EB-2014-0073

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

AND IN THE MATTER OF an application by Festival Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015.

REPLY ARGUMENT OF THE APPLICANT, FESTIVAL HYDRO INC.

December 3, 2014

EB-2014-0073
Festival Hydro Inc.

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FESTIVAL HYDRO INC.

EB-2014-0073

**REPLY ARGUMENT OF THE APPLICANT,
FESTIVAL HYDRO INC.**

1. INTRODUCTION

Festival Hydro Inc. ("**Festival**") has applied to the Ontario Energy Board (the "**Board**") for rates commencing January 1, 2015 with an application that was assigned proceeding number EB-2014-0073. Festival's previous cost of service Application ("**COS**") was for the 2010 rate year which commenced May 1, 2010 and was approved in a decision and order of the Board in EB-2009-0263. While much has changed since 2010, with the installation of Smart Meters, a new Transformer Station and new Chief Executive Officer, Festival remains committed to delivering value for its customers and this Application demonstrates that value. Festival's revenue deficiency, $427,552[1], is less than to the annual RTSR savings of $475,200 that customers first started receiving in December of 2013 when Festival energized its new Transformer Station.

This Reply Argument addresses the submissions of Board Staff, the Schools Energy Coalition ("**SEC**"), the Association of Major Power Consumers in Ontario ("**AMPCO**"), the Vulnerable Energy Consumers Coalition ("**VECC**") and the Energy Probe Research Foundation ("**Energy Probe**"). The parties to this proceeding filed a proposed Partial Settlement Agreement with the Board dated October 23, 2014 which the Board, during the second day of the oral hearing, confirmed was accepted. As such, a limited number of issues remain to be decided by the Board in this proceeding including Rate Base, Operating, Maintenance and Administration ("**OM&A**"), Revenue Requirement, the Incremental Capital Module ("**ICM**") true-up and the Fixed-Variable split for the General Service greater than 50kW rate class.

Festival serves the communities of the City of Stratford, the towns of Seaforth, Brussels, Hensall, Zurich, Dashwood and St. Marys. Festival serves approximately 20,500 customers and has seen an approximately 1% growth of the past few years which is anticipated to continue. However, as noted during the oral hearing, Festival lost 2 industrial customers in 2012-13 which reduced its throughput. Despite the loss of these two larger loads, Festival has

[1] This revenue deficiency incorporates both the recently issued Cost of Capital Parameters and the evidence update of November 11, 2014. A Revenue Requirement Work Form ("**RRWF**") has been provided with these submissions at **Attachment A** with this information included.

maintained control of costs such that rates remain stable – and in most cases the customers' bills have decreased, as shown on Table 2.

Table 1 – 2015 Test Year Customer Counts[2]

	2015 Test Year Customer Counts filed with Settlement Proposal
Residential	18,224
General Service < 50 kW	2,029
General Service >50 to 4999 kW	227
Large Use	1
Unmetered Scattered Load (per connection)	227
Sentinel Lighting (per connection)	41
Street Lighting (per light)	6,626
Totals	27,375

On November 20, 2014, one week following the oral hearing, the Board issued its letter to distributors and transmitters provide the *Cost of Capital Parameters Updates for 2015 Applications*.[3] Festival incorporated those parameters, along with the updated regulatory cost change and calculated the revised revenue requirement of $10,581,189 net of Other Revenue. Festival had previously committed in the Partial Settlement Agreement to implementing the new parameters once they became available. A copy of the updated Revenue Requirement Work Form has been attached to these submissions.

As is evident from Table 2 below, most customers will see lower bills which should be considered a great news story. Festival has been able to do this by maintaining a constant number of Full-Time Equivalent ("**FTE**") staff despite the increased workload brought on by the changing requirements of Smart Meters, regional planning, customer engagement, the largest capital project in the company's history (the Transformer Station) and additional work for arrears management. In concert with these new demands, Festival has re-organized its executives, essentially 4 to 3, and created an environment to more actively manage the business based upon future risks rather than relying upon past performance. This will assist Festival and its customers in the future to ensure value is provided through enhanced performance and risk management.

[2] Approved Partial Settlement Agreement, October 23, 2014, page 18.
[3] A copy of the Board's letter may be found at **Attachment B.**

Table 2 – Summary of Customer Bill Impacts[4]

Customer Class	2014 Distribution Charge	2015 Proposed Distribution Charge	Dollar Change	% Change	2014 Total Bill	2015 Total Bill from Undertakings	Dollar Change	% Change
Residential, 250 kWh	25.24	22.28	(2.96)	-11.7%	54.70	51.56	(3.14)	-5.7%
Residential, 250 kWh subject to Global Adjustment	25.24	22.93	(2.31)	-9.2%	54.70	52.22	(2.48)	-4.5%
Residential, 800 kWh	35.57	30.02	(5.55)	-15.6%	128.52	122.46	(6.06)	-4.7%
Residential, 800 kWh subject to Global Adjustment	35.57	32.10	(3.47)	-9.8%	128.52	124.58	(3.94)	-3.1%
GS < 50 kW, 2,000 kWh	70.44	62.03	(8.41)	-11.9%	313.47	303.88	(9.59)	-3.1%
GS < 50 kW, 10,000 kWh	204.67	166.65	(38.02)	-18.6%	1,416.30	1,372.50	(43.80)	-3.1%
GS >50 to 4,999 kW, 100 kW, 51,100 kWh	494.59	441.22	(53.37)	-10.8%	6,961.26	6,880.91	(80.35)	-1.2%
GS >50 to 4,999 kW, Interval, 600 kW, 306,600 kWh	1,755.21	1,443.81	(311.40)	-17.7%	42,568.00	42,084.53	(483.47)	-1.1%
Large Use, 5000 kW, 2,555,000 kWh	17,211.31	14,253.44	(2,957.87)	-17.2%	360,845.07	356,237.07	(4,608.00)	-1.3%
Unmetered Scattered Load SL, 340 kWh	18.74	10.19	(8.55)	-45.6%	60.39	51.51	(8.88)	-14.7%
Sentinel Lights, 131 kWh, 0.36 kW	6.30	5.86	(0.44)	-7.0%	22.31	21.82	(0.49)	-2.2%
Street Lights, 657 kW, 239,805 kWh	6,965.27	5,072.83	(1,892.44)	-27.2%	39,638.74	37,396.32	(2,242.42)	-5.7%

Festival recognizes the Board's requirement, as provided for in the *Renewed Regulatory Framework for Electricity,*[5] ("**RRFE**") for the Application to incorporate and reflect the customer's preferences and deliver value. Customers have indicated reliability is the paramount concern and Festival has provided an Application that provides the same quality of service and reliability where the customer pays less. As such, Festival is of the view that this Application clearly meets those objectives contained in the RRFE. Further, with a flat capital spend that will improve Festival's overall efficiency rating, Festival will see improved performance rankings. Finally, what is not necessarily evident is that Customers benefit from Festival's loss factor which remains very good at 1.0291% and its efficiency with OM&A at $250.28 per customer.

Festival requests the Board approve the following:

(a) Rate Base of $62,965,507[6] comprised of:

a. $53,358,152 for net fixed assets; and

b. $9,607,355 in respect of Working Capital calculated in accordance with the Board's Filings Guidelines;

[4] This table of customer impacts includes: (a) Cost of Capital Parameters issued November 17, 2014; (b) Revised regulatory charges updated November 11, 2014; (c) ICM true-up rate rider of $389,681 and $244,815; (d) reduced network connection charges of $475,200; and (e) new TOU/RPP pricing effective November 1, 2014.

[5] Ontario Energy Board, Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, October 18, 2012.

[6] These numbers reference the RRWF provided in **Attachment A**.

(b) Operating, Maintenance and Administration expenses of $5,156,282;

(c) A revenue requirement of $11,336,888;

(d) Retaining the fixed charge for the General Service Greater than 50kW rate class at $227.57 consistent with the Board's Filing Guidelines; and

(e) Rate riders for true-up for the construction of the new transformer station for both non-OM&A investments of $389,681[7] and OM&A costs of $244,815 to be recovered over 1 year.

Festival will address each of the outstanding issues in these submissions and repeats and relies upon its submissions in chief in support of its position.

2. RATE BASE

Festival is seeking approval for a rate base of $62,965,507 which is comprised of $53,358,152 for net fixed assets and $9,607,355 for the allowance for working allowance ("**WCA**"). Festival noted that rate base increased significantly since the 2010 cost of service as a result of the construction of the Transformer Station, Smart Meters and more typical capital improvements. Festival noted that it is at the end of a capital intensive period which resulted from the original purchase of the distribution systems in need of significant investment to bring them to current standards in the towns that comprise its service territory.[8] This capital spend has resulted, at least in part, from the condition of the plant that was present in the communities at the time of the industry restructuring. Festival's capital plans were approved by the Board on several occasions and it is those expenditures that have resulted in Festival having quality, reliable service with very low losses which has benefited the customer.

Table 3 – Loss Factors

Total Loss Factor – Secondary Metered Customer < 5,000 kW	**1.0291**
Total Loss Factor – Secondary Metered Customer > 5,000 kW	**1.0176**
Total Loss Factor – Primary Metered Customer < 5,000 kW	**1.0188**
Total Loss Factor – Primary Metered Customer > 5,000 kW	**1.0075**

[7] Festival had previously requested approval to recover $415,111 but updated Exhibit K2.1 (Updated) filed November 18, 2014, in which Festival revised its calculation to accord with Energy Probe's calculation.
[8] Transcript, Volume 1, November 13, 2014, page 39, lines 18 to 21.

In addition, Festival testified that it was taking to heart the direction of the RRFE and the results of the benchmarking plan. Festival would note that historically the Board's efficiency rating (the "**PEG Report**") considered only the OM&A of the utility over a relatively short horizon of 3 years. However, this year a more comprehensive review of efficiency was used which considered capital spending for the very first time. Festival would note that capital is considered over a much longer time period, more than a decade, and so it is very difficult, to near impossible, to move efficiency rankings in one or two years. Even a zero capital spend in a year, which no one would reasonably advocate, would not improve the ranking appreciably.

As such, Festival has struck a balance to plan for a flat capital spend over the next several years which will improve its ranking even if other utilities do not increase their spending. This is intended to improve Festival's ranking in the most recent Board benchmarking exercise.[9] Mr. Semsedini testified that maintaining a flat spend would improve Festival's ranking from Group 4 to Group 3 over a 3 year period and Group 4 to Group 2 over a ten year period. This spending pattern will maintain the current quality of the system and reliability for customers while avoiding swings in rates which would inevitably arise from an abrupt change in spending patterns. This shows a commitment to improving performance. Given the plan, and prudent long-term approach, there should be no doubt of Festival's commitment to improved efficiency consistent with the objectives of the RRFE.

Festival would note that prior to this year's efficiency ranking, Festival had always been in the top-performing cohort when the analysis only pertained to OM&A and this is the very first ranking involving capital spending. Festival would note that the Board recognized the limited value gained during the early stage of reviewing performance when it stated:

> The Scorecard will allow customers to gain a better sense of how well their distributor is performing. Over time, it will also let the customer see how their distributor compares to others…..
>
> As distributors and the Board gain experience under the scorecard approach and gain an improved understanding of customer preferences, refinements and improvements will be made. The Board will monitor the effectiveness of the

[9] Empirical Research in Support of Incentive Rate Setting: 2013 Benchmarking Update – Report to the Ontario Energy Board, Pacific Economics Group Research LLC, July 2014.

> Scorecard as a performance monitoring tool and work with stakeholders to ensure that it continues to support the Board's objectives.[10]

As such, Festival would urge caution about reading too much into the results given it is the very first study of its kind. Further, Festival would suggest that the Board should be more interested in what a distributor is doing to respond to the information rather than just looking at the absolute number – context to the numbers is meaningful.

However, Festival did review the results of the PEG Report released during the summer of 2014 – approximately 3 months after the submission of this Application. Festival would note that it has concerns with the current benchmark rankings in that there appears to be an error of approximately $3.2 million carried through the capital analysis[11]. Festival continues to work with the Board to resolve the discrepancy in the data used by the Board's consultant. If Festival is correct, its ranking would improve just through correction of the error.

Festival expressed its view of the PEG Report findings and provided an explanation regarding the historical spend and how Festival planned to improve its ranking during cross-examination by Energy Probe when Mr. Semsedini testified that:

> MR. AIKEN: Then for 2014 and '15, Festival is now in group 4, which is the second-least efficient group.
>
> MR. SEMSEDINI: Correct.
>
> MR. AIKEN: My question is: What changed?
>
> MR. SEMSEDINI: The methodology in which the PEG report determines efficiencies changed. Now the Board is looking at more of a total cost model.
>
> If you look at the breakdown of what the new numbers are generated from, there is an OM&A component and there is a capital component. In the OM&A component, Festival Hydro, even if you compare our 2015 request versus actual 2013 of all other distributors, Festival Hydro is still the twentieth-lowest OM&A per customer utility in the province, so I would say that hasn't changed.
>
> In the capital side, Festival Hydro has spent money after we purchased six other municipalities. We've spent a lot of money upgrading the

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[10] EB-2010-0379, Report of the Board – Performance Measurement for Electricity Distributors: A Scorecard Approach, pages 7 and 8.
[11] Transcript, Volume 1, November 13, 2014, page 39, lines 25 to page 40, line 1.

