20,685	21,090	21,508
Community Relations	1,500	1,399	1,431	1,740	1,806	2,124	2,194	2,221	2,250	2,276
Administrative and General	36,101	35,554	33,506	34,246	38,635	39,413	40,248	40,665	41,433	41,937
Total	**82,792**	**82,941**	**80,849**	**85,454**	**92,558**	**96,216**	**101,808**	**103,724**	**106,109**	**108,228**
%Change (year over year)			-2.30%		8.30%	4.00%	5.80%	1.90%	2.30%	2.00%

3.6.2 PowerStream is seeking to increase its OM&A from approximately $83 million it had spent (and was approved) in 2013 to over $108 million at the end of this rate plan. Such a 30% increase in operating costs cannot, by any stretch of the imagination be considered part of an “incentive” rate plan.

3.6.3 In other cases utilities have shown that customer growth has a 10-20% dollar change. This means that customer growth of between 9-11% should add less than 1% to 2% in costs.

3.6.4 Board staff’s submission correctly points out the two main drivers for this increase: vegetation management and CIS related costs. To this we would add the unrealistic FTE forecast that are used by PowerStream (see 3.7 below).

3.6.5 The pattern shown in PowerStream’s OM&A proposal is all too familiar to VECC. We invite the Board to examine the pattern of OM&A spending and forecast spending in the year before the test year and the year immediately following. As is the case with PowerStream, the uptick in costs is often dramatic and well in excess of inflation. In this case, inflation between 2014 and 2016 would add around $2.5 million to 2016 costs. Customer growth might account for another $1.5 million. Extraordinary items are perhaps in the range of another $1 million. If one were to add this $5 million to the 2014 actuals then the only reasonable conclusion is that 2016 OM&A ought to be $6 million less than proposed.

3.6.6 VECC observes that this Utility like many others it has reviewed shows a distinct pattern of OM&A increases in the bridge and test year. In PowerStream’s case the increase from the year prior to the bridge year to that after the test year is that increase is around 20%.

3.6.7 It is clear that PowerStream is about to embark on a change that will reduce costs, especially FTEs. In VECC’s submission, it is inappropriate to build into this an extraordinary increase in OM&A. To do so is to saddle ratepayers with paying an unjustifiable dividend to the PowerStream shareholders. We ask that the Board reduce the 2016 test year by $6 million dollars.

3.7 Is the compensation strategy for 2016 – 2020 appropriate and does it result in reasonable compensation costs?

3.7.1 A considerable amount of the increase in costs as between 2012 and 2016 comes from the change in FTEs. In 2012 PowerStream had approximately 519 FTEs. The Board approved a 2013 cost for around 550. The Utility never reached that number. As of June 2015 it was operating with 537 staff[44]. The vacancy rate during the same period was around 12 FTEs.

Table I-SEC-9-1: Vacancies 2011-2015 (source II-SEC-9)

	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 (Jan-Jun) Actual
Total FTE Vacancy Rate	3	11	17	13	8

3.7.2 The average total cost per employee is approximately $128,000 in 2016. The saving from the average vacancy rate of this utility is a reduction in OM&A costs by over $1.5 million.

3.7.3 VECC supports an envelope approach to setting the OM&A for the test year. It is clear from this simple analysis that this Utility has room to show improvement in its compensation management.

3.8 Are the proposed other operating revenues for 2016 – 2020 appropriate?

3.8.1 Power Stream's Other Operating Revenues are forecast to be in the order of $12.6 M to $13.1 M over the 2016-2020 CIR period. This compares with Other Operating Revenues of $13.5 M and $14.0 M for 2013 and 2014 respectively.

3.8.2 VECC has a couple of issues with respect to Power Stream's forecast for Other Operating Revenues, the first being with respect to the amounts forecast for Gain on Disposition of Property (Account #4355) which are zero for the years 2015-2020 .

3.8.3 During the oral proceeding, PowerStream explained that historically Account #4355 had included gains from fibre-optic sales which are not part of the distribution business and excluded from the revenue requirement calculation. It then went on to explain that Power Stream did sell some land in 2013 and 2014 which is reflected in the Application but that it was not forecasting any similar sales for the years to come.

