Parry Sound Power

2009 EDR Application

EB-2008-0240

Submitted: 18 August, 2008

PARRY SOUND POWER
125 WILLIAM STREET,
PARRY SOUND, ONTARIO P2A 1V9

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Application

ONTARIO ENERGY BOARD

IN THE MATTER OF THE Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, S.O 1998, c 15;

AND IN THE MATTER OF an Application by Parry Sound Power Corporation to the Ontario Energy Board by an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2009;

APPLICATION

Introduction

The Applicant is Parry Sound Power Corporation (referred to in this Application as PSP"). PSP is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Town of Parry Sound.

PSP hereby applies to the Ontario Energy Board (the "OEB") pursuant to section 78 of the Ontario Energy Board Act, 1998 as amended (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2009.

PSP followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated November 14, 2006 (the "Filing Requirements") in preparing this Application.

Proposed Distribution Rates and Other Charges

The Schedule of Rates and Charges proposed in this Application is identified in Exhibit 1, Tab 1, Schedule 5 and the material being filed in support of this Applications sets out PSP's approach to its 2009 distribution rates and charges.

Proposed Effective Date of Rate Order

PSP requests that the OEB make its Rate Order effective May 1, 2009 in accordance with the Filing Requirements. PSP requests, that if for any reason final rates are not approved and effective May 1, 2009 that interim rates be approved effective May 1, 2009 until final rates are approved by the Board. PSP requests the interim rates would be the current approved rates.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

PSP submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

- the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;
- the proposed rates are necessary to recover prudently incurred costs and to meet PSP's Market Based Return ("MBRR"), Debt Rate and Payments in Lieu of Taxes ("PILS") requirements;
- there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by PSP or the implementation of any other mitigation measures.

Relief Sought

PSP applies for an Order or Orders approving the proposed distribution rates and other charges set out in this Application as just and reasonable rates and charges pursuant to section 78 of the OEB Act, to be effective May 1, 2009, or as soon as possible thereafter.

DATED at Parry Sound, Ontario this 18th day of August , 2008

Parry Sound Power Corporation

F. Miles Thompson

Miles Thompson

Financial Officer

Summary of Application

Purpose and Need

PSP self-nominated for 2009 rebasing. PSP continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. PSP capital expenditure includes upgrade and streamlining work to our primary feeders, secondary upgrades as well as transformer upgrades. OEB approval of PSP's smart meter plan is in process and therefore is not included in our 2009 application. Once PSP's smart meter plan is approved by the OEB, PSP will be submitting an application to permit recovery of its 2009 and 2010 smart meter capital costs outside of this application. PSP's forecasts also include increases in OM&A Expenses which reflect increases in employees, regulatory costs and other expenses.

PSP's revenue requirement for 2009 contemplates the recovery of its costs of providing distribution service; its permitted Return on Equity and the funds necessary to service its debt (based on the OEB's deemed debt/equity rates which is subject to adjustment this year to move it toward the OEB-mandated 60% debt/40% equity) and its Payments in Lieu of Taxes ("PILS"). When its forecasted customers and volumes for 2009 are taken into account, PSP estimates that its present rates will produce a deficiency in distribution revenue of $133,170 for the 2009 Test Year. PSP therefore seeks the Board's approval to revise its rates applicable to its distribution of electricity.

Through this Application, PSP seeks to recover the Revenue Deficiency arising from changes in OM&A, Amortization, Rate of Return and PILS. PSP seeks to recover the balances of Deferral and Variance Accounts in the amount of $187,563 over a three year period or $62,521 in this application. PSP seeks to recover $1.00 as a rate rider per month per residential and general service customers to assist with the mitigation of costs associated with the smart metering infrastructure.

PSP has been assisted in preparing this application by Elenchus Research Associates who provided the model used in the determination of just and reasonable 2009 Distribution Rates. PSP has based this Application on its forecasted results for the 2009 Test Year. As required by the OEB, PSP is also presenting the historical actual information for fiscal 2006 and 2007; information for the 2008 Bridge Year and 2009 Test Year.

Timing

The financial information supporting the Test Year for this Application will be PSP's fiscal year ending December 31, 2009 (the "2009 Test Year"). However, this information will be used to set rates for the period May 1, 2009 to April 30, 2010. The Test Year revenue requirement is that forecast by PSP as needed to enable it to recover the amounts discussed for fiscal 2009.

Current Rates Schedule

Residential

Service Charge	$	16.95
Distribution Volumetric Rate	$/kWh	0.0143
Regulatory Asset Recovery	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.41
Distribution Volumetric Rate	$/kWh	0.0110
Regulatory Asset Recovery	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	170.55
Distribution Volumetric Rate	$/kW	3.8105
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.5528
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5353
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.8479
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.8623
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	8.92
Distribution Volumetric Rate	$/kWh	0.0530
Regulatory Asset Recovery	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	1.74
Distribution Volumetric Rate	$/kW	7.0713
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.1770
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2117
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.41
Distribution Volumetric Rate	$/kW	4.4250
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.1711
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1868
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	15
Account history	$	15
Credit reference/credit check (plus credit agency costs	$	15
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30
Returned Cheque (plus bank charges)	$	15

Charge to certify cheques	$	15
Legal letter charge	$	15
Special meter reads	$	30
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30
Non-Payment of Account		
Late Payment - per month	%	1.5
Late Payment - per annum	%	19.56
Collection of account charge – no disconnect	$	30
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65
Disconnect/Reconnect Charge - At pole During Regular Hours	$	185
Install/Remove load control device – during regular hours	$	65
Service call – customer owned equipment	$	30
Temporary Service install & remove – overhead – no transformer	$	500
Temporary Service install & remove – underground – no transformer	$	300
Temporary Service install & remove – overhead –with transformer	$	1000
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.6
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0586
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0480
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Proposed Rates Schedule

Parry Sound Power has chosen to follow cost allocation guidelines, OEB direction and most importantly our customer's needs in setting the proposed 2009 rates. PSP's proposed rates are listed below.

Residential

Service Charge	$	18.88
Distribution Volumetric Rate	$/kWh	0.0173
Regulatory Asset Recovery	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Les Than 50 kW

Service Charge	$	32.33
Distribution Volumetric Rate	$/kWh	0.0153
Regulatory Asset Recovery	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	154.03
Distribution Volumetric Rate	$/kW	3.6620
Regulatory Asset Recovery	$/kW	0.2724
Retail Transmission Rate – Network Service Rate	$/kW	1.5528
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5353
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010

Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge	$	13.37
Distribution Volumetric Rate	$/kWh	0.0872
Regulatory Asset Recovery	$/kWh	0.0009
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	3.99
Distribution Volumetric Rate	$/kW	18.6082
Regulatory Asset Recovery	$/kW	0.2925
Retail Transmission Rate – Network Service Rate	$/kW	1.1770
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2117
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.25
Distribution Volumetric Rate	$/kW	15.9668
Regulatory Asset Recovery	$/kW	0.2440
Retail Transmission Rate – Network Service Rate	$/kW	1.1711
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1868
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Arrears Certificate	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque charge (plus bank charges)	$	15.00

Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge / change of occupancy charge	$	30.00
Special Meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Late Payment - per month	%	1.50
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Install / remove load control device – during regular hours	$	65.00
Service call – customer-owned equipment	$	30.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Service Transaction Request -- request fee (per request)	$	0.25

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor -Secondary Metered Customer < 5,000 KW	1.0586
Total Loss Factor -Secondary Metered Customer > 5,000 KW	
Total Loss Factor-Primary Metered Customer <5,000 KW	1.0480
Total Loss Factor-Primary Metered Customer >5,000 KW	

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Summary of Bill Impact

To achieve the revenue to cost ratio on our Residential customers, PSP is proposing a Test Year Fixed Rate of $18.88 and a Variable Rate of $0.0173 per kWh. The overall bill impact to our residential customers at 1,000 kWh per month is 5.3%.

Table 1 Residential Bill Impact

1,000 kWh's	**Metric**	**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
		Volume	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$16.95			$18.88	$1.93	11.4%
Distribution	kWh	1,000	$0.0143	$14.30	1,000	$0.0173	$17.30	$3.00	21.0%
Sub-Total (Distribution)				**$31.25**			**$36.18**	**$4.93**	**15.8%**
Deferral/Variance Dispositions	kWh	1,000			1,000	$0.0007	$0.70	$0.70	
Electricity (Commodity)	kWh	1,059	RPP-Winter	$53.46	1,059	RPP-Winter	$53.46		
Transmission - Network	kWh	1,059	$0.0042	$4.45	1,059	$0.0042	$4.45		
Transmission - Connection	kWh	1,059	$0.0043	$4.55	1,059	$0.0043	$4.55		
Wholesale Market Service	kWh	1,059	$0.0052	$5.50	1,059	$0.0052	$5.50		
Rural Rate Protection	kWh	1,059	$0.0010	$1.06	1,059	$0.0010	$1.06		
Debt Retirement Charge	kWh	1,000	$0.0065	$6.50	1,000	$0.0065	$6.50		
TOTAL BILL				**$106.77**			**$112.40**	**$5.63**	**5.3%**

To achieve the revenue to cost ratio on our GS< 50 customers PSP is proposing a Test Year Fixed Rate of $32.33 and Variable Rate of $0.0153 per kWh. The overall bill impact to our GS<50 customers at 2,000 kWh per month is 8.2%

Table 2 General Service (GS < 50) Bill Impact

kWh's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$25.41			$32.33	$6.92	27.2%
Distribution	kWh	2,000	$0.0110	$22.00	2,000	$0.0153	$30.60	$8.60	39.1%
Sub-Total (Distribution)				**$47.41**			**$62.93**	**$15.52**	**32.7%**
Deferral/Variance Dispositions	kWh	2,000			2,000	$0.0007	$1.40	$1.40	
Electricity (Commodity)	kWh	2,117	RPP-Winter	$115.91	2,117	RPP-Winter	$115.91		
Transmission - Network	kWh	2,117	$0.0038	$8.05	2,117	$0.0038	$8.05		
Transmission - Connection	kWh	2,117	$0.0039	$8.26	2,117	$0.0039	$8.26		
Wholesale Market Service	kWh	2,117	$0.0052	$11.01	2,117	$0.0052	$11.01		
Rural Rate Protection	kWh	2,117	$0.0010	$2.12	2,117	$0.0010	$2.12		
Debt Retirement Charge	kWh	2,000	$0.0065	$13.00	2,000	$0.0065	$13.00		
TOTAL BILL				**$205.76**			**$222.68**	**$16.92**	**8.2%**

To achieve the revenue to cost ratio on our GS> 50 customers PSP is proposing a Test Year Fixed Rate of $154.03 which is a decrease from the 2008 rate of $170.55 and Variable Rate of $3.6620 per kW, which represents a decrease from the approved 2008 rate of $3.8105 per kW. The overall bill impact to our GS>50 customers at 150,000 kWh and 250 kW per month is 0.1%.

Table 3 General Service (GS > 50) Bill Impact

150,000 kWh's 250 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
				$170.55			$154.03	($16.52)	(9.7%)
Distribution	kW	250	$3.8105	$952.63	250	$3.6620	$915.50	($37.13)	(3.9%)
Sub-Total (Distribution)				**$1,123.18**			**$1,069.53**	**($53.65)**	**(4.8%)**
Deferral/Variance Dispositions	kW	250			250	$0.2724	$68.10	$68.10	
Electricity (Commodity)	kWh	158,790	$0.0545	$8,654.06	158,790	$0.0545	$8,654.06		
Transmission - Network	kW	250	$1.5528	$388.20	250	$1.5528	$388.20		
Transmission - Connection	kW	250	$1.5353	$383.83	250	$1.5353	$383.83		
Wholesale Market Service	kWh	158,790	$0.0052	$825.71	158,790	$0.0052	$825.71		
Rural Rate Protection	kWh	158,790	$0.0010	$158.79	158,790	$0.0010	$158.79		
Debt Retirement Charge	kWh	150,000	$0.0065	$975.00	150,000	$0.0065	$975.00		
TOTAL BILL				**$12,508.77**			**$12,523.22**	**$14.46**	**0.1%**

To achieve the revenue to cost ratio on our Unmetered Scattered Load customers PSP is proposing a Test Year Fixed Rate of $ 13.37and Variable Rate of $0.0872 per kWh. The overall bill impact to our unmetered scattered load customers at 650 kWh is 29.8%.

Table 4 Unmetered Scattered Load Bill Impact

650 kWh's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$8.92			$13.37	$4.45	49.9%
Distribution	kWh	650	$0.0530	$34.45	650	$0.0872	$56.68	$22.23	64.53%
Sub-Total (Distribution)				**$43.37**			**$70.05**	**$26.68**	**61.5%**
Deferral/Variance Dispositions	kWh	650	$0.0000	$0.00	650	$0.0009	$0.59	$0.59	0.0%
Electricity (Commodity)	kWh	688	RPP-Winter	$34.40	688	RPP-Winter	$34.40	$0.00	0.0%
Transmission - Network	kWh	688	$0.0038	$2.61	688	$0.0038	$2.61	$0.00	0.0%
Transmission - Connection	kWh	688	$0.0039	$2.68	688	$0.0039	$2.68	$0.00	0.0%
Wholesale Market Service	kWh	688	$0.0052	$3.58	688	$0.0052	$3.58	$0.00	0.0%
Rural Rate Protection	kWh	688	$0.0010	$0.69	688	$0.0010	$0.69	$0.00	0.0%
Debt Retirement Charge	kWh	650	$0.0065	$4.23	650	$0.0065	$4.23	$0.00	0.0%
TOTAL BILL				**$91.56**			**$118.83**	**$27.27**	**29.8%**

To achieve the revenue to cost ratio on our Sentinel Light customers PSP is proposing a Test Year Fixed Rate of $3.99 and Variable Rate of $18.6082 per kW. The overall bill impact to our Sentinel Light customers at 88 kWh at 0.23 kW is 51.0%.

Table 5 Sentinel Light Bill Impact

88 kWh's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
0.23 kW's		Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$1.74			$3.99	$2.25	>100%
Distribution	kW	0.23	$7.0713	$1.61	0.23	$18.6082	$4.24	$2.63	>100%
Sub-Total (Distribution)				**$3.34**			**$8.23**	**$4.88**	**>100%**
Deferral/Variance Dispositions	kW	0.23	$0.0000	$0.00	0.23	$0.2922	$0.07	$0.07	0.0%
Electricity (Commodity)	kWh	93	RPP-Summer	$4.66	93	RPP-Summer	$4.66	$0.00	0.0%
Transmission – Network	kW	0.23	$1.1770	$0.27	0.23	$1.1770	$0.27	$0.00	0.0%
Transmission – Connection	kW	0.23	$1.2117	$0.28	0.23	$1.2117	$0.28	$0.00	0.0%
Wholesale Market Service	kWh	93	$0.0052	$0.48	93	$0.0052	$0.48	$0.00	0.0%
Rural Rate Protection	kWh	93	$0.0010	$0.09	93	$0.0010	$0.09	$0.00	0.0%
Debt Retirement Charge	kWh	88	$0.0065	$0.57	88	$0.0065	$0.57	$0.00	0.0%
TOTAL BILL				**$9.70**			**$14.65**	**$4.95**	**51.0%**

To achieve the revenue to cost ratio and mitigate bill impacts on our Street Light customers PSP is proposing a Test Year Fixed Rate of $1.25 and Variable Rate of $15.9668 per kW. The overall bill impact to our Street Light customers (one light) at 72 kWh at 0.20 kW is 49.1%. PSP has moved the street light rate 50% closer to the lower end of the OEB recommended revenue to cost ratio bands. Management is of the opinion that moving street light customers all the way in one year would cause too large of a bill impact. PSP proposes to move the 70% revenue to cost ratio over the two year IRM period following the cost of service application.

Table 6 Street Light Bill Impact

72 Kwh	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
0.20 kW		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$0.41			$1.25	$0.84	>100%
Distribution	kW	0.20	$4.4250	$0.89	0.20	$15.9668	$3.21	$2.32	>100%
Sub-Total (Distribution)				**$1.30**			**$4.46**	**$3.16**	**>100%**
Deferral/Variance Dispositions	kW	0.20	$0.0000	$0.00	0.20	$0.2439	$0.00	$0.05	0.0%
Electricity (Commodity)	kWh	76	RPP-Summer	$3.81	76	RPP-Summer	$3.81	$0.00	0.0%
Transmission - Network	kW	0.20	$1.1711	$0.24	0.20	$1.1711	$0.24	$0.00	0.0%
Transmission – Connection	kW	0.20	$1.1868	$0.24	0.20	$1.1868	$0.24	$0.00	0.0%
Wholesale Market Service	kWh	76	$0.0052	$0.40	76	$0.0052	$0.40	$0.00	0.0%
Rural Rate Protection	kWh	76	$0.0010	$0.08	76	$0.0010	$0.08	$0.00	0.0%
Debt Retirement Charge	kWh	72	$0.0065	$0.47	72	$0.0065	$0.47	$0.00	0.0%
TOTAL BILL				**$6.54**			**$9.75**	**$3.21**	**49.1%**

Overall Parry Sound Power's proposed rates are focused on our revenue requirement and moving closer to the OEB revenue to cost ratios. Management has determined that the bill impacts are reasonable, given the need to move the revenue-to-cost ratios for all acceptable in nature.

List of Issues

There are a number of issues that, although they may not all be defined as major, are anticipated to be examined in this case. These issues are listed below:

Capital Structure

PSP's current deemed capital structure is 53.3% debt/46.7% equity. In its December 20, 2006 Report on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors, the OEB mandated a shift to a 60% debt/40% equity ratio for all distributors. Consequently, PSP is requesting a change in its deemed capital structure Specifically, PSP is requesting a decrease in the deemed equity ratio from 46.7% to 43.3% consistent with the 3 year phase-in of PSP's capital structure from 50% to 40% equity.

Return on Equity

In addition, PSP has assumed a return on equity of 8.57% consistent with the methodology outlined in Appendix B of the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006. PSP understands the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information.

Capital Expenditures

PSP continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase is attributed to some growth, but is primarily a replacement of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers.

Operating and Maintenance Costs

Operating and maintenance costs have been updated to reflect the impact of inflation and expected changes in costs and as a result of increased labour force due to succession planning and regulatory requirements.

Smart Meter Infrastructure

PSP, along with other members of Cornerstone Hydro Electric Concepts Association (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. PSP is requesting a rate rider for smart metering infrastructure in the 2009 Rate Application.

Bad Debts

Parry Sound currently has no policy for bad debts or allowance for doubtful accounts write offs. Therefore our aged accounts are removed only when deemed totally uncollectible. The 2006 fiscal year was the last write off period. During 2007 we recovered some costs via collection agency work.

Affiliate Transactions

Parry Sound Power as seen in the organizational chart is wholly owned by Parry Sound Hydro Corporation and two sister corporations; Parry Sound Energy Services Corporation (PSES) and Parry Sound PowerGen Corporation (PGEN). PGEN is located is within PSP service territory. It generates and sells electricity directly to PSP's distribution system. PSES is a service based company which employs all staff and supplies equipment to PGEN and PSP. Service level agreements were created during the deregulation period and are currently under review to ensure compliance with the new affiliate relationship code.

List of Specific Approvals Requested

PSP requests the following specific approvals:

1) Approval to charge rates effective May 1, 2009 to recover a revenue requirement of $2,139,116 including transformer allowance and LV Charges.

2) Approval of our Specific Service charges of $91,874.

3) Approval of PSP's proposed change in capital structure involving the decrease of the deemed common equity component from 46.7% to 43.3%, consistent with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006.

4) Approval for disposition of Deferral/Variance Account Balances as of December 31, 2007 in the amount of $187,563 over a three year period.

5) Approval to recover $1.00 as a rate rider per month per meter per residential and general service customers arising from costs associated with the smart metering infrastructure.

Schedule of Overall Revenue Deficiency/Sufficiency

Overview

This exhibit presents an overview of the revenue deficiency or surplus calculations used to project the deficiency of revenue for the 2009 Test year. The steps used in this process are:

Calculate the Service Revenue using the Rate Base (Exhibit 2), OM & A and Amortization Expenses calculated in Exhibit 4 and the Return on Capital calculated in Exhibit 6.

Calculate the Base Revenue requirement using the PILs calculation and the Revenue Offsets from Exhibit 3.

Use the existing rates and load projections to calculate Utility Income - Net of Taxes and PILs

Use those Calculated Revenues and the Base Revenue requirement to determine Revenue Deficiency or Sufficiency.

Parry Sound Power is forecasting a Revenue Deficiency for the 2009 Test year of $133,170 when existing distribution rates are applied to forecasted load data.

The Schedule of Overall Revenue Deficiency is provided below.

Table 7 Overall Revenue Deficiency and Utility Income

	2009 Projection
Utility Income	299,974
Utility Rate Base	5,281,770
Indicated Rate of Return	5.68%
Requested / Approved Rate of Return	7.71%
Sufficiency / (Deficiency) in Return	(2.03%)
Net Revenue Sufficiency / (Deficiency)	**(107,290)**
Provision for PILs/Taxes *	(25,880)
Gross Revenue Sufficiency / (Deficiency)	**(133,170)**
Deemed Overall Debt Rate	*7.05%*
Deemed Cost of Debt	*211,132*
Utility Income less Deemed Cost of Debt	*88,842*
Return On Deemed Equity	*3.88%*

UTILITY INCOME

Total Net Revenues	1,996,562
OM&A Expenses	1,264,790
Depreciation & Amortization	394,504
Taxes other than PILs / Income Taxes	
Total Costs & Expenses	1,659,295
Utility Income before Income Taxes / PILs	337,267
PILs / Income Taxes	37,293
Utility Income	**299,974**

Causes of the Deficiency/Sufficiency

The forecasted revenue deficiency is mainly attributable to the fact that the 2006 EDR rates do not reflect forecasted increases in OM & A costs, and Capital Investments, since the 2006 EDR (which was based on the 2004 actual OM & A costs).

The 2006 EDR was based on historic (average of 2003 &2004) net fixed assets balances, and the 2004 additions were subject to the half year rule.

PSP invests in capital as needed; we are in the process of formalizing an asset management and capitalization policy. The investments in our infrastructure will continue in 2008 bridge year and 2009 test year.

These investments, results in an increase in return on capital, depreciation expense and in working capital.

Board Findings and Directions from 2007 EDR

There are no Board Findings and Directions from the prior years EDR active for PSP.

Board Findings and Directions from 2006 EDR

There are no Board Findings and Directions from the 2006 EDR active for PSP.

Status of Board Directives

Not Applicable.

Utility Description

PSP operates an electrical distribution system with a total service area of 15 square kilometers of urban service territory within the Town of Parry Sound. The service area population is approximately 6500 people and we have approximately 128 kilometers of line which includes 117 kilometers of overhead and 11 kilometers of underground lines. PSP is a winter peaking utility. The 2007 winter peak was 19,170 kWh with an average for the 2007 year of 14,410 kWh. PSP delivers electricity to approximately 3,300 customers.

Overview

PSP is the electricity distributor licensed by the Ontario Energy Board to serve the Town of Parry Sound. PSP was incorporated under the Business Corporations Act (Ontario) on October 31, 2000. The sole shareholder of PSP is Parry Sound Hydro Corporation. All of PSP's debt is held by The Corporation of the Town of Parry Sound. PSP owns the land, land rights, distribution station, poles, towers and fixtures, overhead and underground conductors and devices, underground conduit, line transformers, services and meters. PSP distributes power to its customers and is responsible for the activities relating to the transmission, distribution and retailing of electricity. PSP's corporate objective is to provide safe and reliable electricity to its customers at a reasonable cost. PSP purchases energy from the affiliate PGEN and IESO.

Contact Information

Calvin Epps
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Parry Sound Power
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P2A 1V9
Email: cepps@pspower.ca

Telephone: 705-746-5866
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Miles Thompson
Financial Officer
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125 William St.
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P2A 1V9
Email: mthompson@pspower.ca
Telephone: 705-746-5866
Fax: 705-746-7789

Neighbouring Utilities

Hydro One Networks Inc.
483 Bay Street
South Tower, 10th Floor
Toronto, Ontario
M5G 2P5

Host or Embedded Utilities

PSP does not host any utilities within its service area.

PSP does not have any embedded utilities within its service area.

PSP is an embedded distributor within Hydro One's service territory. PSP is a registered Market Participant dealing directly with the IESO.

LDC's Distribution License

A copy of the Distribution Licence for PSP is included on the next pages.

Rec'd Dec. 23/03

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
26e étage
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

December 22, 2003

Mr. Calvin Epps
President
Parry Sound Power Corporation
125 William Street
Parry Sound, ON
P2A 1V9

Dear Mr. Epps:

Re: Application for renewal of Electricity Distribution Licence RP-2003-0018/EB-2003-0006

The Board has today issued a decision and order in the above matter. An executed copy is attached.

If you have any questions in this matter, please contact Elaine Wong, Licensing Advisor at 416-440-7638.

Yours truly,

Paul B Pudge

Paul Pudge
Assistant Secretary

Enclosed

c.c. Glen MacDonald, Hydro One Networks

RP-2003-0018 1

EB-2003-0006

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O.1998, c.15, Schedule B; 2

AND IN THE MATTER OF an application by Parry Sound Power Corporation for renewal of its electricity distribution licence. 3

By delegation, before: Mark C. Garner 4

DECISION AND ORDER 5

Parry Sound Power Corporation filed an application dated January 16, 2003 with the Ontario Energy Board under section 60 of the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B for renewal of its electricity distribution licence. 6

A Notice of Application and Written Hearing was published on November 26, 2003 and November 29, 2003. Hydro One Networks Inc. provided written submissions in response to the Notice. 7

The applicant has entered into a service agreement with Parry Sound Energy Services Corporation (the "Service Agent") under which it receives services relating to the operation of the applicant's distribution system. The Service Agent is an affiliate of the applicant. The applicant provided a copy of the service agreement and information related to the outsourced distribution services. 8

An important objective of the Board in licensing electricity distributors is to protect the interests of consumers with respect to prices and the reliability and quality of electricity service. Where a distributor has outsourced distribution services, the distributor must retain sufficient control over the provision of those services to ensure that it is capable of meeting the requirements of its licence. The application indicates that the applicant has outsourced a significant number of activities. 9

Notwithstanding the service agreement between the applicant and Service Agent, the licensee is expected to take all necessary steps as may be required to ensure that the distribution system is operated in compliance with the licence. If there is a failure of distribution services as a result of some action or omission on the part of the Service Agent, the applicant is not relieved from the obligation to comply with its licence. 10

The continued existence of the service agreement is critical to the applicant's ability to ensure that 11
the provision of the outsourced services meets regulatory requirements. Changes to, or termination of, the existing service agreement could affect the provision of reliable distribution services and therefore it is appropriate to include certain conditions in the distribution licence to require the licensee to report to the Board regarding material changes to, or intended or actual termination of, the service agreement. These conditions appear at sections 14.3 to 14.5 of the licence. The conditions emphasize the responsibility of the licensee to ensure that distribution services to consumers remain uninterrupted.

The issuance of this licence does not imply consent of, or limit the Board's consideration of, the 12
cost consequences of the service arrangement in setting just and reasonable rates. Nothing in this Decision and Order alter the applicant's obligation to be prudent with respect to the costs it incurs to operate the distribution system. The applicant is also expected to include in all service agreements such conditions as are necessary to ensure compliance with all regulatory requirements.

The Service Agent is an affiliate and the applicant must ensure that it is in compliance with the 13
Affiliate Relationship Code for Electricity Transmitters and Distributors. The service agreement was not reviewed for the purpose of assessing compliance. Should a subsequent Board review of the service agreement find that it is not in compliance with the Affiliate Relationship Code the licensee may be subject to a compliance order and, if it fails to rectify the situation, revocation of the licence.

After considering the application, the written submissions by Hydro One Networks regarding the 14
definition of the applicant's service area, and the additional material filed by the applicant, I find that it is in the public interest to issue the electricity distribution licence under Part V of the Ontario Energy Board Act, 1998.

IT IS THEREFORE ORDERED THAT: 15

The application by Parry Sound Power Corporation to renew its electricity distribution licence is 16
granted, on such conditions as are contained in the licence [12Y8X-0:1].

DATED at Toronto, December 22, 2003.

ONTARIO ENERGY BOARD

Mark C. Garner
Secretary

Electricity Distribution Licence

ED-2003-0006

Parry Sound Power Corporation

Valid Until
December 21, 2023

M.C. Garner

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: December 22, 2003

Ontario Energy Board	Commission de l'Énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
26th. Floor	26e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

1 Definitions 1

In this Licence: 2

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee; 3

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B; 4

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies; 5

"**distribution services**"means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order; 6

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems; 7

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A; 8

"**Licensee**" means: Parry Sound Power Corporation; 9

"**Market Rules**" means the rules made under section 32 of the Electricity Act; 10

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act; 11

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge; 12

"**regulation**" means a regulation made under the Act or the Electricity Act; 13

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers; 14

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity; 15

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act; 16

"**wholesaler**" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer. 17

2 Interpretation 18

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day. 19

3 Authorization 20

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence: 21

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence; 22

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and 23

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act. 24

4 Obligation to Comply with Legislation, Regulations and Market Rules 25

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts except where the Licensee has been exempted from such compliance by regulation. 26

4.2 The Licensee shall comply with all applicable Market Rules. 27

5 Obligation to Comply with Codes 28

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence: 29

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 30

b) the Distribution System Code; 31

c) the Retail Settlement Code; and 32

d) the Standard Supply Service Code. 33

5.2 The Licensee shall: 34

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and 35

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 36

6 Obligation to Provide Non-discriminatory Access 37

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence. 38

7 Obligation to Connect 39

7.1 The Licensee shall connect a building to its distribution system if: 40

a) the building lies along any of the lines of the distributor's distribution system; and 41

b) the owner, occupant or other person in charge of the building requests the connection in 42
writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 43

a) the building is within the Licensee's service area as described in Schedule 1; and 44

b) the owner, occupant or other person in charge of the building requests the connection in 45
writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance 46
with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted 47
to do so by the *Act* or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity 48

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in 49
accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity 50

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in 51
the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates 52

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set 53
out in Appendix A of this Licence.

11 Distribution Rates 54

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board. 55

12 Separation of Business Activities 56

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board. 57

13 Expansion of Distribution System 58

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules. 59

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine. 60

14 Provision of Information to the Board 61

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time. 62

14.2 Without limiting the generality of condition 14.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs. 63

14.3 The licensee shall inform the Board as soon as possible of any material changes to the service agreement with Parry Sound Energy Services Corporation (the "Service Agreement"). 64

14.4 If either party to the Service Agreement provides notice of its intention to exercise a right to terminate or discontinue any services under the services agreement, the Licensee shall: 65

a) Immediately notify the Board in writing of the notice; and 66

b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this licence. 67

14.5 In the event of termination of the Service Agreement for any reason, the Licensee shall: 68

a) ensure there is no interruption of distribution services to the consumers as a result of the termination, 69

b) notify the Board of the name of the new company that will provide the distribution services, and 70

c) file with the Board the distribution services agreement with the new company. 71

15 Restrictions on Provision of Information 72

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator. 73

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed: 74

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 75

b) for billing, settlement or market operations purposes; 76

c) for law enforcement purposes; or 77

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 78

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified. 79

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent. 80

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed. 81

16 Customer Complaint and Dispute Resolution 82

16.1 The Licensee shall: 83

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 84

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 85

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours; 86

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 87

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective. 88

17 Term of Licence 89

17.1 This Licence shall take effect on December 22, 2003 and expire on December 21, 2023. The term of this Licence may be extended by the Board. 90

18 Fees and Assessments 91

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 92

19 Communication 93

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change. 94

19.2 All official communication relating to this Licence shall be in writing. 95

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 96

a) when delivered in person to the addressee by hand, by registered mail or by courier; 97

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 98

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 99

20 Copies of the Licence 100

20.1 The Licensee shall: 101

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and 102

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 103

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA 104

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence. 105

The Town of Parry Sound as of January 1, 1982. 106

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE 107

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act. 108

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders. 109

SCHEDULE 3 LIST OF CODE EXEMPTIONS 110

This Schedule specifies any specific Code requirements from which the Licensee has been exempted. 111

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it. 112

APPENDIX A MARKET POWER MITIGATION REBATES 113

1 Definitions and Interpretation 114

In this Licence, 115

> "embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity; 116

> "embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates; 117

> "host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant. 118

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO. 119

2 Information Given to IMO 120

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to: 121

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 122

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. 123

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to: 124

i consumers served by a retailer where a service transaction request as defined in the Retail 125
Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed 126
price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity 127
consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IMO may issue instructions or directions providing for any information to be given under this 128
section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded 129
generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3 Pass Through of Rebate 130

A distributor shall promptly pass through, with the next regular bill or settlement statement after the 131
rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service 132
transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario* 133
Energy Board Act, 1998 and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity. 134

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated 135
in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement: 136

"ONTARIO POWER GENERATION INC. rebate" 137

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt. 138

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 139

Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account. 140

Map of LDC's Distribution System

A copy of PSP's distribution system map is set out on the next page.

TOWN OF
Parry Sound
Charting Sound Opportunities
Mill Lake
TOWN LIMIT
TOWN LIMIT
TOWN LIMIT
TRANS - CANADA HIGHWAY
NORTH ROAD
Two Lanes
QUARRY RD.
HALL'S MARINA RD.
HIGHWAY #69/400
Divided Hwy Ends
Four Lanes
MCDOUGALL RD.
MCDOUGALL RD.
BOWES STREET ENTRANCE
BOWES STREET
LOUISA STREET
ACCESS ROAD (OLD HWY #69)
HARMONY LANE
PARRY SOUND DRIVE
MALL DRIVE
BAYSIDE DRIVE
HWY #124
OAKRIDGE RD.
SMITH CRES.
HAWTHORNE CRES.
MAPLEVIEW DRIVE
RIVERDALE
HIGHLAND
ELIZABETH CRES.
WILLIAM
SEGUIN RIVER
MARION AVE
ISABELLA
KITCHENER
CASCADE
LOGAN'S LN.
ROSETTA ST.
McMURRAY
MARY ST.
SEGUIN STREET
BOWES STREET
GIBSON ST.
JAMES STREET
JOHNSON STREET
MILLER STREET
CHURCH
GREAT NORTH ROAD
DUFFERIN ST.
WAKEFIELD ST.
REDWOOD
SPRUCE
CEDAR
BRENDA
NANCY DR.
AVENUE
CAROL COURT
GREENWOOD
EDWARD STREET
ALBERT STREET
BEAVER
MEADOW
PINE DR.
GEORGE
FOREST
SOUND
BOOTH
MELISSA
RAILWAY AVE.
FLECK
PARRY
CHAMPAIGNE ST.
MACFARLANE
STREET
TRANSFER STATION
McCURRY LAKE
KATE
OLIVE
EMILY
BIRCH
ROSE POINT ROAD
SALT DOCKS
TOWN BEACH
PARRY SOUND OF THE GEORGIAN BAY
BIG SOUND MARINA
TOWN DOCK
WASAUKSING FIRST NATION (PARRY ISLAND)
SWING BRIDGE
TO PARRY ISLAND
FITNESS TRAIL
CANADIAN PACIFIC RAILWAY
CANADIAN NATIONAL RAILWAY
HOSPITAL
CHURCH
SCHOOL
LOOKOUT TOWER
©NORTH STAR PUBLISHING

Utility Organizational Chart

Organizational Descriptions

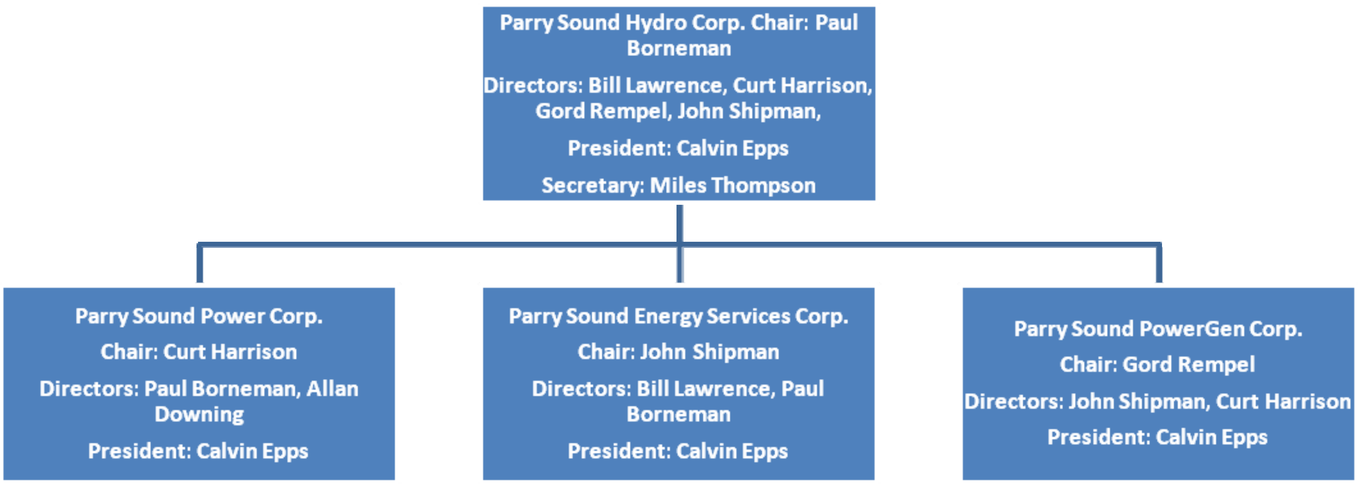
Parry Sound Hydro Corporation ("Holdco"), and its wholly owned subsidiaries Parry Sound PowerGen Corporation ("Genco"), Parry Sound Power Corporation ("Wiresco") and Parry Sound Energy Services Corporation ("Servco") were all incorporated under the Ontario Business Corporations Act on October 31, 2000. On November 1, 2000, pursuant to Section 142 of the Electricity Act, 1998 and in accordance with By-Law 2000-4303 of the Corporation of the Town of Parry Sound (the "Town"), all of the assets, liabilities, employees, rights and obligations of the Parry Sound Public Utility Commission (the "Commission") were transferred to Holdco and its subsidiaries.

The board of directors for Holdco consists of a representative from the Town of Parry Sound and four appointed members. The subsidiary boards are selected by the Holdco Board.

In accordance with various regulations of the province of Ontario, Holdco, Wiresco, Genco and Servco became taxable entities on October 1, 2000 and became responsible for making payments in lieu of taxes, equivalent to federal and provincial income and capital taxes, to the Ontario Electricity Financial Corporation, to pay down the residual debt of the former Ontario Hydro.

The directors annual compensation is allocated directly to each subsidiary company quarterly at cost.

Corporate Entities Relationships and Utility's Organization



Parry Sound Hydro Corporation owns the building and property located at 125 William Street, Parry Sound, Ontario. Holdco rents the premises to Parry Sound Energy Services. Holdco general operating costs are allocated to PSES quarterly on a cost basis.

Parry Sound Power Corporation operates as an electrical distributor within the Town of Parry Sound. Parry Sound Power Corporation has no employees. It rents office space and administrative staff from its sister corporation PSES. PSP purchases man hours and equipment time from its affiliate PSES.

Parry Sound Energy Services Corporation ("PSES") owns the motor vehicles, general office equipment and rental water tank inventory, employs 11 full-time staff. PSES provides services to Hydro, PGEN and PSP. PSES also operates a water heater rental program, performs streetlight, traffic light and tree trimming services for the Town and performs similar services for individuals at competitive rates. In addition, PSES also provides meter reading and billing services related to water and sewage for the Town of Parry Sound. PSES is a service based business but does not retail electricity.