> system, so capital costs from the kind of 2002 to current day, in updating those areas.
>
> So if you look at what our main cost driver is within the PEG analysis, it is really capital; it is not the OM&A that is leading us to be a fourth grouping utility.
>
> In the capital amounts, we have sent a letter to the Board Staff, saying that we can't reconcile $3.2 million of gross capital spend within the PEG analysis to what we have on our records as capital spend. I'm still waiting for a comment back on that discrepancy.
>
> I would also like to note that previous to this filing, Festival Hydro was -- I believe it was the 28th highest spending utility when you look at capital versus depreciation, as a percentage of depreciation.
>
> With our new DSP plan and a 16 percent reduction that we've taken in our plan going forward, we are actually now the ninth lowest spending utility as it relates to capital as a percentage of depreciation.
>
> That reduction alone should move us -- even if the numbers at the PEG analysis are correct, which I'm not saying they are. But if we use those numbers as a baseline, that would move Festival Hydro from the fourth cohort to the third cohort over a two and a half year period, and would put us at benchmark spending within a ten-year period.
>
> So we have looked at the analysis. We have taken to heart within our DSP what our customers have said. We have reduced our capital spend to one of the lowest in the province. And we think over a ten-year period that will bring us back into line with benchmarking costs.[12]

Festival would note that its proposed capital spend as a percentage of depreciation is 9th lowest among utilities in the province when comparing Festival's 2015 Test Year with 2013 reported years for other utilities. Festival's reduction in capital spends results in an improvement of 36 positions. This demonstrates a real commitment to increased performance.

Festival views efficiency improvements as either doing more with the same resources or performing the same task with fewer resources. While it would appear that Intervenors may recognize only the latter as being more efficient, it does not reflect the challenges facing distributors. Festival noted that it was constantly looking for improvements in efficiency in providing its services. It has reduced its fleet size, maintained a constant FTE count while providing more services and invested in capital to reduce RTSR costs for its customers.

[12] Transcript, Volume 1, November 13, 2014, page 39, line 4 to page 40, line 21.

> MR. RUBENSTEIN: And in terms of capital, putting aside the compensation component that makes its way into capital, with respect to how you're implementing your capital plan and your capital program, how are you becoming more efficient?
>
> MR. SEMSEDINI: I mean, I think there are different elements. So we put in -- if you look at it in an element-by-element basis, we are doing pole inspections. So this will allow us to catch poles that might critically fail and extending the life by doing treatments on those poles.
>
> So that has an impact on the number of poles that we replace on a year-over-year basis.
>
> I think if you look at our vehicle assessment, we are reducing the numbers of vehicles owned and operated by Festival Hydro, which makes our fleet more efficient.
>
> As positions come up, we look at is it more efficient to keep those positions in-house or sub them out to external sources to reduce costs.
>
> These are all things that we do to ensure that we are efficient in our operation on a year-over-year basis.[13]

The evidence clearly shows that Festival is aware of its current and future needs to continue to provide customers with quality reliable service. As noted by Energy Probe, at page 3 of its Submissions, 77% of Festival's customers are satisfied with the existing level of reliability and the remaining customers are split about increased spending to improve reliability. Festival would say this indicates its current approach is on the mark. This awareness has been factored into its capital program and business decision making. Further, Festival has taken a long-term view to ensure that customers are not provided minor, temporary savings only to be shocked in a few years with a distribution system in need of major capital expenditures to catch up for years of below sustainment spending. As such, Festival views its approach to capital as entirely consistent with the RRFE and prudent management of a utility.

As such, Festival requests the Board approve a rate base of $62,965,507 as reasonable for the reasons above and the additional reasons discussed below.

2.1 **2015 Test Year Capital Spend**

Festival has requested approval for a 2015 Test Year capital spend of $2,471,500[14] while Intervenors have suggested reductions, either on a global basis or, in some cases, in respect of

[13] Transcript, Volume 1, November 13, 2014, page 68, line 25 to page 69, line 16.

a particular project or program. Festival will first deal with the broader issues and then focus on the specific programs being the electric vehicle and the wood pole replacement program. Festival would submit that the Intervenor's focus on issues below the materiality threshold is indicative of the quality Application.

Envelope

Festival has proposed a net capital spend of $2,471,500 and this should be considered in light of the individual programs and the capital spending program. Festival would note that it has historically spent more on capital, see Table below, which shows an average capital spend of $3,990,017 for the years 2010 to 2014. With the exception of the expenditure on the electric car, Energy Probe was supportive of Festival's approach to 2015 capital spending. Board Staff did not raise issues with the 2015 Test Year capital program. Therefore, in its historical context, Festival's proposed 2015 Test Year capital spend is in-line with its historical pattern and may even be considered conservative. Mr. Semsedini noted this when he stated:

> MR. SEMSEDINI: ……….With our new DSP plan and a 16 percent reduction that we've taken in our plan going forward, we are actually now the ninth lowest spending utility as it relates to capital as a percentage of depreciation.[15]

Table 4. Capital Spend 2010-2014[16]

Year	Amount
2010	$2,707,301
2011	$2,952,336
2012	$6,710,201
2013	$4,957,247
2014	$2,623,000
5 year average	**$3,990,017**

Festival had noted that its planned capital investment pattern in 2016 to 2019 exceeds the amount requested for the setting of rates for 2015 Test Year. Table 5 below shows the forecasted capital spend for 2016 to 2019 which, other than the submissions in respect of the pole replacement program, was not challenged at all through cross-examination. As such the

[14] Gross capital spend is $2,621,500, Capital contributions are $150,000 to net at $2,471,500.
[15] Transcript, Volume 1, November 13, 2014, Page 40, lines 6 to 9.
[16] Actuals for 2010 to 2013 and 2014 is Forecasted.

future planned spending should be accepted by the Board as reasonable and the amount of $2,501,500 net of capital contributions considered appropriate.

Table 5. Forecasted Gross Capital Spending for 2015 to 2019

Year	Amount
2015 Test Year	$2,471,500
2016	$2,582,000
2017	$3,015,500
2018	$2,669,000
2019	$2,674,500
5 year average	$2,682,500

Any concern about the fact that Festival has in the past slightly underspent its capital budget can be eliminated by considering the following:

- First, Festival would note that the largest underspends were in 2010 and 2011 and the more recent years have shown a very small underspend.
- Second, it should be noted the current budget is based upon the asset management and distribution system plans provided in the evidence and is significantly lower than its historical spending and 7.8% lower than its forecast capital spending.
- Third, the prior years are not what Festival considered typical years with the installation of Smart Meters, the construction of the Transformer Station.
- Fourth, Mr. Semsedini also provided examples of projects, such as the ODS project for $100,000, which was originally budgeted as capital but Festival secured a service contract that resulted in a better deal for its customers but resulted in an OM&A expense rather than capital. This type of decision making is consistent with the RRFE's objective of delivering value for customers and evidences a utility putting its ratepayers' interest ahead of the interests of its shareholder. Such decisions should be encouraged by the Board.

For those reasons, Festival's proposed capital spend is appropriate when considered in the aggregate.

Electric Vehicle

As part of its fleet replacement program, Festival had identified the purchase of a single electric car. The cost of the electric car at $70,000 is greater than a regular gas fueled vehicle ($30,000 to $40,000). As such, the difference in cost between the vehicles is just over half of the amount of the materiality threshold of $56,834.[17] Festival is seeking to include the car in rate base to not only utilize the vehicle as it would a gas fuelled vehicle but to gain valuable information on the characteristics of the vehicle which are likely to be peculiar to Stratford.

Festival acknowledges that electric vehicles have not had significant penetration into the local market and that only 9% of residents[18] indicated a plan to purchase an electric vehicle. However, 9% means 1 in 10 and Festival has 20,000 customers – with the number of residents significantly higher than the customer count. However, that is only a part of the story – Festival is seeking to gain insight into the vehicles in order to understand the potential interaction between the vehicle and the distribution system with visitors to its service area. Mr. Semsedini noted this dual purpose:

> MR. AIKEN: Now, is this vehicle a replacement of an existing vehicle or an addition to your fleet?
>
> MR. SEMSEDINI: Our overall fleet plan will reduce the number of vehicles that we have, so this would act as a replacement and a kind of test vehicle for us as well.
>
> MR. AIKEN: Okay, so if it's a replacement, the $70,000 then is not really then an incremental cost, it is -- some portion of that would be incremental over a standard vehicle; is that correct?
>
> MR. SEMSEDINI: Correct.
>
> MR. AIKEN: Do you have an estimate of what that would be?
>
> MR. SEMSEDINI: We could say that that increase would be maybe a 30- to $40,000 difference.[19]

[17] This is the updated Materiality Threshold. Original Materiality Threshold was $59,355 as found Exhibit 1, Tab 5, Schedule 1, page 1.
[18] IR 2-OEB Staff-25.
[19] Transcript, Volume 1, November 13, 2014, page 28, lines 2 to 15.

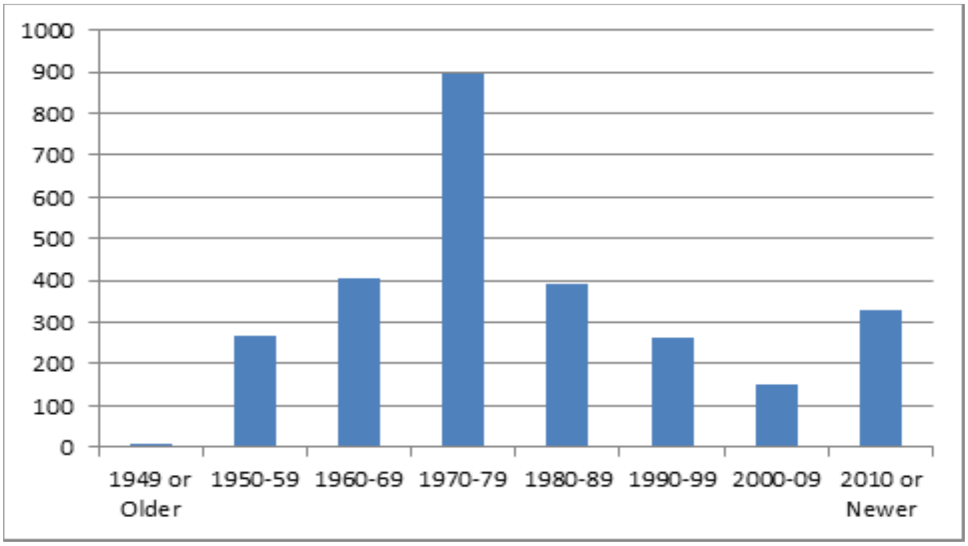
Festival noted that the City of Stratford receives over 600,000 visitors each year and with the prevalence of electric cars increasing, Festival is anticipating more visitors having electric cars in the future. Festival anticipates restaurants and hotels to be particularly impacted by the tourist traffic. As such, while customers may not own the electric cars, many of Festival's commercial customers will deal with tourists that will own electric cars. Therefore, these customers have a vested interest in understanding the potential issues and impacts of these vehicles. Festival has committed to approach other utilities to ensure that other utilities were not gathering similar information so that Festival's information would be new and unique.

In the context of its overall fleet, Festival noted that it is reducing its overall fleet complement and fleet cost and so there should be no debate regarding the need for a vehicle. Further, while the electric vehicle is intended to serve as a vehicle, it will also foster a better understanding of the impact the burgeoning electric car market will have in Festival's service territory. As noted, the electric car is approximately $30,000 to $40,000 higher in capital cost than the traditional corresponding fleet vehicle it is replacing. Given the overall management, cost, environmental and informational value, Festival believes the electric car is appropriate to include in rate base in the amount of $70,000.

Pole Replacement

As part of its asset management plan Festival developed a plan to replace approximately 100 wood poles per year over the five years of this rate cycle. Festival noted that this program would maintain the current pole age demographic which sees approximately 25% of the 2,736 wood poles being older than 40 years. This is consistent with customer expectations of maintaining the current level of reliability and cost. Festival's current pole demographic is provided below.

Figure 6. Wood Pole Demographic[20]



To understand Festival's program it will help to consider the age demographic of its wood poles. Almost 300 poles are of a pre-1959 vintage or are currently 55 years of age or older. At its proposed replacement rate, it will take Festival approximately three years to eliminate the current number of poles greater than 55 years of age. Festival would note there were 406 wood poles installed in the 1960-69 range. In three years, the oldest poles installed in 1960 will be almost 60 years old. As such, the Board should understand that Festival uses a 45 year useful life for depreciation and as an indicator that the wood pole is approaching the end of its life – not as the trigger for the immediate replacement of the pole. However, to be clear, Festival is not requesting pole replacements at 40 years, rather it is requesting that a pole replacement program retain the same population of poles in excess of 40 years.

Further Festival noted that it has 3,484 concrete poles which will start to reach end of life in 8 years and Festival will need to start replacing those poles. In addition, the wood pole age demographic shows a large spike in the 1970s which means that such poles will be in excess of 50 years at the same time the concrete poles will begin needing replacement. As such, if Festival defers spending on wood poles it runs the risk of a significantly expanded capital program in future years, something Festival's CEO indicated it was trying to avoid:

[20] Exhibit 2, Tab 2, Schedule 1, Appendix 1, Asset Management Plan, page 10 of 24.

MR. SEMSEDINI: When you start getting poles that are reaching the end of useful life -- and 40 years, yes, it does match us from an accounting standpoint, but we also know that poles deteriorate, so we have to pick a line in the sand somewhere and say that say we need to start addressing poles that hit a certain age.

For us, our belief is the 40 years and older is a good demographic if the expected life is -- if Hydro One is saying their poles fail at 62, to say that between 40 and 62 we are looking at replacements for these poles.

