EB-2010-0131

IN THE MATTER OF the *Ontario Energy Board Act*, *1998,*

being Schedule B to the *Energy Competition Act, 1998* S.O. 1998, c. 15;

AND IN THE MATTER OF an Application by Horizon Utilities Corporation to the Ontario Energy Board for an Order or Orders approving of fixing just and reasonable rates and other service charges for the distribution of Electricity as of January 1, 2011.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES") RESPONSES TO ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #1

Reference: Energy Probe Interrogatory #4 & Exhibit 2, Tab 2, Schedule 2, Figure 2-11

a) Please explain the reduction in the opening balance of approximately $869,000 as shown in the interrogatory response as compared to the original evidence (in accounts 1915, 1920, 1925 and 1940).

b) Does Horizon now have actual data for capital expenditures in 2010? If not, when will this information be available? If yes, please update the interrogatory response to reflect actual data.

Response:

a) As noted in the footnote to Horizon Utilities' response to Energy Probe Interrogatory 4 (at the bottom of the Fixed Asset Continuity Schedule), the 2010 opening balances were restated to reflect the reclassification of certain Smart Meter expenditures. As part of the preparation of the Interrogatory Responses for Horizon Utilities' Application for a Smart Meter Funding Adder (EB-2010-0292), and based on a detailed review of all Smart Meter related expenditures, Horizon Utilities reclassified certain capital expenditures previously recorded in fixed assets in prior years to the Smart Meter variance account in 2010.

b) The table on the following page presents the actual capital expenditures for 2010.

Please note these figures are subject to the review and final approval of 2010 financial results by Horizon Utilities' Board of Directors.

Horizon Utilities Corporation

Fixed Asset Continuity Schedule

December 31, 2010

		Cost				Accumulated Depreciation				
OEB	Asset Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1675	Standby Generators	-	-	-	-	-		-	-	-
1805	Land - Substations	414,741.45	-	-	414,741.45	-	-	-	-	414,741.45
1808	Buildings - Substations	2,138,307.23	15,175.00	-	2,153,482.23	1,534,816.36	76,082.58	-	1,610,898.94	542,583.29
1810	Leasehold Improvements	20,885.65	-	-	20,885.65	20,885.65	-	-	20,885.65	-
1820	Substation Equipment	11,774,640.47	968,939.14	-	12,743,579.61	9,116,218.72	295,743.63	-	9,411,962.35	3,331,617.26
1830	Poles, Towers & Fixtures	69,899,086.43	7,038,048.89	1,508,582.26	75,428,553.06	26,066,828.00	2,840,907.27	1,508,582.26	27,399,153.01	48,029,400.05
1835	OH Conductors & Devices	71,233,394.76	4,338,975.06	1,185,472.71	74,386,897.11	31,392,269.25	2,897,758.13	1,185,472.71	33,104,554.67	41,282,342.44
1840	UG Conduit	115,114,231.17	4,791,623.87	2,516,570.76	117,389,284.28	62,741,200.83	4,598,464.66	2,516,570.76	64,823,094.73	52,566,189.55
1845	UG Conductors & Devices	117,085,475.74	8,042,752.05	2,322,149.80	122,806,077.99	56,742,929.44	4,724,862.50	2,322,149.80	59,145,642.14	63,660,435.85
1850	Line Transformers	96,118,395.81	6,188,044.31	2,636,334.25	99,670,105.87	46,038,177.24	3,834,234.30	2,636,334.25	47,236,077.29	52,434,028.58
1855	Services (OH & UG)	24,184,344.55	1,987,036.06	181,818.45	25,989,562.16	8,685,690.83	1,051,388.38	181,818.45	9,555,260.76	16,434,301.40
1860	Meters	37,819,862.01	1,715,776.09	218,192.17	39,317,445.93	16,605,869.60	1,479,361.33	218,192.17	17,867,038.76	21,450,407.17
1860	Smart Meters	-	-	-	-	0.00	-	-	0.00	(0.00)
1905	Land	1,067,629.41	-	-	1,067,629.41	-	-	-	-	1,067,629.41
1906	Land Rights	162,636.38	-	-	162,636.38	68,811.22	3,338.04	-	72,149.26	90,487.12
1908	Buildings & Fixtures	27,974,291.61	602,913.54	-	28,577,205.15	17,025,093.37	1,264,769.99	-	18,289,863.36	10,287,341.79
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1915	Office Furniture & Equipment	4,912,728.77	386,855.14	-	5,299,583.91	3,572,955.60	195,441.85	-	3,768,397.45	1,531,186.46
1920	Computer - Hardware	5,613,068.40	-	-	5,613,068.40	5,586,452.41	17,095.08	-	5,603,547.49	9,520.91
1920	Computer - Hardware post Mar 22/04	3,146,170.79	1,304,463.75	-	4,450,634.54	1,389,433.14	501,245.58	-	1,890,678.72	2,559,955.82
1925	Computer - Software	10,838,623.58	1,035,450.75	-	11,874,074.33	6,275,340.06	1,333,617.51	-	7,608,957.57	4,265,116.76
1930	Transportation Equipment	17,306,131.00	1,590,515.73	833,682.54	18,062,964.19	11,223,609.71	1,339,990.91	790,271.61	11,773,329.01	6,289,635.18
1935	Stores Equipment	892,540.18	75,520.96	-	968,061.14	508,718.12	41,479.34	-	550,197.46	417,863.68
1940	Tools, Shop & Garage Equipment	7,332,746.94	515,236.30	-	7,847,983.24	5,749,616.33	292,263.94	-	6,041,880.27	1,806,102.97
1945	Measurement & Testing Equipment	1,458,621.39	54,129.85	-	1,512,751.24	947,240.12	91,163.81	-	1,038,403.93	474,347.31
1950	Power operated Equipment	144,034.63	-	-	144,034.63	97,238.19	11,436.36	-	108,674.55	35,360.08
1955	Communications Equipment	1,350,163.26	94,910.37	-	1,445,073.63	511,344.49	123,491.14	-	634,835.63	810,238.00
1960	Load Management controls	515,329.99	-	-	515,329.99	151,458.99	51,532.92	-	202,991.91	312,338.08
1980	System Supervisory Equipment	3,777,542.26	-	-	3,777,542.26	3,026,481.78	80,148.96	-	3,106,630.74	670,911.52
1995	Hydro One S/S Contribution	7,973,483.12	2,356,666.67	-	10,330,149.79	899,179.47	214,058.77	-	1,113,238.24	9,216,911.55
1995	Contributions & Grants	(31,486,410.68)	(8,512,542.04)	-	(39,998,952.72)	(3,509,459.21)	(1,389,916.63)	-	(4,899,375.83)	(35,099,576.89)
Total 2105	Sub-Total	608,782,696.30	34,590,491.49	11,402,802.94	631,970,384.85	312,468,399.72	25,969,960.36	11,359,392.01	327,078,968.07	304,891,416.78
2055	Work in Process	6,315,953.40	2,841,192.68		9,157,146.08	-	-	-	-	9,157,146.08
	Total	615,098,649.70	37,431,684.17	11,402,802.94	641,127,530.93	312,468,399.72	25,969,960.36	11,359,392.01	327,078,968.07	314,048,562.86
						Less Fleet	1,339,990.91			
						Less Stores	41,479.34			
						Net Depreciation	24,588,490.11			

1

EB-2010-0131

**HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS**

DELIVERED: February 23rd, 2011

QUESTIONS TC #2

Reference: Energy Probe Interrogatory #5

a) Please confirm that the GST included as part of the $7.3 million cost of the Vansickle TS station is not included in rate base.

b) The projects shown in the table in response to part (a) of the interrogatory result in a total CWIP amount of $2,176,894. How does this figure compare to the amount originally forecast to be in CWIP versus in rate base at the end of 2010?

