EB-2014-0073

Ontario Energy Board

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 or just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015.

VULNERABLE ENERGY CONSUMERS COALITION ("VECC") CROSS-EXAMINATION COMPENDIUM

November 14, 2014

FESTIVAL HYDRO INC.

2015 RATE APPLICATION

(EB-2014-0073)

VECC COMPENDIUM

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	T

TAB 1

RATE BASE

b) The phases in the GIS implementation have yet to be planned out. Much of this work will be completed based on the system chosen from the RFP process. FHI will look to reduce costs and timelines through shared services with the municipality or other utilities were possible.
c) FHI plans to include all asset groups within the GIS system, including: poles, transformers, switchgear and underground cable.

50. 2. AMPCO 7

Ref: Exhibit 2, Tab 1, Schedule 11, Page 9

a) Please discuss if the focus during spring, summer and fall months on capital will have any impact on maintenance spending in 2014.

b) Please provide the actual capital in-service additions to date and the forecast to year end for 2014.

Response:

a) It's customary that FHI has a heavier O&M focus on the first two quarters of the year with a shift to capital spending in the summer and fall months. This should cause no issues in the overall 2014 maintenance spending

b) The following projects have already been completed

Brunswick Street
CN Road
Dunedin
Queen and Albert Street

Projects to be completed in Q3
Mornington St
Remove M5 Feeder
Elgin Street
Underground Drill – Britannia at Fairgrounds

Projects to be completed in Q4
Re-insulate
Church St. N & Egan
Center Street (OH and UG)
MS#8
Switchgear
Vault Repair

51. 2. AMPCO 8

26. UNDERTAKING NO. JT1. 25:

Ref: Page 94

To update appendix 2AA to show the latest in-service additions for 2014 and reconcile them to AMPCO7(B).

Response:

Capital additions to the end of August (latest capital update) are included in Appendix JT1.25. The submission for Ampco 7(b) is included below with changes highlighted since the last update.

The following projects have already been completed
Brunswick Street
CN Road
Dunedin
Queen and Albert Street

Projects to be completed in Q3
Mornington St (will complete in Q4)
Remove M5 Feeder
Elgin Street (complete)
Underground Drill – Britannia at Fairgrounds (complete)

Projects to be completed in Q4
Re-insulate
Church St. N & Egan
Center Street (OH and UG)
MS#8
Switchgear
Vault Repair

27. UNDERTAKING NO. JT1. 26:

Ref: Page 104

To break out 2010 costs for Training, Unallocated Engineering, Operations, Supervision and Truck Stores.

Response:

For the comparative purpose of this question – the analysis in the table below identifies the overhead allocated to each cost category from appendix 2JC and all other costs included in each cost category for 2010 – 2015. In this way – it is clear what the impact is of overhead allocation changes on each cost category, versus direct cost changes.

Appendix 2-AA
Capital Projects Table

Projects	2010	2011	2012	2013	2014 Bridge Year	2014 Year to date	2015 Test Year
Reporting Basis							
System Access							
Subdivisions	199,708		240,986	40,177			
Customer Connection/Extension		305,005		88,353			
Goderich St reet E (LTLT)			60,719				
Capital Additions					200,000	28,894	204,000
New Upgraded Services					115,000	66,934	117,500
Sub-Total	199,708	305,005	301,705	128,530	315,000	95,828	321,500
Miscellaneous	86,160	134,981	201,417	143,697			
Project Total	**285,868**	**439,986**	**503,122**	**272,227**	**315,000**	**95,828**	**321,500**
General Plant							
Truck 4 - Single Bucket	226,311						
Truck 22 - Backhoe		75,425					
Computer Equipment		76,969	90,259	293,712	290,000	60,686	245,000
Truck #2 - RBD			322,414				
Land and Buildings					80,000	0	90,000
Electric Vehicle							70,000
Sub-Total	226,311	152,394	412,673	293,712	370,000	60,686	405,000
Miscellaneous	132,855	67,012	92,614	111,496	90,000	8,628	95,000
Project Total	**359,166**	**219,406**	**505,287**	**405,208**	**460,000**	**69,314**	**500,000**
System Renewal							
Centre St. & Helen St. - spun secondary	$104,383						
Cobourg Area 1F1 Phase 2 - conversion	$303,048						
Delamere (Mornington to Romeo)	$229,748						
St. George St.	$154,788						
9M4 - Northwest Section	$182,440						
Brantford - rear lot conversion	$73,024						
Transformers	$203,773	$188,460	$93,776	$232,841	$200,000	$110,311	$205,000
Distribution Meters	$198,305	$147,080	$152,023	$91,138	$190,000	$28,280	$175,000
Switchgear at MS#1	$66,713						
St. David Rebuild (Downie to Church)		$194,855					
Devon St. Rebuild (Romeo to T.S.)		$177,240					
Lorne Ave. W. Rebuild (Boyd to St. Vincent)		$305,866					
9M4-Northwest Section Ph 2		$113,385					
Cemetery @ Charles St.		$63,412					
Market St. Rebuild (High to deadend)		$66,917					
Flora St. to Turnberry St.		$180,012					
M.S. #8 Phase 1 - Conversion		$170,086					
Packham Road - Rebuild (3ph double circuit)			$320,190				
Park Street Rebuild (east of Romeo)			$74,838				
M1 Feeder - Cemetry to James St. South			$146,227				
Turnberry Rebuild (Flora to PME)			$170,856				
West Gore Rebuild (John to Sewage Plant)				151,110			
Victoria Street M4 Rebuild (RRX to Wellington)				85,535			
Jones St W Rebuild & Salina St S				160,436			
Queen St. Rebuild				177,154			
Sports Drive, Thomas & Maple				123,534			
Brunswick Street (Romeo to Queen)					$145,000	$190,958	
Mornington St. Rebuild (Delamere to Quinlan)					$255,000	$107,412	
Elgin St (Ontario to West End & Warner)					$130,000	$106,644	
Chuch St. N. & Egan St.					$110,000	$22,541	
CN Road, Princess St., Albert St.					$100,000	$90,616	
Dunedin Drive Rebuild (Turnberry to Burgess)					$65,000	$38,919	
M.S. #8 Ph 2					$180,000	$6,690	
M8 Feeder Rebuild (Ontario to Douro)							$125,000
Trinity Street (Brunswick to Regent)							$90,000
King Street (Albert to Douro)							$60,000
Elgin Street (Church to James)							$90,000
Jones Street (James to Church & Peel)							$60,000
John Street (High St to Sparling)							$75,000
Jarvis Street & Lloyd Eisler St.							$150,000
M.S. #9 Conversion Ph 1							$230,000
Sub-Total	1,516,223	1,607,313	957,911	1,021,748	1,375,000	702,371	1,260,000
Miscellaneous	600,713	698,955	802,002	1,014,652	313,000	155,647	230,000
Project Total	2,116,936	2,306,268	1,759,913	2,036,400	1,688,000	858,018	1,490,000
System Service							
Wrigt Blvd. Extension & Gibb Road tie line	$159,056						
TS Conduit	$142,562						
Switchgear Replacement			259,867	112,695	110,000		110,000
Line Re-insulation			232,385	98,812	150,000	84,841	150,000
O'Loane Feeder Tie				306,280			
Forman Feeder Tie				132,318			
Sub-Total	301,618	0	492,252	650,105	260,000	84,841	260,000
Miscellaneous	76,215	93,154	30,839	23,847	50,000	13,281	50,000
Project Total	377,833	93,154	523,091	673,952	310,000	98,122	310,000
Total	**3,139,803**	**3,058,814**	**3,291,413**	**3,387,787**	**2,773,000**	**1,121,282**	**2,621,500**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*							
Total	**3,139,803**	**3,058,814**	**3,291,413**	**3,387,787**	**2,773,000**	**1,121,282**	**2,621,500**
Notes:							

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category.

TAB 2

46. 2. OEB STAFF 23

Ref: E2/T2/S1/Att. 1/Appendix 4/p. 15 and Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, March 28, 2013/pp. 16 -17 – 5.4.5.2 Material Investments – Distribution Transformers

At the first reference the "2015 Board Capital Plan" under "Transformers", it is indicated that $205,000 is needed to meet load growth, replacements, conversions and new development. This indicates that the "Transformer" investment can be split between the three main categories namely: System Access; System Renewal; and System Service.

At the second reference it is stated that:

Despite the 'multi-purpose' character of a project or activity, for 'summary' purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or 'trigger') driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. [emphasis added]

a) Please allocate the $205,000 cost of transformers among the various projects included for the 2015 Test Year as outlined in Appendix 4 as well as the sum total for each of the three noted categories - namely System Access; System Renewal; and System Service.

Response:

a) For the $205,000 identified in transformer purchases for the 2015 Test year it is expected that $56,500 will be for System Access, $60,750 will be for System Service and $87,750 for System Renewal based on known work and historical forecasts.

