Board Staff Interrogatories
2009 Electricity Distribution Rates
Innisfil Hydro Distribution Systems Ltd.
EB-2008-0233

1 OPERATING COSTS

1.1 General – Historical OM&A Expenses Data

Ref: *http://www.oeb.gov.on.ca/OEB/_Documents/EB-2006-0268/Comparison_of_Distributors_with_2007_data.xls*

The figures in Table 1 below are taken directly from the public information filing of Innisfil in the Reporting and Record-keeping Requirements ("RRR") initiative of the OEB. The figures are available on the OEB's public website.

Table 1

	2003	2004	2005
Operation	$489,610	$494,923	$616,202
Maintenance	$371,329	$452,465	$401,407
Billing and Collection	$664,946	$778,884	$842,374
Community Relations	$18,086	$10,841	$43,853
Administrative and General Expenses	$835,138	$919,729	$790,623
Total OM&A Expenses	**$ 2,379,109**	**$ 2,656,841**	**$ 2,694,458**

Please confirm Innisfil's agreement with the numbers for Total OM&A Expenses that are summarized in Table 1. If Innisfil does not agree with any figures in Table 1, please explain why not and provide amended tables with a full explanation of all changes.

Response #1.1

The following table reflects the total OM&A Expenses for 2003 to 2005 as provided by Innisfil Hydro in Exhibit 4/Tab 2/Schedule 1 Total OM&A before Amortization:

Historical OM&A Expense Data

	2003	2004	2005
Operations	$ 489,640	$ 494,923	$ 616,202
Maintenance	371,329	452,465	401,407
Billing and Collecting	664,946	778,884	842,374
Community Relations	18,086	10,841	43,853
Administrative & General	835,138	919,729	790,623
Total OM&A Expenses	$ 2,379,139	$ 2,656,842	$ 2,694,459
Adjustments			
Property taxes-6105	8,960	12,191	12,084
Adjusted total OM&A Expenses	**$ 2,388,099**	**$ 2,669,033**	**$ 2,706,543**

The updated table includes property taxes expense incurred for the administration building.

1.2 General – OM&A Expenses

Ref: Exhibit 4/Tab 1/Schedule 1/ p. 1

Board staff took the figures from the evidence provided in Exhibit 4 of Innisfil's application and prepared Table 2 as a summary of Innisfil's OM&A expenses. Please note that rounding differences may occur, but are not material to the questions that follow.

Table 2

	2006 Board Approved	2006 Actual	2007	2008 Bridge	2009 Test
Operation	$ 494,922	$ 600,374	$ 639,277	$ 733,700	$ 778,575
Maintenance	$ 452,465	$ 416,921	$ 489,578	$ 580,100	$ 657,080
Billing and Collection	$ 808,784	$ 829,894	$ 923,175	$ 950,950	$ 1,010,600
Community Relations	$ 8,290	$ 60,213	$ 49,890	$ 10,600	$ 11,700
Administrative and General Expenses	$ 1,216,272	$ 989,218	$ 1,071,420	$ 1,237,175	$ 1,463,165
Total OM&A Expenses	$ 2,980,733	$ 2,896,620	$ 3,173,340	$ 3,512,525	$ 3,921,120

Board staff took the figures from the evidence provided in Exhibit 4 of Innisfil's application and prepared Table 3 which summarizes Innisfil's OM&A forecasted expenses. Please note that rounding differences may occur, but are not material to the questions that follow.

Table 3

	2006 Board Approved	Variance 2006/2006	2006 Actual	Variance 2007/2006	2007 Actual	Variance 2008/2007	2008 Bridge	Variance 2009/2008	2009 Test	Variance 2009/2006
Operation	494,922	105,452	600,374	38,903	639,277	94,423	733,700	44,875	778,575	178,201
		21.3%		6.5%		14.8%		6.1%		29.7%
Maintenance	452,465	-35,544	416,921	72,657	489,578	90,522	580,100	76,980	657,080	240,159
		-7.9%		17.4%		18.5%		13.3%		57.6%
Billing & Collections	808,784	21,110	829,894	93,281	923,175	27,775	950,950	59,650	1,010,600	180,706
		2.6%		11.2%		3.0%		6.3%		21.8%
Community Relations	8,290	51,923	60,213	-10,323	49,890	-39,290	10,600	1,100	11,700	-48,513
		626.3%		-17.1%		-78.8%		10.4%		-80.6%
Administrative and General Expenses	1,216,272	-227,054	989,218	82,202	1,071,420	165,755	1,237,175	225,990	1,463,165	473,947
		-18.7%		8.3%		15.5%		18.3%		47.9%
Total OM&A Expenses	2,980,733	-84,113	2,896,620	276,720	3,173,340	339,185	3,512,525	408,595	3,921,120	1,024,500
		-2.82%		9.55%		10.69%		11.63%		35.37%

a) Please confirm that Innisfil agrees with the figures presented in Table 2 and Table 3. If Innisfil does not agree with any figures in the tables, please explain why not and provide amended tables with a full explanation of all changes.

b) Please complete Table 4 below by identifying and listing the key cost drivers that are contributing to the overall increase of 35.4% in total 2009 OM&A expenses over 2006 historical actuals. Please add additional rows to Table 4 if there are more than four cost drivers. Some examples of specific costs drivers include items such increase in staff compensation, hiring staff, increase in cost of contractors, increase in inflation, etc.

Table 4

	2006	2007	2008	2009
Opening Balances	**2,980,733**	**2,896,620**	**3,173,340**	**3,512,525**
e.g., hiring X staff				
e.g., X% increase in cost of contractors				
Closing Balances	**2,896,620**	**3,173,340**	**3,512,525**	**3,921,120**

c) For the period 2006 to 2009, please provide detailed and specific explanations for each cost driver in Table 4 above.

Response #1.2

a) Innisfil Hydro is providing the following table as the Total OM&A Expenses from 2006 EDR to 2009 Test year:

	2006 EDR	2006	2007	2008	2009
Operation	494,922	600,374	639,277	733,700	778,575
Maintenance	452,465	416,921	489,578	580,100	657,080
Billing and Collection	808,784	829,894	923,175	950,950	1,010,600
Community Relations	8,290	60,213	49,890	10,600	11,700
Admin & General	1,216,272	989,218	1,071,420	1,237,175	1,463,165
Property taxes	12,192	9,751	9,979	10,300	10,600
Total OM&A Expenses	2,992,925	2,906,371	3,183,319	3,522,825	3,931,720
% change		-2.9%	9.5%	10.7%	11.6%
% change from 06 Actual to 09 Test year					35.3%

Innisfil Hydro is including the property taxes recorded to account 6105. The total OM&A Expenses in the above table reflect submitted Exhibit 4/Tab 2/Schedule 1.

b) The following table identifies key cost drivers from 2006 EDR to 2009 Test year:

	2006	2007	2008	2009
Opening Balances	2,992,925	2,906,371	3,183,319	3,522,825
OEB reclassification	(351,000)	32,000	-	-
Payroll changes	161,000	35,000	168,000	151,000
Change in cost of service providers	17,000	41,000	(13,000)	82,000
Change in cost of contractors	(40,000)	71,000	74,000	72,000
Inflation	126,446	97,948	110,506	103,895
Closing Balances	2,906,371	3,183,319	3,522,825	3,931,720

c) 2006 Cost Drivers

a) OEB reclassification ($351,000) –

i. LV charges of ($314k) are reclassified to Cost of Power from account 5665.

ii. Innisfil Hydro OMER’s cost from Jan-Apr 2006 was reclassified to regulatory account 1508 from account 5645 resulting in a total variance of ($49k) to the 2006 EDR in account 5645.

iii. Innisfil Hydro recorded ($33k) of collection revenue to account 5310. This was allocated to Other Distribution in the 2006 EDR filing.

iv. Innisfil Hydro is showing increased costs in account 5415 for CDM educational activities that were funded through 3rd tranche distribution revenue costing $45k. The offsetting revenue is recorded within the Distribution Revenue.

b) Payroll Changes $161,000 –

i. Innisfil Hydro hired a Operations Supervisor $70k to manage the outside contracted line crews, management of SCADA system with backup and succession planning of the Director of Operations & Engineering.

ii. A part time Customer Service Clerk was changed to a full time position $27k due to increased demands of billing, collecting and settlements.

iii. An accounting student, $10k, was hired to assist with yearend rather than utilize outside services.

iv. An IT student, $9k, was hired to assist with Innisfil’s network, hardware, software and communication demands.

v. Two staff positions were partially vacant in 2004, Engineering Tech and General Accountant. The positions were fully staffed in 2006 $45k.

c) Change in cost of service providers $17,000 –

i. Innisfil Hydro reduced outside services costs by utilizing an accounting student for yearend work ($24k) in account 5630

ii. Injury and damages insurance premiums were reduced ($10k) due to reduced claims and is reflected in account 5640.

iii. A reserve of $25k for estimated cost awards for interveners’ costs was established and recorded to regulatory expense account 5655.

iv. Additionally increased software maintenance fees due to upgrading of software modules such as accounting and file imaging software and new engineering job estimating and tracking software $26k in account 5675.

d) Change in cost of contractors ($40,000) –

Innisfil Hydro outside line crew costs decreased due to reduced trouble call costs and the elimination of PCB removal costs compared to 2002-2004 average costs ($40k).

e) Inflation $126,446 –

Inflation for 2005 and 2006 is 4.2%.

2007Cost Drivers

a) OEB reclassification $32,000 -

Innisfil Hydro OMER's cost from Jan-Apr 2006 totalling $32k were reclassified to regulatory account 1508. There was no reduction for the OMERs costs in 2007.

b) Payroll Changes $35,000 –

i. The Director of Operations and Engineering retired in 2007 which resulted in vacation and overtime payout of $24k.

ii. Additional overtime costs for the New Director of Operations $11k.

c) Change in cost of service providers $41,000 –

i. Innisfil Hydro property insurance premiums were increased $35k due to updating the distribution station assets to 2006 values and the addition of the Bob Deugo Station in account 5635.

ii. Innisfil Hydro bad debts expenses increased $36k in account 5335 due to the bankruptcy of a GS>50 kW customer and an increase of bad debt reserve due to the timing of outstanding customer accounts. The bad debt reserve increase is a timing issue and reverses in 2008.

iii. Innisfil Hydro outside services account 5630 costs reduced by ($30k) due to wind up of union legal case with Innisfil Energy Services and no cost allocation study costs as done in 2006.

d) Change in cost of contractors $71,000 –

i. Innisfil Hydro began contracted pole inspections in 2007 for an increase cost of $23k to account 5120.

ii. Innisfil Hydro's tree trimming schedule was changed to cycle the tree trimming within the distribution area every 3 years instead of 4 years due to the rural nature of the distribution territory to improve system reliability and keep repair costs minimal when storms occur. This has resulted in an increased cost of $48k to account 5135.

e) Inflation $97,948 –

Inflation is 3.4% due to increasing contractor contract costs and payroll.

2008 Cost Drivers

a) OEB reclassification $0 –

i. Innisfil Hydro did not incur any CDM expenditures relating to the 3rd tranche which results in reduced costs of ($37k) in account 5415.

ii. Innisfil Hydro reallocated collection revenue from account 5310 to other distribution revenue account 4235 per Exhibit 3 Tab 3 Schedule 1 which results in increased costs of $37k.

b) Payroll Changes $168,000 –

i. Innisfil Hydro hired an Information Technologist late February 2008 resulting increased costs of $65k. This position was added to assist with the increasing demands of the SCADA, GIS, network security, hardware and software support.

ii. Effective 2008 the President of Innisfil Hydro is no longer carrying out the duties of the Director of Community Services for the Town of Innisfil. Due to the increasing demands of both of these positions, it was determined the Town would hire a full time position and the President would dedicate 100% of his time to Innisfil Hydro. This resulted in increased cost of $78k.

iii. Additional on call and training costs incurred for the Operations Management staff totalling $10k.

iv. Additional management payroll costs totalling $32k for 6 management staff positions spread over two years for salary adjustments or $16k of additional costs in 2008. The salary adjustments were done to bring the management salaries in line with the average salaries published by the EDA and in line with the Town of Innisfil comparable management positions.

c) Change in cost of service providers ($13,000) –

i. Innisfil Hydro will be incurring increased costs, $27k, for the upgrading of the GIS systems. Innisfil Hydro will be integrating the GIS mapping with the Town of Innisfil and the increased costs are Innisfil Hydro's portion of developing the GIS system. This will assist with locates and trouble calls relating to response time and accuracy.

ii. Innisfil Hydro will incurring increased costs of $11k for additional meter repairs and staff attending a meter apprentice program in account 5065.

iii. Innisfil Hydro has obtained General Service customer insurance to help mitigate bad debts going forward for a cost of $6k.

iv. Innisfil Hydro will have reduced cost due to the reversal of a 2006 cost awards reserve of ($18k) in account 5655.

v. Innisfil Hydro will have reduced cost of ($4k) in account 5630 due to reduced audit fees via an RFP process with the CHEC group.

vi. Innisfil Hydro bad debts expenses have decreased ($35k) in account 5335 a reversal of a reserve made in 2007 and no unusual bankruptcies as in 2007.

d) Change in cost of contractors $74,000 –

Innisfil Hydro was informed in January 2008 the non union line contractor that had been utilized for the past several years (McG) was being sold to K Line. In March 2008 a Tender for Overhead and Underground Hydro Utility Line works was requested by Innisfil Hydro for any interested contractors. The contract was awarded to K Line, as the lowest price increase. The cost overall of the line crew work is expected to increase in excess of 20% in 2008 and 2009. This is reflected in the maintenance and capital addition costs. This is estimated to cause an increase of $74k in the various operations and maintenance accounts.

e) Inflation $110,506 –

Inflation is 3.5% due to increasing contractor contract costs and payroll.

2009 Cost Drivers

a) Payroll Changes $151,000 –

i. Innisfil Hydro plans to hire a regulatory analyst to assist with the increasing demands and regulatory interpretations and requirements of the OEB reporting for projects such as rate filings, cost allocations, regulatory accounting, economic evaluations, the regulatory agencies monthly, quarterly and annual filings, and distribution generation for an estimated cost of $70k.

ii. Innisfil Hydro will incur a shift of payroll costs due to the sale of the water heaters within Innisfil Energy Services totalling $29k. Management will no longer be providing services to Innisfil Energy Services.

iii. Innisfil Hydro will be providing post retirement benefits effective January 2009. An estimate for these benefits were provided by an actuary totalling $23k spread over 3 years recovery plus an estimated annual cost of $2k equalling $9k for 2009 in account 5645.

iv. Innisfil Hydro negotiated the union contract in 2007 that resulted in wage adjustments for engineering and customer service due to job evaluations totalling $14k

v. Innisfil Hydro hired an Information Technologist late February 2008 resulting increased costs of $7k for 2009 due to a full year of salary.

vi. Additional management payroll costs totalling $32k for 6 management staff positions spread over two years for salary adjustments or $16k of additional costs in 2009. The salary adjustments were done to bring the management salaries in line with the average salaries published by the EDA and in line with the Town of Innisfil comparable management positions.

vii. The President of Innisfil Hydro full year payroll costs will be reflected in Innisfil Hydro's OM&A expenses $6k.

b) Change in cost of service providers $82,000 –

i. Innisfil Hydro will be incurring increased costs, $63k in account 5655 due the estimated cost for the 2009 cost of service filing spread over 4 years for $37k and the effect of 2008 costs award reversal compared to the 2009 reserve of $4k resulting in an increase cost of 2009 over 2008 equalling $26k.

ii. Additional cost in account 5065 for $5k due to the costs of reverification of meters as required by Measurement Canada.

iii. Additional cost in account 5620 for $7k due to internet bandwidth upgrading for efficiencies

iv. Additional cost in account 5310 meter reading for the addition of two wholesale meters and 6 retail interval meters totalling $7k.

c) Change in cost of contractors $72,000 –

Innisfil Hydro was informed in January 2008 the non union line contractor that had been utilized for the past several years (McG) was being sold to K Line. In March 2008 a Tender for Overhead and Underground Hydro Utility Line works was requested by Innisfil Hydro for any interested contractors. The contract was awarded to K Line, as the lowest price increase. The cost overall of the line crew work is expected to increase in excess of 20% in 2008 and 2009. This is reflected in the maintenance and capital addition costs. This is estimated to cause an increase of $72k in the various operations and maintenance accounts.

d) Inflation $103,895 –

Inflation is 2.9% due to increasing contractor contract costs and payroll.

1.3 General – Cost Efficiency Programs

Ref: Exhibit 4/Tab 2/Schedule 1/ p. 1-2

Please describe and quantify the benefits of any cost efficiency programs that Innisfil has undertaken, e.g. cost reduction, contract negotiations, system automation, cost savings or other programs that are either in place now or are contemplated at some future time.

Response #1.3

- Innisfil Hydro has 8.32kV Voltage conversion to 27.6kV on the 20th Side Road at 5th and 6th Lines scheduled in 2009 to reduce line voltage reductions and reduce line losses in conjunction with a new 27.6kV line to the new Lefroy development. Line losses are expected to decrease.
- Two vehicles scheduled for replacement in 2009 will be replaced with hybrid vehicles. It is expected that fuel savings of 40% per vehicle will be achieved.
- Innisfil Hydro is a member of the Cornerstone Hydro-Electric Concepts Association. A joint Auditing RFP has reduced 2009 audit costs by 10%.
- Four 44kV and three 27.6kV remote operated switches are planned for 2009. Estimating the operation of each switch six times, two Line personnel with a four hour minimum call-out, 320 person hours can be mitigated. The major benefit will improve SAIDI statistics. A call out to operate a switch will take 60-120 minutes for response. A remote operated switch will take 5-7 minutes to operate.
- Three sets of radio controlled fault indicators are planned for 2009. During power interruptions, they save time in identifying where problems occur. They also increase service life of breakers and switches to prevent them from closing in on fault situations. The major benefit will improve SAIDI statistics and the life of breakers and switches.
- Two sets of reclosure automation is planned for 2009. These vacuum reclosures need less maintenance compared to the oil filled units. One will replace reclosures at Brian Wilson DS F4 to allow them to be operated by the SCADA system. The other one will go to Brian Wilson DS F2 to replace existing reclosures that have had reliability issues and are not supported by the manufacturer.
- Corporate wide switch to Telus/Mike communication devices to share in pooled savings for cost reductions of approximately 7%.

1.4 Contracted Services

Ref: Exhibit 4/Tab 2/Schedule 1/ p. 1-2

a) From 2006 through 2009, please identify the portion of total OM&A expenses that is related to contracted services.

b) For each of the years, 2006 through 2009, please identify the selection process for the contracted services.

c) For each contracted service, please identify the year in which the selection process was used to select a particular contractor.

d) Please provide examples of contracted services for the period of 2006 through 2009 in which Innisfil negotiated cost savings or contemplates achieving costs savings. Regarding contracted services, please provide evidence, if any that demonstrates that Innisfil has implemented cost efficiency initiatives or it is contemplating undertaking initiatives that help Innisfil achieve savings at some future time.

Response #1.4

a) The following schedule identifies OM&A expenses that relate to contracted services:

Vdr #	Vdr Name	2007 Actual	2008 Bridge	2009 Test	06-09 Selection Process	Year Selection Process Used	06-09 Cost Savings Examples
AEG01	AEGISYS Network and IT security support	15,336	15,800	10,000	Industry Expert	1997	Avoidance of hiring staff
AES01	Acumen Engineered Solutions ESA Consulting	10,425	10,700	11,000	Quotation	2006	Lowest Cost Provider
AUT02	Automated Solutions Inc Engineering software maint fees & support	26,892	27,700	28,500	Quotation	1997	Lowest Cost provider
BDO01	BDO Dunwoody Annual accting software maintenance fee	21,320	22,000	22,700	Quotation	2004	Lowest Cost Provider
CHE02	CHEC Membership dues	13,942	14,145	14,300	Voluntary Membership	2001 Co-op	Centralized Conditions of Service, CDM reporting Policies, Equipment sharing, advacacy
DKE01	DK Engineering Services PHD engineering services	15,018	15,500	16,000	Industry Expert	1998	Avoidance of hiring staff
DOB01	Dave Dobinson Excavating Yard maintenance and snow removal	15,018	15,500	16,000	Tender	Annual	Lowest Cost Provider
EDA	EDA Membership dues	23,200	23,900	24,600	Industry Association	Annual	None
EUL01	Euler Hermes General Service bad debt insurance	9,351	9,600	9,900	Quotation	2007	Will mitigate large customer bad debt
GRA03	Grant Thorton Audit fees	34,000	29,000	30,000	Quotation with CHEC	2008	10% cost decrease from previous year
GWG01	Graham, Wilson and Green Legal services	7,037	7,500	8,000	Neighbouring Firm	1993	Local, less cost than Toronto firms
HAR01	Harris Computer Systems Annual software maintanence fee	59,341	61,100	62,900	RFP	1999	Lowest Cost provider
K	K Line Contracted line crew	-	200,600	393,200	Tender	2008	Lowest Cost provider
KTE01	K-Teck Electro Services Distribution Station maintenance	25,158	25,900	26,700	Tender	2006	Lowest Cost Provider

Vdr #	**Vdr Name**	**2007 Actual**	**2008 Bridge**	**2009 Test**	**06-09 Selection Process**	**Year Selection Process Used**	**06-09 Cost Savings Examples**
LAK01	Lakeside Tree Experts Tree trimming	107,392	110,600	113,900	Tender	Annual	Lowest Cost Provider
LAW01	The Lawn Baron Property maintenance	9,609	9,900	10,200	Tender	Annual	Lowest Cost provider
LOR02	Loris Technologies Annual software maintanence fees	18,458	19,000	19,600	Quotation	2000	Lowest Cost Provider
McG	Mc G Pole Line Ltd Contracted line crew	240,856	124,000	-	Tender	Did not bid 2008	Not Applicable
MEA02	M E A R I E Auto, property and liability Insurance	82,664	85,100	87,700	Quotation	2003	Lowest Cost provider
MIK01	Mike Telus In territory radio system	10,129	10,400	10,700	Quotation	1998	Lowest Cost Provider
OEB01	OEB Regulator cost assessment	46,686	48,100	49,500	Regulatory Expense	Annual	None
OLA01	Olameter Inc Meter reading services	139,101	143,300	147,600	RFP	2004	Lowest Cost Provider
OSH02	Oshawa PUC Services Inc Wholesale and retail interval meter reads	20,250	20,900	21,500	RFP CHEC Group	2004	Lowest Cost Provider
POL02	Polecare International Pole testing	20,250	20,900	21,500	Quotation	2006	Lowest Cost Provider
SAV01	Savage Data Systems Ltd Wholesale settlement data management	50,133	51,600	53,100	Collective Purchase	2000	With the Upper Canada Energy Alliance Shared Expense
SOL01	Solve Environmental Office Cleaners	12,025	12,400	12,800	Tender	2001	Lowest Cost provider
SYS01	Systrends Inc EBT Hub Services	30,571	31,500	32,400	Quotation	2001	Lowest Cost Provider
	Annual Total	**1,064,161**	**1,166,645**	**1,254,300**			

b) Please see table in above question 1.4a)

c) Please see table in above question 1.4a)

d) Please see table in above question 1.4a)

1.5 Capitalization of Employee Compensation

Ref: Exhibit 4/Tab 2/Schedule 7/ p. 1/ Table 1

Using the information from evidence provided in Exhibit 4 of the application, Board staff developed Table 5 below which shows the total compensation charged to OM&A. As Table 5 illustrates, from 2007 to 2009, Innisfil capitalized 7% of total compensation

Table 5

	2006 Board Approved	2006 Actual	2007	2008 Bridge	2009 Test
Total Compensation	$ 1,310,125	$ 1,641,929	$ 1,745,568	$ 1,920,501	$ 2,117,298
Less Capitalized Amount	$ 65,000	$ 89,159	$ 118,763	$ 131,600	$ 147,000
Total Compensation Charged to OM&A	$ 1,245,125	$ 1,552,770	$ 1,626,805	$ 1,788,901	$ 1,970,298
Capitalized	5%	5%	7%	7%	7%

Board staff notes that the capitalization rate for 2008-2009 is approximately 7%. Please provide an explanation for Innisfil's capitalization policy including the rationale for the selection of this rate.

Response #1.5

Innisfil Hydro does not directly employ line crew staff. Capital and operating services are contracted to an outside company. In 2009 Innisfil Hydro will be contracting this service to K Line. The contractor costs for this service is not included in the Total Compensation in Table 5 noted above. Innisfil Hydro utilizes a job costing systems to capture cost incurred for a specific job. Actual staff time spent on the specific job is recorded to the appropriate APH account. Innisfil Hydro does not utilize a fixed capitalization percentage to record staff compensation costs to capital accounts.

1.6 Average Yearly Base Wage per Management Employee

Ref: Exhibit 4/Tab 2/Schedule 7/ p.1/ Table 1

Referencing to Table 1 from the above evidence provided in Exhibit 4 of the application ("Employee Information – Compensation – Average Yearly Base Wages"), Board staff notes that the total base wage per management employee increased from $84,218 in 2008 to $90,994 in 2009. This represents an increase of 8% in compensation.

Please provide an explanation and justification for this increase.

Response #1.6

The main items driving the 8% increase in average yearly base wages for management are:

1) The 2009 average wages reflect salary adjustments to bring the management salaries in line with the average salaries published by the EDA and in line with the Town of Innisfil comparable management positions (2.4%)
2) Management time that will no longer be spent on Innisfil Energy management issues (2.4%)
3) President full time employee for Innisfil Hydro (0.8%)
4) Inflationary increases (2.5%)

1.7 Personnel Management

Ref: Exhibit 4/Tab 2/Schedule 7/ p.1

Please provide a description of plans (if any) to address the issue of an aging workforce.

Response #1.7

The majority of Innisfil Hydro's staff commenced employment July 1993. Therefore Innisfil Hydro does not have an aging workforce issue because there are few employees that have long service levels with the OMERS pension plan so therefore a plan is not necessary. Innisfil Hydro has taken the necessary steps to ensure succession planning within the management team.

1.8 Shared Services / Corporate Cost Allocation

Ref: http://www.oeb.gov.on.ca/documents/minfilingrequirements_report_141106.pdf

Pursuant to section 2.5 (Exhibit 4 Part A and D) of the Filing Requirements for Transmission and Distribution Applications (see reference above), applicants are to file the following information:

a) The type of shared service and the total annual expense by service.

b) A detailed description of the assumptions underlying the corporate cost allocation as well as provide documentation of the overall methodology and policy.

c) Please complete Table 6 below for the years 2006 through 2009 describing all services that Innisfil provides and receives from its parent company as well as affiliate companies. Please duplicate the table for each year 2006 to 2009 to show the required information for the respective year. Please use additional rows, if necessary.

Response #1.8

a) As per Exhibit 4/Tab 2/Schedule 4/Table 1 the following are services Innisfil Hydro provides to Innisfil Energy Services Limited:

Innisfil Hydro provides the following services to Innisfil Energy

Activity	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Management Services	31,555	26,328	27,727	-
Billing and Collecting Services	18,624	18,595	19,016	-
AP Services	1,217	1,363	1,358	-
Total	**51,396**	**46,286**	**48,101**	**-**

b) Innisfil Hydro is wholly owned by the Town of Innisfil and does not allocate or receive any corporate cost from the Town of Innisfil. The Town of Innisfil also wholly owns Innisfil Energy Services Limited. Innisfil Hydro does not allocate or receive any corporate cost from its affiliate Innisfil Energy Services Limited.

c)
<u>Table 6</u>

Year: 2006

Name of Company		Type of Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation	Explanation
From	To						
Innisfil Hydro	Innisfil Energy Services	Management Services	Cost + 15%	$31,555	$27,439	N/A	
Innisfil Hydro	Innisfil Energy Services	Billing and Collecting	Fixed mthly $20 Mthly per acct $0.80	$18,624		N/A	Costs are within APH accounts 5310 & 5315. The revenue is Other Distribution offset per 2006 EDR filing
Innisfil Hydro	Innisfil Energy Services	AP Services	Service Per: Account set up $24.00 Info change $5.00 Invoice process $2.00 Cheque issued $5.00	$1,217		N/A	Costs are within APH accounts 5615. The revenue is Other Distribution offset per 2006 EDR filing
Innisfil Hydro	Innisfil Energy Services	Loan for fibre optic investment	Prime less .25%	$55,012	$55,012	N/A	Interest on short term borrowing charged at the bank rate
Innisfil Hydro	Town of Innisfil	Management Services	Cost	$65,149	$65,149	N/A	President's time and mileage spent as the Director of Community Services for the Town of Innisfil
Innisfil Hydro	Town of Innisfil	Work Orders	Cost plus 35% for labour and contractor Cost plus 15% for materials	$15,838	$11,836	N/A	
Town of Innisfil	Innisfil Hydro	Property Taxes	Market based pricing	N/A	$48,638	N/A	

Town of Innisfil	Innisfil Hydro	Water, fuel, CDM program & Town CAO board stipend	Market for water Market less $0.10 per litre for fuel Cost for	N/A	$85,099	N/A	Converted street lights to energy efficiency via CDM funds $45k.

Type of Service Offered: Services such as billing, accounting, payroll, etc.
Pricing Methodology: Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. Please provide evidence to demonstrate the pricing methodology that was used.
Price for the Service: The amount the entity pays for the service that it receives.
Cost for the Service: The cost of to provide the service.
%Allocation: % of the costs that is allocated to the entity for the service being offered.