Response:

a) Horizon Utilities confirms that the GST included in the $7.3 million cost of the Vansickle TS project was not included in rate base. The amount included in rate base for the Vansickle TS project was $6,933,466. Such is the amount of the contribution without GST.

b) The 2010 year-end CWIP amount of $2,176,894 relates only to distribution projects in excess of $500,000. Horizon Utilities does not prepare forecasts of CWIP amounts by project, and therefore cannot provide a corresponding forecast figure.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #3

Reference: Energy Probe Interrogatory #6 & Exhibit 2, Tab 4, Schedule, Appendix 2-2

a) Please confirm that based on the figures provided in the response to part (d) that the RPP volumes as a total share of the volumes consumed in 2010 have gone down relative to that used in the cost of power calculation. For example, the residential RPP share used in the original calculation in Exhibit 2, Tab 4, Schedule 1, Appendix 2-2 was approximately 97.47%, whereas the actual share in 2010 was 84.19%.

b) Please update the response provided in part (g) to reflect the RPP/non-RPP split shown in the table provided in the response to part (d).

Response:

a) Horizon Utilities confirms that the figures provided in the response to Energy Probe Interrogatory 6 d) correctly represent the RPP volumes as a total share of the volumes consumed in 2010.

b) The table below has been updated to reflect the RPP/non-RPP split as requested. At this time, Horizon Utilities has available the actual 2010 demand and consumption data for the Large Use class and has therefore updated the 2011 cost of power data in the table below. Additionally, Horizon Utilities has corrected the Volume Metrics for Wholesale Market Service and Rural Rate Assistance charges and has used the most recent Regulated Price Plan Price Report dated October 18, 2010 for the period November 1, 2010 to October 31, 2011.

2011 COST OF POWER FORECAST CALCULATION

Electricity - Commodity		2011	2011		
Class per Load Forecast	**2011 Forecasted Metered kWhs**	**Loss Factor**	**Uplifted**	**Cost Of Energy**	**Total Cost**
Residential	1,580,203,371	1.0410			
- Rpp			1,384,918,520	0.06838	$94,700,728
- Non Rpp			260,073,189	0.06561	$17,063,402
GS<50kW	552,044,772	1.0410			
- Rpp			485,086,213	0.06838	$33,170,195
- Non Rpp			89,592,395	0.06561	$5,878,157
GS>50kW	1,781,012,386	1.0421			
- Rpp			209,727,210	0.06838	$14,341,147
- Non Rpp			1,646,265,798	0.06561	$108,011,499
Large User	704,134,030	1.0067			
- Rpp			0	0.06838	$0
- Non Rpp			708,851,728	0.06561	$46,507,762
Unmetered Scattered Load	12,541,586	1.0410			
- Rpp			12,200,637	0.06838	$834,280
- Non Rpp			855,154	0.06561	$56,107
Sentinel Lighting	502,459	1.0410			
- Rpp			508,519	0.06838	$34,773
- Non Rpp			14,541	0.06561	$954
Street Lighting	40,006,298	1.0410			
- Rpp			220,727	0.06838	$15,093
- Non Rpp			41,425,829	0.06561	$2,717,949
TOTAL	**4,670,444,902**		**4,839,740,459**		**$323,332,045**

Transmission - Network		Volume			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	1,644,991,709	$0.0059	$9,705,451
GS<50kW		kWh	574,678,608	$0.0052	$2,988,329
GS>50kW		kW	4,856,870	$2.0572	$9,991,554
Large User		KW	2,853,449	$2.3501	$6,705,890
Unmetered Scattered Load		kWh	13,055,791	$0.0053	$69,196
Sentinel Lighting		kW	1,421	$1.7095	$2,429
Street Lighting		kW	111,295	$1.6195	$180,242
TOTAL					**$29,643,091**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	1,644,991,709	$0.0049	$8,060,459
GS<50kW		kWh	574,678,608	$0.0045	$2,586,054
GS>50kW		kW	4,856,870	$1.7739	$8,615,602
Large User		KW	2,853,449	$2.0385	$5,816,756
Unmetered Scattered Load		kWh	13,055,791	$0.0046	$60,057
Sentinel Lighting		kW	1,421	$1.4275	$2,028
Street Lighting		kW	111,295	$1.3918	$154,900
TOTAL					**$25,295,856**

Wholesale Market Service		Volume			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	1,644,991,709	$0.0052	$8,553,957
GS<50kW		kWh	574,678,608	$0.0052	$2,988,329
GS>50kW		kWh	1,855,993,007	$0.0052	$9,651,164
Large User		kWh	708,851,728	$0.0052	$3,686,029
Unmetered Scattered Load		kWh	13,055,791	$0.0052	$67,890
Sentinel Lighting		kWh	508,519	$0.0052	$2,644
Street Lighting		kWh	41,646,556	$0.0052	$216,562
TOTAL			**4,839,725,918**		**$25,166,575**

Rural Rate Assistance		Volume			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	1,644,991,709	$0.0013	$2,138,489
GS<50kW		kWh	574,678,608	$0.0013	$747,082
GS>50kW		kWh	1,855,993,007	$0.0013	$2,412,791
Large User		kWh	708,851,728	$0.0013	$921,507
Unmetered Scattered Load		kWh	13,055,791	$0.0013	$16,973
Sentinel Lighting		kWh	508,519	$0.0013	$661
Street Lighting		kWh	41,646,556	$0.0013	$54,141
TOTAL			**4,839,725,918**		**$6,291,644**

	2011
4705-Power Purchased	$323,332,045
4708-Charges-WMS	$25,166,575
4714-Charges-NW	$29,643,091
4716-Charges-CN	$25,295,856
4730-Rural Rate Assistance	$6,291,644
4750-Low Voltage	$251,010
TOTAL	**409,980,221**

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #4

Reference: EP Interrogatory 7 & Exhibit 2, Tab 4, Schedule 1, Appendix 2-3

a) The evidence indicates that the billing lag was estimated to be 17.35 days. Was this estimate based on the assumption that the lag was the same for each rate class? If not, please provide a table showing the calculation of the overall 17.35 day billing lag.

b) Similar to (a) above, was the estimate of the overall payment processing lag of 1.21 days based on the assumption that the lag was the same for each rate class? If not, please provide a table showing the calculation of the overall 1.21 day payment processing lag.

c) The evidence indicates that the collection lag is a dollar weighted average. Please provide a table, similar to the response provided in part (a) of the interrogatory, showing the calculation of the collection lag.

d) The response provided to part (a) of the interrogatory indicates that the number of customers/accounts was used for the weighting. What year was used to arrive at these figures?

e) The response provided to part (a) of the interrogatory shows that the weighting factor used to arrive at the overall service lag is the number of customers/accounts. Please provide a revised calculation of the overall service lag if the weighting factors were changed from the number of customers/accounts to revenue (i.e. distribution revenue, transmission related costs, cost of power, regulatory charges, debt retirement charge, etc.).

Response:

a) Yes, the estimate that the billing lag was estimated to be 17.35 days was based on the assumption that the lag was the same for each rate class.

b) Yes, the estimate of the overall payment processing lag of 1.21 days was based on the assumption that the lag was the same for each rate class.

c) The following table provides the computation of the collection lag:

RECEIVABLES BALANCES - $s	
Current	45,710,004
Less Than 30 Days	10,531,479
31 - 60 days	1,999,527
61 - 90 days	788,233
> 90 Days	1,955,275
Total	60,984,518
PERCENT OF TOTAL	
Current	74.95%
Less Than 30 Days	17.27%
31 - 60 days	3.28%
61 - 90 days	1.29%
> 90 Days	3.21%
AVERAGE LAG TIME (Days)	
Current	16.00
Less Than 30 Days	23.00
31 - 60 days	38.00
61 - 90 days	53.00
> 90 Days	190.50
TOTAL WEIGHTED LAG TIME	**24.0032 days**

d) The year 2009 was used to arrive at the figures.

e) Service Lag is intended to measure the amount of time between the start of a period of energy delivery to a customer and the time the service period ends and the customer's meter is read. For working capital purposes, the overall service lag for Horizon Utilities would be exactly at the mid-point of the service lags for all customers served.