And the other thing that I think you need to take into account is pacing, so with Festival Hydro we've created a plan here that over a ten-year period keeps our spending flat, and we don't want to get into the positions, as other utilities do, where they push the boundaries of useful life and all of a sudden they need to come back to their customers and say, Oh, by the way, we've gone from replacing 100 poles a year to now 700 poles a year because we weren't maintaining the proper level of change, so we believe it is really a pace issue and it's an issue of maintaining reliability of our customers, and we've heard that messaging loud and clear from them.[21]

SEC indicated that Hydro One’s wood poles have a useful life of 62 years and that given such a difference the Board should curtail Festival’s wood pole replacement program. Festival would note there are significant differences between Hydro One’s predominantly rural service territory and customer density and Festival’s urban area with significantly higher customer density. Festival’s management expressed its concerns and the philosophy of its program during cross-examination:

Mr. Semsedini: …..we don't feel letting a pole stay out there until it fails is the right approach, and from a safety perspective, from a reliability perspective, from what we've heard from our customers, we believe that changing poles at this pace is the right pace for our utility.”[22]

Mr. Semsedini:….When you are in an urban populated area, if a pole fails you could have safety issues. That could be different than Hydro One's approach, especially when they are looking at long rural feeders with not a lot of population around.

[21] Transcript Volume 1, November 13, 2014, page 76, line 23 to page 77, line 16.
[22] Transcript Volume 1, November 13, 2014, page 77, line 26 to page 78, line 3.

> So from our perspective it is really to maintain pole failures at almost a zero percent."[23]

Festival is not in a position to definitively comment upon Hydro One's pole replacement program other than to say the factors and considerations for Hydro One are not the same as for Festival. Further, Festival is concerned that deferring replacement will have adverse impacts on safety and reliability. As such, there is no evidence that Festival's plan is overly conservative but there is a real concern that reducing spending will have adverse consequences for customers in both the short and longer term.

Festival's customers have indicated satisfaction with Festival's current reliability and cost. Reducing the capital budget has the potential to reduce reliability which is not in the interests of customers. As such, reducing spending is contrary to the objectives of the RRFE and prudent long-term management of the utility's assets.

2.2 **2014 Bridge Year Spend**

Festival's 2014 Bridge Year capital spend is forecasted to be $2,773,000 less capital contributions of $150,000 for a net addition of $2,623,000. Festival confirmed it is on target to fully spend to its 2014 Bridge Year forecasted amount. Festival had indicated that historically its annual cycle front loads the calendar year with OM&A expenses and then shifts to capital projects towards the end of the calendar year.

> MR. SEMSEDINI: So that's just -- this is something we went over yesterday. Festival Hydro paces -- the way we pace our builds, at the beginning part of the year we are really into OM&A. So a lot of tree trimming activity, training, all the OM&A activity we are really front end-loaded. And then we kind of make that transition coming out of the summertime, where we then move to almost completely capital work for the last part of the year.
>
> So the 2014, I guess, pacing of our capital work as a percentage is not really any different than 2013 or years before. So it is our expectation, we've reported to our board, that we expect to be at budget by year-end, with all projects complete.[24]

The only significant project remaining incomplete requires the installation of switchgear which Festival confirmed required less than 1 day and was to be completed in December.

[23] Transcript Volume 1, November 13, 2014, page 79, lines 16 to 22.
[24] Transcript, Volume 2, November 14, 2014, page 8, line 27 to page 9, line 11.

> MR. RUBENSTEIN: And then you will able to, between whenever you get them in December and the end of the year, be able to complete the entire $110,000?
>
> MR. SEMSEDINI: Correct. Yes.[25]

As such, there has been no allegation that Festival was imprudent or that it will not spend the amount forecasted. Therefore the Bridge Year spending is appropriate and should be included in rate base.

2.3 **2013 Historical Capital Spend**

Aside from the new Permanent Bypass Agreement ("**PBA**") with Hydro One Networks Inc. ("**Hydro One**"), Festival is not aware of any concerns with its historical rate base and it should therefore be accepted by the Board.

2.4 **Transformer Station**

Festival sought approval from the Board in EB-2012-0124 for the construction of a transformer station on the south side of Stratford. The City of Stratford has historically been supplied by a single TS owned by Hydro One – the Devon Street TS. Festival has sought to include the net amount of $14,946,001 for the transformer station in rate base. Festival has only included the actual cost in rate base and reflected depreciation based upon the month installed – December 2013. Energy Probe[26] supported inclusion of this amount in rate base as it is consistent with the actual spend and accounting for depreciation. Festival is of the view that the amount in rate base and the true-up should reflect a consistent approach in order to ensure neither the ratepayer nor the utility is exposed to unnecessary charges. The true-up for the transformer station is dealt with later in sections 6.1 and 6.2 of these Reply Submissions.

Prior to constructing the new TS, the sole feed to the City of Stratford through Hydro One's Devon Street Transformer Station was over-capacity which created a number of issues for Festival and Hydro One. It reduced operational flexibility and resulted in difficulty coordinating maintenance activities. Further, the Devon Street TS was not near the industrial customers or the new load growth in the south of the City of Stratford. This resulted in long feeders and reliability concerns for customers.

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[25] Transcript, Volume 1, November 13, 2014, page 73, lines 8 to 11.
[26] Energy Probe Submissions, page 32, Issue. 5.3.

At the time of EB-2012-0124, Hydro One had assigned Festival approximately 77MW of allocated capacity at the Devon Street TS. The Board reviewed and approved Festival's request for the ICM for the new transformer station and determined the expenditure was in the public interest. There should be no question at this time that the construction of the TS was appropriate.

At that time of EB-2012-0124, the amount of the overload was 4 MW which would not be subject to a bypass payment obligation as a result of section 6.7.9 of the Transmission System Code ("**TSC"**). The TSC, section 6.7.9 also states that overloads of connection facilities are to be avoided. Festival had forecasted load growth of approximately 2MW to 3MW over the 2014 to 2019 period. To date, net new growth has not been quite as strong as forecasted. The new transformer station is intended to meet today's needs and long-term growth as noted by Mr. Vanderbaan:

> MR. VANDERBAAN: So it would be a small portion of that, but any overload is -- you need something to pick that load up, so it makes sense to build something that is going to last 25 to 45 years rather than something that only lasts a few years.[27]

The construction of the transformer station provided Festival with an option on how to operate its system in the optimal manner. The PBA was not triggered by "the absence of new demand". The primary reason FHI considered a permanent bypass was for operational reasons. Mr. Semsedini stated:

> MR. SEMSEDINI: There is also a reliability element, so by being able to pick up the 20 megs of load it -- so where the station is located is really in the heart of the industrial park within Stratford, so the 20 megs of load is really picking up all the establishments that are around it.
>
> So not only does the customer receive a benefit, but we receive a benefit at Festival Hydro through the reliability of those customers. The feeder that they used to be on was a very long feeder, and they were at the end of it, so outage times would now go down to those feeders, so it is additional revenue for Festival Hydro during outage situations. So there is really multi-benefit to the bypass.[28]

This was reinforced by Mr. Vanderbaan in cross-examination by Board Staff.

[27] Transcript, Volume 2, November 14, 2014, page 46, lines 15 to 19.
[28] Transcript Volume 1, November 13, 2014, page 52, line 28 to page 53, line 13.

MS. DJURDJEVIC: So in terms of how much of a bypass you decided -- or actually, maybe explain it to us -- the bypass is for 20 megawatts. Is that an amount that the company determined or is that assigned by Hydro One, or how did you arrive at that amount and not another amount?

MR. VANDERBAAN: It was the number that we came up with, based on how the electrical system operates within the city of Stratford, ensuring that we had capacity on both our station and Hydro One's station to move load back and forth as necessary during switching operations.

It also made sense logically on where the open points between feeders would go on how the system actually looks like. It was an operational decision to arrive at that number.[29]

While the actual load in Stratford was less than anticipated due to the closure of two industrial customers, this only impacted the magnitude of the bypass, not the decision to proceed with the bypass. In other words, had the two industrial customers maintained their load, the amount of the bypass would have been reduced by approximately 8 MW, so a bypass amount of 12 MW would have been necessary to achieve the operational effectiveness and reliability improvements that result from the movement of load from the Hydro One transformer station to the Festival transformer station.

2.5 **Permanent Bypass Agreement**

Festival entered into a bypass agreement ("**PBA**") with Hydro One in 2013 in order to permanently bypass the Hydro One Devon Street Transformer Station. The bypass agreement requires a payment by Festival to Hydro One in 2015 in the amount of approximately $1,230,026 with the final amount to be determined based upon the actual load bypassed as provided in the PBA. Festival does not anticipate this amount changing.

Intervenors are concerned that Festival has included the PBA as an asset in rate base. Energy Probe, Board Staff, VECC and AMPCO submitted the amount of the payment to be made to Hydro One should be treated as an expense and recovered through a rate rider rather than through rate base. SEC takes a more extreme approach by stating the Board should deny recovery as it is a prior period expense and would constitute retroactive ratemaking. Notably, not one party questioned the appropriateness of entering into the PBA and the realization of the benefits of $475,000 per year which customers have been receiving since December 2013.

[29] Transcript, Volume 2, November 14, 2014, page 47, lines 20.

Festival is of the view there is no evidence to support a departure from the long held practice of treating asset investments as part of rate base.

As the PBA is an asset, it should be considered as any other capital expense from a prior year and included in rate base at its net value. There should be no concern about it being a prior period expense as it is not an expense. Further, SEC's position violates the matching principle.

It has long been held that a utility is entitled as part of the regulatory compact to earn a return on the value of the investment it employs for the benefit of the public. Further, rates that do not permit the utility a reasonable rate of return are not just and reasonable. Regulators and courts have recognized this fundamental principle by citing the following passage:

> [40] The costs upon which GLPL's rate Deferral Plan is premised were never reviewed by the OEB and it would violate the OEB's statutory obligation to ratepayers and the "regulatory compact" (as coined by the Supreme Court of Canada in Atco Gas & Pipelines Ltd. v. Alberta (Energy Utilities Board) (2006), 2006 SCC 4 (CanLII), 263 D.L.R. (4th) 193 at para. 63 (S.C.C.), requiring a balancing of rights and interests of utilities against those of ratepayers) to permit recovery of those costs without this necessary review.[30]

Festival is merely seeking to earn a return on its investment in the PBA – an investment that yields annually $475,200 in benefits for its customers at a return for Festival of approximately $6,000 per year. Festival has invested in the PBA to secure benefits for its customers over the life of the transformer station and that investment should result in Festival being compensated. Festival has received offers of long-term financing from a major financial institution.

In response to Undertaking JT1.14, a copy of which is attached to these submissions at **Attachment C**, Festival provided a detailed explanation of the rationale to support the inclusion of the PBA as an asset in rate base. Without repeating the content of the Festival's response, it concluded that recognition as an asset was the only appropriate accounting treatment.

Festival would note that it considered whether the PBA was an expense and the analysis confirmed it was **not appropriate** to classify the PBA as an expense. The accounting treatment was not seriously challenged by any party. Of note, Festival's witness panel included 3 accountants, Ms. McCann, Ms. Reece and Mr. Vanderbaan, plus their independent auditor. No evidence was presented by any other party to rebut Festival's position as to the proper

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[30] Great Lakes Power Limited v. Ontario Energy Board, 2009 CanLII 39062 at paragraph 40 (ON SCDC), <http://canlii.ca/t/24t35> retrieved on 2014-12-02.

characterization of the PBA as an asset for accounting purposes. Further, the Board's accounting procedures do not provide any direction on the proper treatment of the PBA, nor do they provide any reason to depart from the accounting principles. During cross-examination, excerpt below, Festival explained it had considered several accounting requirements and determined its course of action which received concurrence from the independent auditor.

> MR. RUBENSTEIN: With respect to the bypass compensation specifically and how that was classified, did you consult with Mr. Jeffreys or anyone from his firm or any other external accounting professionals?
>
> MS. REECE: Yes, we did consult with KPMG, with Mr. Jeffreys.
>
> MR. RUBENSTEIN: Did he provide an opinion specifically on that issue, or was it just sort of an oral discussion? Can you help me understand what conversations were had?
>
> MS. REECE: I had -- I did my analysis in reference to the CPA Handbook as to the treatment of this asset, as well as reference to APH section 410. And I did contact KPMG to provide them with the information that that was the plan that we were going to -- the accounting treatment that we planned for this asset.
>
> MR. RUBENSTEIN: And what was KPMG's response? If it's Mr. Jeffreys, he can provide that answer.
>
> MR. JEFFREYS: Our response is actually contained in our auditor's report, that -- we've issued an unqualified auditor's report. The discussion as Debbie has described it is accurate, but we look at financial statements as a whole, not independent, individual one-off items.
>
> And by virtue of issuing an unqualified auditor's report, we've effectively agreed with management's decision and treatment of bypass payment.
>
> MR. RUBENSTEIN: But Ms. Reece was just saying that with respect to this specific issue, they consulted with KPMG. And I'm trying to understand the answer to this specific issue with the bypass.
>
> I understand how you look at the financial statements as a whole, but I'm just asking about -- it seemed to me that they asked KPMG for its opinion on how to classify or did you concur with management's classification of this specific asset.
>
> MR. JEFFREYS: "Concurrence" is the right term. They presented us their rationale, and in undertaking our audit of the financial statements we concurred with their treatment.[31]

[31] Transcript, Volume 2, November 14, 2014, page 63, line 1 to page 64, line 11.