Parry Sound PowerGen Corporation ("PGEN") owns the generating assets, building, fixtures, land, control dams and maintains the watershed. A rental building and related land is also included. PGEN is responsible for those activities relating to the generation of power. PGEN sells electricity generated at the spot market price.

Planned Changes in Corporate or Operational Structure

PSP does not have any planned changes in corporate and operational structure at the present time.

Conditions of Service/Service Charges

Parry Sound Power's Conditions of Service are attached on the following pages.

CONDITIONS OF SERVICE

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SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

The Distributor is licensed by the Ontario Energy Board "OEB" to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the Electricity Act and the Ontario Energy Board Act.

The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

1.1.1 General

Nothing contained in this document or in any contract for the supply of electricity by the Distributor shall prejudice or affect any rights, privileges, or powers vested in the Distributor by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: ESA, Ministry of Labour, Ministry of Transportation, etc.

The Distributor will normally provide one electrical service to each customer location at a nominal service voltage.

Modifications to an existing service must comply with the requirements of the standards in effect at the time of the modifications.

The customer or their authorized representative must make application for new or upgraded electric services and temporary power services.

The customer or their representative shall consult with the Distributor concerning the availability of supply, the voltage of supply, service location, metering and any other details. These requirements are separate from and in addition to those of the Electrical Inspection Authority. The Distributor will confirm, in writing, the Characteristics of Electric Supply available at a specific site.

The customer is required to provide the Distributor sufficient lead-time in order to ensure:

(a) the timely provision of supply to new and upgraded premises or
(b) the availability of adequate capacity for additional loads to be connected in existing premises.

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. The customer will be notified of any extended lead times.

Customers will be required to pay the cost of repair or replacement of the Distributors' equipment that has been damaged through the customers' action or neglect.

The supply of electricity is conditional upon the Distributor being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should the Distributor not be permitted to supply or not be able to do so, it is under no responsibility to the customer whatsoever.

The customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of the Distributor, interfere with the proper and safe operation of the Distributor's facilities or adversely affect compliance with any applicable legislation in the sole opinion of the Distributor.

Prior to commencing any service work, the customer must consult with the Distributor to ensure compliance with current requirements.

The customer is responsible for selecting a qualified/competent contractor. Careful selection of a contractor can significantly affect the cost of a project. The Distributor shall be consulted prior to the selection of a mutually acceptable contractor.

The customer maintains the responsibility to ensure that all work is done in accordance with the distributor's design and technical standards and specifications.

The Distributor, at the expense of the customer, reserves the right to inspect the work throughout the duration of the project, and the Contractor shall supply him such accommodations as he may require. The Inspector shall request that the Contractor stop work at any time he feels the Contractor is not proceeding in accordance with these "conditions of service". The customer shall confer with the Distributor before work recommences to mitigate undue cost and construction delays for the project.

Customers may be required to pay Capital Contributions for the addition of new and upgraded electrical services in accordance with the Economic Evaluation process as defined in the Distribution System Code.

1.2 Related Codes and Governing Laws

The Distributor is limited in its scope of operation by the:

1. *Electricity Act, 1998*
   www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm
2. *Ontario Energy Board Act, 1998*
   www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98o15_e.htm

3. *Distribution Licence*
   Licence Numbers
4. *Affiliate Relationships Code*
   http://www.collus.com/images/stories/Documents/ARC.pdf
5. *Distribution System Code*
   http://www.collus.com/images/stories/Documents/DSC.pdf
6. *Retail Settlements Code*
   http://www.collus.com/images/stories/Documents/RSC.pdf
7. *Standard Service Supply Code*
   http://www.collus.com/images/stories/Documents/SSSC.pdf
8. *Transmission System Code*
   http://www.collus.com/images/stories/Documents/TSC.pdf
9. *Ontario Regulation 22/04* - Electrical Distribution Safety
   http://www.e-laws.gov.on.ca/html/source/regs/english/2004/elaws_src_regs_r04022_e.htm
10. *Measurement Canada*
    http://strategis.ic.gc.ca/epic/site/mc-mc.nsf/en/h_lm03862e.html

In the event of a conflict between this document and the Distribution Licence or regulatory Codes issued by the OEB, or the Electricity Act, the provisions of the Act, the Distribution License and associated regulatory Codes shall prevail.

When planning and designing for electricity service, Customers and their agents must refer to all applicable Provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. The work shall be conducted in accordance with the Ontario Occupational Health and Safety Act, the Regulations for Construction Projects and the E&USA (or the OHSC Safety) rulebook.

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- *Headings and underlining are for convenience only and do not affect the interpretation of these Rules.*
- *Words referring to the singular include the plural and vice versa.*
- *Words referring to a gender include any gender.*

1.4 Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of any Contract made between the Distributor and any connected Customer, Generator or their agents.

In the event of changes to this Conditions of Service, a Public notice shall be made in the form of either a notice in the local newspaper, or a notice on the Distributors' Website.

The Customer is responsible for contacting the Distributor to ensure that the Customer has, or to obtain the current version of the Conditions of Service. The Distributor may charge a reasonable fee to recover costs for providing the Customer with more than one copy of this document.

1.5 Contact Information

The Distributor and its agents can be contacted during normal working hours. Please refer to the Contact Listing in the Appendices for phone number of the Local Distribution Company servicing your area.

1.6 Customer Rights

In those instances where the Customer will own their secondary or primary service, the Customer has the right to hire a Contractor to supply and install the service.

The customer has the right to demand identification from any person purporting to be an authorized agent or employee of the distributor.

A customer, who believes that he has suffered damages to his property or equipment as a result of negligence on the part of the Distributor, may submit a written claim for damages to the Distributor. The Distributor will investigate the claim and respond in writing within 10 business days of the receipt of the claim.

1.7 Distributor Rights

In those instances where the Customer has the authority to hire a Contractor to construct plant which will become part of the Distributors' system, the Distributor shall have the right to require the Contractor to submit proof of previous experience and satisfactory performance, and, the Distributor shall have the right to investigate such proof and approve the Contractor prior to the Owner awarding a contract for the work to the Contractor.

The Distributor shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998*.

1.8 Disputes

If, following good faith negotiations between a customer or other market participant and the Distributor, a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

Any dispute which shall arise between the Distributor and a customer(s) and other market participants subject to the terms of these Conditions of Service concerning the rights, duties or obligations of the Distributor or others subject to these Conditions of Service, shall be subject to the following dispute resolution procedure:

Mediation

- Either party (the "Initiating Party") may invoke the dispute resolution procedure by sending a written notice to the other party (the "Respondent Party") describing the nature of the dispute and designating a representative of the Initiating Party with appropriate authority to be its representative in negotiations relating to the dispute. The responding Party shall, within five business days of the receipt of such notice, send a written notice to the Initiating Party, designating a representative of the Responding party with the appropriate authority to be its representative in negotiations relating to the dispute.

- Within ten business days of the receipt by the Initiating Party of the written notice of the Responding Party the designated representatives shall enter into good faith negotiations with a view to resolving the dispute. If the dispute is not resolved in thirty days of the commencement of such negotiations, or such longer period as may be agreed upon, either party may, by written notice to the other party, require that the parties be assisted in their negotiations by the Ontario Energy Board. In accordance with the OEB dispute resolution process, The Ontario Energy Board will complete its review of the dispute within 150 days.

SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

This section includes information that is applicable to all customer classes of the distributor. Items that are applicable to only a specific customer class are covered in Section 3.

2.1.1 Building that Lies Along

As provided in Section 28 of the Electricity Act 1998 the Distributor has the Obligation to Connect any Building that ‘lies along” its distribution system subject to conditions outlined in section 2.1.3.
A building ‘lies along” a distribution line if it can be connected to the distributor distribution system without an expansion or enhancement.

A Building that appears to ‘lie along’ a distribution line may be refused connection to that line should the distribution line not have sufficient capacity for the requested connection. In such instances, the distributor shall make an offer to connect which will include the cost of the enhancement.

2.1.2 Offer to Connect

The Distributor will make an Offer to Connect to any customer requesting a connection within the Distributors licensed territory. As required by the Distribution Code, the Offer to Connect must be Fair and Reasonable and be based on the distributors’ design standard. The Offer to Connect must also be made within a reasonable time from the request for connection and the receipt of all required information from the Customer.

The Distributor may require a customer to pay all or a part of the costs of electrical plant installed to supply only that customer. Such capital contributions will be calculated using the guidelines set out by the OEB in the Distribution System Code. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

2.1.3 Connection Denial

The Distribution System Code in section 3.1 sets outs the conditions for a Distributor to deny connections. A Distributor is not obligated to connect a building within its service territory if the connection would result in any of the following:

- Contravention of existing Canadian Laws, and those of the Province of Ontario.

- Violations of conditions in a Distributors' Licence.
- Use of a distribution system line for a purpose that it does not serve and that the Distributor does not intend to serve.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributors' distribution system.
- A material adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Potential increases in monetary amounts that already are in arrears with the distributor

The distributor shall inform the person requesting the connection of the reason(s) for not connecting and, where the distributor is able to provide a remedy, make an offer to connect. If the distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection may be made.

2.1.4 Inspections Before Connections

The Distributor has the right to request an inspection prior to any connection.

All customer electrical installations shall be inspected and approved by the Electrical Safety Authority, referred to herein as the ESA.

The Distributor requires notification from the ESA of this approval prior to the connection of a customer's service.

Services that have been disconnected for a period of six months or longer shall also be inspected and approved by the ESA prior to reconnection.

Temporary services, for construction purposes, are approved by the ESA for a period of twelve months and must be re-inspected should the period of use exceed twelve months.

The Distributor reserves the right to inspect and approve Transformer rooms, Vaults and Pads prior to, during, and following the installation of equipment.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

Customer owned substations must be inspected by both the Electrical Safety Authority and the Distributor, prior to connection to the Distribution system.

Duct banks and road crossings shall be inspected and approved by the Distributor prior to the pouring of concrete and again before backfilling.

The Distributor reserves the right to inspect any underground trenches prior to backfilling.

The Distributor reserves the right to approve the installation and location of all submarine cable. All documentation and permits required for laying of submarine cable must be provided to the Distributor. The installation of submarine cable must meet the requirements of all governing legislation.

All work done on existing Distributor plant must be authorized by the Distributor and carried out in accordance with all applicable safety acts and regulations.

In accordance with the Distribution System Code, if the Distributor refuses to connect a building in its service territory that lies along one of its distribution lines, the distributor shall inform the person requesting the connection of the reasons for not connecting, and where the distributor is able to provide a remedy, make an offer to connect. If the Distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection can be made.

2.1.5 Relocation of Plant

The Distributor will, where feasible, accommodate requests to relocate electrical plant such as poles and metal enclosed equipment.

The customer will be required to pay all of the costs incurred by the relocation.

Requests by civic authorities to relocate distribution facilities will be done so in accordance with the appropriate regulations. See *Public Service Works on Highways Act*.

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, the Distributor has the right to have supply facilities on private property registered against title to the property. Easements are required whenever the Distributors' underground or overhead plant is to be located on private property or crosses over an adjacent private property to service a Customer.

The Customer shall acquire and grant in the distributors name, at no cost to the Distributor, where required, an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by the Distributor. The easement shall be granted prior to connection of the service.

The Owner shall furnish to the Distributor, free and clear of all encumbrances, sufficient easements to enable the servicing of all existing or proposed developments or subdivisions from plants located on the Owners' property.

Sufficient property at suitable locations shall be made available for the purpose of the installation of distributors' assets.

The Customer will prepare at its own costs a reference plan and associated easement documents to the satisfaction of the Distributors' solicitor prior to its registration and register the easement plan. Details will be provided upon application for service.

Where surface restoration by the Distributor is required following any repairs or maintenance to a service, the Distributor will in so far as is practicable, restore the property to its original condition; and provide compensation for any damages caused by the entry that cannot be repaired.

2.1.7 Contracts

Standard Form of Contract - All customers will be requested to complete and sign the standard form of contract to apply for a connection. A Standard Contract for service shall be considered as being in force from the date it is signed by the Customer and the Distributor and shall remain in force until terminated by either party.

Implied Contract - In all cases, notwithstanding the absence of a formal contract, the taking and using of electrical energy from the Distributor by any Person or Persons constitutes the acceptance of the terms and conditions of all regulations, conditions and rates as established by the Distributor. Such acceptance and use of energy shall be deemed to be the acceptance of a binding contract with the Distributor and the Person so accepting shall be liable for payment for such energy and the contract shall be binding upon the Person's heirs, administrators, executors, successors or assigns.

Special Contracts - Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- *construction sites*
- *mobile facilities*
- *non-permanent structures*
- *special occasions, etc.*
- *generation*

2.2 Disconnection

The Distributor has the right and/or obligation to disconnect the supply of electrical energy to a Customer for causes including but not limited to:

(a) contravention of the laws of Canada or the Province of Ontario including the Ontario Electrical Safety Code;

(b) violation of conditions in a distributor's licence;

(c) materially adverse effect on the reliability or safety of the distribution system;

(d) imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system;

(e) a material decrease in the efficiency of the distributor's distribution system;

(f) inability of the distributor to perform planned inspections and maintenance;
(g) a materially adverse effect on the quality of distribution services received by an existing connection; and
(h) if the person requesting the connection owes the distributor money for distribution services, or for non-payment of a security deposit.

2.3 Conveyance of Electricity

2.3.1 Guaranty of Supply

The Distributor agrees to use reasonable diligence in providing a regular and uninterrupted supply but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Customer by reason of any failure in respect thereof.

Customers requiring a high degree of security of supply or power quality are responsible to provide their own back-up or standby facilities.

When power is interrupted, or the Customer is experiencing power quality problems the Customer or their electrical contractor shall first ensure that interruption is not due to problems within the customer owned installation. If after verifying that the cause of the problem does not reside on the customers' installation, the customer shall contact the Distributor. The Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

Although it is the Distributors' policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve the Distributors' system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by the Distributor, arrangements suitable to the Customer and the Distributor may be made to minimize any inconvenience. The Distributor will endeavor to provide the Customer with reasonable advance notice, except in cases of emergency, involving danger to life and limb, or impending severe equipment damage.

The Distributor will endeavor to notify Customers prior to interrupting the supply to any individual service. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to the Distributor or the public, service may be discontinued without notice.

Depending on the outage duration and the number of Customers affected, the Distributor may issue a news release to advise the general public of the outage.

2.3.2 Power Quality

The distributor will respond to and take reasonable steps to investigate consumer power quality complaints and report to the consumer on the results of the investigation. The method and level of investigation will be at the discretion of the Distributor.

If the source of a power quality problem is caused by the consumer making the complaint, the distributor may seek reimbursement for the time and cost spent to investigate the complaint.

If the source of a power quality problem is caused by a consumer, the Distributor may direct the consumer to take corrective action. If the Consumer does not take such action within a reasonable time, the Distributor may disconnect the supply of power to the Customer. (*see section 2.2*)

2.3.3 Electrical Disturbances

There are levels of voltage fluctuation and other disturbances that can cause flickering lights and more serious difficulties for Customers connected to the Distributor distribution system.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms.

No electrical equipment, which may produce an undesirable system disturbance, shall be connected by a customer to a customer's service without prior approval of the Distributor.
Examples of equipment, which may cause disturbance, are large motors, welders and variable speed drives. In planning the installation of such equipment, the customer is required to consult with the Distributor.

The Distributor will endeavour to maintain voltage variation limits, under normal operating conditions, at the Customers' Delivery Points, as specified by the latest edition of the Canadian Standards Association, C235. However, more sensitive electronic equipment such as computers can be seriously affected by variations in quality of supply voltage. Customers who need electrical power of high quality and with rigid voltage tolerances are responsible for providing their own power conditioning equipment.

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of the Distributors' supply.

The customer shall provide such protective devices as may be necessary to protect his property or equipment from any disturbance beyond the control of the distributor.

2.3.4 Standard Voltage Offerings

2.3.4.1 For Secondary Voltage

The Supply Voltage governs the limit of supply capacity for any Customer. General guidelines for supply from overhead street circuits are as follows:

- *at 120/240 V. single phase, or*
- *347/600 V. three phase, four wire, or*
- *120/208 V three phase, four wire,*

OR

Where street circuits are buried, the Supply Voltage and limits will be determined upon application to the Distributor.

OR

Where the Customer or Developer provides a pad on private property;

- *at 120/240 V single phase, or*
- *at 120/208 V three phase, four wire, or*
- *at 347/600 V three-phase, four-wire*

2.3.4.2 For Primary Voltage

Primary supplies to transformers or customer-owned substations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *27,600 volts 3 phase 3 wire delta*
- *44,000 volts 3 phase 3 wire*

The customer shall contact the Distributor when planning their service to verify standard transformer availability and supply capacity.

2.3.5 Voltage Guidelines

The Distributor maintains service voltage at the Customers' service entrance within the guidelines of C.S.A. Standard CAN3-C235 (latest edition) which allows variations from nominal voltage of: http://www.csa-intl.org/onlinestore/GetCatalogDrillDown.asp?Parent=542,

6% for Normal Operating Conditions
8% for Extreme Operating Conditions

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis.

Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

2.3.6 Back-up Generators

Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back-feed on the Distributors' system.

To access the Code: http://www.esasafe.com/Corporate/gr_004.php?s=8
To review Generator Safety Info: http://www.esasafe.com/GeneralPublic/sgi_001.php?s=23

Customers with permanently connected emergency generation equipment shall notify the Distributor regarding the presence of such equipment.

The distributor reserves the right to have the connection of this equipment inspected.

Generation systems found to be feeding into the Distribution system without proper approval of the Distributor shall be subject to immediate disconnection.

2.3.7 Metering

2.3.7.1 General

2.3.7.1.1 Access

The Distributor or its agents shall have the right to access and read any of the Distributors' electricity meters on the Customer’s premises.

All metering installations shall be accessible from a public area.

2.3.7.1.2 Costs

All the Distributor metering equipment located on the Customer’s premises are in the care and at the risk of the Customer and if destroyed or damaged, other than by normal usage, the Customer will pay for the cost of repair or replacement.

Regardless of any charges for metering installations, all meters and meter instrumentation equipment shall remain the property of the Distributor and maintenance of this equipment shall be the Distributors’ responsibility.

2.3.7.1.3 Voltage

Generally, metering will be at utilization voltage. Where the Distributor provides primary transformation, primary voltage metering will be allowed only in special circumstances following full discussion with the Distributor.

Customer-owned substations may require primary metering. The provisions required for these installations shall be specified and approved by the Distributor for each application.

2.3.7.1.4 Primary Metering

Primary metering units may be installed outdoors or within an electrical vault as outlined in the current Electrical Safety Code. Where the customer prefers not to provide an approved electrical vault, the Distributor at additional cost can provide a metering unit with non-flammable coolant.

2.3.7.1.5 Bulk Metering

Non-residential or mixed-use buildings will normally be bulk metered by a single meter. However, where specific areas are clearly and permanently defined and in other respects as a separate entity, individual metering of the loads may be required.

Individual residential condominium or apartment units should be metered individually to empower the residents with control over their individual costs. In such instances, one or more bulk meters may still be required at the facility for the purpose of calculating house loads and/or transformer allowances (on customer owned transformers) where applicable.

In all installations where the Customer requests revenue metering remote from the secondary entrance equipment or downstream from a Customer-owned dry-core transformer, provisions are required for a bulk meter directly after the main switch. This bulk metering is required in addition to any public metering provisions. The Customer will be required to contribute to the cost of the metering installation.

Where more than one meter is required, the meters shall be grouped where practical.

The customer shall permanently and legibly identify all metered services with respect to correct municipal 911 address and unit #. The identification shall be applied to all service switches and breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to the service switch. The customer shall insure that all service identifications are accurate and by not doing so will be held responsible. The Distributor shall issue a Meter Verification Sheet for this purpose to the owner or contractor.

In any case, a copy of the metering layout plan shall be forwarded to the Distributor for review and approval.

If the distribution of the metered load circuit is in dispute, (ie: circuits from one premise is found to supply a second premise) the Distributor reserves the right to transfer all accounts into the Property Owners' name until such time as the problem has been resolved, and the individual metering can be clearly identified with the individual units.

2.3.7.1.6 Locks

All devices on the line side of the Distributor metering shall have provisions for padlocking.

For commercial and industrial services the Customer's main switch shall have provisions for padlocking the switch handle in the open position, and the switch cover (or door) in the closed position.

When a disconnect device has been locked in the "OFF" position by the Distributor, under no circumstances shall anyone other than the Distributor or its authorized agent remove the lock.

At the discretion of the Distributor, a dual locking arrangement, a Distributor master key arrangement, a key box arrangement, or a copy of the access key will be required for access.

2.3.7.1.7 Meter Seals

All devices used by the Distributor for metering are sealed. Only the Distributor or its authorized agents have the authority to break this seal. Tampering with the seal will require the Distributor to investigate the cause of the tampering. Following the investigation, the proper authorities will be contacted as required (*ESA, Police, Fire*). The customer shall be responsible for all reasonable costs associated with the investigation.

2.3.7.2 Current Transformer Boxes

Where a current transformer box is required, it shall be CSA approved, of a size and type as stipulated by the Distributor, and include a provision for padlocks. A removable plate shall be provided in the box for mounting the equipment.

As an alternative to a separate CT box and meter, a single enclosure combining both functions may be feasible. Contact the Distributor for details.

In cases where the CTs only meter a portion of the metal clad switchgear (such as house loads), a separate disconnect switch must be installed ahead of the metering compartment so that the service can be de-energized without any interruption to the main service supply.

Generally, one house load meter only will be allowed. Additional house load meters will require authorization from the Distributor.

Conductors should enter the current transformer box at the top and leave at the bottom, or vice versa. If this cannot be arranged, the next largest CT box must be used to enable conductors to be trained in place. Where parallel conductors are used, the sum of the conductors will determine the size of the CT box to use. In all cases the Customer shall supply suitable cable termination lugs.

On all electrical services that require current transformers and the neutral for metering, an isolated neutral block shall be provided in the current transformer box.

2.3.7.3 Interval Metering

The Distribution System Code, as amended from time to time, requires the Distributor to meter Customers of specific load levels with pulse-recording meters, or interval meters, which are interrogated remotely. The Distributor, at its' sole discretion, may also require such metering on any customer whose load characteristics may have a significant impact on the Net System Load Shape, or where reasonable access to the meter for the purpose of acquiring metering data may be limited due to location.

A customer that requests interval metering shall compensate a distributor for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and re-verification of the meter, installation and ongoing provision of communication line or communication link with the customer' s meter, and cost of metering made redundant by the customer requesting interval metering. The communication system utilized for interval meters shall be in accordance with the distributors' requirements.

Where such metering exists the Distributor will consider customer requests to provide a secondary pulse for load control or customer-owned metering at the customers' expense.

In keeping with the intent of the Legislation and accompanying amendments, once an interval meter installation is processed as part of the distributors' settlement process, and has affected the relevant changes to the distributors net system load, the installation must not be changed back to a non-interval meter installation.

Where a customer submits a request to read their own interval meter, the Distributor shall make this access available given the following conditions are met:

- The meter has the capability of read-only password protection
- The customer provides a signed copy of the “Interval Metering Access Agreement” to the Distributor.

2.3.7.3.1 Interval Metering Communications

- Solid-state recorders and/or Electronic Interval Meters installed by the Distributor have provision for remote interrogation. When a phone line is required for this purpose, the Owner will facilitate the provision of a telephone line in the metering cabinet for the Distributors’ metering purposes.
- At its’ sole discretion, for metering installations where loss of metering data would cause a substantial impact on the Distributors Settlement System and other customers, the Distributor may require the phone line to be dedicated for metering purposes only.
- When such dedicated phone lines are required, phone lines must be installed and functioning prior to the new service being energized
- A dedicated phone line is a voice quality telephone line, which is active 24 hours a day to the metering location extension jack, which is mounted on the metering board.

2.3.7.3.2 Smart Meters

The Ontario Government has mandated the installation of Smart Meters as a replacement to current metering technology. The LDC will install smart meters in accordance with regulations and policies set out by Government authorities.

Residential and small General Service customers, who are billed on an energy-only basis, will be provided with a smart meter free of charge during the smart meter conversion. Metering requirements for Large General Service customers will be reviewed in concert with any new Regulations.

2.3.7.4 Meter Reading

The Distributor will read all meters on a regularly scheduled basis whenever possible. If an actual meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.5 Final Meter Reading

When a service is no longer required, or the Customer is switching Energy Providers, the Customer shall provide the Distributor sufficient notice of the date so that a final meter reading can be obtained. The Customer shall provide access to the Distributor or its agents for this purpose.

If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand

and/or energy for electricity used since the last meter reading. Estimates will be based on available historical consumption.

2.3.7.6 Faulty Registration of Meters

Metering electricity usage for the purpose of billing is governed by the Federal Electricity and Gas Inspection Act and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. The Distributors' revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, the Distributor will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay for all the energy supplied, a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by the Distributor, due regard being given to any change in the character of the installation and/or the demand.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the billing correction will apply for the duration of the error. The Distributor will correct the bills for that period in accordance with the regulations under the Act.
http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

2.3.7.7 Meter Dispute Testing

The Distributor will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, the Distributor will conduct an internal investigation to verify the accuracy of any meter the Customer believes to be recording incorrectly. If the internal investigation does not resolve the matter, the Customer or the Distributor may request Measurement Canada to test the meter.
http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

If the test indicates that the meter is not accurate, the Customer's historic billing will be adjusted, and the Distributor shall pay the full costs of the meter dispute testing.

2.3.7.8 Location

The location of the indoor or outdoor meter shall be readily accessible at all times and acceptable to the Distributor. If a meter is recessed or enclosed after installation, without the prior approval of the Distributor, the service may be subject to disconnection.

The location of the service entrance, routing of duct banks, metering, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

In all locations where Commercial/Industrial revenue metering is accessible to the general public, a lockable enclosure or a room for service equipment and meters, shall be provided by the Owner at the discretion of the Distributor, as follows:

- *An electrical room reserved solely for metering equipment or*
- *Metal enclosed switchgear approved by the Distributor or*
- *A suitable metal metering cabinet or*
- *A vandal proof cage.*

2.3.7.9 Meter Mounting Heights

Provision for metering shall facilitate a practical mounting height for revenue meters in compliance with the Distributor's standard specifications and all applicable codes and regulations.

2.3.7.10 Environment

The following requirements apply to the areas allocated for revenue metering.

The customer to the satisfaction of the Distributor shall provide where there is the possibility of danger to workmen, or damage to equipment from moving machinery, dust, fumes, or moisture, protective arrangements.

A clear safe working space of not less than 1.2 m (48") in front of the installation from the floor to ceiling with a minimum ceiling height of 2.1 m (84") provided to insure the safety of the Distributor or other authorized employee(s) who may be required to work on the installation.

Where excessive vibration may affect or damage metering equipment, adequate shock-absorbing mounting shall be provided and installed by the customer.

2.3.7.11 Meter Sockets

The owner will supply and install a meter socket as specified by the Distributor. Meter sockets will be directly accessible to the Distributors' staff.

A listing of approved revenue metering sockets is available from the Distributor.

2.3.7.12 Cabinets

Where required by these Conditions of Service the Owner shall supply and install a meter cabinet to The Distributors' requirements.

Meter cabinets shall be installed indoors, except where special permission is granted by the Distributor to install the meter cabinet outside. In such cases, an approved weather proof, lockable, C.S.A. approved meter cabinet shall be provided by the Customer.

2.3.7.13 Metering Loops

Three-phase, four-wire services will require a loop for metering, within the meter cabinet, for all three phases.

Mineral insulated, solid, or hard drawn wire conductors are not acceptable as metering loops.

2.3.7.14 Metal Enclosed Switchgear

The following regulations apply to the installation of instrument transformers and metering equipment within metal enclosed switchgear.

The Distributor will provide the following revenue metering equipment as required:

- Colour coded secondary wiring
- Revenue meters

The Owner shall:

- Consult with The Distributor regarding the installation of metering equipment, which may include:
  - Potential transformers
  - Potential transformer fuse holders and fuses
  - Current transformers
  - Phone line for remote interrogation of meters
  - Duplicate Pulse Initiators
  - Provide complete shipping instructions for instrument transformers for those projects where these are to be provided by the Distributor for installation by the switchboard manufacturer.
  - Install instrument transformers, metering cabinet and conduit.
  - Each main bus bar to be drilled and tapped (10-32) or (10-24) on the line side of the removable current transformer link.

- Submit two copies of the manufacturer's switchboard drawings, for approval, dimensioned to show provision for and arrangement of The Distributors' metering equipment.

Meters shall be installed by the Distributor in a customer-owned metal cabinet of a size and type pre-approved by the Distributor, mounted at an approved location separate from the switchgear.

Tamper proof or sealable rigid conduit or any equally approved conduit of a size and type specified by the Distributor shall be installed between the CT compartment of the switchgear and the meter cabinet.

For conduit installations greater than 30 m (100'), in length or where several bends are necessary, larger conduits or other special provision may be required, at the discretion of the Distributor.

2.3.7.15 Switchgear Connected to Wye Source

Where a Wye source neutral connection is to be used or grounded, the Owner shall provide a conductor sized to the requirements of the Ontario Electrical Safety Code from the instrument transformer compartment to the neutral connection.

2.3.7.16 Four Quadrant Metering (Generation)

All Ontario Energy Board-licensed generators connected to the distribution system that sell energy and settle through the distributor's retail settlement process shall be required to install metering that meets the requirements of the Distribution System Code as approved by the Ontario Energy Board, and/or the Market Rules as approved by the Independent Electricity System Operator. http://www.theIESO.com/

2.3.7.17 Net Metering for Embedded Generation

Customers with specific generation facilities may reduce their net energy costs by exporting surplus generated energy back onto the utility distribution system. Surplus energy exported onto the utility distributions system will be calculated as a credit against the energy the customer consumes from the distribution system.

All customers wishing to become a Net Metering participant must meet all of the following conditions:

1. The electricity is generated primarily for the customer's own use;
2. The electricity generated is conveyed to the customer's own consumption point without reliance on the utility's distribution system;
3. The maximum cumulative output capacity of the generator does not exceed 500 kW; and
4. The electricity is solely generated from a renewable energy source (such as wind, drop in water elevation, solar radiation, agricultural bio-mass, or any combination thereof).

In order to participate in the Net Metering program, the customer will be required to meet all the parallel generation requirements for Connecting Micro-Generation Facilities (10 kW or less) or Other Generation Facilities (greater than 10 kW and less than 500 kW), as applicable to the generator size, as found in Section 3.5 - Embedded Generation Facilities

The customer must have a bi-directional revenue meter that records energy flow in both directions.

2.3.7.18 Ontario Power Authority (OPA) Standard Offer Program for Embedded Generation

The Ontario Power Authority has established a Standard Offer Program (SOP) to encourage and promote greater use of renewable energy sources such as wind, solar, photovoltaic (PV), renewable biomass, biogas, bio-fuel, landfill gas, or drop in water elevation for generating electricity. Renewable energy electricity generation projects with a capacity of 10 MW or less that meets the program's requirements may be connected to the distribution system in order to export electricity.

Generating facilities participating in the Standard Offer Program will connect directly to the distribution system at a voltage of 44kV or less. Output from the generating facility shall be metered in a manner to ensure proper collection of required information for settlements. Such metering may include:

a. for generators of 10 kW or less and connected to the line side of the load meter
   - (i) a bi-directional kWh meter to measure energy consumed and energy exported; or
   - (ii) a bi-directional interval meter to measure hourly energy consumed and energy exported

b. for all other generators, an interval meter must be installed.

In some instances, the load meter may also have to be changed in order to accommodate proper settlement calculations for the SOP. The generator will be solely responsible for any costs associated with the connection to the distribution system and any required metering installation.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for Service Connections are set out in the Distributors approved rates, (Miscellaneous Rates and Charges) and may be obtained by request from the Distributor. Notice of Rate revisions may be published in the local newspapers and or mailed out to all customers with the first billing issued at revised rates.

2.4.2 Energy Supply

The Distributor shall provide Customers connected to the Distribution System with access to electricity through Standard Supply Service as defined in the Retail Settlement Code published by the OEB or as mandated though Legislation or Regulations issued by the Ministry of Energy.

Disputes arising from charges relating to Standard Supply Service shall be directed to the Distributor.

Customers will be switched to their Retailer of choice only if the retailer has a Service Agreement with the Distributor. The Customer's authorized Retailer through the Electronic Business Transaction system (EBT) must make the Service Transfer Request (STR) in accordance with the rules established and amended from time to time by the Ontario Energy Board.

Disputes arising from charges relating to Retailer Service shall be directed to the Retailer.

The Distributor may, at its discretion, refuse to process a Service Transfer Request for a Customer to switch to a Retailer if that Customer owes money to the Distributor for Distribution Services and or Standard Supply Service.

2.4.2.1 Wheeling of Power

Customers considering delivery of electricity through the Distributors' Distribution System shall contact the Distributor for technical requirements and current applicable Rates.

2.4.3 Supply Deposits & Agreements

Whenever required by the Distributor, the Customer shall provide and maintain security as specified in the Distribution System Code. The Distributor shall require security amounts based on the existing security and deposit policies.

Where a customer proposes the development of premises that requires the Distributor to place equipment orders for special projects, the customer is required to sign the necessary Supply Agreements and furnish a suitable deposit before such equipment is ordered by the Distributor. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

2.4.4 Billing

The Distributor may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis. The option applicable to the customer shall be identified to the customer at the time of application for service.

Prorating of Service and Demand charges will be performed at the discretion of the Distributor.

2.4.4.1 Competitive Charges:

Are based on rates as determined by:

i. the Hourly Ontario Spot Market Price (HOEP); or
ii. the utilities Weighted Average Price (WAP) as determined by net system load; or
iii. the customers retailer contract rate; or
iv. the rates published by the OEB; or
v. Legislation or Regulations issued by the Ministry of Energy.

2.4.4.2 Non-competitive Charges:

Non-competitive Charges are based on rates approved by the Ontario Energy Board, and fall outside the scope of this document as they are adjusted on an annual basis. Approved rates as they relate to the transmission, distribution and other non-competitive elements may be attained through the utilities rate documents. These documents will be provided by the utility at the customer's request.

2.4.4.3 Billable Engineering Units:

Customers will be billed on:

i. actual or estimated meter reading data; or
ii. derived consumption data (Streetlights, sentinel lights and other scattered loads); or
iii. a flat rate, depending on the type of load being billed.

2.4.4.4 Use of Estimates:

In months where a bill is issued, but no reading is obtained, the Distributor estimates usage in order to determine billing quantities. The estimate is based on historical usage for the premise, or a pre-determined quantity if there is no historical usage information available.

2.4.5 Payments and Late Payment Charges

Bills are rendered for distribution services and electrical energy used by the Customer. Bills are payable in full by the due date.

Bills are due when rendered by the utility. A customer may pay the bill without the application of a late payment charge up to a due date, which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill. This due date shall be identified clearly on the customer's bill.

Where payment is made by mail, payment will be deemed to be made on the date post-marked. Where payment is made at a financial institution acceptable to the utility, payment will be deemed to be made when stamped/acknowledged by the financial institution or an equivalent transaction record is made.
A partial payment will be applied to any outstanding arrears before being applied to the current billing, unless special considerations have been made by the utility.

Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued or limited. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

The Distributor shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge may apply where the service has been disconnected due to non-payment.

The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

2.4.6 Unauthorized Energy Use

The Distributor shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, the Distributor shall notify, if appropriate, Measurement Canada, The Electrical Safety Authority, Police Officials, Retailers that service customers affected by an authorized energy use, or other entities.

The Distributor may recover from the parties responsible for the unauthorized energy use all costs incurred by the Distributor arising from unauthorized energy use, including an estimate of the energy used, inspection and repair costs.

A service disconnected due to unauthorized use of energy shall not be reconnected until such time as all arrears resulting from the unauthorized use has been resolved to the satisfaction of the Distributor.

Prior to reconnection, the Distributor shall require proper authorization from applicable authorities.

2.5 Customer Information

The Distributor reserves the right to request specific information from the customer in order to facilitate the normal operation of its business. Failure of a customer to supply such information may prevent the normal continuation of service.

The Retail Settlement Code as amended from time to time specifies the rights of customers and their retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information.

Under these requirements, the Distributor shall upon authorization by a customer make the following information available to the Customer or the Retailer that provides electricity to a customer connected to the Distributors' distribution system:

- The Distributors' account number for the customer,
- The Distributors' meter number for the meter or meters located at the customer's service address
- The customer's service address,
- The date of the most recent meter reading,
- The date of the previous meter reading,
- Multiplied kilowatt-hours recorded at the time of the most recent meter reading,
- Multiplied kilowatt-hours recorded at the time of the previous meter reading,
- Multiplied kW for the billing period (if demand metered),
- Multiplied kVA for the billing period (if available),
- Usage (kWh's) for each hour during the billing period for interval-metered customers
- An indicator of the read type (e.g., distributor read, consumer read, distributor estimate, etc.)
- Average distribution loss factor for the billing period

This information will be provided to the Customer / Retailer upon request twice per year at no charge. The Distributor may request a fee to recover costs for additional requests. A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

The Distributor acknowledges that no confidential information regarding its' customers shall be released to a third party without the expressed prior written consent of the customer unless the request is rightfully received from the third party requesting the information, or the Distributor is legally required to disclose such information under the terms and in accordance with the Freedom of Information and Protection of Privacy Act, R.S.O. 1990, c. F.31.
HOTLINK http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

SECTION 3 CUSTOMER SPECIFIC

3.1 Residential

This section refers to the supply of electrical energy to Customers residing in residential dwelling units.

3.1.1 General

Energy is generally supplied as single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts.

There shall be only one Delivery Point to a dwelling.

In circumstances where two existing services are installed to a dwelling, and one service is to be upgraded, the upgraded service will replace both of the existing services.

All new single-family homes will be required to install their primary and secondary service wires to the specifications contained within the Distributors' technical specification document.

Whether the method of supply will be overhead or underground will be at the discretion of the distributor. The Distributor will adhere to any existing regulations subject to requirements of authorities.

Unless specifically documented otherwise to the Customer, where the distributor has taken ownership of such plant all services installed by the Distributor or by an approved contractor using approved materials, will be maintained by the Distributor.

3.1.2 Early Consultation

The Customer shall supply a completed Site Planning document and related information to the Distributor well in advance of installation commencement. (see appendix) The information shall be supplied in a manner requested by the Distributor at the time of the application.

3.1.3 Standard Connection Allowance

For the purposes of calculating customer connection fees, the Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service.

The basic connection for each customer shall include;

i. supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
ii. up to 30 meters of overhead conductor or an equivalent credit for underground services.

In the case of an upgrade to an existing service, where the existing service is below the basic connection, the credit up to the basic connection will apply.

Secondary services exceeding the basic 30 meter length may require specific design approved by the Distributor to ensure power quality.

3.1.4 Variable Connection Fees

Any requirements above the defined basic connection shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. The distributor may recover this amount from a customer through a connection charge or equivalent payment.

3.1.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

3.1.5.1 Secondary Service Connections

The Point of Demarcation for residential services up to and including 400 amps is at the line side of the Meter Base for Underground services, and at the top of the stack for Overhead services, beyond which the customer bears full responsibility for installation and maintenance.

The Point of Demarcation for residential services over 400 amps is at the secondary side of the transformer.

For Secondary Services wholly owned and maintained by the Customer, the Demarcation Point is the secondary connection at the transformer or the service bus.

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

(a) conductor terminations are inside the Customer's building;
(b) conductor is installed beyond the service entrance;
(c) conductor is connected to a Primary Service; or
(d) conductor is a non-standard installation.

3.1.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

3.1.6 Supply Voltage

(a) A Residential building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.1.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.1.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Local Distribution Company and:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.1.9 Overhead Service

The Owner will provide service equipment to both the Distributors' and ESA requirements, and be of sufficient height to maintain proper minimum clearances. The Owner's main switch and the overhead service conductors will be of compatible capacity.