Assume hypothetically that a utility such as Horizon Utilities has two customers: Customer A whose meter is read bi-monthly and Customer B whose meter is read monthly. The mid-point of the service period for the bi-monthly customer would be 30 days and that for the monthly customer would be 15 days. All else being equal, a weighted average of the time that service was received from the Company by both customers and meters were read would be 22.5 days i.e., (30+15)/2. Horizon Utilities submits that this result is appropriate given that the weighted average service time is exactly at the mid-point of the mid-point of both customers.

Assume further that that the bi-monthly customer (Customer A) has a bill of $1,000 and the monthly customer (Customer B) has a bill of $9,000. Using dollars to weight the period of service would indicate that the average period of service for both customers would be (30 * $1,000/$10,000) + (15 * $9,000/$10,000), i.e., 16.5 days. Horizon Utilities submits that this result of 16.5 days is not appropriate given that it is not representative of how service was provided to both customers, particularly the bi-monthly customer.

Respectfully, Horizon Utilities submits that it is not appropriate to use weights based on revenues to calculate the service lag. Horizon Utilities' meter reading and billing cycles initiate a revenue cycle which affects specific customers irrespective of the revenues associated with those specific customers. In the example above, the meter reading and billing cycles would occur when the service period ends and meters are read. Horizon Utilities has a fixed meter reading schedule that is dependent on the resources available, the number of customers that receive service, where they are located, and how their meters are read (e.g., AMR, manual, etc.). Horizon Utilities' meter reading schedule is not based on expectations of revenues from any particular class or type of customer and thus, it would be inappropriate to use a revenue weighting approach to determine the average period of time over which Horizon Utilities' customers receive service.

With consideration for the foregoing submissions, the following is a revised calculation of the overall service lag if the weighting factors were changed from the number of customers/accounts to revenue. The service lag for 2009 would be 26.70 days.

Rate Classification	Revenues from Monthly Customers	Revenues from Bi Monthly Customers	Total Revenues	Service Lag Monthly Customers Days	Service Lag Bi Monthly Customers Days	Monthly	Bi Monthly	Weighted Lag
Residential	$ -	$55,192,117	$55,192,117	15.21	30.42	0.00%	62.31%	18.95
General Service < 50	-	10,889,476	10,889,476	15.21	30.42	0.00%	12.29%	3.74
General Service > 50	15,201,214	-	15,201,214	15.21	30.42	17.2%	0.00%	2.61
Large Users	4,797,288	-	4,797,288	15.21	30.42	5.4%	0.00%	0.82
Unmetered and Scattered	-	822,018	822,018	15.21	30.42	0.0%	0.93%	0.28
Sentinel	-	30,105	30,105	15.21	30.42	0.00%	0.03%	0.01
Streetlights	1,650,885	-	1,650,885	15.21	30.42	1.86%	0.00%	0.28
Total	$21,649,387	$66,933,717	$ 88,583,104					**26.70**

1

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO

ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTIONTC #5

Reference: Energy Probe Interrogatory #13

a) What is the $150,000 in account 4325 related to?

b) When will Horizon complete its year end process for 2010? If now completed, please provide an updated Table 3-25 that reflects actual 2010 data.

Response:

a) The $150,000 that was included in account 4325 for the 2010 Bridge Year represents 3 years of Merchandising Revenue. This is the 2010 forecast for this account, based on the September 30, 2010 forecast. Horizon Utilities includes a markup on costs charged to external parties such as repairs due to traffic accidents and the markup thereon is included as Merchandising Revenue.

b) Please find below the Updated Table 3-25 showing actual 2010 data. Please note these figures are subject to the review and final approval of 2010 financial results by Horizon Utilities' Board of Directors.

Expense Description	2010 Bridge
Other Distribution Revenue	
4082-Retail Services Revenues	0
4084-Service Transaction Requests (STR) Revenues	0
4210-Rent from Electric Property	1,344,410
4220-Other Electric Revenues	0
4225-Late Payment Charges	940,190
4235-Miscellaneous Service Revenues	1,793,409
4325-Revenues from Merchandise, Jobbing	151,374
4355-Gain on Disposition of Utility and Other Property	99,313
4360-Loss on Disposition of Utility and Other Property	0
4375-Revenues from Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	1,079,214
4405-Interest and Dividend Income	55,044
Sub-Total	**5,462,954**
4080-Distribution Services Revenue - SSS Admin. Fee	599,926
Total	**6,062,880**

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES") RESPONSES TO

ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #6

Reference: Energy Probe Interrogatory #14 & VECC Interrogatory #27

The responses provided indicate that any assets used would principally be related to information technology costs such as computer hardware and software and that the cost recoveries do not include a return on the assets used.

a) Are any of the depreciation costs associated with assets used to provide the services recovered through the management fee? If yes, please quantify.

b) Why are there no information technology costs allocated to Horizon Utilities for non-regulated billing services, as shown in the response to the Energy Probe interrogatory?

c) Please calculate the fully allocated percentage of computer hardware and software that is used in the provision of services covered by the management fee.

d) Please calculate the fully allocated percentage general plant (such as office equipment, furniture, etc.) that is used in the provision of services covered by the management fee.

Response:

a) No, depreciation expense is not specifically included in the management fee. Please refer to Horizon Utilities' response to VECC Technical Conference Question 15.

b) Within Horizon Utilities, information technology costs are charged to each department, including non-regulated billing services, as a "distributable cost" (as defined in Horizon Utilities' response to VECC Interrogatory 19 e), rather than as an allocated charge for shared services. The total amount of information technology OM&A expenses distributed to the Customer Services department for 2011 is $1,465,000. Such costs are then allocated to the non-regulated billing services.

With respect to the assets used to provide the non-regulated billing services, the primary assets used are computer hardware and software, and more specifically the Daffron Customer Information System ("Daffron CIS"). The Daffron CIS was purchased in 2000 and is fully depreciated. In addition, as documented in Horizon Utilities' response to VECC Technical Conference Question 15, to the extent any assets are used exclusively by a non-rate regulated entity in conjunction with shared services provided by Horizon Utilities, such assets are owned by the non-regulated entity and are not included in the rate base. With respect to any software modifications to the Daffron CIS that are specifically related to the non-regulated billing services, such costs are directly charged to the customer.

c) Please refer to Horizon Utilities' response to VECC Technical Conference Question 15

d) To the extent that any general plant assets are used exclusively by any non-rate regulated entity, such assets are owned by that entity and have not been included in the rate base.

The primary departments that provide shared services include Information Technology, Human Resources, Supply Chain and Finance. With respect to these departments, Horizon Utilities has not undertaken a detailed cost allocation study to determine the other specific general plant assets used in providing shared services to non-regulated businesses. In general, such assets would include office furniture and equipment and building space. As such, it is not possible to provide an allocated percentage of the general plant that is used in the provision of shared services.

With respect to the building space, such shared service departments occupy the following space as a percentage of the total square footage of the John St. location:

Human Resources	5.5%
Information Technology	5.5%
Finance and Supply Chain	11.0%
Customer Services	11.0%

The estimated NBV of the John St. building is approximately $3.9MM as at January 1, 2011.