It is reasonable to conclude that while the auditor did not express an opinion in respect of the specific transaction, the absence of any qualification in the audit report confirms the appropriateness of Festival's approach. Ms Reece testified that management does not expect any change in treatment as a result of the change in accounting policies and Mr. Jeffreys concurred with that expectation.

> MR. STOLL: Okay. You indicated in your prior answer -- and correct me -- that there was not a significant difference between the two -- the IAS and the CGAAP standards. Would you expect any different result from your auditor for the 2014 or 2015 statements as a result of the transition in the accounting standards?
>
> MS. REECE: Unless the standards themselves changed between now and then, I do not expect that they would -- there will be a reclassification of that asset.
>
> MR. STOLL: And, Mr. Jeffreys, would you have any reason to disagree with that answer from Ms. Reece?
>
> MR. JEFFREYS: I would not -- pardon me. I would not.[32]

Further no evidence was elicited that would indicate the PBA is more properly treated as an expense. It seems that Intervenors are pursuing a results oriented strategy rather than the principled approach of characterizing the nature of the transaction and using that to inform the regulatory treatment. The Intervenors want to deprive Festival of recovery as an asset and expose customers to an immediate significant cost increase through a rate rider. Festival would suggest that departing from the normal course of placing assets in rate base is contrary to ratemaking principles and there is no evidence that would support a departure from that long accepted behaviour.

Festival would note that it testified its practice was consistent with that of other utilities. Ms. Reece indicated that Kitchener-Wilmot Hydro Inc. ("**KWHI**") had included the costs of a bypass payment in its 2010 rate filing as a decommissioning cost.[33] This cost was included in KWHI's 2014 COS Application (EB-2013-0147), Exhibit 2, Tab 1, Schedule 2, page 13, Line 14 Acct # 1815 Decommissioning of Detweiler Station in the amount of $5,039,500. Oral testimony is evidence and Board Staff's comment that such a statement should be disregarded in the absence of tested contradictory evidence is without foundation. Further, Festival was able to

[32] Transcript, Volume 2, November 14, 2014, page 39, lines 6 to 17.
[33] Transcript, Volume 2, November 14, 2014, page 62, lines 6 to 21.

provide the specific reference contrary to Board Staff's submission that such evidence could not be found.

Regulatory compliance is not an option. It is antithetical to think the regulator can require a regulated utility to undertake an investment and provide no mechanism for recovery which was suggested by SEC. The Bypass payment is required by the TSC, sections 6.7.6 which is provided below:

> 6.7.6 Subject to section 6.7.2, 6.7.7 and 6.7.8, for all or a portion of existing load a load customer may bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person, provided that the load customer compensates the transmitter.

Therefore, in order to comply with the TSC, which is a condition of Festival's license, once a decision to permanently bypass the Hydro One Devon Street TS was made, the only decision remaining would be the amount of the permanent bypass which Festival determined for operational reasons would be 20MW and yields $475,200 annually in consumer savings in exchange for the $1.2 million investment by the utility.

Contrary to Board Staff's contention that the Board was unaware of the PBA issue prior to this Application, Festival would note that Hydro One informed the Board, as required by the TSC, in November 2013 that it was entering into the PBA with Festival. A copy of the Hydro One letter to the Board may be found at Attachment D to these Reply Submissions. Festival would note that Board Staff had not raised the issue of whether Hydro One had complied with the requirement in the TSC to notify the Board of the potential bypass. As such, this was Festival's only opportunity to ensure the record was correct.

Festival disagrees with Board Staff's contention that the bypass payment is intended to compensate Hydro One for lost revenue. The TSC, section 6.7.7, provides the formula to be used to determine bypass compensation is based upon net book asset value, including salvage value and reasonable removal and environmental costs. Not a single element of the formula includes revenue. Ms. Reece confirmed that Hydro One was reducing rate base as a result of the PBA.

SEC's contention that the absence of a clawback provision in the PBA exposes customers to an unfair allocation of risk is inconsistent with the fact that Festival does not intend to put any new load in the foreseeable future back to the Devon Street TS so there is no anticipated situation in which SEC's scenario would arise. Festival intends to adjust its distribution system to ensure the existing Devon Street TS load is maintained while Festival's new TS will serve all new load. Mr. Vanderbaan confirmed to the Panel:

> MS. LONG: Mr. Vanderbaan, I just want to understand this better. It seems to me from what I hear from your evidence that you have a static number of customers that are served by Hydro One, and the fluctuation and bypass would be based on what they're consuming, but new customers that come on to your system, I'm assuming, will be serviced by your new transformer station? Is that...
>
> MR. VANDERBAAN: That's correct.
>
> MS. LONG: Like, you're not adding and subtracting from the Hydro One transformer station that you are paying bypass on?
>
> MR. VANDERBAAN: Correct, we expect most of, if not all the major new load growth, to be around the new station, which is where it was built.
>
> MS. LONG: Right. Okay. Thank you for that clarification.[34]

As such, the PBA represents great value for the consumer without exposure to risks as suggested by SEC. The PBA is properly classified as an asset under current and future accounting rules and Festival's request for inclusion in rate base is consistent with the PBA being an asset, with Hydro One's treatment of the transaction and the treatment other utilities have received for payments for permanent bypass agreements.

Festival would also note that VECC's contention that the lowest cost solution should be invoked is not correct. Utilities have never been obligated to provide the least cost short term solution but rather to make prudent decisions.

Festival undertook a significant amount of due diligence to determine that the PBA should be included in rate base. No party has provided a sound rationale for any treatment other than as an asset and inclusion of rate base. In the absence of any defined regulatory accounting rule to the contrary, as is the case for the PBA, Festival submits normal accounting practices should be followed to provide predictable treatment to such transactions. As such, Festival's approach is appropriate and results in significant benefits for consumers and the PBA should be included in rate base.

[34] Transcript, Volume 2, November 12, 2014, page 50, line 14 to page 51, line 1.

2.6 **Working Capital Allowance**

Festival Hydro applied for a 13% allowance using the default amount provided by the Board in its letter dated April 12, 2012 which explained changes to the Board's 2013 Filing Guidelines. In that letter, distributors were given 2 options – (1) the filing of a lead-lag study; or (2) the use of the 13% default value. Festival was not ordered to conduct a lead-lag study in its last cost of service proceeding. Festival, as was its right, chose to use the default value. Board Staff noted that Festival has followed the Board's policies for WCA and supported Festival's approach.

On April 17, 2012, the Board issued a letter to all licensed electricity distributors entitled "update to Chapter 2 of the filing requirements for transmission and distribution applications allowance for working capital", which update the options for the calculation of the working capital allowance for the 2013 rate year. Prior to the letter, the Board's filing requirements for cost-of-service distribution rate applications provided for a 15 percent rate to be used for the calculation of the working capital allowance. However, in the April 12, 2012 letter the OEB stated:

> The Board has reviewed the approaches to the calculation of WCA and will not require distributors to file lead/lag studies for 2013 rates, unless they are required to do so as a result of previous Board decision.

The Board determined that the default value going forward would be 13% of the sum of cost of power and controllable expenses and that this rate would be applicable to the 2013 rate applications and beyond. That policy has not changed and that is what Festival included in its Application. This requirement is reflected in section 2.5.1.3 of the filing requirements for electricity distribution rate applications, which describes the Board's expectation with respect to the working capital allowance and allows for the default 13% approach in the absence of previous Board direction to undertake a lead/lag study.

Festival would note that the dominant practice amongst distributors is to use the 13% default WCA. Ten of the eleven 2014 cost-of-service filers used the 13% WCA in their applications. Only Veridian, which had previously agreed in 2012 to file a lead/lag study, did not use the 13% default value. The 13% WCA has been accepted by the Board in a number of decisions, such as Burlington Hydro, Oakville Hydro, Kitchener Wilmot Hydro Inc., Cooperative Hydro Embrun, Fort Frances Power Corporation, and Hydro Hawkesbury.[35]

Festival understands the Board accepted the use of 13% for WCA for at least 2 of the utilities, Hydro Hawkesbury and Fort Frances, which are monthly billing utilities. Of note, the Board stated:

> It does not consider it appropriate to adopt the results of a lead/lag study from another utility without a thorough analysis concluding that the two utilities are comparable.[36]

I would also commend the panel to the recent decision in EB-2013-0147/EB-2014-0155 where the Board stated:

> The Board finds that using a consistent WCA default value in cases where lead/lag studies have not been conducted to be a better approach than attempting to use simplified methods to derive utility-specific WCA value for each case from other lead/lag studies which may not reflect the unique circumstance of such utility.[37]

The Board went on to state:

> The Board finds that there is no compelling evidence in this case to suggest that a WCA value other than the default 13% was more appropriate and, therefore, confirms its earlier finding that KWHI proposed 13% is acceptable.[38]

As noted by Festival, monthly billing was just one of many factors that would impact a lead/lag study. Festival acknowledged that all other things being equal a monthly billing utility would have less demand for working capital than the same utility if it billed every two months.

> MR. JANIGAN: Okay. And I believe in the exchange yesterday -- and you can correct me if I'm in error -- that you agreed that obviously whether a utility is a monthly or a bimonthly biller has an effect on its working capital requirements.

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[35] Burlington Hydro [EB-2013-0115], Oakville Hydro [EB-2013-0159], Kitchener Wilmot Hydro Inc. [EB-2013-0147/EB-2014-0155], Cooperative Hydro Embrun Inc. [EB-2013-0122], Fort Frances Power Corporation [EB-2013-0130], and Hydro Hawkesbury [EB-2013-0139].
[36] EB-2013-0139, Decision and Order dated January 30, 2014, Ontario Energy Board, page 10. See, also, EB-2013-0122, Decision and Order, Ontario Energy Board dated December 23, 2013, at page 4.
[37] EB-2013-0147/EB-2014-0155, Decision, OEB, page 4.
[38] EB-2013-0147/EB-2014-0155, Decision, OEB, page 4.

MR. SEMSEDINI: Sorry, could you repeat that last part again? So if you are monthly or bimonthly, that it would have an impact on the working requirements? That's the question?

MR. JANIGAN: Yes.

MR. SEMSEDINI: It would, but I would also say that you need to understand the complete organization to know what that new number should be.[39]

Energy Probe clearly confirmed that a utility need for working capital was utility specific by providing reference to a few large utilities that each had unique working capital requirements.[40] Festival would note that there was no evidence indicating that the studies referenced were reflective of Festival. As such, there is no evidence that would warrant the Board departing from its current practice of following its 2015 Filing Guidelines in this respect.

Festival supports the Board's initiative, as part of section 4.1.2 of the draft Report of the *Board on Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance*, to consider whether amendments to its WCA policy are warranted, and agree that it is important to examine factors beyond the impact of monthly billing on WCA.

In the absence of its own lead/lag study, Festival respectfully requests that the Board's default factor of 13% be used in calculating its allowance for working capital. The amount requested for inclusion in rate base is $9,607,355 subject to any change in controllable expenses resulting from the Board’s decision. Festival does not support all small utilities being required to conduct lead/lag studies as it is of the view that the costs outweigh the benefits.

3. **OPERATING, MAINTENANCE & ADMINISTRATION**

Whether the Board considers an envelope approach or a line-by-line approach for reviewing OM&A, Festival’s view is that its request for OM&A $5,156,282[41] for the 2015 Test Year is appropriate, as Board Staff concurred. Festival’s request includes the cost for the oral hearing which had not been included in its original Application. Intervenors, other than Board Staff, provided a range of reductions from $104,000 to as much as $279,000 or from 2% to 6% of

[39] Transcript, Volume 2, November 14, 2014, page 15, lines 6 to 18.
[40] Exhibit K1.1, page 2.
[41] This amount excludes PILs of $19,225 and LEAP funding of $13,000 which Festival did not include in OM&A. PILs and LEAP were settled in the Partial Settlement Agreement.

OM&A. Festival is of the view it is inappropriate for Intervenors to primarily rely upon issues that are below the materiality threshold to justify their position.

Following the filing of the Settlement Agreement, Festival filed an update to its evidence[42] which provided for a change in regulatory costs to reflect the fact a two day oral hearing would be required. Festival's evidence prior to that point had always indicated no oral hearing would be required. This change noted in the updated Appendix 2-M provided a total cost for the 2015 rate application as $282,000 with an annualized cost of $56,400. No one seriously challenged the magnitude of the cost despite being provided the opportunity in the oral hearing to cross-examine on original submission and the updated evidence.

As noted by Board Staff, Festival remains one of the lowest OM&A cost per customer utilities at $250.28.[43] Festival's superior OM&A performance has been documented for a number of years through the Board's benchmarking report which had placed Festival in the best performing quartile for the years 2010 to 2013 – the last year for which OM&A results were issued. In addition, Festival has created an annual savings of RTSR in the amount of $475,000 exclusive of the $34,000 in other savings (sub-station, fleet, building) which should not be ignored when considering the impact on customers.

To consider the envelope approach to spending it is helpful to understand where Festival was in 2010 and what has changed – both in and outside of Festival's control. Energy Probe provided a detailed but somewhat flawed analysis in an attempt to justify a reduction in OM&A. Table 7 below takes the Energy Probe analysis and provides the proper adjustments to effectively create a normalized spending pattern over the 2010 to 2015 period. What is evident in the table is the increase measured over time is less than 3% annually which considering the rate of inflation – and the prior collective bargaining agreement which had included 3% wage increases – provides a very different picture.