47. 2. OEB STAFF 24

Ref: E2/T2/S1/Att. 3, Appendix 2-AA and E2/T2/S1/Att. 1/p. 65 – 5.4.5.2 Material Investments – Smart Meters

At the first reference for Distribution Meters, it shows historical capital expenditures for 2010 to 2013, and forecast for the bridge year (2014) and the 2015 Test Year. For convenience the relevant portion covering Distribution Meters from Appendix 2-AA, is shown below:

	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year
Distribution Meters	$198,000	$147,080	$152,023	$91,138	$190,000	$175,000

At the second reference it is stated in part that:

The main drivers for distribution meters are failure and mandated service obligations. This value takes into account historical growth rates and potential meter replacements as part of non-warranty smart meter failures. Festival Hydro smart meters have experienced a failure rate of 7.5% per year since their installation in 2011. These failures are for the most part still being covered by Trilliant outside of the warranty period, but it is unclear how long this may continue. Given the uncertainty of warranty coverage FHI is budgeting 26% of its metering budget to the replacement of failed smart meters.

a) Please indicate whether or not FHI received any warranty from Trilliant for the Smart Meters? If not, please elaborate as the reasons for not receiving such a warranty.
b) Is the failure rate of 7.5% per year in the range experienced by other Distributors?
c) Please provide the number of Smart Meter failures from January 1, 2014 to present date? Please indicate whether or not Trilliant charged FHI for the cost of replacing these Smart Meters.
d) What is the total number of smart meters installed by FHI in 2011, and what is the installed cost per meter, broken to (Meter & Material) and labour.

Response:

a) Trilliant provided a one year warranty on defective meters. The warranty only covers the replacement of the meter and does not cover the labour or shipping costs associated with a warranty exchange.

b) FHI cannot speak to the failure rates for all other distributors, but based on some discussions had with some distributors the current Trilliant failure rate seems to exceed the expected industry failure rate.

c) From Jan 1 2014 to present there have been 600 meter failures. Trilliant has covered the cost of repair of all but 19 meters. (again Trilliant only covers the meter costs)

d) There were 104 meters installed by FHI in 2011. Meter costs were $40,275 and labour costs were $7,226. The equals a per meter cost of $387 and an installation cost of $69.

48. 2. OEB STAFF 25

Ref: E2/T2/S1/Att. 1/p. 68 & Appendix 4/p. 15; E2/T2/S1/Att. 1/Appendix 2 "Customer Consultation Results"/Question 4 and Report of the Board, Supplementary Report on Smart Grid, February 11, 2013 (EB-2011-0004) – 5.4.5.2 Material Investments – Electric Vehicle

At the first reference under "Vehicles and Trailers", it is indicated that introducing an electric vehicle, within FHI's fleet would allow for assessment of the impact on the electrical system; and potential operational efficiencies gained through hybrid technology. On page 15 of Appendix 4, Festival Hydro shows that the cost of the electric vehicle is $70,000.

TAB 3

c) Miscellaneous projects within system renewals are simply smaller infrastructure replacement projects. These projects make up part of the overall requirements of the DSP and they contribute directly to maintain system reliability and safety.

d) The alternatives that are considered for infrastructure renewal projects were described in section 5.4.5.2 of the DSP. Festival Hydro evaluates the need of the infrastructure being considered for replacement and assess if a change in design could make the rebuild redundant. This process ensures the pace of replacement is maintained overtime while increasing system efficiency.

34. 2. OEB STAFF 11

Ref: Appendix 2-AA – Capital Expenditures – New 62 MVA Transformer station

a) Please confirm that the capital expenditures for the new 62 MVA Transformer station, funded through the ICM mechanism, is incorporated into the historical capital expenditures for comparison? If not, please provide table showing Festival Hydro capital expenditures from 2010 Board-approved to 2015 test year forecast inclusive of the new Transformer station.

Response:

TS capital expenditures are not included in Table 2AA, but are reflected in table 2AB under the total expenditures section.

35. 2. OEB STAFF 12

Ref: Appendix 2-AA – Capital Expenditures – Capital Additions and E2/T2/S1, Appendix 4, p.14

Under the category of System Access, Festival Hydro forecasted $200,000 of capital additions in 2014 and $204,000 in 2015. On page 14 Festival Hydro notes that this investment category is unbudgeted, miscellaneous projects, which are completely customer driven.

a) Please provide further explanation as to the capital additions planned for the 2014 and 2015 rate years under this category and provide a historic comparison.

b) Please provide the up-to-date capital expenditure for the 2014 rate year under this category and compare to the equivalent time period in the previous year.

Response:

a) Capital additions are not planned in advance, but planned as requested by customers. This type of work could include pole line extensions, transformer installations or subdivision work. Some of this type of work is known in advance while other work becomes identified as needed. The $200,000 per

year spending is based on a 4 year historical average 2009 – 2012 (numbers provided below). Please note as mentioned in 2 – Staff – 10 pre 2014 capital additions were based on a combination of FHI and customer requested capital additions. The values presented below contain the customer requested additions.

2009 – $305,529
2010 – $256,445
2011 - $72,708
2012 – $133,615

4 year average = $192,704

b) 2014 capital additions spending up to June 30th is at $0. There are currently 4 identified projects for the 2014 year and an additional 4 potential projects identified. The 2013 spend in capital additions for this point in the year was $168,543.

36. 2. OEB STAFF 13

Ref: E2/T2/S1, Attachment 1, p. 25 – Variance Analysis

In section 5.2.3, p. 25 of the DSP, Festival Hydro provided the following table as a variance analysis over its historic capital expenditure.

On p. 26, Festival Hydro provides a brief variance analysis for capital expenditures in the 2009, 2010 and 2013 rate years. Board staff notes that Festival Hydro did not provide any variance analysis for the 2011 and 2012 rate years.

Actual spend vs budget (per year and over system planning forecast)

Year		Budget	Actual		Spending overage
					to Budget
2009		$3,352,000	$3,823,284		14%
2010		$2,992,000	$2,989,043		0%
2011		$3,350,400	$3,010,362		-10%
2012		$3,370,800	$3,021,956		-10%
2013		$3,388,400	$2,953,866		-12%
Average		$3,290,720	$3,159,702		-4%

Appendix 2-AA shown the following capital expenditures from 2010 – 2015 in the excerpt below.

Projects	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year

Total	**3,139,803**	**3,058,814**	**3,291,413**	**3,387,787**	**2,773,000**	**2,621,500**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*						
Total	**3,139,803**	**3,058,814**	**3,291,413**	**3,387,787**	**2,773,000**	**2,621,500**

a) Please reconcile the actual capital expenditures provided in Appendix 2-AA with the table above.

b) Please provide a variance analysis for the missing years

c) Please explain in detail why Festival Hydro's actual capital expenditure from 2011 – 2013 was 10%, 10% and 12 % below its budget, respectively.

d) Please explain to what extent deferred investments have resulted in any backlog of work.

e) Please explain if and how Festival Hydro's lower actual capital expenditures impacts system reliability at its current levels, given that the customer survey shows that reliability is the major concern for customers.

f) Please state how this trend has been incorporated into the 5 year capital plan laid out in the DSP.

Response:

a) Actual capital expenditures (as provided in 2-AA) vary with respect to the variance analysis presented in section 5.2.3 because of timing and the projects which represent the capital. The variance analysis uses the capital spending as identified in FHI work order system. The work order system closes in mid-January and isn't reconciled with accruals or subdivision. It also may not include certain projects outside the scope of Engineering and Operations including elements of the TS build, smart meters or generation projects. Table 2AA uses capital values from the GL and captures the total capital spend of the corporation including activities outside of Engineering and Operations. The work order system provides FHI staff an opportunity to access spending on a project by project basis. Although the final numbers aren't exact they are close enough to perform a variance analysis to identifying major trends.

2010, Appendix 2-AA shows an amount $150,760 higher – this can be reconciled as follows:

Additional costs in the GL inputted after WO close or charged directly to a GL
OH and UG projects - $44,522
New and Upgrades Services - $54,311
Distribution Meters -$17,726
Buildings - $1720
Vehicles - $145
Computer Equipment - $32,333

2011, Appendix 2-AA shows an amount $48,452 higher – this can be reconciled as follows:
Additional costs in the GL inputted after WO close or charged directly to a GL
OH and UG projects - $50,202
New and Upgrades Services - $4,068
Buildings - $11,986
Vehicles - $4,448

TAB 4

NAVIGANT

Working Capital Requirements of Toronto Hydro Electric System Limited's Distribution Business

Prepared for:

Navigant Consulting Ltd.
333 Bay Street
Suite 1250
Toronto, ON, M5H 2R2

www.navigant.com

June 27, 2014

Section I: Executive Summary

Summary

This report provides the results of the working capital requirements of THESL's distribution business.

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated distribution business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

Results from the lead-lag study using 2012 data identify the following working capital amount in Table 1, below.

Table 1: Summary of Working Capital Requirements

Year	2012
Percentage of OMA	7.91%
Working Capital Requirement	$218,720,393

The results of the study indicate a lower working capital requirement compared to THESL's EB-2007-0680 distribution lead-lag study. A considerable amount of time has lapsed between the two studies. The primary reason for the difference is the decrease in retail revenue lag days due to the upgrade of THESL's Customer Information System since the prior study. The retail revenue lag days have decreased by approximately 20 percent. Table 2, below summarizes the detailed working capital requirements for 2012 calculated in the study.

Table 2: THESL Distribution Working Capital Requirements (2012)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses	Working Capital Requirements
Cost of Power	55.04	32.84	22.20	6.07%	$ 2,450,597,565	$ 148,654,316
OM&A Expenses	55.04	33.86	21.19	5.79%	$ 312,961,220	$ 18,115,434
PILS	55.04	(48.95)	103.99	28.41%	$ 7,831,000	$ 2,225,034
Interest Expense	55.04	46.17	8.87	2.42%	$ 76,173,950	$ 1,845,550
DRC	55.04	33.31	21.74	5.94%	$ 162,416,324	$ 9,645,577
Total					**$ 3,009,980,059**	**$ 180,485,912**
HST						$ 38,234,481
Total - Including HST						**$ 218,720,393**
Working Capital as a Percent of OM&A incl. Cost of Power						**7.91%**

NAVIGANT

Working Capital Requirements of Hydro One Networks' Distribution Business

Prepared for:

hydro one

Navigant Consulting Ltd.
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December 3, 2013

NAVIGANT

Section I: Executive Summary

Summary

In preparation for a 2015-2019 distribution rate filing before the Ontario Energy Board ("OEB"), Hydro One Networks, Incorporated ("HONI") retained Navigant Consulting Limited ("Navigant") to prepare an update to its prior working capital study. This report provides the results of the update and the working capital requirements of HONI's distribution business.