By way of illustration, assuming that an appropriate cost driver for the allocation of general plant assets is the same driver used to allocate the Human Resources OM&A costs, the allocation to the shared services for building costs could be computed as follows:

	Horizon Utilities Regulated Ops	Hamilton Utilities Corporation/ Hamilton Hydro Services Inc.	Hamilton Hydro Services Inc. Water Heater Billing
January 1, 2011			
Estimated Opening NBV, John St. Building	$ 3,900,000		
Allocation of NBV based on Square Footage - Human Resources Department (5.5%)		$ 214,500	$ 214,500
Allocation % based on Human Resources Cost Driver		1.716%	0.2000%
Allocation of NBV based on % above		$ 3,681	$ 429
2011 Rate of Return		7.27%	7.27%
Maximum ROE on NBV of Building Asset Used to Provide Shared Services		$ 268	$ 31

Horizon Utilities respectfully submits that the allocated return on such assets would not be material and that the incremental cost of conducting a detailed cost allocation study would outweigh any resulting benefit to the ratepayer.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO

ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #7

Reference: Energy Probe Interrogatory #17

a) Please provide the most recent year-to-date information available with respect to the OM&A expenses incurred in 2010 if complete 2010 data is not yet available. Please note that this information is not required by USoA account number. An aggregate total of OM&A is sufficient.

b) Please provide the corresponding figure for the same year-to-date period in 2009.

Response:

a) Total OM&A, excluding Smart Meters, for the regulated distribution operations for the year ended December 31, 2010 was $39.5MM. Please note the results for the year ended December 31, 2010 are still subject to the final review and approval by Horizon Utilities' Board of Directors.

b) As shown in Exhibit 4, Tab 2, Schedule 1, Page 1, actual total OM&A in 2009 was $38.8MM (excluding property taxes of $762,905).

**HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO**

ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #8

Reference: Energy Probe Interrogatory #31

a) The response to part (b) is not clear. Please confirm that the total number of apprentices eligible for the Ontario Apprenticeship Tax Training Credit in 2011 will be 34, consisting of 8 hired in 2009, 13 in 2010 and 11 in 2011. If this is not correct, please indicate how many apprentice positions are eligible for this tax credit in 2011

b) The following is copied from http://www.cra-arc.gc.ca/tx/ndvdls/tpcs/ncm-tx/rtrn/cmpltng/ddctns/lns409-485/412/jctc-eng.html

Apprenticeship Job Creation Tax Credit (AJCTC)

The AJCTC is a non-refundable tax credit equal to 10% of the eligible salaries and wages payable to eligible apprentices in respect of employment after May 1, 2006. The maximum credit an employer can claim is $2,000 per year for each eligible apprentice. If your business hires an "eligible apprentice", you qualify to claim the credit.

Who is an "eligible apprentice"?

An "eligible apprentice" is someone who is working in a prescribed trade in the first two years of their apprenticeship contract. This contract must be registered with a federal, provincial or territorial government under an apprenticeship program designed to certify or license individuals in the trade.

A prescribed trade includes the 53 trades currently listed as Red Seal Trades. For more information, see the Interprovincial Standards Red Seal Program.

Since the apprenticeship contracts are registered with the province and the reference to the Red Seal Trades appears to be used only to identify the prescribed trades that are eligible, please explain why Horizon does not believe it is eligible for the federal apprenticeship job creation tax credit.

c) Has Horizon investigated or sought a ruling on whether or not its apprentice positions are eligible for the federal credit? If not, why not? Has Horizon talked about this issue with any other Ontario electricity distributor that is claiming this tax credit?

Response:

a) There are 34 apprentices eligible in 2011 in part, consistent with the breakdown provided for 2009, 2010, and 2011 with a carryover of 2 eligible apprentices from 2008.

b) Horizon Utilities has investigated its eligibility for the AJCTC further. Based on such review, Horizon Utilities believes that its "Powerline Maintainer" trades, which correspond to the "Powerline Technician" Red Trades, would qualify for this credit. Of the 34 apprentices noted in a), 19 would represent Powerline Technician trades in 2011.

It will be Horizon Utilities' intention to file for the AJCTC in 2010 and 2011.

In order to ensure the integrity of its evidence, Horizon Utilities submits revised PILs Tax Calculations provided in Exhibit 4, Tab 3, Schedule 2 as follows:

- Table 4-37;
- Table 4-38;
- Table 4-39;
- Table 4-40

These tables have been revised and appear below to provide for the following:

1. Eligibility of 34 apprentices in 2011 for the Ontario Tax Training Apprenticeship Credit, which results in an aggregate credit of $340,000 (provided in Table 4-37);
2. Eligibility of 15 Powerline Technician apprentices in 2011 for the AJCTC (provided in Table 4-37), which results in an aggregate credit of $38,000;
3. Recognition that 1. And 2. are taxable credits and, as such, are adjusted as Other Additions through line 295 of Table 4-38;
4. Correction of Table 4-39 for 2010 and Table 4-40 for 2011 with respect to Class 52 assets. The nature of the correction is to recognize the following:
   a. Class 52 additions in the year are not subject to the ½ year rule. As such, CCA will be adjusted in Table 4-39 for 2010 to reflect full Class 52 UCC

utilization in that year. The 2010 UCC Ending Balance in Table 4-39 is corrected to report $0;

b. Table 4-40 incorrectly reports additions in Class 52 for 2011. Class 52 is no longer valid following January 31, 2011. Such additions reported in Class 52 in Table 4-40 are properly recorded in Class 50. As such, the following changes have been made in Table 4-40:
   i. The UCC Prior Ending Balance for Class 52 is restated to $0 to correspond to the change in 4.a.;
   ii. The $1,612,172 of additions reported as Class 52 have been now reported as additions in Class 50;
   iii. UCC and CCA balances and amounts have been revised to reflect the changes in 4.b.i. and 4.b.ii.

Table 4-38 has been revised to reflect the corrected CCA values resulting from 4.

Based on the revisions reported in 1.-4. above, Horizon Utilities submits a revised 2011 Total PILs value of $6,042,540 for recovery in its Application.

c) Please refer to the response in b.)

Revised Table 4–37 – Horizon Utilities – Detailed Tax Calculations

2010 Capital Taxes

Description	OCT	LCT
Total Rate Base	369,164,571	341,312,649
Exemption	-15,000,000	0
Deemed Taxable Capital	**354,164,571**	**341,312,649**
Rate	0.075%	0.000%
Gross Tax Payable	265,623	0
Surtax	0	0
Net Capital Tax Payable	**265,623**	**0**

2010 PILs Schedule

Description	Source or Input	Tax Payable
Accounting Income	10' Rev Def	17,194,379
Tax Adj to Accounting Income	10' Rev Def	881,304
Taxable Income		**18,075,683**
Combined Income Tax Rate	PILs Rates	31.000%
Total Income Taxes		**5,603,462**
Investment Tax Credits		
Apprentice Tax Credits		-
Other Tax Credits		-
Total PILs		**5,603,462**

2010 Total Taxes

Description	Tax Payable
Total PILs	5,603,462
Net Capital Tax Payable	265,623
PILs including Capital Taxes	5,869,085

2011 Capital Taxes

Description	OCT	LCT
Total Rate Base	376,890,026	369,164,571
Exemption	0	0
Deemed Taxable Capital	**376,890,026**	**369,164,571**
Rate	0.000%	0.000%
Gross Tax Payable	**0**	0
Surtax	0	0
Net Capital Tax Payable	**0**	**0**