Year: 2007

Name of Company		Type of Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation	Explanation
From	To						
Innisfil Hydro	Innisfil Energy Services	Management Services	Cost + 15%	$26,328	$22,894	N/A	
Innisfil Hydro	Innisfil Energy Services	Billing and Collecting	Fixed mthly $20 Mthly per acct $0.80	$18,595		N/A	Costs are within APH accounts 5310 & 5315. The revenue is Other Distribution offset per 2006 EDR filing
Innisfil Hydro	Innisfil Energy Services	AP Services	Service Per: Account set up $24.00 Info change $5.00 Invoice process $2.00 Cheque issued $5.00	$1,363		N/A	Costs are within APH accounts 5615. The revenue is Other Distribution offset per 2006 EDR filing
Innisfil Hydro	Innisfil Energy Services	Loan for fibre optic investment	Prime less .25%	$14,121	$14,121	N/A	Loan repaid in 2007
Innisfil Hydro	Town of Innisfil	Management Services	Cost	$81,488	$81,488	N/A	President's time and mileage spent as the Director of Community Services for the Town of Innisfil
Innisfil Hydro	Town of Innisfil	Work Orders	Cost plus 35% for labour and contractor Cost plus 15% for materials	$45,165	$34,038	N/A	
Town of Innisfil	Innisfil Hydro	Property Taxes	Market based pricing	N/A	$49,722	N/A	
Town of Innisfil	Innisfil Hydro	Water, fuel, CDM program & Town CAO board stipend	Market for water Market less $0.10 per litre for fuel	N/A	$32,383	N/A	

Year: _2008_____

Name of Company		Type of Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation	Explanation
From	**To**						
Innisfil Hydro	Innisfil Energy Services	Management Services	Cost + 15%	$27,727	$24,110	N/A	
Innisfil Hydro	Innisfil Energy Services	Billing and Collecting	Fixed mthly $20 Mthly per acct $0.80	$19,016		N/A	Costs are within APH accounts 5310 & 5315. The revenue is Other Distribution offset per 2006 EDR filing
Innisfil Hydro	Innisfil Energy Services	AP Services	Service Per: Account set up $24.00 Info change $5.00 Invoice process $2.00 Cheque issued $5.00	$1,358		N/A	Costs are within APH accounts 5615. The revenue is Other Distribution offset per 2006 EDR filing
Innisfil Hydro	Town of Innisfil	Management Services	Cost	$7,600	$7,600	N/A	President's time and mileage spent as the Director of Community Services for the Town of Innisfil
Innisfil Hydro	Town of Innisfil	Work Orders	Cost plus 35% for labour and contractor Cost plus 15% for materials	$49,680	$37,441	N/A	
Town of Innisfil	Innisfil Hydro	Property Taxes	Market based pricing	N/A	$52,208	N/A	
Town of Innisfil	Innisfil Hydro	Water, fuel & Town CAO board stipend	Market for water Mket less $0.10 per litre fuel	N/A	$34,301	N/A	

Year: 2009

Name of Company		Type of Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation	Explanation
From	To						
Innisfil Hydro	Innisfil Energy Services	Management Services	Cost + 15%	$0	$0	N/A	Innisfil Hydro will not be providing these services in 2009
Innisfil Hydro	Innisfil Energy Services	Billing and Collecting	Fixed mthly $20 Mthly per acct $0.80	$0		N/A	Innisfil Hydro will not be providing these services in 2009
Innisfil Hydro	Innisfil Energy Services	AP Services	Service Per: Account set up $24.00 Info change $5.00 Invoice process $2.00 Cheque issued $5.00	$0		N/A	Innisfil Hydro will not be providing these services in 2009
Innisfil Hydro	Town of Innisfil	Management Services	Cost	$0	$0	N/A	President will not be providing management services as the Director of Community Services to the Town of Innisfil
Innisfil Hydro	Town of Innisfil	Work Orders	Cost plus 35% for labour and contractor Cost plus 15% for materials	$57,132	$43,057	N/A	
Town of Innisfil	Innisfil Hydro	Property Taxes	Market based pricing	N/A	$54,818	N/A	
Town of Innisfil	Innisfil Hydro	Water, fuel & Town CAO board stipend	Market for water Mket less $0.10 per litre fuel	N/A	$35,356	N/A	

1.9 Corporate Cost Allocation

Ref: EB-2005-0001 Decision with Reason for Enbridge Gas Distribution Inc. Chapter 10 p.69-91

The five principles listed below formed the basis of the Board's acceptance of Enbridge's corporate cost allocations in EB-2005-0001.

1. The service is specifically required by the utility;
2. The level of service provided is required by the utility;
3. The costs are allocated based on cost causality and cost drivers;
4. The cost to provide the service internally would be higher and the cost to acquire the service externally on a stand-alone basis would be higher; and
5. There are scale economies.

Please provide information as to how Innisfil's corporate cost allocation policy meets each of these principles.

Response #1.9

Innisfil Hydro does not participate with any corporate cost allocation with its shareholder, the Town of Innisfil or its affiliate Innisfil Energy Services Limited.

2 COST OF CAPITAL - CAPITAL STRUCTURE AND WEIGHTED AVERAGE COST OF CAPITAL

2.1 Long Term Debt Rate

Ref: Exhibit 6/Tab 1/Schedule 3/ p.2

Innisfil includes a new bank loan to be issued on May 1, 2009 with a rate of 5.08%.

Please provide a more detailed explanation of how this rate was determined including the relevant calculations.

Response #2.1

Innisfil Hydro has registered in the pre-application process with Infrastructure Ontario, IO. IO is a Crown corporation dedicated to building and renewing public infrastructure.

IO provides the following benefits:

a) affordable borrowing rates

b) all capital expenditures are eligible for financing

c) long terms up to 40 years

d) no extra fees or need to refinance

e) hassle-free access to capital market financing if necessary

Innisfil Hydro requested a quote on a 25 year serial loan for $3,950,000 and IO supplied a rate of 5.08% as of May 16, 2008. Attached is the web based calculator schedule supplied by IO, detailing the principle and interest payments in the file Appendix A responses to OEB IR Q 2.1 Infrastructure Ontario debt 2009. Innisfil Hydro utilized this calculation within its rate application based on the reasonableness of the estimate as of the end of May 2008. As of October 31, 2008 the 25 year rate for a serial loan is 6.17% per the Infrastructure Ontario web site quotes for LDCs'.

At the time final rates are determined, Innisfil Hydro proposes the debt rate to be used for the 25 year serial loan would be set based on the debt rate quoted by Infrastructure Ontario when the OEB sets the deemed long term debt rate, the deemed short term debt rate and the rate of return of equity for 2009 cost of service/rebased applicants.

3 RATE BASE AND CAPEX

3.1 Capital Program Increase

Ref: Exhibit 2/Tab 3/Schedule 1/ p. 8

Innisfil is proposing a substantial increase in its capital program which is envisaged to rise from a 2007 actual level of $1.5 million to a $3.4 million level in the 2008 Bridge Year to $6.5 million in the 2009 Test Year:

a) Please provide the breakdown fore each 2006 through 2009 the capital expenditures that are “one-time programs” vs. “ongoing programs”.

b) Please discuss the extent to which Innisfil considered a phased approach to its capital program and if a phased approach was considered, why it was not adopted. If a phased approach was not considered, please explain why not.

c) Please describe how the costs of capital investment programs for 2009 were estimated. Please provide evidence and supporting documents such as calculations, market-based contractor bids, etc.

d) Innisfil is proposing a substantial increase in its capital program for the test year. Please provide an explanation on the measures that Innisfil has taken or will undertake, e.g. use of tendering process and deploying the lowest bid contractor, negotiations with suppliers on purchase of material and equipment, etc. to execute capital program projects in the most cost-effective way. Please file with the Board any evidence that demonstrates Innisfil’s effort in undertaking and implementing measures that would demonstrate achieve cost savings for Innisfil’s capital programs.

e) Please state why Innisfil believes that it has the capacity to complete such a large capital program in 2009. In this context, please provide an update as to where the 2008 capital program stands on a completion basis as of September 30, 2008. Please also discuss whether or not Innisfil anticipates having any carryover projects from 2008 and, if so, what their impacts would be in 2009.

Response #3.1

a)

2006 Actual Capital Expenditures			
Distribution Plant major capital request			
	Description	**Amount**	**Program**
	WO 6698 Thor School	$ 29,051	One-Time
	WO 6868 Pole replacement	$ 183,057	On-Going
	WO 6870 Alcona Voltage conversion	$ 156,695	On-Going
	WO 7616 Lefroy DS F3 feeder	$ 36,406	One-Time
	WO 7623 Royal Distributing UG	$ 38,954	One-Time
	WO 8151 Siscor	$ 73,540	One-Time
	Capitalized subdivision assets trf	$ 498,556	One-Time
	Bob Deugo Distribution Station	$ 1,301,539	One-Time

2007 Actual Capital Expenditures			
Distribution Plant major capital request			
	Description	**Amount**	**Program**
	WO 10012 H1 9M3 & 9M6 double circuit	$ 35,179	One-Time
	WO 10137 IBR relocate	$ 50,011	One-Time
	WO 10280 7267 5th SD RD	$ 210,551	One-Time
	WO 55691 815 Harbour private primary	$ 19,639	One-Time
	WO 7618 Town booster station	$ 36,905	One-Time
	WO 7630 Alcona voltage conversion	$ 315,260	On-Going
	WO 7640 UG primary service Town Admin	$ 39,834	One-Time
	WO 7641 Road relocate	$ 131,068	On-Going
	WO 7644 Subaru car dealership	$ 38,099	One-Time
	WO Mercedez car dealership	$ 36,023	One-Time
	WO 7660 Shell & Tim Hortons	$ 30,250	One-Time
	WO C123 Woodlawn Park subdivision	$ 27,152	One-Time

Analysis of the 2008 Forecasted Capital Requests			
Distribution Plant major capital request			
CR #	**Description**	**Amount**	**Program**
CDP2008-1	Line Ext 15th Line West of Cookstown	$ 81,900	One-Time
CDP2008-2	44kV Line Ext BBP	$ 360,400	On-Going
CDP2008-3	Line Rebuild Hwy 27	$ 125,800	One-Time
CDP2008-4	Guard Rails	$ 170,000	On-Going
CDP2008-5	Urbanization	$ 750,000	On-Going
CDP2008-6	carried forward - H1 double circuit	$ -	One-Time
CDP2008-7	44kV Mechanized Altdi-Ruptor Scada Switches	$ 192,950	On-Going
CDP2008-8	27.6 kV Mechanized Scada-mate switches	$ 132,750	On-Going
CDP2008-9	carried forward - 9M3 9M6	$ -	One-Time
CDP2008-10	Pole replacement	$ 236,510	On-Going
CDP2008-12	Meter Analyzer	$ 27,000	One-Time
CDP2008-13	Wholesale meters	$ -	One-Time
CDP2008-14	Conventional meters	$ 53,000	On-Going

Analysis of the 2009 Budgeted Capital Request

Distribution Plant major capital request

CR #	Description	Amount	Program
DO-001	Pole Replacement	$ 271,500	On-Going
DO-002	44 kV Load Interrupters	$ 290,540	On-Going
DO-003	Industrial Park Rd Transformer replacment	$ 52,200	One-Time
DO-004	9M4 ext-20 SR 10th line	$ 198,900	One-Time
DO-005	Reclosurer automation	$ 133,900	On-Going
DO-006	Utility relocates	$ 266,900	On-Going
DO-007	27.6 SCADA mates	$ 149,600	On-Going
DO-008	44 kV line ext 20th SR	$ 389,300	One-Time
DO-010	Wholesale meters	$ 140,000	One-Time
DO-011	Guard rails	$ 132,900	On-Going
DO-012	Urbanization	$ 788,800	On-Going
DO-013	27 kV voltage conver 20 SR 5th & 6th	$ 184,100	One-Time
DO-014	27 kV voltage extension 20 SR 7th & 4th	$ 714,550	One-Time
DO-015	Infrastructure Betterment	$ 184,700	On-Going
DO-016	Hydro One contribution	$ 500,000	One-Time
DO-017	Line extension	$ 853,186	One-Time

b)

2009 Capital Program	Considered Phased Approach	Reason
Pole replacement	Yes	Eight Year Cycle
44 kV Load Interruptors	Yes	Multi-year plan
Industrial Park Road Transformer replacement	No	Not a large project
9M4 extension-20 SR 10th line Lockhart rd	No	Phasing not practical
Recloser automation & replacement	yes	Multi-year plan
Utility relocates	No	Must be done on demand
27.6 SCADA mates	Yes	Multi-year plan
44 kV line ext 20th SR Lockhart to Fairway Rd	Yes	Phase 2 in 2009
SMI-Meters, installations & finance/corporate	No	Not practical, separate rate rider
Wholesale meters	No	Required by IESO
Guard rails	Yes	Multi-year plan
Urbanization	Yes	Multi-year plan
27 kV voltage conversion 20 SR 5th & 6th Ln	No	Not a large project
27 kV voltage conversion 20 SR 7th & 4th Ln	No	Required for new subdivision
Infrastructure betterments	Yes	Multi-year plan
Hydro One contribution	No	Required by Hydro One
Line extension	No	Required for Growth

c)

2009 Capital Program	Price Estimating Proceedure
Pole replacement	In-house, per unit and hourly calculations
44 kV Load Interruptors	In-house, per unit and hourly calculations
Industrial Park Road Transformer replacement	In-house, per unit and hourly calculations
9M4 extension-20 SR 10th line Lockhart rd	In-house, per unit and hourly calculations
Recloser automation & replacement	In-house, per unit and hourly calculations
Utility relocates	In-house, per unit and hourly calculations
27.6 SCADA mates	In-house, per unit and hourly calculations
44 kV line ext 20th SR Lockhart to Fairway Rd	In-house, per unit and hourly calculations
SMI-Meters, installations & finance/corporate	In-house, per unit and hourly calculations
Wholesale meters	In-house, per unit and hourly calculations
Guard rails	External Engineering firm estimates
Urbanization	External Engineering firm estimates
27 kV voltage conversion 20 SR 5th & 6th Ln	In-house, per unit and hourly calculations
27 kV voltage conversion 20 SR 7th & 4th Ln	In-house, per unit and hourly calculations
Infrastructure betterments	In-house, per unit and hourly calculations
Hydro One contribution	External, from Hydro One
Line extension	In-house, per unit and hourly calculations

Attached is the file containing the details of the 2009 capital estimates named IHDSL responses to OEB IR 3.1 c)

d) Innisfil Hydro has undergone a competitive bid process (tender) to choose an overhead line contractor. Underground capital works will be undertaken via a public tender. Materials are sourced by lowest cost methods (multiple bids/tenders).

e) Innisfil Hydro has no reason to doubt its ability to complete the capital program in 2009. Engineering is predominantly done in-house except for guard rails and urbanization. All of the physical construction is contracted out. Labour, equipment and material shortages are not expected, especially if there will be a construction slow down.

Innisfil Hydro expects that the road widening and Hydro relocates for Innisfil Beach Road urbanization will be carried over from 2008 to 2009. The anticipated 2009 Innisfil Beach Road urbanization is expected to be carried over from 2009 to 2010. A major impact in 2009 is not anticipated because this is a multi-year project where all stages will be pushed back one year.

The following table provides an update on the status of 2008 capital projects as requested.

Analysis of the 2008 Forecasted Capital Requests

Distribution Plant major capital request			**Status, Sep 30, 2008**
CR #	Description	Amount	
CDP2008-:	Line Ext 15th Line West of Cookstown	81,900	Done
CDP2008-;	44kV Line Ext BBP	360,400	Done
CDP2008-:	Line Rebuild Hwy 27	125,800	Done
CDP2008-·	Guard Rails	170,000	With Engineering Design Firm
CDP2008-!	Urbanization	750,000	With Engineering Design Firm
CDP2008-(	carried forward - H1 double circuit	-	
CDP2008-'	44kV Mechanized Altdi-Ruptor Scada Switches	192,950	Material ordered, Engineering complete
CDP2008-!	27.6 kV Mechanized Scada-mate switches	132,750	90% Done
CDP2008-!	carried forward - 9M3 9M6	-	
CDP2008-:	Pole replacement	236,510	65% Done
CDP2008-:	Meter Analyzer	27,000	Done
CDP2008-:	Wholesale meters	-	
CDP2008-:	Conventional meters	53,000	Done

3.2 Capital Program Increase

Ref: Exhibit 2/Tab 3/Schedule 1/ p.8/ Table 2

On this page, Table 2 provides a breakdown by category of Distribution Plant Projects comprising the increase in capital expenditures of about $3 million from the 2008 Bridge Year to the 2009 Test Year. The two main categories comprising the increase are reliability which increases by roughly $1.6 million and capacity which increases by $1.1 million.

a) Please state the basis of Innisfil's belief that a $1.6 million increase in expenditures for the Reliability category in 2009 is necessary. Please provide service reliability indicators such as SAIDI, SAIFI and CAIDI for a sufficient period of time to indicate any deterioration in reliability that would support this requirement. If reliability statistics do not show deterioration, please justify the proposed increase in this context.

b) In regards to capital expenditure for system capacity, Table 2 shows that in the years 2005 to 2008, the greatest amount spent was less than $40,000. Please state in this context why $1.1 million in 2009 is a reasonable level of expenditure in this category and justify this investment.

Response #3.2

a) The following chart was referenced from Exhibit 2, Tab 3, Schedule 1, Page 7 of 8 for reliability expenditures:

Analysis of the 2009 Capital Requests			
Distribution Plant major capital request Reliability			
CR #	**Description**	**Amount**	**Program**
DO-002	44 kV Load Interruptors	$ 290,540	On-Going
DO-005	Recloser automation & replacement	$ 133,900	On-Going
DO-007	27.6 SCADA mates	$ 149,600	On-Going
DO-011	Guard rails	$ 132,900	On-Going
DO-016	Hydro One contribution	$ 500,000	One-Time
DO-017	Line extension	$ 853,186	One-Time

DO-002, 44kV Load Interruptors. This involves four new loadbreak switches that will operate via the SCADA system in an effort to reduce interruption durations and allow the devises to operate under system load.

These four switches replace existing airbreak switches or mid-span openers that have exceeded their respectful useful lives.

DO-005, Reclosure automation and replacement. Two sets of Cooper Kyle Nova electronically controlled reclosures are to be added to the distribution system. These low maintenance units utilize vacuum break technology rather than hydraulic oil versions. This dramatically reduces the cost of maintenance over the long term of the asset. These units are also automated using SCADA technology to isolate or restore in outage conditions greatly improving restoration times as well as reducing line staff time.

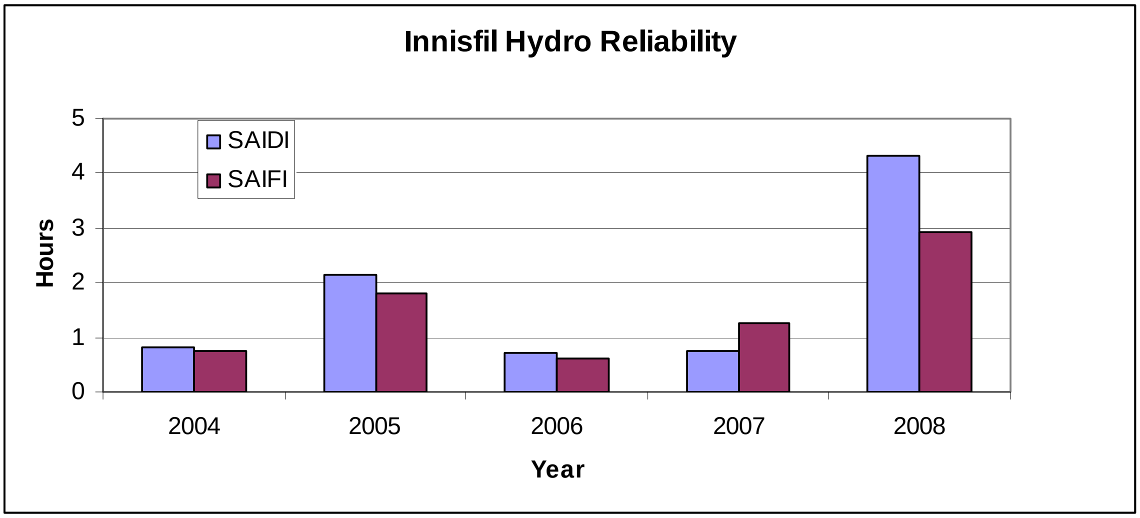
DO-007, 27.6kV SCADA mates. Three mechanized 27.6 kV SCADA mate switches are to be strategically placed to assist in the restoration of power to the Industrial Park at Highway 400 & Innisfil beach road. These switches replace existing single phase in-line switches that must be physically operated by line staff in bucket trucks.

DO-011, Guard Rails. New guard rails around rural 44kV Load Interruptor switch poles are designed to protect these assets from vehicle impact. The roadways targeted have 80km/h road speeds and the poles are in close proximity to the travelled portion of the road.

DO-016 & DO-017, Hydro One Contribution and Line extension. Innisfil Hydro is an embedded distributor within Hydro One. It has had the same supply capacity for the past 15+ years. In an effort to deal with load growth in Simcoe County, Hydro One had initiated a Simcoe County Supply Study Plan (2004-2014) with Barrie Hydro, Innisfil Hydro, Collingwood Utility Services, Honda, Wasaga Distribution and Midland Power Utility Corp. The result of this plan was for Hydro One to construct a new transformer station, Everett TS. With this new station, two 44kV feeder locations were freed up from Alliston TS, 9M3 & 9M6, which are available for Innisfil Hydro's needs. Without these two new feeders, the Town of Innisfil's Growth management plan and the County of Simcoe's draft Official Plan are moribund. There are no other practical options available to Innisfil Hydro for increasing electricity supply into the Town of Innisfil in the foreseeable future.

Hydro One's estimate for constructing the two new circuits to Innisfil Hydro's territory has increased from $500k to $932k just recently. This means that the $1.6 million in 2009 has been understated by $432k. The incremental expenditure for installing two new feeders is expected to service Innisfil Hydro's growth requirements for 14 years.

The following graph has been provided with SAIDI and SAIFI statistics from 2004 to October 8, 2008:



An increase in 2005 SAIDIs and SAIFIs were attributed to a line galloping situation on the two main 44kV circuits supplying Innisfil. This pole-line was rebuilt in 2006 to mitigate this storm weather phenomenon. The main 44kV pole line supplying Innisfil has two circuits on the same pole line and is supplied by a Hydro One TS from over 12km outside of Innisfil Hydro's distribution territory. There is huge reliability risk to Innisfil by not having a back-up for these two main 44kV feeders.

The huge increase in SAIDIs and SAIFIs for 2008 actual to date are contributed to the fact that Innisfil does not have back-up feeders for the two main feeders supplying Innisfil. This reliability problem will be mitigated by the construction of the two new 44kV feeders from Alliston TS, 9M3 & 9M6. If the two new 44kV circuits were installed in 2007as originally planned, the 2008 SAIDIs and SAIFIs would be in line with 2007 reliability statistics.

b) The following chart was referenced from Exhibit 2, Tab 3, Schedule 1, Page 7 of 8 for capacity expenditures:

Analysis of the 2009 Capital Requests			
Distribution Plant major capital request Capacity			
CR #	**Description**	**Amount**	**Program**
DO-008	44 kV line ext 20th SR Lockhart to Fairway Rd	$ 389,300	One-Time
DO-014	27 kV voltage conversion 20 SR 7th & 4th Ln	$ 714,550	One-Time

DO-008, 44kV line extension 20th SR from Lockhart to Fairview Rd. This project is the continuation of the Barrie 13M3 feeder line extension that will eliminate the radial feed and serve as a loop fed system to the Kempenfelt Centre and Big Bay Point Distribution Station. The first phase of this project in 2008 replaced all of the poles with ESA approved pole sizes for the new 44kV conductor and 8.32kV and future 27.6kV underbuild. It provided space and framing for a future 27.6kV circuit to supply the Big Bay Point resort development with an estimated requirement of 6.7MW. The stringing of the 27.6kV circuit will occur in 2011 to meet the requirements for the new Big Bay Point development in 2012.

DO-014, 27.6kV Voltage conversion20th SR 7th to 4th lines. The line extension of the 27.6kV distribution system is to accommodate the LSAMI development in Lefroy. The 27.6kV circuit is required to service the development as the current 8.32kV substation is near capacity. This will also provide redundant back-up supply between Brian Wilson DS and a future 44kV-27.6kV substation in Lefroy.

Subsequent to the rate application, information from the Town of Innisfil Planning Department indicates a one year delay in the development of a 1182 lot plan of subdivision in the settlement area of Lefroy. This would allow the postponement of a 27.6kV line extension on the 20th Side Road from 7th Line to 4th Line and 27.6kV voltage conversion on the 20th Side Road at 5th and 6th Lines. This capital expenditure of $714,550 and $184,100 for a total of $898,650 could be deferred from 2009 to 2010. Out of this amount, $432,000 will be required for a recent economic cost increase from Hydro One to construct two 44kV circuits (9M3 & 9M6 from Alliston TS) carried over from 2008 to 2009.

Attached is the Simcoe County Supply Study file name Appendix B responses to OEB IR Q 3.2 b) Simcoe Study.

3.3 Capital Expenditure Forecasts

Ref: Exhibit 2/Tab 3/Schedule 1/ p.8/ Table 2

Please provide the total “Gross Asset Total” forecasts for 2010, 2011, and 2012.

Response #3.3

The 5 year plan for 2009 to 2013 has not yet been approved by Innisfil Hydro’s board of directors. We are supplying the Gross Asset Totals for 2010, 2011 and 2012 from the most recent approved 5 year plan 2008 to 2012 approved in November 2007. Please be advised the Gross Asset Totals do not include the increased pricing effect of the new line crew contractor K Line.

2010 $4,316,100

2011 $3,880,700

2012 $3,942,300

3.4 Asset Management Plan

Ref: Exhibit 2/Tab 1/Schedule 1/Appendix A

Please indicate if Innisfil has utilized any asset condition study in developing its Asset Management Plan. Please file any such study, if available.

Response #3.4

Innisfil Hydro Staff are mindful of asset conditions as a precursor to yearly budgets and five year plans. Innisfil Hydro has not undertaken an asset condition study from an outside agency which is estimated to cost ~$40k.

3.5 Asset Management Plan

Ref: Exhibit 2/Tab 1/Schedule 1/Appendix A

Innisfil’s asset management plan contains a number of stated exclusions from its budget. For instance on page 16, it is stated that a plan of testing and inspecting is a necessity for Fault Indicators to ensure good reporting with high reliability, but that the amount for such testing has not been budgeted for in 2009 and subsequent years. A similar exclusion is made for Load Balancing on the same page. On page 14, it is stated that Innisfil has not proposed funding to engage in a number of inspections referenced in the DSC. There are a number of other references in the asset management plan to amounts that are not budgeted.

a) Please discuss how Innisfil's asset management plan links to its proposed CAPEX program. Please include in the discussion explanations of the stated exclusions in the asset management plan in the wake of such a large increase in the proposed CAPEX levels.

b) Please an explanation on how the 2009 programs were prioritized and selected while some programs that are referenced above were excluded.

Response #3.5

a) The Asset Management Plan identifies not only capital replacements, but on-going maintenance to increase asset life spans in order to reduce capital requirements, not to mention system reliability.

   a. On page 16, it is stated that a plan of testing and inspecting is a necessity for Fault Indicators to ensure good reporting with high reliability. This testing and inspection cost involves maintenance and does not impact capital expansion requirements.

   b. On page 16, it is stated that the balancing of distribution feeders is desirable to remedy seasonal distribution station load imbalances. This feeder balancing cost involves operations and does not impact capital expansion requirements.

   c. On page 14, it is stated that the up-close inspection of overhead transformers has not been budgeted for, which is beyond the visual inspection, infra-red scanning and typical line patrols. This up-close inspection cost involves maintenance and does not impact capital expansion requirements.

The Asset Management Plan has the following links to the proposed CAPEX program:

Background Page 3, describes load growth projections for Simcoe County which is linked to the capital requirement for building two new 44kV feeders as identified in the 2009 CAPEX program under 'Hydro One Contribution', 'Line extension' and 'Wholesale meters'.

3.4 Pole testing Page 9-11, outlines the process for pole testing and replacements, which has been incorporated into the pole replacement budget for the replacement of 60 poles as identified in the 2009 CAPEX program under 'Pole Replacement'.

3.5 Switches Page 11-13, outlines switch addition and replacement schedules to deal with capital requirements and is identified in the 2009 CAPEX program under ‘44kV Load Interruptors’ and ’27.6 SCADA mates’.

3.6 Reclosures Page 13, outlines inspection and the rebuilding of reclosures which has been identified in the 2009 CAPEX program under ‘Reclosure Automation and Replacement’.

3.8 Transformers Page 14, outlines overhead transformer inspection and replacement which is identified in the 2009 CAPEX program under ‘Industrial Park Road Transformer Replacements’.

4.5 Primary underground cables Page 20, describes the inspection process for underground cables. The link is to the Five Year Plan for ‘Sandy Cove North Rebuild’ for cable replacements.

6.1 Retail Meters Page 25, describes the meters regulated under the authority of Measurement Canada which is identified in the 2009 CAPEX program under ‘Meters’.