Listed below are key findings and conclusions from this study:

1. In terms of lead-lag days, the results from this study are generally comparable with HONI's previous distribution working capital study (EB-2009-0096). Where there are differences, they have been identified, explained, and their impact on working capital requirements quantified;
2. The approach and methods used in this study are generally consistent with prior HONI studies as well as studies performed by other local distribution companies in Ontario; and,
3. Data from calendar year 2012 was used as a basis for this analysis. Results from the lead-lag study applied to HONI's test years identify the following working capital amounts.

Table 1: Summary of Working Capital Requirements

Year	2015	2016	2017	2018	2019
Percentage of OMA	7.40%	7.39%	7.46%	7.52%	7.58%
Working Capital Requirement $(M)	$236.21	$239.08	$240.76	$239.75	$241.11

Organization of the Report

Section II of this report discusses the lag times associated with HONI's collections of revenues. This includes a description of the sources revenues and how an overall revenue lag is derived.

Section III presents the lead times associated with HONI's expenses. This includes a description of the types of expenses incurred by HONI's distribution operations and how expenses are treated for the purposes of deriving an overall expenses lead.

Section IV presents the working capital requirements of HONI's distribution business including the working capital requirement associated with the Harmonized Sales Tax ("HST").

Section V presents a summary comparison of the results from this study with results from EB-2009-0096 study. Differences between the two have been noted, explained, and their impacts on working capital quantified. The intent of presenting the discussion in Section V is to demonstrate that the approach used in this study is an accurate reflection of the current distribution operations of HONI and that the results are reasonable when compared with the prior distribution studies.

TAB 5

OM&A

22. UNDERTAKING NO. JT1. 21:

Ref: Page 83

To provide the financials of the Affiliate.

Response:

Affiliate financials are included in Appendix JT1.21.

23. UNDERTAKING NO. JT1. 22:

Ref: Page 85

To produce the Mearie Report and if not, to explain why not.

Response:

Mearie UPM survey included in Appendix JT1.22 a and b.

24. UNDERTAKING NO. JT1. 23:

Ref: Page 86

To provide reports to the board with respect to benchmarking trends.

Response:

UPM benchmarking trends presented to FHI Board are included in Appendix JT1.23 a and b.

The MEARIE Group

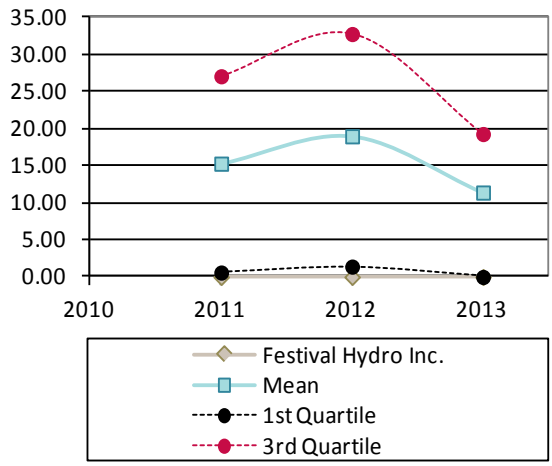
2014 Utility Performance Management Survey

Performance Scorecard

Festival Hydro Inc.

UPM Survey

FR040: Number of Days Cash Reserve



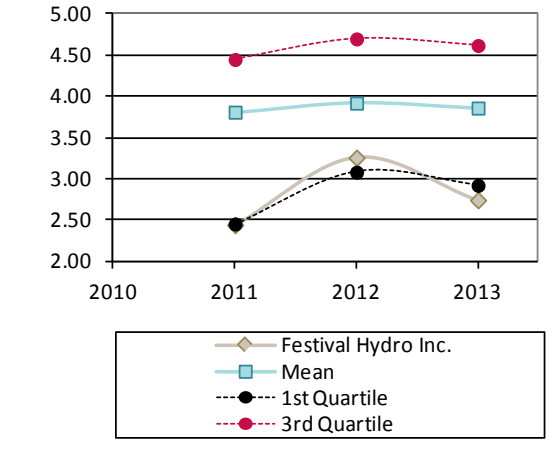
This ratio is defined as:

Cash + Short Term Investments
(Cost of Power, Operations, Maintenance, Admin., Financing charges, and Capital Expenditures) / 365

This ratio measures the utility's ability to meet its short term cash requirements. Your 2013 results indicate that you may want to review your levels of cash and short term investments.

Because your number of days reserve is lower than the mean, you may not be as able to meet your short term cash requirements as the average survey participant.

FR140: Operating Ratio (%)



Operating Ratio is defined as

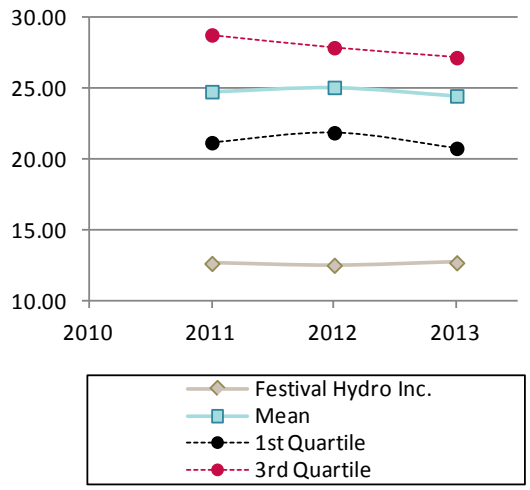
Total O & M Expenses
Total Revenue

This ratio provides an indication of the utility's effectiveness in managing operation and maintenance costs as a percent of its total electricity revenue.

Your results indicate a lower level of O&M costs per revenue than most participants in 2013. Influences include the age of the plant and the amount of plant replacement carried out by the utility.

3. Asset Utilization

FR050: Number of Days Sales Outstanding

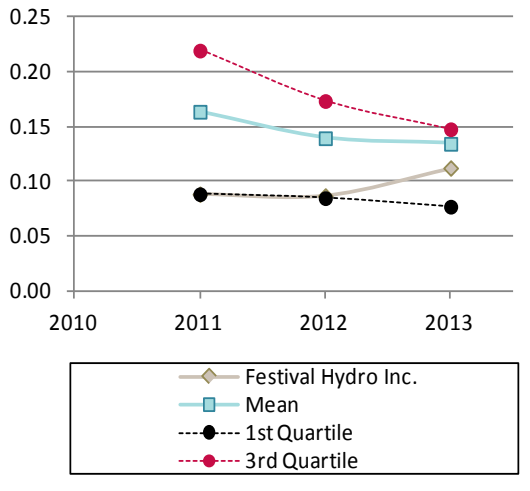


This ratio is defined as:

Accounts Receivable: Electrical Energy at Year End
(Total Service Revenue **/ 365**)

This ratio relates to the utility's ability to expedite the collection of its accounts receivable related to the sale of energy. It is influenced by utility collection practices and, together with the ratio Number of Days of Unbilled Revenue (FR070), will provide an indication of the utility's ability to manage its major accounts receivable balances.
You were below average in this area in 2011, 2012 and 2013, meaning your collections practices are more effective than other participants.

FR100: Bad Debt as % of Revenue



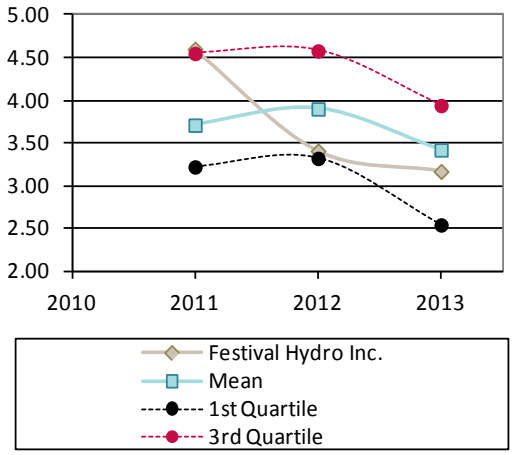
This ratio is defined as:

Bad Debt
Total Revenue

It indicates how effectively a utility is collecting revenue - the lower the percentage, the more effective the utility is at collecting service revenue. Major variances from year to year may result from economic conditions, or from large customers becoming insolvent.
You were below average for this ratio in 2012 and 2013, meaning that you are more effective in managing bad debt than the average LDC participant.