[44] Section B, Tab 2, Schedule 4, pg. 121 Appendix 2-K

3.8.4 However, in response to earlier interrogatories Power Stream provided a breakdown of Other Operating Revenues for the first half of 2015 and, contrary to this testimony, shows revenues for Account #4355 of over $115,000. VECC submits that based on this most recent history it would be appropriate to attribute revenues to Account #4355 of $230,000 annually for each of the years 2016-2020 in the CIR period.

Water Billing

3.8.5 VECC's second issue is with respect to forecast revenues for water/sewer billing. Currently Power Stream provides water billing service to the cities of Markham and Vaughan with forecast revenues for 2016 being in the order of $2.65 M increasing to $2.98 M in 2020. This forecast is based on the current contracts and annual increases in revenue of 3%.

3.8.6 While current water/sewer billing contracts expire in 2015 and PowerStream is in the process of renegotiating them, Power Stream has made no allowance in its forecast for increases in the charges for water/sewer billing to help cover the incremental costs of the new CIS system which will support this service.

3.8.7 Powerstream's has made minimal effort to ensure that the services extended to its shareholder municipalities provided by its over budget CIS system are based on an appropriate basis of fully allocated costs or the prevailing market price. The Board promulgated the Affiliated Relationship Code with a view to "*preventing a utility from cross-subsidizing affiliate*", and "*ensuring there is no preferential access to utility services*",[45] Because of the adoption of the reference to affiliate bearing the same meaning of the Ontario Business Corporations Act in the Code, the Company has elected not to follow the ratepayer protective provisions of the Code.

3.8.8 VECC argues that the intent and language of the Code provide a meaningful criteria for assessing the conduct of the distributor when it comes to providing services for one or more of its shareholder owners, even though their ownership levels do not reach the level that qualifies the Company as a subsidiary within the meaning of the aforesaid Act. This is because there is indeed the possibility of influence upon the decisions of the Company when it comes to provision of services where the results of possible preferential treatment are only manifest in the bills of its ratepayers.

[45] "Affiliated Relationships Code for Electricity Distributors and Transmitters", Ontario Energy Board Revised March 15, 2010, Section 1.1 (b) and (d)

3.8.9 The Code provides that:

> **2.3.3.6** Where a reasonably competitive market exists for a service, product, resource or use of asset, a utility shall charge no less than the greater of (i) the market price of the service, product, resource or use of asset and (ii) the utility's fully-allocated cost to provide service, product, resource or use of asset, when selling that service, product, resource or use of asset to an affiliate.
>
> and
>
> **2.3.4.1** Where it can be established that a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility acquires from an affiliate, the utility shall pay no more than the affiliate's fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost may include a return on the affiliate's invested capital. The return on invested capital shall be no higher than the utility's approved weighted average cost of capital.

3.8.10 The position of Powerstream is because there was no new functionality purchased for the water billing function with the new system the costs charged were solely for the any additional work for the two municipalities, Vaughan and Markham. However, during the oral proceeding, Power Stream acknowledged that its current CIS system is about 30 year old, had experienced a couple of failures and that the installation of a new system would have been required even if there had been no requirement for updated electricity billing functionality.

3.8.11 This approach is also advanced by Powerstream in relation to cost overruns associated with the new CIS system[46] :

> MR. JANIGAN: Now, can you advise what portion of the cost overruns were due to trying to incorporate water billing functionality into the system?
>
> MR. MACDONALD: None.
>
> MR. JANIGAN: How do you know that, if you weren't tracking the incremental needs of the water billing functionality in the billing system?
>
> MR. MACDONALD: As I indicated earlier, the system was done for PowerStream LDC for the core business, and really the water metering data just comes in, the calculation is done, and it goes on the bill.