10.0 Innisfil Beach Road Urbanization Page 29-30, identifies a multi-year road widening project which is identified in the 2009 CAPEX program under ‘Urbanization’.

b) Programs whether O&M or Capital are generally prioritized as follows:

1. Health & Safety
2. Legislative
3. Growth
4. Reliability

2009 Capital Program	**Prioritation**
Pole replacement	Health & safety
44 kV Load Interruptors	Reliability
Industrial Park Road Transformer replacement	Reliability
9M4 extension-20 SR 10th line Lockhart rd	Reliability
Recloser automation & replacement	Reliability
Utility relocates	Legislative
27.6 SCADA mates	Reliability
44 kV line ext 20th SR Lockhart to Fairway Rd	Reliability
SMI-Meters, installations & finance/corporate	Legislative
Wholesale meters	Legislative
Guard rails	Health & safety/Reliability
Urbanization	Legislative
27 kV voltage conversion 20 SR 5th & 6th Ln	Growth
27 kV voltage conversion 20 SR 7th & 4th Ln	Growth
Infrastructure betterments	Reliability
Hydro One contribution	Reliability/Growth
Line extension	Reliability/Growth

d. On page 16, it is stated that a plan of testing and inspecting is a necessity for Fault Indicators to ensure good reporting with high reliability. Fault Indicators can reduce interruption duration (SAIDI) but do not directly cause interruptions if they fail. Although good utility practice, this expense was not budgeted for.

e. On page 16, it is stated that the balancing of distribution feeders is desirable to remedy seasonal distribution station load imbalances. Feeder balancing improves distribution system performance but it is difficult to quantify any reliability impact. Although good utility practice, this expense was not budgeted for.

f. On page 14, it is stated that the up-close inspection of overhead transformers has not been budgeted for, which is beyond the visual inspection, infra-red scanning and typical line patrols. It is difficult to quantify any reliability improvements associated with this up-close inspection. Although good utility practice, this expense was not budgeted for.

3.6 Service Quality and Reliability

Ref: Exhibit 2

Please provide the following information on service reliability indicators recorded and used by Innisfil:

a) a listing of the Service Reliability Indicators maintained and used, and their actual values for the years 2002 through 2007;

b) Innisfil's 2008 and 2009 reliability improvement targets, if any, for the SAIDI, SAIFI and CAIDI indicators; and

c) If Innisfil has established reliability improvement targets, a copy of the plan that identifies programs or projects that Innisfil will undertake to achieve these targets.

Response #3.6

a) The following table represents the actual Services Reliability Indicators from 2002 to 2007 and the targets for 2008 and 2009. There is no information prior to 2007 separating the SRIs' by LDC specific and loss of supply causes.

Service Reliablity Indicators

	SAIDI	SAIFI	CAIDI
2002 Actual	1.93	1.71	1.13
2003 Actual	4.90	2.68	1.83
2004 Actual	0.83	0.76	1.09
2005 Actual	2.14	1.79	1.19
2006 Actual	0.70	0.60	1.16
2007 Actual	0.76	1.25	0.60
2008 Target	1.16	1.19	0.98
2009 Target	0.85	0.99	0.86

b) The 2008 and 2009 reliability improvement targets are shown in the above table 3.6a).

c) The majority of power interruptions in Innisfil are caused by tree contact and loss of supply. Innisfil Hydro has increased the frequency of tree trimming and is planning to build two new 44kV feeders to address these primary issues and improve reliability. A formal plan has not been created.

4 SMART METERS

Ref: Exhibit 1/Tab 1/Schedule 7/ p. 2
Ref: Ontario Energy Board – Guideline, Smart Meter Funding and Cost Recovery, G-2008-002, p. 9-10,
http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/OEB_Guideline_SmartMeters.pdf/

On page 1 of Exhibit 1/Tab 1/Scheudle 8 of its application, Innisfil stated that:

> "*Innisfil Hydro, along with other members of the CHEC group, have met with the Ministry of Energy staff to arrange approval to begin installation of smart meters in our service territory in order to meet the Government's 2010 timeline. Innisfil Hydro is requesting continuation of the rate rider for smart metering infrastructure in the 2009 Rate Application and expects to submit an application at a later date for a revised Smart Meter Rate Rider once the process for Innisfil Hydro becomes more definite with respect to inclusion in the Ministry Regulations for the procurement of Smart Meters.*"

With reference to the Board guideline on smart meter funding and cost recovery (pages 9-10):

a) Please provide a statement that the Innisfil is not planning to start a smart meter program in the rate test year.

b) Please indicate the steps Innisfil intends to take in order to mitigate future rate impacts related to the implementation of smart meters in its service area.

Response #4

Following the submission of Innisfil Hydro's rate application EB-2008-0233, the Ontario Energy Board released a document G-2008-0002. "Guideline for Smart Meter Funding and Cost Recovery".

As part of the Guide, the Board established two distinct sets of distributors. “Non-Implementing Distributors” as noted in section 1.3, and “Distributors Implementing Smart Meters” in section 1.4

Innisfil Hydro participated in the Ministry sanctioned extension of the London RFP, and as a result is recognized as an Authorized Distributor under O. Reg 235/08:

“ Amends O. Reg. 427/06, Smart Meters: Discretionary Metering Activity and Procurement Principles, to add a new category of distributors that are authorized to undertake smart meter activities. This new category is comprised of distributors that acquire their smart meters pursuant to and in compliance with a specified Request for Proposal issued by London Hydro Inc. Also amends O. Reg. 427/06 to confirm that six named distributors may continue their smart metering activities.”

Innisfil Hydro is proceeding with deployment of SENSUS meters through purchase arrangements with KTI/Sensus as per the findings of the Fairness Commissioner. It is Innisfil Hydro’s intent to complete full deployment of smart meters by the end of the third quarter of 2009. Together with a consortium of distributors as part of the Cornerstone Hydro Electric Concepts Inc. (CHEC), Innisfil Hydro is in final contract negotiations for the installation of the communication towers required to establish the Advanced Metering Infrastructure within our Territory.

In keeping with our ongoing efforts to control costs, Innisfil Hydro is working collectively with a consortium of distributors having issued a RFP for the selection of qualified mass deployment installation contractors. This RFP selection process is scheduled to be completed no later than the end of January, 2009 to allow for a scheduled rotation of installation crews across the various distributor territories of those participating in the collective effort.

The following chart depicts the estimated budgets for the Smart Meter plan established for Innisfil Hydro’s Service Territory:

Rate Filing	Category	2008	2009	2010	2011	2012	2013	TOTAL
Smart Meter Unit Costs	A	$0.00	$1,780,395.10	$19,317.99	$19,317.99	$19,317.99	$19,317.99	$131.06
Smart Meter Other Unit Costs	B	$56,700.00	$536,970.00	$21,000.00	$0.00	$0.00	$0.00	$43.37
Smart Meter Installation Costs Per Unit	C	$0.00	$326,398.76	$0.00	$0.00	$0.00	$0.00	$23.03
Smart Meter Other Costs Per Unit	D	$2,211.30	$112,404.41	$0.00	$0.00	$0.00	$0.00	$8.09
AMI Computer Hardware Costs	F	$0.00	$238,140.00	$0.00	$0.00	$0.00	$0.00	
AMI Computer Software Costs	G	$0.00	$19,985.70	$0.00	$0.00	$0.00	$0.00	
Other Computer Hardware Costs	H	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Other Computer Software Costs	I	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Incremental AMI O&M Expenses	J	$0.00	$191,167.97	$263,455.10	$200,845.85	$242,550.53	$211,013.67	
Incremental AMI Admin Expenses	K	$0.00	$0.00	$3,402.00	$0.00	$0.00	$0.00	
Incremental Other O&M Expenses	L	$0.00	$0.00	$22,680.00	$22,680.00	$22,680.00	$22,680.00	
Incremental Other Admin Expenses	M	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Utility Safety & Maintenance Capital Budget	2	$108,494.88	$108,494.88	$0.00	$0.00	$0.00	$0.00	
TOU Billing Budget	3	$0.00	$173,645.96	$145,773.89	$77,948.78	$75,775.76	$76,883.65	
	Grand Total	$167,406.18	$3,487,602.78	$475,628.98	$320,792.63	$360,324.28	$329,895.31	

The costs noted in the above chart are currently “best estimates” given that final negotiations resulting from the Installation Vendor RFP have not been completed. Additionally, Innisfil Hydro continues to work with the staff from KTI/Sensus to establish the most cost effective system of communications for the AMI. Values provided are estimates of costs based on input from the vendor and research prepared by Util-Assist who have been contracted by Innisfil Hydro to coordinate the Smart Meter project.

In keeping with the guidelines established by the Ministry for minimum functionality adopted in O. Reg 425/06, Innisfil Hydro has selected not to add additional functionality beyond the base meter provided by KTI/Sensus. Additional functionality such as Remote Disconnects, Interior Home Displays, or Integrated Load Control Features are not included in the base meter product provided by Sensus, and Innisfil Hydro has not requested any of these add-on options to be included in the procurement process.

Innisfil Hydro has not incurred nor intends to incur any costs associated with functions for which the SME has exclusive authority to carry out pursuant to O. Reg. 393/07. At present, Innisfil Hydro plans to begin registration with the SME and integration to the MDMR during the first quarter of 2010 in an effort to be fully capable for implementation of TOU rates before the end of the third quarter.

The following chart is a detailed proposed smart meter deployment schedule for Innisfil Hydro’s territory:

Smart Meter Delivery and Installation Schedule

			Jan-09				Feb-09				Mar-09					Apr-09			
			05 to 09	12 to 16	19 to 23	26 to 30	02 to 06	09 to 13	16 to 20	23 to 27	02 to 06	09 to 13	16 to 20	23 to 27	30 to 3	06 to 10	13 to 17	20 to 24	27 to 01
	Volume	Staffing	5	5	5	5	5	5	4	5	5	5	5	5	5	4	5	5	5
Innisfil Delivery Schedule	**14,245**										3648					3648			
Innisfil Installation Schedule	**14,245**	**4**											800	800	800	640	800	800	800

			May-09				Jun-09					Jul-09				Aug-09			
			04 to 08	11 to 15	18 to 22	25 to 29	01 to 05	08 to 12	15 to 19	22 to 26	29 to 03	06 to 10	13 to 17	20 to 24	27 to 31	03 to 07	10 to 14	17 to 21	24 to 28
	Volume	Staffing	5	5	4	5	5	5	5	5	4	5	5	5	5	4	5	5	5
Innisfil Delivery Schedule	**14,245**			3648				6949											
Innisfil Installation Schedule	**14,245**	**4**	800	800	640	800	800	800	800	800	640	800	800	325					

When the final rates are determined the $1.00 smart meter adder will be reflected in those rates.

b) Innisfil Hydro will continue to endeavour, as it has in the past, to obtain the best possible pricing for the smart meter initiative as per the guidelines provided by the Fairness Commissioner with the London RFP phase 2.

5 PILS

5.1 Appropriateness of tax rate

Ref: Exhibit 4/Tab 3/Schedule 1

Innisfil used a combined income tax rate of 33.0% in its application for 2008 even though its taxable income is below the $1.5 million threshold for this tax rate. Please explain why Innisfil believes that the 33% rate is the correct one to use, or if not, please provide a revised version of this evidence making use of the appropriate rate.

Response #5.1

The 2008 bridge year combined tax rate used in Exhibit 4/Tab 3/Schedule 1 is 33.50%. The 2008 tax rate reflecting the $1.5 million threshold impact is 32.84%. The following table shows the revised calculations of the Income Taxes for 2008:

Income Taxes Calculation for 2008 Bridge Year

	Revised	Original
Taxable Regulatory income	**$ 1,299,284**	**$ 1,299,284**
Federal Tax rate	19.50%	19.50%
Ontario Tax rate to $500k	5.50%	14.00%
Ontario Tax rate from $501k to $1.5m	18.25%	0.00%
Federal Tax	253,360	253,360
Ontario Tax	173,369	181,900
Total Income Tax	**$ 426,730**	**$ 435,260**
Combined Tax Rate	**32.84%**	**33.50%**

The following table reflects the threshold impacts to the 2009 regulatory taxable income as provided in Exhibit 4/Tab 3/Schedule 1:

Income Taxes Calculation for 2009 Test Year

	Ex4/Tab 3/Sch 1
Taxable Regulatory income	**$ 1,745,198**
Federal Tax rate	19.00%
Ontario Tax rate	14.00%
Federal Tax	331,588
Ontario Tax	244,328
Total Income Tax	**$ 575,915**
Combined Tax Rate	**33.00%**

	Backup
Taxable Regulatory income	**$ 1,745,198**
Federal Tax rate	19.00%
Ontario Tax rate to $500k	5.50%
Ontario Tax rate from $501k to $1.5m	18.25%
Ontario Tax rate over $1.5m	14.00%
Federal Tax	331,588
Ontario Tax @ 5.5%	27,500
Ontario Tax @ 18.25%	182,500
Ontario Tax @ 14.0%	34,328
Total Income Tax	**$ 575,915**
Combined Tax Rate	**33.00%**

5.2 Consistency of income numbers

Ref: Exhibit 4/Tab 3/Schedule 1/ p. 1

Please show the calculation of the distribution income before taxes of $1,470,445 for the 2009 test year. Please also show the calculation of 2009 test year income before taxes based on the following calculation:

a) Rate base multiplied by the percentage that equity comprises in the capital structure multiplied by the percentage return on equity.

b) If there is a difference between the dollar figure of $1,470,445 and the result in a) above, please explain why there is a difference.

Response #5.2

a) The following is the analysis of regulatory taxable income to ROE:

Reconcilation of Taxable Income vs ROE

			2009
Utility Income before deducting income taxes			1,470,445
Consist of:			
Fixed Assets Opening Bal 2009	18,688,011		
Fixed Assets Closing Bal 2009	23,205,068		
Average Fixed Asset Bal 2009	20,946,539		
Working Capital Allowance	3,142,827		
Rate Base	24,089,366		
Deemed Portion of equity	43.33%		
	10,437,922		
Deemed Return on equity %	8.57%		
Deemed Return on equity			894,530
		Variance	575,915
		Grossed up PILS	575,915
		Variance	0

b) The variance between the utility income and the deemed return on equity is the grossed up PILS of $575,915 on Exhibit 4/Tab 3/Schedule 1/Table 1.

5.3 Provision of Actuals

Ref: Exhibit 4/Tab 3/Schedule 1

On this page, Innisfil provides its tax calculations including information for the years “2006 Board Approved”, “2008 Bridge” and “2009 Test.” Please provide a revised version of this table incorporating 2006 and 2007 actuals.

Response #5.3

The following table includes the 2006 and 2007 actuals:

Table 1
Tax Calculations

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Determination of Taxable Income					
Utility Income Before Taxes	1,605,847	2,111,827	1,303,941	950,250	1,470,445
Book to Tax Adjustments					
Additions to Accounting Income:					
Depreciation and amortization	1,454,453	1,550,134	1,666,910	1,775,255	1,980,834
Income or Loss for tax Purposes-joint ventures or partnerships	3,652	2,556	0	0	0
Interest and penalties on taxes	2,091	0	0	0	0
Meals & entertainment / Mileage	2,087	3,080	4,423	3,276	3,375
Non-deductible club fees and dues	0	0	0	0	0
Taxable Capital Gains	0	0	0	0	0
Tax reserves beginning of year	43,357	798,552	352,580	0	0
Reserves from financial statements -balance at year end	0	0	0	0	0
Pensions	55,856	49,790	42,244	0	0
Non-deductible contributions	359,401	741,728	642,594	0	0
Total Additions	**1,920,897**	**3,145,840**	**2,708,751**	**1,778,531**	**1,984,209**
Deductions from Accounting Income:					
Capital Cost Allowance	950,533	1,090,543	1,237,358	1,400,814	1,681,652
Gain on disposal of assets per financial statements	0	0	7,615	0	0
Cumulative eligible capital deduction	34,379	32,006	29,967	28,683	27,804
Tax reserves end of year	43,357	352,580	1,094,517	0	0
Excess Interest	47,665	0	0	0	0
Pensions	56,038	62,236	35,150	0	0
Deductible contributions	359,401	741,728	642,594	0	0
Total Deductions	**1,491,373**	**2,279,093**	**3,047,201**	**1,429,497**	**1,709,456**
Regulatory Taxable Income	**2,035,371**	**2,978,574**	**965,491**	**1,299,284**	**1,745,198**
Corporate Income Tax Rate	36.12%	36.33%	36.36%	0	0
Subtotal	**735,176**	**1,082,116**	**351,053**		
Less: R&D ITC (0.3)	11,271				
Regulatory Income Tax	**723,905**	**1,082,116**	**351,053**	**435,260**	**575,915**
Calculation of Utility Income Taxes					
Income Taxes	723,905	1,082,116	351,053	435,260	575,915
Large Corporation Tax	0	0	0	0	0
Ontario Capital Tax	37,881	42,470	35,150	13,304	20,451
Total Taxes	**761,786**	**1,124,586**	**386,202**	**448,564**	**596,367**
Tax Rates					
Federal Tax	22.12%	22.60%	23.68%	19.50%	19.00%
Federal Surtax					
Provincial Tax	14.00%	13.73%	12.68%	14.00%	14.00%
Total Tax Rate	**36.12%**	**36.33%**	**36.36%**	**33.50%**	**33.00%**
Calculation of Large Corporation Tax					
Total Rate Base	22,626,868	24,015,961	24,665,300	20,912,835	24,089,366
Less: Exemption	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Taxable Capital	**(27,373,132)**	**(25,984,039)**	**(25,334,700)**	**(29,087,165)**	**(25,910,634)**
LCT Rate	0.125%	0.125%	0.125%	0.125%	0.125%
Subtotal	(34,216)	(32,480)	(31,668)	(36,359)	(32,388)
Federal Surtax	0	0	0	0	0
Large Corporation Tax	**0**	**0**	**0**	**0**	**0**
Calculation of Ontario Capital Tax					
Total Rate Base	22,626,868	24,015,961	24,665,300	20,912,835	24,089,366
Less Exemption	10,000,000	9,859,163	12,332,042	15,000,000	15,000,000
Taxable Capital /Deemed taxable capital	**12,626,868**	**14,156,798**	**12,333,258**	**5,912,835**	**9,089,366**
OCT Rate	0.300%	0.300%	0.285%	0.225%	0.225%
Ontario Capital Tax	**37,881**	**42,470**	**35,150**	**13,304**	**20,451**

Please note Innisfil Hydro has updated the 2006 Board Approved Utility Income Before Taxes to reflect the gross up of PILs income tax of $723,905 per the 2006 Tax Model v2.1 filed with the 2006 EDR.

6 LOAD FORECAST

6.1 Load Forecast and Methodology - Weather Normalization

Ref: Exhibit 3/Tab 2/Schedule 3/p.p. 4-5/ 2nd Paragraph of p. 4

On pages 4-5, Innisfil states: "*The forecasted weather normalized amount for 2008 and 2009 is determined by using a forecast of the dependent variables in the predication formula on a monthly basis. In order to incorporate weather normal conditions, the average monthly heating degree days and cooling degree days which has occurred from 2002 to 2007 is applied in the prediction formula*."

Using a similar method to develop the weather normalized forecast of total system purchases for 2009, please provide the following scenarios.

a) Instead of using the average monthly heating degree days (HDD) and cooling degree days (CDD) from 2002 to 2007, please develop the weather normalized forecast of total system purchases for 2009 by using **average** monthly HDD and CDD from 1998 to 2007. Please calculate the variance and percent variance from 2009 proposed weather normalized forecast for total system purchases.

b) Instead of using the average monthly heating degree days (HDD) and cooling degree days (CDD) from 2002 to 2007, please develop the weather normalized forecast of total system purchases for 2009 by using a **trend** of monthly HDD and CDD from 1988 to 2007. Please calculate the variance and percent variance from 2009 proposed weather normalized forecast for total system purchases.

Response #6.1

a) The 2009 proposed weather normalized forecast in IHDSL's application is 240,434,436 kWh. The 2009 weather normalized forecast using average monthly HDD and CDD from 1998 to 2007 is 238,808,093 kWh. This amount is 1,626,343 kWh lower or 0.68% lower than the forecasted value assumed in the application.

b) The 2009 weather normalized forecast using a trend of monthly HDD and CDD from 1988 to 2007 is 239,059,717 kWh. This amount is 1,374,719 kWh lower or 0.57% lower than the forecasted value assumed in the application.

6.2 Economic and Growth Projections

Ref: Exhibit 3/Tab 2/Schedule 3/p. 6/ 1st paragraph

On page 6 Innisfil states: "*The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data……*"

Please provide supporting material related to the Innisfil's customer/connection forecast.

Response #6.2

As outlined in Exhibit 3/Tab 2/Schedule 3/p. 6 and 7 of IHDSI's application, the customer/connection forecast is based on reviewing the historical customer/connection from 2002 to 2007 shown in Table 6 on the referenced page 6 see below:

Table 6.21
Historical Customer/Connection Data

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
2002	12,227	841	73	2,107	177	0	15,425
2003	12,409	880	73	2,196	181	0	15,739
2004	12,670	888	74	2,309	183	0	16,124
2005	12,821	890	82	2,371	189	0	16,353
2006	12,949	903	67	2,490	184	0	16,593
2007	13,132	831	72	2,588	188	85	16,896

From this historical information, the annual growth rate and the geometric mean of these growth rates are determined and provided in Table 7 (see below) of the referenced page 6. Except for the unmeterered scattered load class, the geometric mean is applied to 2007 values to determine the 2008 forecast. Then the geometric mean is then applied to the 2008 value to determine the 2009 values. For the unmetered scattered load class the number of connections is held constant at the 2007 values as there is no historical data for this class. The resulting forecast of customer/connection data is provided in Table 8 on the referenced page 7.

Table 6.22
Growth Rate in Customer Numbers

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads
2002						
2003	101.49%	104.64%	100.00%	104.22%	102.26%	0.00%
2004	102.10%	100.91%	101.37%	105.15%	101.10%	0.00%
2005	101.19%	100.23%	110.81%	102.69%	103.28%	0.00%
2006	101.00%	101.46%	81.71%	105.02%	97.35%	0.00%
2007	101.41%	92.03%	107.46%	103.94%	102.17%	0.00%
Geometric mean	1.44%	-0.24%	-0.28%	4.20%	1.21%	0.00%

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
2008	189	-2	0	109	2	0	298
2009	192	-2	0	113	2	0	305

Table 6.23 below, was provided to Innisfil Hydro from the Town of Innisfil Planning Department after the initial rate application. New dwelling construction activity for 2009 is estimated by the Town of Innisfil to be a total of 285 units for the calendar year. Incorporating a normal distribution for connecting these units, it is reasonable to conclude that the equivalent of 142 units will be providing revenue for the entire year, (1/2 of the year end estimate).

Innisfil Hydro compared the reasonableness of the load forecast of the residential customers and the Town of Innisfil's Planning Department forecast and has determined the load forecast to be more aggressive than the Town of Innisfil Planning. The rate application had estimated revenue from an additional 192 units leaving a revenue shortfall from 50 units in 2009, (192 minus 142). With the vigorous down-turn in the economy anticipated, a 50 unit shortfall may actually be much larger. There is also the likelihood of increased bad-debts by virtue of the economic down-turn. The shortfall in anticipated revenue and the increase in bad-debt expenses needs be allocated to fewer customers. These items should therefore be factored into the final approved rates as deemed by the Board.

Table 6.23

Estimated New Dwelling construction activity

Area	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Alcona	260	260	260	260	260	260	260	260	260	260
Cookstown	c	50	50	50	50	50	50			
Gilford		2	2	2	2	2	2	2	2	2
Lefroy			50	50	50	50	50	50	50	50
Big Bay Point (Res)			b	100	100	100	100	100	100	100
New Growth Areas				a		100	100	100	100	100
Balance (rural)	25	25	25	25	25	25	25	25	25	25
Totals	285	337	387	487	487	587	587	537	537	537

Area	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals	Population
															30000
Alcona	260	260	260	260	260	260	260	260	260	260	260	260	260	6455	18719.5
Cookstown														300	870
Gilford														18	52.2
Lefroy	50	50	50	50	50	50	50	50	50	50	50	50	50	1050	3045
Big Bay Point (Res)	100	100	100	100	100	100	100	100	100					1600	4640
														0	0
New Growth Areas	100	100	100	100	100	100	100	100	100	100	100	100	100	1800	5220
Balance (rural)	25	25	25	25	25	25	25	25	25	25	25	25	25	625	1812.5
Totals	535	535	535	535	535	535	535	535	535	435	435	435	435	11848	64359.2

6.3 Customer Count

Ref: Exhibit 3/Tab 2/Schedule 3/p. 6/ 3rd paragraph

On page 6, Innisfil states: "*In most cases where the geometric mean is determined, the resulting geometric mean is applied to the 2007 customer/connection numbers to determine the forecast of customer/connections in 2008 and 2009.*"

Board staff is not clear what method (i.e., geometric mean, arithmetic average, or others) is used to determine to forecast customer/connection figure. Board staff has confirmed the calculation for residential growth rate using an arithmetic average approach. However, Board staff has been unable to duplicate the calculations for the growth rate for customer/connection for GS<50kW and GS>50kW using geometric mean. Please provide details for these calculations.

Response #6.3

The table below provides the information similar to the information provided in Table 7 in Exhibit 3/Tab 2/Schedule 3/p. 6. The Geometric Mean value is determined by using the GEOMEAN function in Excel. According to the documentation in Excel it states:

> *"This function returns the geometric mean of an array or range of positive data. For example, you can use GEOMEAN to calculate average growth rate given compound interest with variable rates."*

In other words, the geometric mean shown in the following table is the average compounding growth rate for the period 2002 to 2007.

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads
Growth Rate in Customer/Connection						
2002						
2003	1.0149	1.0464	1.0000	1.0422	1.0226	0
2004	1.0210	1.0091	1.0137	1.0515	1.0110	0
2005	1.0119	1.0023	1.1081	1.0269	1.0328	0
2006	1.0100	1.0146	0.8171	1.0502	0.9735	0
2007	1.0141	0.9203	1.0746	1.0394	1.0217	0
Geometric Mean	1.0144	0.9976	0.9972	1.0420	1.0121	N/A

6.4 kWh Load and Revenue

Ref: Exhibit 3/Tab 2/Schedule 3/p. 8/Table 10

On page 8, Innisfil states: "*For the forecast of usage per customer/connection the historical geometric mean was used for all classes except Unmetered Load*."

Board staff is not clear what method (i.e., geometric mean, arithmetic average, or others) is used to determine the usage per customer/connection forecast. Board staff has been unable to duplicate the calculations for the growth rate for usage per customer/connection forecast using geometric mean approach for all classes that are shown in Table 10. Please provide details for these calculations.

Response #6.4

As per response to Question 6.3, the geometric mean method is used in the same manner as explained in Question 6.3

6.5 kWh Load

Ref: Exhibit 3/Tab 2/Schedule 3/p. 7/Table 9

Innisfil provides historical annual usage per customer in Table 9. Using the same format as Table 9, please provide the total actual consumptions in kWh by classes for the period of 2002 to 2007.

Response #6.5

The requested information is provided in following table.

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Energy (kWh)							
2002	137,801,223	21,581,848	38,866,916	1,170,774	131,904	0	199,552,665
2003	148,207,370	25,087,307	38,564,040	949,748	135,903	0	212,944,368
2004	152,140,510	27,254,448	36,230,510	1,240,917	135,154	0	217,001,539
2005	155,519,152	28,103,764	39,986,875	1,470,265	131,737	0	225,211,793
2006	147,617,301	27,543,435	39,648,974	1,450,335	131,698	0	216,391,743
2007	152,967,169	28,694,771	40,322,203	1,497,459	125,854	562,039	224,169,495

6.6 Customer Count, kWh load, kW load and Revenue

Ref: Exhibit 3/Tab 1 & 2

Some of Innisfil's evidence may be required to be adjusted in light of responses to the preceding customer count, load and revenue forecasting interrogatories.

Please re-file any tables in Exhibit 3 that are required to be updated as a result of changes in the Innisfil's evidence.

Response #6.6

Innisfil Hydro does not plan to update its evidence as a result of responses to the preceding interrogatories 6.1 to 6.5.

7 DEFERRAL AND VARIANCE ACCOUNTS

7.1 Continuity Schedule for Regulatory Assets

Ref: Exhibit 5/ Tab 1/ Schedule 1

Innisfil is requesting disposition of the regulatory variance accounts in Exhibit 5/Tab 1/Schedule 1, p. 1. Please complete the attached continuity schedule for regulatory assets and provide a further schedule reconciling the continuity schedule with the amounts requested for disposition, as provided in Exhibit 5/Tab 1/Schedule 1, p. 1. Please note that forecasting principal transactions beyond 2007 and the accrued interest on these forecasted balances and including them in the attached continuity schedule is optional.

Response #7.1

Innisfil Hydro has completed the continuity schedule for the regulatory assets and attached as file Appendix C responses to OEB IR Q 7.1 Reg Accounts Continuity Schedule_20081023. Innisfil Hydro is also attaching the file reconciling the continuity schedule with the amounts requested for disposition as file Appendix D responses to OEB IR Q 7.1 DVA disposition.

8 LOSS FACTORS

8.1 Supply Facilities Loss Factor

Ref: Exhibit 4/Tab 2/Schedule 9/p. 2

Embedded distributors typically use a Supply Facilities Loss Factor (SFLF) of 1.0340, comprising losses of 1.0060 in the transformer at the grid interface and losses of 1.0278 within the HONI distribution system. On Page 2, Innisfil states that it proposes to use a SFLF of 1.0257 for the 2009 Test Year. Please explain the reason for proposing a SFLF that is different from the industry standard.

Response #8.1

Innisfil Hydro has collected the wholesale data from 2002 to 2007 as noted in Exhibit 4 Tab 2 Schedule 9 Table 2. There appears to be a downward trend with the losses Innisfil Hydro is being charged for from the IESO. Innisfil Hydro is proposing to use the 2007 loss factor of 1.0257 to more accurately reflect the cost of power to the customers based on the loss factor being charged to Innisfil Hydro by the IESO. Innisfil Hydro has 6 primary metering points (PME) with supply loss factors ranging from 1.0045 to 1.034. This results in an average of 1.0257 for 2007.