2011 PILs Schedule

Description	Source or Input	Tax Payable
Accounting Income	10' Rev Def	20,892,007
Tax Adj to Accounting Income	10' Rev Def	1,835,569
Taxable Income		**22,727,576**
Combined Income Tax Rate	PILs Rates	28.250%
Total Income Taxes		**6,420,540**
Investment Tax Credits		
Apprentice Tax Credits		378,000
Other Tax Credits		-
Total PILs		**6,042,540**

2011 Total Taxes

Description	Tax Payable
Total PILs	6,042,540
Net Capital Tax Payable	-
PILs including Capital Taxes	6,042,540

Revised Table 4-38 – Horizon Utilities – Tax Adjustments to Accounting Income

Determination of Tax Adjustments to Accounting Income for 2010				
Line Item	**T2S1 line #**	**Total for Legal Entity**	**Non-Distribution Eliminations**	**Utility Amount**
Additions:				
Interest and penalties on taxes	103	0	0	0
Amortization of tangible assets	104	27,357,679	0	27,357,679
Amortization of intangible assets	106	0	0	0
Recapture of capital cost allowance from Schedule 8	107	0	0	0
Gain on sale of eligible capital property from Schedule 10	108	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	109		0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112	0	0	0
Taxable Capital Gains	113	0	0	0
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	0	0	0
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120		0	0
Non-deductible meals and entertainment expense	121	65,000	0	65,000
Non-deductible automobile expenses	122	0	0	0
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves beginning of year	125	350,000	0	350,000
Reserves from financial statements- balance at end of year	126	20,203,341	0	20,203,341
Soft costs on construction and renovation of buildings	127	0	0	0
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0
Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
Debt Financing Expenses for Book Purposes	294		0	0
Other Additions	295	0	0	0
Total Additions		**47,976,020**	**0**	**47,976,020**
Deductions:				
Gain on disposal of assets per financial statements	401		0	0
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	25,593,656	0	25,593,656
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	787,718	0	787,718
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	0	0	0
Tax reserves end of year	413	350,000	0	350,000
Reserves from financial statements - balance at beginning of year	414	20,203,341	0	20,203,341
Contributions to deferred income plans	416	0	0	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	0	0
Interest capitalized for accounting deducted for tax	390	0	0	0
Capital Lease Payments	391	0	0	0
Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
Financing Fees for Tax Under S.20(1)(e)	393	0	0	0
Other Deductions	394	160,000	0	160,000
Total Deductions		**47,094,716**	**0**	**47,094,716**
Other Adjustments to Taxable Income				
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 7-1	332	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
Total Adjustments		**0**	**0**	**0**
Tax Adjustments to Accounting Income		**881,304**	**0**	**881,304**

0

Determination of Tax Adjustments to Accounting Income for 2011

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Interest and penalties on taxes	103	0	0	0
Amortization of tangible assets	104	28,782,602	0	28,782,602
Amortization of intangible assets	106	0	0	0
Recapture of capital cost allowance from Schedule 8	107	0	0	0
Gain on sale of eligible capital property from Schedule 10	108	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	109		0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112	0	0	0
Taxable Capital Gains	113	0	0	0
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	0	0	0
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120		0	0
Non-deductible meals and entertainment expense	121	60,000	0	60,000
Non-deductible automobile expenses	122	0	0	0
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves beginning of year	125	350,000	0	350,000
Reserves from financial statements- balance at end of year	126	20,203,341	0	20,203,341
Soft costs on construction and renovation of buildings	127	0	0	0
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0
Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
Debt Financing Expenses for Book Purposes	294		0	0
Other Additions	295	378,000	0	378,000
Total Additions		**49,773,943**	**0**	**49,773,943**
Deductions:				
Gain on disposal of assets per financial statements	401		0	0
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	26,472,455	0	26,472,455
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	732,578	0	732,578
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	0	0	0
Tax reserves end of year	413	350,000	0	350,000
Reserves from financial statements - balance at beginning of year	414	20,203,341	0	20,203,341
Contributions to deferred income plans	416	0	0	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	0	0
Interest capitalized for accounting deducted for tax	390	0	0	0
Capital Lease Payments	391	0	0	0
Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
Financing Fees for Tax Under S.20(1)(e)	393	0	0	0
Other Deductions	394	180,000	0	180,000
Total Deductions		**47,938,374**	**0**	**47,938,374**
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 7-1	332	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
Total Adjustments		0	0	0
Tax Adjustments to Accounting Income		**1,835,569**	**0**	**1,835,569**

Revised Table 4-39 – Horizon Utilities – Continuity Schedule (2010)

CCA Continuity Schedule (2010)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	200,055,459	0	0	200,055,459	507,500	0	200,562,959	253,750	200,309,209	4%	8,012,368	192,550,591
2	Distribution System - pre 1988	44,221,606	0	0	44,221,606	0	0	44,221,606	0	44,221,606	6%	2,653,296	41,568,310
6	Buildings (No footings below ground)	19,844	0	0	19,844	0	0	19,844	0	19,844	10%	1,984	17,860
8	General Office/Stores Equip	6,782,224	0	0	6,782,224	1,263,169	0	8,045,393	631,585	7,413,809	20%	1,482,762	6,562,631
10	Computer Hardware/ Vehicles	4,648,691	0	0	4,648,691	1,305,000	0	5,953,691	652,500	5,301,191	30%	1,590,357	4,363,334
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	520,101	0	0	520,101	1,600,261	0	2,120,362	800,131	1,320,232	100%	1,320,232	800,131
3		0	0	0	0	0	0	0	0	0	20%	0	0
			0	0	0	0	0	0	0	0		0	0
13 3	Lease # 3	0	0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	88,130	0	0	88,130	0	0	88,130	0	88,130	8%	7,050	81,080
43.1	Certain Energy-Efficient Electrical Generating Equipment	538,223	0	0	538,223	0	0	538,223	0	538,223	30%	161,467	376,756
45	Computers & Systems Hardware acq'd post Mar 22/04	637,091	0	0	637,091	0	0	637,091	0	637,091	45%	286,691	350,400
50	Computers & Systems Hardware acq'd post Mar 19/07	0	0	0	0	0	0	0	0	0	55%	0	0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	88,630,710			88,630,710	35,881,039	0	124,511,749	17,940,520	106,571,230	8%	8,525,698	115,986,051
52	Computers & Systems Hardware acq'd post Jan 27/09 and before Feb 2011	438,919			438,919	1,112,831		1,551,750	0	1,551,750	100%	1,551,750	0
	SUB-TOTAL - UCC	**346,580,998**	**0**	**0**	**346,580,998**	**41,669,800**	**0**	**388,250,798**	**20,278,485**	**367,972,314**		**25,593,656**	**362,657,142**
						-3,241,295	9,393,500						
CEC	Goodwill	11,253,119	0	0	11,253,119								
CEC	Land Rights		0	0	0								
CEC	FMV Bump-up		0	0	0								
	SUB-TOTAL - CEC	**11,253,119**	**0**	**0**	**11,253,119**								

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				11,253,119
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	11,253,119
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				11,253,119
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	11,253,119
Cumulative Eligible Capital Balance				11,253,119
CEC Deduction	7%			787,718
Cumulative Eligible Capital - Closing Balance				10,465,401

Revised Table 4–40 – Horizon Utilities – Continuity Schedule (2011)