3.1.10 Underground Service

Underground secondary services will be installed at the Owners' expense, to the Distributor's specifications. The Owner's main switch and the underground service conductors will be of compatible capacity.

3.1.11 Street Townhouses and Condominiums:

NOTE: Street Townhouses and Condominiums requiring centralized or bulk metering will be covered under section 3.2 of these Conditions of Service. Also 3.1.11.2

3.1.11.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system and services will be designed and installed.

The Owner will provide all of the civil works to accommodate the Distributor and will pay the complete cost of the electrical distribution system, design and services.

- The distribution system and services shall be underground unless otherwise approved.
- One service will be provided for each unit.
- The nominal service voltage will be 120/240 volts, 1 phase, 3 wire.
- The Distributor will approve the location of duct banks, service routings and meter bases.

- Distribution plant shall not be installed until grade is at +/- 150 mm of final grade unless otherwise approved by the Distributor.
- Street lighting will be to Municipal standards and installed at the Owner's expense.

3.1.11.2 Metering:

The Owner will supply and install meter sockets specified by the Distributor.

Multiple or grouped meter bases will be accepted only when prior approval has been given by the Distributor both as to type and proposed location. A completed meter verification form shall be provided to the distributor prior to energization.

Meter sockets will be located on the exterior front wall of the units and will be directly accessible to the Distributor.

- Mounted on the front wall 1.7 metres above finished grade to the centre of the meter
- Installed ahead of (on the line side of) the main disconnect switch
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

Normally the service will not be energized until the outside finish in the area of the revenue meter has been completed. If exceptions are made to this, then the general contractor will be responsible for ensuring that the meter is suitably protected while work is being done on the exterior wall adjacent to the meter. The general contractor will be entirely responsible for all costs for materials and labour for repairing or replacing a damaged meter. Meters must always remain fully accessible for reading, replacement, repair, and general maintenance. Customers and/or their contractors should contact the Distributor prior to enclosing meters and/or meter bases to ensure that safety and access are not compromised or the Distributor may disconnect the service until remedial action, as determined by the Distributor, are undertaken

3.1.12 Seasonal and Remote Dwellings:

Due to the varied nature of Seasonal and Remote Dwellings some special arrangements may be required to service these locations. Arrangements will be made in such a manner to provide services such as restoring power, maintenance of equipment or new construction requests to water access or remote customers, without endangering personnel or the public.

3.1.12.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system services will be provided.

In the event of a power interruption, the Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

3.1.12.2 Access:

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: ESA, Ministry of Labour, Ministry of Transportation, etc.

- **Night crossings**

  The Distributors' transportation equipment will not be used to cross any water ½ hour before sunset and ½ hour after sunrise due to safety concerns. It will be at the discretion of the Distributor whether they will board customer owned transportation equipment in these circumstances.

- **Ice conditions**

  Recognizing seasonal ice hazards, the Distributor reserves the right to suspend water passage during freeze up and spring thaw, as well as any such time deemed unsafe by the Distributor.

- **Severe weather conditions**

  Recognizing that severe weather conditions may pose undue safety hazards, the Distributor reserves the right to postpone attempts to restore power until restoration can be performed in a safe manner.

3.1.13 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.2 General Service (Below 50 kW)

3.2.1 General

This section refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section 3.1.8 that require centralized bulk metering.

General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

3.2.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.2.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Below 50 kW) shall be recovered through a variable connection Fee.

3.2.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.2.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.2.5.1 Secondary Service Demarcations

A General Service Customer Demarcation Point is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Demarcation Point at the top of stack for overhead services or at the meter base for underground services.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.2.5.2 Primary Service Demarcations

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

3.2.6 Supply Voltage

(a) A General Service building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.2.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.2.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Distributor and unless otherwise specified during the early consultation process:

- Mounted 1.7 metres from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 metres of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.2.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.2.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.2.11 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.2.12 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.3 General Service (Above 50 kW)

3.3.1 General

This section refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load greater than 50 kW.

3.3.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.3.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 50 kW) shall be recovered through a variable connection Fee.

3.3.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a "variable connection charge". The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.3.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.3.5.1 Secondary Service Connections

A General Service Customer Demarcation Point for customers above 50 kW is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Delivery point at the top of stack for overhead services or at the meter base for underground services.

The location of the service entrance, routing of duct banks and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.3.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

In some circumstances the owner may be required to construct a private pole line. Primary conductors will be terminated complete with cut-out(s) at the Demarcation Point by the Distributor at the owners' expense.

Where a private pole line is to be constructed by the Owner with an approved contractor, this shall be constructed to the ESA and the Distributors' requirements.

An electrical requirement in excess of 300 kVA may require a customer owned substation.

In some instances primary metering may be required.

3.3.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.
Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

Depending upon the location of the building Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.3.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.3.8 Metering:

Meter installations will be directly accessible to the Distributor. The owner will consult with the Distributor well in advance of installation commencement to allow the Distributor time for proper planning and ordering of equipment.

For more details refer to section 2.3.7 in these Conditions of Service.

3.3.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.3.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.3.11 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line. The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.3.12 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.3.13 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.3.14 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.4 General Service (Above 500 kW)

3.4.1 General

This section refers to the supply of electrical energy to General Service Services requiring a connection at a connected load greater than 500 kW.

3.4.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Customer shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment, and coordination with ESA requirements etc.

Note: Larger services may require approval by the ESA to ensure compliance with their design requirements. The customer should contact the ESA early in the planning stages.

The Distributor will:

- *Advise the customer of the suitability of the in-service date*
- *Arrange with the customer for a Service Contract*
- *Review the submitted drawings; return one set to the customer with comments and/or approval. If requested by the Distributor, the customer shall resubmit the drawings where the comments are extensive and require major changes*
- *Specify the required main fuse link or relay setting for co-ordination with the system. In case of multiple transformer stations, a complete co-ordination study shall be submitted by the customer for approval.*
- *Make the final connection to the source of supply*
- *Determine metering requirements*
- *Advise the Transmitter of the particulars of the customer owned substation*

3.4.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 500 kW) shall be recovered through a variable connection Fee.

3.4.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.4.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Primary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

The Distributor reserves the right to direct the operations of any customer owned switchgear connected to the distribution system including those located beyond the point of demarcation.

3.4.5.1 Service Installation

In General, the Demarcation Point for a General Service Customer with a demand of over 500 kW is on the primary side of the transformer at the first available distributor owned point of isolation, or as otherwise set by the distributor. This delivery point might be located on an adjacent property from which the Distributor has an authorized easement. In all cases the final Demarcation Point will be the decision of the Distributor.

The location of the service entrance, routing of duct banks, metering facilities, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Distributor will install overhead supply lines and required cut-outs to the first point of support on private property. The location of this support must be approved by the Distributor and shall be within 30 metres of the Distributors' existing overhead plant. All costs for materials and labour shall be at the customers' expense.

The service pole or first point of support on private property shall be considered self-supported and shall be complete with suitable hardware for attaching the suspension insulators. The Customer shall be responsible for all costs associated with equipment, installation, and inspection.

Where the customer wishes an underground supply, the customer shall supply and install the underground cables and termination pole complete with primary switch, fuses and lightning arresters. The installation shall be subject to ESA inspection and specific approval of the Distributor. The customer owned termination pole must comply with items as prescribed by the Distributor.

At the Distributors' discretion, the customers' underground service may be connected to a termination pole owned by the distributor. In such cases, the Distributor shall supply and install at the customers expense, any required primary switch, fuses, and lightning arrestors.

When requested, the customer shall make provision in the substation switchgear or transformer, for loop feeding the Distributors' supply cables via load interrupter switches.

In some instances, primary metering may be required.

3.4.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.

General Service connections above 500 kW may require a customer owned substation.

Depending upon the location of the building, Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.4.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

Where the high voltage interrupting switches are located inside a building, a direct outside entrance to the switchgear room must be provided.

The outside door providing direct access to the transformer or switchgear room must be compliant with all applicable codes and requirements, and of a quality to be approved by the Distributor.

3.4.8 Metering:

The owner will supply and install provisions for metering following the details outlined both in these Conditions of Service, and technical documents provided to the customer during the consultation process.

For more details refer to section 2.3.7 in these Conditions of Service.

3.4.9 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line.

The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.4.10 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.4.11 Drawings

Apart from the regular drawings submission to the ESA, the customer shall provide two sets of the following drawings and details to the Distributor.

Survey Plan: prepared by an Ontario Land Surveyor, showing the property limits, registered plan and existing buildings or easements if any.

Site Plan: showing the location of the station relative to buildings, structures and set backs from adjacent property lines. The site plan shall also include the exact location of existing Distributor owned plant and the proposed route of the incoming supply.

Schematic or Single-Line Diagram: indicating the major components of the station and their electrical ratings. Where additions or alterations are being made, these shall be clearly distinguished from unchanged portions of the installation.

Electrical Details: sufficient details shall be provided in order to enable fast processing and approval of the station drawings. The following represents the minimum data required.

- Plan, elevation and profile views of the station structure, switchgear, transformer(s), termination poles, duct banks, etc.

- Dimensions to clearly indicate the electrical, physical and working clearances as well as relative location of all equipment.

- Pole or structure for dead-ending the Distributor lines shall be complete with suitable hardware for attaching the suspension insulators that will be supplied and installed by the Distributor.

- Fencing arrangement.

- Grounding details. (In the case of indoor metal enclosed switchgear, when the Distributor has operating control of any interrupter switches, the assembly shall further incorporate ground rod parking stands and stirrups per the Distributors Specifications.)

- Details of vault construction (if indoor substation).

- Manufacturer's drawings of metal-enclosed switchgear showing internal arrangement of equipment, clearances, means of access, interlocking and provision for personal safety. Where the Distributors' cables terminate in the switchgear, the customer shall provide suitable terminators for the size and type of cable as specified by the Distributor.

- When the customer's switchgear is used for loop feeding the Distributors' supply cables, provision for padlocking the in and out load interrupter switches and the associated bay doors shall be required.

- Indoor and outdoor switchgear assemblies shall contain a space heater and protective guard in each bay, along with thermostat(s), sized to promote air circulation and to prevent condensation from forming.

- At the discretion of the distributor, the customer shall make provisions for a future system neutral connection to the customer's dead-ending pole or structures installed by the Distributor. Where the Distributors' neutral terminates in the customer's switchgear, the customer shall provide a suitable connector on the ground bus for the size and type of cable specified by the Distributor.

3.4.12 Pre-Service Inspection

The customer shall present to the Distributor a final "Pre-service Inspection Report" a minimum of 3 working days before connection can be affected.

The "Pre-Service Inspection Report" shall outline and document the results of all tests and inspection carried out on the substation components. The information contained in the report must be to the satisfaction of the Distributor before connection can be authorized.

The "Pre-Service Inspection Report" shall be required in case of:

- ***New Substation****: in which case all components of the substation shall be reported upon.*
- ***Modified substation****: in which case all components of the substation shall be reported upon.*

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.5 Embedded Generation

3.5.1 General

An Embedded Generator shall provide the Distributor with proof of compliance of IESO or OEB registration Requirements, and appropriate Licences.

The Distributor shall collect costs reasonably incurred with making an offer to connect a generator from the entity requesting the connection. Costs reasonably incurred include costs associated with:

- Preliminary review for connection requirements.
- Detailed study to determine connection requirements.
- Final proposal to the generator.

A Generator that is or wishes to become connected to the distributors' distribution system shall enter into a Connection Agreement with the Distributor.

If damage or increased operating costs result from a connection with a Generator, the Generator shall reimburse the Distributor for these costs.

The Embedded Generator is responsible for providing suitable embedded generator equipment to protect his plant and equipment for any conditions on the distributor and interconnected transmission systems such as reclosing, faults and voltage unbalance.

To incorporate the connection of embedded generator to the distribution system, the line/feeder protection including settings and breaker reclosing circuits must be reviewed and modified if necessary by the distributor or transmission authority. This process may be complex and may require significant time.

The embedded generator must submit a proposed single line diagram and protection scheme for review to the distributor contact as identified by the distributor.

Based on the transformer connection proposed by the embedded generator additional significant protection cost may be incurred (e.g. delta HV transformer winding may require 3 phase HV breaker / reclosure device). The embedded generator shall not order the protection equipment and transformer until the station line diagram is reviewed and accepted by the distributor.

The purpose of the distributor review is to establish that the embedded generator electrical interface design meets the distributor requirements.

The protection schemes shall incorporate adequate facilities for testing/maintenance.

Negative phase sequence protection shall be installed where required, to detect abnormal system condition as well as to protect the generator.

The embedded generator may be required to install utility grade relays for those protections that could affect the distributor or transmission authority system.

The embedded generator may be required to submit a Ground Potential Rise study for review by the distributor, if telecommunications circuits are specified for remote transfer trip protection.

3.5.2 Protection

The embedded generator should provide protection systems to cover the following conditions:

3.5.2.1 Internal Faults:

The Generator should provide adequate protections to detect and isolate generator and station faults.

3.5.2.2 External Faults:

The protection system should be designed to provide full feeder coverage complete with a reliable DC supply. In some cases redundancy in protection schemes may be required.

Normally the following fault detection devices are required for synchronous generator(s) installation(s).

3.5.2.3 Ground Faults:

When the HV winding of the Generator station transformer is wye connected with the neutral solidly grounded, then ground over-current protection in the neutral is required to detect ground faults.

If the Embedded generator station transformer HV winding connected to the Distributor system is ungrounded wye or delta, then ground under-voltage and ground over-voltage protections shall be required to detect ground faults.

Depending on the size, type of generator and point of connection, a distributor may require the relaying system to be duplicated, complete with separate auxiliary trip relays and separately fused DC supplies to ensure reliable protection operation and successful isolation of the embedded generator.

3.5.2.4 Phase Faults:

To detect phase faults, at least one of the following protections should be installed with acceptable redundancy where required depending on fault values:

- Distance
- Phase directional over-current
- Voltage-restrained over-current
- Over-current
- Under-voltage

3.5.2.5 Islanding/Abnormal Conditions:

Voltage and frequency protections are required to separate the embedded generator from the distribution system for an islanded condition and thus maintain the quality of supply to distribution system customers. This also will enable speedy restoration of the distribution system.

Typically, the protections required to detect islanding/abnormal conditions are:

- Over-voltage
- Under-voltage
- Over-frequency
- Under-frequency
- Voltage-balance

The above protections should be timed to allow them to ride through minor disturbances.

3.5.3 Induction Generator

Due to the operating characteristics of the induction generator the protection package required is normally less complex than the synchronous generator. An embedded generator should design the protection scheme to trip for the same conditions as stated for synchronous generators. An induction generator is an asynchronous machine that requires an external source such as a healthy distribution system to produce normal 60 Hz power. Alternatively, if there is an outage in the distribution system then there is unlikely to be 60 Hz output from the induction generator. In certain instances, an induction generator may continue to generate electric power after the source is removed. This phenomenon, known as self-excitation, can occur whenever there is sufficient capacitance in parallel with the induction generator to provide the necessary excitation and when the connected load has certain resistive characteristics.

3.5.4 DC Remote Tripping / Transfer Tripping

Remote or transfer tripping may be required between the Generator and the feeder circuit breaker if the Generator is connected at a critical location in the distribution system. This feature will provide for isolation of the embedded generator when certain faults or system disturbances are detected at the feeder circuit breaker location.

Additional Protection Features, such as Remote Trip and Generator end open signal, may be required in some applications. Remote Trip Protection will often involve the participation of a neighboring or Host LDC. Early consultation is important to ensure a timely connection to the system.

3.5.5 Maintenance

An Embedded Generator shall have a regular scheduled maintenance plan to assure the Distributor that all connection devices and protection & control systems are maintained in good working order. These provisions shall be included in the Connection Agreement. A complete copy of the inspection report shall be delivered to the Distributor within 30 days.

In developing a maintenance plan, the Generator should consider the following requirements:

- Qualified personnel should carry out all inspections and repairs.
- Periodic tests should be performed on protection systems to verify that the system operates as designed. Testing intervals for protection systems should not exceed four (4) years for microprocessor-based systems and two (2) years for electro-mechanical based systems.
- Isolating devices at the point of connection should be operated at least once per year.
- The Generator facility should be inspected visually at least once per year to note obvious maintenance problems such as broken insulators or other damaged equipment.
- Any deficiencies identified during inspections shall be noted and repairs scheduled as soon as possible, with timing dependent on the severity of the problem, due diligence concerns (of both the Distributor and the Generator) and financial and material requirements. The Distributor shall be notified of any deficiencies involving critical protective equipment.
- The Distributor shall be provided with copies of all relevant inspection and repair reports that may affect the protection and performance of the Distributors' systems. The Distributor has the right to witness any relevant test being performed by the generator.

3.6 Embedded Market Participant

An Embedded Market Participant shall provide the Distributor with proof of compliance of IESO registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Market Participant must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

3.7 Embedded Distributor

An Embedded Distributor shall provide the Distributor with proof of compliance of IESO and OEB registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Distributor must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

Metering requirements of the Embedded Distributor shall be at the discretion of the Host Distributor.

3.8 Miscellaneous Small Services

This section pertains to the supply of electrical energy for Street Lighting, Traffic Signals, Bus Shelters, Telephone Booths, Cable T.V. Amplifiers, Decorative Street Lighting, Bill Boards, and other similar small loads.

3.8.1 General

At the discretion of the Distributor, the service voltage will be:

120/240 volts, single phase three wire or
120 volts, single phase two wire or
347/600V three phase, four wire

The method and location of the supply will vary based on the conditions present on the Distributors' plant, and will be established for each application through consultation with the Distributor.

Where specified by the Distributor during the Early Consultation process, the Customer will provide underground ducts to the Distributor's specifications.

The Owner shall be responsible for all costs associated with the supply and installation of service conductors

The Distributor at the Owners' expense will install required transformation.

Where at the discretion of the Distributor, a meter is not installed, energy consumption will based on the connected wattage and the calculated hours of use.

Prior to energization of a service the Distributor will require notification from the ESA that the installation has been inspected and approved for connection.

3.8.2 Early Consultation

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc. Information required includes:

- Required in-service date
- Requested Service Entrance Capacity and voltage rating of the service entrance equipment
- Locations of other services, gas, telephone, water and cable TV
- Survey plan and site plan indicating the proposed location of the service equipment with respect to public rights-of way and lot lines.

3.8.3 Street Lighting

Town street-lighting that is designed, installed, and maintained by the Distributor shall be fully funded by the Municipality to ensure adherence to the Affiliate Relationship Code and the Distributors' Licence.

3.8.4 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority.

3.8.5 Bus Shelters

Bus Shelter Lighting is owned and maintained by the Customer.

3.8.6 Decorative Street Lighting

Such installations could be lighting for festive occasions or "neighbourhood character" street-scaping and will be maintained by the Customer.

SECTION 4 GLOSSARY OF TERMS

"Conditions of Service" means the document developed by the distributor in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for the distributor;

"Condominiums" are located on common land, which is the property of a condominium corporation or is owned by the Owner of all of the units (rental property). These units usually front onto internal roads that are also privately owned;

"Condominium Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit and have direct outside access at ground level;

"Connection" means the process of installing and activating connection assets in order to distribute electricity;

"Connection Agreement" means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

"Connection assets" means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributors' main distribution system and the ownership Demarcation Point with that customer;

"Consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate;

"Customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions;

"Demand meter" means a meter that measures a consumers' peak usage during a specified period of time;

"Demarcation Point" means the point at which the obligation of the Distributor ends and those of the Customer begin for the purposes of maintenance and repair of the distribution service;

"Disconnection" means a deactivation of connection assets, which results in cessation of distribution services to a consumer;

"Distribute", with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

"Distribution losses" means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows;

"Distribution loss factor" means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.;

"Distribution services" means services related to the distribution of electricity and the services the Board has required distributors to carry out.

"Distribution system / plant" means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect a customer to the main distribution system;

"Distribution System Code," means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards of distribution systems;

"Distributor" means a person who owns or operates a distribution system;

***"Electricity Act*"** means the *Electricity Act, 199*8, S.O. 1998, c.15, Schedule A;

"Energy Competition Act" means the *Energy Competition Act, 199*8, S.O. 1998, c. 15;

"Electrical Safety Authority" or **"ESA"** means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

"Embedded Distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

"Embedded Generation Facility" means a generator whose generation facility is not directly connected to the IESO-controlled grid but instead is connected to a distribution system;

"Embedded Load Displacement Generation Facility" means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale;

"Embedded Market Participant" means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity, or that could adversely affect the reliability of the electricity system;

“Emergency backup generation facility” means a generation facility that has a transfer switch that isolates it from a distribution system;

“Enhancement” means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth;

“Expansion” means an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system;

“Four-quadrant Interval Meter” means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

“Generate”, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

“Generation Facility” means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

“Generator” means a person who owns or operates a generation facility;

“Geographic Distributor” with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

“Good Utility Practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

“Holiday” means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

“IESO” means the Independent Electricity System Operator established under the Electricity Act;

“IESO-Controlled Grid” means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation;

“Interval meter” means a meter that measures and records electricity use on an hourly or sub-hourly basis;

“Large Embedded Generation Facility” means an embedded generation facility with a name-plate rated capacity of 10MW or more;

“Lies Along” means a property can be connected to the distributor distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of the distributor who owns or operates the distribution line.

“Load Transfer” means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

“Load Transfer Customer” means a customer that is provided distribution services through a load transfer;

“Market Rules” means the rules made under section 32 of the *Electricity Ac*t;

“Measurement Canada” means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Ac*t, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131);

“Medium Sized Embedded Generation Facility” means an embedded generation facility with a name-plate rated capacity of less than 10 MW and:

a) more than 500 kW in the case of a facility connected to a less than 15kV line;
b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

“Meter Service Provider” means any entity that performs metering services on behalf of a distributor, generator, or registered market participant;

“Meter Installation” means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

“Metering Services” means installation, testing, reading and maintenance of meters;

“Micro Embedded Load Displacement Generation Facility” means an embedded load displacement generation facility with a name-plate rated capacity of 10 kW or less;

“Net Metering” means a settlement process for Embedded Generation behind a Load Customer meter as defined by Ontario Regulation 541/05

“Ontario Electrical Safety Code” means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

“Ontario Energy Board Act” means the *Ontario Energy Board Act, 199*8, S.O. 1998, c.15, Schedule B;

“Operational Demarcation Point” means the physical location at which a distributors’ responsibility for operational control of distribution equipment including connection assets ends at the customer;

“Ownership Demarcation Point” means the physical location at which a distributors’ ownership of distribution equipment including connection assets ends at the customer;

“Physical Distributor” with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly;

“Point of Supply” with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into a distribution system;

“Rate” means any rate, charge or other consideration, and includes a penalty for late payment;

“Rate Handbook” means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

“Regulations” means the regulations made under the *Act or the Electricity Act*;

“Retail”, with respect to electricity means,

a) To sell or offer to sell electricity to a consumer
b) To act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) To act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity.

“Retail Settlement Code” means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors’ obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

“Retailer” means a person who retails electricity;

“Service Area” with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity;

“Small Embedded Generation Facility” means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

“Smart Meter” means a device that measures electrical energy use (kilowatt-hours, kWh) on an hourly or sub-hourly basis and is part of an integrated data management system. The meter records, stores and transmits date and time-stamped meter readings to a utility’s computer to facilitate Time-of-Use and Hourly billing. Smart meters may also include other capabilities and features to aid in load management and energy conservation.

“Standard Offer” means a settlement process for distribution connected Embedded Generation under contract for supply with the Ontario Power Authority.

“Total losses” means the sum of distribution losses and unaccounted for energy;

“Townhouses” are usually a free hold property, the land is owned by the individual Owners of each unit, fronting onto a municipal street;

“Townhouse Development” is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit, and have direct outside access at ground level;

“Transmission System” means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

“Transmission System Code” means the Board approved code that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

“Transmit” with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

“Transmitter” means a person who owns or operates a transmission system;

“Unaccounted-for Energy” means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and un-metered loads, energy theft and non-attributable billing errors;

“Un-metered loads” means electricity consumption that is not metered and is billed based on estimated usage;

“Validating, Estimating and Editing (VEE)” means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;

"Wholesale Market Participant" means a person that sells or purchases electricity or ancillary services through the IESO-administered markets;

SECTION 5 APPENDICIES

Contact Information

Distribution Connection Process

Request For Connection Form

Electrical Planning Requirements Document

Electric Service Meter Base/ Service Verification Form

Contact Information

Local Distribution Company	Contact Phone Number	
Centre Wellington Hydro Ltd. Licence # ED-2002-0498	Phone: (519) 843-2900	730 Gartshore Street, Box 217 Fergus, Ont. N1M 2W8
COLLUS Power Corp. Licence # ED-2002-0518	Phone: (705) 445-1800	Box 189, 43 Stewart Road Collingwood, Ont. L9Y 3Z5
Grand Valley Energy Inc. Licence # ED-2002-0512	Phone: (519) 928-3112	P.O. Box 400 - 400 C Line Orangeville, Ont. L9W 2Z7
Hydro 2000 Inc. Licence # ED-2002-0542	Phone: (613) 679-4093	265 St. Philippe Street P.O.Box 370 Alfred, Ont. K0B 1A0
Innisfil Hydro Distribution Systems Limited. Licence # ED-2002-0520	Phone: (705) 431-4321	2073 Commerce Park Drive Innisfil, Ont. L9S 4A2
Lakefront Utilities Inc. Licence # ED-2002-0545	Phone: (905) 372-2193	207 Division St. P.O. Box 577 Cobourg, Ont. K9A 4L3
Lakeland Power Distribution Ltd. Licence # ED-2002-0540	Phone: (705) 789-5442	5-45 Cairns Cres. Huntsville, Ont. P1H 2M2
Midland Power Utility Corporation Licence # ED-2002-0541	Phone: (705) 526-9361	16984 Highway #12 Midland, Ont. L4R 4P4
Orangeville Hydro Ltd. Licence # ED-2002-0500	Phone: (519) 942-8000	P.O. Box 400 - 400 C Line Orangeville, Ont. L9W 2Z7
Orillia Power Distribution Corporation Licence # ED-2002-0530	Phone: (705) 326-2495	360 West St. South, P.O. Box 398 Orillia, Ont. L3V 6J9
Parry Sound Power Corporation Licence # ED-2003-0006	Phone: (705) 746-5866	125 William Street Parry Sound, Ont. P2A 1V9
Rideau St. Lawrence Distribution Inc. Licence # ED-2003-0003	Phone: (613) 925-3851	985 Industrial Rd. P.O. Box 699 Prescott, Ont. K0E 1T0
Wasaga Distribution Inc. Licence # ED-2002-0544	Phone: (705) 429-2517	950 River Road West P.O. Box 20 Wasaga Beach, Ont. L0L 2P0
Wellington North Power Inc. Licence # ED-2002-0511	Phone: (519) 323-1710	290 Queen Street West, P.O. Box 359 Mount Forest, Ont. N0G 2L0
Westario Power Inc. Licence # ED-2002-0515	Phone: (519) 507-6937 Toll Free: 1-866-978-2746	24 Eastridge Road R.R. #2 Walkerton, Ont. N0G 2V0
West Coast Huron Energy Inc. Licence # ED-2002-0510	Phone: (519) 524-7371	64 West Street Goderich, Ont. N7A 2K4
Woodstock Hydro Services Inc. Licence # ED-2003-0011	Phone: (519) 537-3488	16 Graham Street P.O. Box 1598 Woodstock, Ont. N4S 0A8

Note: Licence Numbers published by OEB as of May 8, 2008

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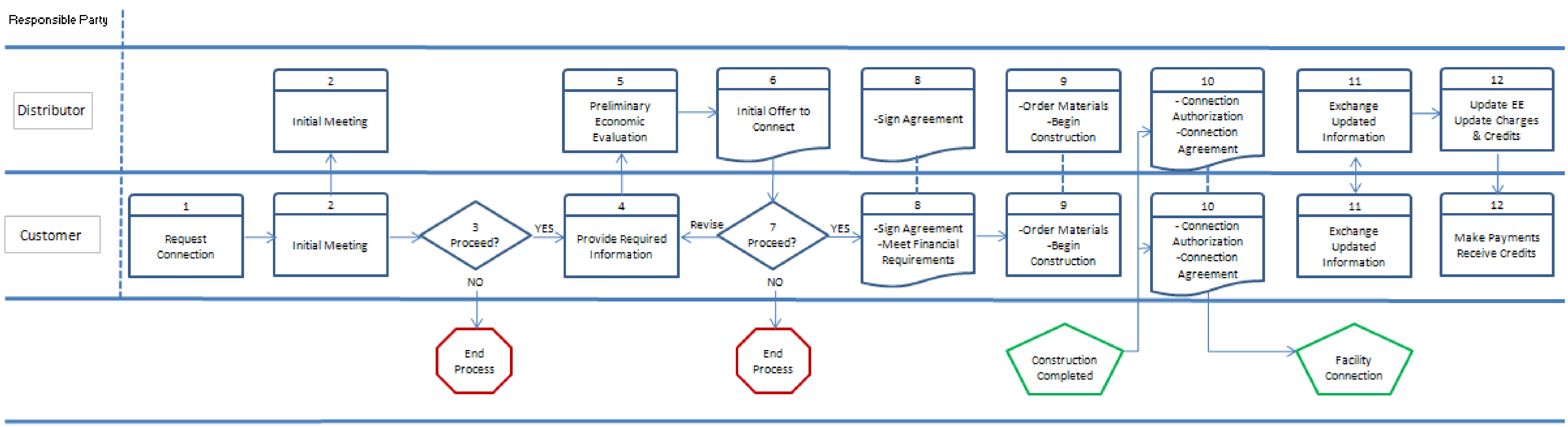
Distribution Connection
Developments & General Service Customers



Distribution Connection
Developments & General Service Customers

If you are planning on building a Subdivision, Commercial Building, or an Industrial Development, the process of connecting to the Local Distribution Infrastructure will require coordination with the Distributor.

The following information in conjunction with the preceding chart is designed to assist the parties in meeting their respective obligations and facilitate the required connection. It is important to note although the steps identified in both the chart and the following descriptions need to be followed in proper order, some of the steps may be combined to help speed up the process if all the required information is provided in a timely manner.

Step 1 – Request for Connection

Customer submits a connection request to the Distributor. Initial request should at a minimum include the following information:

- Location of proposed development
- General description of development
- Proposed construction date
- Contact information for Development

Step 2 – Initial Meeting

Customer and Distributor meet to review proposed new development and connection requirements. Initial meeting will provide both parties with an opportunity to gain a better understanding of the proposed development and identify any issues related to timing and connection to the Distribution System.

Based on the information provided by the customer prior to the meeting, the Distributor will be able to provide at a high level:

- An initial concept of the type of work that may be required to facilitate a connection. ie:
    - o Extension of an existing Feeder
    - o Potential requirement for a new DS
    - o Add a second or third phase to an existing feeder
- An understanding of the of the customer responsibilities
- An understanding of what must be managed by the Distributor
- An understanding of what may be contracted by the customer
- An estimated timeline required to provide connection facilities
- An initial estimate of required enhancement or expansion costs – note: more detailed estimates on costs will be provided with the Offer to Connect should the Customer choose to continue to Step 4.

Step 3 – Customer Decision

Based on the results of the initial meeting, the Customer decides on proceeding with the process or withdrawing their Request for Connection.

Step 4 – Customer Provides Required Information

If the Customer decides to proceed with the process for acquiring a connection, the Customer notifies the Distributor and provides the relevant detailed information as noted below:

- A statement noting if the Customer intends on managing the contestable work noted during the consultation
- Number of Residential Connections
- Residential – Type, Number, and size of units
- Number of Commercial / Industrial Connections
- Estimated Average Monthly consumption (at minimum winter & summer estimates)
- Estimated annual facility connections over five years from date of LDC system connection

The following information is also required however the Distributor reserves the right to perform the work internally or through an external consultant:

- Design and engineering specifications including but not limited to stamped site service drawings
- Determination of required Transformation based on estimated building loads
- Estimated Capital costs of facilities which would be assumed by the Distributor following energization

To assist the Customer in providing the required information, a submission summary sheet is provided as an attachment to this document.

Step 5 – Preliminary Economic Evaluation

Upon receipt of the required information from the Customer, if an expansion of the distribution system is required, the Distributor will perform a preliminary Economic Evaluation following the process as required in the Distribution System Code.
The Preliminary Economic Evaluation will assist the Distributor in calculating what (if any) portion of the Capital Costs the LDC will invest and will be used in the preparation of the Offer to Connect.

Step 6 – Offer to Connect

Using the information provided by the Customer, and following the completion of the Preliminary Economic Evaluation, the Distributor will prepare an “Offer to Connect”. The Offer to Connect will contain the following information:

- A statement as to whether the offer is a firm offer or an estimate to be revised after the actual costs are known
- The amount of Capital Contribution that will be required from the Customer
- The amount of the Expansion Deposit that will be required from the Customer
- A description of the costs related to the Capital Contribution
- The costs for inspections
- A description of the deliverables required from the Customer before Connection
- An estimated Connection Date

Step 7 – Customer Decision

Customer Reviews Offer to Connect and decides if they would like to continue with the project as planned. Three options are available to the Customer:

- Customer elects to drop the project a notice of withdrawal of the Request for Connection shall be provided to the Distributor.
- Customer would like to revise their Connection request, a notice informing the Distributor of the requested changes shall be provided to the Distributor (go back to Step 4)
- Customer agrees with the Offer to Connect,

Step 8 – Construction Agreement
Once the Customer accepts the Distributor's Offer to Connect, the parties shall enter into an agreement covering the construction and connection requirements and responsibilities.
The Customer and the Distributor sign the agreement and the Customer provides the financial deposits and/or guarantees as required.

Step 9 – Construction
Following receipt of signed Construction Agreement and required financial deposits and/or guarantees from the Customer, both parties shall begin ordering materials and begin construction.

Step 10 – Connection Authorization
Once construction is completed, both parties will ensure that inspections are completed and all required connection authorizations are in place. After receipt of a signed connection agreement and any additional financial contributions, the Distributor will authorize and connect the facility. If the customer is coordinating the work on the expansion facilities within the development, the customer is also required to provide "As-Built" drawings and a detailed material listing to ensure the Distributor has sufficient information in hand to verify system security prior to energization.

Step 11 – Exchange Updated Information
The Customer and the Distributor shall exchange any required updated information on the project including, but not limited to:
- All applicable Connection Authorizations
- All applicable Warranties
- Any new information that was provided as an estimate in Step 4
- Actual costs of any "capital works" related to the expansion facilities within the development
- Detailed site plan with appropriate Municipal Address information for individual services

Step 12 –Updated Economic Evaluation
As required, the Distributor shall recalculate the Preliminary Economic Evaluation using actual information acquired during and following the construction process.

If the development includes estimated connections that are not energized at the time of the initial Connection, the Distributor shall re-run the Economic Evaluation on an annual basis using actual customer connection information during the five (5) year connection horizon used in the initial Economic Evaluation.

Request for Connection

Development Name:	
Site Plan Identification	

Contact Information:

Contact Name:	
Street:	
Town:	
Postal Code:	

Requested Connection Date:	

Multi-Phase Development?	Y / N
If YES - Identify Phase	

<u>Type & Number of Connections:</u>

		Average Monthly Consumption Per Unit - Winter	Per Unit - Summer
Residential:		Kwh's	Kwh's
Commercial:		Kwh's	Kwh's
Industrial:		Kwh's	Kwh's

Residential Dwelling Design:

Town Homes	
Semi-Detached	
< 1,500 SqFt Single Dwellings	
>1,500 <3,500 SqFt Single Dwellings	
> 3,500 SqFt Single Dwellings	

Connection Horizon

Year 1		
Year 2	Estimated connections in 1st year	
Year 3	Estimated connections in 2nd year	
Year 4	Estimated connections in 3rd year	
Year 5	Estimated connections in 4th year	
	Estimated connections in 5th year	

Capital Costs:

Distribution Infrastructure:	
Transformers:	
Ducts & Structures:	

Date: Submitted:	
Submitted By:	
Signature:	

Electrical Planning Requirements

It is essential that the following information be provided to:

a) enable an assessment to be made on the impact of the proposed project on the Electrical Distribution System.

b) enable the Distributor to prepare pertinent information for the developer.

Please supply answers to the following questions as soon as possible as electrical planning cannot proceed until the Distributor has reviewed this information.

Preliminary electrical site plan drawings are to be submitted together with this form. Electrical drawings are to be submitted to the Distributor for approval prior to any related job tenders or the commencement of any electrical construction. The drawings shall be drawn to a scale usable by the Distributor, shall show local pole locations, proposed transformer location, proposed electrical room/metering location and show how access to the metering would be gained (i.e.: the path to the metering).

Electrical site plan drawings are to be submitted to the Distributor on one (1) Paper copy and in an electronic format as approved by the Distributor.

Project Location: **(Municipal Address)** ____________________

Name of Project: ____________________

Name of Applicant: ____________________

Address: ____________________

Contact Name: ____________________

Address: ____________________

E-Mail: ____________________

Telephone: ( ) ____________________ **Fax:** ( ) ____________________

Service Classification (☒ as many as apply):

☐ Residential

☐ General Service < 50kW

☐ General Service > 50kW

☐ General Service >500kW

☐ Unmetered os Miscellaneous Load

☐ Temporary Service

Service Entrance Switchboard with Utility CT and PT Compartment ☐ Yes ☐ No

Capacity of Main Service (in Amperes):

Maximum rated capacity: ____________

Estimated Connected Load - Demand in kW:

Maximum initial Demand: ___________ kW

Maximum Future Demand: ___________ kW

What service voltage is required (☒ one only):

☐ 120/240 Volt Single Phase

☐ 120/208 Volt Three Phase

☐ 347/600 Volt Three Phase

☐ Primary

Metering Type (☒ one only):

☐ Single Meter

☐ Multiple Meters

Quantity of Meter installations

100A or less: _________

101A to 200A: _________

more than 200A: _________

Required In-Service Date:

Month / Day / Year ______/_______/_________

Comments: **Please use the back of this form for comments**

Signed: ____________________ **Date:** ____________________

(Representative of Applicant)

Name: ____________________ **Title:** ____________________

____

CornerstonE Cornerstone Hydro Electric Concepts Association Inc. CornerstonE

Electric Service Meter Base With Municipal Address Verification Form

LOCAL DISTRIBUTION COMPANY NAME: ______________________________ (UTILITY)

This form **must** be completed by a Licensed Electrical Contractor or their legal representative prior to service connection. Accurate information must be provided or service will not be activated. ***(Sections A & B must be fully completed.)***

Electric Service Municipal Address: (Print) ______________________________
Name of Owner: ______________________________
Telephone: (________) ______________ Fax: (________)______________
Name of Electrical Contractor: ______________________________
Telephone: (________) ______________ Fax: (________)______________

In area (A) provided below, a 'front-view' layout of the Electric Meter Base(s) is shown including an assigned number for each base. Provide Municipal Address (B) information for each corresponding meter base number for billing purposes.

(A) FRONT VIEW OF ELECTRIC METER BASE(S)	(B) MUNICIPAL ADDRESS (Print)
	1)
	2)
	3)
	4)
	5)
	6)
	7)
	8)

The following regulations are agreed upon by the undersigned with receipt of the completed form by an authorized representative of the Utility: *(A copy of the utility authorized form will be provided for your records.)*

1. That all information contained on this form is accurate.
2. That if any information is determined to be inaccurate, the Utility will not be able to energize the service connection(s).
3. That if any information has to be corrected by Utility personnel there will be applicable charges to prepare an amended form.
4. That an amended form must be signed and returned along with payment of any applicable invoice, as per Part 3, prior to further consideration as to the activation of the service connection.
5. **The Electrical Contractor completes Section (C) below to apply for service activation. A property owner MAY complete Section (D) rather than the contractor, to apply for service activation.**

(C) The undersigned acknowledges agreement to all terms and conditions contained on this form.
(Please print names in full)

Company Name:

Representative:

Title/Position: Date: (m / d / y)

Signature ______________________________

(D) OPTIONAL if section (C) has been completed. The undersigned acknowledges agreement to all terms and conditions contained on this form.