3.8.12 The assertion that the water billing component does not attract costs that are additional to the core system seems difficult to understand given that the increased functionality and the need to separate customers of the municipalities receiving water billing from those obtaining simply bills for electricity distribution. Extra functionality often comprehends extra costs. The move to monthly billing,

[46] TR. Vol. 2 pg.72)

for example, cost $3million. Yet throughout this proceeding PowerStream has put forward to the Board that creating a water billing function for its new CIS system was costless. This simply defies all logic. Since PowerStream does not do water billing in all its territories the CIS must contain a database for water billing customers separate from that for electricity customers. The system must have algorithms developed and data entries for the difference in metering and customer payments (as per the Board's own rules). System notes on water customer will not be the same for those held for electricity customers. The truth is that PowerStream simply <u>does not know</u> what these costs are because they never asked.

> MR. GARNER: Now, I am trying to put that response together with the response that you then went on to say that if you were going to do monthly billing, your vendor said that would cost you $3 million for things such as a different interface. Now, doesn't the water billing system have an interface aspect to it? Doesn't it show up somewhere? I mean, it seems to me it must, if someone has to look at it.
>
> MS. CLARKE: There is an interface aspect, yes.
>
> MR. GARNER: Would it be fair to say this, that it's not that the water billing component doesn't have an incremental cost. Would it be more correct to say that you never asked your vendor to give you a cost for a utility billing system, and then a billing system to incorporate water billing in addition to that?
>
> MS. CLARKE: No, I don't think that's completely correct. So the water billing aspect of the system is not a specific component of the new CIS system. It's an extra line on the bill, not specifically integrated to what you are suggesting.
>
> MR. GARNER: It's an extra line on the bill. So isn't there a data component for the billing of water? Doesn't the system track data for water?
>
> MS. CLARKE: So there are meter reading components that are read manually and are tracked in the system, yes.
>
> MR. GARNER: Right. So I am correct, though, that you never asked your vendor to give you a quote for an electricity billing system, and then asked your vendor to then give us a quote for the incremental cost of incorporating the water component -- another billing system in order to create water billing services?
>
> MS. CLARKE: That's correct.[47]

[47] TC Vol. 1 pgs. 57-58. Sept 9, 2015

3.8.13 What is also true is having paid for the functionality of water billing prior to renegotiating its water billing contracts PowerStream is now finds itself in a weak negotiating positon to increase water billing service charges.

3.8.14 VECC would submit that this set of circumstances cannot control the attribution of revenue associated with the water billing service. VECC believes that Powerstream's revenue stream from water billing must be set on the basis of fully allocated costs regardless of the approach it might take in setting the charges with the members of the ownership group. While the ARC may not technically apply, the Board's clear intent was to avoid the substance and appearance of arrangements with utility owners that makes use of utility assets in other than a fashion prevalent in a competitive market. Powerstream's arrangements with Vaughan and Markham are not sufficiently even handed to be prudent for all its ratepayers.

3.8.15 Based on this evidence, VECC submits that, for rate setting purposes the revenues forecasts for water/sewer billing services should be increased and set so as to recover a portion of the cost of the new CIS system net of any savings from the retirement of the existing system. Unfortunately, PowerStream has not done an analysis of the changes in cost of billing due to the new CIS system or know what portion of the cost of the new system would be attributable to water/sewer billing. Given these circumstances, VECC submits that the OEB should direct Power Stream to: i) undertake a fully allocated cost study to determine the costs attributable to water/sewer billing for the period 2016-2020 based on its costs as approved by the Board in this proceeding and ii) establish a variance account to track the difference between these costs and the revenues for water/sewer billing (as proposed by Power Stream) for future refund/recovery from customers. In VECC's submission such a study should include expert opinion as to the estimated cost of the functionality purchased by PowerStream for water billing in its new CIS system.

4 Load Forecast, Cost Allocation and Rate Design

4.1 Is the load forecast, including the application of CDM savings and setting of the savings references for the LRAMVA appropriate?