CCA Continuity Schedule (2011)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	192,550,591	0	0	192,550,591	1,540,500	0	194,091,091	770,250	193,320,841	4%	7,732,834	186,358,257
2	Distribution System - pre 1988	41,568,310	0	0	41,568,310	0	0	41,568,310	0	41,568,310	6%	2,494,099	39,074,211
6	Buildings (No footings below ground)	17,860	0	0	17,860	0	0	17,860	0	17,860	10%	1,786	16,074
8	General Office/Stores Equip	6,562,631	0	0	6,562,631	2,677,128	0	9,239,759	1,338,564	7,901,195	20%	1,580,239	7,659,520
10	Computer Hardware/ Vehicles	4,363,334	0	0	4,363,334	1,445,500	0	5,808,834	722,750	5,086,084	30%	1,525,825	4,283,009
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	800,131	0	0	800,131	1,933,578	0	2,733,709	966,789	1,766,920	100%	1,766,920	966,789
3		0	0	0	0	0	0	0	0	0	20%	0	0
		0	0	0	0	0	0	0	0	0	0%	0	0
13 3	Lease # 3	0	0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	81,080	0	0	81,080	0	0	81,080	0	81,080	8%	6,486	74,593
43.1	Certain Energy-Efficient Electrical Generating Equipment	376,756	0	0	376,756	0	0	376,756	0	376,756	30%	113,027	263,729
45	Computers & Systems Hardware acq'd post Mar 22/04	350,400	0	0	350,400	0	0	350,400	0	350,400	45%	157,680	192,720
50	Computers & Systems Hardware acq'd post Mar 19/07	0	0	0	0	1,612,172	0	1,612,172	806,086	806,086	55%	443,347	1,168,825
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	115,986,051			115,986,051	34,283,221	0	150,269,272	17,141,611	133,127,661	8%	10,650,213	139,619,059
52	Computers & Systems Hardware acq'd post Jan 27/09 and before Feb 2011	0			0	0		0	0	0	100%	0	0
	SUB-TOTAL - UCC	**362,657,142**	**0**	**0**	**362,657,142**	**43,492,099**	**0**	**406,149,241**	**21,746,050**	**384,403,191**		**26,472,455**	**379,676,786**
						-5,899,099	0						
CEC	Goodwill	10,465,401	0	0	10,465,401								
CEC	Land Rights	0	0	0	0								
CEC	FMV Bump-up	0	0	0	0								
	SUB-TOTAL - CEC	**10,465,401**	**0**	**0**	**10,465,401**								

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				10,465,401
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	10,465,401
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				10,465,401
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	10,465,401
Cumulative Eligible Capital Balance				10,465,401
CEC Deduction	7%			732,578
Cumulative Eligible Capital - Closing Balance				9,732,823

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #9

Reference: VECC Interrogatory #2

Please provide the 2011 test year forecast that results from the equation estimated in response to part (c) of the question.

Response:

Please see Horizon Utilities' response to VECC Technical Question 1 a).

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #10

Reference: CCC Interrogatory #32 & Energy Probe Interrogatory #26

Please provide a revised table as found in the response to the CCC interrogatory that shows the customers per FTEE for the years shown based on the actual FTEEs based on filled positions as shown in the Energy Probe response

Response:

Please find the revised table below.

	FTE's				
Department	**2008**	**2009**	**2010 Budget**	**2010 Q3 Forecast**	**2011**
Executive/Directors	15	17	17	15	18
Construction & Maintenance	132	132	139	135	147
Supply Chain Management	29	30	30	27	31
Engineering & Operating	46	49	50	48	57
Regulatory Affairs	6	7	7	6	9
Finance	11	14	16	14	18
Information Systems & Technology	11	17	20	17	24
Corporate Services & Human Resources	7	8	8	8	9
Corporate Communications	2	2	2	2	2
Health & Safety	2	2	2	2	2
Customer Service	63	64	66	66	66
Customer Connections	36	36	36	36	37
Facilities	8	8	8	8	8
Total	368	386	401	384	428
Customers	233,177	234,920	235,000	235,000	235,000
Customers/FTEE	634	609	586	612	549

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES") RESPONSES TO

ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #11

Reference: Board Staff Interrogatory #15

a) Please confirm that the actual 2010 large use consumption was 715.05 GWh.

b) Please provide the actual kW data for each month of 2010 and 2010 as a whole for the large use class.

Response:

a) Please see Horizon Utilities' response to AMPCO Technical Conference Question 4 a).

b) Please see Horizon Utilities' response to AMPCO Technical Conference Question 4 e).

**HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO**

ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #12

Reference: Energy Probe Interrogatory #38

The IR asked for a history of substation transformer failures for the years 2000 through 2010. The response listed only those failures that occurred from 2007 – 2010.

Please provide the listing of substation transformer failures by year for the period 2000 – 2006.

Response:

Horizon Utilities does not have any record of transformer failures between 2000 to 2006.

The table below lists all of the known substation transformer failures during the years 2000 – 2010. In addition to the information Horizon Utilities previously provided in its response to Energy Probe Interrogatory 38, Horizon Utilities has added an additional transformer, specifically Bartonville Spare, which was not in the original list. This brings the total number of substation transformer failures over the quoted time period to eight.

Although this transformer was not in service, Horizon Utilities was attempting to energize this transformer as a back-up transformer for this station, when it failed.

The sharp increase in substation transformer failures since 2007 is a clear indicator of aging assets that are now beyond end of useful life and the condition of these transformers is at a critical juncture where the assets are beginning to fail at an unacceptable rate.

Horizon Utilities' formal Asset Management Plan provides the age of its assets in more detail. The completion of a detailed Asset Condition Assessment Study on Horizon Utilities' substation assets is an important element to understanding the overall condition of these assets. Substations are the most critical component to the reliability of the distribution system; the information from the Asset Condition Assessment Study was an important element in planning Horizon Utilities' 4kV and 8kV Renewal Plan.

Some of these substations will remain in service for another 40 years until the 4kV and 8kV Renewal Plan is complete, so condition assessment studies of these assets assist in the prioritization of the renewal and decommissioning of these assets.

The two transformer failures in 2010 were identified as a high risk for failure in the Asset Condition Assessment Study. Such study highlights the risks associated with these aging assets. The identified risks in the study are, in fact, supported by the recent transformer failures.

Station Transformer	**Year of Failure**
Spadina T2	2007
Wentworth T2	2008
Eastmount T4	2009
Stroud's Lane T2	2009
Bartonville Spare	2009
Webster T1 (Blue Phase)	2010
Hughson T2	2010

EB-2010-0131

**HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO**

ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #13

Reference: Energy Probe Interrogatory #42

The IR asked for the study by Roy Billinton that developed the Value of Service metrics used by Horizon in its Customer Impact Score computations as well as the "Supplemental Applications Guidelines" referred to in the exhibit. The IR response indicated that both of the requested documents were attached to the IRR but only the "Supplemental Applications Guidelines" appears to have been included.

Please provide the study by Mr. Billinton.

Response:

Please find attached the Value Based Reliability Assessment Report authored by Roy Billinton as requested. Such report was omitted by error in Horizon Utilities' original response to Energy Probe Interrogatory 42.

Value Based Reliability Assessment

Introduction

Value Based Reliability Assessment (VBRA) involves the ability to perform quantitative reliability assessment of the system or subsystem and to estimate the outage costs associated with possible design, planning or operating alternatives. In the electric power system context, VBRA is a logical extension of quantitative reliability evaluation [1] that involves the assessment of reliability worth using customer electric power interruption costs [2]. Reference 3 contains a compendium of 150 papers and publications in the general literature that deal with interruption cost assessment and applications of these data in reliability worth evaluation.

A variety of methods has been utilized to evaluate customer impacts due to electric service interruptions. These methods [3] can be grouped, based on the methodological approach, into the three broad categories of: various indirect analytical evaluations, case studies of blackouts, and customer surveys.

The indirect analytical methods infer interruption cost values from associated indices or variables. The most common technique in this approach is estimate the value of unsupplied energy expressed in $/kWh by the ratio of the annual gross national product and the total electrical consumption. This technique usually results in a relatively low estimate of the cost of unserved energy. Additional analytical techniques are described in [2]. The main advantages of these methods are that they are reasonably easy to appreciate, use readily available data and therefore are easy and inexpensive to implement. The main disadvantages are that they are based on many severely limiting assumptions. These methods usually produce global values rather than specific results and generally do not reveal variations in cost with specific parameters that are important in the electric power industry.