9 COST ALLOCATION

9.1 Cost Allocation Informational Filing

Ref: Exhibit 8/Tab 1/Schedule 1

Please file Sheets O1 and O2 from the Cost Allocation Informational Filing EB-2006-0247 as part of the record of this application. Please file Run 1 or 2, whichever one is more closely representative of Innisfil's situation. Alternatively, as a means of avoiding the difficulties described in the third paragraph of the reference page, file a modified run that is more closely representative than either of the runs in the Informational Filing.

Response #9.1

Attached please find Output Sheet O1 and O2 of the Cost Allocation Informational filing model reflecting an alternative cost allocation run which is consistent with Innisfil Hydro's proposed treatment of the Transformer Ownership Allowance. The Excel file is named "Appendix E response to OEB IR Q 9.1 Modified CA O1 and O2 for TA".

To accomplish this response, Worksheets I3 and I9 of the Cost Allocation Informational filing model was adjusted to Directly Allocate the transformer allowance costs to accounts 5035 – Overhead Distribution Transformer – Operation, and 5160 – Maintenance of Line Transformers.

On Worksheet I6 of the Cost Allocation Informational filing the "Approved Distribution Rev from approved EDR, Sheet 7-1 Col AK + Sheet 7-3 Col H" row was adjusted to remove $8,954 of revenue associated with the transformer allowance from each of the customer classes based on the proportions on Sheet 7-1 of the EDR model at column “Y”. The total transformer allowance of $8,954 was then added to the GS>50kW class only.

9.2 Monthly Fixed Service Charge

Ref: Exhibit 9/Tab 1/Schedule 1/ p. 4/ Table 6

With reference to Sheet O2 of the Cost Allocation Informational Filing EB-2006-0247 “Fixed Charge Floor/Ceiling” that Innisfil is required to file with the Board, please provide an explanation of any variances for the proposed Monthly Fixed Charge for GS<50 and GS>50 rate classes that may exceed the ceiling as set out in Sheet O2 Fixed Charge Floor/Ceiling.

Response #9.2

The OEB has issued a report of the Board on November 28, 2007 for the Application of Cost allocation for Electricity Distributors. In section 4.2.2 page 12 of the report, the Board does not require distributors that are currently above this value to make changes to their current monthly service charge to or below this level at this time.

Innisfil Hydro is submitting the following analysis of the fixed distribution charge by customer class:

Innisfil Hydro Fixed Distribution Charge

	Residential	GS <50	GS>50	Street Light	Sentinel	USL
CA Sheet O2 Fixed Charge per approved 2006 EDR	$19.41	$36.55	$357.94	$0.66	$1.33	$19.94
CA Sheet O2 Customer Unit Cost per mth-Minimum System with PLCC Adjust	$20.14	$26.66	$132.63	$15.68	$15.97	$31.81
Fixed Charge per 2009 Cost of Service application	$19.24	$34.00	$359.80	$3.00	$4.50	$23.24

Innisfil Hydro is proposing to change the Street Lighting and Sentinel Lighting fixed charges due to the cost allocation methodology within these classes as determined by the Cost Allocation Report filed with the OEB in 2007. Innisfil Hydro is proposing to move these customers to the 70% revenue to cost ratio over the next three years. Innisfil Hydro is requesting the fixed charges for Street and Sentinel Lighting to remain approximately within the fixed revenue proportion as noted in Exhibit 9/Tab1/Schedule 1/ Table 5 and Table 6. The General Service > 50 kW fixed rate is the current OEB approved rate.

9.3 Unmetered Scattered Load

Ref: Exhibit 9 /Tab 1/ Schedule 2/p. 1

a) Innisfil states that the total bill impact for its USL class is over 10%, due to “the move in the revenue to cost ratio to get that class into the band as required by the Cost Allocation report dated November 28, 2007”. Please explain how a change in the current revenue to cost ratio of 78.9% to 80%, results in a total bill impact increase of 35% for the USL rate class.

b) On Page 1, Innisfil proposes to meter all customers in its USL customer class. Please explain Innisfil’s rationale for the eventual elimination of this rate class.

Response #9.3

a) Innisfil Hydro filed the Cost Allocation Report in 2007 and the USL revenue to cost ratio produced results of 78.9% based on a historical normalized load of 776,045 kWh. The 2007 actual load was 562,039 kWh which resulted in a 2009 estimated normalized load of 562,039 kWh. This has resulted in the 2006 Cost Allocation Revenue Requirement percentage being spread over less kWh.

b) Unmetered scattered loads supply telecom amplifiers, railway crossings, traffic lights, cross-walks, traffic signs, phone booths, billboards, MTO weather stations etc. It will not be practical to eliminate all USL customers so this rate class would not be eliminated. Innisfil Hydro proposes to meter as many USL devices as practical. A number of these USL devices utilize electric heat to maintain electrical components during cold weather, which energy usage may not be reflected in the energy estimation. By installing smart meters on USL devices, those customers would pay for their actual energy usage at the appropriate TOU rates instead of their energy usage contributing to Innisfil Hydro’s line losses, paid for by all other rate classes.

10 RATE DESIGN

10.1 Retail Transmission Service Rates

Ref: Exhibit 4/Tab 2/Schedule 8/Page 1
Ref: Ontario Energy Board Guideline (G-2208-001) - Electricity Distribution Retail Transmission Service Rates, p. (III-IV), http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/Board_Guideline_EDRTS.pdf

On August 28, 2008, the Board issued its Decision and Rate Order in proceeding EB-2008-0113, setting new Uniform Transmission Rates (UTR) for Ontario transmitters, effective January 1, 2009. The change in the UTRs affects the retail transmission service rates (RTSR) charged by distributors. Given that Innisfil is fully embedded within Hydro One Distribution, its wholesale cost of transmission service is affected by the approved UTRs change.

On October 22, 2008, the Board issued its guideline on Electricity Distribution Retail Transmission Service Rates, outlining the evidence it expects distributors to file in support of their cost of service applications.

Innisfil is expected to file an update to that application detailing the calculations for adjusting its RTSRs.

a) Please file a variance analysis using 2 years of actual data examining what, if any, trend is apparent in the monthly balances in the RTSR deferral accounts

b) Please file a calculation of the proposed RTSR rates that includes the adjustment of the UTRs effective January 1, 2009 and an adjustment to eliminate ongoing trends in the balances in the RTSR deferral accounts

---

Response #10.1

a) The following table represents the variance analysis of the RTSR deferral accounts from January 2006 to September 2008:

Regulatory account variances for Network and Connection
Jan 2006 to Sept 2008

APH	Description	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Ytd change
1584	RSVANW	(41,999)	(18,151)	(24,634)	(42,134)	(8,456)	(28,367)	(8,319)	45,183	9,319	(117,559)
1586	RSVACN	3,431	16,128	12,475	(5,123)	1,810	35,429	13,123	62,637	27,754	167,664
	Total	(38,568)	(2,024)	(12,159)	(47,257)	(6,646)	7,062	4,804	107,820	37,073	50,106

APH	Description	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Ytd change
1584	RSVANW	4,645	(27,835)	(32,517)	27,154	(36,381)	(51,152)	34,582	(323)	55,165	(82,861)	(11,663)	(16,759)	(137,945)
1586	RSVACN	40,288	10,503	25,093	35,640	(1,629)	(11,360)	54,383	25,694	77,029	(41,077)	14,492	23,744	252,800
	Total	44,933	(17,331)	(7,423)	62,794	(38,009)	(62,512)	88,965	25,370	132,194	(123,938)	2,829	6,985	114,855

APH	Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Ytd change
1584	RSVANW	(6,637)	24,059	26,069	(11,908)	(202,167)	94,130	(40,111)	(63,765)	(22,832)	(62,744)	(43,642)	(45,931)	(355,478)
1586	RSVACN	4,758	35,899	39,919	(613)	(909,438)	106,045	(1,930)	(22,072)	3,807	(6,376)	(11,878)	15,726	(746,152)
	Total	(1,879)	59,958	65,988	(12,521)	(1,111,605)	200,175	(42,041)	(85,837)	(19,025)	(69,119)	(55,520)	(30,205)	(1,101,630)

b) The OEB has issued guidelines for retail transmission service rates on October 22, 2008. Innisfil Hydro is applying an increase of 11.3% to Network rates and 5.5% to Connection rates based on the increases noted for the Uniform Transmission Rates on page 2 of the guidelines.

The OEB has issued guidelines for adjustments to the Network and Connections rates based on the deferral account balances generated on October 22, 2008 section 5 page 3. Innisfil Hydro has determined it is applying for rate changes to Network of -16.9% and Connection 20.9% rates based on the deferral account trend from May to July 2008 compared to the revenue collected for that same period noted in the table below. The most recent rate change from Hydro One is reflected from May 2008 to Sept 2008. Due to load shifting by Hydro One and timing issues of billing and outstanding credits from Hydro One, the variances in August and September do not reflect the outstanding credits.

The following table reflects the above requested changes:

Retail Transmission Service Rates Analysis

	May to July 08 Revenue	May to July 08 Reg variance	%
Network	(45,143)	267,602	-16.9%
Connection	50,362	240,401	20.9%
Total	5,220	508,003	1.0%

Retail Transmission Service Rates

RTS Category	Customer class	Unit of measure	2009 Test Year Rates	UTR chges	DVA chges
Network	Residential	kWh	0.0052	1.113	0.8313
	GS<50	kWh	0.0047	1.113	0.8313
	GS>50	kW	1.9079	1.113	0.8313
	Street Lights	kW	1.4389	1.113	0.8313
	Sentinel Lights	kW	1.4462	1.113	0.8313

When final rates are determined this item will be reflected in those rates.

Ontario

INFRASTRUCTURE ONTARIO

Serial Debenture Schedule

Organization Name	**Innisfil Hydro Distribution Systems Limited**
Principal Amount	**$3,950,000.00**
Annual Interest Rate	**5.08%**
Loan Term (Year)	**25**
Debenture Date (m/d/yyyy)	**5/1/2009**
Maturity Date (m/d/yyyy)	**5/1/2034**
Payment Frequency	**Semi Annual**
Loan Type	**Serial**

Payment Date	Total Payment	Principal Amount	Interest Amount	Principal Balance
11/2/2009	$180,704.38	$79,000.00	$101,704.38	$3,871,000.00
5/3/2010	$177,054.02	$79,000.00	$98,054.02	$3,792,000.00
11/1/2010	$175,052.92	$79,000.00	$96,052.92	$3,713,000.00
5/2/2011	$173,051.82	$79,000.00	$94,051.82	$3,634,000.00
11/1/2011	$171,556.49	$79,000.00	$92,556.49	$3,555,000.00
5/1/2012	$169,049.61	$79,000.00	$90,049.61	$3,476,000.00
11/1/2012	$168,016.07	$79,000.00	$89,016.07	$3,397,000.00
5/1/2013	$164,574.62	$79,000.00	$85,574.62	$3,318,000.00
11/1/2013	$163,969.89	$79,000.00	$84,969.89	$3,239,000.00
5/1/2014	$160,594.40	$79,000.00	$81,594.40	$3,160,000.00
11/3/2014	$160,803.31	$79,000.00	$81,803.31	$3,081,000.00
5/1/2015	$155,756.57	$79,000.00	$76,756.57	$3,002,000.00
11/2/2015	$156,295.33	$79,000.00	$77,295.33	$2,923,000.00
5/2/2016	$153,040.79	$79,000.00	$74,040.79	$2,844,000.00
11/1/2016	$151,435.51	$79,000.00	$72,435.51	$2,765,000.00
5/1/2017	$148,653.76	$79,000.00	$69,653.76	$2,686,000.00
11/1/2017	$147,785.15	$79,000.00	$68,785.15	$2,607,000.00
5/1/2018	$144,673.54	$79,000.00	$65,673.54	$2,528,000.00
11/1/2018	$143,738.96	$79,000.00	$64,738.96	$2,449,000.00
5/1/2019	$140,693.33	$79,000.00	$61,693.33	$2,370,000.00
11/1/2019	$139,692.78	$79,000.00	$60,692.78	$2,291,000.00

Simcoe County Supply Study

Adequacy of Transmission Facilities

And

Transmission Supply Plan 2004-2014

November 12, 2004

Collingwood Utility Services

WASAGA LOGO
MIDLAND LOGO

Forward

This report is the result of a joint study by Barrie Hydro Distribution Inc., Collingwood Utility Services, Honda of Canada, Hydro One Networks Inc., Innisfil Hydro Distribution Systems Inc., Midland Power Utility Corp. and Wasaga Distribution Inc. The study team members were:

Alessia Celli, Hydro One Networks
Shelly Cunningham, Barrie Hydro
Wayne Dupuis, Midland Power Utility
Raj Ghai, Hydro One Networks
Chong Han, Honda of Canada
Charlie Lee, Hydro One Networks
Richard Shannon, Hydro One Networks
George Shaparew, Innisfil Hydro
Christine Spears, Hydro One Networks
Paul Trace, Wasaga Distribution
Darius Vaiciumas, Collingwood Utility Services

The load forecast is based on information available to Barrie Hydro, Midland Power Utility, Collingwood Utility Services, Innisfil Hydro, Wasaga Distribution and Hydro One-Distribution, at the time of the study.

The preferred plans have been selected based on technical considerations. Where applicable, these plans will be subject to Environmental Assessment approval and / or Ontario Energy Board (OEB) Leave to Construct approval.

The issue of cost allocation between utilities was not addressed.

Signatures

We have reviewed this report and concur with its recommendations.

Utility	Signature	Title
Barrie Hydro Distribution Inc.		Shelly Cunningham Manager – System Planning and Control
Collingwood Utility Services		Darius Vaiciunas Load Management & Regulatory Coordinator
Honda of Canada Manufacturing		Chong Han Engineering Facilities Department
Hydro One Networks-Distribution		Bob Singh Manager, Distribution Development
Innisfil Hydro Distribution Systems Inc.		George Shaparew President
Midland Power Utility Corp.		Wayne Dupuis Manager of Operations
Wasaga Distribution Inc.		Paul Trace Manager Planning and Technical Services
Hydro One Networks Inc. – Transmission		John Sabiston Team Leader/ Senior Advisor

Date: November 12, 2004

TABLE OF CONTENTS

Executive Summary

Background

Simcoe County is located between the southeastern shore of Georgian Bay and Lake Simcoe. Electrical supply in this area is provided through 500 kV, 230 kV, and 115 kV transmission lines and step down transformation facilities as shown in Map 1 and Figure 1. Load forecasts provided by the Local Distribution Companies (LDCs) in Simcoe County indicate that electrical load growth is expected to continue at a summer average rate of 3.1% per year and a winter average rate of 2.7% per year, for the next ten years.

In November of 2003, a joint utility planning study was initiated between six of the LDCs in Simcoe County, one large industrial customer and Hydro One Networks - Transmission. LDCs and industrial customer participants in this joint study were:

- Barrie Hydro Distribution Inc.
- Collingwood Utility Services
- Hydro One Networks – Distribution
- Innisfil Hydro Distribution Systems Ltd.
- Midland Power Utility Corp.
- Wasaga Distribution Inc.
- Honda of Canada Mfg.

This study assessed the transmission system in Simcoe County. The supply stations in the area were also reviewed to identify additional capacity requirements to meet the projected load growth. The study then investigated several transmission alternatives for addressing the needs and deficiencies as soon as practical.

Need

The needs assessed in the study were divided into two areas - (1) North Simcoe County - north of and including Essa Transmission Station (TS); and, (2) South Simcoe County - south of Essa TS.

1. North:

<u>Station Overloads</u>

- Waubaushene TS is currently loaded beyond its station winter capacity limit;
- Meaford TS is expected to reach the station capacity limit by winter 2006;
- The 230/115 kV auto-transformers at Essa TS are expected to be at their capacity limit by 2007;
- The 750 MVA 500/230 kV auto-transformers at Essa TS are expected to be at their capacity limit by 2014; and,
- Midhurst TS is expected to be near station capacity by summer 2014.

<u>Voltage Deficiencies</u>

- Stayner TS is currently experiencing voltage deficiencies during winter peak periods. It is expected to be below operation and planning standards in peak loading periods by summer 2007. A load rejection scheme was installed at Stayner TS ten years ago to reduce the risk of a voltage collapse in the area in the event of a contingency;
- Meaford TS is currently experiencing voltage deficiencies on long distribution lines supplying load that was originally transferred from Stayner TS in the last decade;
- The 230 kV and 115 kV voltages in the Essa area are expected to be below operation and planning standards by 2009; and,

- The 230 kV voltage in the local area is expected to be below operation and planning standards by 2014.

Circuit Overloads

- Distribution lines emanating from Meaford TS are currently at capacity. These lines are supplying load that is local to Stayner. Voltage deficiencies at Stayner TS prohibit the transfer of this additional load to the station.

2. South:

Station Overloads

- Alliston TS is currently loaded at its station capacity and local area load is forecasted to grow.

The study was conducted under the assumption that by 2006 additional voltage support would be provided by means of a 245 MVar capacitor bank on the 230 kV bus at Essa TS. The additional voltage support is needed in order to prevent excessive voltage decline in the event that one auto-transformer at Essa TS is out of service for maintenance and the companion auto-transformer is forced out of service. Hydro One will be installing the required capacitor by summer 2006.

Recommended Transmission Reinforcements

Various options were assessed in the study. Viable options were combined to effectively resolve problems in the specific geographical areas. Two independent projects are recommended for implementation as soon as possible to address the immediate needs listed above:

1. North

Convert Stayner TS from 115 kV to 230 kV, and rebuild the existing 115 kV circuit (S2E) from Stayner TS to Essa TS to a double circuit 230 kV transmission line. A 230/115 kV auto-transformer at Stayner TS is required to maintain the electrical connection to Meaford TS. This plan also includes upgrading the existing transformers at Stayner TS to 75/125 MVA capacity, to serve local load growth.

This plan will resolve voltage deficiencies and will create additional capacity at Stayner TS. The additional capacity can be used to address overload issues at Meaford TS and voltage deficiencies on Meaford distribution lines. Increasing capacity at Stayner TS also provides the opportunity for relieving capacity at Waubaushene TS by cascading load transfers to Stayner TS, through Midhurst TS. Finally, the conversion of Stayner TS from 115 kV to 230 kV relieves capacity on the remaining 115 kV system and 230/115 kV auto-transformers at Essa TS to accommodate future load growth in the Barrie and Innisfil areas. The earliest possible in service date for this plan is winter 2007.

2. South

A new transformer station near Alliston will resolve the electrical supply requirements in the growing South Simcoe area including local areas (New Tecumseth, Adjala-Tosorontio and Essa Townships), and Innisfil, for the next 10 years. The earliest possible in service date for this plan is summer 2006.

Recommendations

Several recommendations can be drawn from this study to address the current system deficiencies and provide system capacity to meet forecasted load growth. These recommendations are:

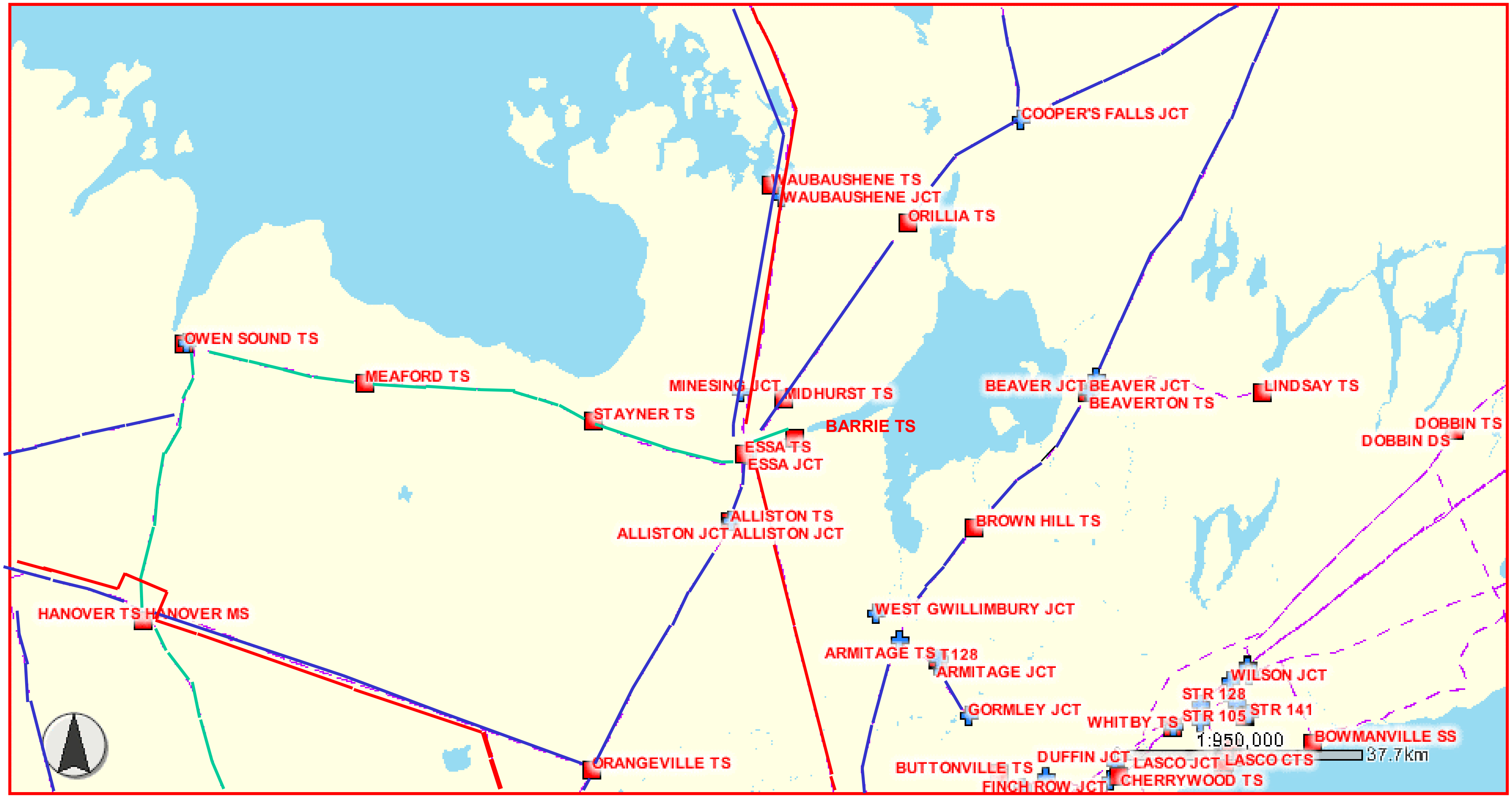
1. Hydro One Networks Inc. to initiate the approval processes required for the conversion of Stayner TS from 115 kV to 230 kV, and the upgrading of the existing 115 kV transmission line from Stayner TS to Essa TS (circuit S2E) to a double circuit 230 kV transmission line.

2. Hydro One Networks Inc. to commence the preliminary engineering and consultation with the local distribution companies, and to initiate the approval processes on the construction of a new transformer station, near Alliston.

3. Hydro One Networks Inc. to review the study in 2007 with updated Simcoe County load forecasts for the potential need for a 2nd 230 kV, 245 MVAR capacitor bank and a 3rd 500/230 kV, 750 MVA auto-transformer at Essa TS for implementation in 2009 and 2014, respectively.

4. The local electric utilities to continue to monitor load growth in the southern Simcoe County area and to review options for long-term growth based on the location of new developments and load forecasts.

5. The local electric utilities in the northern Simcoe County area (specifically in the Barrie area) to continue to monitor load growth and the loading of Midhurst TS.



500 kV Right of Way Corridor

230 kV Right of Way Corridor

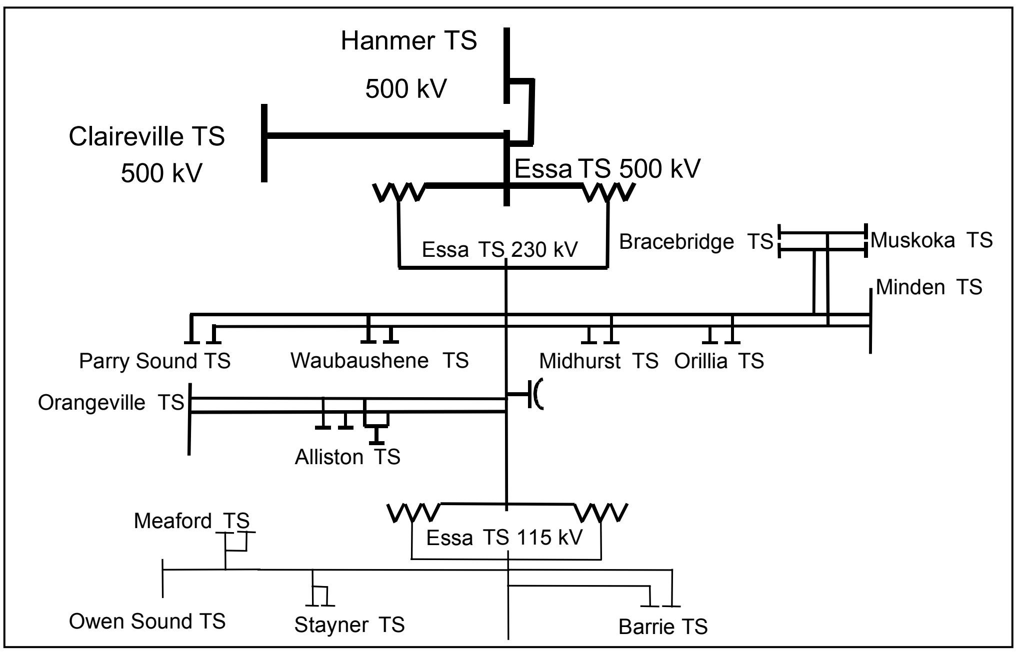
115 kV Right of Way Corridor

Map 1: Existing Transmission Facilities in Simcoe County

1. Introduction

Simcoe County is located between the southeastern shore of Georgian Bay and Lake Simcoe. It consists of eighteen townships and/or municipalities - Adjala-Tosorontio, Barrie, Bradford West Gwillimbury, Clearview, Collingwood, Essa, Innisfil, Midland, New Tecumseth, Orillia, Oro-Medonte, Penetanguishene, Ramara, Severn, Springwater, Tay, Tiny, and Wasaga Beach. The Simcoe County has a combined electrical load of over 800 MW. Electrical supply in this area is provided through 500 kV, 230 kV and 115 kV transmission lines and step down transformation facilities (transmission stations, TS) as shown in Map 1 and Figure 1.

Figure 1: Existing Transmission System in Simcoe County



Load growth in Simcoe County has been increasing, and the transmission stations in the area are consistently peaking above their capacity limits (limited time ratings[1]), as well as experiencing voltage problems related to high loading. In November of 2003, a joint study was initiated between six LDCs in Simcoe County, one large industrial customer and Hydro One.

The purpose of this joint study was to assess the load growth in the Simcoe County area and ensure that adequate transmission and connection facilities will be available to meet the electrical demand requirements over the next decade. LDCs and industrial customer participants in this joint study were:

- Barrie Hydro Distribution Inc.
- Collingwood Utility Services

[1] Limited Time Rating (LTR): With respect to transformers, LTRs are a set of 15-minute, 2-hour and 10-day MVA ratings to accommodate shorter time interval emergency loading periods. With respect to transmission lines, LTR are a set of 5-minute and 15-minute summer and winter ampacity ratings to accommodate shorter time interval emergency loading periods.

- Hydro One Networks – Distribution
- Innisfil Hydro Distribution Systems Ltd.
- Midland Power Utility Corp.
- Wasaga Distribution Inc.
- Honda of Canada Mfg.

2. Existing Transmission System and Needs

The hub of the electrical system in Simcoe County is Essa TS. Essa TS provides the single connection to the 500 kV system in this area, through which is provided the majority of resources to meet demand in Simcoe County. Simcoe County transmission system is connected from Essa TS as follows (refer to Figure 1 and Map 1):

1. Two 230 kV radial circuits (E26/E27) emanating north to supply Waubaushene TS and Parry Sound TS;
2. Two 230 kV circuits (E8V/E9V) first heading south to Orangeville TS, and then going west providing a connection to Bruce A Generation Station (GS);
3. Two 230 kV circuits (M6E/M7E) heading northeast to Midhurst TS and making a network connection at Minden TS;
4. Two 115 kV circuits (E3B/E4B) into Barrie TS; and,
5. One 115 kV circuit (S2E-S2S) heading west connecting Stayner TS and Meaford TS.

Load forecasts provided by the LDCs in Simcoe County indicate that electrical load growth is expected to continue at a summer average rate of 3.1%/year and a winter average rate of 2.7% per year, for the next ten years. Some stations in the area are consistently peaking above their capacity limits (LTRs), as well as experiencing voltage deficiencies related to high loading.

In the early 1990's, an analysis of the adequacy of the transmission system and step-down transformation facilities in the Stayner-Collingwood area was conducted. A preferred system plan and route was approved by the Ministry of Environment upon completion of the Class Environmental Assessment (EA) process. The preferred system plan is described in the 1991 Supply to Collingwood Environmental Study Report (ESR)[2]. This consists of replacing the existing 115 kV transmission line from Essa TS towards Stayner TS with two 230 kV circuits, and build a new transmission station to supply the load growth expected in the Stayner-Collingwood vicinity. Subsequently, this transmission expansion was deferred and demand management and load transfer options were implemented. Load was transferred to stations further from the Stayner area, to Meaford TS, and to Midhurst TS, causing cascading[3] load transfers up to Waubaushene TS. However, we have now reached a point where Stayner TS is experiencing voltage deficiencies, the load growth in the Stayner area continues to increase and the stations carrying load located closer to Stayner TS are beyond capacity. The 1991 preferred system plan is one of the options considered in this study.