No Submissions

4.2 Are the proposed billing determinants appropriate?

Customer Counts

4.2.1 In past Applications, Power Stream based its customer/connection count forecast on historical average growth rates. However, for purposes of the current Application Power Stream adopted a different approach and developed individual customer forecast models/approaches for each rate class. For the Residential and GS>50 classes, customer counts were forecast using a regression model that related number of customers to the Toronto CMA population as published by the Conference Board of Canada. For the GS<50 and Street Lighting classes customer/connection counts were forecast using a simple regression model based on the number of Residential customers. USL and Sentinel Light customer counts were forecast using a simple linear trend model, while the number of Large Use customers was held constant at 2014 levels.

4.2.2 The forecasts were initially based on an economic/population forecast provided by the Conference Board of Canada in December 2014. However, this forecast was subsequently updated to reflect a more recent Conference Board of Canada forecast prepared in August 2015. The updated forecast can be found in Power Stream's response to JTC1.6.

4.2.3 In the case of the Residential class, Power Stream has assumed that roughly 936 of the additional customers in each year (2015-2020) will be condominium units served by 3rd party sub-metering providers and were transferred to the GS>50 class (assuming 250 units per building) .

4.2.4 VECC supports Power Stream's use of individual rate class model to forecast future customer/connection counts by rate class. VECC's only major concern regarding Power Stream's actual customer/connection count forecast is with respect to the Residential forecast. The more recent population forecast provided by the Conference Board of Canada shows an average annual growth rate between 2014 and 2020 of 1.75%. This compares to historical growth rates of 1.61% (between 2008 and 2014) and 1.36% (between 2011 and 2014). However, the updated Residential customer count forecast for 2014 - 2020 is decreasing slightly from 2.2% per annum over the period used to estimate the model to 1.99% per annum. Power Stream has attempted to explain this result by pointing out that it has historically experienced decreasing Residential customer growth rates while, at the same time, increasing population growth rates. However, while this may be the case for select years, VECC submits that intuitively such a forecast result is inconsistent with a model that positively correlates Residential customer numbers with population. VECC submits that at a minimum, with a higher population growth, the forecast growth rate for Residential should be at least equivalent to the historic value of 2.2% (2008-2014).

4.2.5 While the increase in the Residential customer growth rates proposed by VECC may not seem material the higher growth will also affect the forecasted customer/connection counts for GS<50 and Street Lights and becomes increasingly important for the Residential class itself as the rate design is moved to 100% fixed.

<u>Volume Forecast (Pre-CDM)</u>

4.2.6 Power Stream has also used individual customer class models to forecast customer use (kWh) prior to any manual adjustments required for CDM. In the case of the Residential class, the volumes were reduced to account for the new Residential customers assumed to be served by 3rd party in-suite metering and the GS>50 volumes increased accordingly.

4.2.7 These forecasts were also initially based on the Conference Board of Canada's December 2014 population/economic forecast but were subsequently updated to reflect the Conference Board's August 2015 forecast. For weather sensitive classes, Power Stream's models included heating and cooling degree days as explanatory variables and, for purposes of forecasting used a ten-year average as its definition of "weather normal".

4.2.8 For those classes that are demand billed, the forecast kW billing determinants were derived from the kWh forecasts based on a 3-year average historical relationship between kW and kWh.

4.2.9 VECC also supports Power Stream's use of individual class models to forecast (pre-CDM) volumes. VECC only concern is with respect to Power Stream's volume forecast for the Street Lighting class. VECC notes that the model used to forecast Street Lighting volumes only uses Hours of Daylight and Specific Monthly Dummies as explanatory variables. In contrast the models developed for the other classes include explanatory variables that reflect the number of customers/connections (e.g., population in the case of Residential, GDPI/Manufacturing GDPI in the case of GS<50 and GS>50, and actual customer count in the case of Sentinel Lights). The result is that while the Street Lighting connection counts and volumes have been increasing historically and connection counts are forecast to increase further over the 2014-2020 period, Street Lighting volumes are projected to remain constant prior to any CDM impacts. This means that the annual usage per connection declines from an average of 727 kWh over the 2012-2014 period to 628 kWh prior to any impacts attributable to LED conversion.