Festival collective bargained the agreement with the union and is of the view it is improper to isolate a single element for criticism as SEC has done in respect of the overtime rate. As all parties and the Board are aware settlement of an entire package requires give and take and should be viewed in the totality of the agreement. As noted in cross-examination from SEC, by Mr. Semsedini, the overall compensation provided is very competitive.

[42] Appendix 2-M, Updated, November 11, 2014.
[43] Board Staff Submissions, page 20.

> MR. SEMSEDINI: ……I also think if you look at our metric in terms of pay for per employee, the average employee cost and the average management cost amongst our neighbouring utilities, we are the second-lowest in both categories amongst all the neighbouring utilities that we compare it to.[44]

And Mr. Semsedini clarified which utilities Festival was comparing itself to in making these statements during cross-examination from Energy Probe.

> MR. AIKEN: My last question under the OM&A is, do you compare your compensation levels and increases to other distributors? And I think you heard this morning that you said your neighbouring distributors?
>
> MR. SEMSEDINI: Correct.
>
> MR. AIKEN: Which ones do you generally compare yourself to?
>
> MR. SEMSEDINI: The ones that -- so neighbour us, I mean, in our area, Waterloo, Kitchener, Cambridge, Erie-Thames, London Hydro, and we don't really compare ourselves to Hydro One.[45]

Further, a review of historical spending on over-time would lead to the conclusion that SEC's concern is less than the materiality threshold of $56,834.[46] In response to Oral Hearing Undertaking J1.4, Festival indicated that its average overtime expenditure was $186,032. A reduction of overtime rate from double time to time and half is a 25% reduction or $46,508.

Festival's OM&A costs have increased since 2010 which is to be expected given the number of changes that have occurred during the intervening 5 years. For example, distributors have switched to IFRS [$148,000], been subjected to OMERS increases [$171,862], smart meters [$136,000] and, for Festival, the construction of the transformer station has brought a new type of OM&A activity [$140,000] in order to achieve the savings for the customers. Festival had testified that the majority of the increase from 2010 to 2015 was non-controllable expenses, 57%, while controllable expenses increased by 43%.

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[44] Transcript, Volume 1, November 13, 2014, page 68, lines 17 to 21.
[45] Transcript, Volume 1, November 13, 2014, page 46, lines 5 to 15.
[46] Note the initial Application the materiality threshold was $59,355.

Table 7. Energy Probe Submission – Revised by Festival

EP Submission Page 10 - Table Revised by Festival							
	2010 BA	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Adjustments to OM&A							
Total OM&A - E4T2S1 Att 1, 2015 RRWF	3,980,676	4,039,859	4,002,784	4,739,503	4,950,908	5,016,404	5,188,505
Special Purpose Charge (App 2-JB)		- 114,813					
Smart Meter Expense (E4-T2-S1)				- 546,293			
PST costs (E4T2S1)	115,494	115,494	189,001	241,798			
PST costs (4-EP-23)					- 79,393		
Accounting change (App. 2-DA & 4-EP-46TC)			11,593	32,627	35,173		
Billable Work (4-SEC-15 & 4-EP-46TC)					- 254,313	- 167,816	- 148,417
Adjusted total per Energy Probe					- 44,433		- 25,000
Festival additional test year adjustments							
Transformer station incremental costs							- 140,000
OMERS premium incremental costs			- 53,689	- 108,169	- 155,075	- 165,321	- 171,862
	4,096,170	4,040,540	4,149,689	4,359,466	4,452,867	4,683,267	4,703,226
			2.70%	5.06%	2.14%	5.17%	0.43%
							2.96%

Further, Festival's prudent approach is confirmed if one considers the increases in the context of an increase in customers over a period of 5 years. In respect of controllable cost increases, customers have experienced approximately a 1.51% per year increase in OM&A which is below the rate of inflation. This analysis is demonstrated in Table 8 below.

Table 8. Energy Probe Compendium – Revised by Festival

Section 2 of page 241 of Energy Probe Compendium							
	2010 BA	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Adjustments to OM&A							
Total OM&A - E4T2S1 Att 1, 2015 RRWF	3,980,676	4,039,859	4,002,784	4,739,503	4,950,908	5,016,404	5,188,505
Special Purpose Charge (App 2-JB)		- 114,813					
Smart Meter Expense (E4-T2-S1)				- 546,293			
PST costs (E4T2S1)	115,494	115,494	189,001	241,798			
PST costs (4-EP-23)					- 79,393		
Accounting change (App. 2-DA & 4-EP-46TC)			11,593	32,627	35,173		
Billable Work (4-SEC-15 & 4-EP-46TC)					- 254,313	- 167,816	- 148,417
Adjusted total per Energy Probe					- 44,433		- 25,000
Festival additional test year adjustments							
Transformer station incremental costs							- 140,000
Smart meter incremental costs							- 136,000
OMERS premium incremental costs							- 172,000
	4,096,170	4,040,540	4,203,378	4,467,635	4,607,942	4,848,588	4,567,088
Increase since 2010 BA							470,918
% Increase since 2010 BA							11.50%
Avg % Increase per year since 2010 BA							2.30%
# of Customers	19,828						20,554
Normalized OM&A cost/customer	206.59						222.20
% Increase since 2010 BA							7.56%
Avg % increase per year since 2010 BA							1.51%

Festival would note that Energy Probe has ignored issues such as OMERS increases in its analysis. However, Festival is obligated make the contributions and has no ability to reduce such an expenditure. As summarized in Table 9 below, OMERS costs have increased from $229,589 by $171,862 to $401,451 over the period. This is a 75% increase in a material cost. OMERS had been approximately 5.6% of the OM&A and is now more than 7.5% of OM&A.

Smart Meters also created a new OM&A requirement which Festival has been able to meet without an increase in FTEs. As such, one must carefully review the spending and the circumstances – and when such is done in this case – Festival's OM&A is appropriate. Festival is managing its spending within its control.

Table 9. OMERS

OMERS					
Table at top of page 3 of E4/T2/S1 - OMERS premium rates					
OMERS Premium Rates					
Year	**YMPE**	**YMPE Below**	**YMPE Above**	**Employer Portion**	**Increase**
2010	$ 47,200	6.4%	9.7%	229,589	
2011	$ 48,300	7.4%	10.7%	283,278	53,689
2012	$ 50,100	8.3%	12.8%	337,758	54,480
2013	$ 51,100	9.0%	14.6%	384,664	46,906
2014	$ 52,122	9.0%	14.6%	394,910	10,246
2015 (Estimate)	$ 52,122	9.70%	15.8%	401,451	6,541

Tree Trimming

Festival coordinates its tree-trimming activities with the City of Stratford to ensure the tree-trimming program is delivered in an efficient manner with one-third of the City of Stratford covered in any given year. Through this co-ordination Festival ensures that multiple trips to the same area are avoided thereby saving costs. In the other villages, Festival undertakes tree-trimming without the formal involvement of the municipality. Festival correctly noted that it had survived the 2013 ice storm with relatively little damage from fallen limbs and therefore, relatively few outages compared to some other utilities. However, such a result does not suggest it is appropriate to cut-back on tree-trimming rather it suggests Festival has an appropriate level of activity to ensure it is providing reliable service which is the paramount concern of customers. Festival would note that having survived the ice storm with little damage, it was not exposed to significant overtime costs and even was able to provide assistance to other utilities and earn revenue.

Training, Travel & Conferences

VECC's suggestion for a $20,000 reduction in training, travel and conferences is misguided, shortsighted and has the potential to decrease safety. Festival's OM&A in respect of Training for Operations & Maintenance Staff has increased from $31,309 (2010) to $61,247 (2015) as a result of the changes in accounting that have re-classified certain training programs from capital to OM&A. As such, there is no "new" training program being undertaken, rather Festival is continuing its same level of training which has resulted in an enviable safety record. Reducing the current level of training by 1/3 would increase the risk of an injury or may result in decreased productivity.

EDA Membership

With respect to Festival's membership fees of $30,761[47] in the Electricity Distributor Association ("**EDA**"), Festival clearly stated there were many benefits to being an EDA member in Mr. Semsedini's exchange with Mr. Janigan which is reproduced below. To focus on a small part of the EDA's mandate to object to the total membership fees ignores the obvious benefits provided through the membership. Again, Festival would note the entire amount of the EDA membership fee is approximately one half of the materiality threshold of $56,834[48]. Festival had understood that Intervenors were to focus on material items – not individual segments of costs that are less than the materiality threshold.

> MR. JANIGAN: Okay. Now, at tab 8 it shows that Festival is suggesting that $45,000, [sic] EDA membership costs, should be paid by customers. Is EDA's job to lobby on behalf of shareholders, rather than customers?
>
> MR. SEMSEDINI: I would say that part of their job is to lobby for LDCs as corporations.
>
> MR. JANIGAN: Yes. When customers are paying for that.
>
> MR. SEMSEDINI: Yes, but we get -- we get lots of benefits from the EDA in terms of -- you see some of the work that they're doing, for example, in smart metering, in updating smaller LDCs on what's going on, being able to pinpoint where issues for smaller LDCs are.
>
> All these sorts of things save us labour in terms of needing specialists who spend all of their time looking at the newest regulatory, so the distribution system plan, for example, is an area that EDA put on sessions for us to show us what was in the plan, what we need to focus on, and how to go forward.
>
> So I think that this cost is -- is very worthwhile for the utility, and that the customers are actually receiving dividends on it.[49]

Billing

Festival's OM&A included $25,000 in respect of changes in billable work resulting from limitations in its current system which did not permit it to charge for overhead. Again, Festival is

[47] Response to IR 4-VECC-27(a)
[48] Updated from original Application amount of $59,355 found at Exhibit 1, Tab 5, Schedule 1.
[49] Transcript Volume 2, page 24, line 8 to page 25, line 1.

concerned that Intervenors are focused on issues that are less than half the materiality threshold and provides evidence that Intervenors are scrounging to find potential savings.

OM&A Summary

Festival requests the Board approve its OM&A in the amount of $5,156,282 for the 2015 Test Year as supported by Board Staff. Reductions in OM&A suggested by Intervenors increase the risk of reliability issues – the number one concern for customers and in Festival's view would be contrary to the objectives in the RRFE. Festival remains one of the most efficient utilities in respect of OM&A per customer and the 2015 Test Year request is less than the rate of inflation higher than the 2014 Bridge Year forecasted spend.

4. REVENUE REQUIREMENT

Energy Probe has indicated that it is not in a position to comment upon the revenue requirement at this stage because neither rate base nor OM&A is determined. Festival understands that following the Board's decision Festival will be required to prepare an update of the revenue requirement and a draft rate order reflecting the Board's decision in respect of the outstanding issues.

Festival expects Intervenors will comment upon the derived revenue requirement at that time. However, Festival anticipates relatively few comments given the Parties understanding of the calculation and the extent of the outstanding issues.

5. GS>50KW FIXED-VARIABLE SPLIT

Festival's current proposal is to maintain the same fixed charge of $227.57/month for the GS>50kW rate class as existed prior to the Application. AMPCO, Board Staff, Energy Probe and VECC supported the continuation of the fixed monthly charge of $227.57. SEC was the only party seeking a reduction in the monthly fixed charge with the amount being the Minimum System with PLCC Adjustment Rate of $64.58/month.[50]

[50] These numbers were updated in accordance with the Updated RRWF in **Attachment A**. The Fixed Charge at Minimum with PLCC was updated from $64.55 to $64.58. The volumetric rates were also adjusted as per the RRWF.

Board Staff noted in support of Festival's approach that it was consistent with the 2015 Filing Requirements while Energy Probe also noted Festival's proposal was consistent with prior Board decisions on this issue. Festival submits its proposal is appropriate in the circumstances as it is consistent with Board policy, approach in the Large Use rate class and will maintain better rate stability.

Table 10. Comparison of GS>50kW: FHI Proposed v. Minimum PLCC[51]

	Monthly Fixed	**Volumetric Rate**
FHI - Fixed/Variable at 2015Proposed Rates	$227.57/mth	$2.4910per kW
Intervenor - At System Minimum with PLCC	$64.58/mth	$2.9620 per KW

The 2015 Filing Requirements deal specifically with this situation and provide the distributor with the option to maintain the current fixed charge. The 2015 Filing Requirements provide in section 2.11.1:

> *If a distributor's current fixed charge is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling.*

Festival's proposed in the original application dated May 29, 2014 to maintain fixed/variable splits for all rate classes which are close to our existing fixed variable splits. In Festival's view, there is no need to cause further fluctuations in bills by adopting splits that differ greatly from the existing splits. To demonstrate the fluctuations, Festival has prepared Table 11 below to show the shift in costs that would result for three customers under the two scenarios. Festival's proposal clearly results in less extreme bill impacts within the same rate class.

Table 11. Customer Charge Fluctuation Comparison

Customer Demand (A)	**Monthly Cost Existing (B)**	**Monthly Cost Festival (C)**	**Difference (D = B-C)**	**Monthly Cost Min. PLCC (D)**	**Difference (F = B-D)**
50kW	$344.22	$352.12	$7.90	$212.60	($131.62)
1000kW	$2,560.87	$2,718.57	$157.70	$3,026.58	$465.78
2500kW	$6,060.82	$6,455.07	$394.25	$7,469.58	$1,408.75

Festival would note that its proposal is also consistent with the methodology that was agreed to by the parties for the Large Use customer as part of the accepted Settlement Agreement.

[51] These numbers were updated in accordance with the Updated RRWF in **Attachment A**. The Fixed Charge at Minimum with PLCC was updated from $64.55 to $64.58. The volumetric rates were also adjusted as per the RRWF.