4. Employees

MR020: Short Term Absenteeism: Days per FTE

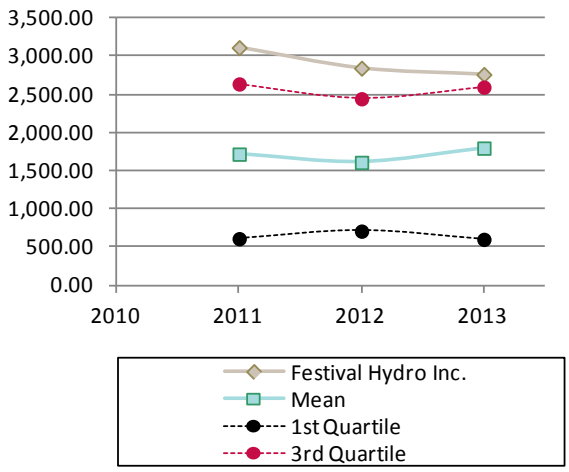


This ratio is defined as:

$$\frac{\text{Number of Short Term Absences}}{\text{Number of FTEs}}$$

This ratio calculates the number of work days lost due to short term absenteeism (5 days or less) per FTE. Absenteeism may be an indicator of employee satisfaction and/or health or safety or environmental conditions at the utility.
Short term absenteeism has decreased at your location since 2011 and, in 2013, you were below the mean for this metric.

MR070: Staff Development Expenses per FTE



This ratio is defined as:

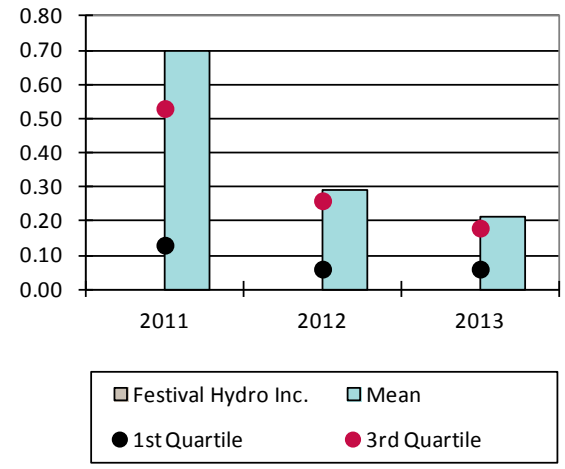
$$\frac{\text{Total Costs of Staff Development}}{\text{Number of FTEs}}$$

This ratio indicates the average cost spent per employee on staff development.

You have been spending more than most survey participants on staff development over the 2011 to 2013 period.

TAB 6

CR100: Percent of Bills Cancelled and Re-issued

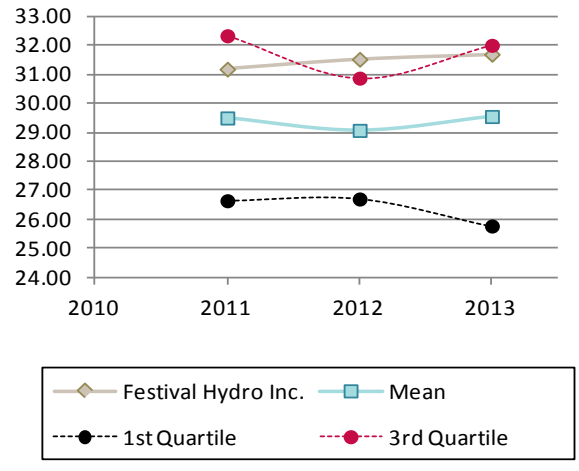


The calculation for this ratio is:

$$\frac{\text{Number of Bills Cancelled \& Reissued}}{\text{Total Number of Bills Issued}}$$

You do not currently track this metric, but it might interest you to know that the rate of bill cancellation and re-issue has decreased significantly for most survey participants since 2011 and through 2013. This reflects good quality control on bill preparation and issue.

S172: Monthly Bill for 1000kWh Residential Customers



This figure includes both customer and distribution charges.

Your customers paid more than the customers of most of your peers in 2011, 2012 and 2013.

TAB 7

Linemen Overhead Cost Summary - 2013	
Standby & Union Business Labour	23,494
Safety Meeting Labour	13,507
Supplies & Phone Expense for service centre	16,898
Boot/Uniform Purchases	15,351
Training Labour	40,728
Subcontractor labour to teach trainings	22,788
Travel, Hotel, Meals & training registrations	10,323
Labour overhead for benefits & supervision	59,792
Safety Equipment	5,212
	208,093

b) The costs included in linemen overhead prior to January 1, 2013 were allocated at a rate of 20% per labour dollar of linemen accumulated in capital or operations & maintenance general ledgers. The true P&L impact however is only the portion of costs that would've been allocated to capital via this overhead rate. The fact that the costs no longer follow labour dollars in other operating and maintenance accounts has no bottom line impact. As highlighted in the first table for 37a) above – in the years prior to 2013, the intention was to zero out linemen overhead costs from this account and fully allocate them to capital and OM&A accounts – and the 20% allocation/labour dollar did this leaving immaterial balances unallocated. The appendix 2DA is meant to represent the portion of this account that can no longer be capitalized only. As such – Festival cannot reconcile the change in this project cost category to appendix 2-DA – but expects that the information included above will provide sufficient detail of what makes up this project cost category included in appendix 2-JC.

c) As noted in the detail provided above, Festival incurs approximately $10K on average each year to provide a community safety program whereby representatives from our line professional team go into various classrooms throughout our distribution territory to teach children about electrical safety. The program costs include the time and supplies utilized in the program. The line crew also attend various safety meetings and courses each year and their labour as well as the cost of course registration or hiring an instructor to teach the course is incurred. These costs are as detailed in the linemen overhead cost summary provided above using 2013 actual figures as an example.

103. 4. OEB STAFF 38

Ref: E4/T3/S1, Appendix 2-JC; E4/T3/S1, p. 3

Festival Hydro shows an increase in Billing and Settlement costs of approx. $296K or 75%. Festival Hydro noted that this increase began in 2013 as the result of new operating cots required with the implementation of smart meters.

a) Please provide a breakdown of this cost category.

b) Please state how much of this increase is due to smart meters.
c) Please explain the ongoing nature of these costs.
d) Board staff notes that meter reading expenses have also increased by approx. 24%. Please explain if and where Festival Hydro was able to realize some efficiency gains due to implementing the smart meter program.
e) If not, please provide more detailed explanation as to these costs.

Response:

a) A breakdown of this cost category is included in the table below.

Billing & Settlement Summary						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Supervision - Billing	11,870	13,103	12,617	14,591	14,182	14,534
Smart Meter Billing Costs			17,917	92,977	118,049	119,938
Customer Billing	293,129	362,423	337,941	469,083	498,917	512,543
Billing - STR Processing	1,547	350	290	296	249	246
Billing - Other Retailer Services	40,859	32,500	29,052	25,380	26,391	-
SSS Admin Charge	40,912	40,912	40,912	40,913	41,567	42,232
Reconnection Charge Offset	- 32,243	- 35,084	- 30,523	- 30,048	-	-
	356,074	414,204	408,206	613,192	699,355	689,493

b) Based on the table above – smart meter billing costs are estimated at $120K in 2015 and were zero in our last rebasing year.

c) The smart meter billing costs include costs relating to Festival's ODS service provider, Web presentment provider, head end system software support, and verification, editing, and estimation service provider. All of these costs are considered to be ongoing in nature.

d) The meter reading cost driver includes costs for smart meter data backhaul averaging around $100K/year which is a new cost as a result of smart meters. Festival continues to pay approximately $30K/year for manual meter reads for meters that are not a part of the smart meter program. Festival notes that we have reduced our meter reading costs by approximately $84K/year as a result of the implementation of smart meters.

e) Refer to efficiency response in 38d.

104. 4. OEB STAFF 39

Benchmarking

TAB 8

b) Please provide Festival's forecast for inflation for 2014 and 2015.

Response:

a) As per stats Canada's historical summary – the annual change in consumer price index for the period requested is as follows:
2010 – 1.8%
2011 – 2.9%
2012 – 1.5%
2013 – 0.9%

b) Please refer to the table provided at 1.0-VECC-1 for Festival's forecast for inflation for 2014 and 2015.

136. 4. VECC 27

Reference: E4/

For each of the years 2011 through 2015 please provide:
a) EDA membership fees
b) All other corporate membership fees

Response:

a) & b) Please refer to data provided in table below as response to these questions.

	2011	2012	2013	2014	2015
EDA Membership Fees	26,950	28,450	29,800	30,277	30,761
Other Corporate Membership Fees	12,668	14,858	14,218	14,445	14,677

137. 4. VECC 28

Reference: E4/T3/S1

a) Please provide all training and conference costs for the 2011-2015 period broken down into the following categories
i. Training – for operations/maintenance staff
ii. Training – executive and other
iii. Conferences (all)
iv. Travel (all)

Response:

Please refer to data provided in the table below as response to this question.

TAB 9

Response:

a) Festival bills all customer classes monthly. Festival is aware some LDCs have undertaken lead/lag studies but Festival has not reviewed the results of their lead/lag studies in detail.

66. 2.0 - VECC 4

Reference: E2/T1/S1& S2/pg.3 & E4/T2/S1/pg.7

a) Please show how the $475k in annual savings for network connection costs is calculated. The evidence at E4 suggests there are further savings from the new transformer station. Please provide an estimate of these other savings (specify if one-time or annual).

b) Please explain the rationale for a 25 year amortization of the bypass compensation amount of $1,230,026.

c) Was the by-pass agreement and its estimated cost discussed in the evidence of EB-2013-0214? If yes please provide the extract of that evidence.