4.2.10 Power Stream attempted to explain this apparent inconsistency by noting that as a result of technology changes volumes will not necessarily increase even though the number of connections does. VECC has two issues with this explanation. The first is that the historical data (2010-2014) does not bear out this explanation as both volumes and connections are increasing over the period. Second, and more importantly, the initial Street Lighting forecast prepared by Power Stream is meant to reflect future volumes prior to the implementation of new technology. In this regard, it is noted that the Street Lighting forecast is subsequently reduced significantly to specifically account for LED conversions planned over the forecast period.

4.2.11 To address this inconsistency VECC submits that forecast (pre-LED conversion) volumes for Street Lighting should be based on the forecast number of connections multiplied by 727 kWh, the average annual usage per connection over the 2012-2014 periods. Furthermore, the impact of the LED conversion should be based on a 50% reduction relative to this usage level.

<u>CDM Adjustments</u>

4.2.12 Power Stream's assigned 2015-2020 CDM target is 535 GWh. In the Application, Power Stream set out it planned savings in each year as submitted to the IESO and the assumed impact on each year's volumes, incorporating the ½ year rule per the Board's filing guidelines. The allocation of these savings to customer classes is provided in Power Stream's response to III-VECC-25 a). Power Stream has also included in its manual CDM adjustments the estimated impact of the Street Lighting LED conversion, previous discussed above. It is noted that this LED conversion is not being done under the auspices of an IESO CDM program.

4.2.13 VECC has no issues with Power Stream's manual CDM adjustments. In the case of the LED Street Light conversion, VECC agrees with the proposed 50% reduction but, as discussed above, recommends that the adjustment be applied to a forecast use based on volumes that reflect the average use per connection over 2012 to 2014.

LRAMVA Baselines

4.2.14 In its Application Power Stream is proposing that the LRAMVA Baseline for each year of the CIR period be based on the forecast savings actually included in the Load Forecast, including the ½ year adjustment for the current year's savings. Consistent with this proposal, Power Stream has confirmed that, for the first year of a CDM program, its future LRAM claims will be based on ½ of the actual savings verified by the IESO.

4.2.15 VECC notes that Power Stream's proposed approach to establishing the LRAMVA Baseline for each forecast year and for calculating actual LRAM amounts differs from that generally used by Ontario's electricity distributors in that it does not utilize the annualized savings planned by the utility or eventually reported by the IESO when considering the first year impacts of a CDM program. However, VECC supports the approach proposed by Power Stream as it aligns with both the load forecast methodology and how the CDM savings will actually occur.

4.3 Are the inputs to the cost allocation model appropriate?

No Submissions

4.4 Are the costs appropriately allocated?

4.4.1 As a result of both the pre-filing process conducted with stakeholders and the interrogatory process subsequent to filing its Application with the OEB Power Stream has made a number of updates to its cost allocation methodology, including adoption of the Board's CA model based on its new cost allocation policy for Street Lighting.

4.4.2 VECC's only concern regarding the inputs used to the costs allocation model is with respect to the determination of revenue at current rates as input to the Cost Allocation model for purposes of determining the Status Quo Revenue to Cost Ratios. In its Application, Power Stream has used the current 2015 rates in order to determine these revenues for 2017, 2018, 2019 and 2020 cost allocation runs as well as for 2016.

4.4.3 VECC submits that the appropriate approach for the 2017 cost allocation is to use the 2016 proposed rates for purposes of determining the 2017 revenue at current rates and the resulting revenue to cost ratios. Similarly, for the 2018, 2019 and 2020 cost allocations the proposed rates for 2017, 2018 and 2019 respectively should be used. Power Stream suggests that the results may not be all that different. However, VECC believe its proposed approach is the correct one and should be adopted. Particularly over the 2016-2020 period when the fixed-variable split for the Residential class is changing significantly and customer counts for the class are increasing while volumes are not. The cost allocation results using this approach were requested in Undertaking 3.10 but, since the cost allocation models themselves were not provided, VECC has been unable to verify whether, for purposes of the response provided, the inputs have all been revised as requested.