All stations in the Simcoe County study area were considered and this joint study addresses those stations where capacity and load growth were an issue, and where there were known voltage deficiencies in the system.

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[2] Ontario Hydro, Design and Development Division-Transmission: Supply to Collingwood Environmental Study Report. August 1991, Report # 90337.

[3] Cascading: The transferring of load in successive stages using the distribution network to numerous transmission stations (TS). Each stage of load transfer depends on the cumulative load at a particular station. For example, once the cumulative Midhurst local load and the load transferred from Stayner TS to Midhurst TS reached Midhurst TS station capacity, some Midhurst local load was then transferred to Waubaushene TS.

The needs assessed in the study were divided into two areas - (1) North Simcoe County - north of and including Essa Transmission Station (TS); and, (2) South Simcoe County - south of Essa TS.

1. North:

Station Overloads

- Waubaushene TS is currently loaded beyond its station winter capacity limit;
- Meaford TS is expected to reach the station capacity limit by winter 2006;
- The 230/115 kV auto-transformers at Essa TS are expected to be at their capacity limit by 2007;
- The 750 MVA 500/230 kV auto-transformers at Essa TS are expected to be at their capacity limit by 2014; and,
- Midhurst TS is expected to be near station capacity by summer 2014.

Voltage Deficiencies

- Stayner TS is currently experiencing voltage deficiencies during winter peak periods. It is expected to be below operation and planning standards in peak loading periods by summer 2007. A load rejection scheme was installed at Stayner TS ten years ago to reduce the risk of a voltage collapse in the area in the event of a contingency;
- Meaford TS is currently experiencing voltage deficiencies on long distribution lines supplying load that was originally transferred from Stayner TS in the last decade;
- The 230 kV and 115 kV voltages in the Essa area are expected to be below operation and planning standards by 2009; and,
- The 230 kV voltage in the local area is expected to be below operation and planning standards by 2014.

Circuit Overloads

- Distribution lines emanating from Meaford TS are currently at capacity. These lines are supplying load that is local to Stayner. Voltage deficiencies at Stayner TS prohibit the transfer of this additional load to the station.

2. South:

Station Overloads

Alliston TS is currently loaded at its station capacity and local area load is forecasted to grow.

3. Load Growth

Load forecasts provided by the LDCs in Simcoe County indicate that electrical load growth is expected to continue at a summer average rate of 3.1% per year and a winter average rate of 2.7% per year, for the next ten years.

The summer loading at the stations that were observed in this study are expected to increase at an average rate of 3.4% annually until 2009, with the long-term growth rate between 2009 and 2014 at 2.7% annually. The winter loading at the stations that were observed in this study are expected to increase at an average rate 3.1% annually until 2009, with the long-term growth rate between 2009 and 2014 at 2.3% annually.

Tables 1 and 2 indicate the summer and winter load forecasts at each connection station covered in this study until the end of the study period for summer and winter respectively.

Table 1: Forecast - Summer Peak Load (MVA)

Transmission Station	Station LTR	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Alliston TS	99.9	121.6	124.4	130.2	130.9	134.6	138.3	142.0	145.8	149.4	153.2	156.9	160.8
Barrie TS*	115.0	140.6	137.8	113.7	104.1	108.5	114.5	115.0	115.6	116.2	116.8	117.4	118.0
Meaford TS	53.9	27.9	30.5	31.9	34.4	35.9	37.4	37.8	38.2	38.6	39.0	39.5	39.9
Midhurst TS DESN #2 (planned in-service date of 2004)	208.0	0.0	0.0	55.0	80.4	87.0	94.4	107.2	120.0	132.8	145.6	158.5	171.3
Midhurst TS DESN #1 (existing)	171.5	145.2	165.5	153.8	152.6	156.8	159.6	161.2	162.7	164.2	165.7	167.3	168.8
Stayner TS*	111.6	83.8	84.8	85.8	86.8	87.9	90.2	91.1	92.3	93.5	94.8	96.0	97.4
Waubaushene TS	99.6	96.2	98.5	99.8	102.0	103.3	104.4	105.6	106.9	108.1	109.3	110.5	111.8
Alliston TS #2	99.9	30.1	39.9	41.0	42.3	43.5	44.9	46.2	47.6	49.0	50.5	52.0	53.6
TOTAL:		***645.4***	***681.4***	***711.1***	***733.5***	***757.5***	***783.7***	***806.1***	***829.1***	***851.8***	***874.8***	***898.1***	***921.6***

Station LTR: Summer 10-day Limited Time Ratings
* Station load does not reflect the power factor correction afforded by the existing capacitors

Table 2: Forecast - Winter Peak Load (MVA)

Transmission Station	Station LTR	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Alliston TS	114.9	115.0	117.8	123.3	123.2	126.0	129.1	132.3	135.4	138.8	142.1	145.5	149.0
Barrie TS*	127.7	110.1	110.1	118.7	94.8	86.5	92.5	93.0	93.6	94.2	94.8	95.4	96.0
Meaford TS	60.8	53.9	56.6	59.3	61.9	64.6	66.3	66.9	67.5	68.1	68.7	69.3	69.9
Midhurst TS DESN #2 (planned in-service date of 2004)	140	0.0	0.0	0.0	44.0	65.1	72.6	82.5	92.4	102.3	112.2	122.0	131.9
Midhurst TS DESN #1 (existing)	193.9	138.8	162.9	175.0	166.4	165.9	165.7	167.5	169.1	170.9	172.6	174.5	176.3
Stayner TS*	126.5	105.8	108.0	110.2	111.4	112.7	114.0	115.0	116.4	117.8	119.3	120.7	122.2
Waubaushene TS	109.9	118.2	120.4	121.6	123.8	125.1	126.3	127.5	128.8	130.0	131.3	132.6	133.9
Alliston TS #2	114.9	29.6	30.5	31.5	32.4	35.6	36.7	37.8	38.9	40.1	41.3	42.6	43.8
TOTAL:		***671.4***	***706.3***	***739.6***	***758.0***	***781.5***	***803.1***	***822.5***	***842.1***	***862.1***	***882.2***	***902.6***	***923.2***

Station LTR: Winter 10-day Limited Time Ratings
*Station load does not reflect the power factor correction afforded by the existing capacitors

The major load centre in Simcoe County exists around the city of Barrie. The load in the Barrie area is summer peaking and is supplied from Barrie TS and Midhurst TS. Load in the Alliston area is also summer peaking and is supplied from Alliston TS. All other load, particularly in the Collingwood area, is winter peaking and is supplied from Stayner TS, Meaford TS and Waubaushene TS. Overall, the total forecasted seasonal loads are greater in the winter for the period of study. Near the end of the study, the seasonal load growths become fairly similar due to a slight decline in the winter growth rates in the latter part of the study.

Due to equipment limitations, various transmission stations are either summer or winter critical[4]. Barrie TS and Midhurst TS are summer critical; Stayner TS and Meaford TS are winter critical; and Alliston TS and Waubaushene TS are both summer and winter critical.

Since the ampacity limitations for stations and transmission lines are generally lower in summer, as compared to winter, the Simcoe County area is in general summer critical. The one exception in this study was Stayner TS, which tended to have a more critical winter load due to the large winter tourist activity in the Collingwood and Blue Mountain (part of Grey County) areas which experiences voltage deficiencies under heavy load with certain contingencies.

[4] winter/summer critical means less available margin between loading and applicable equipment rating for a particular season

4. System Assumptions

Certain assumptions were made in order to assess the effects of different contingencies to verify the system capacity. The assumptions used in the study were:

1. A study period of 10 years, from 2004 to 2014, was used to assess the transmission requirements.

2. Peak loads were based on forecasts provided by the participating utilities. The forecasted loads were provided in MVA, with an assumed power factor of 0.92 for summer loads and 0.94 for winter loads.

3. Equipment continuous and limited time ratings were based on an ambient temperature of 30°C for summer and 10°C for winter with a wind speed of 4km/hour for both seasons.

4. The minimum voltage on the 230 kV transmission system under normal conditions is 220 kV, with a maximum allowable decline of 10% for a single element contingency. One exception to this is that the minimum acceptable voltage at Essa TS is 238 kV, which is consistent with the Independent Electricity Market Operator's (IMO) operating guidelines (SCO S-South, Table 4).

5. The minimum acceptable voltage on the 115 kV buses is 113 kV with a maximum allowable voltage decline of 10% for a single element contingency.

6. The study was conducted under the assumption that by 2006 additional voltage support would be provided by means of a 245 MVar capacitor bank on the 230 kV at Essa TS. The additional voltage support is needed in order to prevent excessive voltage decline in the event that one auto-transformer at Essa TS is out of service for maintenance and the companion auto-transformer is forced out of service. Hydro One will be installing the required capacitor by summer 2006.

5. Adequacy of Existing Facilities

This section reviews the adequacy of the existing 500 kV, 230 kV and 115 kV transmission facilities to supply the load in Simcoe County from step-down transformation facilities Alliston TS, Barrie TS, Essa TS, Meaford TS, Midhurst TS, Stayner TS and Waubaushene TS. It also reviews the transformation capacity at these load stations.

5.1. 500 kV Bulk Transmission System

The majority of electricity supply in Simcoe County is provided via the 500/230 kV auto-transformers located at Essa TS. The connection between the 500 and 230 kV systems via the two 750 MVA auto-transformers at Essa supplies the local area with adequate voltage support. The voltage on the 230 and 115 kV systems in this area is adequate under single contingency condition (one auto-transformer out of service); however, it does expose the area to a risk of unacceptable voltages if the remaining auto-transformer is unexpectedly forced out of service. Consequently, the periodic maintenance and sustainability of the auto-transformers and associated 500 and 230 kV equipment, becomes difficult to achieve. In addition, due to the load growth in the area, the two 750 MVA auto-transformers would be nearing capacity[5] by 2014.

During the study period, the voltage in the area was increasingly dependent on the full-time operation of the two 750 MVA auto-transformers at Essa TS. Thus, the study was run under the assumption that a planned 245 MVAR capacitor bank on the 230 kV bus at Essa TS would be in-service by the time any of the results from this study could be implemented. Nevertheless, even with this capacitor bank available by 2006, a second capacitor bank would be required by 2009 to support the voltage due to increased loading in the area. An additional 230 kV supply source (i.e., a third 500/230 auto-transformer) would be required to support the voltage in the local area by the end of the study period.

5.2. 230 kV Transmission System & Line Capability

Three double circuit 230 kV lines emanate out of Essa TS to supply power to step-down transformation stations in Simcoe County:

- Parry Sound TS and Waubaushene TS are supplied via two radial northward circuits (E26 and E27);
- Alliston TS is supplied via a double circuit line (E8V and E9V) running southwest towards Orangeville TS; and,
- Midhurst TS and several other transformer stations outside of the study area, are supplied via double circuit line (M6E and M7E) running northeast towards Minden TS.

The 230 kV circuits were all within continuous ratings throughout the 10-year study period for all load forecasts and contingency situations. Relief for these circuits is not anticipated prior to 2014.

[5] Auto-transformers nearing capacity means running the transformer continuously over 50% of its capacity under normal operating conditions, and over 95% of its capacity after the loss of a companion auto-transformer.

The 230/115 kV auto-transformers at Essa TS are nearing their capacity limits. Assuming no major element is changed on the 115 kV system in this area, these 115 MVA auto-transformers are sufficient to handle the existing load forecast until 2007. Auto-transformer T1 is the limiting element and will be loaded to 100% of its summer 10-day LTR in the event that its companion auto-transformer T2 is removed from service.

5.3. 115 kV Transmission Line Capability

Two 115 kV lines supply power to step-down transformation stations in Simcoe County:

- One single circuit 115 kV line from Essa TS to Stayner TS (S2E) and from Stayner TS to Owen Sound TS via Meaford TS (S2S); and,
- Two single circuit 115 kV lines from Essa TS to Barrie TS (E3B and B4B).

Under normal operating conditions, the Bruce (GS) supplies nearly half of the load at Stayner TS via the 115 kV circuit between Owen Sound TS and Stayner TS, through Meaford TS. This situation becomes particularly problematic during the contingency loss of the 115 kV circuit (S2E), which runs between Stayner TS and Essa TS. During this contingency, the voltage at Stayner TS drops below acceptable levels when Stayner TS is under heavily loaded conditions (winter peaks). Temporary measures have been in place in the form of a load rejection scheme[6] to address this problem.

The two 115 kV lines between Essa TS and Barrie TS (E3B and E4B) are also nearing capacity as the load at Barrie TS increases. This is particularly apparent on one half-kilometre section of circuit E3B near Essa TS. These lines will be sufficient to supply Barrie TS in its existing state, however, if station capacity is increased at Barrie TS, and/or a new connection is made to circuits E3B and E4B, these circuits will require upgrading.

5.4. Step Down Transformation Facilities

Capacity of step-down transformers posed a problem at several stations. Load forecasts for these stations throughout the study period are shown in Tables 1 and 2.

- Alliston TS, consisting of two 50/83 MVA transformers, has currently peaked beyond its summer 10-day LTR, and will be loaded beyond its winter 10-day LTR by 2004. This station has no additional capacity to supply the increasing load in the area. Distribution lines emanating out of the station have taken up all available road allowance space.

- Waubaushene TS is currently over its winter 10-day LTR, and will also be loaded beyond its summer 10-day LTR by 2005.

- Meaford TS will be over its winter 10-day LTR by 2006 and distribution lines emanating from the station are overloaded as of 2004. Due to the existing voltage issues at Stayner TS, building new distribution lines to Stayner to relieve Meaford TS or its distribution lines is not an

[6] load rejection scheme: a load rejection scheme disconnects pre-defined amounts of load to prevent equipment overloads and/or excessive voltage declines which jeopardize system security. The load rejection scheme is armed for activation under severe system conditions or when there are outages to key transmission facilities. Activation of the load rejection scheme occurs only if there is further deterioration of system conditions or there is a loss of another critical facility.

acceptable option. This problem can be addressed via an overall transmission solution that will address several transmission needs simultaneously.

- Barrie TS is currently over its summer 10-day LTR. To support the growing Barrie Hydro load, Hydro One is currently building a second DESN at Midhurst TS thus providing relief to Barrie TS by 2005.

- The load forecasts show that both the existing Midhurst TS DESN #1 and the new Midhurst TS DESN #2 (to be placed in service in December 2004) will be near capacity limits by 2014.

5.5. Needs Summary

A summary of the needs to be addressed via transmission and step-down transformation facilities as proposed in this study are shown in Figure 2.

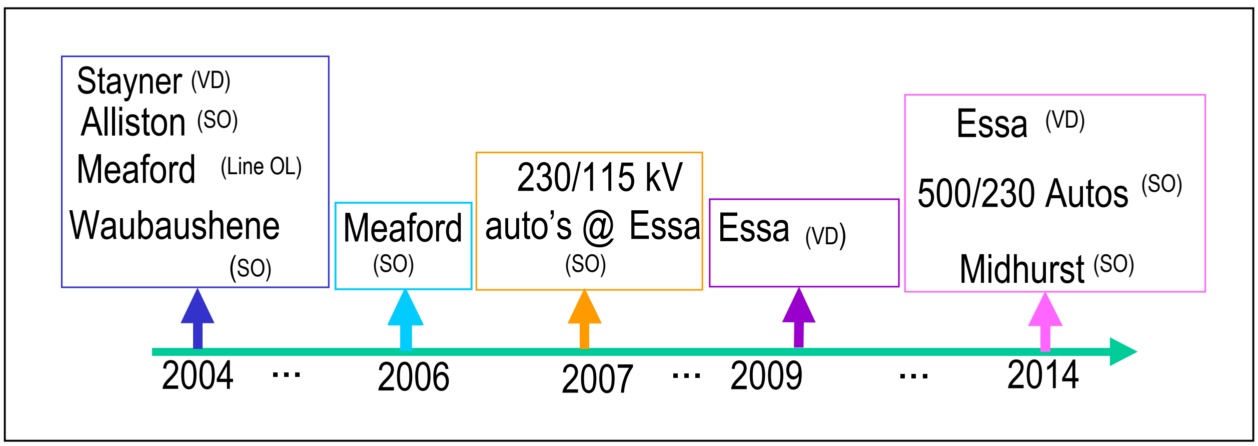


Figure 2: Summary of Needs 2004 – 2014

Legend: VD= Voltage Deficiencies
SO= Station Overload
Line OL = Line Overload

6. Possible Options to Address Supply Capacity & Voltage Stability

This section outlines all possible options considered in the study in order to address the identified needs in Simcoe County. Table 4 itemizes the options that are rejected and those that are further analyzed. Detailed descriptions of all options are given in Appendix A.

Table 4: Summary of Considered Options

Option	Description	Status
"Do Nothing"	"Do Nothing"	Rejected
Relief for Stations North of Essa TS		
S1	Cascading Load Transfers to Stayner TS	Rejected in isolation – however, part of overall plans in Section 7
S2	Build a New 115 kV Circuit to Stayner TS and 2nd DESN at Stayner	Further analyzed
S3	Convert Stayner TS to 230 kV, 75/125 MVA Fed Via a New 230 kV Double Circuit from Essa TS	Further analyzed
S4	Upgrade the Existing 115 kV Circuit to a double 230 kV Circuit from Essa TS and build "Collingwood Area" TS (operated at both 115 kV and 230 kV)	Rejected
Relief for Stations North of Essa TS - Stayner TS, Meaford TS & Waubaushene TS		
B1	2nd DESN at Barrie TS	Rejected
B2	Convert Barrie TS to 230 kV, 75/125 MVA Fed Via a New 230 kV Double Circuit from Essa TS	Rejected in isolation – however, part of overall plans in Section 7
230 kV and 115 kV System Capacity & Voltage Support		
E1	2nd 245 MVAR Capacitor Bank at Essa TS	Further analyzed
E2	3rd 750 MVA Auto-transformer at Essa TS	Further analyzed
E3	Build a 230 kV Double Circuit from Holland Marsh to Essa TS	Rejected
E4	Essa 230/115 kV Auto-transformers Upgraded to 250 MVA	Rejected in isolation – however, part of overall plans in Section 7
Relief for Stations South of Essa TS		
A1	Upgrade Alliston TS to 75/125 MVA	Further analyzed
A2	New DESN Near Alliston, 50/83 MVA	Further analyzed
I1	Innisfil TS Supplied from Holland Marsh Junction	Rejected
I2	Innisfil TS Supplied from E3B/E4B	Rejected
I3	Holland Marsh TS Supplied	Rejected
I4	Innisfil TS Supplied from Essa TS	Rejected

6.1. *"Do Nothing"*

The "Do Nothing" approach will aggravate the existing problems at Alliston TS, Waubaushene TS, Meaford TS and Stayner TS and accelerate issues with the auto-transformers at Essa TS.

Stayner TS currently experiences voltage deficiencies during winter peak conditions in the event of a single contingency (i.e. loss of S2E). For this reason a load rejection scheme was implemented at this station as a means of decreasing the risk of a voltage collapse. Stayner TS is also nearing voltage limitations on the high voltage bus during summer load peaks under a single contingency event, specifically the loss of S2E. The forecasted summer load is such that the voltage decline under this contingency is 9% by 2006, and greater than 10% of the pre-contingency voltage by 2007. If this voltage is allowed to continue its decline, it could cause a voltage collapse in the Collingwood area without greater reliance on load rejection schemes.

This alternative is not acceptable and is not considered further.

6.2. *Relief for Stations North of Essa TS*

Stayner TS, Meaford TS & Waubaushene TS

S1: ***Cascading Load Transfers to Stayner TS***
Load could be transferred from Waubaushene TS and cascaded down to Stayner TS via Midhurst TS. This would relieve the loading at Waubaushene TS and would be a reverse of load transfers originally made in the mid 1990s. Similarly, load from Meaford TS could also potentially be transferred to Stayner TS – originally transferred from Stayner TS. This option was considered in isolation but rejected, as it would only exacerbate existing problems at Stayner TS. However, it is utilized in combination with other options as part of the plans in Section 7.

S2: ***Build a New 115 kV Circuit to Stayner TS and 2nd DESN at Stayner***
The option improves voltage stability and reliability at Stayner TS by building an additional 27 km 115 kV circuit from Stayner TS to Essa TS alongside existing circuit S2E. This solution would also allow for building a second 50/83 MVA DESN at Stayner TS to accommodate the load transfers from Waubaushene TS and Meaford TS.

S3: ***Convert Stayner TS to 230 kV, 75/125 MVA Fed Via a New 230 kV Double Circuit from Essa TS***
Stayner TS is converted to 230 kV and 27 km circuit S2E is converted to a double 230 kV circuit. This option also consists of placing a 115 MVA, 230/115 kV auto-transformer at Stayner TS to maintain the electrical connection to Meaford TS and upgrading the existing 50/83 MVA transformers to 75/125 MVA.

S4: ***Upgrade the Existing 115 kV Circuit to a double 230 kV Circuit from Essa TS and build "Collingwood Area" TS (operated at both 115 kV and 230 kV)***
This is the preferred system plan recommended in the 1991 ESR as stated previously in Section 2. At that time, high load growth was projected for the Collingwood area. This plan was considered as one of the options in this study as well. About 37 km of existing 115 kV circuit is replaced with a double 230 kV circuit between Essa TS and a new 230/44 kV DESN station to be built in the Collingwood area. One circuit would operate at 115 kV and the other at 230 kV. The new DESN would operate initially at both 115 kV and 230 kV. In addition to servicing the local Collingwood and Stayner load, load could be transferred from Waubaushene TS and Meaford TS as in option S1. This option requires more line and station construction than options S2 or S3. It would require

voltage relief at Stayner TS by 2014 and provides significantly more transformation connection capacity in the area then the load forecast justifies. Option S4 is a more costly option compared to S2 and S3 due to the additional 10 km of double 230 kV circuit and construction of an entirely new station, "Collingwood area" TS in Nottawa. Further, the high load growth projected during the 1991 study did not materialize fully in the Collingwood area and has dispersed into other areas of Simcoe County. Thus, this option was considered and rejected.

Barrie TS

B1: ***2nd DESN at Barrie TS***
Capacity at Barrie TS is increased by installing a second 50/83 MVA DESN at the station. This option would require line upgrades to the limiting section(s) of circuit E3B. Increasing capacity at Barrie TS would strand capacity until such time as Midhurst TS would be at capacity (~2014) and not affect the immediate needs that exist elsewhere in the system. Thus, this option was considered and rejected for this study because it would not be required for at least 10 years in the future.

B2: ***Convert Barrie TS to 230 kV, 75/125 MVA Fed Via a New 230 kV Double Circuit from Essa TS***
Barrie TS is converted to 230 kV, 8.5 km 115 kV circuits E3B/E4B are converted to a double 230 kV circuit and the two step-down transformers at Barrie TS are upgraded to 75/125 MVA. This option would temporarily strand capacity at Barrie for the first 10 years, before being more efficiently utilized. This option does not address any of the immediate concerns in Simcoe County except that it would provide available capacity on the 115 kV system. Thus, this option was considered in isolation but rejected; however, it is utilized in combination with other options as part of the plans in Section 7.

6.3. 230 kV and 115 kV System Capacity & Voltage Support

E1: ***2nd 245 MVAR Capacitor Bank at Essa TS***
A second 245 MVAR capacitor bank on the 230 kV bus will be needed at Essa TS by 2009 to provide further voltage support.

E2: ***3rd 750 MVA Auto-transformer at Essa TS***
Additional 500/230 kV autotransformation capacity will be required by 2014. This option could be accelerated and used in place of E1 (*2nd 245 MVAR Capacitor Bank*) in 2009 to provide additional voltage support.

E3: ***Build a 230 kV Double Circuit from Holland Marsh to Essa TS***
Voltage support could be supplied via an additional 230 kV circuit connection to the 230 kV system near the Greater Toronto Area, specifically, supplied from Holland Marsh Junction, along B82V and B83V. This option was considered and rejected due to technical inferiority to option E2, combined with the relative cost of constructing two new 230 kV circuits to a third auto-transformer.

E4: ***Essa 230/115 kV Auto-transformers Upgraded to 250 MVA***
Capacity on the 115 kV system would be increased by upgrading Essa T1 and T2 230/115 kV auto-transformers from 115 MVA to 250 MVA. This option performed technically well for the 10-year period; however, in the longer term, the 115 kV system experiences more significant voltage problems than those which exist today. Thus, this option was considered in isolation but rejected; however, it is utilized in combination with other options as part of the plans in Section 7.

6.4. Relief for Stations South of Essa TS

A1: ***Upgrade Alliston TS to 75/125 MVA***
Replace the two 50/83 MVA step-down transformers at Alliston TS with two 75/125 MVA transformers. This capacity would be sufficient to cover the expected load growth in the Alliston and Innisfil areas until 2022. The upgrade would require at least four station egress positions to make efficient use of the additional capacity. Existing distribution lines emanating out of the station have taken up all available road allowances. The additional distribution lines could potentially be brought out of the station underground; however, due to local issues with road allowances, these distribution lines would need to be underground for several kilometres which would present significant distribution costs.

A2: ***New DESN Near Alliston, 50/83 MVA***
A new 50/83 MVA DESN near Alliston TS would be built to supply load growth in the local area and in Innisfil. Two potential study areas for this DESN were evaluated – in the vicinity of Highway 89 and Adjala 2nd, and in the vicinity of County Road 15 and County Road 5. Both study areas would be acceptable from a technical performance perspective. The transmission costs for either station would be the same. As such, the deciding factor is the distribution costs associated with these two locations.

I1: ***Innisfil TS Supplied from Holland Marsh Junction***
This option consists of building a new step-down transformer station in the Municipality of Innisfil supplied via double circuit 230 kV lines emanating from Holland Marsh Junction in the south. This option would require a new high voltage capacitor bank located either at Holland Marsh Junction or at the new Innisfil TS. This option was considered for south Simcoe's immediate need and rejected because the Alliston area would still require further relief by 2010, and does not address any of the other immediate concerns of Simcoe County.

I2: ***Innisfil TS Supplied from E3B/E4B***
This option consists of a new transformer station built along the border of the Barrie and Innisfil Municipalities supplied via 115 kV circuits (continuation of E3B and E4B). This option would require upgrades to limiting sections of circuit E3B and would need to incorporate Option E4 or S3. Connection of these facilities would be limited to a 50/83 MVA DESN station. This option was considered for south Simcoe's immediate need and rejected because the Alliston area would still require further relief by 2010, and does not address any of the other immediate concerns of Simcoe County.

I3: ***Holland Marsh TS Supplied***
This option consists of a new 230/44 kV, 75/125 MVA transformer station built at Holland Marsh Junction. This option presents opportunities for supplying load in the south end of Innisfil, as well as load at all the identified locations where new communities may develop. This location would not benefit south Barrie load in the long term. The station required a high voltage capacitor bank on the 230 kV bus at Holland Marsh. This option was considered for south Simcoe's immediate need and rejected because the Alliston area would still require further relief by 2010, and does not address any of the other immediate concerns of Simcoe County.

I4: ***Innisfil TS Supplied from Essa TS***
Option I1 could be implemented supplying the new transformer station via double 230 kV circuits from Essa TS. This option was explored, and performed technically well, however there would be

insufficient room along the right of way of circuits E3B and E4B in which to string two additional 230 kV conductors. This option was thus considered and rejected. In addition, this option was considered for south Simcoe's immediate need and rejected because the Alliston area would still require further relief by 2010, and does not address any of the other immediate concerns of Simcoe County.

7. Plans: Option Combinations

Those options not rejected as discussed in Section 6 were combined in Tables 5, 6 and 7 to address with the immediate problems in specific geographical areas.

7.1. Relief for Stations North of Essa TS

The needs in the North consist of:

- 230/115 kV auto-transformers capacity limits at Essa TS;
- Voltage deficiency at Stayner TS;
- Capacity limits at Waubaushene TS; and,
- Capacity limits at Meaford TS and voltage deficiency on Meaford TS distribution lines.

Table 5: Plans (Option Combinations) for North Simcoe County Needs

Plan	***Option***	***Title***	***Need Addressed***	***Year in Service***
NORTH 1	S3	Convert Stayner TS to 230 kV, 75/125 MVA Fed Via a New 230 kV Double Circuit from Essa; Include auto-transformer	• Capacity limits on 230/115 kV auto-transformers at Essa TS • Voltage deficiencies at Stayner TS • Creates capacity at Stayner	2007
	S1	Cascading Load Transfers to Stayner TS	• Off-load Waubaushene TS (already over capacity) • Off-load Meaford TS (nearing capacity) • Made possible by Option S3 – effectively increasing capacity at Stayner TS	2007
NORTH 2	S2	Build a New 115 kV Circuit to Stayner and 2nd DESN at Stayner	• Voltage deficiency at Stayner TS • Creates capacity at Stayner TS	2007
	S1	Cascading Load Transfers to Stayner TS	• Off-load Waubaushene TS (already over capacity) • Off-load Meaford TS (nearing capacity) • Made possible by Option S2 – effectively increasing capacity at Stayner TS	2007
	B2	Barrie TS Conversion to 230 kV, 75/125 MVA	• Capacity limits on 230/115 kV auto-transformers at Essa TS • Some impact on the South Simcoe area, but relatively small	2007
NORTH 3	S2	Build a New 115 kV Circuit to Stayner and 2nd DESN at Stayner	• Voltage at Stayner TS • Creates capacity at Stayner TS	2007
	S1	Cascading Load Transfers to Stayner TS	• Off-load Waubaushene TS (already over capacity) • Off-load Meaford TS (nearing capacity) • Made possible by Option S2 – effectively increasing capacity at Stayner TS	2007
	E4	Essa T1 and T2 Upgraded to 250 MVA	• Capacity limits on 230/115 kV auto-transformers at Essa TS	2007

Plans NORTH1, NORTH 2 and NORTH 3 met the needs for the northern Simcoe County area identified in this study and performed well from a technical perspective throughout the 10-year study period. Technical performance results of these plans are given in Appendix B.