Response:

a) The monthly reduction of 20,000 kW arising from the Permanent Bypass Agreement with Hydro One results in annual savings of $475,200 in transformation connection charges. The kW reduction has been reflected monthly in the RTSR Model on Tab # 8 Forecasted Wholesale. In summary:

Tab 7 Current Wholesale (2013)	1,042,640 kW @ $1.98	$2,064,427
Tab 8 Forecast Wholesale (2015)	802,640 kW @ $1.98	$1,589,227
Reduction	240,000 kW	$ 475,200

In addition, customers will save the 13% HST, which is another $61,776 (slightly less for those eligible for OCEB). The 2013 IRM submission (EB 2012-0124) provides, in detail, the expected costs associated with the TS construction compared to the many benefits to be achieved such as addressing of capacity requirements, feeder loading issues, voltage issues and reliability improvements.

b) The Permanent Bypass is subject to a 45 amortization period, which is equal to the depreciation period for the major component of the transformer station, namely the transformers and the switch gear. The 25 year period as stated is not correct. Note that all our calculations have been based on this cost being amortized over a 45 year period.

c) It was not discussed as part of evidence in EB 2013-0124 as the need for a Permanent Bypass Agreement was not envisaged at that time.

TAB 10

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.

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.

16. UNDERTAKING NO. JT1. 15:

Ref: Page 52

To provide the difference in cost or revenue requirement if Festival were to use a deferral account to recover the amount of the bypass penalty over three years.

Response:

Festival has completed an analysis comparing the NPV associated with treating the asset as an intangible asset within rate base compared to the recovery as a Deferral account over 3 years. As noted in the table below, including the costs in the rate base over a 45 year life span results in a much higher NPV value than treating it as an asset in a Deferral account.

With the deferral account method, there is a small positive net present value arise on the 3 year deferral account whether it is financed over a 25 year period or a 3 year period. This positive return is primarily due to the fact that the deferral account, which will be established effective January 1, 2014, will have the full value of the contract of $1,230,026 added to the account. At the OEB prescribed interest rate of 1.47%, that will result in $18,081 carrying charges being earned in 2014. Since Festival does not expect to borrow the funds until December 2014 at the earliest, the carrying charges earned in 2014 and 2015 to 2017 will more than offset the cost of borrowing associated with the loan over the three year period (the loan being calculated at 2.24% - the Infrastructure Ontario's current 5 year rate).

JT 1.15									
Treatment as Intangible Asset within Rate Base			**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Asset Value			1,230,026	1,227,748	1,200,414	1,173,080	1,145,746	1,118,412	1,091,078
Accum depreciation			- 2,278	- 27,334	- 27,334	- 27,334	- 27,334	- 27,334	- 27,334
Net Book Value			1,227,748	1,200,414	1,173,080	1,145,746	1,118,412	1,091,078	1,063,745
Average Balance				1,214,081					1,077,411
Debt portion of WACC	60% at 4.17%	0.02502		30,376	30,376	30,376	30,376	30,376	26,957
Equity portion of WACC	40% at 9.36%	0.03744		45,455	45,455	45,455	45,455	45,455	40,338
	Total WACC	0.06246		75,832	75,832	75,832	75,832	75,832	67,295
Interest Expense on Loan:				50,697	49,483	48,218	46,898	45,523	44,089
Net Equity remaining				25,134	26,348	27,614	28,933	30,309	23,207
NPV of treatment in rate base:									
Collected through rates Debt, Equity Depn)				103,165	103,165	103,165	103,165	103,165	94,629
Less Loan P & I Payments				- 80,156	- 80,156	- 80,156	- 80,156	- 80,156	- 80,156
Net annual cash position				23,009	23,009	23,009	23,009	23,009	14,473
Net Cash to date				23,009	46,019	69,028	92,038	115,047	129,520
NPV of 45 year of return	$343,017.86								
(non tax effected)									
Treatment as a DVA Account - 25 year loan									
Cashflow Impact:			**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Rate Rider Recovery (DVA & Interest) - 3 years				425,532.00	425,532.00	425,532.00		-	-
Less Loan P & I Payments				- 80,156	- 80,156	- 80,156	- 80,156	- 80,156	- 80,156
Tax savings on interest differential									
Net annual cash position			0	345,376	345,376	345,376	- 80,156	- 80,156	- 80,156
NPV of 25 year of return	$1,860.77								
Treatment as a DVA Account - 3 year loan									
Cashflow Impact:			**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Rate Rider Recovery (DVA & Interest)				425,532.00	425,532.00	425,532.00			
Less Loan P & I Payments				- 424,320	- 424,320	- 424,320			
Tax savings on interest differential			-4701.06	2,044	1,263	451			
Net annual cash position			-4701.06	3,256	2,475	1,663			
NPV of 3 year of return	$2,089.46								
%									

TAB 11

Festival proposes placing these costs for 2013 and 2014 into account # 1572 Extraordinary Event Costs. Festival has included these amounts on the EDVARR schedule to be disposed of as part of the Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.). The bill impacts under Undertaking JT 1.24 have been presented including the $244,815 in the variance account.

14. UNDERTAKING NO. JT1. 13:

Ref: Page 49

To update the response to 4-STAFF-75-TCQ regarding the employee future benefit accrual.

Response:

Festival incorrectly reported the amount of $44,850 as owing to Festival Hydro, when in fact it is owing to the customers as follows:

2015 DVA Account
Required:

Closing Accrual under CICA, Dec 31, 2014	1,401,958	(Festival accrued/expensed)
Closing Accrual under IAS19, Dec 31, 2014	1,357,108	(Accrual needed under IAS 19)
Difference arising on converting to IFRS	44,850	(owing to ~~Festival Hydro~~customers)

The deferral account, if directed by the Board to be established, will be recorded as a payable to customers. The amount does not meet the materiality level, however, from a causality point of view; it was Festival's belief that LDCs and the ratepayer would be held whole on amounts arising from the conversion from CGAAP to IFRS.
The bill impacts under Undertaking JT 1.24 have been presented including the $(44,850) in the DVA accounts. Festival has included it in the Acct 1572, as an offset to the $244,815 TS expenses for net amount of $199,965.

15. 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.

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.

16. UNDERTAKING NO. JT1. 15:

Ref: Page 52

To provide the difference in cost or revenue requirement if Festival were to use a deferral account to recover the amount of the bypass penalty over three years.

Response:

Festival has completed an analysis comparing the NPV associated with treating the asset as an intangible asset within rate base compared to the recovery as a Deferral account over 3 years. As noted in the table below, including the costs in the rate base over a 45 year life span results in a much higher NPV value than treating it as an asset in a Deferral account.

With the deferral account method, there is a small positive net present value arise on the 3 year deferral account whether it is financed over a 25 year period or a 3 year period. This positive return is primarily due to the fact that the deferral account, which will be established effective January 1, 2014, will have the full value of the contract of $1,230,026 added to the account. At the OEB prescribed interest rate of 1.47%, that will result in $18,081 carrying charges being earned in 2014. Since Festival does not expect to borrow the funds until December 2014 at the earliest, the carrying charges earned in 2014 and 2015 to 2017 will more than offset the cost of borrowing associated with the loan over the three year period (the loan being calculated at 2.24% - the Infrastructure Ontario's current 5 year rate).

TAB 12

ICM Rate Rider ACCOUNT # 1508 - Continuity Schedule (REVISED to agree to 2 staff 8)				
		2013	**2014**	**Jan 1, 2015 transfer**
Opening, Jan 1		0	15,058,931	14,710,516
TS O & M Expenses		104,816	140,000	-244,816
Interest		17,623	217,469	-235,093
Transfer in from CWIP		15,311,782	0	-15,311,782
Depreciation & Amortization		28,137	337,647	-365,784
Accumulated Depreciation & Amort		-28,137	-337,647	365,784
Less ICM Rate Rider Recovery		-375,291	-705,884	1,081,174
Ending Bal, Dec 31		**15,058,931**	**14,710,516**	**-0**
Entry required for Jan 1, 2015 disposition:				
		USOA		
TS Land	DR	1805	913,474.39	
TS capital	DR	1815	13,961,839.83	
CCRA agreement	DR	1609	436,468.00	
Interest Income	DR	4405	235,092.89	
Distribution Revenue	CR	4080		1,081,174.36
Depn Exp	DR	5705	346,870.00	
Amort Exp	DR	5715	18,914.00	
Accum Depn	CR	2105		346,870.00
Accum Amort	CR	2120		18,914.00
TS O & M Expenses	DR	5015	244,815.74	
ICM Variance Acct	CR	1508		14,710,516.49
			16,157,474.85	16,157,474.85
Transfer back to fixed asssets1805,1815,1609 (gross)			15,311,782.22	
Less Accuimulated Depreciation/Amortization			-365,784.00	
Net book value upon transfer , Jan 1, 2015			14,945,998.22	

32. 2. OEB STAFF 9

Ref: E2/T2/S1, p. 14 – Stratford Transformer Station – Permanent Bypass Agreement

On page 14, Festival Hydro states that:

As a result of Festival constructing a new transformer station, Festival entered into a Permanent Bypass Compensation Agreement with Hydro One for the purpose of addressing the bypass compensation payable by Festival in accordance with Section 6.7.7 of the Transmission System Code. The agreement allows for a Bypass Capacity from the existing Hydro One station at an estimate 20 MW with a Bypass Compensation Estimate amount of $1,230,026.