There have been relatively few case studies conducted on actual system disturbances and have been limited to major large-scale outage events, such as the 1977 New York blackout. This study considered both direct and indirect short-term costs and a wide range of societal and organizational impacts. The results indicated that indirect costs such as emergency and civil disorder costs were much higher than the direct costs associated with loss of sales, wage loss, food spoilage, etc. etc. Post-disturbance cost data on significant power outage events in Australia, Canada, New Zealand, Norway, Sweden and the U.S.A. are presented in [3].

Customer surveys have been used in many jurisdictions [3] to assess direct, short-term customer interruption costs. In this approach, customers are asked to estimate their monetary costs/losses due to electric supply outages of various durations and frequencies at different times of the day and year. Direct costs are relatively easy to determine for some customer groups, such as industrial and commercial, and are less tangible for other groups such as residential consumers. A major advantage of the survey approach is that it can be tailored to obtain specific information deemed important to the electric power utility industry. Survey preparation is an important task in this approach and the overall cost and effort required is higher than in the other approaches. The survey approach, however, appears to be the method favoured by electric power utilities that require outage cost data for design, planning and operating purposes. The general philosophy behind the design and utilization of the survey approach to interruption cost evaluation is described in detail in [2]. Customer interruption cost surveys are usually focused on major customer categories or sectors, such as residential, industrial, commercial, agricultural, etc. Further customer categorization can, and has been employed, using the Standard Industrial Classification (SIC) system of customer identification. There is considerable variation in the costs within SIC groups in each sector and between SIC groups. The variations within groups, however, are considerably less than between groups [2]. The literature contains a wide array of detailed information in this area [3-8].

Cost of Interruption Surveys

Many cost of interruption surveys have been conducted by electric power utilities around the world. The following table from [3] presents a summary of these activities.

Table 1
Summary of the Surveys in CIGRE Report 38.06.09 [3]

Survey	Customer Sectors	Duration of Outage	Normalization	Year of Survey
Australia	A,C,I,L,R	2 sec – 48 h	Annual energy	1996-1997
Canada	A,C,I,O,R	2 sec – 24 h	Annual energy; Peak demand	1985-1995
Denmark	A,C,I,O,R	1 sec – 8 h	Peak demand	1993-1994
Great Britain	C,I,L,R	Momentary–24 h	Annual energy; Peak demand	1993
Greece	C,I	Momentary–24 h	Peak demand	1997-1998
Iran	C,I,R	2 sec – 2 h	Peak demand	1995
Nepal	C,I,R	1 min – 48 h	Annual energy; Peak demand	1996
New Zealand	C,I,R	< 2 h		1987
Norway	A,C,I,R	1 min – 8 h	Peak demand	1989-1991
Portugal	C,I,R	1 min – 6 h	Annual energy	1997-1998
Saudi Arabia	C,I,R	20 min – 8 h	Annual energy; Peak demand	1988-1991
Sweden	A,C,I,R	2 min – 8 h	Peak demand	1994
USA	A,C,I,R	Momentary–4 h	Unserved energy	1986-1993

A – Agricultural   C – Commercial   I – Industrial
L - Large Users   O – Office   R - Residential

Customer Damage Functions

A convenient way to display customer interruption costs is in the form of a Customer Damage Function (CDF). A CDF shows the variation in interruption cost with outage duration and can be determined for a particular SIC customer type and aggregated to produce sector customer damage functions for the various customer classes in the system.

Customer outage costs are normalized in order to make them usable in a wide range of applications. Normalization is usually done with regard to the total annual consumption, the annual peak demand or the energy not supplied. Table 2 shows a set of sector CDF expressed in kilowatts of peak demand [1, 9]. These values were determined from a series of Canadian surveys [5-8].

Table 2
Sector Customer Interruption Cost Estimates (CDF) expressed
in $/kW of peak demand – 1991

	Interruption duration				
User sector	1 min	20 min	1 hr	4 hr	8 hr
Large users	1.005	1.508	2.225	3.968	8.240
Industrial	1.625	3.868	9.085	25.163	55.808
Commercial	0.381	2.969	8.552	31.317	83.008
Agricultural	0.060	0.343	0.649	2.064	4.120
Residential	0.001	0.093	0.482	4.914	15.690
Govt. & Inst.	0.044	0.369	1.492	6.558	26.040
Office & Bldg.	4.778	9.878	21.065	68.830	119.160

The sector CDF or individual customer CDF can be aggregated at a particular load point in the system to produce a Composite Customer Damage Function (CCDF) at that load point. The assumption in this case is that all load curtailments at the load point will be distributed proportionally across all the customer sectors at that load point. The CDF weighting is usually done using the per-unit energy for each sector. It has been suggested that for short interruptions (less than 1 hour) weighting by peak demand is more appropriate since losses are more related to a power shortage than an energy shortage [10].

The creation of a CCDF is illustrated in the following example where it is assumed that a particular load point has three customer sector groups. The load point sector distribution is 25% industrial, 35% commercial and 40% residential for both energy and peak load.

Table 3 shows the individual sector CDF taken from Table 2 and the CCDF obtained by aggregating the CDF using the load point sector distribution values. Table 3 shows two CCDF. The first CCDF is expressed in $/kW and is the most common representation. The second CCDF is expressed in $/kWh and is obtained by dividing the $/kW at each data point by the outage duration. The individual sector CDF and the CCDF in \$/kW are shown pictorially in Figure 1. The CCDF in \$/kWh is shown in Figure 2.

Table 3
Sector CDF and Load Point CCDF - 1991

	Interruption duration				
User sector	1 min	20 min	1 hr	4 hr	8 hr
Industrial	1.625	3.868	9.085	25.163	55.808
Commercial	0.381	2.969	8.552	31.317	83.008
Residential	0.001	0.093	0.482	4.914	15.690
	Composite Customer Damage Functions				
CCDF \$/kW	0.540	2.043	5.458	19.217	49.281
CCDF \$/kWh	32.400	6.129	5.458	4.804	6.160

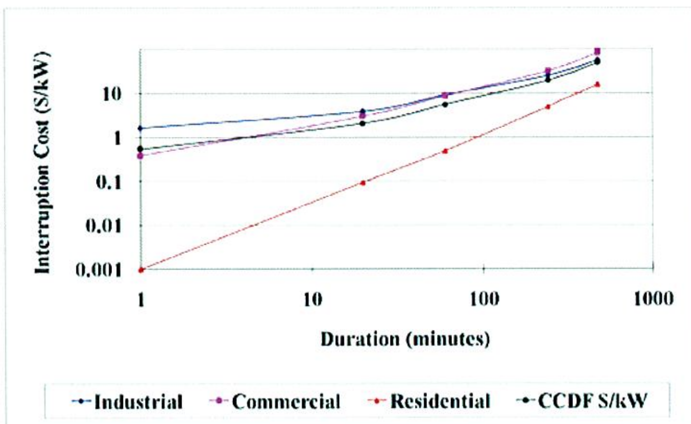

Figure 1: Sector CDF and Load Point CCDF expressed in \$/kW

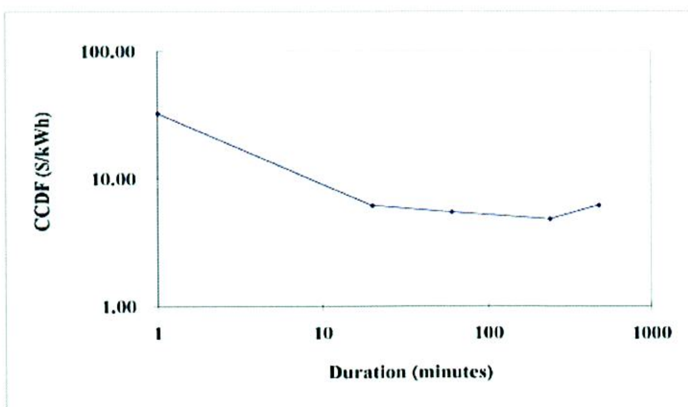

Figure 2: Load Point CCDF expressed in \$/kWh

Figure 2 shows that the cost of unserved energy is dependent on the duration of the outage event. The $/kWh value is high for short durations and decreases as the outage duration increases. The actual monetary cost increases as the outage duration increases but the ratio of this cost to the unserved energy generally remains relatively constant. This variation is not recognized in many applications and in these cases the usual practice is to utilize a single representative value known as the Interrupted Energy Assessment Rate (IEAR) to link the monetary cost with the expected energy not supplied (EENS) as shown in Equation 1.