Owner Name: *(Please print)*

Signature: ______________________________ Date: (m / d / y)

For COLLUS Power office use only:

Received : ______________________ Date ___/___/___ Approved: ______________________
(Authorized Rep's Name) (m / d / y) (Rep's Signature)

______________________ ______________________
(Address) (Telephone #)

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Changes in Conditions of Services

PSP is a member of the CHEC group which reviews and changes our Conditions of Service in accordance with changes to the Distribution System Code and Guidelines set out by the Ontario Energy Board.

List of Witnesses and their Curriculum Vitae

PSP will be pleased to provide a list of witnesses if an oral hearing is required.

Budget Directives (Capital and Operating)

PSP compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information is compiled for both the Bridge and Test Years.

Revenue Forecast

The revenue forecast was developed using historical load data and a weather normalization forecasting methodology model to forecast kW and kWh for the bridge and test years. This model was developed by ERA, ERA also projected load forecast data.

Operating and Maintenance Expense Forecast

The operating and maintenance expenses for fiscal 2008 Bridge Year and 2009 Test Year have been forecasted using two methods. Where appropriate we used a zero based methodology, while some sections required using prior year information. Each item is reviewed by account for each of the forecast years.

Capital Budget

All capital expenditures are budgeted on an USofA and/or project basis. The budget process involves previous year's spending along with forward year planning. In addition, PSP completes ground inspections throughout the year while completing maintenance on the distribution system which aids in the determination of capital projects. PSP currently does not have a formal budgeting process nor capital policy, both these items are currently under development and will likely be in place once approved by our board in early 2009.

Changes in Methodology

PSP has no planned changes in Methodology.

Financial Statements (2006)

PSP's 2006 Financial Statements is attached on the following pages.

Parry Sound Power Corporation

Financial Statements

For the year ended December 31, 2006

Parry Sound Power Corporation

Financial Statements
For the year ended December 31, 2006

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Summary of Significant Accounting Policies 6

Notes to Financial Statements 8

CULL, GORDON, GINGRICH & HARRIS Chartered Accountants

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• BRACEBRIDGE
F. GLENN GORDON, C.A.

Auditors' Report

To the Shareholder of
Parry Sound Power Corporation

We have audited the balance sheet of Parry Sound Power Corporation as at December 31, 2006 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with the accounting principles prescribed by the Ontario Energy Board.

Cull, Gordon, Gingrich & Harris

Parry Sound, Ontario
April 4, 2007

Chartered Accountants

Parry Sound Power Corporation
Balance Sheet

December 31	2006	2005
Assets		
Current		
Cash	**$ 3,491,293**	$ 2,665,522
Accounts receivable (Note 2)	**1,715,004**	1,402,091
Inventories	**117,263**	114,960
Prepaid expenses	**25,018**	25,247
Unbilled revenue	**484,521**	452,999
	5,833,099	4,660,819
Capital assets (Note 4)	**4,141,205**	4,384,862
Other Assets		
Incorporation/organization costs (Note 5)	**242,938**	291,526
Regulatory assets (Note 3)	**-**	-
Long term investments (Note 6)	**100**	-
	$ 10,217,342	$ 9,337,207
Liabilities and Shareholder's Equity		
Current		
Accounts payable (Note 7)	**$ 2,185,566**	$ 1,687,405
Other current liabilities	**244,465**	211,952
Due to related parties (Note 9)	**-**	9,063
Current portion of customer deposits	**158,943**	140,388
Due to Town of Parry Sound - Sewage and water billings	**516,928**	517,332
	3,105,902	2,566,140
Long-term portion of customer deposits	**128,229**	95,809
Promissory Note - Town of Parry Sound (Note 10)	**2,433,728**	2,433,728
Regulatory liabilities (Note 3)	**283,388**	178,919
	5,951,247	5,274,596
Contingencies (Note 12)		
Shareholder's equity		
Miscellaneous paid in capital	**1,332,900**	1,332,900
Share capital (Note 11)	**2,433,727**	2,433,727
Retained earnings	**499,468**	295,984
	4,266,095	4,062,611
	$ 10,217,342	$ 9,337,207

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Parry Sound Power Corporation
Statement of Operations and Retained Earnings

For the year ended December 31	2006	2005
Revenue (effective with May 1, 2002 market opening)		
Distribution revenue - fixed customer charges	$ 790,967	$ 776,169
Distribution revenue - variable charges	1,027,791	1,019,272
	1,818,758	1,795,441
Recovery of regulatory assets	(109,977)	(197,947)
	1,708,781	1,597,494
Other operating revenue (expense)		
Late payment charges	14,360	13,468
Interest earned	132,665	43,087
Regulatory assets interest	(16,175)	(76,036)
Pole rentals	36,439	27,655
Change of occupancy charges	19,697	11,659
Miscellaneous income	6,871	3,187
	193,857	23,020
	1,902,638	1,620,514
Operations, maintenance and administration expense		
Distribution - Operations (Note 9)	51,120	78,638
Distribution - Maintenance	213,937	239,154
Billing and collecting	375,543	312,457
Community expense	30,656	24,803
Other administration & general	376,570	354,721
Interest on long-term debt	176,444	176,444
PILS - payment in lieu of capital tax (Note 1)	-	2,923
Amortization of capital assets	331,496	332,359
Amortization of organization costs	48,588	48,588
Non-utility write down of transition costs	-	7,168
	1,604,354	1,577,255
Income before PILS	298,284	43,259
PILS - Payment in lieu of income tax (Note 1)	94,800	29,722
Net income for the year	203,484	13,537
Retained earnings, beginning of year	295,984	282,447
Retained earnings, end of year	$ 499,468	$ 295,984

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Parry Sound Power Corporation
Statement of Cash Flows

For the year ended December 31	2006	2005
Cash provided by (used in)		
Operating activities		
Net income for the year	$ 203,484	$ 13,537
Adjustments required to reconcile net income with net cash provided by operating activities		
Amortization of capital assets	331,496	332,359
Amortization of organization costs	48,588	48,588
Changes in non-cash working capital balances		
Accounts receivable	(312,913)	200,664
Inventories	(2,303)	3,184
Prepaid expenses	229	(5,257)
Unbilled revenue	(31,522)	(129,535)
Accounts payable	498,161	731,603
Due from / to related parties	(9,063)	655
Other current liabilities	32,513	12,162
Due to Town of Parry Sound	(404)	25,487
	758,266	1,233,447
Investing activities		
Purchase of capital assets	(87,839)	(123,075)
Regulatory assets / liabilities	104,469	560,642
Investment in 1713637 Ontario Inc.	(100)	-
	16,530	437,567
Financing activities		
Increase in customer deposits	50,975	41,751
	50,975	41,751
Increase in cash during the year	825,771	1,712,765
Cash, beginning of year	2,665,522	952,757
Cash, end of year	$ 3,491,293	$ 2,665,522

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Parry Sound Power Corporation
Summary of Significant Accounting Policies

December 31, 2006

General

These financial statements have been prepared in accordance with accounting policies for Municipal Electrical Utilities in Ontario as required by the Ontario Energy Board under the authority of the Ontario Energy Board Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Manual.

Financial Instruments

The company's financial instruments consist of cash, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, customer deposits, long-term debt, amounts due to (from) related parties and a promissory note payable. Unless otherwise noted, it is management's opinion that the company is not exposed to significant interest, currency or credit risks arising from its financial instruments. The fair value of these financial instruments approximate thier carrying values, unless otherwise noted.

Inventories

Inventory consists of repairs parts, supplies and materials valued at the lower of cost and replacement cost.

Regulatory Assets

The corporation is required to bill customers for various charges including the cost of power, wholesale market charges, transmission charges on behalf of third parties and other costs as directed by the Ontario Energy Board. In turn the corporation must pay for these items. The difference between what is billed to customers versus what is paid is carried on the balance sheet as a regulatory asset (liability).

Parry Sound Power Corporation
Summary of Significant Accounting Policies

Capital Assets

Capital assets are stated at cost less accumulated amortization. Cost for capital assets installed by the Corporation include material, labour and overhead. Amortization of the assets, and the related Contributions and Grants in aid of Capital, is provided as follows:

Distribution station equipment - Straight line basis over 30 years
All other plant and equipment - Straight line basis over 25 years

The amortization lifetime includes the years the assets were owned by the former Utility

Service Revenue

Service revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year.

Use of Estimates

Since precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements in accordance with generally accepted accounting principles necessarily involves the use of estimates and approximations. These have been made using careful judgments.

December 31, 2006

1. The Organization

Parry Sound Hydro Corporation was incorporated under the Ontario Business Corporations Act on October 31, 2000. Pursuant to section 142 of the Electricity Act, 1998 and in accordance with By-Law 2000-4303 of the Corporation of the Town of Parry Sound, all of the assets, liabilities, employees, rights and obligations of the Parry Sound Public Electric Utility Commission were transferred to Parry Sound Power Corporation, Parry Sound Powergen Corporation and Parry Sound Energy Services Corporation, all wholly owned subsidiaries of Parry Sound Hydro Corporation, and to Parry Sound Hydro Corporation, which is wholly owned by the Corporation of the Town of Parry Sound. These corporations will continue the transmission, distribution, generation and retailing of electricity and the associated business activities of the former Parry Sound Public Electric Utility Commission.

In accordance with various regulations of the Province of Ontario, Parry Sound Power Corporation became a taxable entity on October 1, 2001. As at that date, the corporation was responsible for making payments in lieu of taxes, equivalent to federal and provincial income and capital taxes, to the Ontario Electricity Financial Corporation, to pay down the residual debt of the former Ontario Hdyro.

2. Accounts Receivable

	2006	2005
Consumers	**$ 1,729,921**	$ 1,437,091
Goods and service tax receivable	**20,083**	-
Allowance for doubtful accounts	**(35,000)**	(35,000)
	$ 1,715,004	$ 1,402,091

3. Regulatory assets / liabilities

			2006	2005
PILS variance account	$ 900,470			$ 750,393
Interest	13,786			14,017
Recovery of PILS through distribution revenue	(840,789)			(700,846)
True up	(80,067)			(76,095)
	(6,600)			(12,531)
PILS contra account	(6,600)			(12,531)
			$ -	$ -
Conservation and demand side management	$ (150,212)			$ (137,382)
CDM - Tranche recovery	150,212			137,382
			-	$ -
Pre-market opening energy variance	$ -			$ 121,730
Interest	-			32,411
			-	$ 154,141
Qualifying transition costs	$ -			$ 71,684
Interest @ 7.25%	-			19,003
Transition cost reduction	-			(7,168)
Recovery of qualifying transition costs	-			(16,034)
			-	$ 67,485
Retail settlement variance accounts - *pg 11*			(509,334)	(109,045)
Ontario Energy Board Costs			12,701	12,469
Low Voltage Variance			32,166	-
Smart Meter Recovery			(5,156)	-
Other			994	16,679
Recovery of Regulatory assets			185,241	(320,648)
			$ (283,388)	$ (178,919)

3. **Regulatory assets / liabilities continued...**

PILS variance account
The company is entitled to receive the full value of the regulatory PILS (payments in lieu of income and capital taxes) embedded in rates approved by the Ontario Energy Board. The regulatory PILS are accrued and recorded on an equal monthly basis. The portion of distribution revenue collected which is related to PILS is recorded as a recovery against the variance account. Interest of 4.15% per annum is accrued on the previous months variance account balance.

Conservation and demand side management
This account relates to conservation and demand side management activities under process by Parry Sound Power. Included in the dollar value is the allowable recovery from the distribution rates. The total recovery was collected over a one year period.

Pre-market opening energy variance
This account relates to the difference between the cost of power purchased for non-time of use customers and the deemed cost of power revenue from non-time of use customers for the period January 1, 2001 to April 30, 2002. The amounts were recovered in 2006 in accordance with direction from the Ontario Energy Board.

Qualifying transition costs
Qualifying transition costs include fees and expenses that meet the qualifying criteria established in the Electric Distribution Rate Handbook. The portion of distribution revenue collected which is related to qualifying transition costs is recorded as a recovery against the variance account. Interest of 7.25% is accrued on the previous months balance and is recorded in the current income statement. The amounts were recovered in 2006 in accordance with direction from the Ontario Energy Board.

Retail settlement variance accounts
The retail settlement variance accounts record the difference between the amounts billed to customers for energy costs, wholesale market service charges, network and connection charges, transmission charges and the amounts paid by the utility in respect of these items. These variances will be disposed of in accordance with direction from the Ontario Energy Board.

3. **Regulatory assets / liabilities continued...**

	2006	2005
Retail settlement variance accounts		
Revenue - supply of power and regulatory charges		
Power	$ 5,253,960	$ 5,464,856
Wholesale market service charge	577,498	587,946
Network service charge	468,634	523,517
Connection service charge	390,538	434,424
	6,690,630	7,010,743
Expense - supply of power and regulatory charges		
Power Purchased		
- Independent Electricity Market Operator and Hydro One Networks Inc. (net of RPPP*)	4,702,155	4,776,673
- Parry Sound Powergen Corporation (Note 9)	308,694	306,563
Wholesale market service charge	344,521	640,236
Network service charge	625,541	364,251
Connection service charge	307,656	541,691
One time	1,774	4,799
	6,290,341	6,634,213
Current year retail settlement variance	400,289	376,530
Prior years cumulative total	109,045	(267,485)
Retail settlement variance accounts	$ 509,334	$ 109,045

* RPPP - Regulated price protection plan

December 31, 2006

4. Capital Assets

	2006			2005
	Cost	**Accumulated Amortization**	**Net Book Value**	Net Book Value
Land	$ 74,305	$ -	$ 74,305	$ 74,305
Land rights	35,048	34,608	440	460
Work in progress	12,320	-	12,320	40,345
Distribution station equipment	1,600,520	959,092	641,428	674,818
Poles, towers & fixtures	1,493,586	894,467	599,119	625,282
Overhead conductors & devices	2,172,656	1,317,261	855,395	905,951
Underground conduit	591,997	263,489	328,508	327,132
Underground conductors & devices	754,264	336,542	417,722	418,574
Line transformers	2,076,319	1,228,547	847,772	869,727
Services	1,240,644	723,410	517,234	545,686
Meters	479,713	298,807	180,906	181,041
	10,531,372	6,056,223	4,475,149	4,663,321
Less: Contributions & grants	(401,903)	(67,959)	(333,944)	(278,459)
	$ 10,129,469	$ 5,988,264	$ 4,141,205	$ 4,384,862

5. Other Assets

Incorporation/Organization costs include fees and expenses relating to the incorporation and organization of the corporation on November 1, 2000. Further costs are also reported by the parent and sister corporations for their share of such costs. These costs are amortized over the next 10 years (straight-line).

6. Long Term Investments

Utility Collaborative Services Inc.
Parry Sound Power Corporation owns a 25% interest in Utility Collaborative Services Inc. (UCS). The investment is recorded at cost of $100.00. UCS provides standards based utility back office services through stable group licencing models.

Cornerstone Hydro Electric Concepts Inc.
Parry Sound Power owns 1 common share of Cornerstone Hydro Electric Concepts Inc. (CHEC). The 6.25% interest is recorded using the cost method of $NIL.

7. Accounts Payable

	2006	2005
Independent Electricity Service Operator **	$ 1,197,426	$ 1,197,426
Independent Electricity Service Operator - December bill	585,136	-
Hydro One Networks Inc.	153,263	145,020
Hydro One Networks Inc. - Regulatory asset low voltage charge	67,289	93,346
Goods and service tax payable	-	36,993
Ontario price credit rebate	2,395	93,651
Other	180,057	120,969
	$ 2,185,566	$ 1,687,405

As explained in Note 9, all operations, maintenance and administration costs are paid for by Parry Sound Energy Services and are included in the amount due to this sister corporation.

** This amount is subject to final approval by the Ontario Electric Finance Corporation based on the 2005 reconciliation submitted. The 2006 reconciliation has not been completed as the OEFC has not approved the 2005 reconciliation process and has not determined the procedures to be followed by the utilites.

8. Fixed Price vs Market Price

Small volume customers are charged a fixed rate per kwh for the cost of power. The corporation must pay market price for the power it purchases, but receives an adjustment from the IESO for the difference between this fixed rate and the market rate. As the customers are billed for their usage this liability is reduced.

9. Related Party Transactions

At the end of the year, the amounts due from (to) related parties are as follows:

	2006	2005
Parry Sound Energy Services Corporation	$ -	$ (9,063)

Parry Sound Powergen Corporation, a sister company of Parry Sound Power Corporation is responsible for those activities relating to the generation of power. Until Market Opening, Parry Sound Powergen Corporation charged Parry Sound Power Corporation for power equal to actual operating costs only, with no mark-ups. At market opening, Parry Sound Powergen Corporation charged Parry Sound Power Corporation the actual spot market price for all energy delivered to Parry Sound Power Corporation.

Included in trade accounts receivable and payables are intercompany balances of $NIL (2005 - $2,251) and $148,967 (2005 - $91,068), respectively. These are current receivables and payables arising in the normal course of operations.

Parry Sound Energy Services Corporation (PSES), a sister company of Parry Sound Power Corporation, employs all staff from the former Parry Sound Electric Utility Commission and provides services to its parent and sister corporations. PSES charges operations labour to these corporations at cost (including overhead) plus mark up. Trucks are charged out at market rates. PSES records certain administrative salaries and expenses for all four companies and allocates these costs to each company based on an estimated share of costs.

All administration costs related to Parry Sound Hydro Corporation, the parent company, are then charged to Parry Sound Energy Services which in turn bills the other two sister companies for their share of all expenses.

10. Promissory Note

In connection with the reorganization of the former Parry Sound Electric Public Utility and By-Law 2000-4303, the purchase price of assets transferred to the four new corporations consisted of the issuance of common shares in each corporation and unsecured promissory notes to the Town of Parry Sound.

Commencing January 1, 2002, the interest on the promissory note is 7.25% on the outstanding principal, payable quarterly. The Corporation has the option of repaying the principal amount at any time.

11. Share Capital

Authorized:
Unlimited number of common shares

Issued:

		2006	2005
2,433,727	Common shares	**$ 2,433,727**	$ 2,433,727

12. Contingencies

A class action claiming $500 million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against Toronto Hydro Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged Late Payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Municipal Electric Association is undertaking the defense of this class action. At this time it is not possible to quantify the effect, if any, on the financial statements of the Power Corporation.

Financial Statements (2007)

PSP's 2007 Financial Statements is attached on the following page.

Parry Sound Power Corporation

Financial Statements

For the year ended December 31, 2007

Parry Sound Power Corporation

Financial Statements
For the year ended December 31, 2007

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Auditors' Report

To the Shareholder of
Parry Sound Power Corporation

We have audited the balance sheet of Parry Sound Power Corporation as at December 31, 2007 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with the accounting principles prescribed by the Ontario Energy Board.

Cull, Gordon, Gingrich & Harris

Chartered Accountants, Licensed Public Accountants

Parry Sound, Ontario
March 19, 2008

Parry Sound Power Corporation
Balance Sheet

December 31		2007	2006
Assets			
Current			
Cash		$ **1,007,780**	$ 3,491,293
Short-term investments (Note 2)		**1,800,899**	-
Accounts receivable (Note 3)		**1,825,712**	1,715,004
Inventories		**111,587**	117,263
Prepaid expenses		**34,308**	25,018
Unbilled revenue		**355,407**	484,521
		5,135,693	5,833,099
Capital assets (Note 5)		**3,958,872**	4,141,205
Other Assets			
Incorporation/organization costs (Note 6)		**194,351**	242,938
Long term investments (Note 7)		**100**	100
		$ **9,289,016**	$ 10,217,342
Liabilities and Shareholder's Equity			
Current			
Accounts payable (Note 8)		$ **920,696**	$ 2,185,566
Other current liabilities		**234,195**	244,465
Current portion of customer deposits		**162,581**	158,943
Due to Town of Parry Sound			
- Sewage and water billings		**606,493**	516,928
		1,923,965	3,105,902
Long-term portion of customer deposits		**128,229**	128,229
Promissory Note - Town of Parry Sound (Note 11)		**2,433,728**	2,433,728
Regulatory liabilities (Note 4)		**300,641**	283,388
		4,786,563	5,951,247
Contingencies (Note 13)			
Shareholder's equity			
Miscellaneous paid in capital		**1,332,900**	1,332,900
Share capital (Note 12)		**2,433,727**	2,433,727
Retained earnings		**735,826**	499,468
		4,502,453	4,266,095
		$ **9,289,016**	$ 10,217,342

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Parry Sound Power Corporation
Statement of Operations and Retained Earnings

For the year ended December 31		2007		2006
Revenue (effective with May 1, 2002 market opening)				
Distribution revenue - fixed customer charges	$	**790,443**	$	790,967
Distribution revenue - variable charges		**962,220**		1,027,791
		1,752,663		1,818,758
Recovery of regulatory assets		**33,297**		(109,977)
		1,785,960		1,708,781
Other operating revenue (expense)				
Late payment charges		**16,906**		14,360
Interest earned		**163,027**		132,665
Regulatory assets interest		**17,204**		(16,175)
Pole rentals		**36,541**		36,439
Change of occupancy charges		**27,504**		19,697
Miscellaneous income		**528**		6,871
		261,710		193,857
		2,047,670		1,902,638
Operations, maintenance and administration expense				
Distribution - Operations (Note 10)		**63,190**		51,120
Distribution - Maintenance		**266,047**		213,937
Billing and collecting		**334,602**		375,543
Community expense		**89,801**		30,656
Other administration & general		**361,840**		376,570
Interest on long-term debt		**176,444**		176,444
Amortization of capital assets		**332,645**		331,496
Amortization of organization costs		**48,588**		48,588
		1,673,157		1,604,354
Income before PILS		**374,513**		298,284
PILS - Payment in lieu of income tax (Note 1)		**138,155**		94,800
Net income for the year		**236,358**		203,484
Retained earnings, beginning of year		**499,468**		295,984
Retained earnings, end of year	$	**735,826**	$	499,468

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Parry Sound Power Corporation
Statement of Cash Flows

For the year ended December 31	2007	2006
Cash provided by (used in)		
Operating activities		
Net income for the year	**$ 236,358**	$ 203,484
Adjustments required to reconcile net income with net cash provided by operating activities		
Amortization of capital assets	**332,645**	331,496
Amortization of organization costs	**48,588**	48,588
Changes in non-cash working capital balances		
Accounts receivable	**(110,708)**	(312,913)
Inventories	**5,676**	(2,303)
Prepaid expenses	**(9,290)**	229
Unbilled revenue	**129,114**	(31,522)
Accounts payable	**(1,264,870)**	498,161
Due from / to related parties	**-**	(9,063)
Other current liabilities	**(10,270)**	32,513
Due to Town of Parry Sound	**89,565**	(404)
	(553,192)	758,266
Investing activities		
Purchase of capital assets	**(150,313)**	(87,839)
Regulatory assets / liabilities	**17,253**	104,469
Investment in 1713637 Ontario Inc.	**-**	(100)
	(133,060)	16,530
Financing activities		
Increase in customer deposits	**3,638**	50,975
Increase (decrease) in cash during the year	**(682,614)**	825,771
Cash, beginning of year	**3,491,293**	2,665,522
Cash, end of year	**$ 2,808,679**	$ 3,491,293
Cash consists of:		
Cash	**$ 1,007,780**	$ 3,491,293
Short-term Investments	**1,800,899**	-
	$ 2,808,679	$ 3,491,293

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

General

These financial statements have been prepared in accordance with accounting policies for Municipal Electrical Utilities in Ontario as required by the Ontario Energy Board under the authority of the Ontario Energy Board Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Manual.

Financial Instruments

The company's financial instruments consist of cash, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, customer deposits, long-term debt, amounts due to (from) related parties and a promissory note payable. Unless otherwise noted, it is management's opinion that the company is not exposed to significant interest, currency or credit risks arising from its financial instruments. The fair value of these financial instruments approximate thier carrying values, unless otherwise noted.

Temporary Investments

Temporary investments are stated at the lower of cost and market value.

Inventories

Inventory consists of repairs parts, supplies and materials valued at the lower of cost and replacement cost.

Regulatory Assets

The corporation is required to bill customers for various charges including the cost of power, wholesale market charges, transmission charges on behalf of third parties and other costs as directed by the Ontario Energy Board. In turn the corporation must pay for these items. The difference between what is billed to customers versus what is paid is carried on the balance sheet as a regulatory asset (liability).

Parry Sound Power Corporation
Summary of Significant Accounting Policies

December 31, 2007

Capital Assets

Capital assets are stated at cost less accumulated amortization. Cost for capital assets installed by the Corporation include material, labour and overhead. Amortization of the assets, and the related Contributions and Grants in aid of Capital, is provided as follows:

Distribution station equipment - Straight line basis over 30 years
All other plant and equipment - Straight line basis over 25 years

The amortization lifetime includes the years the assets were owned by the former Utility

Service Revenue

Service revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year.

Use of Estimates

Since precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements in accordance with generally accepted accounting principles necessarily involves the use of estimates and approximations. These have been made using careful judgments.

1. The Organization

Parry Sound Hydro Corporation was incorporated under the Ontario Business Corporations Act on October 31, 2000. Pursuant to section 142 of the Electricity Act, 1998 and in accordance with By-Law 2000-4303 of the Corporation of the Town of Parry Sound, all of the assets, liabilities, employees, rights and obligations of the Parry Sound Public Electric Utility Commission were transferred to Parry Sound Power Corporation, Parry Sound Powergen Corporation and Parry Sound Energy Services Corporation, all wholly owned subsidiaries of Parry Sound Hydro Corporation, and to Parry Sound Hydro Corporation, which is wholly owned by the Corporation of the Town of Parry Sound. These corporations will continue the transmission, distribution, generation and retailing of electricity and the associated business activities of the former Parry Sound Public Electric Utility Commission.

In accordance with various regulations of the Province of Ontario, Parry Sound Power Corporation became a taxable entity on October 1, 2001. As at that date, the corporation was responsible for making payments in lieu of taxes, equivalent to federal and provincial income and capital taxes, to the Ontario Electricity Financial Corporation, to pay down the residual debt of the former Ontario Hdyro.

2. Short-term Investments

	2007	2006
Bankers Acceptance - at cost on December 21, 2007		
- TD Bank - 4.35%, matures January 23, 2008	$ **900,456**	$ -
- TD Bank - 4.43%, matures February 19, 2008	**900,443**	-
	$ **1,800,899**	$ -

3. Accounts Receivable

	2007	2006
Consumers	$ **1,774,369**	$ 1,729,921
Goods and service tax receivable	**86,343**	20,083
Allowance for doubtful accounts	**(35,000)**	(35,000)
	$ **1,825,712**	$ 1,715,004

4. Regulatory assets / liabilities

		2007	2006
PILS variance account	$ 833,804		$ 900,470
Interest	12,257		13,786
Recovery of PILS through distribution revenue	(766,492)		(840,789)
True up	(80,067)		(80,067)
	(498)		(6,600)
PILS contra account	(498)		(6,600)
		$ -	$ -
Conservation and demand side management	$ (56,342)		$ (150,212)
CDM - Tranche recovery	56,342		150,212
		-	$ -
RCVA STR	$ 142		$ -
Interest	(21)		-
		121	$ -
Retail settlement variance accounts - *pg 11*		(556,100)	(509,334)
Ontario Energy Board Costs		18,479	12,701
Low Voltage Variance		158,662	32,166
Smart Meter Recovery		(14,985)	(5,156)
Other		1,033	994
Recovery of Regulatory assets		92,149	185,241
		$ (300,641)	$ (283,388)

PILS variance account
The company is entitled to receive the full value of the regulatory PILS (payments in lieu of income and capital taxes) embedded in rates approved by the Ontario Energy Board. The regulatory PILS are accrued and recorded on an equal monthly basis. The portion of distribution revenue collected which is related to PILS is recorded as a recovery against the variance account. Interest of 4.15% per annum is accrued on the previous months variance account balance.

4. Regulatory assets / liabilities continued...

Conservation and demand side management
This account relates to conservation and demand side management activities under process by Parry Sound Power. Included in the dollar value is the allowable recovery from the distribution rates. The total recovery was collected over a one year period.

Retail settlement variance accounts
The retail settlement variance accounts record the difference between the amounts billed to customers for energy costs, wholesale market service charges, network and connection charges, transmission charges, other additional items and the amounts paid by the utility in respect of these items. These variances will be disposed of in accordance with direction from the Ontario Energy Board.

Retail settlement variance accounts

	2007	2006
Revenue - supply of power and regulatory charges		
Power	$ 5,296,824	$ 5,253,960
Wholesale market service charge	586,794	577,498
Network service charge	454,628	468,634
Connection service charge	398,375	390,538
	6,736,621	6,690,630
Expense - supply of power and regulatory charges		
Power Purchased		
- Independent Electricity Market Operator and Hydro One Networks Inc. (net of RPPP*)	5,187,430	4,702,155
- Parry Sound Powergen Corporation (Note 10)	258,599	308,694
Wholesale market service charge	444,518	344,521
Network service charge	435,847	625,541
Connection service charge	360,207	307,656
One time	3,254	1,774
	6,689,855	6,290,341
Current year retail settlement variance	46,766	400,289
Prior years cumulative total	509,334	109,045
Retail settlement variance accounts	$ 556,100	$ 509,334

* RPPP - Regulated price protection plan

December 31, 2007

5. Capital Assets

	2007			2006
	Cost	**Accumulated Amortization**	**Net Book Value**	Net Book Value
Land	$ 74,305	$ -	$ 74,305	$ 74,305
Land rights	35,048	34,628	420	440
Work in progress	47,348	-	47,348	12,320
Distribution station equipment	1,600,520	1,007,391	593,129	641,428
Poles, towers & fixtures	1,521,195	945,360	575,835	599,119
Overhead conductors & devices	2,185,621	1,389,893	795,728	855,395
Underground conduit	592,235	286,274	305,961	328,508
Underground conductors & devices	763,777	365,919	397,858	417,722
Line transformers	2,136,920	1,297,155	839,765	847,772
Services	1,266,500	767,044	499,456	517,234
Meters	490,493	312,571	177,922	180,906
	10,713,962	6,406,235	4,307,727	4,475,149
Less: Contributions & grants	(434,181)	(85,326)	(348,855)	(333,944)
	$ 10,279,781	$ 6,320,909	$ 3,958,872	$ 4,141,205

6. Other Assets

Incorporation/Organization costs include fees and expenses relating to the incorporation and organization of the corporation on November 1, 2000. Further costs are also reported by the parent and sister corporations for their share of such costs. These costs are amortized over the next 10 years (straight-line).

7. Long Term Investments

Utility Collaborative Services Inc.
Parry Sound Power Corporation owns a 25% interest in Utility Collaborative Services Inc. (UCS). The investment is recorded at cost of $100.00. UCS provides standards based utility back office services through stable group licencing models.

Cornerstone Hydro Electric Concepts Inc.
Parry Sound Power owns 1 common share of Cornerstone Hydro Electric Concepts Inc. (CHEC). The 6.25% interest is recorded using the cost method of $NIL.

8. Accounts Payable

	2007	2006
Independent Electricity Service Operator **	**$ (93,060)**	$ 1,197,426
Independent Electricity Service Operator - December bill	**602,969**	585,136
Hydro One Networks Inc.	**73,759**	153,263
Hydro One Networks Inc. - Regulatory asset low voltage charge	**31,512**	67,289
Ontario price credit rebate	**-**	2,395
Trade payables and other	**305,516**	180,057
	$ 920,696	$ 2,185,566

As explained in Note 10, all operations, maintenance and administration costs are paid for by Parry Sound Energy Services and are included in the amount due to this sister corporation.

** This amount is subject to final approval by the Ontario Electric Finance Corporation based on the 2006 & 2007 reconciliations submitted. During 2007, the OEFC approved the 2005 reconciliation and the amount owing was paid.

9. Fixed Price vs Market Price

Small volume customers are charged a fixed rate per kwh for the cost of power. The corporation must pay market price for the power it purchases, but receives an adjustment from the IESO for the difference between this fixed rate and the market rate. As the customers are billed for their usage this liability is reduced.

December 31, 2007

10. Related Party Transactions

Parry Sound Powergen Corporation, a sister company of Parry Sound Power Corporation is responsible for those activities relating to the generation of power. Until Market Opening, Parry Sound Powergen Corporation charged Parry Sound Power Corporation for power equal to actual operating costs only, with no mark-ups. At market opening, Parry Sound Powergen Corporation charged Parry Sound Power Corporation the actual spot market price for all energy delivered to Parry Sound Power Corporation.

Included in trade accounts receivable and payables are intercompany balances of $1,983 (2006 - $NIL) and $183,974 (2006 - $148,967), respectively. These are current receivables and payables arising in the normal course of operations.

Parry Sound Energy Services Corporation (PSES), a sister company of Parry Sound Power Corporation, employs all staff from the former Parry Sound Electric Utility Commission and provides services to its parent and sister corporations. PSES charges operations labour to these corporations at cost (including overhead) plus mark up. Trucks are charged out at market rates. PSES records certain administrative salaries and expenses for all four companies and allocates these costs to each company based on an estimated share of costs.

All administration costs related to Parry Sound Hydro Corporation, the parent company, are then charged to Parry Sound Energy Services which in turn bills the other two sister companies for their share of all expenses.

11. Promissory Note

In connection with the reorganization of the former Parry Sound Electric Public Utility and By-Law 2000-4303, the purchase price of assets transferred to the four new corporations consisted of the issuance of common shares in each corporation and unsecured promissory notes to the Town of Parry Sound.

Commencing January 1, 2002, the interest on the promissory note is 7.25% on the outstanding principal, payable quarterly. The Corporation has the option of repaying the principal amount at any time.

12. Share Capital

Authorized:
Unlimited number of common shares

Issued:

		2007	2006
2,433,727	Common shares	**$ 2,433,727**	$ 2,433,727

13. Contingencies

A class action claiming $500 million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against Toronto Hydro Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged Late Payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Municipal Electric Association is undertaking the defense of this class action. At this time it is not possible to quantify the effect, if any, on the financial statements of the Power Corporation.

Pro Forma Statements (2008 & 2009)

PSP's Pro Forma Statements for 2008 and 2009 are attached on the following pages.

Table 8 2008 Pro Forma Balance Sheet

PARRY SOUND POWER CORPORATION **Unaudited**
BALANCE SHEET
AS AT DECEMBER 31, 2008
With comparative for the YEAR ending December 31, 2007

	December 2008	December 2007
ASSETS		
Current		
Cash	$911,387	$1,007,780
Accounts receivable	$1,739,369	$1,825,712
Unbilled revenue	$355,407	$355,407
Current Investments	$0	$1,800,899
Prepaid Expenses	$34,308	$34,308
Inventory	$111,587	$111,587
	$3,152,058	$5,135,694
Capital Assets	$3,989,506	$3,958,871
Other		
Regulatory Assets	-$344,065	-$300,641
Incorporation/organization costs	$145,763	$194,351
Long Term Investments	$100	$100
	-$198,202	-$106,190
	$6,943,362	$8,988,375
LIABILITIES		
Current		
Accounts payable and other current liabilities	$884,630	$970,970
Due to Town of Parry Sound - Water and Sewage	$606,493	$606,493
Due to Related Parties	$183,921	$183,921
	$1,675,044	$1,761,384
Other		
Customer deposits	$290,810	$290,810
Promissory Note - Town of Parry Sound - 7.25%	$2,433,727	$2,433,727
	$2,724,537	$2,724,537
Total Liabilities	$4,399,581	$4,485,921
SHAREHOLDER'S EQUITY		
Miscellaneous paid in capital	$0	$1,332,900
Share capital - 2,433,727 common shares	$2,433,727	$2,433,727
Retained earnings (deficit)		
Balance beginning of period	$735,825	$499,469
Dividend Paid	-$735,825	
Net income (loss) for the period	$110,054	$236,358
Balance, end of the period	$110,054	$735,827
Total shareholder equity	$2,543,781	$4,502,454
	$6,943,362	$8,988,375

Table 9 2008 Pro Forma Statement of Income

PARRY SOUND POWER CORPORATION **Unaudited**
STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2008
With comparative for the YEAR ending December 31, 2007

	December 2008	December 2007
Revenue		
Distribution Revenue - fixed customer charges	$843,247	$790,443
Distribution Revenue - variable charges	$965,840	$962,220
Regulatory Recovery		33,297
	$1,809,088	$1,785,960
Other operating revenue		
Late payment charges	15,067	16,906
Interest earned	87,329	180,231
Pole rentals	36,542	36,541
Other Service Revenue, occupancy change, RSR, etc	31,737	27,504
Miscellaneous income	0	528
	170,675	261,710
Operations, maintenance & administration expense		
Distribution - Operations	70,918	63,190
Distribution - Maintenance	310,470	266,047
Billing and collecting	394,041	334,602
Community expense	68,465	89,801
Directors salaries and expense	12,015	8,147
Other administration & general	413,324	353,693
Amortization	384,102	381,233
	$1,653,335	$1,496,713
Net income before PILS and interest	326,428	550,958
Interest to Town of Parry Sound	176,444	176,444
PILS	39,931	138,155
Net income	110,054	236,359

Table 10 2009 Pro Forma Balance Sheet

PARRY SOUND POWER CORPORATION **Unaudited**
BALANCE SHEET
AS AT DECEMBER 31, 2009
With comparative for the YEAR ending December 31, 2008

		December 2009	December 2008
	ASSETS		
Current			
Cash		1,274,301	$911,387
Accounts receivable		1,739,369	1,739,369
Unbilled revenue		355,407	355,407
Current Investments		0	0
Prepaid Expenses		34,308	34,308
Inventory		111,587	111,587
		3,514,972	$3,152,058
Capital Assets		3,943,038	3,989,506
Other			
Regulatory Assets		-$395,265	-$344,065
Incorporation/organization costs		97,175	145,763
Long Term Investments		100	100
		-$297,990	-$198,202
		7,160,021	$6,943,362
	LIABILITIES		
Current			
Accounts payable and other current liabilities		874,028	884,630
Due to Town of Parry Sound - Water and Sewage		606,493	606,493
Due to Related Parties		183,921	183,921
		1,664,442	$1,675,044
Other			
Customer deposits		301,410	290,810
Promissory Note - Town of Parry Sound - 7.25%		2,433,727	2,433,727
		2,735,137	$2,724,537
Total Liabilities		4,399,579	4,399,581
	SHAREHOLDER'S EQUITY		
Miscellaneous paid in capital		0	0
Share capital - 2,433,727 common shares		2,433,727	2,433,727
Retained earnings (deficit)			
	Balance beginning of period	110,054	735,825
			-$735,825
	Net income (loss) for the period	216,659	110,054
	Balance, end of the period	326,713	110,054
Total shareholder equity		2,760,442	2,543,781
		7,160,021	$6,943,362

Table 11 2009 Pro Forma Statement of Income

PARRY SOUND POWER CORPORATION
STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2008
With comparative for the YEAR ending December 31, 2007

	December 2009	December 2008
Revenue		
Distribution Revenue - fixed customer charges	925,196	$843,247
Distribution Revenue - variable charges	1,025,330	$965,840
Regulatory Recovery		
	1,950,526	$1,809,088
Other operating revenue		
Late payment charges	15,067	15,067
Interest earned	95,861	87,329
Pole rentals	36,542	36,542
Other Service Revenue, occupancy change, RSR, etc	31,737	31,737
Miscellaneous income		0
	179,207	170,675
Operations, maintenance & administration expense		
Distribution - Operations	76,689	70,918
Distribution - Maintenance	302,064	310,470
Billing and collecting	410,303	394,041
Community expense	18,298	68,465
Directors salaries and expense	12,015	12,015
Other administration & general	459,582	413,324
Amortization	394,504	384,102
	$1,673,455	$1,653,335
Net income before PILS and interest	456,278	326,428
Interest to Town of Parry Sound	176,444	176,444
PILS	63,173	39,931
Net income	$216,659	110,054

Cost of Power Projections

The table below indicates the customer class, revenue/expense accounts, volumes and rates forecasted to be the "Passthrough Charges" for the test and bridge years. The volume is determined using historical data, weather normalization, growth trends, etc. ERA provided the load forecast data based on historical number supplied by PSP.