The cost of this Bypass agreement was not part of the original construction budget used for the ICM rate rider. However, the cost is a component of the overall cost of the transformer station. Festival commenced the bypass on December 1, 2013 upon energizing its first customer for the new TS. Currently (Feb 2014), there is about 12 MW being bypassed with a plan to migrate close to the 20 MW during 2014.

a) Please confirm that Festival is including an incremental $1.23M in rate base for a permanent Bypass Agreement with HONI.
b) Please explain why the cost of the Bypass agreement was not part of the ICM application for the 2013 rate year.
c) Please provide a revised assessment that shows that the cost of the new transformer station, including the cost of the bypass agreement, was still the best option.
d) Has the amount of $1.23M been paid in full to HONI as a one-time cost?
i. If so, provide the date the transaction.
ii. If not, please provide a payment schedule and describe the accounting treatment of the off-setting entry to intangible assets.
iii. Does Festival Hydro expect to incur future costs related to the bypass agreement?
e) Please explain how Festival believes the Stratford Transformer Station Permanent Bypass meets the definition of an intangible asset under IAS 38.
f) Please indicate if Festival has discussed this with its external auditor and provide any documents received by Festival that express the views and opinions of its external auditor.

Response:

a) Confirmed. $1.23M has been added to the rate base for the Permanent Bypass Agreement with HONI.

b) At the time of creating the Transformer Station (TS) budget, it was not envisage that a Permanent Bypass arrangement was going to be required.

c) Below is the table presented in Festival's 2013 IRM Application (EB-2012-0124) comparing the various options available to Festival Hydro for construction of the TS. The decision to build was not solely based on the Net present value of the best option, but also on how the option would best address other critical factors such as capacity requirements, voltage issues and reliability performance. The preferred option which addressed all issues and was also the lowest cost was the 4th option - Festival Hydro to construct the TS.

Scenario	NPV[1]	Address Capacity Issue?	Address Voltage Issue?	Address Reliability Issue?
Hydro One Replaces One Transformer at Devon TS in 2010, Festival Builds New Feeder in 2010, Hydro One Builds Second TS in 2015	$16.8M	yes	Not until 2015	Minimal until 2015
Hydro One Replaces One Transformer at Devon TS in 2010, Festival Builds New Feeder in 2010, Festival Hydro Builds Second TS in 2015	$14.7M	yes	Not until 2015	Minimal until 2015
Hydro One Builds Second TS in 2010	$13.3M	yes	yes	Yes
Festival Hydro Builds Second TS in 2010	$10.5M	yes	yes	Yes

Festival is of the opinion that with the addition of the cost of the Permanent Bypass the decision for Festival to construct was still the best option. The TS has been successfully up and operational since December 2013 with minimal problems encountered. With the TS build completed by Festival, Festival has been able to successfully achieve the requirements of the other major criteria identified as critical to the project, that being the issues of capacity, voltage and reliability.

Outlined below is the financial analysis of the actual TS expenditure compared to budget if Permanent Bypass is considered :

Original TS Budget	$15,863,114 (on page 15 of 2013 IRM)
Actual Expenditures:	
Capital spend	$15,311,782 (capital transferred to 1508)
Permanent Bypass	1,025,481 ($1,230,026 in 2010 dollars)
Total Capital Spend	$16,337,263
Amount over original budget	$ 474,149

If the over budget amount of $474K is added to the original projected NPV of $10.5 the amount of $11.0M is still less than the $13.3M for the second lowest cost option, and this is without even taking into account the $475K being saved annually on transmission connection charges.

d) The $1.23M bypass agreement was set up as an Accounts Payable at December 31, 2013. The transformer station went into service on December 2, 2013 and Festival's customers have been receiving the benefits of reduced transmission charges since that date through reductions in transmission charges form the IESO. However, the bypass assessment date is not being completed until in or around June 1, 2014, and the payment due date is 180 days following that, so Festival

[1] A discount rate of 5.5% was used. Adjusting the discount rate from a low of 2.5% to a high of 7.5% made no difference in the relative ranking of the scenarios.

Hydro expects to make the payment in December 2014. The accounting entry to set up the bypass agreement as an asset was Debit 1609 Capital Contributions Paid and Credit # 2205 Accounts Payable. Upon settlement, the entry will be to Debit #2205 Accounts Payable and Credit #1005 Cash. At this time, Festival does not expected to incur any additional costs related to the Permanent Bypass. Excerpts from the Permanent Bypass agreement are copied below:

in or around June 1, 2014, the Customer intends to by-pass Hydro One's Stratford TS (the "**Station & Line Assets**") in respect of a portion of the Existing Load; and

Bypass Compensation – Estimate:

$1,230,026 $= [NBV_T + DC_T - SC_T] \times [BC/TNSC_T] + [NBV_L + DC_L - SC_L] \times [BC/TNSC_L]$

e) Article 410 of the OEB Handbook is fairly specific that intangible assets include capital contributions paid by the distributor to other distributors for capital projects. 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. The account definition of USOA # 1609 states "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. "The nature of the agreement fits the description of Acct # 1609
From an IAS 38 standpoint:
    a) The payment meets the definition of an asset - it is an identifiable non-monetary asset without physical substance that was/is controlled by Festival as a result of past events; and will derive future economic benefit from making the payment.
    b) The payment is identifiable because it meets both criteria in IAS 38, paragraph 12.
    c) Festival controls the asset – as Festival has the power to obtain future economic benefit from it – i.e. the ability to distribute power through the TS and bill customers for it
    d) Can be recognized as an intangible according to IAS 38, paragraphs 21 and 22, because the payment meets the criteria required for recognition as an intangible.

f) The accounting treatment was discussed in advance of the 2013 yearend audit with our external auditors to ensure proper accounting treatment was met. Being it was a material dollar value, the agreement was subject to external audit review. In the Notes to the 2013 audited financial statements, Section 1 Significant Accounting Policies – section f) provides the policy related to Intangible Assets. Under Note 5 is provided the details of the agreements associated with the balance in the Intangible Asset account.

The auditors issued an unqualified auditors' report on Festival's 2013 financial statements which include this amount being included as an intangible asset.

TAB 13

ICM RATE RIDER

Incremental Capex: $15,311,782-28137+$3,489,000-$3,642,654)/12*8 (for revised 2014) (Actual spend less 2013 depn exp add normal capital less threshold/12mths x 8 mths)

b) CAPEX noted above.

c) Attached are the ICM Project Workforms which contain the CCA deductions for each of the above three noted models (filed in Festival's 2015 COS web drawer called:
FESTIVAL_2013_IRM3_Incremental_Capital_Wrkfrm_Updated for 2015 COS
9 staff 64 FESTIVAL_2013_IRM3_Incremental_Capital_Wrkfrm_V1.0_20140827
FESTIVAL_2014_IRM3_Incremental_Capital_Wrkfrm_ for 2014 year Updated for 2015 COS

182. 9. VECC 41

Reference: E9/T3/S4

a) Please provide an estimate of the remaining costs related to implementation of IFRS that are expected to be incurred after 2014.

Response:

Please refer to 9 Board 58 as it relates to further IFRS conversion expenses estimated at $20,000 and added to the EDVARR schedule as noted below:

a) With an updated version of Appendix 2 – U available, Festival has filed the revised 2 - U to place the 2013 balance in the correct columns and has also added $20,000 of costs expected to be incurred in 2014 related to final accounting advisory services, assistance on financial statement notes, and the cost of auditing the opening IFRS balances for a revised total of $135,083. The EDVARR continuity schedule and the Rate rider determination shown on E9/T1/T1 have been updated to reflect this change. In addition, this account can be closed as part of the 2015 COS application and no continuation is necessary.

183. 9. VECC 42

Reference: E9/T3/S12

a) Please explain the rationale for continuation of the ICM rate rider, specifically why does Festival believe that that it should recover the variance (shortfall) as between the calculated ICM rate rider and the actual costs if actual costs are incorporated into rate base for 2015?

b) Please show the derivation of the $326k Festival is seeking to recover specifically showing the cost impact of:

i. adjustment due to under budget of project of 551k
ii. adjustment due to forecast vs. actual in-service date
iii. adjustment due to IFRS depreciation rate changes

Response:

a) Please refer to 9 Staff 64 and 9 EP 39 for supporting documents related to the additional $326 K being identified to be recovered by Festival Hydro. The Board approved the ICM rate rider recovery based on the original budget amount to be in effect until the effective date of the next cost of service based rate order. Under this model the half year rule applied to 2013 and to the 8 months of the 2014 rate year. i.e. whereby only one half the value of the asset is allowed. Being the half rule was applied to the 2013 rate year, Festival is making a claim for the 8 months in 2014 based on the full value of the asset and related depreciation as the half year rule had been met in the 2013 rate year. Festival has recalculated 2013 based on the actual costs (i.e. 551K lower than budget for 2013) and applying the half year rule to the capital asset amount. Festival has then for the 8 month period of 2014 calculated the 2014 recovery based on the full net book value of the asset (and full depreciation). The rationale for the continuation of the ICM rate rider is to recover this shortfall arising due to applying the half year rule for both 2013 and 2014.

b)

I. 9 EP 39 shows the CAPEX calculation completed by Festival. In Festival's true up calculations for 2013 and 2014 the actual capital expenditure is used; not the original budget amount.

II. The TS was originally expected to be energized sometime in the summer of 2013 but did not get energized until December 2, 2013. There were vendor related issues that prevented the TS from becoming operational at the earlier date. However, the bulk of the funds were paid out before May 30, 2013, that being the date in which the $14 million CWIP loan was converted to a fixed rate loan. So even though it was no energized until a later date, the funding had for the most part been spent by mid 2013 (other than holdbacks).

III. Festival adopted new depreciation and overhead allocation polices effective January 1, 23013, so the depreciation rates for the TS are the identical under both CGAPP and IFRS with no adjustments required.