Festival does not believe it is appropriate to apply a fundamentally different approach to rate design for the GS>50kW rate class when a different, consistent and principled based approach has been agreed to as part of partial settlement for the Large Use class under the same circumstances.

Finally, Festival would note that in its review of 22 distributors for the 2013 Rate year that the average monthly charge for those utilities was $180.57 with a range from $69.54 to $375.40 for the GS>50kW rate class. With the SEC proposal Festival would be almost 10% below the lowest charge rather than in the middle of the range as it currently exists.

As such, Festival submits its rate design is consistent with Board policy, results in more stable charges to consumers, is consistent with the approach for other rate classes and within the existing range of charges for by other utilities for the same rate class. As such, Festival submits its proposal is superior to that of SEC.

6. **ICM – RATE RIDER**

The Board's Filing Guidelines requires a distributor that was approved for an ICM to come forward at its next cost of service proceeding with a "true-up". In order to understand the nature of the true-up it is useful to consider the sequence of events.

As Festival had rebased in 2010, it was scheduled to rebase in 2014. Festival applied to the Board in 2012 for the ICM for the new Transformer Station. Given Festival was scheduled to rebase in 2014, Festival had applied the half-year rule for the purpose of the ICM in accordance with the Board's expectations.

However, in January 2013, while the ICM proceeding was underway, Festival requested the Board defer rebasing until 2015. Subsequent to the request the Board issued Festival approval for the ICM and the rate rider was implemented effective May 1, 2013. At that time, Festival was unsure of the status for its request to defer rebasing and it did not amend its ICM application in respect of the half-year rule.

Following the issuance of the ICM decision, Festival learned that the Board had granted its request to defer rebasing. At about the same time, Festival realized it would incur OM&A costs in 2013 for the Transformer Station. Unsure how to account for such costs, Festival considered its experience with smart meters which allowed for the tracking of capital and OM&A in the same account [USoA #1555] and Z-factor events [USoA #1572] which also recorded capital and OM&A in the same account. Festival reasoned that the ICM account would work in the same manner in that all costs, capital and OM&A were tracked and would be subject to a prudence review during the true-up process. Festival sought advice in respect of the approach from Board Staff, who in an email confirmed Festival's approach was appropriate.[52] As such, Festival did not apply for a separate deferral account for OM&A for the transformer station but rather Festival tracked the costs which it expected to be reviewed prior to recovery and included in this Application.

6.1 **True-Up of Non-OM&A Items**

Festival had sought to recover $415,111 through a rate rider implemented over a 1 year period but has agreed the updated amount is $389,681. Energy Probe provides an acceptable description of the basis for the change in amount and supports Festival's recovery. AMPCO, Board Staff and SEC support the recovery of the $389,681.

VECC appears to agree with a portion of the true-up but then attempts to justify a clawback by stating that Festival had over-earned in prior years. Again, VECC has adopted the approach of anything to reduce costs rather than an approach founded in regulatory principles.

6.2 **True-Up of OM&A**

As part of its true-up, Festival has also sought recovery of certain new OM&A expenses, $244,815, related to the new Transformer Station. Energy Probe supported partial recovery of amounts related to expenses that had been identified in the ICM application as capital investments but were re-categorized as a result of the changing accounting rules. As identified by Energy Probe, Festival has incurred $39,826 in 2013 and forecasted $3,000 for 2014 in training costs that had been identified in EB-2012-0124 as capital but was ultimately accounted for as an expense.

Festival is of the view that it should be able to recover the entirety of the OM&A expenditures. Returning to fundamentals, utilities should be entitled to recover their prudently incurred costs and no party has suggested these costs were not prudent. Further, these costs allowed the energization of the new TS and the immediate savings for the customers in the RTSR. Festival would note that the use of a rate rider as an interim recovery measure requiring a true-up

[52] Oral Hearing Undertaking J1.5.

effectively renders the rate rider an interim rate. Given the interim nature of the rate rider, costs incurred during its existence are not prior period expenses but expenses incurred during the period in which final costs are being determined. Therefore, neither the timing of the costs nor the timing of the request for recovery of the costs should prohibit recovery in this case. Finally, Festival would note there is no express prohibition against recovery in the Board's 2015 Filing Guidelines.

Festival would note the Transformer Station was the first time it had applied for an ICM and there have been very few of these cases brought to the Board. In other cases decided by the Board, such as North Bay[53] and Hydro One[54] the Board took a principled approach to consider the circumstances to determine what was just and reasonable. Denying a utility the recovery of prudently incurred costs is not just and reasonable.

Festival would ask that the Board take a similar principled approach in the present case and not just reject the costs out of hand because of the timing of the request. Form should not triumph over substance. It bears noting that there has been no question that the expenses were prudently incurred and have resulted in the realization of more than $475,200 in customer benefits since December 2013 through the reduced RTSR charges. For those reasons, Festival requests approval to recover $244,815 for OM&A in 2013 and 2014 in relation to the new Transformer Station.

7. SUMMARY

Intervenors have requested recovery of 100% of their reasonable costs. Festival does not dispute that reasonable costs should be recovered. However, Festival reserves its rights to comment upon the reasonableness of the costs claimed until it receives such requests.

Festival requests the Board approve the following:

(a) Rate Base of $62,965,507 comprised of:

   a. $53,358,152 for net fixed assets; and

[53] EB-2007-0794, Decision, Ontario Energy Board, page 6.
[54] EB-2008-0187, Decision, Ontario Energy Board, page 9.

b. $9,607,355 in respect of Working Capital calculated in accordance with the Board's Filings Guidelines;

(b) Operating, Maintenance and Administration expenses of $5,156,282;

(c) A revenue requirement of $11,336,888;

(d) Retaining the fixed charge for the General Service Greater than 50kW rate class at $227.57 consistent with the Board's Filing Guidelines; and

(e) Rate riders for true-up for the construction of the new transformer station for both non-OM&A investments of $389,681[55] and OM&A costs of $244,815 to be recovered over 1 year.

All of which is respectfully submitted.

December **3**rd, 2014

Original signed by,

____

Scott Stoll
Counsel for Festival Hydro Inc.

20854889.1

[55] Festival had previously requested approval to recover $415,111 but updated Exhibit K2.1 (Updated) filed November 18, 2014, in which Festival revised its calculation to accord with Energy Probe's calculation.

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)	Adjustments		Argument-in-Chief	(6)	Adjustments		Per Board Decision	
1	**Rate Base**										
	Gross Fixed Assets (average)	$101,093,557		($7,863,626)	(1)	$ 93,229,931				$93,229,931	
	Accumulated Depreciation (average)	($47,443,019)	(5)	$7,571,240		($39,871,779)				($39,871,779)	
	Allowance for Working Capital:										
	Controllable Expenses	$5,144,253		($112,742)	(2)	$ 5,031,511				$5,031,511	
	Cost of Power	$67,551,604		$1,319,618		$ 68,871,222				$68,871,222	
	Working Capital Rate (%)	13.00%	(9)			13.00%	(9)			13.00%	(9)
2	**Utility Income**										
	Operating Revenues:										
	Distribution Revenue at Current Rates	$10,165,694		($12,057)		$10,153,637					
	Distribution Revenue at Proposed Rates	$11,115,311		($534,122)		$10,581,189					
	Other Revenue:										
	Specific Service Charges	$132,833		$0		$132,833					
	Late Payment Charges	$118,090		$0		$118,090					
	Other Distribution Revenue	$277,117		$0		$277,117					
	Other Income and Deductions	$227,659		$0		$227,659					
	Total Revenue Offsets	$755,699	(7)	$0		$755,699					
	Operating Expenses:										
	OM+A Expenses	$5,112,027		$44,255	(2)	$ 5,156,282				$5,156,282	
	Depreciation/Amortization	$2,522,288		($412,395)		$ 2,109,893				$2,109,893	
	Property taxes	$19,225				$ 19,225				$19,225	
	Other expenses	$13,000				13000				$13,000	
3	**Taxes/PILs**										
	Taxable Income:										
	Adjustments required to arrive at taxable income	($1,426,578)	(3)			($1,838,973)					
	Utility Income Taxes and Rates:										
	Income taxes (not grossed up)	$203,020				$123,386					
	Income taxes (grossed up)	$262,844				$167,872					
	Federal tax (%)	15.00%				15.00%					
	Provincial tax (%)	7.76%				11.50%					
	Income Tax Credits	($10,000)				($10,000)					
4	**Capitalization/Cost of Capital**										
	Capital Structure:										
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)				(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%					
	Prefered Shares Capitalization Ratio (%)										
		100.0%				100.0%					
	Cost of Capital										
	Long-term debt Cost Rate (%)	4.32%				4.18%					
	Short-term debt Cost Rate (%)	2.11%				2.16%					
	Common Equity Cost Rate (%)	9.36%				9.30%					
	Prefered Shares Cost Rate (%)	0.00%				0.00%					

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(1) Capital impact of compensation cost updates

(2) OM&A impact of compensation cost updates - $27,155, less fully allocated depreciation included in OM&A expenses - $156,997

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Argument-in-Chief	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$101,093,557	($7,863,626)	$93,229,931	$ -	$93,229,931
2	Accumulated Depreciation (average)	(3)	($47,443,019)	$7,571,240	($39,871,779)	$ -	($39,871,779)
3	Net Fixed Assets (average)	(3)	$53,650,538	($292,386)	$53,358,152	$ -	$53,358,152
4	Allowance for Working Capital	(1)	$9,450,461	$156,894	$9,607,355	$ -	$9,607,355
5	**Total Rate Base**		$63,100,999	($135,492)	$62,965,507	$ -	$62,965,507

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Argument-in-Chief	Adjustments	Per Board Decision
6	Controllable Expenses		$5,144,253	($112,742)	$5,031,511	$ -	$5,031,511
7	Cost of Power		$67,551,604	$1,319,618	$68,871,222	$ -	$68,871,222
8	Working Capital Base		$72,695,857	$1,206,876	$73,902,733	$ -	$73,902,733
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$9,450,461	$156,894	$9,607,355	$ -	$9,607,355

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Argument-in-Chief	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$11,115,311	($534,122)	$10,581,189	$ -	$10,581,189
2	Other Revenue	(1)	$755,699	$ -	$755,699	$ -	$755,699
3	Total Operating Revenues		$11,871,010	($534,122)	$11,336,888	$ -	$11,336,888
	Operating Expenses:						
4	OM+A Expenses		$5,112,027	$44,255	$5,156,282	$ -	$5,156,282
5	Depreciation/Amortization		$2,522,288	($412,395)	$2,109,893	$ -	$2,109,893
6	Property taxes		$19,225	$ -	$19,225	$ -	$19,225
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$13,000	$ -	$13,000	$ -	$13,000
9	Subtotal (lines 4 to 8)		$7,666,540	($368,140)	$7,298,400	$ -	$7,298,400
10	Deemed Interest Expense		$1,579,125	($50,826)	$1,528,299	$47,436	$1,575,734
11	Total Expenses (lines 9 to 10)		$9,245,665	($418,966)	$8,826,699	$47,436	$8,874,134
12	**Utility income before income taxes**		$2,625,345	($115,156)	$2,510,189	($47,436)	$2,462,754
13	Income taxes (grossed-up)		$262,844	($94,972)	$167,872	$ -	$167,872
14	**Utility net income**		$2,362,501	($20,184)	$2,342,317	($47,436)	$2,294,881

Notes

Other Revenues / Revenue Offsets

		Initial Application	Adjustments	Argument-in-Chief	Adjustments	Per Board Decision
(1)	Specific Service Charges	$132,833	$ -	$132,833		$132,833
	Late Payment Charges	$118,090	$ -	$118,090		$118,090
	Other Distribution Revenue	$277,117	$ -	$277,117		$277,117
	Other Income and Deductions	$227,659	$ -	$227,659		$227,659
	Total Revenue Offsets	$755,699	$ -	$755,699	$ -	$755,699

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Argument-in-Chief	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,362,501	$2,342,317	$2,357,429
2	Adjustments required to arrive at taxable utility income	($1,426,578)	($1,838,973)	($1,426,578)
3	Taxable income	$935,923	$503,344	$930,851
	Calculation of Utility income Taxes			
4	Income taxes	$203,020	$123,386	$123,386
6	Total taxes	$203,020	$123,386	$123,386
7	Gross-up of Income Taxes	$59,824	$44,486	$44,486
8	Grossed-up Income Taxes	$262,844	$167,872	$167,872
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$262,844	$167,872	$167,872
10	Other tax Credits	($10,000)	($10,000)	($10,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	7.76%	11.50%	11.50%
13	Total tax rate (%)	22.76%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
		Initial Application			
	Debt				
1	Long-term Debt	56.00%	$35,336,560	4.32%	$1,525,868
2	Short-term Debt	4.00%	$2,524,040	2.11%	$53,257
3	**Total Debt**	60.00%	$37,860,600	4.17%	$1,579,125
	Equity				
4	Common Equity	40.00%	$25,240,400	9.36%	$2,362,501
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$25,240,400	9.36%	$2,362,501
7	**Total**	100.00%	$63,100,999	6.25%	$3,941,627
		Argument-in-Chief			
	Debt				
1	Long-term Debt	56.00%	$35,260,684	4.18%	$1,473,897
2	Short-term Debt	4.00%	$2,518,620	2.16%	$54,402
3	**Total Debt**	60.00%	$37,779,304	4.05%	$1,528,299
	Equity				
4	Common Equity	40.00%	$25,186,203	9.30%	$2,342,317
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$25,186,203	9.30%	$2,342,317
7	**Total**	100.00%	$62,965,507	6.15%	$3,870,616
		Per Board Decision			
	Debt				
8	Long-term Debt	56.00%	$35,260,684	4.32%	$1,522,592
9	Short-term Debt	4.00%	$2,518,620	2.11%	$53,143
10	**Total Debt**	60.00%	$37,779,304	4.17%	$1,575,734
	Equity				
11	Common Equity	40.00%	$25,186,203	9.36%	$2,357,429
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$25,186,203	9.36%	$2,357,429
14	**Total**	100.00%	$62,965,507	6.25%	$3,933,163