Table 12 Cost of Power Details

Electricity (Commodity)									
	Customer	**Revenue**	**Expense**	**2008**	***rate ($/kWh):***	**$0.05450**	**2009**	***rate ($/kWh):***	**$0.05450**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4006	4705	35,247,109		1,920,967	34,781,817		1,895,609
kWh	General Service Les Than 50 kW	4035	4705	17,611,565		959,830	17,596,902		959,031
kWh	General Service 50 to 4,999 kW	4035	4705	40,806,320		2,223,944	41,749,576		2,275,352
kWh	Unmetered Scattered Load	4035	4705	125,181		6,822	125,181		6,822
kWh	Sentinel Lighting	4030	4705	16,944		923	16,944		923
kWh	Street Lighting	4025	4705	918,702		50,069	918,702		50,069
	TOTAL	0	0	94,725,820		5,162,557	95,189,121		5,187,807

Transmission - Network									
	Customer	**Revenue**	**Expense**	***2008***			***2009***		
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4066	4714	35,247,109	$0.0042	148,038	34,781,817	$0.0042	146,084
kWh	General Service Les Than 50 kW	4066	4714	17,611,565	$0.0038	66,924	17,596,902	$0.0038	66,868
kW	General Service 50 to 4,999 kW	4066	4714	93,846	$1.5528	145,724	96,015	$1.5528	149,092
kWh	Unmetered Scattered Load	4066	4714	125,181	$0.0038	476	125,181	$0.0038	476
kW	Sentinel Lighting	4066	4714	41	$1.1770	48	41	$1.1770	48
kW	Street Lighting	4066	4714	2,424	$1.1711	2,839	2,424	$1.1711	2,839
	TOTAL	0	0	53,080,165		364,049	52,602,380		365,407

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Transmission - Connection									
	Customer	**Revenue**	**Expense**	***2008***			***2009***		
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4068	4716	35,247,109	$0.0043	151,563	34,781,817	$0.0043	149,562
kWh	General Service Les Than 50 kW	4068	4716	17,611,565	$0.0039	68,685	17,596,902	$0.0039	68,628
kW	General Service 50 to 4,999 kW	4068	4716	93,846	$1.5353	144,082	96,015	$1.5353	147,412
kWh	Unmetered Scattered Load	4068	4716	125,181	$0.0039	488	125,181	$0.0039	488
kW	Sentinel Lighting	4068	4716	41	$1.2117	50	41	$1.2117	50
kW	Street Lighting	4068	4716	2,424	$1.1868	2,877	2,424	$1.1868	2,877
	TOTAL	0	0	53,080,165		367,744	52,602,380		369,016

2

Wholesale Market Service									
	Customer	**Revenue**	**Expense**	**2008**	***rate ($/kWh):***	**$0.00520**	**2009**	***rate ($/kWh):***	**$0.00520**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4062	4708	35,247,109		183,285	34,781,817		180,865
kWh	General Service Les Than 50 kW	4062	4708	17,611,565		91,580	17,596,902		91,504
kWh	General Service 50 to 4,999 kW	4062	4708	40,806,320		212,193	41,749,576		217,098
kWh	Unmetered Scattered Load	4062	4708	125,181		651	125,181		651
kWh	Sentinel Lighting	4062	4708	16,944		88	16,944		88
kWh	Street Lighting	4062	4708	918,702		4,777	918,702		4,777
	TOTAL	0	0	94,725,820		492,574	95,189,121		494,983

3

Rural Rate Protection									
	Customer	**Revenue**	**Expense**	**2008**	***rate ($/kWh):***	**$0.00100**	**2009**	***rate ($/kWh):***	**$0.00100**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4062	4730	35,247,109		35,247	34,781,817		34,782
kWh	General Service Les Than 50 kW	4062	4730	17,611,565		17,612	17,596,902		17,597
kWh	General Service 50 to 4,999 kW	4062	4730	40,806,320		40,806	41,749,576		41,750
kWh	Unmetered Scattered Load	4062	4730	125,181		125	125,181		125
kWh	Sentinel Lighting	4062	4730	16,944		17	16,944		17
kWh	Street Lighting	4062	4730	918,702		919	918,702		919
	TOTAL	0	0	94,725,820		94,726	95,189,121		95,189

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Debt Retirement Charge									
	Customer	**Revenue**	**Expense**	**2008**	***rate ($/kWh):***	**$0.00650**	**2009**	***rate ($/kWh):***	**$0.00650**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	TOTAL	0	0	0		0	0		0

Low Voltage Charges									
	Customer	**Revenue**	**Expense**	***2008***			***2009***		
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	TOTAL (Input amount)	4075	4750	0	54,379	54,379	0	183,000	183,000
GRAND TOTAL		0	0	0		6,536,029	0		6,695,403

Reconciliation between Financial Statements and Financial Results Filed

PSP RRR Filings are submitted on a cash basis as directed by OEB staff, the annual Audited Financial Statements are based on an accrual method matching revenue and expenses. The 2.1.7 annual RRR filing matches the annual Audit Statements. OEB staff is in the process of an information audit of PSP's deferral/variance accounts including RRR reporting. Any staff findings and/or recommendations involving our accounting or filing practices or policies will be reviewed by management and were appropriate implemented. PSP finds the RRR filing timeline not consistent with the time required to adhere to GAAP for quarterly statement processing and RRR filing.

Proposed Accounting Treatment for long lived assets

The following information relates to the accounting treatment of long lived assets. Long-lived assets include property, plant and equipment and intangibles that are subject to amortization.

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition. Gains or losses at retirement or disposition of such assets are credited or charged to “Other income” in the Statement of Income

PSP’s follows the APH when recording transaction involving “Long Lived Assets”. PSP tracks construction or work in process in the 2055 account group while in process. PSP does not capture the cost of funding capital projects (AFUDC) in these accounts and accordingly has not reflected any amounts concerning this practice. Should the need to fund future capital projects arise PSP will follow the Board’s Uniform System of Accounts using the prescribed interest rate in effect at that time.

Compliance with the Uniform System of Accounts

PSP follows the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the USoA during the "day to day operations" and in the preparation of this Application. When the need arises PSP has and will continue to contact and utilize board staff for interpretation and guidance on any accounting related matters.

Accounting Orders

PSP is not aware of any accounting orders at this time.

Annual Report

PSP annual reporting process involves audited statement presentation to the Parry Sound Power Board of Directors, The PSP board in turn reports to Parry Sound Hydro Corporation Board which reports to the shareholder – Town of Parry Sound. Reporting to our shareholder is done through an annual general meeting at which time a verbal report is presented. PSP currently has no formal policy or procedure document for capital budget, asset management plan, dividend declaration or long term business plan. Therefore the annual reporting process is managed through the Annual General Meeting. The board has been advised that the policies and practices listed above require development and implementation in the near future.

Prospectus, information and recent share issue update

Not Applicable.

Extraordinary Circumstances

Not Applicable.

Rate Base Overview

A projection of PSP's rate base is provided for both the Bridge Year (2008) and the Test Year (2009). Comparisons are also provided for the 2006 EDR and 2006 actual data and 2007 actual data.

PSP's forecast rate base for the test year is $5,281,770. The rate base underlying the test year revenue requirements includes a forecast of net fixed assets, plus a working capital allowance.

This Exhibit includes discussion and analysis on the following:

- Fixed Assets;
- Capital Plan;
- Allowance for Working Capital.

1 # Rate Base Summary Table

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Working Capital Allowance

		2009
Eligible Distribution Expenses:		
3500-Distribution Expenses - Operation		76,689
3550-Distribution Expenses – Maintenance		302,064
3650-Billing and Collecting		410,303
3700-Community Relations		18,298
3800-Administrative and General Expenses		457,437
3950-Taxes Other Than Income Taxes		0
Total Eligible Distribution Expenses		1,264,790
3350-Power Supply Expenses		6,695,403
Total Expenses for Working Capital		7,960,193
Working Capital Allowance	**15.0%**	**1,194,029**
-		

TOTAL RATE BASE

-

		2009
Net Fixed Assets in Service:		
Opening Balance	4,135,269	
Closing Balance	4,040,214	
Average Balance		4,087,741
Working Capital Allowance		1,194,029
TOTAL RATE BASE		**5,281,770**

3

Variance Analysis on Rate Base Table

Variances that exceed the materiality thresholds as prescribed in the Filing Guidelines are explained comparing:

- 2006 Actual compared to 2006 Approved
- 2007 Actual compared to 2006 Actual
- 2008 Bridge compared to 2007 Actual
- 2009 Test Year compared to 2008 Bridge

Table 1 Rate Base Variance Analysis

	Variances in excess of $41,353 are shown in bold				
	2009 Projection	2008 Projection		Var $	Var %
Net Capital Assets in Service: Opening Balance	4,135,269	4,105,875		29,394	0.7%
Ending Balance	4,040,214	4,135,269		-95,055	(2.3%)
Average Balance	4,087,741	4,120,572		-32,831	(0.8%)
Working Capital Allowance	1,194,029	1,168,665		25,364	2.2%
Total Rate Base	5,281,770	5,289,237		-7,467	(0.1%)

	Variances in excess of $41,059 are shown in bold				
	2008 Projection	2007 Actual		Var $	Var %
Net Capital Assets in Service: Opening Balance	4,105,875	4,371,821		-265,947	(6.1%)
Ending Balance	4,135,269	4,105,875		29,394	0.7%
Average Balance	4,120,572	4,238,848		-118,276	(2.8%)
Working Capital Allowance	1,168,665	1,157,413		11,252	1.0%
Total Rate Base	5,289,237	5,396,261		-107,024	(2.0%)

	Variances in excess of $43,718 are shown in bold				
	2007 Actual	2006 Actual		Var $	Var %
Net Capital Assets in Service: Opening Balance	4,371,821	4,636,042		-264,220	(5.7%)
Ending Balance	4,105,875	4,371,821		-265,947	(6.1%)
Average Balance	4,238,848	4,503,932		-265,084	(5.9%)
Working Capital Allowance	1,157,413	1,125,409		32,004	2.8%
Total Rate Base	5,396,261	5,629,340		-233,080	(4.1%)

	Variances in excess of $45,653 are shown in bold				
	2006 Actual	2006 EDR Approved		Var $	Var %
Net Capital Assets in Service: Opening Balance	4,636,042	4,492,507		143,535	3.2%
Ending Balance	4,371,821	4,638,067		-266,245	(5.7%)
Average Balance	4,503,932	4,565,287		-61,355	(1.3%)
Working Capital Allowance	1,125,409	974,930		150,478	15.4%
Total Rate Base	5,629,340	5,540,217		89,123	1.6%

2006 EDR to 2006 Actual

The variance from the 2006 EDR to 2006 actual is a direct result of the averaging used in the 2006 EDR process combined with actual asset additions versus average additions. PSP's variance is 1.6% over the 2006 approval.

2007 Actual compared to 2006 Actual

PSP's rate base for 2007 shows a decline of $233,080 (4.1%) lower than 2006 actual. The drop in rate base is a result of the capital expenditures net of contributions are less than the year's amortization expense. Therefore the working capital allowance is also lower.

2008 Bridge compared to 2007 Actual

The 2008 Bridge Year Rate Base also shows a decline over the 2007 actual year of $107,024 (2.0%). The planned capital investments during the bridge year are less than the amortization expense. Therefore there is a drop in rate base and working capital allowance.

2009 Test Year compared to 2008 Bridge

Test Year projected rate base of $5,281,770 is non-inclusive of "Smart Meter" investment. The rate base will show a slight decline from Bridge Year of $-7,467 (0.1%) without the smart meter costing. PSP does plan to move ahead with smart meters as directed once all regulations have been met.

Fixed Asset Continuity Statements

Table 2 Fixed Asset Continuity – 2006 EDR vs 2006 Actual

	2006 EDR Balance	2006 EDR to 2006 Actual Changes			2006 Balance	Variance	Variance %
		Additions	Retirements	Amortization			
1606-Organization							
Gross Assets	69,762.37	291,280.23			361,042.60	291,280.23	80.68%
Accumulated Amortization	-17,440.60			-100,663.52	-118,104.12	-100,663.52	85.23%
Net Book Value	52,321.77				242,938.48	190,616.71	78.46%
1805-Land							
Gross Assets	74,304.52				74,304.52	0	0.00%
Accumulated Amortization					0		
Net Book Value	74,304.52	0			74,304.52	0	0.00%
1806-Land Rights							
Gross Assets	34,798.00	250			35,048.00	250	0.71%
Accumulated Amortization	-34,558.00			-50	-34,608.00	-50	0.14%
Net Book Value	240				440	200	45.45%
1820-Distribution Station Equipment - Normally Primary below 50 kV							
Gross Assets	1,443,290.46	157,229.05			1,600,519.51	157,229.05	9.82%
Accumulated Amortization	-839,631.58			-119,460.13	-959,091.71	-119,460.13	12.46%
Net Book Value	603,658.88				641,427.80	37,768.92	5.89%
1830-Poles, Towers and Fixtures							
Gross Assets	1,428,801.58	64,784.41			1,493,585.99	64,784.41	4.34%
Accumulated Amortization	-767,723.41			-126,743.68	-894,467.09	-126,743.68	14.17%
Net Book Value	661,078.17				599,118.90	-61,959.27	-10.34%
1835-Overhead Conductors and Devices							
Gross Assets	2,123,899.53	48,756.65			2,172,656.18	48,756.65	2.24%
Accumulated Amortization	-1,132,322.06			-184,940.11	-1,317,262.17	-184,940.11	14.04%
Net Book Value	991,577.47				855,394.01	-136,183.46	-15.92%
1840-Underground Conduit							
Gross Assets	557,717.54	34,278.98			591,996.52	34,278.98	5.79%
Accumulated Amortization	-207,188.03			-56,300.49	-263,488.52	-56,300.49	21.37%
Net Book Value	350,529.51				328,508.00	-22,021.51	-6.70%
1845-Underground Conductors and Devices							
Gross Assets	723,579.97	30,683.75			754,263.72	30,683.75	4.07%
Accumulated Amortization	-264,467.79			-72,074.22	-336,542.01	-72,074.22	21.42%
Net Book Value	459,112.18				417,721.71	-41,390.47	-9.91%
1850-Line Transformers							
Gross Assets	2,000,261.99	76,057.39			2,076,319.38	76,057.39	3.66%
Accumulated Amortization	-1,066,144.59			-162,401.93	-1,228,546.52	-162,401.93	13.22%
Net Book Value	934,117.40				847,772.86	-86,344.54	-10.18%
1855-Services							
Gross Assets	1,198,279.65	42,364.35			1,240,644.00	42,364.35	3.41%
Accumulated Amortization	-614,772.91			-108,636.90	-723,409.81	-108,636.90	15.02%
Net Book Value	583,506.74				517,234.19	-66,272.55	-12.81%
1860-Meters							
Gross Assets	451,290.01	28,422.58			479,712.59	28,422.58	5.92%
Accumulated Amortization	-265,114.54			-33,692.74	-298,807.28	-33,692.74	11.28%
Net Book Value	186,175.47				180,905.31	-5,270.16	-2.91%
1995-Contributions and Grants – Credit							
Gross Assets	-291,117.67	-110,785.76			-401,903.43	-110,785.76	27.57%
Accumulated Amortization	32,562.33			35,396.74	67,959.07	35,396.74	52.09%
Net Book Value	-258,555.34				-333,944.36	-75,389.02	22.58%
TOTAL							
Gross Assets	9,814,867.94	663,321.63	0	0	10,478,189.57	663,321.63	6.33%
Accumulated Amortization	-5,176,801.18	0	0	-929,566.98	-6,106,368.16	-929,566.98	15.22%
Net Book Value	4,638,066.76	663,321.63	0	0	4,371,821.41	-266,245.35	-6.09%

Table 3 Fixed Asset Continuity – 2006 vs 2007

	2006	2007 Changes			2007		
	Balance	Additions	Retirements	Amortization	Balance	Variance	Variance %
1606-Organization							
Gross Assets	361,042.60				361,042.60	0	0.00%
Accumulated Amortization	-118,104.12			-48,587.70	-166,691.82	-48,587.70	29.15%
Net Book Value	242,938.48				194,350.78	-48,587.70	-25.00%
1805-Land							
Gross Assets	74,304.52				74,304.52	0	0.00%
Accumulated Amortization	0				0		
Net Book Value	74,304.52				74,304.52	0	0.00%
1806-Land Rights							
Gross Assets	35,048.00				35,048.00	0	0.00%
Accumulated Amortization	-34,608.00			-20	-34,628.00	-20	0.06%
Net Book Value	440				420	-20	-4.76%
1820-Distribution Station Equipment – Normally Primary below							
Gross Assets	1,600,519.51				1,600,519.50	-0.01	0.00%
Accumulated Amortization	-959,091.71			-48,299.27	-1,007,390.98	-48,299.27	4.79%
Net Book Value	641,427.80				593,128.52	-48,299.28	-8.14%
1830-Poles, Towers and Fixtures							
Gross Assets	1,493,585.99	27,609.19			1,521,195.17	27,609.19	1.81%
Accumulated Amortization	-894,467.09			-50,892.48	-945,359.57	-50,892.48	5.38%
Net Book Value	599,118.90				575,835.60	-23,283.29	-4.04%
1835-Overhead Conductors and Devices							
Gross Assets	2,172,656.18	12,964.83			2,185,621.01	12,964.83	0.59%
Accumulated Amortization	-1,317,262.17			-72,632.28	-1,389,894.44	-72,632.27	5.23%
Net Book Value	855,394.01				795,726.57	-59,667.44	-7.50%
1840-Underground Conduit							
Gross Assets	591,996.52	238.4			592,234.92	238.4	0.04%
Accumulated Amortization	-263,488.52			-22,785.00	-286,273.52	-22,785.00	7.96%
Net Book Value	328,508.00				305,961.40	-22,546.60	-7.37%
1845-Underground Conductors and Devices							
Gross Assets	754,263.72	9,513.67			763,777.39	9,513.67	1.25%
Accumulated Amortization	-336,542.01			-29,376.96	-365,918.96	-29,376.95	8.03%
Net Book Value	417,721.71				397,858.43	-19,863.28	-4.99%
1850-Line Transformers							
Gross Assets	2,076,319.38	60,600.56			2,136,919.93	60,600.56	2.84%
Accumulated Amortization	-1,228,546.52			-68,608.90	-1,297,155.42	-68,608.90	5.29%
Net Book Value	847,772.86				839,764.51	-8,008.34	-0.95%
1855-Services							
Gross Assets	1,240,644.00	25,856.47			1,266,500.47	25,856.47	2.04%
Accumulated Amortization	-723,409.81			-43,634.06	-767,043.87	-43,634.06	5.69%
Net Book Value	517,234.19				499,456.60	-17,777.59	-3.56%
1860-Meters							
Gross Assets	479,712.59	10,780.51			490,493.10	10,780.51	2.20%
Accumulated Amortization	-298,807.28			-13,763.34	-312,570.62	-13,763.34	4.40%
Net Book Value	180,905.31				177,922.48	-2,982.83	-1.68%
1995-Contributions and Grants - Credit							
Gross Assets	-401,903.43	-32,277.68			-434,181.11	-32,277.68	7.43%
Accumulated Amortization	67,959.07			17,367.24	85,326.30	17,367.23	20.35%
Net Book Value	-333,944.36				-348,854.81	-14,910.45	4.27%
TOTAL							
Gross Assets	10,478,189.57	115,285.95	0	0	10,593,475.50	115,285.94	1.09%
Accumulated Amortization	-6,106,368.16	0	0	-381,232.75	-6,487,600.90	-381,232.74	5.88%
Net Book Value	4,371,821.41	115,285.95	0	-381,232.75	4,105,874.60	-265,946.80	-6.48%

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Table 4 Fixed Asset Continuity – 2007 vs 2008

	2007	2008 Changes			2008		
	Balance	Additions	Retirements	Amortization	Balance	Variance	Variance %
1606-Organization							
Gross Assets	361,042.60	0	0	0	361,042.60	0	0.00%
Accumulated Amortization	-166,691.82	0	0	48,587.70	-118,104.12	48,587.70	-41.14%
Net Book Value	194,350.78	0	0	48,587.70	242,938.48	48,587.70	20.00%
1805-Land							
Gross Assets	74,304.52	0	0	0	74,304.52	0	0.00%
Accumulated Amortization	0	0	0	0	0		
Net Book Value	74,304.52	0	0	0	74,304.52	0	0.00%
1806-Land Rights							
Gross Assets	35,048.00	0	0	0	35,048.00	0	0.00%
Accumulated Amortization	-34,628.00	0	0	20	-34,608.00	20	-0.06%
Net Book Value	420	0	0	20	440	20	4.55%
1820-Distribution Station Equipment – Normally Primary below !							
Gross Assets	1,600,519.50	77,078.51	0	0	1,677,598.01	77,078.51	4.59%
Accumulated Amortization	-1,007,390.98	0	0	49,584.91	-957,806.07	49,584.91	-5.18%
Net Book Value	593,128.52	77,078.51	0	49,584.91	719,791.94	126,663.42	17.60%
1830-Poles, Towers and Fixtures							
Gross Assets	1,521,195.17	141,166.42	0	0	1,662,361.59	141,166.42	8.49%
Accumulated Amortization	-945,359.57	0	0	52,074.55	-893,285.02	52,074.55	-5.83%
Net Book Value	575,835.60	141,166.42	0	52,074.55	769,076.57	193,240.97	25.13%
1835-Overhead Conductors and Devices							
Gross Assets	2,185,621.01	64,969.83	0	0	2,250,590.84	64,969.83	2.89%
Accumulated Amortization	-1,389,894.44	0	0	71,492.95	-1,318,401.49	71,492.95	-5.42%
Net Book Value	795,726.57	64,969.83	0	71,492.95	932,189.35	136,462.78	14.64%
1840-Underground Conduit							
Gross Assets	592,234.92	2,389.26	0	0	594,624.18	2,389.26	0.40%
Accumulated Amortization	-286,273.52	0	0	22,832.79	-263,440.73	22,832.79	-8.67%
Net Book Value	305,961.40	2,389.26	0	22,832.79	331,183.45	25,222.05	7.62%
1845-Underground Conductors and Devices							
Gross Assets	763,777.39	15,006.84	0	0	778,784.23	15,006.84	1.93%
Accumulated Amortization	-365,918.96	0	0	29,677.10	-336,241.86	29,677.10	-8.83%
Net Book Value	397,858.43	15,006.84	0	29,677.10	442,542.37	44,683.94	10.10%
1850-Line Transformers							
Gross Assets	2,136,919.93	68,146.82	0	0	2,205,066.75	68,146.82	3.09%
Accumulated Amortization	-1,297,155.42	0	0	69,971.84	-1,227,183.58	69,971.84	-5.70%
Net Book Value	839,764.51	68,146.82	0	69,971.84	977,883.17	138,118.66	14.12%
1855-Services							
Gross Assets	1,266,500.47	28,442.19	0	0	1,294,942.66	28,442.19	2.20%
Accumulated Amortization	-767,043.87	0	0	43,137.89	-723,905.98	43,137.89	-5.96%
Net Book Value	499,456.60	28,442.19	0	43,137.89	571,036.68	71,580.08	12.54%
1860-Meters							
Gross Assets	490,493.10	16,296.00	0	0	506,789.10	16,296.00	3.22%
Accumulated Amortization	-312,570.62	0	0	14,089.26	-298,481.36	14,089.26	-4.72%
Net Book Value	177,922.48	16,296.00	0	14,089.26	208,307.74	30,385.26	14.59%
1995-Contributions and Grants - Credit							
Gross Assets	-434,181.11	0	0	0	-434,181.11	0	0.00%
Accumulated Amortization	85,326.30	0	0	-17,367.24	67,959.06	-17,367.24	-25.56%
Net Book Value	-348,854.81	0	0	-17,367.24	-366,222.05	-17,367.24	4.74%
TOTAL							
Gross Assets	10,593,475.50	413,495.87	0	0	11,006,971.37	413,495.87	3.76%
Accumulated Amortization	-6,487,600.90	0	0	384,101.75	-6,103,499.15	384,101.75	-6.29%
Net Book Value	4,105,874.60	413,495.87	0	384,101.75	4,903,472.22	797,597.62	16.27%

Table 5 Fixed Asset Continuity – 2008 vs 2009

	2008	2009 Changes			2009		
	Balance	Additions	Retirements	Amortization	Balance	Variance	Variance %
1606-Organization							
Gross Assets	361,042.60	0	0	0	361,042.60	0	0.00%
Accumulated Amortization	-118,104.12	0	0	48,587.70	-69,516.42	48,587.70	-69.89%
Net Book Value	242,938.48	0	0	48,587.70	291,526.18	48,587.70	16.67%
1805-Land							
Gross Assets	74,304.52	0	0	0	74,304.52	0	0.00%
Accumulated Amortization	0	0	0	0	0		
Net Book Value	74,304.52	0	0	0	74,304.52	0	0.00%
1806-Land Rights							
Gross Assets	35,048.00	0	0	0	35,048.00	0	0.00%
Accumulated Amortization	-34,608.00	0	0	20	-34,588.00	20	-0.06%
Net Book Value	440	0	0	20	460	20	4.35%
1820-Distribution Station Equipment – Normally Primary below							
Gross Assets	1,677,598.01	77,286.36	0	0	1,754,884.37	77,286.36	4.40%
Accumulated Amortization	-957,806.07	0	0	52,157.66	-905,648.41	52,157.66	-5.76%
Net Book Value	719,791.94	77,286.36	0	52,157.66	849,235.96	129,444.02	15.24%
1830-Poles, Towers and Fixtures							
Gross Assets	1,662,361.59	62,045.30	0	0	1,724,406.89	62,045.30	3.60%
Accumulated Amortization	-893,285.02	0	0	55,072.70	-838,212.32	55,072.70	-6.57%
Net Book Value	769,076.57	62,045.30	0	55,072.70	886,194.57	117,118.00	13.22%
1835-Overhead Conductors and Devices							
Gross Assets	2,250,590.84	66,471.29	0	0	2,317,062.13	66,471.29	2.87%
Accumulated Amortization	-1,318,401.49	0	0	72,537.66	-1,245,863.83	72,537.66	-5.82%
Net Book Value	932,189.35	66,471.29	0	72,537.66	1,071,198.30	139,008.95	12.98%
1840-Underground Conduit							
Gross Assets	594,624.18	2,680.00	0	0	597,304.18	2,680.00	0.45%
Accumulated Amortization	-263,440.73	0	0	22,934.17	-240,506.56	22,934.17	-9.54%
Net Book Value	331,183.45	2,680.00	0	22,934.17	356,797.62	25,614.17	7.18%
1845-Underground Conductors and Devices							
Gross Assets	778,784.23	16,507.52	0	0	795,291.75	16,507.52	2.08%
Accumulated Amortization	-336,241.86	0	0	30,307.38	-305,934.48	30,307.38	-9.91%
Net Book Value	442,542.37	16,507.52	0	30,307.38	489,357.27	46,814.90	9.57%
1850-Line Transformers							
Gross Assets	2,205,066.75	25,246.40	0	0	2,230,313.15	25,246.40	1.13%
Accumulated Amortization	-1,227,183.58	0	0	71,839.70	-1,155,343.88	71,839.70	-6.22%
Net Book Value	977,883.17	25,246.40	0	71,839.70	1,074,969.27	97,086.10	9.03%
1855-Services							
Gross Assets	1,294,942.66	31,286.42	0	0	1,326,229.08	31,286.42	2.36%
Accumulated Amortization	-723,905.98	0	0	43,640.67	-680,265.31	43,640.67	-6.42%
Net Book Value	571,036.68	31,286.42	0	43,640.67	645,963.77	74,927.09	11.60%
1860-Meters							
Gross Assets	506,789.10	17,925.60	0	0	524,714.70	17,925.60	3.42%
Accumulated Amortization	-298,481.36	0	0	14,773.69	-283,707.67	14,773.69	-5.21%
Net Book Value	208,307.74	17,925.60	0	14,773.69	241,007.03	32,699.29	13.57%
1995-Contributions and Grants - Credit							
Gross Assets	-434,181.11	0	0	0	-434,181.11	0	0.00%
Accumulated Amortization	67,959.06	0	0	-17,367.24	50,591.82	-17,367.24	-34.33%
Net Book Value	-366,222.05	0	0	-17,367.24	-383,589.29	-17,367.24	4.53%
TOTAL							
Gross Assets	11,006,971.37	299,448.89	0	0	11,306,420.26	299,448.89	2.65%
Accumulated Amortization	-6,103,499.15	0	0	394,504.09	-5,708,995.06	394,504.09	-6.91%
Net Book Value	4,903,472.22	299,448.89	0	394,504.09	5,597,425.20	693,952.98	12.40%

Materiality/Variance Analysis on Gross Assets

The calculation of the materiality level as set out in the Filing Guidelines are those variances that exceed 1% of net fixed assets.

Table 6 Materiality Threshold

	EDR – 2006	Actual – 2006	Actual – 2007	Bridge – 2008	Test - 2009
Gross	9,814,868	10,478,190	10,593,476	11,006,971	11,306,420
Accumulated Amortization	-5,176,801	-6,106,368	-6,487,601	-6,103,499	-5,708,995
Net Fixed Assets	4,638,067	4,371,821	4,105,875	4,903,472	5,597,425
Percent	1%	1%	1%	1%	1%
Minimum Filing Threshold	46,381	43,718	41,059	49,035	55,974

PSP has selected to explain all variances from EDR Year to Test Year. The variance analysis is done on an account level basis by job number. The job numbers are detailed by year and the accounts used per job are listed. The 2006 EDR year to 2006 actual is explained by the averaging methodology used by the 2006 EDR application process between 2003 & 2004 combined with 2005 and 2006 additions, this pertains to the capex as well as amortization. PSP will review 2005 to 2009 capex.

PSP has explained all capital jobs from 2005 to Test Year 2009.

1 **2005 Actual**

2 **CAPITAL ADDITIONS - SUMMARY OF JOBS & DESCRIPTIONS**

3

Job Number	Descriptions	Total
2005-1	Farrer Street Rebuild - Water to William Street	$52,390.00
2005-2	McFarlane Street-Sewage Plant	$15,754.07
2005-3	McFarlane Street-Emily Street	$1,009.15
2005-4	USF Membership Dues	$10,000.00
2005-5	Electrical Meters	$4,751.86
2005-6	Misc. Secondary Services	$6,202.17
GRAND TOTAL		**$ 90,107.25**

GL Account	Total
1820-Dist. Station Equip.	$1,800.00
1830-Poles, Towers & Fixtures	$19,773.93
1835-Overhead Conductors & Devices	$29,802.82
1840-	$10,000.00
1850-Line Transformers	$15,776.47
1855-Services	$8,202.17
1860-	$4,751.86
GRAND TOTAL	**$90,107.25**

4

2005-1
Description: Farrer Street Rebuild - Water to William Street

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather

conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 4 poles will be replaced from Water Street to William Street. The existing primary conductors will be transferred to the new improved framed poles to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacements, new hardware, insulators, guying, grounding and anchoring will be placed. Existing transformer loading will be calculated and if required a rebalance of the electrical load will be undertaken within the scope of this project.

Cost:

Acct.# & Description	Amount
1820-Dist. Station Equip.	$1,800.00
1830-Poles, Towers & Fixtures	$18,900.00
1835-Overhead Conductors & Devices	$28,000.00
1850-Line Transformers	$1,690.00
1855-Services	$2,000.00
	$52,390.00

5

1

2005-2
Description: McFarlane Street-Sewage Plant

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 2 poles will be replaced on pole line ROW. The existing primary conductors will be transferred to the new improved framed poles to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacements, new hardware, insulators, guying, grounding and anchoring will be placed. Existing transformer loading will be calculated and if required a rebalance of the electrical load will be undertaken within the scope of this project. 3 new transformers will be added to satisfy upgraded service requirements.

Costs:

Acct.# & Description	Amount
1830-Poles, Towers & Fixtures	$740.72
1835-Overhead Conductors & Devices	$926.88
1850-Line Transformers	$14,086.47
	$15,754.07

Description: McFarlane Street-Emily Street

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 2 poles will be replaced at intersection of McFarlane & Emily St.. The existing primary conductors will be transferred to the new improved framed poles to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacements, new hardware, insulators, guying, grounding and anchoring will be placed and associated hardware transferred. In-Line switch's will be installed to effectively isolate lateral 3 phase line on McFarlane Street.

Cost:

Acct.# & Description	Amount
1830-Poles, Towers & Fixtures	$133.21
1835-Overhead Conductors & Devices	$875.94
	$1,009.15

2005-4
Description: USF Membership Dues
Need: ESA Requirements to have all utility work engineered by Professional Engineer prior to construction and energization to meet E.S.A. Regulation 22/04.

Scope: Parry Sound Power will enter into agreement and pay membership dues to Utility Standard Forum (USF) in order to obtain approved Specifications and drawings that will satisfy E.S.A. Regulation 22/04

Cost:

Acct.# & Description	Amount
1840-Underground Conduit	$10,000.00
	$10,000.00

2005-5

Description: Electrical Meters

Need: Parry Sound Power to recalibrate meter samples to satisfy Measurement Canada rules and regulations.

Scope: Parry Sound Power will pull sample lots of Electrical Meters to have tested for seal extensions. Tests to be done by accredited meter shop.

Cost:

Acct.# & Description	Amount
1860- Electrical Meters	$4,751.86
	$4,751.86

2005-6

Description: Misc. Secondary Services

Need: Connection or upgrades for residential secondary services.

Scope: Time and material to connect secondary residential secondary services

Cost:

	Address	Description	Amount
1855	49 Miller Street	Upgrade Connections for additional Services	$502.55
	76 Bowes Street	Upgrade service	$367.00
	2 Foster	Install New service	$581.18
	4 Beatty Street	Upgrade service	$447.89
	34 Great North Road	Upgrade service	$237.16
	11 Cascade Street	Upgrade service	$194.55
	17 Wood Street	New service	$177.08
	3a Mann Ave	Upgrade service	$273.84
	53a Isabella	Install new service	$274.77
	8 Ansley	Install new service	$327.97
	8 Willow	Upgrade service	$196.93
	129 Louisa Street	Upgrade Service	$174.61
	11& 14 Avery Court	Install new service	$546.35
	12 Georgina	Install new service	$179.90
	128 Isabella Street	Install new service	$173.84
	3 Ginnie Street	Upgrade service	$233.89
	39 Waubeek street	Upgrade service	$285.70
	33 Cascade	Upgrade service	$187.12
	11 Highland Cres.	Upgrade service	$173.84
	16 Cascade Street	Upgrade service	$173.84
	74 Waubeek St.	Install new service	$217.12
	4 Mann Ave	Install new service	$275.00
			$6,202.17

2006 Actual

CAPITAL ADDITIONS - SUMMARY OF JOBS & DESCRIPTIONS

Job Number	Totals by Job
2006-01	$ 865.73
2006-2	$ 2,689.05
2006-3	$ 929.57
2006-4	$ 7,686.91
2006-5	$18,460.54
2006-6	$ 9,737.88
2006-7	$ 1,792.14
2006-8	$45,005.05
2006-9	$19,101.93
2006-10	$ 2,392.19
2006-11	$ 40,455.95
GRAND TOTAL	**$ 149,116.94**

GL Account	Total by GL Account
1830	$ 16,965.87
1835	$ 53,801.87
1845	$ 20,810.59
1850	$ 35,482.92
1855	$ 13,132.76
1820	$ 10,400.87
1840	$ 24,151.43
GRAND TOTAL	**$ 149,116.94**

2006-1

Description: 7 Mary Street.- New Service connections

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: Existing poles will be made ready for new Residential Service. New conductors and associated hardware will be added at this time.

Cost:

Acct.# & Description	Amount
1830-Poles, Towers & Fixtures	$166.02
1835-Overhead Conductors & Devices	$273.13
1855-Services	$426.58
	$865.73

2006-2

Description: 29 Parton Road.- New Service connections

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: Existing poles will be made ready for new Residential Service. New conductors and associated hardware will be added at this time.

Cost:

Acct.# & Description	Amount
1845- Underground Conductors & Devices	$286.20
1850-Line Transformers	$2,402.85
	$2,689.05

2006-3

Description: 76 Cascade St. New Road Crossing Upgrade.

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 1 poles will be replaced fronting 76 Cascade St. The new secondary road crossing will be installed in order to satisfy load growth. New conductors and associated hardware will be added at this time.

Cost:

Acct.# & Description	Amount
1830-Poles, Towers & Fixtures	$608.15
1835-Overhead Conductors & Devices	$119.53
1855-Services	$201.89
	$929.57

1

2006-4

Description: 90 Bowes St. New Road Crossing Upgrade.

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 1 poles will be replaced fronting 90 Bowes St. The new primary road crossing will be installed in order to satisfy load growth. New conductors and associated hardware will be added at this time. New padmount transformer will be added to this project to meet electrical demand.

Cost:

Acct.# & Description	**Amount**
1830-Poles, Towers & Fixtures	$2,711.22
1835-Overhead Conductors & Devices	$1,901.05
1845- Underground Conductors & Devices	$1,047.46
1850-Line Transformers	$2,027.18
	$7,686.91

2006-5

Description: 123 Louisa St.- New Service connections

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: Existing poles will be made ready for new General Service. New conductors and associated hardware will be added at this time.

Capital Costs

Acct.# & Description	**Amount**
1830-Poles, Towers & Fixtures	$564.38
1835-Overhead Conductors & Devices	$959.50
1850-Line Transformers	$16,936.66
	$18,460.54

2

2006-6

Description: Ansley Ave.

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 3 poles will be replaced on Ansley Avenue. The existing primary conductors will be transferred to the new improved framed poles to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacement, new hardware, insulators, guying, grounding and anchoring will be placed and associated hardware transferred. Overhead primary conductors will be extended for three spans to satisfy the increased load in this area.

Capital Costs

Acct.# & Description	**Amount**
1830-Poles, Towers & Fixtures	$2,984.04
1835-Overhead Conductors & Devices	$2,663.42
1850-Line Transformers	$4,090.42
	$9,737.88

2006-7

Description: Bowes/Louisa St.

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 1 pole will be installed fronting Bowes/Louisa Intersection... The new primary conductors will be transferred to the new improved framed poles to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacement, new hardware, insulators, guying, grounding and anchoring will be placed and associated hardware transferred. Pole will be framed for new sec. service.

Capital Costs

Acct.# & Description	**Amount**
1830-Poles, Towers & Fixtures	$1,264.83
1850-Line Transformers	$407.78
1855-Services	$119.53
	$1,792.14

1

2006-8

Description: Pole line rebuild on Farrer St..

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 4 poles will be replaced along Farrer Street.. The new primary road crossing conductors will be transferred to the new improved framed poles to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacement, new hardware, insulators, guying, grounding and anchoring will be placed and associated hardware transferred. New riser pole connections will be done on the first pole at the Sub Station.

Capital Costs

Acct.# & Description	**Amount**
1830-Poles, Towers & Fixtures	$2,051.19
1835-Overhead Conductors & Devices	$40,506.40
1850-Line Transformers	$2,364.14
1855-Services	$83.32
	$45,005.05

Description: Isabella-Joseph St.