7.2. Relief for Stations South of Essa TS

The needs in the South consist of:

- Capacity limits at Alliston TS;
- Insufficient connection capacity to accommodate expected load growth in Innisfil; and,
- Insufficient connection capacity to accommodate expected load growth in south Barrie.

Table 6: Plans (Options) for South Simcoe County

Plan	Option	Title	Need Addressed	Year In Service
SOUTH 1	A1	Upgrade Alliston to 75/125 MVA	• Capacity limits at Alliston TS • Load growth in Innisfil	2006
SOUTH 2	A2	New DESN Near Alliston, 50/83 MVA (2 potential locations)	• Capacity limits at Alliston TS • Load growth in Innisfil	2006

Both plans (options) met the needs for the southern Simcoe County area identified in this study and performed well from a technical perspective throughout the 10-year study period. Technical performance results of these plans are given in Appendix B.

7.3. 230 kV and 115 kV System Capacity & Voltage Support

There were also options to deal with the transmission system needs that currently exist in Simcoe County, or that are expected to arise during the 10-year period over which this study takes place. The transmission system needs consist of:

- Voltage support on the 230 and 115 kV systems by 2009; and,
- Need for additional 230 kV supply by 2014

Table 7: Options for 230 kV and 115 kV Transmission System

Option	Title	Need Addressed	Year In Service
E1	2nd 245 MVAR Capacitor Bank	• Voltage support on 230 and 115 kV systems by 2009	2009
E2	3rd 750 MVA Auto-transformer at Essa	• Voltage support on 230 and 115 kV systems by2009 • Need for additional 230 kV supply by 2014	2009 or 2014

8. Selection of Preferred Plan

8.1. Technical Evaluation

As stated in sections 7.1 and 7.2, all plans met the needs addressed during the 10-year study period. These plans were further technically evaluated with respect to the long-term system planning requirements by assessing them for expected 2024 conditions. This method provides a snapshot of the long-term viability of each of the plans, and how each would perform under the increasing load growth that is expected in Simcoe County. Load forecasts as far out as 2024 were provided by the participants of this study. The outcome of this evaluation enables a selection of a preferred plan for each geographical area. A point system was used to rank the options based on their technical performance (refer to Table 8).

Table 8: Point System for Technical Performance Ranking

Points	***Description***	***Minimum Requirements***
1	Technical performance did not meet minimum requirements in 2024	One point is awarded if the following criteria is not met: • Flows are greater than 100% OR • 115 kV voltages are less then 113 kV
3	Technical performance met minimum requirements in 2024	Three points are awarded under the following criteria: • May require additional facilities before 2024 OR • Flows are between 70-100 % of rating OR • 115 kV voltages are between 113 kV and 120 kV
5	Technical performance exceeded minimum requirements in 2024	Five points are awarded if all the following criteria are met: • No additional facilities are required before 2024 AND • Flows are less than 70 % of rating AND • 115 kV voltages are greater than or equal to 120 kV

A detailed comparison of the technical performance of all options can be seen in Appendix C. The scored points were summed to provide an indication of how the plans performed relative to each other and relative to the longer-term (2024) requirements. The final results are shown in Table 9 indicating the preferred solution considering the technical performance criteria.

Table 9: Final Results of Technical Performance Ranking of Plans

NORTH		
Plan	**Scored Points**	**Ranking**
NORTH 1	**46**	**1**
NORTH 2	42	2
NORTH3	40	3

SOUTH		
Plan	**Scored Points**	**Ranking**
SOUTH A1	20	2
SOUTH A2	**22**	**1**

8.2. Cost Comparison

The cost comparison between the different plans is shown in Table 10. These estimated costs are preliminary and used for the purpose of ranking.

Table 10: Cost Comparison of Options

NORTH PLANS		***Costs***
NORTH 1 (S3)	Stayner @ 230 kV- Barrie unchanged	$ 41M
NORTH 2 (S2, B2)	Stayner 115 kV upgrade, Barrie 230 kV upgrade	$ 57M
NORTH 3 (S2, E4)	Essa 115 kV auto upgrade, Stayner 115 kV upgrade, Barrie unchanged	$ 40M

SOUTH PLANS		***Costs***
SOUTH A1	Alliston TS – upgrade to 75/125 DESN	$ 11M
SOUTH A2	New 50/83 DESN west of Alliston adjacent to the right of way (E8V/E9V)	$ 12M

Table 10 indicates that the cost of plans NORTH1 and NORTH 3 are comparable and both outrank the cost of plan NORTH 2. As plan NORTH 1 outranks NORTH 3 technically when evaluated with respect to the long-term system planning requirements as concluded in section 8.1 (Table 9), NORTH 1 is therefore the preferred plan in the north Simcoe County area.

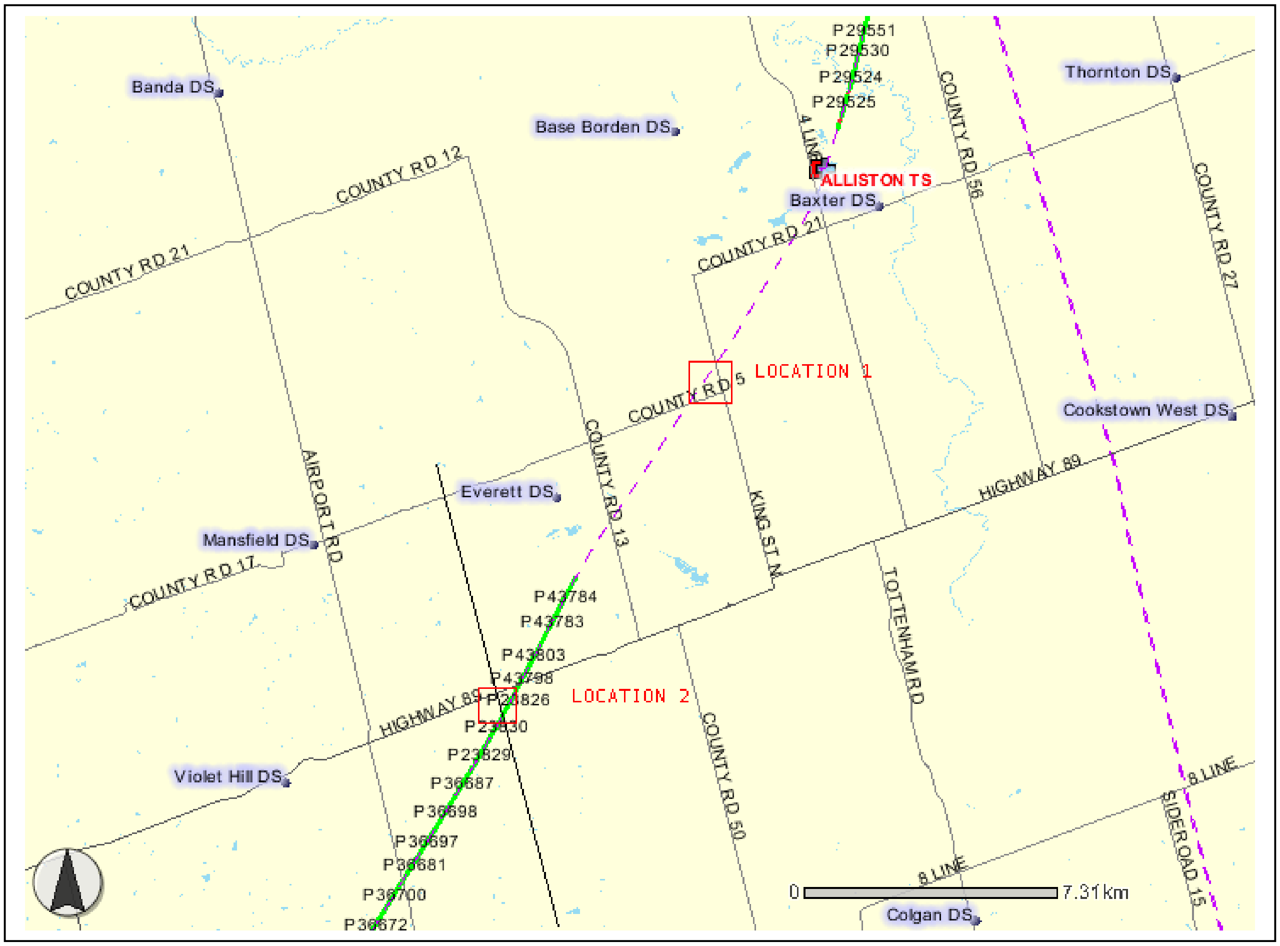
Table 10 also indicates that the cost of plans SOUTH A1 and SOUTH A2 are comparable. The costs associated with SOUTH A1 and A2 options were therefore further assessed in terms of the impact on the distribution costs that would be reflected on the customers in the area. These distribution costs are shown in Table 11.

Table 11: Distribution Costs for SOUTH A1 and SOUTH A2

Plan	***Description***	***Relative Distribution Cost***
South A1	Alliston – upgrade to 75/125 DESN	$6.0M
South A2	New 50/83 DESN west of Alliston adjacent to the right of way (in the vicinity of County Rd 15 & County Rd 5)	$0.0M

The least cost plan is SOUTH A2 as shown in Table 11. This is due to its proximity to the growing communities, to the better use of existing distribution facilities and to the accessibility for new distribution lines. SOUTH A2 improves reliability of south Simcoe supply and avoids extensive new distribution costs. It is noted that a second study location for a new 50/83 DESN was considered west of Alliston adjacent to the right of way (E9V/E9V) in the vicinity of Hwy 89 and Adjala 2nd, and the relative distribution cost was of $3.0M.

Conclusively, plan SOUTH A2 is both technically and economically superior to SOUTH A1 and is therefore the preferred plan in the south Simcoe County area.



Map 2: Location of Existing Alliston TS and Potential Study Area for Plan SOUTH A2

9. Discussion

North

NORTH 1 is the preferred plan in northern Simcoe County. NORTH 1 plan performed consistently well under all relevant contingencies for the 10-year period beyond 2014. The contingencies considered can be seen in Appendix C along with the results for each plan. NORTH 1 displayed voltage stability in the Stayner area, without any additional voltage support beyond a second high voltage capacitor on the Essa 230 kV bus placed in service for summer 2009. Waubaushene TS reaches capacity again in 2022, but could be deferred until 2024 by transferring approximately 3 MVA of load to Stayner TS in 2022. Meaford TS also reaches capacity again by 2024. Voltages at Barrie TS were acceptable and the station loading was within the limits of the existing transformers until 2022, assuming the use of the low voltage capacitor bank. Beyond 2022, additional capacity would be required to support Barrie TS and satisfy the long-term electrical capacity requirements in the southern Simcoe County area.

The NORTH 2 plan performed well in the Barrie area; however, there is some concern that capacity would be stranded at Barrie TS until 2014 when it may become necessary to transfer Midhurst TS load to Barrie TS. If load were transferred from Midhurst TS to Barrie TS in order to prevent overloading Midhurst TS transformers, the incremental load transfer could occur until the upgraded Barrie TS transformers reach capacity in 2023 (combined Midhurst overflow plus Barrie TS load forecast). At the same time, Stayner TS experiences low voltages due to the loading on the 115 kV circuits. Also under consideration was the poor voltage performance in the Stayner area in the event that T3 and the proposed T5 auto-transformers at Essa TS were out of service (existing T4 auto-transformer is limiting). In order to maintain acceptable voltages in the Stayner area, low voltage capacitors would be required on the second Stayner low voltage bus. Under this option, action would be required in the Stayner TS, Midhurst TS and Barrie TS areas before 2024, unlike NORTH 1 where action would only be required in the Midhurst and possibly Barrie areas before 2024.

The NORTH 3 plan performed moderately well under technical consideration. In order to implement this plan as well as plan NORTH 2, a wider right-of-way would be required from that which currently exists. There were no technical performance issues with this plan provided a low voltage capacitor is installed on the low voltage bus of the new Stayner DESN. However, other options performed technically better.

South

SOUTH A2 is the preferred plan in northern Simcoe County. SOUTH A2 plan performed well under technical consideration. The new 50/83 DESN station near Alliston TS was sufficient for the load growth in the Alliston area, and the overflow from Barrie TS (Innisfil load) when Barrie TS reaches capacity limits in 2022. SOUTH A2 also presents the opportunity of cascading transfers between Midhurst TS and Alliston TS, via Barrie TS once Midhurst TS reaches capacity around 2014. SOUTH A2 is closer to the growing communities, makes better use of existing distribution facilities and to the accessibility for new distribution lines. SOUTH A2 improves reliability of south Simcoe supply and avoids extensive new distribution costs.

SOUTH A1 plan performed moderately well under technical consideration. Upgrading to 75/125 MVA transformers at the existing Alliston TS would be sufficient for the load growth around Alliston until 2022, at which point it reaches 99% of its 10-day LTR. Compared to plan SOUTH A2, this plan incurs higher line losses due to longer distances to the load centres in general. Further, the distribution lines emanating Alliston TS would need to be underground for several kilometres due to local issues with road allowances. This would present significant distribution costs reflected on the customers in the area.

10. Conclusions

The following conclusions can be reached from the analysis performed for this study.

- Alliston TS is currently loaded beyond its capacity limit. The earliest possible option to relieve this problem cannot be implemented until 2006.
- Waubaushene TS is currently loaded beyond its capacity limit. The earliest possible option to relieve this problem cannot be implemented until 2007.
- Meaford TS is nearing capacity, expected to be loaded beyond its capacity limit in 2006. Distribution lines emanating from this station are currently overloaded and experiencing voltage deficiencies. The earliest possible option to relieve these problems cannot be implemented until 2007.
- Stayner TS is nearing IMO prescribed limitations in voltage decline. The voltage decline under a single contingency is expected to be greater than 10% by 2007. The earliest possible option to deal with this problem can be implemented by 2007.
- The 230/115 kV auto-transformers at Essa TS are expected to be loaded to 100% of their capacity by 2007. The earliest possible option to resolve this problem can be implemented by 2007.
- The preferred plans to meet all of these needs are:
  1. NORTH 1: Convert Stayner TS to 230 kV, 75/125 MVA fed via a new 230 kV double circuit from Essa TS and cascade load transfers to Stayner TS.
  2. SOUTH A2: New DESN Near Alliston, 50/83 MVA in the vicinity of County Road 15 and County Road 5.

11. Recommendations

Several recommendations can be drawn from this study to address the current system deficiencies and provide system capacity to meet forecasted load growth. These recommendations are:

1. Hydro One Networks Inc. to initiate the approval processes required for the conversion of Stayner TS from 115 kV to 230 kV, and the upgrading of the existing 115 kV transmission line from Stayner TS to Essa TS (circuit S2E) to a double circuit 230 kV transmission line.

2. Hydro One Networks Inc. to commence the preliminary engineering and consultation with the distribution customers, and to initiate the approval processes on the construction of a new transformer station, near Alliston.

3. Hydro One Networks Inc. to review the study in 2007 with updated Simcoe County load forecasts for the potential need of a 2nd 230 kV, 245 MVAR capacitor bank and a 3rd 500/230 kV, 750 MVA auto-transformer both at Essa TS for implementation in 2009 and 2014, respectively.

4. The local electric utilities to continue to monitor load growth in the southern Simcoe County area and to review options for long-term growth based on location of new developments and load forecasts.

5. The local electric utilities in the northern Simcoe County area (specifically in the Barrie area) to continue to monitor load growth and the loading of Midhurst TS.

Appendices

Appendix A: Description of Options

Relief for Stayner, Meaford & Waubaushene

S1: ***Cascading Load Transfers to Stayner TS***
Load could be transferred from Waubaushene TS to and cascaded down to Stayner TS via Midhurst TS. This would relieve the loading at Waubaushene TS and Meaford TS and would be a reverse of load transfers originally made in the mid 1990s to defer the need for additional capacity for load growth in the Stayner TS area. Similarly, load from Meaford could also potentially be transferred to Stayner TS – originally transferred from Stayner TS for the same transmission expansion deferral. However, there is currently insufficient capacity at Stayner TS to account for these load transfers and the voltage at Stayner is such that it would prohibit load transfers, especially those that are winter peaking. At the same time, there is insufficient capacity on the 115 kV system to supply these load transfers. Any load transfers onto the 115 kV system at Stayner TS would overload the 230/115 kV auto-transformers at Essa.

S2: ***Build a New 115 kV Circuit to Stayner and 2nd DESN at Stayner***
Improving voltage stability and reliability at Stayner could be accomplished by building an additional 27 km 115 kV circuit alongside S2E, Stayner by Essa. This solution would also allow for building a second 50/83 MVA DESN at Stayner TS to accommodate the load transfers from Waubaushene TS and Meaford TS. This solution would require providing additional capacity on the 115 kV system, which could be accomplished via options B2 (*Barrie TS Conversion to 230 kV, 75/125 MVA)* or E5 (*Essa T1 and T2 Upgraded to 250 MVA)*. By selecting option B2, a new diameter with three new 230 kV breakers at Essa TS is required. In order to implement this solution, a wider right-of-way would be required from that which currently exists. This caused the option to be more costly than other alternatives investigated in this study. There were no technical performance issues with this option provided a low voltage capacitor is installed on the low voltage bus of the new DESN. However, other options performed technically better.

S3: ***Convert Stayner TS to 230 kV, 75/125 MVA Fed Via a New 230 kV Double Circuit from Essa***
A third option in the Stayner TS area was to convert Stayner TS to 230 kV, and convert S2E to a double 27 km 230 kV circuit. This option also consists of placing a 115 MVA, 230/115 kV auto-transformer at Stayner TS to maintain the electrical connection to Meaford TS. A new diameter with three new 230 kV breakers at Essa TS is required for this option. Converting Stayner TS to 230 kV performed well technically. No voltage issues were encountered at Stayner TS, Meaford TS, or along the S2E 230 kV circuit corridor during the study period. The capacity at Stayner was increased enough to provide for a 13.7 MVA load transfer from Meaford TS and a 25.9 MVA load transfer from Waubaushene TS as well as for load growth in the Stayner TS area for the next 20 years. Under these load transfers, Meaford TS again reaches capacity in the winter of 2024. Waubaushene TS reaches capacity again in 2022, however the additional 2.65 MVA of load could be transferred to Stayner TS to defer changes to Waubaushene TS for two more years (2024). This option does not have the same real estate issues as S2 (*Build a New 115 kV Circuit to Stayner and 2nd DESN at Stayner*) since the existing line would be required to be rebuilt on a single tower. This option would experience some difficulties in construction, as outage windows for S2E would be limited to early spring and late fall, to maintain appropriate voltages at Stayner TS. Another advantage to this option is that it allows for improved voltage stability in the event that wind generation develops in the Meaford/Stayner TS areas. Additional capacity on the 115 kV system (i.e. upgrades to the existing 230/115 kV auto-transformers at Essa TS) would not be required.

S4: ***Upgrade the Existing 115 kV Circuit to a double 230 kV Circuit from Essa TS and build "Collingwood Area" TS (operated at both 115 kV and 230 kV)***

Under this option, about 37 km of existing 115 kV circuit is replaced with a double 230 kV circuit between Essa TS and the new "Collingwood Area" TS. Operate one circuit at 115 kV and the other at 230 kV. A new diameter with three new 230 kV breakers at Essa TS is required for this option. The new 230/44 kV DESN near Collingwood would operate initially at both 115 kV and 230 kV. Besides servicing the local Collingwood and Stayner loads, load could be transferred from Waubaushene TS and Meaford TS as in option S1. Additional capacity on the 115 kV system (i.e. upgrades to the existing 230/115 kV auto-transformers at Essa TS) would not be required within the study period, however, this option would require voltage relief at Stayner TS by 2014. Further, this option requires more line and station construction than options S2 or S3 and provides significantly more connection capacity in the area then the load forecast justifies.

Relief for Barrie TS

B1: ***2nd DESN at Barrie TS***

Increase capacity at Barrie TS by installing a second DESN at the station. This option would require line upgrades to limiting section(s) of E3B, and would need to be incorporated with increasing capacity on the 115 kV system as discussed in Option E4. Increasing capacity at Barrie TS by the amount of an additional 50/83 MVA DESN would strand capacity until such time as Midhurst TS would be at capacity (~2014) and not affect the immediate needs that exist elsewhere in the system, namely in the Stayner, Meaford, Waubaushene and Alliston areas. Even if this option were selected, further investments would be required to address these other immediate issues.

B2: ***Barrie TS Conversion to 230 kV, 75/125 MVA***

Converting Barrie TS to 230 kV and converting the two step-down transformers at Barrie TS to 75/125 MVA would be more than sufficient to cover off the load growth expected in the Innisfil area for the entire study period. A new diameter with three new 230 kV breakers at Essa TS is required for this option. However, as in option B1 (*2nd DESN at Barrie TS*), this option would temporarily strand capacity at Barrie the first 10 years, before being more efficiently utilized. At the same time, it would not address any of the immediate concerns in Simcoe County except that it would provide available capacity on the 115 kV system to effectively allow the auto-transformers at Essa TS to support load transfers from Waubaushene and Meaford to Stayner.

230 and 115 kV System Capacity & Voltage Support

E1: ***2nd 245 MVAR Capacitor Bank***

By about 2009, further voltage support will be required to support the increasing load growth on the 230/115 kV systems. This could be supplied via a second 245 MVAR capacitor bank on the 230 kV bus at Essa.

E2: ***3rd 750 MVA Auto-transformer at Essa***

By 2014, more auto-transformation capacity will be required. Under contingency of the loss of the companion auto-transformer, the remaining auto is loaded at 82% for T3 and 90% for T4. This option could be accelerated and used in place of E2 (*2nd 245 MVAR Capacitor Bank*) in 2009 to provide additional voltage support to prevent a voltage collapse in the event that one auto-transformer is out of service for maintenance and the companion auto-transformer is forced from service on contingency.

However, the auto-transformer becomes necessary by 2014, as a capacitor is insufficient to provide the necessary voltage support.

E3: ***230 kV Double Circuit from Holland Marsh Junction to Essa TS***
Voltage support could be supplied via an additional 230 kV circuit connection to the 230 kV system near the Greater Toronto Area, specifically, supplied from Holland Marsh Junction, along B82V and B83V. Although this solution provides some voltage support, it does not provide sufficient support by 2014 to maintain acceptable voltage levels on the Essa 230 kV system in the event of a contingency. This option was investigated, however proved to be technically inferior to E2. The cost of constructing two new 230 kV circuits to a third auto-transformer also needs to be considered.

E4: ***Essa T1 and T2 Upgraded to 250 MVA***
Capacity on the 115 kV system would be increased by upgrading Essa T1 and T2, (230/115 kV auto-transformers) from 115 MVA to 250 MVA. This option performed technically well for the 10-year period to 2014. However, in the long term, the 115 kV system experiences worse voltage issues than those which exist today. This option would not provide long term voltage stability for the loads on the 115 kV system, without additional reactive support on the 115 kV system.

Relief for Alliston TS and growing load in Innisfil

A1: ***Upgrade Alliston to 75/125 MVA***
Replace the two 50/83 MVA step-down transformers at Alliston TS with two 75/125 MVA transformers. This capacity would be sufficient to cover the expected load growth in the Alliston and Innisfil areas until 2022. There are several advantages to upgrading the existing transformers at Alliston TS. First, the transformers at Alliston TS are leaking and replacement would negate the need for an overhaul. Land is available at Alliston, and environmental approvals would not be required to make these changes. Upgrades to Alliston TS would however present some difficulty in moving power out of the station. An upgrade from 50/83 to 75/125 MVA would require at least 4 feeder positions to make efficient use of the additional capacity. Additional feeders could potentially be brought out of the station underground, however due to local issues with road allowances, these feeders would need to be underground for several kilometres which would present significant distribution costs.

A2: ***New DESN Near Alliston, 50/83 MVA***
Building an additional two by 50/83 MVA DESN near Alliston TS to supply load growth in the local area and in Innisfil. Two potential locations for this DESN were evaluated – at Adjala 2nd Line & Highway 89 and at Everett Road & County Road 15. The first location presents significant feeder construction while the second location makes use of existing feeders, and is closer to the load centres. Both locations would be acceptable from a technical performance perspective.

I1: ***Innisfil TS Supplied from Holland Marsh Junction***
This option consists of building a new step-down transformer station in the Municipality of Innisfil supplied via double circuit 230 kV lines emanating from Holland Marsh Junction in the south. This option would require a new HV capacitor bank located either at Holland Marsh Junction or at the new Innisfil TS. There were two locations identified for this option: K10SB crossing of County Road 88 and K10SB crossing of Concession Road 6. Both locations performed technically the similar and differ only in cost of line construction. Concession Road 6 is south of Bradford, and would be advantageous for any new communities in this area. County Road 88 is more central to Innisfil and would meet growing demands in Innisfil, in addition to new community developments either south or west.

I2: *Innisfil TS Supplied from E3B/E4B*
This option consists of a new transformer station built along the border of the Barrie and Innisfil Municipalities supplied via 115 kV circuits, continuation of E3B and E4B. The station would be located at the K10SB crossing of Lockhart Road. This option would require upgrades to limiting sections of E3B and would need to incorporate Option E5 (*Essa T1 and T2 Upgraded to 250 MVA*) or S3 (*Convert Stayner TS to 230 kV, 75/125 MVA Fed Via a New 230 kV Double Circuit from Essa*). Connection of these facilities would be limited to a 50/83 MVA DESN station.

I3: *Holland Marsh TS Supplied*
This option consists of a new 230/44 kV, 75/125 MVA transformer station built at Holland Marsh Junction. This option presents opportunities for supplying load in the south end of Innisfil, as well as load at all the identified locations where new communities may develop. This location would not benefit south Barrie load in the long term. Technical performance of this option was consistent with option I1 (*Innisfil TS Supplied from Holland Marsh).* The station required a high voltage capacitor bank on the 230 kV bus at Holland Marsh, which is also consistent with the performance of I1.

I4: *Innisfil TS Supplied from Essa*
Option I1 could be implemented supplying the new transformer station via double 230 kV circuits from Essa TS. This option was explored, and performed technically well, however there would be insufficient room along the right of way of E3B and E4B in which to string two additional 230 kV conductors. This option was thus considered and rejected.

Appendix B: Results of North & South Alternatives technical performance 2004 to 2014.

Appendix B is a contingency analysis of the plans outlined in Section 7: Plans: Option Combinations. This analysis indicates that plans NORTH 1, NORTH 2, NORTH 3, SOUTH A1 and SOUTH A2 perform technically well and satisfy their respective needs throughout the study period. Included in this appendix is the contingency analysis for the preferred system plan in the 1991 ESR. The analysis highlights that this system plan violates planning criteria by year 2014.