The Expected Customer Interruption Cost (ECOST) = (IEAR) (EENS). ...(1)

The 1 hour value for the CCDF in $/kW is the same as the 1 hour value in $kWh and is sometimes used as a representative IEAR. Table 3 shows that the load point CCDF is highly dependent on the customer composition at the load point. The 1 hour IEAR value will vary from 9.085 $/kWh to 0.482 $/kWh respectively if the load point composition varies from 100% industrial to 100% residential and is 5.46 $kWh in the three customer sector example.

The CDF values shown in Table 2 were obtained in a series of surveys [6-8] conducted by the Power System Research Group at the University of Saskatchewan and funded by the Canadian Electrical Association, the Natural Science and Engineering Research Council and a group of Canadian electric power utilities. These studies were conducted at various times between 1980 and 1995 and therefore the cost values are dated. It can be seen from Table 1 that the studies conducted in other jurisdictions were done between 1986 and 1998. More recent studies have been done in Italy, Norway, the United Kingdom and the U.S.A. The CDF values shown in Table 3 can be inflated to represent 2008 conditions using Canadian Consumer Price Index (CPI) data. The inflation rate for the period 1990 to 2008 is 41.8%, which is an annual rate of 1.96%. Table 4 shows the CDF values in Table 3 inflated to 2008 dollars.

Table 4
Sector CDF and Load Point CCDF - 2008

	Interruption duration				
User sector	1 min	20 min	1 hr	4 hr	8 hr
Industrial	2.304	5.485	12.883	35.681	79.130
Commercial	0.540	4.210	12.127	44.408	117.705
Residential	0.001	0.132	0.683	6.968	22.248
	Composite Customer Damage Functions				
CCDF $/kW	0.766	2.897	7.739	27.250	69.880
CCDF $/kWh	45.943	8.691	7.739	6.812	8.735

Using the data in Table 4, the 1 hour IEAR value at the three sector load point in Table 3 is 7.74 $/kWh and the value for a 50% industrial and 50% commercial load point is 12.50 $/kWh.

Expected Customer Interruption Cost

The EENS is a fundamental parameter in most power system reliability studies and as noted in Equation 1, the ECOST can be easily estimated using the product of the IEAR and the EENS. The IEAR is an input parameter in these studies. The IEAR can also be obtained as output from a digital computer program that uses contingency enumeration or sequential Monte Carlo simulation to calculate the required reliability indices and the ECOST [1, 9]. Both techniques are applied in the areas of generation, transmission and distribution system reliability assessment.

Reference 3 indicates that a wide range of values for the IEAR have been reported in the jurisdictions shown in Table 1. The report notes that the IEAR is very dependent on the customer composition at the load point or for the system. The Electric Utility Planning Council of Alberta used an IEAR of 12 $/kWh in an application [11] before the Alberta Energy and Utilities Board in 1994 to justify a new generation planning criterion. The British Columbia Transmission Corporation indicate an average cost of unserved energy, designated as the unit interruption cost (UIC), of 9.08 $/kWh in benefit/cost analyses conducted in 2007 [12, 13]. The 9.08 $/kWh value is a composite parameter for a system composed of a number of substations. The individual substation UIC values vary from 4.14 to 15.46 $/kWh.

References

1. R. Billinton, R.N. Allan, "Reliability Evaluation of Power Systems – Second Edition", Plenum Press, New York and London, 1996, pp. 514.

2. G. Wacker, R. Billinton, "Customer Cost of Electric Service Interruptions", Proceedings of the IEEE, Vol. 77, No. 6, 1989, pp. 919-930.

3. R. Billinton, et. al, "Methods to Consider Customer Interruption Costs in Power Systems Analysis", CIGRE Task Force Report No. 38.06.01, Aug. 2001, pp. 100.

4. R. Billinton, G.Wacker, E. Wojczynski, "Comprehensive Bibliography on Electrical Service Interruption Costs", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-102, June 1983, pp.1831-1837.

5. G. Tollefson, R. Billinton, G. Wacker, "Comprehensive Bibliography on Reliability Worth and Electric Service Consumer Interruption Costs 1980-1990", IEEE Transactions on Power Systems, Vol. 6, No. 4, Nov. 1991, pp. 1508-1514

6. R. Billinton, G. Wacker, E. Wojczynski, "Customer Damage Relating From Electric Service Interruptions", Canadian Electrical Association, R&D Project 9007 U 131 Report, 1982.

7. R. Billinton, G. Wacker, G. Tollefson, "Assessment of Reliability Worth in Electric Power Systems in Canada", Final Report, NSERC Strategic Grant STR00455005, March 1993.

8. J. Gates, R. Billinton, G. Wacker, "Electric Service Reliability Worth Evaluation for Governments, Institutions and Office Buildings", IEEE Transactions on Power Systems, Vol. 14, No. 1, Feb. 1999, pp. 43-50.

9. R.F. Ghajar, R. Billinton, "Economic Cost of Power Interruptions: A Consistent Model and Methodology", Journal of Electrical Power and Energy Systems, 28 (2006), pp. 29-35.

10. D.C. Goushleff, "Uses of Interruption Costs in Regional Supply Planning", Ontario Hydro, Report 80-301-K.

11. A Filing by the Alberta Generating Utilities on behalf of the Electric Utility Planning Council with the Energy Resources Conservation Board regarding the Reliability Criterion for Generation Planning in Alberta, February, 1994.

12 British Columbia Transmission Corporation, "Probabilistic Reliability Assessment of the Qualicum Substation Reconfiguration", Report No. 2007-REL-02, July 29, 2007.

13. British Columbia Transmission Corporation, "Benefit/Cost Analysis Based on Reliability and Transmission Loss Considerations For Central Vancouver Island Transmission Project", Report No. 2007-REL-03.2, September 2007.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES") RESPONSES TO

ENERGY PROBE TECHNICAL CONFERENCE QUESTIONS

DELIVERED: February 23rd, 2011

QUESTION TC #14

Reference: Energy Probe Interrogatory #50

The IR asked about actual employee retirements compared to employees eligible for retirement with an undiscounted pension. Part of the response notes that the "*average of those employees that actually retired versus those eligible for an undiscounted retirement is 97 per cent*".

Please provide the calculation used to arrive at this percentage.

Response:

In Horizon Utilities' response to Energy Probe Interrogatory 50, a table is provided comparing the number of employees eligible for an undiscounted retirement and the number of employees that actually retired for the years 2004 through to 2010. The average percentage of retirements was calculated in each of those years. The average of those that actually retired over the 7 year period (2004-2010) was calculated by taking a simple average of the annual percentage included in the table.