184. **NEW** FESTIVAL HYDRO REQUEST for Deferral Account

Request for New Deferral Accounts re: Board Staff Proposal for New Policy Options for the Funding of Capital Investments Board File Number EB-2014-0219

Board staff issued a proposal dated June 20, 2014 which considers revised approaches to the funding of capital. Board staff proposed the following possible D1 factor process:

"1. Eliminate the effect of the half year rule on test year capital additions for the intervening years between rebasing applications (i.e. during the subsequent IR plan) by adjusting for the incremental revenue requirement (depreciation expense plus return on capital and associated taxes/PILs) of the test year capital additions. This is proposed to be accomplished through an adjustment (to be referred to as

TAB 14

- *Account 1508 Other Regulatory Asset, Sub-account Accumulated Depreciation and*
- *Account 1508 Other Regulatory Asset, Sub-account Incremental Capital Expenditures Rate Rider,*

including a breakdown of the carrying charges

Response:

The following is the breakdown of the account balances under Acct # 1508 ICM Rate Rider account as at December 31, 2004:

Account # 1508 ICM Account	**December 31, 2014**
ICM Capital Expenditures – Capital	$15,311,782
ICM Capital Expenditure–Carrying charges @1.47%	243,465
Total Capital	15,555,247
ICM Depreciation & Amort Expense	365,784
ICM Accumulated Depreciation & Amort	-365,784
ICM Rate Rider- Recoveries	-1,081,174
ICM Rate Rider – Interest on Recoveries @ 1.47%	-11,423
Total ICM Recoveries	-1,081,174
Balance prior to O & M Expenditures	14,461,325
TS O & M Expenditures (cost not in 2010 COS)	244,816
TS O & M Expenditures -Carrying charges @ 1.47%	3,051
Total Balance at December 31, 2014	**14,710,517**

172. 9. OEB STAFF 63

Ref: E9/T3/S12/p.2-3 and Supplemental Report of the Board on 3rd Generation Incentive Regulation, September 17, 2008 ("Supplemental Report")

For the ICM Rate Rider Account #1522 table,

a) Please confirm that the ICM Rate Rider Account #1522 should be Account 1508. If not, please explain what Account 1522 is.

b) On p. 30 of the Supplemental Report of the Board, the Board stated that the capital module is intended to be reserved for unusual circumstances…and where the distributor has no other options for meeting its capital requirements within the context of its financial capacity underpinned by existing rates. Festival Hydro is showing OM&A of $244,816 related to the TS.

vi.) Please explain what is included in this amount and why Festival Hydro is recording out-of-period OM&A expenses in account 1522.

vii.) Please state if these OM&A expenses where approved as part of Festival Hydro 2013 IRM-ICM application.

viii.) Please revise the evidence as necessary.

c) Please confirm whether or not the Interest line of $235,093 represents the carrying charges for Incremental Capital Expenditures and Incremental Capital Expenditures rate rider. If not, please clarify what the interest amount is for.

d) Festival is proposing to transfer all accumulated depreciation to Account 2218 and depreciation expense to Account 5705. Please explain what Account 2218 is.

e) Please revise the evidence to reflect the accumulated amortization in Account 2105 Accumulated Depreciation of Electric Utility Plant - Property, Plant and Equipment and Account 2120 Accumulated Amortization of Electric Utility Plant – Intangibles and the depreciation expense in Account 5705 and Account 5715 Amortization of Limited Term Electric Plant.

Response:

a) Agreed. The account for the ICM Rate Rider is USOA # 1508. Account # 1522 as noted is used for internal record keeping purposes only.

b)

i. Festival has adopted accounting practices for its ICM account similar to what was followed for Smart meter, whereby O & M costs were recorded into the smart meter variance account until time of disposition. As was the case for smart meters, for the TS there were no O & M expenses approved as part of 2010 Rate application for operation and maintenance. It is Festival's belief that these costs would be recorded into Account # 1508 and disposed of as part of the overall disposition of the ICM Variance account. The amount represents the December 2013 and 2014 operating costs actually incurred including such items as property taxes, insurance maintenance, monitoring costs (excluding depreciation), of which none of these costs were part of the 2010 O & M expense. As the ICM is intended for extraordinary capital expenses the resulting OM&A from such capital expenses should also be considered extraordinary and such costs should be considered in the same manner and recoverable.

ii. In terms of approval of the expense, the 2013 IRM Decision and Order (EB-2012-0124) does not specifically state whether or not OM & A may be added to the ICM account # 1508.

iii. Under 9 Staff 62 the table breaking down the contents of Acct # 1508 is shown before adding in the O & M expenses (and related interest) and the total including O & M expenses.

c) The $235,093 is the net carrying charges related to the Incremental Capital Expenditures, O & M expenses and Incremental Capital Expenditures rate rider. as broken down for 9 staff 62.

d) The accounts which Festival Hydro uses for recording are: 2105 Accumulated Depreciation of Electric Utility Plant - Property, Account 2120 Accumulated Amortization of Electric Utility Plant – Intangibles: Transformer station > 50 KV depreciation expense in Account 5705 and Account 5715 Amortization of Limited Term Electric Plant.

e) Evidence has been revised accordingly.

9 Staff 63 table					
ICM Rate Rider ACCOUNT # 1508 - Continuity Schedule (REVISED -agrees to 2 staff 8)					
		2013	**2014**	**Jan 1, 2015 transfer**	
Opening, Jan 1		0	15,058,931	14,710,516	
TS O & M Expenses		104,816	140,000	-244,816	
Interest		17,623	217,469	-235,093	
Transfer in from CWIP		15,311,782	0	-15,311,782	
Depreciation & Amortization		28,137	337,647	-365,784	337,644.00
Accumulated Depreciation & Amort		-28,137	-337,647	365,784	
Less ICM Rate Rider Recovery		-375,291	-705,884	1,081,174	
Ending Bal, Dec 31		**15,058,931**	**14,710,516**	**-0**	
(with one mth depn in 2013)					
Entry required for Jan 1, 2015 disposition:					
		USOA			
TS Land	DR	1805	913,474.39		
TS capital	DR	1815	13,961,839.83		
CCRA agreement	DR	1609	436,468.00		
Interest Income	DR	4405	235,092.89		
Distribution Revenue	CR	4080		1,081,174.36	
Depn Exp	DR	5705	346,870.00		
Amort Exp	DR	5715	18,914.00		
Accum Depn	CR	2105		346,870.00	
Accum Amort	CR	2120		18,914.00	
TS O & M Expenses	DR	5015	244,815.74		
ICM Variance Acct	CR	1508		14,710,516.49	
			16,157,474.85	16,157,474.85	
Transfer back to fixed asssets1805,1815,1609 (gross)			15,311,782.22		
Less Accuimulated Depreciation/Amortization			-365,784.00		
Net book value upon transfer , Jan 1, 2015			14,945,998.22		

173. 9. OEB STAFF 64

Ref: E9/T3/S12, pp. 1-9 – Incremental Capital Module True-up

Festival Hydro has provided a true-up of its new 62 MVA Transformer station, which was funded through an incremental capital module as part of its 2013 IRM application. As part of its current application Festival Hydro is requesting additional ICM rate riders to recover incremental revenue requirement as follows:

Description	2013	2014 (8 months)	Total
Inc. Revenue Requirement – as originally filed EB-2001-0124) (2014=2013/12*8)	$672,412	$448,275	$1,120,687
Inc. Revenue Requirement – true up of costs, depreciation and CCA)	$508,652	$938,371	$1,447,023
Variance arising on true up – additional inc capital requirement	**$(163,760)**	**$490,096**	**$326,336**

Proposed Incremental Capital Volumetric Rate Rider effective Jan 1, 2015 to Dec 31, 2015 (1 year) **$ 326,336.00**

Rate Class	2015 Test Year kWh	2015 Test Year kW	Allocatoin based on 2015 TY kWh	Allocated Balance	Volumetric Rate Rider	Unit
Residential	140,900,798	-	23.7%	77,347	$ 0.0005	kWh
GS < 50 kW	64,179,621	-	10.8%	35,231	$ 0.0005	kWh
GS >50 kW to 4,999 kW	361,832,480	946,164	60.9%	198,627	$ 0.2099	kW
Large Use	22,191,326	34,422	3.7%	12,182	$ 0.3539	kW
USL	660,967	-	0.1%	363	$ 0.0005	kWh
Sentinel Lights	150,156	356	0.0%	82	$ 0.2315	kW
Street Lighting	4,559,343	12,017	0.8%	2,503	$ 0.2083	kW
Total	594,474,691	992,959	1	326,336		

a) Please provide a true-up calculation applying the half-year rule as originally applied for, adjusting only for the capital expenditure reduction of $551,330 and final TS asset values.

b) Please provide the resulting net book value for the TS station as of January 1, 2015.

Response:

a) Festival has recalculated the Incremental capital module as requested using the Final TS balances (net of the $551,330) and applying the half year rule. The attached models are called:

9 staff 64 Festival_2013_Incremental_Capital_Project_V1.0_20140827_
9 staff 64 FESTIVAL_2013_IRM3_Incremental_Capital_Wrkfrm_V1.0_20140827
9 staff 64 with Bypass Festival_2013_Incremental_Capital_Project_V1.0_20140827_
9 staff 64 with bypass FESTIVAL_2013_IRM3_Incremental_Capital_Wrkfrm_V1.0_20140827

With the revised model, the 2013 amount is $631,181 plus 8 months of $420,787 for a total of $1,051,968 or $68,719 less than the original filed request.