South A1: Upgrade Alliston to 75/125 MVA

	Loss of Barrie T1	Loss of Barrie T2	Loss of Alliston T3	Loss of Alliston T5	Loss of E3B			Loss of E4B			Loss of E8V						Loss of E9V					
	Barrie T2	Barrie T1	Alliston T5	Alliston T3	E4B	Barrie hv kv	Barrie lv kv	E3B	Barrie hv kv	Barrie lv kv	E9 - ExA	E9 - OxA	E8 - OxA	Essa kV	Al. Lv kv	Al. Hv kv	E8 ExA	E8 - OxA	E9 - OxA	Essa kV	Al. Lv kv	Al. Hv kv
2004	111%	110%	58%	58%	60%	122.9	46.2	85%	122.2	46.5	26%	13%	16%	249.3	46.1	236.2	28%	10%	11%	249.0	46.4	238.7
2005	86%	87%	62%	62%	47%	127.7	46.2	65%	127.2	46.7	26%	12%	17%	249.0	46.6	235.7	28%	10%	11%	248.8	46.2	238.3
2006	80%	80%	62%	62%	44%	124.8	46.0	61%	124.4	46.5	26%	12%	17%	248.6	46.5	235.4	28%	10%	11%	248.4	46.1	238.1
2007	84%	84%	64%	64%	46%	124.4	46.3	64%	123.8	46.1	26%	12%	18%	248.2	46.3	234.9	28%	10%	11%	247.9	46.6	237.7
2008	89%	89%	66%	66%	49%	123.7	46.4	68%	123.2	46.2	26%	11%	18%	247.6	46.1	234.2	28%	9%	10%	247.4	46.4	237.3
2009	90%	89%	69%	69%	49%	123.5	46.3	68%	122.9	46.0	26%	11%	19%	247.3	46.5	233.8	28%	9%	10%	247.0	46.2	236.9
2010	91%	90%	71%	71%	49%	123.2	46.1	70%	122.7	46.5	26%	11%	19%	246.8	46.4	233.3	28%	9%	10%	246.6	46.1	236.5
2011	91%	91%	73%	73%	50%	122.9	46.0	70%	122.4	46.4	26%	11%	20%	246.5	46.2	232.7	28%	9%	10%	246.2	46.5	236.1
2012	90%	89%	73%	73%	49%	125.6	46.5	68%	125.1	46.3	30%	16%	20%	251.8	46.3	235.1	32%	13%	14%	251.5	46.6	238.5
2013	91%	90%	75%	75%	49%	125.3	46.3	70%	124.8	46.1	30%	14%	21%	251.3	46.1	234.5	32%	13%	14%	251.0	46.4	238.0
2014	91%	91%	78%	78%	50%	125.0	46.2	70%	124.4	46.6	30%	14%	21%	250.8	46.5	234.0	32%	12%	13%	250.5	46.2	237.5

- % values are a percentage of applicable equipment ratings
- voltages in kV

South A2: New 50/83 TS Near Alliston

	Loss of Barrie T1	Loss of Barrie T2	Loss of Alliston T3	Loss of Alliston T5	Loss of E3B			Loss of E4B			Loss of E8V						Loss of E9V					
	Barrie T2	Barrie T1	Alliston T5	Alliston T3	E4B	Barrie hv kv	Barrie lv kv	E3B	Barrie hv kv	Barrie lv kv	E9 - ExA	E9 - OxA	E8 - OxA	Essa kV	Al. Lv kv	Al. Hv kv	E8 - ExA	E8 - OxA	E9 - OxA	Essa kV	Al. Lv kv	Al. Hv kv
2004	112%	112%	43%	43%	62%	121.7	46.3	86%	121.0	46.5	30%	16%	13%	247.1	46.5	233.3	31%	13%	9%	246.9	46.1	235.6
2005	89%	89%	45%	45%	49%	123.3	46.3	67%	122.7	46.0	30%	16%	14%	246.8	46.3	232.8	32%	13%	9%	246.6	46.6	235.2
2006	79%	79%	45%	45%	44%	126.6	46.1	60%	126.3	46.6	34%	20%	14%	252.7	46.1	235.7	37%	18%	9%	252.5	46.3	238.2
2007	83%	82%	46%	46%	45%	126.2	46.4	63%	125.6	46.2	34%	19%	14%	252.0	46.5	235.2	36%	18%	9%	251.8	46.1	237.7
2008	88%	88%	48%	48%	48%	125.5	46.6	67%	125.0	46.3	34%	19%	16%	251.5	46.3	234.7	36%	17%	10%	251.3	46.5	237.2
2009	89%	88%	49%	49%	48%	125.2	46.4	67%	124.6	46.1	33%	19%	17%	251.0	46.2	234.2	36%	17%	10%	250.8	46.4	236.8
2010	89%	89%	50%	50%	49%	124.9	46.2	68%	124.4	46.7	34%	19%	17%	250.6	46.0	233.6	36%	17%	10%	250.3	46.3	236.4
2011	90%	90%	52%	52%	49%	124.6	46.1	68%	124.1	46.5	34%	18%	18%	250.1	46.5	233.2	36%	17%	11%	249.9	46.2	236.0
2012	91%	90%	53%	53%	49%	124.4	46.6	70%	123.7	46.3	33%	18%	18%	249.6	46.3	232.6	36%	16%	11%	249.4	46.0	235.6
2013	92%	91%	55%	55%	50%	124.0	46.4	70%	123.4	46.1	33%	18%	19%	249.1	46.2	232.0	36%	16%	11%	248.8	46.5	235.1
2014	92%	92%	56%	56%	50%	123.6	46.2	71%	123.1	46.6	33%	17%	19%	248.6	46.6	231.5	36%	16%	12%	248.3	46.3	234.6

- % values are a percentage of applicable equipment ratings
- voltages in kV

North 1: Stayner/S2E conversion to 230 kV (double cct)

	Loss of Stayner T3		Loss of Stayner T4			Loss of Meaford T1		Loss of Waubaushene T5		Loss of S2E						Loss of S3E (New 230kV)					
	T4	Stayner lv kv	T3	Stay. T5 hv kv	Stay. T5 2nd-v kv	T2	Meaford lv kv	T6	Waub. Lv kv	S3E	S2S1 (MxS)	Stayner lv kv	Stayner hv kv	S3E hv kv (@ Stay)	S2S2 (OxM)	S2E	S2E hv kv	S2S1 (MxS)	Stayner lv kv	Stayner auto 2nd kv	S2S2 (OxM)
2004	26%	47.0	28%	248.2	123.1	23%	46.3	37%	47.0	12%	30%	46.3	237.7	246.6	34%	15%	245.0	27%	46.0	121.7	32%
2005	26%	46.9	28%	247.9	122.9	25%	46.1	37%	47.0	12%	30%	46.2	237.1	246.2	35%	15%	244.8	28%	46.6	121.5	33%
2006	26%	46.8	29%	247.4	122.7	28%	46.4	38%	46.8	13%	30%	46.0	236.3	245.8	36%	16%	244.3	27%	46.4	121.3	33%
2007	25%	46.7	28%	246.7	122.4	31%	46.2	36%	46.7	13%	30%	46.5	235.9	245.3	37%	16%	243.7	27%	46.2	121.0	34%
2008	26%	47.0	28%	246.2	122.1	33%	46.0	36%	47.1	13%	30%	46.3	234.8	244.7	38%	16%	243.2	27%	46.6	120.7	35%
2009	26%	46.9	29%	245.7	121.9	33%	46.4	37%	47.0	13%	30%	46.1	234.3	244.2	39%	17%	242.7	28%	46.5	120.5	35%
2010	26%	46.8	29%	245.3	121.7	34%	46.3	37%	46.8	15%	31%	46.6	234.2	243.9	39%	17%	242.1	28%	46.2	120.2	36%
2011	26%	46.7	29%	244.7	121.4	34%	46.3	36%	46.8	15%	31%	46.5	233.6	243.5	41%	17%	241.7	28%	46.1	120.0	36%
2012	27%	46.8	29%	248.2	123.0	35%	46.1	40%	46.7	18%	31%	46.2	227.2	246.6	42%	24%	244.0	28%	46.3	121.1	36%
2013	28%	46.7	30%	247.4	122.6	36%	46.0	40%	47.1	18%	32%	46.7	226.9	246.0	42%	24%	243.4	28%	46.1	120.8	36%
2014	28%	47.1	31%	246.8	122.3	36%	46.4	40%	46.9	19%	32%	46.5	226.1	245.4	43%	24%	242.8	28%	46.6	120.5	37%

	Loss of S2S1 (MxS)			Loss of S2S2 (OxM)				Loss of E26 (WxE)			Loss of E27 (WxE)		
	S2S2 (OxM)	Meaford hv kv	Meaford lv kv	S2S1 (MxS)	Meaford hv kv	Meaford lv kv	Stayner lv kv	E27	Waub. Hv kv	Waub. Lv kv	E26	Waub. Hv kv	Waub. Lv kv
2004	9%	122.8	46.8	10%	121.0	46.1	46.7	20%	246.0	46.4	20%	246.0	46.4
2005	10%	122.6	46.7	11%	120.6	46.5	46.6	21%	245.6	46.3	20%	245.6	46.3
2006	11%	122.2	46.5	12%	120.0	46.2	46.5	21%	245.1	46.1	21%	245.1	46.1
2007	12%	122.0	46.3	13%	119.6	46.0	47.0	21%	244.5	46.4	21%	244.5	46.4
2008	13%	121.7	46.2	14%	119.0	46.2	46.8	21%	243.9	46.3	21%	243.9	46.3
2009	13%	121.6	46.1	14%	118.7	46.1	46.7	22%	243.4	46.1	21%	243.4	46.1
2010	13%	121.5	46.1	15%	118.4	46.0	46.5	22%	242.9	46.5	22%	242.9	46.5
2011	13%	121.5	46.6	15%	118.1	46.4	47.0	22%	242.4	46.4	22%	242.4	46.4
2012	13%	121.8	46.2	15%	120.0	46.0	46.1	22%	247.4	46.3	22%	247.4	46.3
2013	14%	121.7	46.1	15%	119.7	46.5	46.5	22%	246.8	46.1	22%	246.8	46.1
2014	14%	121.6	46.0	15%	119.3	46.3	46.4	23%	246.2	46.5	22%	246.2	46.5

- % values are a percentage of applicable equipment ratings
- voltages in kV

North 2: New 115 kV Stayner x Essa; Barrie conversion to 230 kV; new DESN @ Stayner

	Loss of Stayner T3			Loss of Stayner T1			Loss of Meaford T1		Loss of Waubaushene T5		Loss of S2E						Loss of S3E (New 115kV)					
	T4	Stayner lv kv	Stayner hv kv	T2	Stayner lv kv	Stayner hv kv	T2	Meaford lv kv	T6	Waub. Lv kv	S3E	S2S1 (MxS)	Stayner lv kv	Stayner hv kv	Stayner2 lv kv	S2S2 (OxM)	S2E	Stayner 2 lv kv	S2S1 (MxS)	Stayner lv kv	Stayner hv kv	S2S2 (OxM)
2004	58%	46.4	124.5	50%	46.5	122.2	23%	46.8	35%	47.1	26%	38%	46.3	122.8	46.1	41%	26%	46.1	36%	46.4	121.7	42%
2005	59%	47.1	124.5	51%	46.3	121.9	25%	46.0	35%	46.9	26%	38%	46.1	122.5	46.5	42%	27%	46.0	36%	46.2	121.3	43%
2006	59%	47.0	124.1	52%	46.1	121.6	28%	46.3	36%	46.8	27%	38%	46.0	122.1	46.3	43%	28%	46.4	36%	46.0	120.9	44%
2007	50%	46.9	124.1	52%	46.4	122.3	30%	46.4	41%	46.9	30%	37%	46.4	122.5	46.2	43%	33%	46.5	35%	46.1	120.8	44%
2008	51%	46.7	123.6	53%	46.2	121.9	33%	46.1	41%	46.8	31%	38%	46.2	122.0	46.0	45%	34%	46.4	36%	46.6	120.4	45%
2009	51%	46.5	123.3	53%	46.1	121.6	33%	46.0	39%	46.7	31%	38%	46.1	121.7	46.4	45%	34%	46.2	36%	46.4	120.0	45%
2010	51%	47.1	123.1	54%	46.0	121.2	33%	46.5	39%	47.1	32%	38%	46.6	121.4	46.3	46%	35%	46.6	36%	46.3	119.7	46%
2011	51%	46.9	122.7	54%	46.3	120.8	34%	46.3	39%	46.9	32%	39%	46.5	121.1	46.2	46%	35%	46.4	37%	46.0	119.3	46%
2012	52%	46.8	122.4	55%	46.1	120.4	35%	46.2	40%	46.8	33%	39%	46.3	120.7	46.0	47%	35%	46.3	37%	46.6	119.1	47%
2013	52%	46.6	122.0	55%	46.0	120.2	36%	46.1	38%	46.7	33%	39%	46.1	120.3	46.4	47%	36%	46.1	37%	46.4	118.6	48%
2014	53%	46.4	121.6	56%	46.3	119.8	36%	46.0	39%	47.0	33%	40%	46.7	120.1	46.4	48%	37%	46.4	38%	46.2	118.2	48%

	Loss of S2S1 (MxS)			Loss of S2S2 (OxM)				Loss of E26 (WxE)			Loss of E27 (WxE)		
	S2S2 (OxM)	Meaford hv kv	Meaford lv kv	S2S1 (MxS)	Meaford hv kv	Meaford lv kv	Stayner lv kv	E27	Waub. Hv kv	Waub. Lv kv	E26	Waub. Hv kv	Waub. Lv kv
2004	9%	121.8	46.4	10%	121.8	46.4	47.0	20%	243.4	46.4	20%	243.4	46.4
2005	10%	121.6	46.3	11%	121.2	46.1	46.9	21%	242.9	46.2	20%	242.9	46.2
2006	11%	121.2	46.1	12%	120.4	46.3	46.6	21%	242.4	46.6	21%	242.4	46.6
2007	12%	121.5	46.1	13%	120.9	46.5	46.2	21%	248.3	46.1	21%	248.3	46.1
2008	13%	121.3	46.0	14%	120.2	46.2	46.6	21%	247.7	46.5	21%	247.7	46.5
2009	13%	121.2	45.9	14%	119.8	46.0	46.5	21%	247.2	46.4	21%	247.2	46.4
2010	13%	121.1	46.5	14%	119.2	46.3	46.3	22%	246.5	46.2	0%	244.3	46.1
2011	13%	121.0	46.4	15%	118.7	46.1	46.1	22%	246.0	46.6	22%	246.0	46.6
2012	13%	120.8	46.4	15%	118.4	46.0	46.6	22%	245.4	46.4	22%	245.4	46.4
2013	14%	120.7	46.3	15%	117.8	46.3	46.4	23%	244.7	46.2	22%	244.8	46.2
2014	14%	120.6	46.2	16%	117.3	46.0	46.2	23%	244.2	46.6	22%	244.2	46.6

- % values are a percentage of applicable equipment ratings
- voltages in kV

North 3: New 115 kV Stayner x Essa; new DESN @ Stayner; Upgrade Essa Autos T1/T2 to 250 MVA

	Loss of Stayner T3			Loss of Stayner T1			Loss of Meaford T1		Loss of Waubaushene T5		Loss of Essa T1		Loss of S2E					
	T4	Stayner lv kv	Stayner hv kv	T2	Stayner lv kv	Stayner hv kv	T2	Meaford lv kv	T6	Waub. Lv kv	T2	115 kv bus kv	S3E	S2S1 (MxS)	Stayner lv kv	Stayner hv kv	Stayner2 lv kv	S2S2 (OxM)
2004	58%	47.1	124.2	51%	46.3	121.7	23%	46.1	35%	47.0	41%	123.3	25%	39%	46.1	122.3	46.4	43%
2005	59%	47.1	124.4	51%	46.3	121.9	25%	46.0	25%	46.9	36%	123.8	25%	39%	46.1	122.4	46.5	43%
2006	59%	47.0	124.2	51%	46.2	121.7	28%	46.3	36%	46.8	34%	123.9	26%	39%	46.0	122.2	46.3	44%
2007	50%	47.1	124.6	52%	46.1	122.8	30%	46.4	41%	46.9	36%	125.6	30%	38%	46.5	122.8	46.3	44%
2008	50%	46.9	124.1	53%	46.4	122.3	33%	46.2	41%	46.8	38%	125.1	31%	39%	46.2	122.2	46.0	45%
2009	51%	46.7	123.8	53%	46.3	122.1	33%	46.1	39%	46.7	38%	124.9	31%	39%	46.1	121.9	46.5	46%
2010	51%	46.6	123.4	54%	46.1	121.7	33%	46.0	39%	47.1	39%	124.6	31%	39%	46.0	121.6	46.4	46%
2011	51%	47.1	123.1	54%	46.0	121.3	34%	46.4	39%	46.9	39%	124.3	32%	40%	46.5	121.3	46.3	47%
2012	52%	46.9	122.8	55%	46.3	120.9	35%	46.3	40%	46.8	40%	124.0	32%	40%	46.3	120.9	46.1	48%
2013	52%	46.8	122.4	55%	46.2	120.6	36%	46.1	38%	47.2	40%	123.7	33%	40%	46.2	120.5	46.5	48%
2014	53%	46.6	122.0	56%	46.0	120.3	36%	46.0	39%	47.0	41%	123.4	33%	41%	46.0	120.2	46.3	49%

	Loss of S3E (New 115kV)						Loss of S2S1 (MxS)			Loss of S2S2 (OxM)				Loss of E26 (WxE)			Loss of E27 (WxE)		
	S2E	Stayner2 lv kv	S2S1 (MxS)	Stayner lv kv	Stayner hv kv	S2S2 (OxM)	S2S2 (OxM)	Meaford hv kv	Meaford lv kv	S2S1 (MxS)	Meaford hv kv	Meaford lv kv	Stayner lv kv	E27	Waub. Hv kv	Waub. Lv kv	E26	Waub. Hv kv	Waub. Lv kv
2004	25%	46.5	41%	46.2	121.2	44%	9%	121.8	46.4	10%	121.0	46.1	46.7	20%	243.3	46.4	20%	243.3	46.4
2005	26%	45.9	41%	46.2	121.3	44%	10%	121.6	46.3	11%	120.9	46.0	46.7	21%	242.9	46.2	20%	242.9	46.2
2006	27%	46.4	40%	46.1	121.0	45%	11%	121.2	46.1	12%	120.3	46.3	46.6	21%	242.4	46.6	21%	242.4	46.6
2007	33%	46.1	40%	46.3	121.2	45%	12%	121.5	46.1	13%	121.2	46.0	46.3	21%	248.3	46.1	21%	248.3	46.1
2008	34%	46.4	40%	46.0	120.5	46%	13%	121.3	46.0	14%	120.5	46.3	46.7	21%	247.7	46.5	21%	247.7	46.5
2009	34%	46.3	40%	46.6	120.4	46%	13%	121.2	45.9	14%	120.1	46.1	46.6	21%	247.1	46.3	21%	247.1	46.3
2010	34%	46.2	41%	46.4	120.0	47%	13%	121.0	46.5	14%	119.6	46.5	46.4	22%	246.5	46.2	21%	246.5	46.2
2011	35%	46.5	41%	46.2	119.6	48%	13%	120.9	46.4	15%	119.1	46.2	46.2	22%	246.0	46.6	22%	246.0	46.6
2012	35%	46.3	41%	46.0	119.2	48%	13%	120.8	46.4	15%	118.6	46.0	46.1	22%	245.3	46.4	22%	245.3	46.4
2013	35%	46.2	42%	46.5	119.0	49%	14%	120.7	46.3	15%	118.2	46.4	46.6	23%	244.7	46.2	22%	244.7	46.2
2014	36%	46.6	42%	46.3	118.6	49%	14%	120.6	46.2	16%	117.8	46.2	46.4	23%	244.1	46.6	22%	244.1	46.6

- % values are a percentage of applicable equipment ratings
- voltages in kV

Option S4 & S1: S2E conversion to 230 kV (double cct)/Build new "Collingwood Area" TS/ operate at both 115 kV & 230 kV

	Loss of Stayner T3		Loss of Nottawa T1		Loss of Nottawa T2		Loss of Waubaushene T5		Loss of SxE (New 230kV, run at 115 kV)					
	T4	Stayner lv kv	Nottawa T2	Nottawa lv kv	Nottawa T1	Nottawa lv kv	T6	Waub. Lv kv	ExN	SxN	NxM	Stayner lv kv	Stayner auto 2nd kv	MxO
2004	67%	46.5	32%	46.8	12%	46.4	64%	46.2	11%	16%	43%	46.0	123.6	45%
2005	67%	46.7	31%	46.8	12%	46.5	66%	46.1	11%	17%	44%	46.6	123.6	46%
2006	68%	46.0	31%	46.7	12%	46.4	67%	46.5	11%	17%	44%	46.4	123.1	47%
2007	67%	46.5	32%	47.2	12%	46.3	68%	46.3	12%	17%	44%	46.3	122.7	48%
2008	67%	46.4	35%	46.7	11%	46.4	70%	46.1	12%	17%	44%	46.4	123	49%
2009	67%	46.2	37%	46.8	10%	46.0	70%	46.5	12%	17%	44%	46.0	121.9	50%
2010	67%	46.1	38%	46.7	11%	46.2	72%	46.3	12%	17%	45%	46.5	121.8	50%
2011	68%	46.0	37%	46.9	10%	46.4	73%	46.2	12%	17%	45%	46.3	121.3	51%
2012	72%	46.3	46%	46.7	12%	46.0	74%	46.1	18%	20%	44%	46.3	113.6	52%
2013	72%	46.3	49%	46.9	11%	46.2	75%	46.5	19%	20%	45%	46.1	113.2	53%
2014	73%	46.1	46%	47.1	12%	46.4	76%	46.3	18%	20%	45%	46.2	**112.2**	54%

Note: Nottawa TS is the name of the "Collingwood Area" transmission station (for example: circuit Stayner by Nottawa is SxN) This is the preferred system plan from the 1991 Supply to Collingwood Environmental Study Report

Loss of SxN										Loss of E26 (WxE)			Loss of Meaford T1	
Essa T2 230/115 auto	Essa T1 230/115 auto	ExN	ExS	NxM	MxO	Stayner lv kv	Stayner hv kv	Nottawa lv kv	Nottawa hv kv	E27	Waub. Hv kv	Waub. Lv kv	T2	Meaford lv kv
57%	67.3%	7%	17%	21%	25%	46.4	124.7	46.4	125.6	20%	244.5	46.1	23%	46.1
50%	59.8%	7%	17%	21%	25%	46.6	125.3	46.3	125.5	21%	244.2	46.5	25%	46.1
48%	56.7%	7%	17%	21%	26%	46.0	125.3	46.2	125.1	21%	243.7	46.3	28%	46.4
49%	58.2%	7%	17%	21%	27%	46.5	125.0	46.0	124.7	21%	243.0	46.1	31%	46.2
51%	60.1%	8%	17%	22%	28%	46.4	124.6	46.2	125.0	22%	242.5	46.5	33%	46.0
51%	60.4%	7%	17%	22%	29%	46.3	124.4	46.4	124.1	22%	241.9	46.3	33%	46.4
51%	60.7%	7%	17%	22%	29%	46.2	124.1	46.2	123.8	22%	241.4	46.2	34%	46.3
51%	61.0%	7%	17%	22%	30%	46.1	123.9	46.1	123.5	22%	240.7	46.6	34%	46.2
53%	62.7%	8%	18%	23%	30%	46.4	123.4	46.9	125.0	22%	246.2	46.6	34%	46.4

53%	63.2%	9%	18%	24%	31%	46.2	123.0	46.9	126.1	22%	245.5	46.4	35%	46.4
53%	63.4%	9%	18%	24%	31%	46.7	122.8	47.0	125.1	23%	244.9	46.2	36%	46.2

Loss of ExN (new 230 kV)								Loss of NxM (115 kV)			Loss of MxO			Loss of Essa T1		
Essa T2 230/115 auto	Essa T1 230/115 auto	SxE	MxO	Nottawa lv kv	Nottawa hv lv	Stayner lv kv	Stayner lv kv	MxO	Meaford lv kv	Meaford hv kv	Essa T2 230/115 auto	NxM	ExS	Essa T2 230/115 auto	Essa 118 kv	Stayner hv kv
50.9%	60.3%	9%	41%	46.5	121.7	46.2	122.7	9%	46.1	122.6	58.2%	9%	18%	78.4%	124	124.1
44.5%	52.8%	9%	41%	46	122.1	46.4	123.1	9%	46	122.4	53.0%	10%	19%	68.2%	124.8	124.8
42.4%	50.2%	9%	42%	46.6	122	46.4	123.1	11%	46.4	122.1	51.4%	12%	19%	64.6%	125	124.9
44.0%	52.2%	9%	43%	46.4	121.6	46.2	122.7	11%	46.3	121.9	53.0%	13%	20%	66.7%	124.6	124.5
46.3%	54.9%	9%	44%	46.1	121	46	122.1	12%	46.1	121.6	54.9%	13%	20%	69.5%	124.2	124.3
46.6%	55.2%	9%	45%	46	120.8	46.6	122	12%	46.1	121.5	55.4%	14%	20%	70.4%	123.7	123.6
47.0%	55.8%	9%	45%	46.5	120.5	46.5	121.6	13%	46	121.4	55.9%	14%	20%	70.8%	123.5	123.4
47.5%	56.4%	9%	46%	46.3	120.2	46.3	121.4	13%	46	121.3	56.4%	14%	21%	71.2%	123.3	123.2
52.0%	61.6%	9%	46%	46.1	119.8	46	120.9	13%	46.7	121.7	56.7%	15%	20%	75.2%	123.3	122.3
52.6%	62.3%	9%	47%	45.9	119.4	46.4	120.6	13%	46.6	121.6	57.0%	15%	21%	75.2%	123.2	122.2
53.2%	63.0%	9%	47%	45.7	119.1	46.3	120.2	14%	46.6	121.5	57.9%	15%	21%	76.7%	122.6	121.5

- % values are a percentage of applicable equipment ratings
- voltages in kV
- **Planning Criteria Violation**

Appendix C: Results of Future Planning Consideration 2014 to 2024.

	TRANSFORMERS						LINES						
Plan	Loss of Midhurst T1 --> resulting flow on T2	Loss of Midhurst T3 --> resulting flow on T4	Loss of Barrie T1 --> resulting flow on T2	Loss of Stayner T3 --> resulting flow on T4	Loss of Meaford T1 --> resulting flow on T2	Loss of Waubaushene T5 --> resulting flow on T6	Loss of S2E	Loss of S2S - Stayner x Meaford	Loss of S2S - Meaford x Owen Sound	Loss of E3B or E4B	Loss of M6E	Loss of Minden x Coopflj	**Total Scored Points**
NORTH 1	95.0%	(4) voltage collapse – prefault flow 125% of Rate A	71.7%	62.6%	44.6%	95.0%	S3E --> 18%; 115 kV voltages look good (121kV+)	voltages good	can support Meaford load via Stayner & voltages good (120kV+)	E4B --> 49.7%	M7E →119% and overloads Midhurst Desn #2	Minden x CoopfljM7 - 54%	
Scored Points	3	1	3	5	5	3	5	5	5	5	1	5	**46**
NORTH 2	93.0%	(4) voltage collapse - prefault flow 125% of Rate A or 73% of Rate B	53.0%	65.0%; HV bus --> 116.0kV (requires LV cap)	46.0%	96.0%	S3E --> 36%; S2S (SxM) --> 39%; S2S (OxM) --> 49%; Meaford HV bus 118.4kV	Voltage good	Essa T1 --> 60%; Essa T2 --> 50%; Meaford HV bus 119.9kV	E4B --> 20.8%	M7E →118% and overloads Midhurst Desn #2 (124%); overloads Minden x Coopflj (96%)	Minden x CoopfljM7 - 57%	
Scored Points	3	1	5	3	5	3	3	5	3	5	1	5	**42**
NORTH 3	95.0%	(4) voltage collapse – prefault flow 125% of Rate A or 73% of Rate B	72.0%	51%; resulting flow on S3E: 39% (w/ LV cap)	46.3%	97.0%	Stayner HV bus: 120.5kV (added LV cap on 2nd Stayner LV bus); Meaford HV bus 121.0kV;flow on S3E: 29%	32% on S2E/S3E; Meaford HV bus 124.1kV	Meaford HV bus 125.2kV; flow on S2E: 41%; Stayner S2E HV bus 125.8kV (w/ LV cap) (caps required)	E4B --> 37.8%	M7E --> 117.4%; Midhurst T2 --> 91.7%; Midhurst T4 --> 131.0%; Minden x CoopfljM7 --> 102.3%	Minden x CoopfljM7 - 54%	
Scored Points	3	1	3	3	5	3	3	5	3	5	1	5	**40**

Plan	Loss of Barrie T1 --> resulting flow on T2	Loss of Alliston T5 --> resulting flow on T6	Loss of E3B --> resulting flow on E4B	Loss of E4B --> resulting flow on E3B	Loss of E8V --> resulting flow on E9V	Loss of E9V --> resulting flow on E9V	Total Scored Points
SOUTH A1	102% (reaches capacity in 2022)	105.0%	50.0%	72.0%	26%; Orangeville voltage: 236.2kV (2x245 MX Essa cap I/s)	29%; Orangeville voltage 237.5 kV 2x(245 MX Essa cap I/s)	
Scored Points	1	1	5	3	5	5	**20**
SOUTH A2	103% (reaches capacity in 2022)	74.0%	50.0%	72.0%	29%; Orangeville voltage: 232.2kV (2x245 MX Essa cap I/s)	31%; Orangeville voltage 233.1 kV (2x245 MX Essa cap I/s)	
Scored Points	1	3	5	3	5	5	**22**

Notes:

(1) Flow percentages of Rate B (10-day LTR for transformers, 15-min. LTR for lines) unless specified otherwise

(2) "--" indicates contingency was non-impactive or was the same as corresponding contingency (ie. effect of T3 loss on T4 = effect of T4 loss on T3

(3) These studies indicate that further relief for Midhurst TS is required sometime between 2014 and 2024.

(4) 5 points are awarded if all the following criteria are met:
- No additional facilities are required before 2024 AND
- Flows are less than 70 % of rating AND
- 115 kV voltages are greater than or equal to 120 kV

3 points are awarded under the following criteria:
- May require additional facilities before 2024 OR
- Flows are between 70-100 % of rating OR
- 115 kV voltages are between 113 kV and 120 kV

1 point is awarded if the following criteria is not met:
- Flows are greater than 100% OR
- 115 kV voltages are less then 113 kV

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Innisfil Hydro Distribution Systems Limited	**LICENCE NUMBER**	ED 2002-0520
NAME OF CONTACT	Laurie Ann Cooledge	**DOCID NUMBER**	EB-2008-0233
E-mail Address	laurriec@innisfilhydro.com		
VERSION NUMBER		**PHONE NUMBER**	705-431-6870
Date	15-Aug-08	**(extension)**	236

Account Description	**Account Number**	**Principal Amounts as of Dec-31 2007**	**Interest to Dec31-07**	**Interest Jan-1 to Dec31-08**	**Interest Jan1-09 to Apr30-09**	**Total Claim**
RSVA - Wholesale Market Service Charge	1580			$ -	$ -	$ -
RSVA - One-time Wholesale Market Service	1582			$ -	$ -	$ -
RSVA - Retail Transmission Network Charge	1584			$ -	$ -	$ -
RSVA - Retail Transmission Connection Charge	1586			$ -	$ -	$ -
RSVA - Power	1588/1589			$ -	$ -	$ -
Sub-Totals		$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets	1508	$ 153,077	$ 15,272	$ 5,128	$ 1,709	$ 175,186
Retail Cost Variance Account - Retail	1518			$ -	$ -	$ -
Retail Cost Variance Account - STR	1548			$ -	$ -	$ -
Smart Meters Revenue and Capital	1555			$ -	$ -	$ -
Smart Meter Expenses	1556			$ -	$ -	$ -
Low Voltage	1550	$ 229,974	$ 7,558	$ 7,704	$ 2,568	$ 247,804
Other Deferred Credits	2425			$ -	$ -	$ -
Sub-Totals		$ 383,051	$ 22,830	$ 12,832	$ 4,277	$ 422,991
Totals per column		$ 383,051	$ 22,830	$ 12,832	$ 4,277	$ 422,991

	Jan 1 08 - April 09
Annual interest rate:	3.35%

Enter the appropriate 2007 data in the cells below.
Once the data in the yellow fields on Sheet 1 has been entered, the relevant allocations will appear on Sheet 2.