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

		Initial Application		Argument-in-Chief		Per Board Decision	
Line No.	Particulars	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$949,615		$427,552		$495,548
2	Distribution Revenue	$10,165,694	$10,165,696	$10,153,637	$10,153,637	$10,153,637	$10,085,641
3	Other Operating Revenue Offsets - net	$755,699	$755,699	$755,699	$755,699	$755,699	$755,699
4	**Total Revenue**	$10,921,393	$11,871,010	$10,909,336	$11,336,888	$10,909,336	$11,336,888
5	Operating Expenses	$7,666,540	$7,666,540	$7,298,400	$7,298,400	$7,298,400	$7,298,400
6	Deemed Interest Expense	$1,579,125	$1,579,125	$1,528,299	$1,528,299	$1,575,734	$1,575,734
8	**Total Cost and Expenses**	$9,245,665	$9,245,665	$8,826,699	$8,826,699	$8,874,134	$8,874,134
9	**Utility Income Before Income Taxes**	$1,675,728	$2,625,345	$2,082,637	$2,510,189	$2,035,202	$2,462,754
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,426,578)	($1,426,578)	($1,838,973)	($1,838,973)	($1,838,973)	($1,838,973)
11	**Taxable Income**	$249,150	$1,198,767	$243,664	$671,216	$196,229	$623,781
12	Income Tax Rate	22.76%	22.76%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$56,707	$272,842	$64,571	$177,872	$52,001	$165,302
14	**Income Tax Credits**	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)
15	**Utility Net Income**	$1,629,021	$2,362,501	$2,028,066	$2,342,317	$1,993,201	$2,294,881
16	**Utility Rate Base**	$63,100,999	$63,100,999	$62,965,507	$62,965,507	$62,965,507	$62,965,507
17	Deemed Equity Portion of Rate Base	$25,240,400	$25,240,400	$25,186,203	$25,186,203	$25,186,203	$25,186,203
18	Income/(Equity Portion of Rate Base)	6.45%	9.36%	8.05%	9.30%	7.91%	9.11%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.30%	9.30%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-2.91%	0.00%	-1.25%	0.00%	-1.45%	-0.25%
21	Indicated Rate of Return	5.08%	6.25%	5.65%	6.15%	5.67%	6.15%
22	Requested Rate of Return on Rate Base	6.25%	6.25%	6.15%	6.15%	6.25%	6.25%
23	Deficiency/Sufficiency in Rate of Return	-1.16%	0.00%	-0.50%	0.00%	-0.58%	-0.10%
24	Target Return on Equity	$2,362,501	$2,362,501	$2,342,317	$2,342,317	$2,357,429	$2,357,429
25	Revenue Deficiency/(Sufficiency)	$733,481	($0)	$314,251	$0	$364,228	($62,547)
26	**Gross Revenue Deficiency/(Sufficiency)**	$949,615 **(1)**		$427,552 **(1)**		$495,548 **(1)**	

Notes:
(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Argument-in-Chief		Per Board Decision	
1	OM&A Expenses	$5,112,027		$5,156,282		$5,156,282	
2	Amortization/Depreciation	$2,522,288		$2,109,893		$2,109,893	
3	Property Taxes	$19,225		$19,225		$19,225	
5	Income Taxes (Grossed up)	$262,844		$167,872		$167,872	
6	Other Expenses	$13,000		$13,000		$13,000	
7	Return						
	Deemed Interest Expense	$1,579,125		$1,528,299		$1,575,734	
	Return on Deemed Equity	$2,362,501		$2,342,317		$2,357,429	
8	**Service Revenue Requirement (before Revenues)**	$11,871,010		$11,336,888		$11,399,435	
9	Revenue Offsets	$755,699		$755,699		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$11,115,311		$10,581,189		$11,399,435	
11	Distribution revenue	$11,115,311		$10,581,189		$10,581,189	
12	Other revenue	$755,699		$755,699		$755,699	
13	**Total revenue**	$11,871,010		$11,336,888		$11,336,888	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	$0	(1)	($62,547)	(1)

Notes

(1) Line 11 - Line 8

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BY E-MAIL AND WEB POSTING

November 20, 2014

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2015 Cost of Service and Custom Incentive Rate-setting Applications

Re: Cost of Capital Parameter Updates for 2015 Applications

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2015 applications. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Cost of Capital Report"), issued December 11, 2009.

Cost of Capital Parameters for 2015 Rates

For rates with effective dates in 2015, the Board has updated the Cost of Capital parameters based on: (i) the September 2014 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low or A:- (A-stable) commercial customers, for the Short-Term debt rate; and (ii) data three months prior to January 1, 2015 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LP, for all Cost of Capital parameters.

The Board has determined that the updated Cost of Capital parameters for 2015 rate applications for rates effective in 2015 are:

Cost of Capital Parameter	Value for 2015 Applications for rate changes in 2015
ROE	9.30%
Deemed LT Debt rate	4.77%
Deemed ST Debt rate	2.16%

Detailed calculations of the Cost of Capital parameters are attached.

The Board considers the Cost of Capital parameter values shown in the above table, and the relationships between them, to be reasonable and representative of market conditions at this time.

As documented in the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379) issued November 21, 2013, the Board now updates Cost of Capital parameters for setting rates only once per year. For this reason, the Cost of Capital parameters above will be applicable for all cost of service and custom IR applications (as applicable) with rates effective in the 2015 calendar year.

The Board monitors macroeconomic conditions and may issue updated parameters if economic conditions materially change. An applicant or intervenors can also file evidence in individual rate hearings in support of different Cost of Capital parameters due to the specific circumstances, but must provide strong rationale and supporting evidence for deviating from the Board's policy.

All queries on the Cost of Capital parameters should be directed to the Board's Industry Relations hotline, at 416 440-7604 or industryrelations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(For rate changes effective in 2015)

Cost of Capital Parameter Calculations

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2014

	Day	Bond Yields (%) Government of Canada 10-yr	Government of Canada 30-yr	A-rated Utility 30-yr	Bond Yield Spreads (%) 30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
1	1-Sep-14					
2	2-Sep-14	2.09	2.64	4.04	0.55	1.40
3	3-Sep-14	2.09	2.63	4.03	0.54	1.40
4	4-Sep-14	2.12	2.66	4.06	0.54	1.40
5	5-Sep-14	2.11	2.67	4.06	0.56	1.39
6	6-Sep-14					
7	7-Sep-14					
8	8-Sep-14	2.14	2.68	4.07	0.54	1.39
9	9-Sep-14	2.17	2.70	4.09	0.53	1.39
10	10-Sep-14	2.20	2.72	4.11	0.52	1.39
11	11-Sep-14	2.20	2.72	4.11	0.52	1.39
12	12-Sep-14	2.24	2.76	4.15	0.52	1.39
13	13-Sep-14					
14	14-Sep-14					
15	15-Sep-14	2.23	2.76	4.15	0.53	1.39
16	16-Sep-14	2.24	2.77	4.16	0.53	1.39
17	17-Sep-14	2.26	2.79	4.18	0.53	1.39
18	18-Sep-14	2.28	2.79	4.18	0.51	1.39
19	19-Sep-14	2.25	2.76	4.14	0.51	1.38
20	20-Sep-14					
21	21-Sep-14					
22	22-Sep-14	2.22	2.74	4.11	0.52	1.37
23	23-Sep-14	2.17	2.72	4.09	0.55	1.37
24	24-Sep-14	2.20	2.73	4.10	0.53	1.37
25	25-Sep-14	2.15	2.68	4.05	0.53	1.37
26	26-Sep-14	2.16	2.68	4.06	0.52	1.38
27	27-Sep-14					
28	28-Sep-14					
29	29-Sep-14	2.13	2.65	4.04	0.52	1.39
30	30-Sep-14	2.15	2.67	4.06	0.52	1.39
31						
		2.18	2.71	4.10	**0.530**	**1.386**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts*	Publication Date:	September-08-14	
	3-month	12-month	Average
September 2014	2.500	3.200	❸ **2.850** %

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	2.850 %
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.530 %
Long Canada Bond Forecast (LCBF)	❹	**3.380** %

Step 4: Return on Equity (ROE) forecast

Initial ROE			9.75 %
Change in Long Canada Bond Yield Forecast from September 2009			
LCBF (September 2014) (from Step :	④	3.380 %	
Base LCBF		4.250 %	
Difference		-0.870 %	
0.5 X Difference			-0.435 %
Change in A-rated Utility Bond Yield Spread from September 2009			
A-rated Utility Bond Yield Spread (September 2014) (from Step 1)	②	1.386 %	
Base A-rated Utility Bond Yield Spread		1.415 %	
Difference		-0.029 %	
0.5 X Difference			-0.015 %
Return on Equity based on September 2014 data			**9.30** %

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2014 (from Step 3)	④	3.380 %
A-rated Utility Bond Yield Spread September 2014 (from Step 1)	②	1.386 %
Deemed Long-term Debt Rate based on September 2014 data		**4.77** %

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations
(For rate changes effective in 2015)

Cost of Capital Parameter Calculations
Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in September, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	Average Spread over 90-day Bankers Acceptance		Date of input
Bank 1	100.0	bps	Sept., 2014
Bank 2	100.0	bps	Sept., 2014
Bank 3	82.5	bps	Sept., 2014
Bank 4	80.0	bps	Sept., 2014
Bank 5	100.0	bps	Sept., 2014
Bank 6			

B. Discard high and low estimates
If less than 4 estimates, take average without discarding high and low.

Number of estimates	5	
High estimate	100.0	bps
Low estimate	80.0	bps

C. Average annual Spread	94.167	bps	❶

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2014

Month:		**September 2014**	
	Day	**Bankers' Acceptance Rate (%) 3-month**	
1	1-Sep-14	Bank holiday	%
2	2-Sep-14	1.21	%
3	3-Sep-14	1.21	%
4	4-Sep-14	1.21	%
5	5-Sep-14	1.21	%
6	6-Sep-14		
7	7-Sep-14		
8	8-Sep-14	1.21	%
9	9-Sep-14	1.21	%
10	10-Sep-14	1.22	%
11	11-Sep-14	1.22	%
12	12-Sep-14	1.22	%
13	13-Sep-14		
14	14-Sep-14		
15	15-Sep-14	1.22	%
16	16-Sep-14	1.22	%
17	17-Sep-14	1.22	%
18	18-Sep-14	1.22	%
19	19-Sep-14	1.21	%
20	20-Sep-14		
21	21-Sep-14		
22	22-Sep-14	1.21	%
23	23-Sep-14	1.21	%
24	24-Sep-14	1.21	%
25	25-Sep-14	1.21	%
26	26-Sep-14	1.21	%
27	27-Sep-14		
28	28-Sep-14		
29	29-Sep-14	1.22	%
30	30-Sep-14	1.22	%
31			
		1.214 ❷	%

Source Bank of Canada / Statistics Canada Series V39071

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	0.942	%	➀
Average Bankers' Acceptance Rate	1.214	%	➁
Deemed Short Term Debt Rate	**2.16**	%	

Reference on Calculation Method:
- Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

1. UNDERTAKING NO. JT1. 14:

Ref: Page 50

To provide a letter from Festival's auditor that under IFRS a bypass agreement would be considered an intangible asset.

Response:

Festival again contacted our auditors regarding a letter and their response was that they prefer not to provide an opinion to a governing body on a single accounting decision. As noted, in our previous submissions, the auditors have issued an unqualified opinion on the 2013 financial statements, which presents the permanent bypass as an intangible asset.

The discussion to date has related to whether the permanent bypass constitutes an intangible asset. At the technical conference, it was suggested by Board staff that it may be considered a penalty (i.e. expense). To support Festival's arguments for intangible asset treatment, as opposed to an expense or penalty item, the following analysis of assets versus expenditures is being presented.

Background

Festival Hydro Inc. ("Festival") constructed a new TS Station in Stratford. Festival's new TS Station was put into operation in December 2013, and had the capacity to service customers previously serviced by a Hydro One Inc. ("HONI") TS Station. Festival desired to connect these customers to its new TS Station in order to improve their service and reliability.

In order to energize the Festival TS Station and connect these customers by by-passing the HONI Stratford Station, Festival was given two options; a temporary or permanent by-pass agreement with HONI. Management's analysis showed that with the temporary by-pass arrangement, Festival had to ensure there was no loss revenue to HONI, so from a customer's financial perspective the customer was indifferent as to the bypass arrangement. However, through the $1.2 million permanent by-pass agreement, customers would receive an annual net benefit of $475,000 through a reduction of transmission connection charges to customers.

As the permanent by-pass agreement option provided a generous benefit to customers, Festival entered into an agreement with HONI to pay approximately $1,230,000 for the right to by-pass 20 MW of load from the HONI TS Station. The by-pass charge is directly related to both the capital spend on the new TS Station (i.e. the charge would not have been incurred if the new TS Station had not been built), the future benefit to customers (the permanent by-pass option benefits customers approximately $475,000 annually), and Festival's ability to improve service and reliability to its customers.