Festival has also calculated the incremental revenue requirement including the $1.2 M Permanent Bypass arrangement. Even though it was not in the original budget, the spending would never have occurred without the existence of the TS station. As such, given the nature of this expenditure this should also be part of the project. When Festival recalculates the Incremental Capital Modules including the Bypass agreement it results in an amount of $682,746 plus 8 months at $455,164 for a total of $1,137,910 or $17,223 higher than the original filed request.

Festival is still of the belief the half year rule should only apply to the 2013 period and the 8 months for 2014 should be compensated at the full asset value, as outlined in E9/T3/S12 of the original filing.

b) *The resulting net book value would be $14,945,998. The change in the values in the ICM model impacts the distribution revenue earned as opposed to the net book value of the asset being transferred.*

174. 9. OEB STAFF 65

Ref: E9/T3/S11 – Stranded Meter Costs

Festival Hydro provided a cost allocation for stranded meter costs based on number of customers.

a) Please provide sheet I 7.1 from Festival Hydro last rebasing cost allocation study.

b) Please provide a cost allocation of stranded meters by rate class based on the breakdown of conventional meter costs found on sheet I7.1 as shown in Festival Hydro's 2010 cost of service application.

Response:

a) Sheet I7.1 from Festival's final 2010 COS Cost Allocation Model attached below.

b) The following is the determination of the stranded meter rate rider based on the 2010 COS Sheet I7.1:

	Residential	**G.S> < 50 kW**	**Total**
Number of Customers/meters per Sheet I7.1	17,115	1,968	19,083
Total weighted metering costs per Sheet I7.1	$1,097,812	$413,280	$1,511,092
% of total costs	72.65%	27.35%	100.00%
Total stranded SM costs per EDVAR continuity Tab 6 Rate Rider Calculation	$170,391	64,146	$234,537
# customers per EDVAR	18,224	2,029	20,363
Monthly per customer fixed Stranded meter RR charge	$0.78 per month fixed charge	$2.63 per month fixed charge	

TAB 15

13. UNDERTAKING NO. JT1. 12:

Ref: Page 43

To explain why O&M and the Bypass Agreement are included in the Deferral account.

Response:

The ICM account # 1508 as presented by Festival includes the following: the capital costs of constructing the TS, the operating costs for 2013 and 2014, funding collected through the ICM rate rider since May 1, 2013 and carrying charges at rate of 1.47%.

Just to clarify, the Permanent Bypass Agreement is not included in the ICM model. It was a spending decision made separate from the Transformer Station construction costs and the spending was justified like any other capital expenditure undertaken by Festival. Under previous accounting rules, consideration would have been made to add this directly to the asset account USoA # 1815. However, based on accounting rules (CGAAP 3048 and IAS 48) in place in 2013, this capital spend has been recognized as an intangible asset, which is described in depth under JT 1 14.

<u>Operating and Maintenance (O & M) Expenses of the Transformer station (TS) included in the ICM account:</u>
Festival included in the ICM variance account the O&M associated with operating the TS station in 2013 and 2014. The same accounting principles were applied as were followed for smart meters. For both smart meters and TS construction, the 2010 rate application did not include the operating costs associated with these assets. Festival has since learned that the ICM policy does not allow for O & M expenses to be included in the ICM account.

In the event these expenses are removed from the ICM account, Festival has reviewed the various policy options available from the Board and request that these expenses be placed into a variance account and be given Z factor recognition.
In Chapter 3 of the Filing Guidelines the following are the filing guidelines for a Z factor event:

- *A distributor must submit evidence that the costs incurred meet the three eligibility criteria (causation, materiality, prudence)*
- *. A distributor must also:*
    - *Notify the Board promptly by letter to the Board Secretary of all Z-factor events. Failure to notify the Board within six months of the event may result in disallowance of the claim.*
    - *Apply to the Board for any cost recovery of amounts recorded in the Board-approved deferral account claimed under Z-factor treatment. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts for which Z-factor treatment is claimed.*
    - *Provide a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations.*

- *Demonstrate that the costs are incremental to those already being recovered in rates as part of ongoing business exposure risk.*

In terms of meeting the criteria of causality, materiality and prudence as described below:

Causality: These costs are unique to the operation of a transformer station and only arise as a result of its operation. In Festival' s 2010 rate application there were no operating expenses as such included in the Board approved O & M, as the TS asset itself was not identified as an expenditure at that time. As such, expenses were incurred in 2013 and are currently being incurred in 2014 as identified in the table below.

Materiality: Festival's materiality is 0.5% of revenue requirement, which based on the RWWF filed with these filing totals close to $57,000. The expenses incurred in 2013 and projected for 2014 total $104,815 and $140,000, respectively. These expenses in each of 2013 and 2014 exceed materiality.

Prudence: The major cost components for the 2013 and 2014 expenses are noted in the table below. Being the station is new the costs being claimed are routine O & M costs. In terms of the station monitoring cost , rather than hiring staff to provide 24-7 coverage (which would have been expensive) , an RFP was put out to surrounding LDCs, with TS monitoring stations, for site monitoring services. Festival assessed the LDCs on various criteria including price, with the lowest priced vendor being selected for site monitoring.

O & M Expenses	2013	2014
Training Costs	39,826	$ 3, 000
TS Monitoring Costs	3,750	15,000
TS Communication Costs	16,614	24,500
Property taxes	9,926	21,500
Insurance & property protection	7,395	18,000
SCADA maintenance		5,000
Internal labour & trucking costs	18,003	13,000
Station maintenance	9,301	40,000
Total	**$ 104,815**	**$ 140,000**

In terms of meeting the six month criteria of notification to the Board, Festival did not originally report the expenses as they did not originally envisage this as being a Z factor claim. The fact these expenses existed were first reported to the Board as part of this original rate application file May 27, 2014. Most of the 2013 expenses were incurred in the last half of 2013.

At a minimum, Festival feels the 2014 costs should be subject to Z factor treatment as these costs are currently being incurred. With respect to 2013 costs, being these costs were not part of 2010 rates, and were not foreseeable costs at that time, Festival submits the 2013 costs also be allowed recovery through the Z factor account. These costs are all incremental in nature.

TAB 16

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January 4, 2013

BY COURIER

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor, P.O. Box 2319
TORONTO, ON M4P 1E4

Re: Festival Hydro Inc. 2014 Cost of Service Application Deferral Request

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Dear Ms. Walli:

Festival Hydro Inc. (Festival) is scheduled to file a Cost of service application for rates effective May 1, 2014 as noted in the Board's letter dated December 11, 2012. Festival respectfully requests a departure from this rebasing schedule and requests a cost of service application be filed by Festival for rates effective January 1, 2015.

Festival highlights that this letter serves two purposes. One to request a transition from May 1 rates to January 1 rates, and secondly to request a deferral from a 2014 cost of service application to a 2015 application based on the report cited below.

Festival notes that in the Board report "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" dated October 18, 2012, page 69 indicates that:

> *"For distributors scheduled to rebased for 2014 and planning to seek the Board's approval for January 1 rates, there will be two options available……(2) Delay rebasing by one year – rebase for January 1, 2015 rates, in which case the application will be filed using the Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements, and the total term will be 5 years."*

Festival is making the deferral request under this highlighted option in the report.

Festival performed significant analysis in determining if a request at this time was feasible. Festival considered the following:

- Benefit of having rate changes aligned with our fiscal year
- Financial impact of rebasing May 1, 2014 versus January 1, 2015
- Approval or disapproval of our ICM application as we may not get a final response on this until as late as April 2013
- A January 1, 2015 application approval would also require one additional third generation IRM filing for an eight month period (May 1, 2014 – January 1, 2015)

Festival's believes the benefits of moving to a rate year that matches our fiscal year are substantial in that this matches distribution rates with the expenses upon which the rates are granted.

Festival performed a financial analysis on the feasibility of the deferral and noted that an eight month deferral would not negatively impact our financial position by any significant amount. Festival also notes that we are not earning an unacceptable return on equity currently. Festival advises that its actual rate of return on average equity for 2011, the most recent year for which complete data is available, was 11.71%, and falls within the trigger of 300 basis points from the Board-approved return of 9.85%. Festival estimates its 2012 rate of return on average equity to be 9.08%, also within the trigger of 300 basis points from the Board-approved return.

Festival also notes that this deferral request is contingent on Board approval of our incremental capital rate rider request in our 2013 IRM application, as our financial analysis performed in making the deferral request indicates that the deferral would not be feasible should the ICM rate rider not be approved. In addition, Festival's deferral decision is based on an ICM rate rider being approved effective May 1, 2013, to be in effect until the effective date of the next cost of service rate rider. Festival has at this point answered all concerns of OEB staff and interveners in regards to our ICM application and believes that the application is supported by Board staff and our interveners. As such Festival feels it is reasonable to move forward with our COS deferral request.

It would be Festival's intention to submit a third generation IRM rate application for rates effective May 1, 2014, with Board approval to defer our cost of service application to January 1, 2015. This amounts to only an eight-month deferral.

In relation to the other considerations the Board will have in deciding on this deferral beyond Festival's financial position, Festival feels our performance with respect to system reliability indicators and electricity service quality requirements as reported to the Board are satisfactory.

In summary, Festival requests deferral of its rebasing due to the fact that it meets the Board requirements to request such deferral and there is a desire to have distribution rates match the fiscal year of the utility. Given the release of the Renewed Regulatory Framework, Festival has been given the option of deferring a January 1, 2014 cost of service application to January 1, 2015.

Should you require any further information or clarification please contact me.

Respectfully submitted,

J. Vanderbaan, Chief Operating Officer

TAB 19