2007 Data By Class	kW	kWhs	Customers	Transmiss Connect Revenue	Dx Revenue	Transmiss Chg per		# Connections
RESIDENTIAL CLASS		152,967,169	13,132	535,385	$ 5,126,937	0.0035	kWh	
GENERAL SERVICE <50 KW CLASS		28,694,771	831	91,823	$ 661,465	0.0032	kWh	
GENERAL SERVICE >50 KW NON TIME OF USE	118,203	40,322,203	72	150,130	$ 632,138	1.2701	kW	
GENERAL SERVICE >50 KW TIME OF USE								
STANDBY								
LARGE USER CLASS								
UNMETERED & SCATTERED LOADS		562,039	12	1,799	$ 24,078	0.0032	kWh	85
SENTINEL LIGHTS	349	125,854	188	350	$ 4,996	1.0023	kW	
STREET LIGHTING	4,157	1,497,459	5	4,081	$ 39,419	0.9818	kW	2588
Totals	122,709	224,169,495	14,240	783,568	$ 6,489,033			

Allocators	kW	kWhs	Cust. Num.'s	Transmiss Connect Revenue	Dx Revenue
RESIDENTIAL CLASS	0.0%	68.2%	92.2%	68.3%	79.0%
GENERAL SERVICE <50 KW CLASS	0.0%	12.8%	5.8%	11.7%	10.2%
GENERAL SERVICE >50 KW NON TIME OF USE	96.3%	18.0%	0.5%	19.2%	9.7%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%	0.0%
STANDBY	0.0%	0.0%	0.0%	0.0%	0.0%
LARGE USER CLASS	0.0%	0.0%	0.0%	0.0%	0.0%
UNMETERED & SCATTERED LOADS	0.0%	0.3%	0.1%	0.2%	0.4%
SENTINEL LIGHTS	0.3%	0.1%	1.3%	0.0%	0.1%
STREET LIGHTING	3.4%	0.7%	0.0%	0.5%	0.6%
Totals	100%	100%	100%	100%	100%

Deferral and Variance Accounts:	Decision Ref.#	Amount	ALLOCATOR	Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Standby	Large Users	Small Scattered Load	Sentinel Lighting	Street Lighting	Total
WMSC - Account 1580	2.0.35	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
One-Time WMSC - Account 1582	2.0.35	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Network - Account 1584	2.0.35	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Connection - Account 1586	2.0.35	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Power - Account 1588	2.0.35	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - RSVA		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Account 1508		$ 175,186	Distr Revenue	$ 138,414	$ 17,858	$ 17,066	$ -	$ -	$ -	$ 650	$ 135	$ 1,064	$ 175,186
Retail Cost Variance Account - Acct 1518		$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account (STR) Acct 1548		$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Low Voltage - Account 1550		$ 247,804	Transmiss Connect	$ 169,316	$ 29,039	$ 47,479	$ -		$ -	$ 569	$ 111	$ 1,291	$ 247,804
Other Deferred Credits - Acct 2425		$ -	Distr Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA, Variable		$ 422,991		$ 307,730	$ 46,897	$ 64,545	$ -	$ -	$ -	$ 1,219	$ 246	$ 2,355	$ 422,991
Smart Meters Revenue and Capital, 1555 (Fixed)		$ -	# of Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Expenses, 1556 (Fixed)		$ -	# of Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA Fixed		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total to be Recovered		$ 422,991		$ 307,730	$ 46,897	$ 64,545	$ -	$ -	$ -	$ 1,219	$ 246	$ 2,355	$ 422,991
Balance to be collected or refunded, Variable		$ 422,991		$ 307,730	$ 46,897	$ 64,545	$ -	$ -	$ -	$ 1,219	$ 246	$ 2,355	$ 422,991
Balance to be collected or refunded, Fixed		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Number of years for Variable	2												
Number of years for Fixed (Smart Meters)													
Balance to be collected or refunded per year, Variable		$ 211,495		$ 153,865	$ 23,448	$ 32,272	$ -	$ -	$ -	$ 609	$ 123	$ 1,177	$ 211,495
Balance to be collected or refunded per year, Fixed		#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

Class			Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Standby	Large Users	Scattered Load	Sentinel Lighting	Street Lighting
Deferral and Variance Account Rate Riders, Variable			$ 0.0010	$ 0.0008	$ 0.2730		$ -		$ 0.0011	$ 0.3517	$ 0.2832
Billing Determinants			kWh	kWh	kW	kW	kW	kW	kWh	kW	kW
Deferral and Variance Account Rate Riders, Fixed (per month)									$ -		$ -
Billing Determinants			# metered cust.	# metered cust.	# metered cust.			# metered cust.			
	Components of 2008 Riders:										
	Variable	RSVA	$ -	$ -	$ -				$ -	$ -	$ -
	Variable	Non RSVA	$ 0.0010	$ 0.0008	$ 0.2730				$ 0.0011	$ 0.3517	$ 0.2832
	Fixed, per month								$ -		$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Innisfil Hydro Distribution Systems Limited	**LICENCE NUMBER**	ED-2002-0520
NAME OF CONTACT	Laurie Ann Cooledge	**DOCID NUMBER**	EB-2008-0233
E-mail Address	laurriec@innisfilhydro.com		
VERSION NUMBER	v3.0	**PHONE NUMBER**	705-431-6870
Date	15-Aug-08	**(extension)**	236

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

		2005								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05 1**	**Transactions (additions) during 2005, excluding interest and adjustments 6**	**Transactions (reductions) during 2005, excluding interest and adjustments 6**	**Adjustments during 2005 - instructed by Board 2**	**Adjustments during 2005 - other 3**	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
RSVA - Wholesale Market Service Charge	1580	$ 351,401	$ 172,334				$ 523,735	$ 51,850	$ 28,189	$ 80,039
RSVA - One-time Wholesale Market Service	1582	$ 54,782	$ 33,773				$ 88,555	$ 4,989	$ 4,728	$ 9,717
RSVA - Retail Transmission Network Charge	1584	$ 261,155	$ (35,287)				$ 225,868	$ 46,311	$ 18,800	$ 65,111
RSVA - Retail Transmission Connection Charge	1586	$ 593,219	$ 289,606				$ 882,825	$ 37,566	$ 59,478	$ 97,044
Sub-Totals		$ 1,260,557	$ 460,426		$ -	$ -	$ 1,720,983	$ 140,716	$ 111,195	$ 251,911
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 17,792	$ 33,155				$ 50,947	$ 256	$ 2,152	$ 2,408
Other Regulatory Assets - Sub-Account - Pension Contributions	1508		$ 81,109				$ 81,109		$ 468	$ 468
Other Regulatory Assets - Sub-Account - Hydro One charges	1508		$ 22,949				$ 22,949		$ 105	$ 105
Other Regulatory Assets - Sub-Account - Other 7	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other 7	1508						$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 7,097		$ (2,484)			$ 4,613	$ 2,780	$ (704)	$ 2,076
Retail Cost Variance Account - STR	1548	$ 64,115		$ 7,880			$ 71,995	$ 7,456	$ 6,360	$ 13,816
Misc. Deferred Debits	1525	$ 41,093					$ 41,093	$ 3,904	$ 2,986	$ 6,890
LV Variance Account	1550						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter C	1555						$ -			$ -
Smart Meter OM&A Variance	1556						$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565		$ (112,210)				$ (112,210)			$ -
CDM Contra	1566		$ 112,210				$ 112,210			$ -
Qualifying Transition Costs 5	1570	$ 256,134	n/a	n/a	$ (25,608)		$ 230,526	$ 49,509	$ 11,785	$ 61,294
Pre-Market Opening Energy Variances Total 5	1571	$ 760,982	n/a	n/a			$ 760,982	$ 147,123	$ 55,260	$ 202,383
Extra-Ordinary Event Costs	1572						$ -			$ -
Deferred Rate Impact Amounts	1574						$ -			$ -
Other Deferred Credits	2425						$ -			$ -
Sub-Totals		$ 1,147,213	$ 137,213	$ 5,396	$ (25,608)	$ -	$ 1,264,214	$ 211,028	$ 78,412	$ 289,440
Deferred Payments in Lieu of Taxes	1562				see PILs reconciliation requested					
2006 PILs & Taxes Variance	1592				see PILs reconciliation requested					
Sub-Totals					see PILs reconciliation requested					
Total		$ 2,407,770	$ 597,639	$ 5,396	$ (25,608)	$ -	$ 2,985,197	$ 351,744	$ 189,607	$ 541,351
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account 8	1563				see PILs reconciliation requested					
RSVA - Power (including Global Adjustment)	1588	$ 544,361	$ (498,145)				$ 46,216	$ 22,670	$ 29,003	$ 51,673
RSVA - Power - Sub-Account - Global Adjustment 4	1588						$ -			$ -
Recovery of Regulatory Asset Balances	1590			$ (1,633,551)			$ (1,633,551)		$ (87,249)	$ (87,249)
		$ 2,952,131	$ 99,494	$ (1,628,155)	$ (25,608)	$ -	$ 1,397,862	$ 374,414	$ 131,361	$ 505,775
		$ 2,952,131								$ 1,903,637
										$ -

P:\Admin\IHDSL\OEB\2008 Filings\2009 Rate Application\Correspondance\Interrogatories\OEB\[Appendix D responses to OEB IR Q 7.1 Reg Accounts Continuity S

1 As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
2 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
2005 Adjustment instructed by the Board of $25,608 is the 10% transition costs write-off
3 Provide supporting statement indicating nature of this adjustments and periods they relate to
4 Not included in sub-total
5 Closed April 30, 2002
6 For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
7 Please describe "other" components of 1508 and add more component lines if necessary.
8 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
9 Interest projected on December 31, 2007 closing principal balance.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Innisfil Hydro Distribution Systems Limited
NAME OF CONTACT	Laurie Ann Cooledge
E-mail Address	laurriec@innisfilhydro.com
VERSION NUMBER	v3.0
Date	15-Aug-08

		2006										
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-06**	**Transactions (additions) during 2006, excluding interest and adjustments [6]**	**Transactions (reductions) during 2006, excluding interest and adjustments [6]**	**Adjustments during 2006 - instructed by Board [2]**	**Adjustments during 2006 - other [3]**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Principal Balance as of Dec-31-06**	**Opening Interest Amounts as of Jan-1-06**	**Interest Jan-1 to Dec31-06**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-06**
RSVA - Wholesale Market Service Charge	1580	$ 523,735	$ (258,393)				$ (351,401)	$ (86,059)	$ 80,039	$ 11,092	$ (85,819)	$ 5,312
RSVA - One-time Wholesale Market Service	1582	$ 88,555	$ 18,960				$ (54,782)	$ 52,733	$ 9,717	$ 3,202	$ (10,285)	$ 2,634
RSVA - Retail Transmission Network Charge	1584	$ 225,868	$ (168,096)				$ (187,382)	$ (129,610)	$ 65,111	$ 6,910	$ (72,684)	$ (663)
RSVA - Retail Transmission Connection Charge	1586	$ 882,825	$ 155,354				$ (901,506)	$ 136,673	$ 97,044	$ 26,166	$ (88,974)	$ 34,236
Sub-Totals		$ 1,720,983	$ (252,175)		$ -	$ -	$ (1,495,071)	$ (26,263)	$ 251,911	$ 47,370	$ (257,762)	$ 41,519
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 50,947	$ 6,764				$ (17,792)	$ 39,919	$ 2,408	$ 4,098	$ (1,410)	$ 5,096
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 81,109	$ 32,050					$ 113,159	$ 468	$ 2,668		$ 3,136
Other Regulatory Assets - Sub-Account - Hydro One charges	1508	$ 22,949	$ 3,825				$ (26,774)	$ -	$ 105	$ 461	$ (566)	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -						$ -	$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 4,613		$ (9,433)			$ (7,097)	$ (11,917)	$ 2,076	$ (176)	$ (2,780)	$ (880)
Retail Cost Variance Account - STR	1548	$ 71,995	$ 7,751				$ (64,115)	$ 15,631	$ 13,816	$ 2,140	$ (7,456)	$ 8,500
Misc. Deferred Debits	1525	$ 41,093					$ (41,093)	$ -	$ 6,890	$ 730	$ (7,620)	$ -
LV Variance Account	1550	$ -	$ 67,718					$ 67,718	$ -	$ 732		$ 732
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter C	1555	$ -						$ -	$ -			$ -
Smart Meter OM&A Variance	1556	$ -						$ -	$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ (112,210)	$ 45,183					$ (67,027)	$ -			$ -
CDM Contra	1566	$ 112,210		$ (45,183)				$ 67,027	$ -			$ -
Qualifying Transition Costs [5]	1570	$ 230,526	n/a	n/a			$ (230,526)	$ -	$ 61,294	$ 5,541	$ (66,835)	$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ 760,982	n/a	n/a			$ (760,982)	$ -	$ 202,383	$ 18,301	$ (220,684)	$ -
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 1,264,214	$ 163,291	$ (54,616)	$ -	$ -	$ (1,148,379)	$ 224,510	$ 289,440	$ 34,495	$ (307,351)	$ 16,584
Deferred Payments in Lieu of Taxes	1562						see PILs reconciliation requested					
2006 PILs & Taxes Variance	1592						see PILs reconciliation requested					
Sub-Totals							see PILs reconciliation requested					
Total		$ 2,985,197	$ (88,884)	$ (54,616)	$ -	$ -	$ (2,643,450)	$ 198,247	$ 541,351	$ 81,865	$ (565,113)	$ 58,103
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account [8]	1563						see PILs reconciliation requested					
RSVA - Power (including Global Adjustment)	1588	$ 46,216	$ 158,470				$ (544,361)	$ (339,675)	$ 51,673	$ 5,728	$ (75,291)	$ (17,890)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -						$ -	$ -			$ -
Recovery of Regulatory Asset Balances	1590	$ (1,633,551)		$ (346,721)			$ 3,187,811	$ 1,207,539	$ (87,249)	$ (655,112)	$ 640,404	$ (101,957)
		$ 1,397,862	$ 69,586	$ (401,337)	$ -	$ -	$ -	$ 1,066,111	$ 505,775	$ (567,519)	$ -	$ (61,744)
											$ -	$ 1,004,367
												$ -

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SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Innisfil Hydro Distribution Systems Limited
NAME OF CONTACT	Laurie Ann Cooledge
E-mail Address	laurriec@innisfilhydro.com
VERSION NUMBER	v3.0
Date	15-Aug-08

Account Description	**Account Number**	**2007** Opening Principal Amounts as of Jan-1-07	Transactions (additions) during 2007, excluding interest and adjustments [6]	Transactions (reductions) during 2007, excluding interest and adjustments [6]	Adjustments during 2007 - instructed by Board [2]	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec31-07	Closing Interest Amounts as of Dec-31-07
RSVA - Wholesale Market Service Charge	1580	$ (86,059)	$ (230,009)				$ (316,068)	$ 5,312	$ (8,532)	$ (3,220)
RSVA - One-time Wholesale Market Service	1582	$ 52,733	$ 7,710				$ 60,443	$ 2,634	$ 2,673	$ 5,307
RSVA - Retail Transmission Network Charge	1584	$ (129,610)	$ (137,945)				$ (267,555)	$ (663)	$ (8,956)	$ (9,619)
RSVA - Retail Transmission Connection Charge	1586	$ 136,673	$ 252,800				$ 389,473	$ 34,236	$ 12,614	$ 46,850
Sub-Totals		$ (26,263)	$ (107,444)		$ -	$ -	$ (133,707)	$ 41,519	$ (2,201)	$ 39,318
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 39,919					$ 39,919	$ 5,096	$ 5,151	$ 10,247
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 113,159					$ 113,159	$ 3,136	$ 1,888	$ 5,024
Other Regulatory Assets - Sub-Account - Hydro One charges	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ (11,917)		$ (4,767)			$ (16,684)	$ (880)	$ (604)	$ (1,484)
Retail Cost Variance Account - STR	1548	$ 15,631	$ 10,534				$ 26,165	$ 8,500	$ 895	$ 9,395
Misc. Deferred Debits	1525	$ -					$ -	$ -		$ -
LV Variance Account	1550	$ 67,718	$ 162,256				$ 229,974	$ 732	$ 6,826	$ 7,558
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ 16,301				$ 16,301	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter C	1555	$ -					$ -	$ -		$ -
Smart Meter OM&A Variance	1556	$ -					$ -	$ -		$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ (67,027)	$ 67,027				$ -	$ -		$ -
CDM Contra	1566	$ 67,027		$ (67,027)			$ -	$ -		$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a			$ -	$ -		$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Sub-Totals		$ 224,510	$ 256,118	$ (71,794)	$ -	$ -	$ 408,834	$ 16,584	$ 14,156	$ 30,740
Deferred Payments in Lieu of Taxes	1562				see PILs reconciliation requested					
2006 PILs & Taxes Variance	1592				see PILs reconciliation requested					
Sub-Totals					see PILs reconciliation requested					
Total		$ 198,247	$ 148,674	$ (71,794)	$ -	$ -	$ 275,127	$ 58,103	$ 11,955	$ 70,058
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [8]	1563				see PILs reconciliation requested					
RSVA - Power (including Global Adjustment)	1588	$ (339,675)	$ 831,709				$ 492,034	$ (17,890)	$ 232	$ (17,658)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -					$ -	$ -		$ -
Recovery of Regulatory Asset Balances	1590	$ 1,207,539		$ (796,906)			$ 410,633	$ (101,957)	$ (11,005)	$ (112,962)
		$ 1,066,111	$ 980,383	$ (868,700)	$ -	$ -	$ 1,177,794	$ (61,744)	$ 1,182	$ (60,562)
										$ 1,117,232

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SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Innisfil Hydro Distribution Systems Limited
NAME OF CONTACT	Laurie Ann Cooledge
E-mail Address	laurriec@innisfilhydro.com
VERSION NUMBER	v3.0
Date	15-Aug-08

Account Description	**Account Number**	**Projected Interest on Dec 31 -07 balance from Jan 1, 2008 to Dec 31, 2008 [9]**	**Projected Interest on Dec 31 -07 balance from Jan 1, 2009 to April 30, 2009 [9]**	**Claim before Forecasted Transactions**	**Forecasted Transactions, Excluding Interest from Jan 1, 2008 to Dec 31, 2008**	**Forecasted Transactions, Excluding Interest from Jan 1, 2009 to April 30, 2009**	**Projected Interest from Jan 1, 2008 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to December 31, 2008**	**Projected Interest from Jan 1, 2009 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2009 to April 30, 2009**	**Total Claim**
RSVA - Wholesale Market Service Charge	1580			$ (319,288)					$ (319,288)
RSVA - One-time Wholesale Market Service	1582			$ 65,750					$ 65,750
RSVA - Retail Transmission Network Charge	1584			$ (277,174)					$ (277,174)
RSVA - Retail Transmission Connection Charge	1586			$ 436,323					$ 436,323
Sub-Totals		$ -	$ -	$ (94,389)	$ -	$ -	$ -	$ -	$ (94,389)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 1,337	$ 446	$ 51,949					$ 51,949
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 3,791	$ 1,264	$ 123,237					$ 123,237
Other Regulatory Assets - Sub-Account - Hydro One charges	1508			$ -					$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -					$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -					$ -
Retail Cost Variance Account - Retail	1518			$ (18,168)					$ (18,168)
Retail Cost Variance Account - STR	1548			$ 35,560					$ 35,560
Misc. Deferred Debits	1525			$ -					$ -
LV Variance Account	1550	$ 7,704	$ 2,568	$ 247,804					$ 247,804
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555			$ 16,301					$ 16,301
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555			$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter C	1555			$ -					$ -
Smart Meter OM&A Variance	1556			$ -					$ -
Conservation and Demand Management Expenditures and Recoveries	1565			$ -					$ -
CDM Contra	1566			$ -					$ -
Qualifying Transition Costs [5]	1570			$ -					$ -
Pre-Market Opening Energy Variances Total [5]	1571			$ -					$ -
Extra-Ordinary Event Costs	1572			$ -					$ -
Deferred Rate Impact Amounts	1574			$ -					$ -
Other Deferred Credits	2425			$ -					$ -
Sub-Totals		$ 12,832	$ 4,277	$ 456,684	$ -	$ -	$ -	$ -	$ 456,684
Deferred Payments in Lieu of Taxes	1562								
2006 PILs & Taxes Variance	1592								
Sub-Totals				$ -					$ -
Total		$ 12,832	$ 4,277	$ 362,295	$ -	$ -	$ -	$ -	$ 362,295
The following is not included in the total claim but is included on a memo basis:									
Deferred PILs Contra Account [8]	1563								
RSVA - Power (including Global Adjustment)	1588			$ 474,376					$ 474,376
RSVA - Power - Sub-Account - Global Adjustment [4]	1588			$ -					$ -
Recovery of Regulatory Asset Balances	1590			$ 297,671					$ 297,671
		$ 12,832	$ 4,277	$ 1,134,342					$ 1,134,342

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2006 COST ALLOCATION INFORMATION FILING

Innisfil Hydro Distribution Systems Limited

EB-2005-0382 EB-2006-0247

Monday, January 15, 2007

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$4.73	$11.79	$85.48	$0.31	$0.54	$14.68
Customer Unit Cost per month - Directly Related	$7.12	$16.84	$125.81	$0.48	$0.85	$23.13
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$20.12	$26.65	$132.80	$15.65	$15.93	$31.83
Fixed Charge per approved 2006 EDR	$19.41	$36.55	$357.94	$0.66	$1.33	$19.94
Current Fixed charge vs avoided cost	410%	310%	419%	211%	245%	136%

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	7	8	9
	Total	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
General Plant - Gross Assets	$3,054,045	$2,381,266	$205,881	$193,107	$241,042	$19,129	$13,620
General Plant - Accumulated Depreciation	($1,407,416)	($1,097,375)	($94,877)	($88,991)	($111,081)	($8,815)	($6,277)
General Plant - Net Fixed Assets	$1,646,629	$1,283,891	$111,003	$104,116	$129,961	$10,314	$7,343
General Plant - Depreciation	$226,347	$176,485	$15,259	$14,312	$17,865	$1,418	$1,009
Total Net Fixed Assets Excluding General Plant	$15,324,462	$11,935,502	$1,053,964	$994,406	$1,179,853	$93,655	$67,083
Total Administration and General Expense	$922,355	$727,275	$71,853	$60,937	$43,727	$3,770	$14,793
Total O&M	$1,756,173	$1,385,248	$137,360	$116,143	$81,550	$7,061	$28,812

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Distribution Plant							
1860	Meters	$1,712,130	$1,163,290	$372,102	$176,738	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($987,601)	($671,016)	($214,638)	($101,947)	$0	$0	$0
	Meter Net Fixed Assets	**$724,529**	**$492,274**	**$157,464**	**$74,791**	**$0**	**$0**	**$0**
	Misc Revenue							
4082	Retail Services Revenues	($13,345)	($11,013)	($1,340)	($450)	($18)	($14)	($509)
4084	Service Transaction Requests (STR) Revenues	($40)	($33)	($4)	($1)	($0)	($0)	($2)
4090	Electric Services Incidental to Energy Sales	($42,122)	($34,763)	($4,231)	($1,421)	($58)	($44)	($1,605)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($71,282)	($59,105)	($6,898)	($4,863)	($41)	$0	($374)
	Sub-total	*($126,789)*	*($104,915)*	*($12,474)*	*($6,736)*	*($117)*	*($57)*	*($2,489)*
	Operation							
5065	Meter Expense	$34,732	$23,599	$7,548	$3,585	$0	$0	$0
5070	Customer Premises - Operation Labour	$46,752	$36,737	$2,236	$215	$6,695	$531	$339
5075	Customer Premises - Materials and Expenses	$8,976	$7,053	$429	$41	$1,285	$102	$65
	Sub-total	*$90,461*	*$67,389*	*$10,213*	*$3,841*	*$7,980*	*$632*	*$404*
	Maintenance							
5175	Maintenance of Meters	$10,400	$7,066	$2,260	$1,074	$0	$0	$0
	Billing and Collection							
5310	Meter Reading Expense	$141,809	$94,933	$7,915	$38,961	$0	$0	$0
5315	Customer Billing	$327,243	$270,076	$32,869	$11,042	$448	$339	$12,470
5320	Collecting	$268,481	$221,579	$26,967	$9,059	$367	$278	$10,231
5325	Collecting- Cash Over and Short	$40	$33	$4	$1	$0	$0	$2
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
	Sub-total	$737,574	$586,621	$67,756	$59,063	$815	$617	$22,702
	Total Operation, Maintenance and Billing	$838,435	$661,076	$80,230	$63,978	$8,795	$1,250	$23,107
	Amortization Expense - Meters	$69,476	$47,205	$15,099	$7,172	$0	$0	$0
	Allocated PILs	$32,542	$22,094	$7,082	$3,366	$0	$0	$0
	Allocated Debt Return	$38,470	$26,119	$8,372	$3,979	$0	$0	$0
	Allocated Equity Return	$37,675	$25,579	$8,199	$3,896	$0	$0	$0
	Total	**$889,808**	**$677,159**	**$106,508**	**$75,654**	**$8,679**	**$1,192**	**$20,618**

Ontario

2006 COST ALLOCATION INFORMATION FILING
Innisfil Hydro Distribution Systems Limited
EB-2005-0382 EB-2006-0247

Monday, January 15, 2007

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$6,247,362	$4,950,149	$594,226	$626,104	$35,444	$5,293	$36,146
mi	Miscellaneous Revenue (mi)	$438,862	$359,266	$41,635	$19,415	$5,760	$731	$12,054
	Total Revenue	**$6,686,224**	**$5,309,415**	**$635,861**	**$645,519**	**$41,204**	**$6,024**	**$48,200**
	Expenses							
di	Distribution Costs (di)	$846,527	$664,040	$50,216	$49,770	$72,695	$5,766	$4,040
cu	Customer Related Costs (cu)	$909,647	$721,208	$87,144	$66,373	$8,855	$1,295	$24,772
ad	General and Administration (ad)	$922,355	$727,275	$71,853	$60,937	$43,727	$3,770	$14,793
dep	Depreciation and Amortization (dep)	$1,454,453	$1,130,845	$101,357	$92,189	$114,549	$9,085	$6,429
INPUT	PILs (INPUT)	$761,785	$593,318	$52,393	$49,432	$58,651	$4,656	$3,335
INT	Interest	$900,562	$701,405	$61,938	$58,438	$69,336	$5,504	$3,942
	Total Expenses	**$5,795,328**	**$4,538,092**	**$424,900**	**$377,139**	**$367,812**	**$30,075**	**$57,311**
	Direct Allocation	**$8,954**	**$0**	**$0**	**$8,954**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$881,942	$686,903	$60,657	$57,229	$67,902	$5,390	$3,861
	Revenue Requirement (includes NI)	$6,686,224	$5,224,995	$485,557	$443,322	$435,714	$35,465	$61,172
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$34,228,605	$26,619,017	$2,389,255	$2,238,785	$2,625,035	$208,256	$148,257
gp	General Plant - Gross	$3,054,045	$2,381,266	$205,881	$193,107	$241,042	$19,129	$13,620
accum dep	Accumulated Depreciation	($18,087,072)	($14,033,321)	($1,301,114)	($1,218,156)	($1,351,055)	($107,153)	($76,272)
co	Capital Contribution	($2,224,487)	($1,747,569)	($129,054)	($115,214)	($205,208)	($16,264)	($11,179)
	Total Net Plant	**$16,971,092**	**$13,219,393**	**$1,164,967**	**$1,098,522**	**$1,309,814**	**$103,968**	**$74,426**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$14,524,264	$10,092,480	$1,674,425	$2,619,727	$80,158	$9,336	$48,138
	OM&A Expenses	$2,678,528	$2,112,523	$209,213	$177,080	$125,277	$10,831	$43,605
	Directly Allocated Expenses	$8,954	$0	$0	$8,954	$0	$0	$0
	Subtotal	***$17,211,746***	***$12,205,003***	***$1,883,637***	***$2,805,761***	***$205,434***	***$20,167***	***$91,743***
	Working Capital	**$2,581,762**	**$1,830,750**	**$282,546**	**$420,864**	**$30,815**	**$3,025**	**$13,762**
	Total Rate Base	**$19,552,854**	**$15,050,144**	**$1,447,513**	**$1,519,387**	**$1,340,629**	**$106,993**	**$88,188**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$9,776,427**	**$7,525,072**	**$723,757**	**$759,693**	**$670,314**	**$53,497**	**$44,094**
	Net Income on Allocated Assets	**$881,941**	**$771,324**	**$210,961**	**$259,426**	**($326,608)**	**($24,051)**	**($9,111)**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$881,941**	**$771,324**	**$210,961**	**$259,426**	**($326,608)**	**($24,051)**	**($9,111)**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	**100.00%**	101.62%	130.95%	145.61%	9.46%	16.99%	78.80%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($1)**	$84,420	$150,304	$202,197	($394,510)	($29,441)	($12,971)
			1.6%	23.6%	31.3%	-957.5%	-488.7%	-26.9%
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.02%	10.25%	29.15%	34.15%	-48.72%	-44.96%	-20.66%