4.5 Are the revenue-to-cost ratios for all rate classes over the 2016 – 2020 period appropriate?

4.5.1 Power Stream's general approach is to move the revenue to cost ratios for all customer classes that are outside the Board's target policy ranges to the top/bottom of the range. For the years 2016-2020 this generally results in a revenue shortfall which is then allocated to all customer classes with ratios below 100% on a pro-rata basis.

4.5.2 VECC agrees with Power Stream's proposal to move the revenue to cost ratios for all customers that are outside the Board's policy range to the top/bottom of the range as appropriate. VECC's only issue is with Power Stream's approach to allocating the revenue deficiency that arises from this adjustment. VECC's understanding of Power Stream's approach is that the shortfall if allocated to all customer classes with revenue to cost ratios less than 100% based on the total revenue requirement allocated to each class. This effectively means that each class' ratio will change by the same absolute amount.

4.5.3 VECC's concern is that this approach does not recognize and account for the fact that revenue to cost ratios for some of these classes are already closer to 100% than for others. VECC submits that a more appropriate approach would be to either:

i. Allocate the shortfall first to the class whose ratio is the furthest below 100%, until it equals the ratio for the class with the next lowest ratio and then both ratios are increased to the next lowest ratio, and so on, until sufficient revenue is generated; or

ii. Allocate the shortfall based on the dollar difference for each class between its allocated costs and the revenues (including miscellaneous revenues) used in the determination of the status quo revenue to cost ratio.

4.5.4 Both of these approaches reassign relatively more costs to those classes whose status quo ratios are the furthest from 100% and lead to larger movements in the revenue to cost ratios for such classes, a result that VECC submits is appropriate. The first approach is more aggressive and, VECC submits should be adopted subject to bill impact considerations.

4.6 Are PowerStream's proposed charges for street lighting appropriate?

No submissions

4.7 Are the proposed fixed and variable charges for all rate classes over the 2016 –2020 period appropriate?

4.7.1 In its initial Application Power Stream proposed that where the current (2015) monthly service charge is at or above the ceiling calculated by the Cost Allocation model the charge would be capped at the 2015 level. Otherwise, the proposed monthly service charge is set at the lower of the calculated charge (based on the current fixed-variable split) and the ceiling per the Cost Allocation.

4.7.2 During the interrogatory process Power Stream updated its Application to address the Board's new Residential Rate Design policy. Power Stream is proposing a four-year transition to a fully fixed rate starting in 2017 and reaching 100% fixed charge in 2020. This one year delay is due to concerns with the total bill impacts in 2016 for the Residential 10th percentile consumption level. The 2016 bill impacts for these customers are already above 10% before any increase in the fixed charged portion of the distribution charge.

4.7.3 VECC has no issues with respect to Power Stream's rate design proposals for the 2016-2020 CIR period and fully supports Power Stream's proposal to delay the start of the transition to fully fixed rates for the Residential class until 2017.

4.8 Are the proposed LV Rates appropriate?

4.8.1 In its Application, Power Stream's forecast LV costs are based on the forecasted LV rates filed by Hydro One Networks with the Board on May 30, 2014 in its 2015-2019 CIR Rate Application. Historic ratios were used to translate forecast purchases into LV demand billing determinants which were then multiplied by these forecast rates. Updated rates were subsequently provided with the interrogatory responses.

4.8.2 VECC has no issues with Power Stream's proposed LV charges?

4.8.2.1 VECC has no issues with Power Stream's proposed LV charges.

4.9 Are the proposed Retail Transmission Service Rates appropriate?

4.9.1 In response to interrogatories Power Stream provided an update RTSR Adjustment Work form reflecting the new UTRs and HON ST Rates approved by the Board on January 8, 2015 and April 23, 2015 respectively. Power Stream is proposing to update the RTSRs on an annual basis so as to reflect the Board approved UTRs for each year.

4.9.2 VECC has no issues with Power Stream's proposed 2016 RTSRs or it proposal to update them annually.

4.10 Are the proposed specific service charges for miscellaneous services over the 2016 – 2020 period reasonable?

4.10.1 PowerStream is not proposing to alter the list of Specific Service charges or change the charges during the CIR period[48].