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 1 poles will be replaced at intersection of Isabella & Joseph St.. The existing primary conductors will be transferred to the new improved framed poles to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacement, new hardware, insulators, guying, grounding and anchoring will be placed and associated hardware transferred. Overhead primary conductors will be converted to underground for 1 span to observe building clearances.

2

1

Capital Costs

Acct.# & Description	Amount
1830-Poles, Towers & Fixtures	$3,543.91
1835-Overhead Conductors & Devices	$4,597.60
1845- Underground Conductors & Devices	$8,598.85
1850-Line Transformers	$2,361.57
	$19,101.93

2

2006-10

Description: Prospect Point

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 3 poles will be rebuilt on Waubeek St.. The existing primary conductors will be transferred to the new improved framed poles to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacement, new hardware, insulators, guying, grounding and anchoring will be placed and associated hardware transferred. Overhead primary conductors will be rearranged in this area to allow for future growth.

Capital Costs

Acct.# & Description	Amount
1830-Poles, Towers & Fixtures	$1,419.95
1835-Overhead Conductors & Devices	$608.00
1850-Line Transformers	$364.24
	$2,392.19

3

2006-11

Description: Misc. Secondary Services

Need: Connection or upgrades for residential secondary services.

Scope: Time and material to connect secondary residential secondary services

Costs

Account	Address	Description	Amount
1855	9 North Mann	Installed New Service	$241.92
		Installed New Service	$179.30
	60 PS Road	Upgrade secondary for new service	$278.35
		Installed New Service	$353.81
	15 John Street	Installed New Service	$119.53
	19 Cascade Street	Removed service for construction of addition	$664.16
	7 Addie St.	Installed New Service	$119.53
	7 Addie St.	Installed New Service	$292.75
	15 Cascade	Installed New Service	$231.92
	4 Gibson St.	Installed New Service	$46.54
	4 Gibson St.	Installed New Service	$59.77
	14 Glen Ave.	Install new Service	$183.79
	48 Forest St.	Upgrade service	$325.61
	33 William	Upgrade service	$119.53
	19 Smith Cres.	Install new Service	$128.53
	32 Forest St.	Upgrade service	$256.01
	11 Farrer St.	Upgrade service	$119.53
	67 Highland Cres.	Upgrade service	$180.85
			$3,901.44
1830	60 PS Road	Installed Guy wires	$217.03
	20 Greenwood	Install Guys for new service	$152.60
	85 River St.	Guy pole	$209.55
	16 Emily St.	Pole replacement	$1,073.00
			$1,652.18
1835	21 Queen Street	Remove Service wires from house	$99.11
	20 Greenwood	Install Road Crossing	$259.92
			$359.03
1820	MS#3 Substation	Install higher fencing for security	**$10,400.87**
1840	123 Louisa St.	Install u/g conduit for new service	**$24,151.43**
		TOTAL MISC	
			$40,455.95

2007 Actual

CAPITAL ADDITIONS - SUMMARY OF JOBS AND DESCRIPTIONS

Job Numbers	Descriptions	Totals by Job
2007-1	Install new service poles at 14 Ansley Ave	$ 2,216.26
2007-2	Install disconnect switch's mid-span.	$ 1,682.07
2007-3	Service pole replacement at 59 Forest Street.	$ 2,924.96
2007-4	Pole line rebuild on Gibson St	$ 14,627.61
2007-5	Prospect Point	$ 13,407.83
2007-6	Misc. Secondary Services	$ 62,562.92
2007-7	Meter Installs and Testing	$ 10,780.51
2007-8	Misc Underground Work	$ 2,565.66
GRAND TOTAL		**$ 110,767.83**

GL Account	Totals by GL
1830-Poles,Towers & Fixtures	$ 16,762.56
1835-Overhead Conductors & Devices	$ 8,553.65
1845-Underground Conductors & Devices	$ 4,165.92
1850-Line Transformers	$ 54,789.18
1855-Services	$ 15,716.01
1860-Meters	$ 10,780.51
GRAND TOTAL	**$110,767.83**

2007-1
Description: Install new service poles at 14 Ansley Ave.

Need: The existing pole line is non existent. New service poles will be installed. The new conductor clearances wiki be enhanced to meet E.S.A. Regulation 22/04.

Scope: New service poles will be placed at 14 Ansley Avenue. Overhead service conductors will be transferred to the new improved framed pole to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacement, new hardware, insulators, guying, grounding and anchoring will be placed and associated hardware transferred.

Cost:

Acct.# & Description	Amount
1830-Poles,Towers & Fixtures	$1,164.69
1855-Services	$1,051.57
	$2,216.26

1

2007-2
Description: Install disconnect switch's mid-span.

Need: Inline switch's to be installed on overhead primary circuit.

Scope: New inline switch’s to be installed at 37 McFarlane Street to allow for complete electrical isolation of current flow on circuit. All work to conform to E.S.A. Regulation 22/04

Cost:

Acct.# & Description	Amount
1830-Poles,Towers & Fixtures	$1,562.54
1855-Services	$119.53
	$1,682.07

2007-3
Description: Service pole replacement at 59 Forest Street.

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 1 pole will be replaced at 59 Forest Street. Overhead service conductors will be transferred to the new improved framed pole to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacement, new hardware, insulators, guying, grounding and anchoring will be placed and associated hardware transferred.

2

Cost:

Acct.# & Description	Amount
1830-Poles,Towers & Fixtures	$2,239.30
1835-Overhead Conductors & Devices	$685.66
	$2,924.96

2007-4
Description: Pole line rebuild on Gibson St..

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged by vehicular traffic. The existing conductor clearances will be enhanced to meet E.S.A. Regulation 22/04.

Scope: 3 poles will be replaced along Gibson Street.. The new primary road crossing conductors will be transferred to the new improved framed poles to satisfy E.S.A. 22/04 regulations. In conjunction with pole replacement, new hardware, insulators, guying, grounding and anchoring will be placed and associated hardware transferred.

Cost:

Acct.# & Description	**Amount**
1830-Poles, Towers & Fixtures	$8,360.71
1835-Overhead Conductors & Devices	$5,766.64
1850-Line Transformers	$500.26
	$14,627.61

2007-5
Description: Prospect Point

Need: Electrical plant is non existent at this location.
New electrical plant will be installed as per Ontario Regulation - 22/04

Scope: New Primary and Secondary conductors will be installed to satisfy electrical load.
Transformation to be included at this time.
Cost:

Acct.# & Description	**Amount**
1830-Poles, Towers & Fixtures	$69.07
1845-Underground Conductors & Devices	$935.48
1850-Line Transformers	$11,718.91
1855-Services	$684.37
	$13,407.83

2007-6
Description: Misc. Secondary Services

Need: Connection or upgrades for residential secondary services.

Scope: Time and material to connect residential secondary services

Cost:

Account	Address	Description	Amount
1830	Isabella / Summitt	Install Guy pole, Anchor and Guys	$379.15
	89 Bowes St.	Install pole for Banner	$1,337.86
	62 Forest St.	Install Anchor and Guys	$467.09
	6 Railway Ave	Install new poles, Anchor and guys	$758.14
	6 Railway Ave	Install new poles, Anchor and guys	$130.25
	1183 Geewadin Road	Install Anchor and Guys for new secondary span	$293.76
			$3,366.25
1835	48 Greenwood Drive	install Secondary Road Crossing	$242.52
	1183 Geewadin Road	Install New Secondary Lines	$1,858.82
			$2,101.35
1845	18 & 28 Baycrest Drive	Install new Secondary lines	**$664.78**
1850	Riverdale Road Sewage	Install new Transformer voltage Delta to Open Delta	$79.47
	54 PS Road	Install new Transformer for new Triplex Service	$547.02
	Stock	Misc. transformers purchased for 2008 projects	$41,943.52
			$42,570.01
1855	57 William St.	Upgrade service	$405.23
	10 Kitchener	Upgrade service	$197.64
	13 Louisa St.	Upgrade service	$197.64
	34 Marion Ave.	Upgrade service	$131.75
	64 Bowes St.	Install new services	$133.32
	10 Baycrest Drive	Install new services	$743.25
	9 Baycrest Drive	Install new services	$912.43
	12 Baycrest Drive	Install new services	$677.24
	Cogeco Cable Boosters	Install new services	$559.95
	10 Belvedere Ave.	Upgrade service	$133.02
	6&8 Avery Court	Install new services	$750.61
	6&8 Avery Court	Install new services	$491.74
	26 Cascade St.	Install new services	$263.51
	17 Macfarlane St	Upgrade service	$132.54
	59 Gibson St.	Upgrade service	$131.75
	62 PS Drive	Upgrade service	$105.67
	48 Greenwood Drive	Install new services	$125.99
	25 Tudhope ST.	Upgrade service	$207.87
	18 & 28 Baycrest Drive	Install new services	$1,473.96
	20 Wakefield St.	Install new services	$302.88
	13 Mann Ave	Install U/G Secondary Lines	$535.16
	13 Mann Ave	Install new services	$302.50
	4 Avery Court	Install new services	$1,270.43
	9 Avery Court	Install new services	$951.15

Cost:

Account	Address	Description	Amount
	22 Beatty St.	Upgrade service	$197.64
	1207 Deepwater Point	Install new services	$355.24
	5 Avery Court	Install new services	$323.78
	5 Avery Court	Install new services	$170.52
	14 Baycrest Drive	Install new service	$582.40
	16 Baycrest	Install new service	$774.41
	10 Avery Court	Install new Service	$319.28
			$13,860.54
Total Cost			**$62,562.92**

2007-7

Description: New Meter Installs and Testing

Need: Install new meters at customer premises to upgrade older services.

Scope: Cost to install or upgrade meters

Cost:

Acct.# & Description	Amount
1860-Meters	$10,780.51
	$10,780.51

2007-8

Description: Miscellaneous Underground Work

Need: upgrade or add to underground devices

Scope: Cost of upgrades or small installs during 2007

Cost:

Acct.# & Description	Amount
1845-Underground Conductors & Devices	$2,565.66
	$2,565.66

2008 Bridge Year

CAPITAL ADDITIONS - SUMMARY OF JOBS AND DESCRIPTIONS

Job Number	Description	Total Cost
2008-1	**Signage**, Fences, Storm Damage	$ 2,078.51
2008-2	SubTransmission Upgrades	$ 75,000.00
2008-3	Forest & Beatty St-upgrades, Isabella,Darlingtons,Salt Docks Pole Line-upgrade/replacement	$ 46,166.42
2008-4	Overhead Conductor Upgrades/Replacements	64,969.83
2008-5	Change out Secondary junction Boxes X2	$ 2,389.26
2008-6	Harris Rd line, Feeder #9, Bowes St Upgrade	$ 15,006.84
2008-7	PCB Change outs, New locations	$ 68,146.82
2008-8	Upgrades based on Bridge Year Estimate from prior years work	$ 28,442.19
2008-9	Upgrades based on Bridge Year Estimate from prior years work	$ 16,296.00
2008-10	Dist Feeder Upgrades & Transfer Customer Upgrades	$ 95,000.00
		$ 413,495.88

GL Account	Total Cost
1820 - Distribution Station Equipment	$ 77,078.51
1830 - Distribution Poles, Towers, Fixtures	$ 141,166.42
1835 - Overhead Conductors	$ 64,969.83
1840 - Underground Conduit	$ 2,389.26
1845 - Underground Conductors	$ 15,006.84
1850 - Line Transformers	$ 68,146.82
1855 – Services	$ 28,442.19
1860 – Meters	$ 16,296.00
Total	$ 413,495.88

2008-1

Description: Install/replace damaged service poles, signage and fences, misc storm damage

Need: miscellaneous storm damage and vehicular mishap clean up required on an as-needed basis

Scope: To replace existing poles, signage and fences due to storm damage or vehicular damage.

Cost:

Acct & Desc.	Amount
1820 - Distribution Station Equipment	$2,078.51
	$2,078.51

2008-2

Description: Upgrades of our sub-transmission lines
Need: To replace existing sub-transmission lines due to deteriorated conditions.

Scope: Replace 2-pole subtransmission structures to new pole mount structure to conform with ESA Reg. 22/04

Cost:

Acct & Desc	Amount
1820 - Distribution Station Equipment	$75,000.00
	$75,000.00

2008-3

Description: Upgrade Lines on Forest St and Beatty St; Upgrade/Replace Pole Lines on Salt Dock Rd, Darlington Lake & Isabella St
Need: The current pole lines and/or tranmission wires will be replaced due to current and future growth.

Scope: To upgrade/replace existing lines and/or poles on various streets.

Cost:

Acct & Desc	Amount
1830 - Distribution Poles, Towers & Fixtures	$46,166.42
	$46,166.42

2008-4

Description: Overhead Conductor Upgrades and Replacements

Need: The current overhead conductors are in need of upgrade or replacement to meet current and future load
growth and to satisfy ESA Reg. 22/04

Scope: To replace existing overhead conductors on various pole lines.

Cost:

Acct & Desc	Amount
1835 - Overhead Conductors	$64,969.83
	$64,969.83

2008-5

Description: Change out Secondary junction Boxes

Need: Two of our secondary junction boxes will be replaced due to deteriorated conditions.

Scope: To replace two existing secondary junction boxes.

1

Cost:

Acct & Desc	Amount
1840 - Underground Conduit	$2,389.26
	$2,389.26

2008-6

Description: Harris Rd line, Feeder #9, Bowes St Upgrade

Need: To install and replace substandard underground conductors & equipment at various locations to satisfy ESA Reg. 22/04.

Scope: To install new or replace existing underground conductors.

Cost:

Acct & Desc	Amount
1845 - Underground Conductors	$15,006.84
	$15,006.84

2008-7

Description: PCB Change outs, Existing locations

Need: To replace P.C.B. contaminated transformers at various locations within the municipality.

Scope: To replace P.C.B. contaminated transformers at various locations within the municipality.

Cost:

Acct & Desc	Amount
1850 - Line Transformers	$68,146.82
	$68,146.82

2008-8

Description: Install and connect new services as required.

Need: Install and connect new services as required.

Scope: Install and connect new services as required.

1

Cost:

Acct & Desc	Amount
1855 - Services	$28,442.19
	$28,442.19

2008-9

Description: Replace various existing meters and install meters for new services

Need: To install new meters as needed or due to Measurement Canada Regulations and install meters for new services as required.

Scope: To install or replace electric meters

Cost:

Acct & Desc	Amount
1860 - Meters	$16,296.00
	$16,296.00

2008-10

Description: Dist Feeder Upgrades & Transfer Customer Upgrades

Need: Upgrade poles as required to obtain clearances and include line extensions to eliminate transfer customers.

Scope: Upgrade poles as required to obtain clearances and include line extensions to eliminate transfer customers.

Cost:

Acct & Desc	Amount
1830 - Poles, Towers & Fixtures	$95,000.00
	$95,000.00

2

2009 Test Year

CAPITAL ADDITIONS - SUMMARY OF JOBS AND DESCRIPTIONS

Job Numbers & Description		Costs
2009-1	Upgrades Based on Estimate from Prior Years Jobs	$2,286.36
2009-2	SubTransmission Upgrades	$75,000.00
2009-3	Primary Lines upgrade Joseph St. Isabella St.,William Street, Joseph Part 2, Isabella Part 2,	$62,045.30
2009-4	Primary Lines upgrade Joseph St. Isabella St.,William Street, Joseph Part 2, Isabella Part 2,	$66,471.29
2009-5	Upgrades based on Estimate from Prior Years Jobs	$2,680.00
2009-6	Upgrades based on Estimate from Prior Years Jobs	$16,507.52
2009-7	Primary Lines upgrade Joseph St. Isabella St.,William Street, Joseph Part 2, Isabella Part 2,	$25,246.40
2009-8	Upgrades based on Estimate from Prior Years Jobs	$31,286.42
2009-9	Upgrades based on Estimate from Prior Years Jobs	$17,925.60
Total		**$299,448.89**

GL & Description		Costs
1820	Distribution Station Equipment	$77,286.36
1830	Distribution Poles, Towers, Fixtures	$62,045.30
1835	O/H Conductors	$66,471.29
1840	U/G Conduit	$2,680.00
1845	U/G Conductors	$16,507.52
1850	Line Transformers	$25,246.40
1855	Services	$31,286.42
1860	Meters	$17,925.60
Total		**$299,448.89**

2009-1
Description: Signage, fences & storm damage

Need: Repair or replace associated hardware as a result of vandalism, storm or vehicular damage at various locations situated within our service territory. Previous years costs are minimal so no major increase in costs are projected.

Scope: Repair or replace associated hardware as a result of vandalism, storm or vehicular damage at various locations situated within our service territory.

Cost:

Acct & Desc:	Amount
1820 - Distribution Station Equipment	$2,286.36
	$2,286.36

2009-2
Description: Sub-Transmission Upgrades

Need: Upgrade and replace badly deteriorated sub-transmission structures on William Street. Current structures have been identified through our yearly inspection program to be sub standard for their needs. Poles and associated hardware will be installed that will be compliant with ESA Reg. 22/04 standards.
Scope: Replace four sub-transmission structures located behind 125 William Street using Live Line Techniques.

Cost:

Acct & Desc.	Amount
1820 - Distribution Station Equipment	$75,000.00
	$75,000.00

2009-3
Description: Primary Lines upgrade Joseph St., Isabella St.,William St., Joseph St. Part 2, Isabella St. #2

Need: Current and future load growth as well as require a need to upgrade existing lines at the above noted locations. Some additional work will be required on some structures in order to obtain clearances to satisfy ESA Reg. 22/04.

Scope: Upgrade insulators on Joseph Street #1 to accept larger conductor size. Replace deteriorated cross arms as needed. Replace anchors and guys as required.
Upgrade insulators on Isabella Street #1 to accept larger conductor size. Replace deteriorated cross arms as needed. Replace anchors and guys as required.
Re-insulate 6 poles spans on William Street to allow for voltage conversion. This voltage conversion required to reduce the load on the existing circuit as well as provide a loop feed for a 12.4 kv. circuit.
Upgrade insulators on Joseph Street #2 to accept larger conductor size. Replace deteriorated cross arms as needed. Replace anchors and guys as required.
Upgrade insulators on Isabella Street #2 to accept larger conductor size. Replace deteriorated cross arms as needed. Replace anchors and guys as required.

Cost:

Acct & Desc	Amount
1830 - Distribution Poles, Towers and Fixtures	$62,045.30
	$62,045.30

2009-4
Description: Primary Lines upgrade Joseph St. Isabella St.,William Street, Joseph Part 2, Isabella Part 2
Need: To upgrade existing lines due to current and future load growth.
Scope: Upgrade conductor size to 3/0 ACSR from #2 ACSR to allow for increase amperage on Joseph Street #1.
Upgrade conductor size to 3/0 ACSR from #2 ACSR to allow for increase amperage on Isabella Street #1.
Install 3/0 ACSR conductor for 6 poles spans on William Street to allow for voltage conversion. This voltage conversion required to reduce the load on the existing circuit as well as provide a loop feed for a 12.4 kV. circuit.
Upgrade conductor size to 3/0 ACSR from #2 ACSR to allow for increase amperage on Joseph Street #2.
Upgrade conductor size to 3/0 ACSR from #2 ACSR to allow for increase amperage on Isabella Street #2.

Cost:

Acct & Desc	Amount
1835 - Overhead Conductors	$66,471.29
	$66,471.29

2009-5
Description: Change-out sub-standard secondary vaults.

Need: Throughout our yearly inspection problem, it has been identified that some of our underground secondary vaults are collapsing under the pressure of the municipal sidewalk plow thus rendering access to the vaults contents inaccessible. This has been a yearly program and will continue until all sub-standard vaults are replaced.

Scope: Remove interlocking brick around the secondary vault and replace vault with a newer synthetic Synertec enclosure. Compact all earth around enclosure and reset interlocking brick.

Cost:

Acct & Desc	Amount
1840 - Underground Conduit	$2,680.00
	$2,680.00

2009-6
Description: Change-out/repair deteriorated conductors and connections

Need: Throughout our yearly inspection program, it has been identified that multiple u/g connections and cables are badly corroding and are in need of replacement. It has also been identified that some concentric neutrals have corroded off the primary voltage cables.

Scope: Replace badly corroded secondary PED connectors as required. Cut back corrosion on conductors and apply an inhibitor prior to reconnecting them in the PED connectors. Primary voltage cables will require isolation and new terminations installed. Concentric neutrals will have an inhibitor applied where required thus eliminating similar future problems.

1

Cost:

Acct & Desc.	Amount
1845 - Underground Conductors	$16,507.52
	$16,507.52

2009-7

Description: Upgrade transformers at various locations due to load growth.

Need: Various locations around our service territory have identified transformers that are heavily loaded. These transformers have been identified by our infra red scanning program done yearly on our entire infrastructure. These transformers require upgrading to alleviate the overheating problem.

Scope: Replace overloaded transformers during the off season when the electric heating load is off.

Cost:

Acct & Desc.	Amount
1850 - Line Transformers	$25,246.40
	$25,246.40

2009-8

Description: Install and connect new services as required.

Need: Various locations within our service territory will require electrical service connections throughout the year. There is currently two active subdivisions under construction as well as multiple building lots that will require new dwellings to be connected to the electrical system..

Scope: Install and connect electrical services to new dwellings. Upgrade conductors for upgraded services on existing locations.

Cost:

Acct & Desc	Amount
1855 - Services	$31,286.42
	$31,286.42

2009-9

Description: Replace or install new electrical meters within our service territory

Need: To maintain compliance with Measurement Canada, various electrical meters that are currently in service will be required to be tested and resealed. Included within this need is the replacement of defective instrument transformers as they are identified. There will be a limited number of these meter installations that will require third party involvement due to the lack of proper qualifications within our work force.

Scope: To upgrade and install meters at various locations as per schedule. Install new meter installations on all new services as the need requires.

2

Cost:

Acct & Desc	Amount
1860 - Meters	$17,925.60
	$17,925.60

1 # Accumulated Depreciation Table

2

Acct	Acct Desc	Useful Life	Depr %
1805	1805- Land	0	0
1806	1806- Land Rights	25	4
1820	1820- Distribution Station Equipment – Normally Primary below 50kV	30	3.3
1830	1830- Poles, Towers and Fixtures	25	4
1835	1835- Overhead Conductors and Devices	25	4
1840	1840- Underground Conduit	25	4
1845	1845- Underground Conductions and Devices	25	4
1850	1850- Line Transformers	25	4
1855	1855- Services	25	4
1860	1860- Meters	25	4
1995	1995- Contributions and Grants – Credit	25	4

3

4 **Accumulated Depreciation Variance**

5 The variance in accumulated depreciation from EDR to Test Year 2009 is caused by the change
6 in asset/capital additions. PSP did not change any CCA rates or move assets between classes.

Summary of Asset Additions

Asset Additions are provided in earlier schedule.

Summary of Asset Retirements

PSP has no asset retirements.

Leave to Construction (under Section 92)

Not Applicable.

System Expansions

PSP has no planned System Expansions due to customer growth.

Capitalization Policy

PSP currently does not have a formal capitalization policy. We are currently in the process of adopting a policy with similar utilities from the CHEC group. Parry Sound Power applies the following general capitalization policies and principles based on Generally Accepted Accounting Principles ("GAAP"), in particular CICA Handbook Section 3060 Capital Assets, as well as guidelines set out by the Ontario Energy Board, where applicable:

- The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. PSP does not currently capitalize interest on funds for construction.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.

Expenditures that create a physical betterment or improvement of the asset (i.e. there is a significant increase in the physical output or service capacity; or the useful life of the capital asset is extended) will be capitalized.

Summary of 2009 Working Capital Allowance

<u>Eligible Distribution Expenses:</u>		
3500-Distribution Expenses – Operation		76,689
3550-Distribution Expenses - Maintenance		302,064
3650-Billing and Collecting		410,303
3700-Community Relations		18,298
3800-Administrative and General Expenses		457,437
3950-Taxes Other Than Income Taxes		0
Total Eligible Distribution Expenses		1,264,790
3350-Power Supply Expenses		6,695,403
Total Expenses for Working Capital		7,960,193
Working Capital Allowance	**15.0%**	**1,194,029**

1 # Working Capital Allowance calculations by accounts

2

Working Capital Allowance Factor:	15.0%	
Account Description	2009 Projected Acct Balance	Working Capital Allowance
4705-Power Purchased	5,187,807	778,171
4708-Charges-WMS	494,983	74,248
4714-Charges-NW	365,407	54,811
4716-Charges-CN	369,016	55,352
4730-Rural Rate Assistance Expense	95,189	14,278
4750-Charges-LV	183,000	27,450
5005-Operation Supervision and Engineering	24,796	3,719
5016-Distribution Station Equipment - Operation Labour	2,400	360
5017-Distribution Station Equipment - Operation Supplies and Expenses	7,465	1,120
5020-Overhead Distribution Lines and Feeders - Operation Labour	4,240	636
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	55	8
5035-Overhead Distribution Transformers- Operation	1,300	195
5040-Underground Distribution Lines and Feeders - Operation Labour	7,875	1,181
5055-Underground Distribution Transformers - Operation	432	65
5065-Meter Expense	21,381	3,207
5095-Overhead Distribution Lines and Feeders - Rental Paid	801	120
5096-Other Rent	5,944	892
5105-Maintenance Supervision and Engineering	7,694	1,154
5114-Maintenance of Distribution Station Equipment	28,431	4,265
5120-Maintenance of Poles, Towers and Fixtures	48,205	7,231
5125-Maintenance of Overhead Conductors and Devices	78,862	11,829
5130-Maintenance of Overhead Services	16,430	2,464
5135-Overhead Distribution Lines and Feeders - Right of Way	67,126	10,069
5145-Maintenance of Underground Conduit	5,899	885
5150-Maintenance of Underground Conductors and Devices	6,139	921
5155-Maintenance of Underground Services	6,490	974
5160-Maintenance of Line Transformers	16,076	2,411
5175-Maintenance of Meters	16,120	2,418
5190-Water Heater Controls - Labour	4,594	689
5310-Meter Reading Expense	48,872	7,331
5315-Customer Billing	276,999	41,550
5320-Collecting	75,610	11,341
5335-Bad Debt Expense	8,822	1,323
5410-Community Relations - Sundry	15,538	2,331
5420-Community Safety Program	2,760	414
5605-Executive Salaries and Expenses	12,015	1,802
5615-General Administrative Salaries and Expenses	188,967	28,345
5620-Office Supplies and Expenses	31,689	4,753
5630-Outside Services Employed	132,612	19,892
5655-Regulatory Expenses	45,653	6,848
5670-Rent	46,500	6,975
	7,960,193	1,194,029

Overview of Distribution Revenue

This Exhibit provides the details of the Applicant's operating revenue for 2006 Board Approved, 2006 Actual, 2007 Actual, the 2008 Bridge Year and the 2009 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenues have been calculated using the rates approved in the OEB's 2008 rate adjustment proceeding in respect to the Applicant. In particular, delivery rates are based on the OEB's Decision and Order in EB-2007-0825, dated March 14, 2008. Distribution revenue does not include revenue from commodity or other pass through rates.

A summary of operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

Distribution Revenue

Information related to the Applicant's distribution revenue includes details such as weather normalized forecasting methodology, normalized volume and customer count forecast tables. Detailed variance analysis on the forecast information is also provided. Detailed information relating to distribution revenue is set out in the Schedules to Exhibit 3, Tab 2.

Other Revenue

Other revenues include Distribution Service Admin charge, Miscellaneous Service Revenues, Late Payment charges, Other Operating Revenue, Other Income & Deduction and Interest Income. A summary of these operating revenues together with a materiality analysis of variances is presented in Exhibit 3, Tab 3, Schedules 1 and 2.

Revenue Sharing:

As noted in Exhibit 3, Tab 4, Schedule 1, the Applicant does not have a revenue sharing practice in place.

Summary of Distribution Revenue Table

Distribution Revenue	**2009 @ new rates**	**Var $ from 2008 Projected**	**2008 Projection**	**Var $ From 2007 actual**	**2007 Actual**	**Var $ From 2006 Actual**	**2006 Actual**	**2006 EDR Approved**	**Var $**
Residential	1,044,548	64,214	980,334	1,103	979,231	49,407	929,824	1,000,350	-70,525
General Service <50 kW	416,040	82,352	333,688	2,268	331,420	3,503	327,917	366,831	-38,914
General Service >50kW	418,239	-44,132	462,371	19,498	442,873	19,420	423,452	424,517	-1,065
Unmetered Scattered Load	12,652	4,281	8,371	-401	8,772	5,690	3,082	8,382	-5,300
Sentinel Lighting	1,354	769	586	114	472	97	375	587	-212
Street Lighting	49,164	33,954	15,210	639	14,571	-603	15,174	13,737	1,437
DISTRIBUTION REVENUE	**1,941,997**	**141,438**	**1,800,560**	**23,221**	**1,777,338**	**77,514**	**1,699,824**	**1,814,405**	**-114,581**

1 **Summary of Distribution Revenue Table (Continued)**

Other Distribution Service Revenue	2009 @ new rates	Var $ from 2008 Projected	2008 Projection	Var $ From 2007 actual	2007 Actual	Var $ From 2006 Actual	2006 Actual	2006 EDR Approved	Var $
4080-Distribution Services Revenue	8,529	0	8,529	-93	8,622	-335	8,957	12,535	-3,578
4082 & 4084 Misc Service Revenue		0	0	0	0	0	0	698	-698
4210-Rent from Electric Property	36,542	0	36,542	1	36,541	102	36,439	5,147	31,295
4220-Other Electric Revenues		0		0		0			0
4225-Late Payment Charges	15,067	0	15,067	-1,839	16,906	2,546	14,360	17,448	-3,088
4230-Sales of Water and Water Power		0		0		0			0
4235-Miscellaneous Service Revenues	23,372	0	23,372	-4,823	28,195	13,872	14,324	24,900	-10,577
4325-Revenues from Merchandise, Jobbing, Etc.		0		0		0			0
4330-Costs and Expenses of Merchandising, Jobbing, Etc.		0		0		0			0
4355-Gain on Disposition of Utility and Other Property		0		0		0			0
4390 Misc Non-Operating Income	8,364	0	8,364	274	8,090	3,858	4,232	4,948	-716
4405-Interest and Dividend Income	95,861	0	95,861	-84,370	180,231	63,741	116,490	21,392	95,098
TOTAL OTHER DISTRIBUTION SERVICE REVENUE	**187,735**	**0**	**187,735**	**-90,850**	**278,584**	**83,783**	**194,802**	**87,065**	**107,737**
Distribution Revenues (see above)	**1,941,997**	**141,438**	**1,800,560**	**23,221**	**1,777,338**	**77,514**	**1,699,824**	**1,814,405**	**-114,581**
TOTAL DISTRIBUTION REVENUES	**2,129,732**	**141,438**	**1,988,294**	**-67,628**	**2,055,922**	**161,296**	**1,894,626**	**1,901,470**	**-6,844**

2

Variance Analysis on Distribution Revenue

PSP's distribution revenue has been calculated using the most recently approved rates. In particular, delivery rates are based on the EB-2007-0825 Rate Order, dated March 14, 2008. Distribution Revenue does not include commodity revenue.

A summary of operating revenues is presented above which is based on the forecasted data provided in Exhibit 3 Tab 1 Schedule 1.

2006 Board Approved

PSP's total Distribution Revenue, including Other Distribution Revenues for 2006 Board Approved was $1,901,470, as shown in Exhibit 3, Tab 1, Schedule 1. Distribution revenue totals $1,814,405 or 96% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $87,065.

2006 Actual

PSP's total Distribution Revenue, including Other Distribution Revenues for 2006 actual was $1,894,626, as shown in Exhibit 3, Tab 1, Schedule 1. Distribution revenue totals $1,699,824 or 90% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $194,802.

Comparison to 2006 Board Approved

As shown in Exhibit 3, Tab 1, Schedule 1, the total Distribution Revenue for 2006 Actual was $6,844 lower than the 2006 Board Approved level.

2007 Actual

PSP's total Distribution Revenue, including Other Distribution Revenues for 2007 Board was $2,055,922, as shown in Exhibit 3, Tab 1, Schedule 1. Distribution revenue totals $1,777,338 or 86% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $278,584.

Fiscal 2007 Actual Comparison to Fiscal 2006 Actual

As shown in Exhibit 3, Tab 1, Schedule 1, the Distribution Revenue is $161,296 above the actual 2006. This increase is caused by an increase in rates and consumption combined with interest revenue and misc service revenue increase.

2008 Bridge Year

PSP's total Distribution Revenue, including Other Distribution Revenues is forecast to be $1,988,294 for Bridge 2008, Distribution revenue totals $1,800,560 or 91% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $187,735.

2008 Bridge Year Comparison to Fiscal 2007 Actual

As shown in Exhibit 3, Tab 1, Schedule 1, the Total Distribution Revenue is expected to be $67,628 lower than the 2007 actual. The distribution revenue shows an increase of $23,221 over 2007 actual caused by an increase in rates and slight increase in consumption. A decrease of $90,850 in other operating revenues make up the overall $67,628 decrease. This portion of the variance is largely attributed to a decrease in interest revenues.

2009 Test Year

PSP's total Distribution Revenue including Other Distribution Revenues is forecast to be $2,129,732 for Fiscal 2009. Distribution revenue totals $1,941,997 or 91% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $187,735.

Comparison to 2008 Bridge Year

As shown in Exhibit 3, Tab 1, Schedule 1, the Total Distribution Revenue is expected to be $141,438 higher than the bridge year level. This variance is the proposed rates and load forecast increase.

Weather Normalization Forecasting Methodology

PSP's customer and load forecast methodology is discussed in this exhibit. PSP contracted with Elenchus Research Associates, known as ERA, to provide weather normalized load forecasts for 2008 bridge year and 2009 test year. ERA also projected the number of customers in each customer class for both the 2008 Bridge Year and the 2009 Test Year. Exhibit 3, Tab 2, Schedule 2 shows historical data for the annual number of customers in each rate class is available for 2003 through to 2007. We have included a Glossary of terms and a Brief synopsis for the Weather Normalization and Load Forecast.

As required by the OEB's Filing Requirements, PSP is providing normalized historical and forecast (Bridge Year and Test Year) throughput data. The ERA model is provided below and describes the process followed.

This section is intended to add the reader with a brief overview and a glossary of terms of how and why to forecast methodology.

Brief synopsis of weather correction and load forecast

A weather normal load forecast is derived for the rate application. Weather normalization involves removing the year-to-year variations in consumption caused by variation due to weather. This is achieved by estimating a statistical relationship between observed monthly weather and observed monthly consumption. In addition to weather, monthly consumption can also be affected by the number of weekdays and holidays in the month, and economic factors. These are also accounted for in the statistical relationship.

Once the statistical relationship between monthly weather and consumption is obtained, year-to-year variance in weather conditions is controlled for by defining a "weather normal" month. For our purposes, we have adopted the most recent 10-year average of observed weather in each month as “weather normal”. Historical observations are weather normalized by replacing actual observed weather with normal weather in the statistical relationship to obtain what consumption would have been if weather had been “normal”. Future consumption is forecast based on normal weather and forecast economic and timing variables.

A Glossary of Terms is provided on the following pages.

Attached following the Glossary of Terms are PSP’s Load Forecast and Community Profile.

Glossary of terms, Weather Normalization and Load Forecast

Heating degree days (HDD): Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C.

Cooling degree days (CDD): Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C.

OLS estimates: Ordinary Least Squares estimates. Ordinary least squares is the standard statistical technique used to estimate a linear regression equation. A simple linear regression equation is

$$Y = bX + e$$

where Y is the dependent variable (dependent upon X) , X is the independent variable, b is the estimated parameter, and e is a random error with a mean of zero. A multiple variable regression equation (where there is more than one independent variable) is

$$Y = b_1X_1 + b_2X_2 + \ldots + b_nX_n + e$$

Where X_1 to X_n are the independent variables and b_1 to b_n are the estimated parameters.

Estimated Parameters: The estimated parameters (b) are called **coefficients** in the load forecast report and describe the relationship between consumption and the explanatory (independent) variables. For example, the constant describes what is essentially monthly base load, the coefficient on HDD and CDD describe how much monthly consumption changes (increases) if an additional CDD or HDD is observed, and the coefficient on peak days describes how much monthly consumption increases as a result of a peak day (non-holiday weekday).

Log-Linear Regression: Still a linear equation (Y = bX + e) but where the Y dependent variable is transformed by applying natural logarithms or ln(Y). This is done if the relationship between the untransformed (actual) dependent variable (consumption) and the independent variables is multiplicative (non-linear), which may be the case.

R^2 or R-Squared: A statistic used universally in regression analysis to describe the goodness of fit, also called the goodness-of-fit statistic. Simplistically, it explains how much of the observed variation is explained by the regression equation. An R^2 of 0.75 means that the regression explains 75% of the observed variation. An R^2 of 0.75 would be considered good, an R^2 of 0.95 would be considered great, and an R^2 of 0.999 would mean the model equation is an all-knowing prophet of the future (as long as the future behaves like the past, a problem for some prophets).

T-Statistic and F-Statistic: Statistical tests to show the statistical significance of estimates. The t-stats show if the individual parameter estimates are significant and the F-Stat to show the overall significance of the regression. For the F-Stat, we want the p-value < .001. For t-stats, it would be nice for the p-value to be <0.1 and, in general, t-stat to be >2. There is a bit more to it than this, but it is beyond the scope of a glossary.

Durbin-Watson Statistic: A bit beyond the scope of this glossary – basically we want it to be between about 1.6 and 2.4. It measures whether a pivotal classical assumption about the underlying data used for regression analysis is being met.

Prais-Winsten estimates: Also beyond the scope of this glossary (by more than a bit). Basically, this is a transformation and alternate estimation technique to OLS when the Durbin-Watson Statistic doesn't meet the criteria above. This technique corrects that and results in more accurate estimates.

Mean Absolute Percentage Errors: Or MAPE, this takes the absolute error of the estimate in each period (year in our case), adds them, and calculates the average. The errors are absolute so the positives don't cancel out the negatives. While it is not scientific, anything less than 5% can be considered good.

CMA: This is a census metropolitan area defined by Statistics Canada (the Greater Toronto Area for example). Outside of CMAs, economic regions are defined for the purpose of measuring employment and unemployment (for example the Kitchener-Waterloo-Barrie economic region (which includes the K-W CMA), the Stratford-Bruce economic region, etc.

Medium Term Weather Normalized Distribution System Load Forecast 2008 to 2009

Prepared for

Parry Sound Power Corporation

May 28, 2008

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Parry Sound Power Corporation's rebasing rate application for 2009 rates. A weather normal load forecast is developed for the bridge year (2008) and test year (2009) and weather normalized historical consumption is also derived.

For the most part, the forecast for Parry Sound Power is based on monthly class specific retail data from May 2003 to December 2007.[1] The retail metered data has been prorated to represent calendar month consumption. That is, the billing data has been adjusted to account for unbilled amounts, the effect of meter reading dates, etc. The retail consumption amounts do not include losses; therefore, distribution system losses are not part of the class retail volumes. These volumes will need to be adjusted for distribution system losses to reconcile with wholesale purchases by the LDC.

Short-term variation in electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the dominant effect for most systems; economic factors (increases or decreases in economic activity leads to changes in employment, industrial and commercial activity, building and population change); and timing factors (non-holiday weekdays when businesses are typically operating). We have tried to incorporate variables to account for all of these factors in considering Parry Sound's load and correcting for weather anomalies.

In order to isolate demand determinants at the class specific level, we have estimated equations to weather normalize and forecast kWh consumption for the residential, GS<50 and GS>50 class. Consumption for street lighting, sentinel lighting, and unmetered scattered load (USL) is not weather sensitive, and these forecasts are based on trend consumption. We have calculated the class kW demand (where applicable) by

[1] The Company provided data from January 2002. However, some classes had anomalous consumption in some months in 2002 and billing system issues were identified for some classes in 2002, so this year was excluded from the analysis.

applying an annual average kW/kWh ratio based on historical values to annual class kWh.