Accounting Treatment

Does the permanent by-pass charge represent an asset or expenditure?

Under Canadian GAAP, Part IV of the CPA Canada Handbook – Accounting:

1000.29 Assets are economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained.

1000.30 Assets have three essential characteristics:

(a) they embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows, and, in the case of not-for-profit organizations, to provide services;

(b) the entity can control access to the benefit; and

(c) the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

In Festival's case, the by-pass charge meets the definition of an asset. Only by payment of the permanent by-pass charge can the net benefit of future cash flows be realized. In addition, Festival controls the TS Station, by virtue of ownership. Customers cannot be connected through the TS Station unless Festival allows the connection, and cannot earn the financial benefit without the existence of the permanent bypass and existence of the TS itself. The transaction giving the right to or control of, the benefit occurred when the TS Station was put into operation and the by-pass agreement signed in December of 2013.

If we compare the definition of an asset to an expense, alternatively, expenses are defined in CPA HBV 1000.38 as:

Decreases in economic resources, either by way of outflows or reduction of assets or incurrences of liabilities, resulting from an entity's ordinary revenue generating or service delivery activities.

As expenses typically relate to the performance of service or revenue generating activities, they would typically be recorded when the full benefit of any outlay has been realized (i.e. revenue has been generated, or an asset has been used to completion). An expense could also be incurred if the future benefits from the expense could not be measured reliably.

In the case of the by-pass agreement charge, the outlay cannot be an expense as the charge provides the right to recover future cash flows from providing service to customers. The benefit of the charge will be realized in the current year and many future dates. This benefit can also be forecasted reliably by management. Furthermore, it is the future potential of revenue generation or service delivery activities that led to the charge, not current revenue or service delivery activities.

<u>What is the nature of the payment?</u>

It should also be considered as to what the actual by-pass charge is for. The calculation of the by-pass charge shows that the payment relates primarily to lost future transmission for HONI as the decommissioning costs are actually less than the salvage value of the HONI TS Station. If the decommissioning cost was higher than salvage, we would expect that a portion of the payment would be for past service used; however, this is not the case. As a result, it appears that Festival is paying for lost future transmission by HONI (essentially the right to the customer base). This is more indicative of an asset which relates to future economic benefit than an expense.

<u>Future Treatment under existing IFRS Standards</u>

The IFRS definition of an asset is more detailed, however, less prescriptive (IFRS "The conceptual framework for financial reporting – Chapter 4.8 – Assets"). Under IFRS, assets embody future economic benefits and result from a past transaction or event. However, control does not necessarily need to be established in order for an asset to exist.

Under existing IFRS standards, it is reasonable that the permanent by-pass charge would also be considered an asset.

Is the Payment to HONI an Intangible asset or an item of Property Plant and Equipment?

Property, Plant and Equipment ("PP&E")

Under Canadian GAAP, Part IV of the CPA Canada Handbook – Accounting:

3061.04, PP&E are identifiable tangible assets that meet all of the following criteria:

(a) are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other property, plant and equipment;

(b) have been acquired, constructed or developed with the intention of being used on a continuing basis; and

(c) are not intended for sale in the ordinary course of business.

The by-pass charge, in and of itself, does not appear to directly meet the above criteria as it lacks physical substance (i.e., not tangible). However, the new transformer station that was constructed does meet this definition.

Under 3061.10, rate regulated PP&E are items of PP&E held for use in operations meeting all of the following criteria:

(a) The rates for regulated services or products provided to customers are established by or are subject to approval by a regulator or a governing body empowered by statute or contract to establish rates to be charged for services or products.

(b) The regulated rates are designed to recover the cost of providing the services or products.

(c) It is reasonable to assume that rates set at levels that will recover the cost can be charged to and collected from customers in view of the demand for the services or products and the level of direct and indirect competition. This criterion requires consideration of expected changes in levels of demand or competition during the recovery period for any capitalized costs.

Based on our understanding of the use of the transformer station and the rate setting process, it is reasonable to assume that the transformer station itself is an item of rate regulated PP&E.

CPA Canada HBV 3061.05 defines the cost as "the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use".

Further guidance as to what is included in the cost of PP&E is provided in CPA Canada HBV 3061.17 as follows:

Purchase price and other acquisition costs such as option costs when an option is exercised, brokers' commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges.

While the Standard doesn't specially list by-pass costs, it is clear that the expenditure on the permanent bypass would not have occurred without the existence of the new transformer station into service; and can be argued that the charge is directly attributable.

Further to be considered is the recoverable amount of the charge, if included in PP&E. Assuming the regulator will permit the inclusion of the charge as a component of PP&E for the purposes of rate setting, it is reasonably certain that the amount will be recovered in future periods.

Intangible Asset

Since the by-pass charge lacks physical substance, it should be considered whether the charge is representative of an intangible asset.
CPA Canada HBV 3064.04 provides guidance with respect to the classification between PP&E and intangible assets:
Standards for the recognition, measurement, presentation and disclosure of tangible capital assets are provided in PROPERTY, PLANT AND EQUIPMENT, Section 3061. Some intangible assets may be contained in or on a physical substance such as a compact disc (in the case of computer software), legal documentation (in the case of a license or patent) or film. In determining whether an asset that incorporates both intangible and tangible elements should be treated under Section 3061 or as an intangible asset under this Section, an entity uses judgment to assess which element is more significant. For example, computer software for a computer-controlled machine tool that cannot operate without that specific software is an integral part of the related hardware and it is treated as property, plant and equipment. The same applies to the operating system of a computer. When the software is not an integral part of the related hardware, computer software is treated as an intangible asset.

In Festival's case, the by-pass charge is a payment to compensate for the decommissioning of the existing asset or cost associated with the stranded asset. As it has been argued in the PPE discussion, this was a critical payment with the purpose of creating future economic benefits to Festival Hydro and to its customers. As a result, it may be more appropriate to recognize the by-pass charge as an asset separate from the TS Station.
CPA Canada HBV 3064.11 describes the criteria for recognition of intangible assets. First, an intangible asset needs to meet the definition of an intangible asset (identifiable, control, future economic benefits). Second, the recognition criteria must be met.

In meeting the definition criteria, identifiability is met as the by-pass charge arose from a contractual right (3064.12(b)). Control over future economic benefits has been established by virtue of ownership of the TS station and the payment of the by-pass fee, which gives Festival control over servicing the customer base. Finally, future economic benefits are expected from the by-pass agreement payment both to Festival, in being able to service customers reliably, and to the customers in terms of future savings. This is not possible without the payment to HONI, as is the situation in the temporary bypass arrangement.

The by-pass charge meets the recognition criteria (3064.21-23) since it is probable that the expected future economic benefits attributable to the asset will flow to the entity and the cost of the asset is measured reliably. As previously discussed, future economic benefits will be received as a result of the by-pass agreement, primarily through obtaining new customers. The cost of the asset is measured reliably as it is outlined in a calculation as part of the by-pass agreement.

Conclusion on classification
The nature of the by-pass payment is that it could be treated as either an intangible asset or PPE. The payment is for a right to access customers and obtain future economic benefit for Festival. This would lead towards treatment as a definite life intangible asset as the asset meets the criteria for recognition. Separate treatment from the PPE TS Station asset may be desirable as it would better highlight the

underlying nature of the transaction and seems to comply more reasonably with the guidance in 3064 & 3061. However, the asset could also be reclassified to PPE and shown as a component of the TS Station, since the asset would not exist without the existence of the TS. In either event, the amortization of the asset would be consistent with the TS Station itself and would not have an impact on the amortization affecting the Statement of Operations. Furthermore, whether the classification should be PPE or Intangible is not significant or material to the financial statements as both asset classifications are long-term.

Treatment under current IFRS
The treatment for recognition of PPE (IAS 16.7) under IFRS is similar to CPA HB V. Assets are recognized as PPE when it is probable that future economic benefits associated with the item will flow to the entity and the cost of the item can be measured reliably. As discussed above, both of these arguments are met. Furthermore IAS16.11 indicates that initial costs may be PPE if they are directly or indirectly related to items of PPE to obtain future economic benefits. Under the current standards it is reasonable to assume that the asset would be able to be recognized as PPE under IAS16.
Similarly, IAS 38.11-24 Intangible Assets currently set out the same criteria as CPA HBV – 3064 (identifiability, control, future economic benefit, etc.). The guidance in both handbooks point to the asset meeting the recognition criteria. As we have noted above in the CPA HBV-3064 section, the following (IAS38.21-22) has been met as well using the same arguments:
IAS38.21 An intangible asset shall be recognized if, and only if:
(a) it is probable that the expected future economic benefits that are attributable to the asset will flow to the entity; and
(b) the cost of the asset can be measured reliably.
IAS38.22 An entity shall assess the probability of expected future economic benefits using reasonable and supportable assumptions that represent management's best estimate of the set of economic conditions that will exist over the useful life of the asset.

Additional considerations
The OEB has issued the Accounting Procedures Handbook ("APH") for Electricity Distributors in order to provide guidance in accounting for transactions. The following are excerpts from the APH related to intangible assets:

Article 220 (Balance Sheet Accounts) describes intangible assets:

1609 Capital Contributions Paid

This account shall include capital contributions paid by a distributor to a host distributor, a transmitter or a generator for capital expenditures (e.g., under a Connection and Cost Recovery Agreement) that meet the IAS 38 Intangible Assets requirements for classification as an intangible asset.

1610 Miscellaneous Intangible Plant

This account shall include the cost of patent rights, licenses, privileges, capitalizable load profile development costs and other intangible property necessary or valuable in the conduct of utility operations and not specifically chargeable to any other account.

Article 410 (Property, Plant and Equipment and Intangible Assets) of the OEB Accounting Procedures Handbook describes accounting for contributions in aid of construction and states:

Contributions paid by a distributor: in some cases distributors will incur expenditures for amounts paid to other distributors or transmitters for capital projects. Distributors who incur such costs, should record the amounts in USoA Account 1609, Intangible Assets – Capital Contributions Paid.

Expenses

The APH does not provide guidance specific to 'penalty payments'.

It is reasonable to conclude that the APH guide suggest using 1609 Capital Contributions Paid (an intangible account). While the payment was not directly attributed to a capital project of another distributor, it was a payment to HONI to facilitate the full operation of the asset Festival constructed and the asset meets the requirements of IAS38.

Conclusion

It is Festival's opinion that after review of the transaction facts and applicable accounting guidance, the transaction embodies the characteristics of an asset and not an expense. Furthermore, the asset meets the definition of an intangible asset under CGAAP and IAS38. The asset could also be considered part of the PPE costs required to get the asset ready for its intended use. However, for accounting purposes, the impact to the financial statements would not be significantly different, aside from the intangible being reported on a separate line item than PPE.

The other factor that needs emphasized is that Festival entered in to this permanent bypass arrangement for the financial benefit to the customer. From Festival's perspective, the transfer of 20 MWh of load represents benefits interms of improved service and reliability. Not to forget, Festival could have entered into a temporary bypass which would have been revenue natural for customers and achieved the same results for Festival. Festival made a conscious decision to add this asset to their rate base and to invest the $1.2 million so as to pass along the $475,000 annual savings to its customers. It is arguably a good investment in terms of return on investment from the customer's perspective. And it would have ben imprudent for Festival not to undertake this transaction and be able to pass along these savings to he customers.

Festival had not looked into any other Board document or policy on guidance as to where the permanent bypass should be classified because Festival was confident it met the definition of an intangible asset and that it also met the criteria of USoA # 1609.

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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

November 15, 2013

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700,
2300 Yonge Street
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Notice of Intention to Bypass at Stratford TS pursuant to TSC 6.7.10

Section 6.7.10 of the Transmission System Code requires that the transmitter notify the Board upon becoming aware that a load customer that is a distributor intends to bypass a transmitter-owned connection facility.

Hydro One Networks Inc. ("Hydro One") has received the attached letter from Festival Hydro Inc. ("Festival Hydro") regarding Festival Hydro's intention to transfer, by the end of 2013, approximately 20 MW of existing load from Hydro One's Stratford TS to Festival Hydro's newly constructed Festival MTS #1. Hydro One intends to seek bypass compensation from Festival Hydro, in accordance with section 6.7 of the Transmission System Code.

Please advise if you require any further documentation or information from Hydro One.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Festival Hydro INC
P.O. Box 397, Stratford, Ontario N5A 6T5

187 ERIE STREET STRATFORD
TELEPHONE: 519-271-4700
TOLL-FREE: 1-866-444-9370
FAX: 519-271-7204
www.festivalhydro.com

September 30, 2013

Hydro One
483 Bay Street
14th Floor, North Tower
Toronto, Ontario
M5G 2P5

Attention: Brad Colden

Dear Brad:

Following discussion with Hydro One staff, this letter confirms that it is Festival Hydro's intention to bypass a portion of the load currently supplied by the Stratford Transformer Station owned and operated by Hydro One. We estimate Festival Hydro will be permanently bypassing approximately 20 MW by transferring this load to the newly constructed Festival MTS#1. This load transfer will start in mid-October and should be complete by the end of December 2013.

In accordance with the Transmission System Code, we understand that compensation to Hydro One is required for this permanent bypass and confirm that we are working toward executing an equitable agreement with Hydro One before the end of 2013.

If you have any questions about our plans regarding this permanent bypass, please let me know.

Sincerely,

FESTI HYDRO INC.

c Vanderbaan, P.Eng., CMA
Chief Operating Officer