4.10.2 While Power Stream is not proposing to change any of its specific service charges, in response to an interrogatory[49] it did provide updated values for some of its specific service charges. Furthermore, Power Stream has indicated that it would be reasonable to update these rates[50].

4.10.3 VECC disagrees. VECC notes that Power Stream has not provided updates to all of its specific service charges and, in particular, has not provided updates to its specific charges for access to power poles or its charges to retailers. VECC submits it would be inappropriate to only update some but not all of the charges at this time, particularly in view of the comprehensive review of miscellaneous charges that the OEB initiated on November 5, 2015. Power Stream should await the outcome of this review rather than adopting a piece-meal approach that see immediate increases in specific charges for some customers but not others.

4.11 Are the proposed line losses over the 2016 – 2020 period appropriate?

4.11.1 Power Stream's proposed loss adjustment factors are based on the average of the most recent complete years available (2011-2013).

4.11.2 VECC notes that Power Stream's historical Total Loss Factor is reasonably

[48] Application, Exhibit I, Tab 1, page 1
[49] II-SIA-3
[50] II-1-Staff-22

constant from year to year and has no issues with its proposal to base the forecast value on a three-year historical average.

5 Deferral and Variance Accounts

5.1 Should the existing deferral and variance accounts proposed for continuation be continued?

5.1.1 VECC adopts Board Staff's submissions with respect to the closing of accounts 1508 and 1555.

5.2 Should the OEB approve any new deferral or variance accounts?

5.2.1 VECC adopts the submission of Board Staff in the use account 1557 to track GS>50 TOU meter costs.

5.3 Are the balances and the proposed methods for disposing of the balances in the existing deferral and variance accounts, appropriate (such as Account 1508)?

5.3.1 Power Stream proposes to refund to customers $504.3 M recorded in Account 1568 (LRAMVA). Details regarding the calculation of the amount are provided in Section III of the Application. The amount relates to CDM impacts in 2013 from 2011-2013 programs (as verified by the OPA/IESO) as well as true-ups reported in 2013 for CDM activities incurred in 2011-2012. The refund arises from the fact that the actual CDM savings achieved in 2013 were less than those included in the load forecast used to derive Power Stream's 2013 rates.

5.3.2 VECC notes that Power Stream has not based its claim strictly on the annualized savings in 2013 from 2013 CDM programs as reported by the OPA/IESO but rather has adjusted these reported savings using a ½ year rule (similar to how it has proposed to calculated the LRAMVA baselines going forward). As noted previously, VECC agrees with this approach.

5.3.3 VECC's has only one issue with respect to Power Stream's calculations of its LRAM claim and this is with respect to the calculation of the billing demand impact for the GS>50 class from CDM programs. In its calculations Power Stream has converted the reported net annual peak saving to billing demand kW savings assuming the net annual peak savings represent billing demand savings in each of the 12 months of the year. During the recent proceeding regarding Kingston Hydro's Custom IR Application (EB-2015-0083), evidence was filed indicating that the Master CDM Agreement executed between all Ontario LDCs and the IESO defined demand savings as

5.3.4 “the maximum reduction in electricity demand between the Base Case and the Energy Efficient Case occurring in the same hour between 11 a.m. to 5 p.m. on business days, May through October”. This would suggest that the reported annual peak reductions should be multiplied by six and not 12 in order to determine the annual impact on billing demand (and first year program savings adjusted further to account for the ½ year rule). VECC submits that, given the Board’s past decision to rely on peak demand savings as defined and reported by the IESO , the calculation of annual billing demand savings should be calculated by multiplying the reported peak demand savings by six and that the Board should direct Power Stream to use such an approach in its calculations.

6 Reasonably Incurred Costs

6.1 VECC submits that its participation in this proceeding has been focused and responsible. Accordingly, VECC requests an award of costs in the amount of 100% of its reasonably-incurred fees and disbursements.