As can be seen below, the equations for class specific consumption generally fit very well with historical data with low average absolute error and high predictive power. Results are outlined in Section 2 below.

2 CLASS SPECIFIC NORMALIZED AND FORECAST RESULTS

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For Parry Sound, we have used monthly HDD and CDD as reported at Sudbury Airport (Environment Canada Weather Station '*Sudbury A*').

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. We have used the monthly employment levels for Ontario, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2063945). Employment for the Greater Sudbury area was also tried but where employment was a significant explanatory variable, the Ontario employment levels were a better fit based on statistical significance.

Finally, we have used the number of non-holiday weekdays in the month to account for peak day consumption. We have included New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, August Civic Holiday (Simcoe Day), Labour Day, Thanksgiving Day, Christmas and Boxing Day. From 2008, we have included the Ontario Family Day holiday in February, but we have not included Remembrance Day in November. The historical data for monthly employment and peak days are displayed in *Table 1* below.

Table 1
Monthly Peak Days

	2003	2004	2005	2006	2007
January	21	21	20	21	22
February	20	20	20	20	20
March	21	23	21	23	22
April	20	20	21	18	19
May	21	20	21	22	22
June	21	22	22	22	21
July	22	21	20	20	22
August	20	21	22	22	22
September	21	21	21	20	19
October	22	20	20	21	22
November	20	22	22	22	22
December	21	21	20	19	19
	Ontario Employment (‘000s)				
January	6,192	6,273	6,327	6,453	6,549
February	6,220	6,295	6,344	6,435	6,559
March	6,237	6,272	6,348	6,467	6,569
April	6,210	6,298	6,379	6,484	6,555
May	6,210	6,313	6,406	6,517	6,569
June	6,227	6,325	6,406	6,514	6,576
July	6,219	6,337	6,399	6,510	6,588
August	6,213	6,319	6,405	6,495	6,594
September	6,252	6,323	6,426	6,489	6,622
October	6,257	6,348	6,450	6,491	6,656
November	6,250	6,346	6,447	6,509	6,639
December	6,286	6,354	6,433	6,547	6,631
Ann % chg	***2.7%***	***1.4%***	***1.3%***	***1.5%***	***1.5%***

Using this data, regression equations describing the relationship between monthly actual energy and the explanatory variables were estimated for residential, GS<50 and GS>50 classes. All the data showed strong correlation with weather, as expected. Residential demand did not appear correlated with economic variables; however, there was a statistically significant relationship between residential energy use and peak days in the month. A time trend was also included and was statistically significant. While the number of residential customers has increased slightly since 2003 (by approximately 0.7 per cent per year), actual kWh consumption has been trending downwards. However, as can be seen below, the equation for residential consumption explains 99 per cent of the variation in kWh consumption, so we can be confident of the result.

Results for Residential kWh

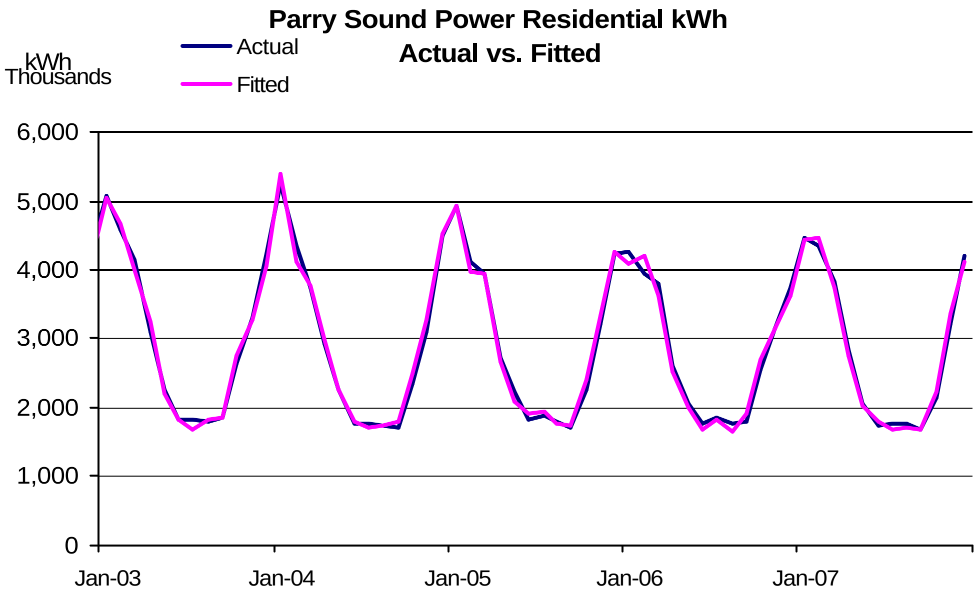
Res kWh = ¦ (HDD, CDD, timetrend, Peakdays) + const

OLS estimates using the 60 observations 2003:01-2007:12

Unadjusted R^2 =0.991152
Adjusted R^2 = 0.990509
F-statistic (4, 55) = 1540.3 (p-value < 0.00001)
Durbin-Watson statistic = 2.34445

Variable Name	Estimated Coeff.	T-Ratio	P-Value
const	918,957.0	3.2132	0.0022
HDD	3,580.4	63.4391	<0.00001
CDD	6,388.9	8.0339	<0.00001
Timetrend	-2,883.3	-3.5593	0.00078
Peak Days	24,339.7	1.8241	0.07358

Actual and fitted values are plotted in the chart below:



Energy consumption in the GS<50 kW class also did not correlate with economic activity variables over the time period for which we had data. Energy demand in this class was sensitive to the number of peak days in the month. A time trend was also fitted to the GS<50 kW class consumption but was found to be insignificant. The results are displayed below.

Results for GS < 50 kW Class kWh

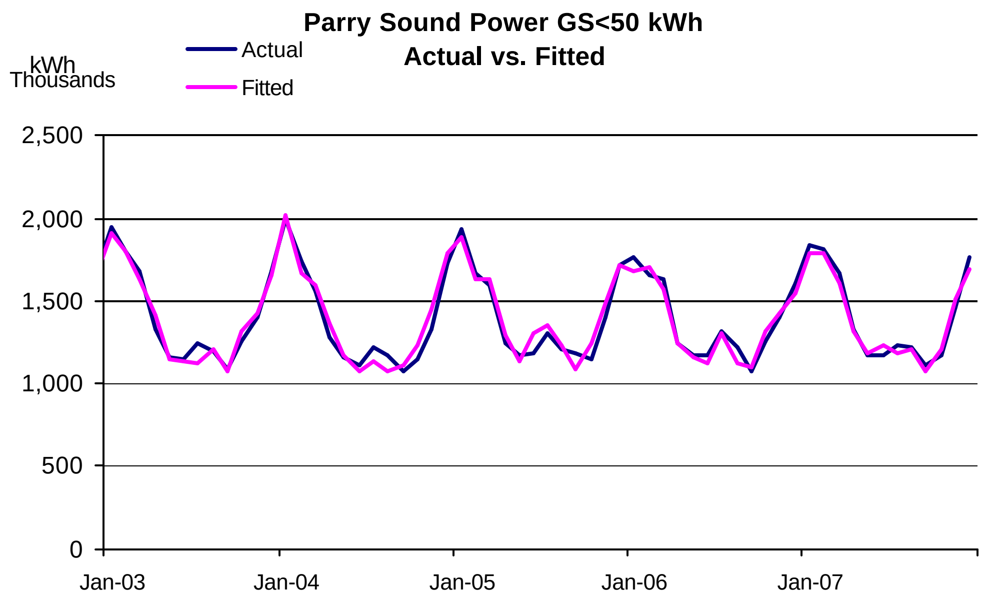
GS<50 kWh = ¦ (HDD, CDD, Peakdays) + const

OLS estimates using the 60 observations 2003:01-2007:12

Unadjusted R^2 = 0.953887
Adjusted R^2 = 0.951417
F-statistic (3, 56) = 386.136 (p-value < 0.00001)
Durbin-Watson statistic = 1.7954

Variable Name	Estimated Coeff.	T-Ratio	P-Value
const	632,021.0	4.0241	0.00017
HDD	971.9	31.1834	<0.00001
CDD	4,523.6	10.2902	<0.00001
PeakDays	13,850.5	1.8764	0.06582

Actual and fitted values are plotted in the chart below:



Energy consumption in the GS>50 kW class was found to be correlated with weather, along with peak days in the month and economic activity (represented by monthly Ontario employment). The regression equation estimated is in log-linear form and has been corrected for first-order autocorrelation of the error term. The results are displayed below.

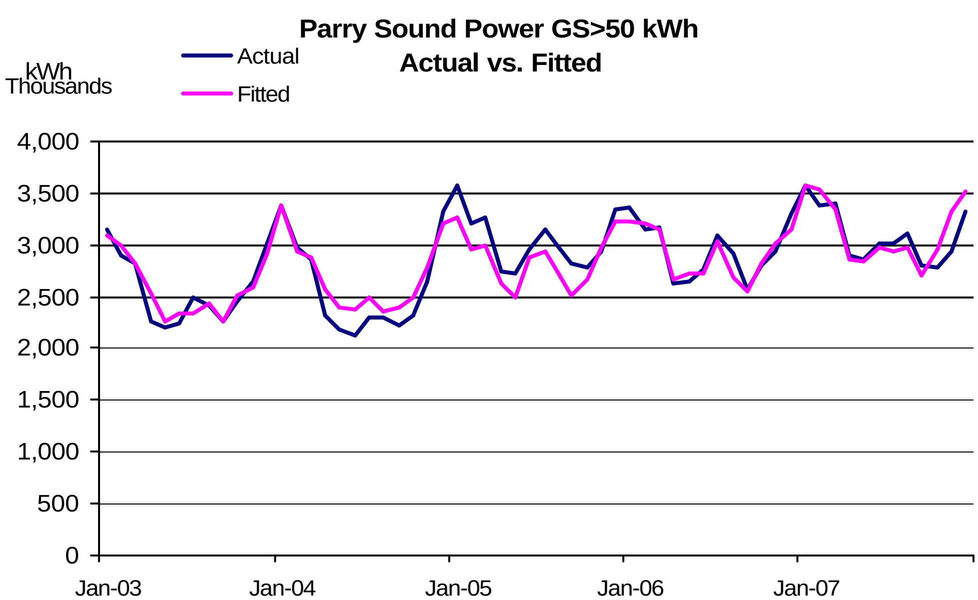
Results for GS > 50 kWh

ln(GS>50 kWh) = ¦(HDD, CDD, Peakdays, Employ) + const

Prais-Winsten estimates using the 60 observations 2003:01-2007:12
Statistics based on the rho-differenced data
Unadjusted R^2 = 0.90387
Adjusted R^2 = 0.896879
F-statistic (4, 55) = 4572.3 (p-value < 0.00001)
Durbin-Watson statistic = 2.05884

Variable Name	Estimated Coeff.	T-Ratio	P-Value
const	11.0546	16.3552	<0.00001
HDD	0.000405247	12.686	<0.00001
CDD	0.0027609	8.0975	<0.00001
PeakDays	0.013015	3.3915	0.00129
OntEmploy	0.000518036	4.9644	<0.00001

Actual and fitted values are plotted in the chart below:



Annual estimates are compared to actual values in the table below. Mean absolute percentage error (MAPE) of the estimates for the period are all less than 3 per cent.

Table 2 – Parry Sound Power – Annual Predicted vs. Actual

Year	*Actual Residential kWh*	*Predicted kWh*	*Error*	*Actual GS<50 kWh*	*Predicted kWh*	*Error*
2003	36,574,671	36,413,307	-0.44%	16,893,042	16,825,379	-0.40%
2004	35,384,766	35,794,856	1.16%	16,475,395	16,649,689	1.06%
2005	34,829,575	34,894,387	0.19%	16,712,968	16,978,769	1.59%
2006	33,237,936	32,910,822	-0.98%	16,473,586	16,292,225	-1.10%
2007	33,976,663	33,990,239	0.04%	16,945,672	16,754,552	-1.13%
		Mean Absolute Percent Error	*0.56%*			*1.06%*
	Actual GS>50 kWh	*Predicted kWh*	*Error*			
2003	30,964,078	31,160,925	0.64%			
2004	30,992,423	32,347,831	4.37%			
2005	36,540,579	34,377,557	-5.92%			
2006	35,380,706	35,009,107	-1.05%			
2007	37,168,353	37,591,494	1.14%			
		Mean Absolute Percent Error	*2.62%*			

2.1 WEATHER NORMALIZATION AND FORECASTED CONSUMPTION

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. For Parry Sound, the 10 year average from 1998 to 2007 has been adopted as the appropriate definition of weather normal. Other definitions also exist. Environment Canada publishes 30 year "Climate Normal" data based on observations from 1971 to 2000. The OEB has considered yet others (for example, a five-year rolling average used to predict heating degree days for bridge year and test year in the case of Natural Resource Gas Limited (RP-2004-0167)). Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Others have also adopted this definition (for example, Toronto Hydro Electric System Limited in EB-2005-0421 and EB-2007-0680).

Presented below is a table outlining the 10-year and 30-year average monthly HDD and CDD for Sudbury Airport (YSB).

Table 3 – 30-yr and 10-yr HDD and CDD, Sudbury Airport (YSB)

	1971-2000 30yr normal		**1998-2007 10yr normal**	
	HDD	**CDD**	**HDD**	**CDD**
Jan	**981.0**	**0.0**	**936.3**	**0.0**
Feb	**829.8**	**0.0**	**789.1**	**0.0**
Mar	**722.0**	**0.0**	**689.7**	**0.0**
Apr	**446.5**	**0.5**	**416.1**	**0.0**
May	**216.1**	**7.6**	**195.9**	**5.5**
Jun	**81.1**	**27.2**	**70.0**	**38.1**
Jul	**25.1**	**57.2**	**23.3**	**60.9**
Aug	**48.1**	**38.9**	**38.3**	**44.1**
Sep	**179.4**	**6.8**	**132.7**	**12.6**
Oct	**378.6**	**0.1**	**356.3**	**0.9**
Nov	**584.1**	**0.0**	**543.1**	**0.0**
Dec	**851.8**	**0.0**	**791.8**	**0.0**
Annual	**5,343.5**	**138.2**	**4,982.6**	**162.1**

Forecasts for Ontario's employment outlook for 2008 and 2009 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 4 - Employment Forecast – Ontario
(figures in annual percentage change)

	BMO *(Winter 2008)*	RBC *(April 2008)*	Scotia *(May 5, 2008)*	TD *(April 16,2008)*	avg
2008	0.7	0.9	1.2	1.0	0.9
2009	0.7	1.0	0.8	0.4	0.7

Incorporating the forecast economic variables, monthly peak days, and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

Table 5 - Weather Corrected Consumption for Parry Sound				
			10-yr (1998-2007)	
Year	Actual residential kWh	%chg	Weather Normal	%chg
2003	36,574,671		35,347,601	
2004	35,384,766	-3.3%	34,981,085	-1.0%
2005	34,829,575	-1.6%	34,517,211	-1.3%
2006	33,237,936	-4.6%	34,102,016	-1.2%
2007	33,976,663	2.2%	33,735,500	-1.1%
2008F			33,295,965	-1.3%
2009F			32,856,430	-1.3%
Year	Actual GS<50 kWh	%chg	Weather Normal	%chg
2003	16,893,042		16,622,806	
2004	16,475,395	-2.8%	16,650,507	0.2%
2005	16,712,968	1.4%	16,622,806	-0.2%
2006	16,473,586	-1.4%	16,622,806	0.0%
2007	16,945,672	2.9%	16,650,507	0.2%
2008F			16,636,657	-0.1%
2009F			16,622,806	-0.1%
Year	Actual GS>50 kWh	%chg	Weather Normal	%chg
2003	30,964,078		30,970,380	
2004	30,992,423	0.1%	32,442,310	4.8%
2005	36,540,579	17.9%	33,714,668	3.9%
2006	35,380,706	-3.2%	35,444,463	5.1%
2007	37,168,353	5.1%	37,414,635	5.6%
2008F			38,547,440	3.0%
2009F			39,438,481	2.3%
Year	Actual GS>50 kW	%chg	Weather Normal	%chg
2003	48,210		48,219	
2004	81,896	69.9%	85,728	77.8%
2005	89,198	8.9%	82,299	-4.0%
2006	88,798	-0.4%	88,958	8.1%
2007	90,489	1.9%	91,088	2.4%
2008F			93,846	3.0%
2009F			96,015	2.3%

Weather corrected class kW for the GS>50 kW class is calculated by determining an annual kW/kWh ratio and multiplying this ratio by the weather normal kWh in the year. Forecast values are based on the kW/kWh in 2007.

The street lighting, sentinel lighting, and USL classes are not weather sensitive. None of these classes are expected to show any customer growth in 2008 or 2009 over 2007 (no additional customers or installations). Therefore, consumption levels for 2008 and 2009 in these classes are held at the 2007 level.

Table 6 - Lighting & USL Historic and Trend Forecast Consumption

	Street Lighting				*Sentinel Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003	833,553		2,438		16,020		41	
2004	870,724	4.5%	2,424	-0.6%	16,004	-0.1%	41	0.0%
2005	867,846	-0.3%	2,424	0.0%	16,017	0.1%	41	0.0%
2006	867,846	0.0%	2,424	0.0%	15,986	-0.2%	41	0.0%
2007	867,846	0.0%	2,424	0.0%	16,006	0.1%	41	0.0%
2008F	867,846	0.0%	2,424	0.0%	16,006	0.1%	41	0.0%
2009F	867,846	0.0%	2,424	0.0%	16,006	0.1%	41	0.0%

	USL	
Year	kWh	%
2003	120,367	
2004	120,581	0.2%
2005	124,708	3.4%
2006	129,531	3.9%
2007	118,251	-8.7%
2008F	118,251	0.0%
2009F	118,251	0.0%

Table 7 below presents the results for class specific historic actual and historic normalized (2007) kWh and kW (where applicable), and normalized forecast values for bridge year (2008) and test year (2009).

Table 7 – Load Forecast (Historical, Bridge and Test Years).

	2007 Actual	2007 Normalized	2008f Normalized	2009f Normalized
Residential (kWh)	33,976,663	33,735,500	33,295,965	32,856,430
GS<50 (kWh)	16,945,672	16,650,507	16,636,657	16,622,806
GS>50 (kWh)	37,168,353	37,414,635	38,547,440	39,438,481
(kW)	90,489	91,088	93,846	96,015
Street Lights (kWh)	867,846	867,846	867,846	867,846
(kW)	2,424	2,424	2,424	2,424
Sentinel Lights (kWh)	16,006	16,006	16,006	16,006
(kW)	41	41	41	41
USL (kWh)	118,251	118,251	118,251	118,251
Total Retail kWh	89,092,790	88,802,745	89,482,165	89,801,570

2.2 CUSTOMER CONNECTIONS

Table 8 below outlines the average annual number of active customer connections in each class and a trend forecast for annual customers based on the average customer additions from 2003 and 2007. No additional customer connections are expected for street lighting, sentinel lighting, or USL customer classes.

Table 8 – Average Annual Customer Connections

	Residential	%chg	GS<50	%chg	GS>50	%chg	Street Light	Sent Light	USL
2003	2,571		496		60			13	17
2004	2,581	*0.4%*	500	*0.8%*	59	*-1.7%*		10	18
2005	2,603	*0.9%*	503	*0.5%*	60	*1.5%*	1,004	13	20
2006	2,610	*0.3%*	505	*0.5%*	61	*0.4%*	1,004	13	20
2007	2,643	*1.3%*	529	*4.7%*	64	*6.2%*	1,004	15	22
2006-2007		**0.7%**		**0.6%**[2]		**1.6%**			
2008f	2,661		532		65		1,004	15	22
2009f	2,680		535		66		1,004	15	22

[2] Includes growth 2003 to 2006 only.

Explanation of Causes and Assumptions for the Volume Forecast

PSP's is a generally urban service area with little growth in our residential class. The GS<50 & GS>50 also remain stable. We expect very little change in any of our rate classes. The table below shows the three year kwh consumption by rate class and the three year average usage per class. PSP's residential class accounts for 38.65% of our overall usage with GS<50 at 19.02% and GS > 50 at 41.72%. The remaining usage is Sentinel, Street Light and USL class consumption.

Table 1 Consumption by rate class (kwh)

Year	Residential	GS<50	GS>50	Street Light	Sentinel Light	USL	Total
2005	34,829,575	16,475,395	36,540,579	867,846	16,017	124,708	88,854,120
% of total	39%	19%	41%	1%	0%	0%	
2006	33,237,936	16,473,586	35,380,706	867,846	15,986	129,531	86,105,591
% of total	39%	19%	41%	1%	0%	0%	
2007	33,976,663	16,945,672	37,168,353	867,846	16,006	118,251	89,092,791
% of total	38.14%	19.02%	41.72%	0.97%	0.02%	0.13%	
3 year average	**38.65%**	**18.90%**	**41.31%**	**0.99%**	**0.02%**	**0.14%**	

As Table 8 Section 2.2 Customer connections in the ERA report (above) indicate PSP's average annual customer connections will not increase by any significant amount.

All data

Parry Sound Ontario (Town) — Select another region

Ontario (Province) — Select another region

Population and dwelling counts	Parry Sound, Town Total	Male	Female	Ontario Total	Male	Female
Population in 2006[1]	5,818			12,160,282†		
Population in 2001[1]	6,124			11,410,046†		
2001 to 2006 population change (%)	-5.0			6.6		
Total private dwellings[2]	2,781			4,972,869		
Private dwellings occupied by usual residents[3]	2,514			4,554,251		
Population density per square kilometre	436.4			13.4		
Land area (square km)	13.33			907,573.82		

Figure

Age characteristics	Parry Sound, Town Total	Male	Female	Ontario Total	Male	Female
Total population[4]	5,815	2,710	3,105	12,160,285	5,930,700	6,229,580
0 to 4 years	265	140	130	670,770	343,475	327,290
5 to 9 years	295	155	135	721,590	369,670	351,920
10 to 14 years	315	165	150	818,445	420,705	397,740
15 to 19 years	380	205	180	833,115	427,185	405,925
20 to 24 years	305	150	150	797,255	400,445	396,815
25 to 29 years	245	105	140	743,695	360,525	383,170
30 to 34 years	265	130	135	791,955	382,030	409,925
35 to 39 years	290	145	145	883,990	430,220	453,770
40 to 44 years	425	195	230	1,032,415	507,130	525,280
45 to 49 years	470	215	255	991,970	486,390	505,585
50 to 54 years	430	205	225	869,400	423,345	446,060
55 to 59 years	400	185	215	774,530	378,530	395,995
60 to 64 years	320	150	175	581,985	283,545	298,440
65 to 69 years	300	135	165	466,240	222,640	243,600
70 to 74 years	310	135	175	401,950	187,510	214,445
75 to 79 years	295	130	160	338,910	149,585	189,325

Normalized Volume Forecast Table

Table 2 Weather Corrected Consumption for Parry Sound

Year	Actual residential KWh	% chg	10-yr Avg. (1998-2007) Weather Normal	% chg
2003	36,574,671		35,347,601	
2004	35,384,766	-3.30%	34,981,085	-1.00%
2005	34,829,575	-1.60%	34,517,211	-1.30%
2006	33,237,936	-4.60%	34,102,016	-1.20%
2007	33,976,663	2.20%	33,735,500	-1.10%
2008F			33,295,965	-1.30%
2009F			32,856,430	-1.30%

Year	Actual GS<50kWh	% chg	Weather Normal	% chg
2003	16,893,042		16,622,806	
2004	16,475,395	-2.80%	16,650,507	0.20%
2005	16,712,968	1.40%	16,622,806	-0.20%
2006	16,473,586	-1.40%	16,622,806	0.00%
2007	16,945,672	2.90%	16,650,507	0.20%
2008F			16,636,657	-0.10%
2009F			16,622,806	0.10%

Year	Actual GS>50 kWh	% chg	Weather Normal	% chg
2003	30,964,078		30,970,380	
2004	360,992,423,	0.10%	32,442,310	4.80%
2005	36,540,579	17.90%	33,714,668	3.90%
2006	35,380,706	-3.20%	35,444,463	5.10%
2007	37,168,353	5.10%	37,414,635	5.60%
2008F			38,547,440	3.00%
2009F			39,438,481	2.30%

Year	Actual GS>50kW	% chg	Weather Normal	% chg
2003	48,210		48,219	
2004	81,896	69.90%	85,728	77.80%
2005	89,198	8.90%	82,299	-4.00%
2006	88,798	-0.40%	88,958	8.10%
2007	90,489	1.90%	91,088	2.40%
2008F			93,846	3.00%
2009F			96,015	2.30%

Table 3 Lighting & USL Historic and Trend Forecast Consumption

Street Lighting

Year	kWh	%	kW	%
2003	833,553		2,438	
2004	870,724	4.5%	2,424	-0.6%
2005	867,846	-0.3%	2,424	0.00%
2006	867,846	0.0%	2,424	0.00%
2007	867,846	0.0%	2,424	0.0%
2008F	867,846	0.0%	2,424	0.0%
2009F	867,846	0.0%	2,424	0.0%

Sentinel Lighting

Year	kWh	%	kW	%
2003	16,020		41	
2004	16,004	-0.1%	41	0.0%
2005	16,017	0.1%	41	0.0%
2006	15,986	-0.2%	41	0.0%
2007	16,006	0.1%	41	0.0%
2008F	16,006	0.1%	41	0.0%
2009F	16,006	0.1%	41	0.0%

USL

Year	kWh	%
2003	120,367	
2004	120,581	0.2%
2005	124,708	3.4%
2006	129,531	3.9%
2007	118,251	-8.7%
2008F	118,251	0.0%
2009F	118,251	0.0%

Customer Count Forecast Table

Table 4 Average Annual Customer Connections

	Residential	%chq	GS<50	%chg	GS>50	%chg	Street Light	Sent Light	USL
2003	2,571		496		60			13	17
2004	2,851	0.4%	500	0.8%	59	-1.7%		10	18
2005	2,603	0.9%	503	0.5%	60	1.5%	1,004	13	20
2006	2,610	0.3%	505	0.5%	61	0.4%	1,004	13	20
2007	2,643	1.3%	529	4.7%	64	6.2%	1,004	15	22
2006-2007		**0.7%**		**0.6%**		**1.6%**			
2008f	2,661		532		65		1,004	15	22
2009f	2,680		535		66		1,004	15	22

Historical Average Consumption

PSP'S Street Light Sentinel Light and USL classes show 0.00% change in consumption patterns as explained in the" Load Forecast" report from ERA. These classes are listed in the above table, however there are not used as part of the variance comparison below.

Historical Approved to Historical Actual

As indicated in the tables above the change from the 2006 EDR year (averaging of prior years) to 2006 Actual in Weather Corrected Consumption is detailed as:

- Residential -1.2% decrease
- GS<50 0.0%
- GS>50 5.1% kwh & 8.1% kW

The residential and GS<50 have no impact on consumption pattern change, the GS<50 however increased by 8.1% caused by a slight increase in customer number and an increase in usage do to building expansion at our local hospital.

Historical Actual 2006 to 2007 Actual

The 2007 weather corrected usage vs 2006 actual weather corrected is detailed as:

- Residential +1.1%
- GS<50 +0.2%
- GS>50 +5.6% kwh & +2.4% kW

PSP's weather corrected usage for these classes are explain by slight changes in customer numbers.

2007 actual to 2008 actual

The 2008 forecast weather corrected usage vs 2007 actual weather corrected is detailed as:

- Residential -1.3%
- GS<50 -0.1%
- GS>50 +3.0% kwh & +3.0% kW

PSP's weather corrected usage for these classes are explain by slight changes in customer numbers.

Bridge Year 2008 vs. Test Year 2009

The 2009 forecast weather corrected usage vs 2008 forecast weather corrected is detailed as:

- Residential 1.3%
- GS<50 +0.1%
- GS>50 +2.3.% kwh & +2.3 % kW.

PSP's weather corrected usage for these classes are explain by slight changes in customer numbers

The geographical location and customer base in our service territory combined with small growth potential lends the primarily straight line weather forecasted data and customer growth. PSP does not expect any large changes in our customer base or movement among the classes, therefore the variance between years is simple growth trends and weather normalization of data.

Other Distribution Revenue

Table 5 Other Distribution Service Revenue ($)

Other Distribution Service Revenue	2006 EDR Approved	2006 Actual	Var $	2007 Actual	Var $ From 2006 Actual	2008 Projection	Var $ From 2007 actual	2009 @ new rates	Var $ from 2008 Projected
4080-Distribution Services Revenue	12,535	8,957	-3,578	8,622	-335	8,529	-93	8,529	0
4082 & 4084 Misc Service Revenue	698	0	-698	0	0	0	0		0
4210-Rent from Electric Property	5,144	36,439	31,295	36,541	102	36,542	1	36,542	0
4220-Other Electric Revenues			0		0		0		0
4225-Late Payment Charges	17,448	14,360	-3,088	16,906	2,546	15,067	-1,839	15,067	0
4230-Sales of Water and Water Power			0		0		0		0
4235-Miscellaneous Service Revenues	24,900	14,324	-10,577	28,195	13,872	23,372	-4,823	23,372	0
4325-Revenues from Merchandise, Jobbing, Etc.			0		0		0		0
4330-Costs and Expenses of Merchandising, Jobbing, Etc.			0		0		0		0
4355-Gain on Disposition of Utility and Other Property			0		0		0		0
4390 Misc Non-Operating Income	4,948	4,232	-716	8,090	3,858	8,364	274	8,364	0
4405-Interest and Dividend Income	21,392	116,490	95,098	180,231	63,741	95,861	-84,370	95,861	0
TOTAL OTHER DISTRIBUTION SERVICE REVENUE	**87,065**	**194,802**	**107,737**	**278,584**	**83,783**	**187,735**	**-90,850**	**187,735**	**0**

Materiality Analysis on Other Distribution Revenue

Table 6 Materiality Threshold

	2006 EDR	2006	2007	2008	2009
1% Materiality	$870	$1,948	$2,785	$1,877	$1,877

The materiality threshold of 1% based on 2006 Board Approved Other Distribution Revenue is shown above. PSP has detail all variances from 2006 EDR to Test 2009 year.

Table 7 2006 Board Approved to 2006 Actual

Account # & Name	2006 EDR	2006 Actual	Variance
4080-Distribution Services Revenue	12,535	8,957	-3,578
4082 & 4084 Misc Service Revenue	698	0	-698
4210-Rent from Electric Property	5,144	36,439	31,295
4225-Late Payment Charges	17,448	14,360	-3,088
4235-Miscellaneous Service Revenues	24,900	14,324	-10,577
4390 Misc Non-Operating Income	4,948	4,232	-716
4405-Interest and Dividend Income	21,392	116,490	95,098

- 4080 SSS admin fee is lower in 2006 actual than board approved as a result of averages used in the EDR process.
- 4082 & 4084 2006 actual no Misc Service dollars are recorded compared to EDR averages used.
- 4210 Rent from Electric Prop increase over approved is a result of the averaging from EDR process and tier 1 adjustments, an increase in rates to cable and phone company also adds to the increase.
- 4225 Late Payment EDR to actual is a decrease caused by averaging and the amounts in arrears vary from year to year.

- 4235 Misc Service Revenue shows a decrease from EDR approved to 2006 Actual averaging and actual customer movement general business activity lends to the change in this account.
- 4390 Misc Non-Operating Revenue reflects a slight decline from EDR to 2006 actual. PSP tracks scrap material sales and other small non-operating items.
- 4405 Interest & Dividend Income shows a large increase from 2006 EDR to 2006 actual, the primary cause of the increase in an increase in cash on hand in 2006 compared to the 2003 & 2004 fiscal year balances. The increase in cash on hands results in larger interest income.

Table 8 2006 Actual to 2007 Actual

Account # & Name	2006 Actual	2007 Actual	Variance
4080-Distribution Services Revenue	8,957	8,622	-335
4082 & 4084 Misc Service Revenue	0	0	0
4210-Rent from Electric Property	36,439	36,541	102
4225-Late Payment Charges	14,360	16,906	2,546
4235-Miscellaneous Service Revenues	14,324	28,195	13,872
4390 Misc Non-Operating Income	4,232	8,090	3,858
4405-Interest and Dividend Income	116,490	180,231	63,741

- 4080 SSS admin fee is slightly lower in 2007 actual than 2006 actual as a result of slight movement in customer base.
- 4082 & 4084 2006 actual Misc Service dollars are recorded in variance accounts.
- 4210 Rent from Electric Prop slight increase in 2007 over 2006.
- 4225 Late Payment 2007 to 2006 actual is an increase caused by the amounts in arrears as this number varies from year to year.
- 4235 Misc Service Revenue shows an increase in 2007 over 2006 PSP receive approval in 2006 to use the rates via the EDR process which PSP implemented in 2006 and was in full use by fiscal 2007.
- 4390 Misc Non-Operating Revenue reflects an increase in 2007 vs. 2006 caused by larger volume of retailer related transaction in 2007 over 2006.

- 4405 Interest & Dividend Income shows a large increase 2007 over 2006 actual, the primary cause of the increase in an increase in cash on hand in 2007 compared to fiscal 2006. The increase in cash on hands results in larger interest income. An increase in PSP regulatory asset accounts caused part of the variance increase.

Table 9 2007 Actual to Bridge 2008

Account # & Name	2007 Actual	2008 Bridge	Variance
4080-Distribution Services Revenue	8,622	8,529	-93
4082 & 4084 Misc Service Revenue	0	0	0
4210-Rent from Electric Property	36,541	36,542	1
4225-Late Payment Charges	16,906	15,067	-1,839
4235-Miscellaneous Service Revenues	28,195	23,372	-4,823
4390 Misc Non-Operating Income	8,090	8,364	274
4405-Interest and Dividend Income	180,231	95,861	-84,370

- 4080 SSS admin fee is slightly lower in 2008 bridge than 2007 actual as a result of slight movement in customer base.
- 4082 & 4084 Misc Service dollars are recorded in variance accounts.
- 4210 Rent from Electric Prop no increase in 2008 bridge estimate over 2007 actual.
- 4225 Late Payment 2008 Bridge to 2007 actual shows a decrease caused by averaging of prior years data for the bridge year estimate.
- 4235 Misc Service Revenue 2008 Bridge to 2007 actual shows a decrease caused by averaging of prior year’s data for estimate used.
- 4390 Misc Non-Operating Revenue an average of historical year’s data indicates very little change in the bridge year over 21007 actual.
- 4405 Interest & Dividend Income shows a decrease in interest revenue in the 2008 bridge year over 2007 actual as a result of cash on hand estimate being lower by end of fiscal 2008. The decrease in cash on hand is caused by a budgeted dividend payment to the shareholder.

Bridge to Test

The 2008 Bridge Year Estimates are mainly made up of historical data, averaging and managements' best guess approach to future requirement. Therefore the 2009 test year estimates are based solely on 2008 estimates resulting in no variances between Bridge and Test year data.

Rate of Return on Other Distribution Revenue

In this application, PSP has applied for the same Specific Service Charges schedule previously approved in the 2008 Tariffs of Rates and Charges (EB-2007-0825). The Specific Service Charges schedule follows the OEB recommended charges and as such PSP has no further information related to the rate of return on non-core delivery activities.

Distribution Revenue Data

The following tables represent an example of distribution revenue calculations based on 2006 EDR approved to 2009 test year. These calculations use annual kwh or kW values, customer numbers and the fixed and variable rates. The numbers in the following tables are based on "Fiscal Year" calculations January to December the actual revenue is calculated using "Rate Year" values being May 1 to April 30 the following year. Therefore these values represent comparison examples only. PSP is in no way trying to introduce or amend any Historical numbers.

Table 10 2006 EDR Approved Distribution Revenue

2006 EDR Approved	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge [1]	Distribution Revenue $	Unit Revenues $/kwh
Residential	2,595	13,198	0.000	$0.0142		$16.82	1,010,103	$0.0295
General Service Les Than 50 kW	535	35,602	0.000	$0.0109		$25.22	369,525	$0.0194
General Service 50 to 4,999 kW	60	409,174	1,338.017		$3.7803	$169.20	425,310	$0.0173
Unmetered Scattered Load	24	4,629	0	$0.0526		$8.85	8,393	$0.0755
Sentinel Lighting	16	806	2		$7.0153	$1.72	590	$0.0457
Street Lighting	1,004	716	1.991		$4.3899	$0.41	13,715	$0.0191
Gross Revenue (before Transformer Allowances)							**1,827,636**	**$0.2066**
Transformer Allowances							-2,728	
Total Revenue							**1,824,908**	
Less: Low voltage charges embedded in distribution rates							-77,110	
DISTRIBUTION REVENUE							**1,747,798**	

[1] *Excluding Smart Meter Rate Adder*

Table 11 2006 Actual Distribution Revenue

*2006 Actual Pro-forma **	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge [1]	Distribution Revenue $	Unit Revenues $/kwh
Residential	2,610	12,735	0.000	$0.0142	$0.0000	$16.82	998,781	$0.0300
General Service Les Than 50 kW	505	32,621	0.000	$0.0109	$0.0000	$25.22	332,395	$0.0202
General Service 50 to 4,999 kW	61	580,012	1,455.705	$0.0000	$3.7803	$169.20	459,537	$0.0130
Unmetered Scattered Load	20	6,477	0	$0.0526	$0.0000	$8.85	8,937	$0.0690
Sentinel Lighting	13	1,230	3	$0.0000	$7.0153	$1.72	556	$0.0348
Street Lighting	1,004	864	2.414	$0.0000	$4.3899	$0.41	15,581	$0.0180
Gross Revenue (before Transformer Allowances)							**1,815,788**	**$0.1849**
Transformer Allowances							-13,795	
Total Revenue							**1,801,993**	
Less: Low voltage charges embedded in distribution rates							-22,384	
DISTRIBUTION REVENUE							**1,779,609**	

[1] *Excluding Smart Meter Rate Adder*

Table 12 2007 Actual Distribution Revenue

*2007 Actual Pro-forma **	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge [1]	Distribution Revenue $	Unit Revenues $/kwh
Residential	2,643	12,855	0	$0.0143		$16.73	1,016,475	$0.0299
General Service Les Than 50 kW	529	32,033	0	$0.0110		$25.20	346,372	$0.0204
General Service 50 to 4,999 kW	64	580,756	1,414		$3.8143	$170.48	476,081	$0.0128
Unmetered Scattered Load	22	5,375	0	$0.0531		$8.93	8,637	$0.0730
Sentinel Lighting	15	1,067	3		$7.0784	$1.74	603	$0.0377
Street Lighting	1,004	864	2		$4.4294	$0.41	15,677	$0.0181
Gross Revenue (before Transformer Allowances)							**1,863,844**	**$0.1920**
Transformer Allowances							-13,915	
Total Revenue							**1,849,929**	
Less: Low voltage charges embedded in distribution rates							-60,821	
DISTRIBUTION REVENUE							**1,789,108**	

[1] *Excluding Smart Meter Rate Adder*

Table 13 2008 Projected Distribution Revenue

*2008 Projection **	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge [1]	Distribution Revenue $	Unit Revenues $/kwh
Residential	2,661	12,513	0	$0.0143	$0.0000	$16.71	1,009,716	$0.0303
General Service Les Than 50 kW	532	31,272	0	$0.0110	$0.0000	$25.17	343,689	$0.0207
General Service 50 to 4,999 kW	65	593,038	1,444	$0.0000	$3.8105	$170.31	490,442	$0.0127
Unmetered Scattered Load	22	5,375	0	$0.0530	$0.0000	$8.92	8,622	$0.0729
Sentinel Lighting	15	1,067	3	$0.0000	$7.0713	$1.74	603	$0.0377
Street Lighting	1,004	864	2	$0.0000	$4.4250	$0.41	15,666	$0.0181
Gross Revenue (before Transformer Allowances)							**1,868,738**	**$0.1924**
Transformer Allowances							-13,800	
Total Revenue							**1,854,938**	
Less: Low voltage charges embedded in distribution rates							-54,379	
DISTRIBUTION REVENUE							**1,800,559**	

[1] *Excluding Smart Meter Rate Adder*

Table 14 2009 Projected Distribution Revenue

2009 Projection	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge [1]	Distribution Revenue $	Unit Revenues $/kwh
Residential	2,680	12,260	0	$0.0173	$0.0000	$17.88	1,142,268	$0.0348
General Service Les Than 50 kW	535	31,071	0	$0.0153	$0.0000	$31.33	454,961	$0.0274
General Service 50 to 4,999 kW	66	597,553	1,455	$0.0000	$3.6620	$153.03	472,806	$0.0120
Unmetered Scattered Load	22	5,375	0	$0.0872	$0.0000	$13.37	13,836	$0.1170
Sentinel Lighting	15	1,067	3	$0.0000	$18.6082	$3.99	1,481	$0.0925
Street Lighting	1,004	864	2	$0.0000	$15.9668	$1.25	53,763	$0.0620
Gross Revenue (before Transformer Allowances)							**2,139,116**	**$0.3456**
Transformer Allowances							-14,119	
Total Revenue							**2,124,997**	
Less: Low voltage charges embedded in distribution rates							-183,000	
DISTRIBUTION REVENUE							**1,941,997**	

Description of Revenue Sharing

PSP does not engage in revenue sharing.

Overview of Operating Costs

Operating Costs

The operating costs presented in this exhibit represent the annual expenditures required to sustain PSP's Distribution Operations. These costs are grouped in two categories:

- Operating, Maintenance and Administration (OM&A), which includes Depreciation, Amortization and Shared Services;
- and Income Tax and Ontario Capital Taxes.

OM&A Costs

The OM&A costs represent PSP's asset maintenance and costs relating to customer activity needs. The expenditures are required to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and Government direction. These costs also include providing services to customers connected to PSP's Distribution system and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

The proposed OM&A costs for the 2009 test year result from PSP's business planning and work prioritization process. Currently PSP does not have a "formal documented" procedure or process document in place for OM&A cost management and planning. However, over the last few years including this rate application process, management has recognized that regulatory compliance and other corporate matters necessitate documenting each and every aspect of PSP's business.

PSP has made progress in this regard and management's efforts to document all aspect of spending and cost control matters are continuing.

The improvements in PSP's internal processes have required on-going investment in developing the staff resources to manage the changes and the new processes. It is anticipated that the short-term increase in staff resources required to develop and implement improved asset management methods and administrative process will produce cost saving in the long run.

As the first step in improving PSP's management process, PSP underwent changes in corporate management including staffing and board members in 2003 and 2004, which was early in the period during which the industry and regulatory environments were restructured. In bringing in new resources, however, PSP has had to confront the reality that bringing in new staff to the electrical industry involves an intensive and lengthy training period. The development of formalized processes requires the blending of electricity industry experience with management expertise. PSP is moving forward in a cost effective manner that manages the increase in costs that are necessary to implement more formalized management process while ensuring that our experienced resources are utilized effectively in maintaining a safe, reliable distribution system.

PSP management continues to apply the best cost controls over operations, maintenance and administrative matters with a "hands-on" approach. The projected costs are needed to ensure we continue to move forward providing our customers with an effective reliable system as we enhance our management and administrative processes. The PEG report, entitled "Benchmarking the Costs of Ontario Power Distributors" dated March 20, 2008 prepared in relation to the Comparison of Ontario Electricity Distributors Costs (EB-2006-0268), indicates that PSP is well within our industry group cost per customer expectation. More specifically, PSP ranks 18th overall on efficiency based on Unit Cost Indexes (Table 7, p. 63-64) and has a lower than group average for OM&A per Customer based on Staff Proposed Metrics (Table 8, p. 69).

Explanation of Variances

The summary table below categorizes costs into the operations 3500, maintenance 3550 billing and collecting 3650, community relations 3700, administrative and general 3800, taxes other than income tax 3950, amortization 3850 and income tax 6110. Each of these main categories is overview below.

The 2006 actual Operations & Maintenance cost vary from the approved 2006 EDR costs because of inflation and the averaging effect used in the 2006 EDR process. Operations costs from Approved year to Test year increase relates to inflation adjustment of wages and other direct costs. Maintenance section from 2006 approved year to 2009 test increases relate to inflating wages and material costing. The addition of two staff to the lineman department in 2004 to handle work loads allow PSP to perform more maintenance tasks Therefore the overall increase in Distribution Expense Maintenance area.

Billing & Collecting from 2006 approved to 2006 actual increase is substantial caused by addition and re-allocation to staffing. These changes afford PSP the ability to manage our Billing & Collections in-house. PSP’s forward thinking process of a “Co-operative” approach to management cost is seen in the investment in a billing company. This area is covered in Exhibit 4, Tab 2, Schedule 3 “Shared Services”.

Community Relations variance from actual to test year are primarily driven by CDM activities, as indicated by the 2009 test year projections after CDM we will remain in line with the 2006 EDR costs.

Admin & General forecasts and historical numbers are inline with approved 2006 EDR numbers. The variation form 2006 actual to 2006 approved as stated above are from staff re-allocations.

Amortization and tax effects year to year related to capital and income variations. Overall PSP’s Total Operating Costs from the 2006 approval to the 2009 Test year increase in these areas from the approved costs to 2009 test year show an increase of 24% which is primarily driven by inflation.

In summary PSP is currently involved in a review of corporate practices directed by our board and shareholder. A consulting firm will provide us direction and planning into the future that will enable management to accomplish our directives. The need to ensure adequately train and skill personnel are deployed to handle tasks that face our future needs.

Income Tax, Large Corporation Tax and Ontario Capital Taxes

This information consists of detailed calculations of income taxes, and indemnity payments to the Province. Details of the expenditures are filed at Exhibit 4, Tab 3, Schedule 1.

Summary of Operating Costs

Table 1 Summary of Operating Costs

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
3500-Distribution Expenses - Operation	$66,823	$51,120	$63,190	$70,918	$76,689
3550-Distribution Expenses - Maintenance	$180,200	$213,937	$266,047	$310,470	$302,064
3650-Billing and Collecting	$283,052	$375,543	$342,691	$394,041	$410,303
3700-Community Relations	$13,011	$30,656	$89,801	$68,465	$18,298
3800-Administrative and General Expenses	$459,698	$365,288	$347,580	$411,179	$457,437
3950-Taxes Other Than Income Taxes	$8,755	$0	$0	$0	$0
Total OM&A Costs	**$1,011,540**	**$1,036,544**	**$1,109,310**	**$1,255,072**	**$1,264,790**
3850-Amortization Expense	$337,069	$380,084	$381,233	$384,102	$394,504
Total Distribution Expenses	**$1,348,609**	**$1,416,628**	**$1,490,542**	**$1,639,173**	**$1,659,295**
6110-LCT,OCT & Income Taxes	$8,755	$94,800	$138,155	$39,931	$63,173
TOTAL OPERATING COSTS	**$1,357,364**	**$1,511,428**	**$1,628,697**	**$1,679,104**	**$1,722,468**

OM&A Costs Table

Account Description	2006 EDR Approved	2006 Actual	2006 vs 2006 EDR	2007 Actual	2007 vs 2006	2008 Projection	2008 vs 2007	2009 Projection	2009 vs 2008
5005-Operation Supervision and Engineering	22,866	18,891	(3,975)	14,605	(4,286)	22,542	7,937	24,796	2,254
5016-Distribution Station Equipment - Operation Labour	31		(31)	518	518	2,040	1,522	2,400	360
5017-Distribution Station Equipment - Operation Supplies and Expenses	5,721	6,691	971	6,894	202	7,166	272	7,465	299
5020-Overhead Distribution Lines and Feeders - Operation Labour	2,197	3,607	1,410	2,335	(1,271)	3,600	1,265	4,240	640
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	55	55	-	55	-	55	-	55	-
5035-Overhead Distribution Transformers- Operation	349	401	53	298	(103)	1,300	1,002	1,300	-
5040-Underground Distribution Lines and Feeders - Operation Labour	7,041	8,631	1,591	7,738	(893)	7,500	(238)	7,875	375
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	71		(71)	-	-	-	-	-	-
5055-Underground Distribution Transformers - Operation	1,493		(1,493)	139	139	405	266	432	27
5065-Meter Expense	26,097	11,313	(14,784)	17,919	6,607	19,565	1,646	21,381	1,816
5070-Customer Premises - Operation Labour	104	110	6	-	(110)	-	-	-	-
5075-Customer Premises - Materials and Expenses		20	20	-	(20)	-	-	-	-
5085-Miscellaneous Distribution Expense		600	600	-	(600)	-	-	-	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	801	801	-	801	-	801	-	801	-
5096-Other Rent			-	11,887	11,887	5,944	(5,944)	5,944	-
5105-Maintenance Supervision and Engineering	7,622	5,633	(1,988)	5,076	(557)	6,994	1,918	7,694	699
5114-Maintenance of Distribution Station Equipment	15,840	(11,903)	(27,743)	23,581	35,484	26,424	2,843	28,431	2,007
5120-Maintenance of Poles, Towers and Fixtures	13,090	39,962	26,872	48,404	8,442	43,959	(4,445)	48,205	4,246
5125-Maintenance of Overhead Conductors and Devices	49,461	94,237	44,776	56,675	(37,562)	71,601	14,926	78,862	7,260
5130-Maintenance of Overhead Services	6,043	11,439	5,396	11,433	(6)	14,981	3,549	16,430	1,448
5135-Overhead Distribution Lines and Feeders - Right of Way	56,813	45,123	(11,689)	78,176	33,052	73,938	(4,238)	67,126	(6,813)
5145-Maintenance of Underground Conduit		733	733	896	163	5,591	4,695	5,899	308
5150-Maintenance of Underground Conductors and Devices	936	2,141	1,205	4,723	2,583	5,572	848	6,139	567
5155-Maintenance of Underground Services	1,692	2,126	433	5,387	3,262	6,196	809	6,490	294
5160-Maintenance of Line Transformers	5,310	10,234	4,923	13,109	2,876	34,953	21,844	16,076	(18,878)
5175-Maintenance of Meters	12,031	4,730	(7,301)	13,991	9,261	15,665	1,674	16,120	455
5190-Water Heater Controls - Labour	11,362	9,482	(1,880)	4,594	(4,888)	4,594	-	4,594	-
5310-Meter Reading Expense	42,813	41,342	(1,470)	47,648	6,306	47,991	343	48,872	881
5315-Customer Billing	157,434	210,790	53,356	190,826	(19,964)	266,256	75,431	276,999	10,742
5320-Collecting	82,770	107,646	24,876	108,645	999	70,971	(37,675)	75,610	4,639
5325-Collecting- Cash Over and Short	35	95	60	(30)	(125)	-	30	-	-
5335-Bad Debt Expense	0	15,669	15,669	(4,398)	(20,067)	8,822	13,220	8,822	-
5340-Miscellaneous Customer Accounts Expenses			-	-	-	-	-	-	-
5410-Community Relations - Sundry	13,011	16,897	3,886	13,368	(3,529)	14,505	1,137	15,538	1,033
5415-Energy Conservation		10,648	10,648	75,485	64,837	51,200	(24,285)	-	(51,200)
5420-Community Safety Program		925	925	948	23	2,760	1,812	2,760	-
5425-Miscellaneous Customer Service and Informational Expenses		2,185	2,185	-	(2,185)	-	-	-	-
5605-Executive Salaries and Expenses	18,892	15,820	(3,072)	8,147	(7,673)	12,015	3,868	12,015	-
5610-Management Salaries and Expenses			-	-	-	-	-	-	-
5615-General Administrative Salaries and Expenses	166,667	164,885	(1,781)	170,034	5,148	176,875	6,841	188,967	12,093
5620-Office Supplies and Expenses	33,845	28,689	(5,156)	32,062	3,374	31,167	(896)	31,689	523
5630-Outside Services Employed	153,904	137,944	(15,960)	124,227	(13,717)	132,303	8,076	132,612	309
5635-Property Insurance	514		(514)	-	-	-	-	-	-
5640-Injuries and Damages			-	1,000	1,000	-	(1,000)	-	-
5655-Regulatory Expenses	9,372	15,267	5,895	12,110	(3,157)	12,319	209	45,653	33,333
5660-General Advertising Expenses			-	-	-	-	-	-	-
5665-Miscellaneous General Expenses	76,417	2,682	(73,734)	-	(2,682)	-	-	-	-
5670-Rent			-	-	-	46,500	46,500	46,500	-
5685-Independent Market Operator Fees and Penalties	88		(88)	-	-	-	-	-	-
6105-Taxes Other Than Income Taxes	8,755		(8,755)	-	-	-	-	-	-
6205-Donations	100	50	(50)	100	50		(100)		-
Total	1,011,640	1,036,594	24,954	1,109,410	72,816	1,255,072	145,662	1,264,790	9,719

Variance Analysis on OM&A Costs Table

The OM&A Cost table shown above compares 2006 approved to 2006 Actual, 2006 Actual to 2007 Actual, 2007 Actual to 2008 Bridge and 2008 Bridge to 2009 Test Year. The variance analysis from the table above is shown on an account level basis and will be analyzed on that level. Although the OEB has set a materiality threshold of 1% of Distribution Expenses, PSP, in an effort to be transparent as possible, will provide a variance analysis on every account regardless of the size of the variance.

2006 Actual VS 2006 Board Approved EDR

Account Description	2006 EDR Approved	2006 Actual	2006 vs. 2006 EDR
5005-Operation Supervision and Engineering	**22,866**	**18,891**	**-3,975**
- decrease caused by averaging process used in the 2006 EDR			
5016-Distribution Station Equipment - Operation Labour	**31**		**-31**
- not used in 2006			
5017-Distribution Station Equipment - Operation Supplies and Expenses	**5,721**	**6,691**	**971**
- increase in property tax and interval meter phone line service costs			
5020-Overhead Distribution Lines and Feeders - Operation Labour	**2,197**	**3,607**	**1,410**
- 3% labour cost increase per year since 2004 data combined with maintenance			
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	**55**	**55**	**-**
5035-Overhead Distribution Transformers- Operation	**349**	**401**	**53**
- increase in labour cost portion and more maintenance work			
5040-Underground Distribution Lines and Feeders - Operation Labour	**7,041**	**8,631**	**1,591**
- Labour cost increase at 3% per year and equipment costs increase, more maintenance done			
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	**71**		**-71**
- not used in 2006			
5055-Underground Distribution Transformers – Operation	**1,493**		**-1,493**
- not used in 2007			
5065-Meter Expense	**26,097**	**11,313**	**-14,784**

Account Description	2006 EDR Approved	2006 Actual	2006 vs. 2006 EDR

- Relates to seal Expiration dates on meters fall within the years used for 2006 EDR process, during 2006 actual less meters needed re-verification

5070-Customer Premises - Operation Labour	**104**	**110**	**6**

5075-Customer Premises - Materials and Expenses		**20**	**20**

5085-Miscellaneous Distribution Expense		**600**	**600**

- cost of participating gin the Mearie Joint Pole Use Agreement

5095-Overhead Distribution Lines and Feeders - Rental Paid	**801**	**801**	**-**

5096-Other Rent			**-**

5105-Maintenance Supervision and Engineering	**7,622**	**5,633**	**-1,988**

- engineering time less in the e2006 actual year than the years used for 2006 EDR process

5114-Maintenance of Distribution Station Equipment	**15,840**	**-11,903**	**-27,743**

- an actual increase in distribution station maintenance, transformer testing etc in 2006 over years used for 2006 EDR process, The Hydro One Meter Rebate fees posted to the account results in a negative value for the 2006 actual

5120-Maintenance of Poles, Towers and Fixtures	**13,090**	**39,962**	**26,872**

- labour cost increase of 3% per year since the years used for 2006 EDR process, materials used for maintenance also increased combined with an increase in maintenance program

5125-Maintenance of Overhead Conductors and Devices	**49,461**	**94,237**	**44,776**

- labour cost increase of 3% per year since the years used for 2006 EDR process, materials used for maintenance also increased combined with an increase in maintenance program

5130-Maintenance of Overhead Services	**6,043**	**11,439**	**5,396**

- labour cost increase of 3% per year since the years used for 2006 EDR process, materials used for maintenance also increased combined with an increase in maintenance program

5135-Overhead Distribution Lines and Feeders - Right of Way	**56,813**	**45,123**	**-11,689**

- 2004 fiscal year included a large maintenance program of the feeders and right away while the 2006 actual is more in line with regular annual costs3 actual year

5145-Maintenance of Underground Conduit		**733**	**733**

- the account was not used until 2005 calendar year, therefore no costs booked for the e2006 EDR process

5150-Maintenance of Underground Conductors and Devices	**936**	**2,141**	**1,205**

- PSP had an increase in underground infrastructure in 2006 calendar year causing more maintenance costs

Account Description	2006 EDR Approved	2006 Actual	2006 vs. 2006 EDR
5155-Maintenance of Underground Services	**1,692**	**2,126**	**433**

- PSP had an increase in underground infrastructure in 2006 calendar year causing more maintenance costs

5160-Maintenance of Line Transformers	**5,310**	**10,234**	**4,923**

- Maintenance cycle for line transformers caused the labour and equipment cost increase for 2006 actual

5175-Maintenance of Meters	**12,031**	**4,730**	**-7,301**

- costs for meter maintenance in 2004calaendar year was high caused by meter cycles, 2006 is more relative to annual costs

5190-Water Heater Controls - Labour	**11,362**	**9,482**	**-1,880**

- The water heater control program became less of an interest for customers as the cost of power decreased with deregulation

5310-Meter Reading Expense	**42,813**	**41,342**	**-1,470**
5315-Customer Billing	**157,434**	**210,790**	**53,356**

- Computer software & office equipment maintenance which included an upgrade to our system in 2006 from 2004 to enhance our interval meter data. Due to retailer traffic in the 2006 calendar year over the years used in the 2006 EDR process there was an increased cost in our spoke service. An increase in labour cost of 3% per year from the years used for the 2006 EDR to the 2006 actual, combined with an increase with overhead costs. PSP underwent a training program to better enable staff to use the Harris billing system. In late 2006 PSP joined forces with two other utilities and a consulting firm to create a billing company that would allow us all to achieve synergies for the back office side of billing. As part of the conversion process with the new billing company PSP chose to print bills in house and had increased costs for stationary etc.

5320-Collecting	**82,770**	**107,646**	**24,876**

- the variance in 5320-collecting of $24,876 from 2006 EDR to 2006 actual is detailed as follows: during the 2004 calendar year better collection practices and policies resulted in payment of previously written-off accounts. As a result of these payments the bad debts expense for 2004 calendar year was in a negative position reflecting a lower than normal collection cost. An increase in collection activities caused by market opening costs of power increases and the provincial government legislation found PSP's labour, overhead and equipment costs increased.

5325-Collecting- Cash Over and Short	**35**	**95**	**60**
5335-Bad Debt Expense	**0**	**15,669**	**15,669**
5340-Miscellaneous Customer Accounts Expenses			**-**
5410-Community Relations - Sundry	**13,011**	**16,897**	**3,886**

Account Description	2006 EDR Approved	2006 Actual	2006 vs. 2006 EDR

- An increase in community activities such as outdoor festivals and other outdoor community programs such as Farmer's Markets and Dragon Boat Festival directly caused an increase in labour and overhead costs.

5415-Energy Conservation		**10,648**	**10,648**

- No energy conservation costs were incurred in this account prior to the 2006 calendar year. In the 2006 calendar year the costs related to CDM customer education programs and activities.

5420-Community Safety Program		**925**	**925**

- 5420 Community Safety programs - PSP uses this account to record the costs of advertising etc for community safety programs and this account was not used until the 2006 calendar year.

5425-Miscellaneous Customer Service and Informational Expenses		**2,185**	**2,185**

- 5425 was not used until the 2006 calendar year. The costs incurred are for participation is a privacy policy development and the introduction of a customer oriented web-site.

5605-Executive Salaries and Expenses	**18,892**	**15,820**	**-3,072**

- The restructuring of the Board of Directors and the allocation of costs relating to their activities caused a decline in the 2006 actual costs.

5610-Management Salaries and Expenses			

5615-General Administrative Salaries and Expenses	**166,667**	**164,885**	**-1,781**

- 5615 remained fairly consistent with the 2006 actual.

5620-Office Supplies and Expenses	**33,845**	**28,689**	**-5,156**

- 5620- This account is used to capture the cost relating to general operation of the office. Small equipment maintenance, postage, membership fees, courier fees, bank charges not relating to interest expense, seminars, Insurance and general office supplies. Because most of these costs are incurred on an as-needed basis, the 2006 actual costs were below average.

5630-Outside Services Employed	**153,904**	**137,944**	**15,960)**

- 5630 - Outside services costs include accounting, legal and other consulting costs. During the 2004 calendar year PSP had an increase in legal costs due to the transfer of our banking arrangements and general security agreements. 2004 also had an increase in consulting costs relating to the electrical industries need for total loss factor calculations and rate setting processes, therefore the 2006 costs are closer to the annual true cost of outside services.

5635-Property Insurance	**514**	**0**	**-514**

5640-Injuries and Damages			**-**

5655-Regulatory Expenses	**9,372**	**15,267**	**5,895**

Account Description	2006 EDR Approved	2006 Actual	2006 vs. 2006 EDR

- 5655- This account in used to capture the costs relating to operating in the regulatory environment. The increases from 2006 EDR to 2006 Actual are a direct result of OEB cost increases and Electrical Safety Authority Cost increases.

5660-General Advertising Expenses			**-**

5665-Miscellaneous General Expenses	**76,417**	**2,682**	**-73,734**

- 5665-An adjustment made during the 2006 EDR Process caused the 2006 EDR approved balance to be higher than normal.

5670-Rent			**-**

5685-Independent Market Operator Fees and Penalties	**88**		**-88**

6105-Taxes Other Than Income Taxes	**8,755**		**-8,755**

- 6105-the 2006 EDR process allowed for $8,755 in taxes other than income tax. PSP uses 6110 to record the costs of income taxes.

6205-Donations	**100**	**50**	**-50**

1 **2006 Actual to 2007 Actual (Account #5005 to #5096)**

Account Description	Jan - Dec 2006	Jan - Dec 2007	2007 VS 2006 $ Change
5005 · Operations Supervision & Eng	**18,890.78**	**14,604.91**	**-4,285.87**
$17,388.15 Engineering 2006 & $14,246.25 Engineering 2007. This accounts for most of the drop in 5005. Additionally, more conferences, training & meetings were attended in 2006 to account for the rest of the difference.			
5016 · DS Equip-Operations Labour			
5016-50 · Labour	0	254.5	254.5
5016-51 · Truck Time	0	60	60
5016-99 · Overhead	0	203.6	203.6
Total 5016 · DS Equip-Operations Labour	**0**	**518.1**	**518.1**
Appears that this account wasn't used until 2007			
5017-55 · Bell Line Cost Primary Meters	2,663.19	2,718.67	55.48
5017-56 · Property Tax	4,028.18	4,175.06	146.88
Total 5017 · DS Equip-Operations Supplies & Expenses	**6,691.37**	**6,893.73**	**202.36**
simply an increase cost from Bell - four lines and billed/paid per month Town of Parry Sound Property Tax increase from 2006 to 2007			
5020-50 · Labour	1,514.17	579.21	-934.96
5020-51 · Truck Time	627.5	530	-97.5
5020-99 · Overhead	1,465.07	802.41	-662.66
5020 · O/H Dist Lines/Feed-Operations Labour - Other	0	423.82	423.82
Total 5020 · O/H Dist Lines/Feed-Operations Labour	**3,606.74**	**2,335.44**	**-1,271.30**
decreased labour & overhead are cause of difference.			
5025 · O/H Dist Line/Feed-Operations Supplies	**55**	**55**	**0**
5035 · O/H Dist. Transformer-Operation			
5035-50 · Labour	188.15	101.63	-86.52
5035-51 · Truck Time	62.5	115	52.5
5035-99 · Overhead Charges	150.51	81.31	-69.2
Total 5035 · O/H Dist. Transformer-Operation	**401.16**	**297.94**	**-103.22**
Small Difference due to decreased labour and overhead.			
5040-50 · Labour	4,107.83	3,100.13	-1,007.70
5040-51 · Truck Time	1,230.00	1,390.00	160
5040-99 · Overhead	3,293.55	2,821.32	-472.23
5040 · U/G Dist Lines/Feed-Operations Labour - Other	0	426.57	426.57
Total 5040 · U/G Dist Lines/Feed-Operations Labour	**8,631.38**	**7,738.02**	**-893.36**
Slight decrease in labour/overhead causing the 10% decline			

Account Description	Jan - Dec 2006	Jan - Dec 2007	2007 VS 2006 $ Change
5055-50 · Labour	0	77.34	77.34
5055-99 · Overhead Charges	0	61.87	61.87
Total 5055 · U/G Dist Transformers - Operations	**0**	**139.21**	**139.21**
Account was not used in 2006			
5065-50 · Labour	3,447.37	5,840.87	2,393.50
5065-51 · Truck Time	1,262.50	2,050.00	787.5
5065-63 · Contractors	245	0	-245
5065-69 · Testing, Calibrating, Sealing	0	2,055.86	2,055.86
5065-70 · MSP- Primary Meters	3,600.00	3,300.00	-300
5065-99 · Overhead Charges	2,757.86	4,672.63	1,914.77
Total 5065 · Meter Expense	**11,312.73**	**17,919.36**	**6,606.63**
several meters seals required the meters be tested and subsequently changed. Consequently this lead to increased labour and overhead.			
5070-99 · Overhead	48.83	0	-48.83
5070 · Customer Premises - Operations Labour - Other	61.04	0	-61.04
Total 5070 · Customer Premises - Operations Labour	**109.87**	**0**	**-109.87**
no entries for 2007 - accounts for 100% difference			
5075-51 · Truck Time	20	0	-20
Total 5075 · Customer Premises-Mat & Expense	**20**	**0**	**-20**
no entries for 2007 - accounts for 100% difference			
5085-01 · Misc Dist Expenses Joint Use	600	0	-600
Total 5085 · Miscellaneous Distribution Expenses	**600**	**0**	**-600**
accounts for special MEARIE Bell Joint Use Project in 2005 & 2006 only. GL Explanation- Participation-Unit Cost & Residual Values Tables Project.			
5095-01 · Pole Attachment Rental	801.08	801.08	0
Total 5095 · O/H Lines/Feed-Rental Paid	**801.08**	**801.08**	**0**
5096-02 · Bell Joint Use of Poles Rental	0	11,887.26	11,887.26
Total 5096 · Other Rent	**0**	**11,887.26**	**11,887.26**
Bell Canada invoiced for 2005 & 2006 Pole Rentals in 2007 no invoice in 2006			
5005 · Operations Supervision & Eng	**18,890.78**	**14,604.91**	**-4,285.87**
$17,388.15 Engineering 2006 & $14,246.25 Engineering 2007. This accounts for most of the drop in 5005. Additionally, more conferences, training & meetings were attended in 2006 to account for the rest of the difference.			

Account Description	Jan - Dec 2006	Jan - Dec 2007	2007 VS 2006 $ Change
5016 · DS Equip-Operations Labour			
5016-50 · Labour	0	254.5	254.5
5016-51 · Truck Time	0	60	60
5016-99 · Overhead	0	203.6	203.6
Total 5016 · DS Equip-Operations Labour	**0**	**518.1**	**518.1**
Appears that this account wasn't used until 2007			
5017-55 · Bell Line Cost Primary Meters	2,663.19	2,718.67	55.48
5017-56 · Property Tax	4,028.18	4,175.06	146.88
Total 5017 · DS Equip-Oper Supplies & Expenses	**6,691.37**	**6,893.73**	**202.36**
simply an increase cost from Bell - four lines and billed/paid per month			
Town of Parry Sound Property Tax increase from 2006 to 2007			
5020-50 · Labour	1,514.17	579.21	-934.96
5020-51 · Truck Time	627.5	530	-97.5
5020-99 · Overhead	1,465.07	802.41	-662.66
5020 · O/H Dist Lines/Feed-Oper Labour - Other	0	423.82	423.82
Total 5020 · O/H Dist Lines/Feed-Oper Labour	**3,606.74**	**2,335.44**	**-1,271.30**
decreased labour & overhead are cause of difference.			
5025 · O/H Dist Line/Feed-Oper Supplies	**55**	**55**	**0**
5035 · O/H Dist. Transformer-Operation			
5035-50 · Labour	188.15	101.63	-86.52
5035-51 · Truck Time	62.5	115	52.5
5035-99 · Overhead Charges	150.51	81.31	-69.2
Total 5035 · O/H Dist. Transformer-Operation	**401.16**	**297.94**	**-103.22**
Small Difference due to decreased labour and overhead.			
5040-50 · Labour	4,107.83	3,100.13	-1,007.70
5040-51 · Truck Time	1,230.00	1,390.00	160
5040-99 · Overhead	3,293.55	2,821.32	-472.23
5040 · U/G Dist Lines/Feed-Oper Labour - Other	0	426.57	426.57
Total 5040 · U/G Dist Lines/Feed-Oper Labour	**8,631.38**	**7,738.02**	**-893.36**
Slight decrease in labour/overhead causing the 10% decline			
5055-50 · Labour	0	77.34	77.34
5055-99 · Overhead Charges	0	61.87	61.87
Total 5055 · U/G Dist Transformers - Operations	**0**	**139.21**	**139.21**
Account was not used in 2006			

Account Description	Jan - Dec 2006	Jan - Dec 2007	2007 VS 2006 $ Change
5065-50 · Labour	3,447.37	5,840.87	2,393.50
5065-51 · Truck Time	1,262.50	2,050.00	787.5
5065-63 · Contractors	245	0	-245
5065-69 · Testing, Calibrating, Sealing	0	2,055.86	2,055.86
5065-70 · MSP- Primary Meters	3,600.00	3,300.00	-300
5065-99 · Overhead Charges	2,757.86	4,672.63	1,914.77
Total 5065 · Meter Expense	**11,312.73**	**17,919.36**	**6,606.63**
several meters seals required the meters be tested and subsequently changed. Consequently this lead to increased labour and overhead.			
5070-99 · Overhead	48.83	0	-48.83
5070 · Customer Premises - Oper Labour - Other	61.04	0	-61.04
Total 5070 · Customer Premises - Oper Labour	**109.87**	**0**	**-109.87**
no entries for 2007 - accounts for 100% difference			
5075-51 · Truck Time	20	0	-20
Total 5075 · Customer Premises-Mat & Expense	**20**	**0**	**-20**
no entries for 2007 - accounts for 100% difference			
5085-01 · Misc Dist Expenses Joint Use	600	0	-600
Total 5085 · Miscellaneous Distribution Expenses	**600**	**0**	**-600**
accounts for special MEARIE Bell Joint Use Project in 2005 & 2006 only. GL Explanation- Participation-Unit Cost & Residual Values Tables Project.			
5095-01 · Pole Attachment Rental	801.08	801.08	0
Total 5095 · O/H Lines/Feed-Rental Paid	**801.08**	**801.08**	**0**
5096-02 · Bell Joint Use of Poles Rental	0	11,887.26	11,887.26
Total 5096 · Other Rent	**0**	**11,887.26**	**11,887.26**
Bell Canada invoiced for 2005 & 2006 Pole Rentals in 2007 no invoice in 2006			

2006 Actual to 2007 Actual – Cont'd (Account #5310 to #6205)

Account Description	2006 Actual	2007 Actual	2007 vs 2006
5310-Meter Reading Expense	**41,342**	**47,648**	**6,306**

- 5310-This increase in meter reading expense is labour and related burden expense. Due to customer movement activity PSP conducted more in-house meter reads and re-reads in 2007.

5315-Customer Billing	**210,790**	**190,826**	**-19,964**

- 5315- There was a decrease in office & computer equipment maintenance of $7600 and a decrease in a contract paid for outside billing services of $79,000. A decrease in training costs of $2000 and a decrease in stationary of $4500 and an increase of printing & stuffing costs of $6000, an increase in postage of $2500 and an increase in EBT costs of $7500 and a new cost for shared billing services of $58,000. The end result is a decrease of $19,964.

5320-Collecting	**107,646**	**108,645**	**999**

- 5320 - The Collection costs remained relatively consistent.

5325-Collecting- Cash Over and Short	**95**	**-30**	**-125**

5335-Bad Debt Expense	**15,669**	**-4,398**	**-20,067**

- In 2007 PSP recovered previously written off accounts resulting in a $4400 credit balance in comparison to the $15,600 balance.

5340-Miscellaneous Customer Accounts Expenses		**-**	**-**

5410-Community Relations - Sundry	**16,897**	**13,368**	**-3,529**

- 5410 - a decrease in labour, overhead and equipment costs because of less interaction in community minded programs.

5415-Energy Conservation	**10,648**	**75,485**	**64,837**

- 5415- an increase 3rd tranche CDM spending in 2007 over 2006 caused a $64,000 increase. A customer survey $1000, CDM Education programs $20,500, CDM promotions $4,000, DR programs $30,000 and low income incentive programs make up the balance of the $64,837 change.

5420-Community Safety Program	**925**	**948**	**23**

5425-Miscellaneous Customer Service and Informational Expenses	**2,185**	**-**	**-2,185**

- 5425- no cost expenditures in this category for 2007.

5605-Executive Salaries and Expenses	**15,820**	**8,147**	**-7,673**

- 5606- the decrease in 2007 over 2006 is caused by convention and seminar cost decrease. The current Board of Directors has been in place for a few years and the education gained from conventions and seminars is usually conducted in the introductory year.

5610-Management Salaries and Expenses		-	-

Account Description	2006 Actual	2007 Actual	2007 vs 2006
5615-General Administrative Salaries and Expenses	**164,885**	**170,034**	**5,148**

- 5615- the increase in 2007 over 2006 is a direct result of a 3% salary increase.

5620-Office Supplies and Expenses	**28,689**	**32,062**	**3,374**

- 5620 - an increase in advertising costs of $1800, non interest bank charges increase by $800, small increase in courier and stationary supplies make up the increase.

5630-Outside Services Employed	**137,944**	**124,227**	**-13,717**

- 5630- a $7700 decrease in the admin fee charged from the affiliate, a $9800 decrease in Regulatory/Finance Consultants fees and a $3600 increase in the audit fee due to new auditing guidelines. This results in a $13,717 decrease.

5635-Property Insurance		**-**	**-**

5640-Injuries and Damages		**1,000**	**1,000**

- 5640- $1000 cost increase resulting from an insurance claim.

5655-Regulatory Expenses	**15,267**	**12,110**	**-3,157**

- 5655- the $3000 decrease was caused from a load shape analysis conducted by Hydro One in 2006. Other regulatory costs remained consistent.

5660-General Advertising Expenses		**-**	**-**

5665-Miscellaneous General Expenses	**2,682**	**-**	**-2,682**

- 5665- this cost category was not used in 2007.

5670-Rent		**-**	**-**

5685-Independent Market Operator Fees and Penalties			

6205-Donations	**50**	**100**	**50**

- 2007 donations

1 **2007 Actual to 2008 Bridge Year (Account #5005 to #5190)**

Account Description	2007	2008	2008 vs 2007
5005 · Operations Supervision & Eng	**14,604.91**	**22,542.20**	**7,937.29**
5016 · DS Equip-Operations Labour			0.00
5016-50 · Labour	254.50	800.00	545.50
5016-51 · Truck Time	60.00	600.00	540.00
5016-99 · Overhead	203.60	640.00	436.40
Total 5016 · DS Equip-Operations Labour	**518.10**	**2,040.00**	**1,521.90**
Substation Breaker Maintenance			
5017-55 · Bell Line Cost Primary Meters	2,718.67	2,990.53	271.86
5017-56 · Property Tax	4,175.06	4,175.18	0.12
Total 5017 DS Equip-Oper Supplies & Expenses	**6,893.73**	**7,165.71**	**271.98**
Inflation Adjustment			
5020-50 · Labour	579.21	1,500.00	920.79
5020-51 · Truck Time	530.00	900.00	370.00
5020-99 · Overhead	802.41	1,200.00	397.59
5020 · O/H Dist Lines/Feed-Oper Labour – Other	423.82	0.00	-423.82
Total 5020 · O/H Dist Lines/Feed-Oper Labour	**2,335.44**	**3,600.00**	**1,264.56**
Load Study-Balance feeders			
5025 · O/H Dist Line/Feed-Oper Supply	**55.00**	**55.00**	**0.00**
5035 · O/H Dist. Transformer-Operation			0.00
5035-50 · Labour	101.63	500.00	398.37
5035-51 · Truck Time	115.00	400.00	285.00
5035-99 · Overhead Charges	81.31	400.00	318.69
Total 5035 · O/H Dist. Transformer-Operation	**297.94**	**1,300.00**	**1,002.06**
Inflation Adjustment			
5040-50 · Labour	3,100.13	3,500.00	399.87
5040-51 · Truck Time	1,390.00	1,200.00	-190.00
5040-99 · Overhead	2,821.32	2,800.00	-21.32
5040 · U/G Dist Lines/Feed-Oper Labour – Other	426.57	0.00	-426.57
Total 5040 · U/G Dist Lines/Feed-Oper Labour	**7,738.02**	**7,500.00**	**-238.02**
5055-50 · Labour	77.34	225.00	147.66
5055-99 · Overhead Charges	61.87	180.00	118.13
Total 5055 · U/G Dist Transformers - Operations	**139.21**	**405.00**	**265.79**
5065-50 · Labour	5,840.87	6,424.96	584.09

Account Description	2007	2008	2008 vs 2007
5065-51 · Truck Time	2,050.00	2,100.00	50.00
5065-63 · Contractors	0.00	0.00	0.00
5065-69 · Testing, Calibrating, Sealing	2,055.86	2,300.00	244.14
5065-70 · MSP- Primary Meters	3,300.00	3,600.00	300.00
5065-99 · Overhead Charges	4,672.63	5,139.97	467.34
Total 5065 · Meter Expense	**17,919.36**	**19,564.93**	**1,645.57**
Inflation Adjustment			
5070-99 · Overhead	0.00		0.00
5070 · Customer Premises - Oper Labour – Other	0.00		0.00
Total 5070 · Customer Premises - Oper Labour	**0.00**		**0.00**
5075-51 · Truck Time	0.00		0.00
Total 5075 · Customer Premises-Mat & Expense	**0.00**		**0.00**
5085-01 · Misc Dist Expenses Joint Use	0.00		0.00
Total 5085 · Miscellaneous Distribution Expe	**0.00**		**0.00**
5095-01 · Pole Attachment Rental	801.08	801.08	0.00
Total 5095 · O/H Lines/Feed-Rental Paid	**801.08**	**801.08**	**0.00**
5096-02 · Bell Joint Use of Poles Rental	11,887.26	5,943.63	-5,943.63
Total 5096 · Other Rent	**11,887.26**	**5,943.63**	**-5,943.63**
Yearly Rental Costs			
5105 · Mtce Supervision & Engineering	**5,076.00**	**6,994.34**	**1,918.34**
5114 · Mtce-Distrib Station Equipment			0.00
5114-01 · Transformer Oil Testing	3,455.00	2,700.00	-755.00
5114-50 · Labour	3,570.33	4,500.00	929.67
5114-51 · Truck Time	982.50	1,750.00	767.50
5114-52 · Materials	1,001.88	450.00	-551.88
5114-58 · Insurance	11,385.36	12,523.89	1,138.53
5114-62 · Maintenance	330.00	900.00	570.00
5114-99 · Overhead Charges	2,856.24	3,600.00	743.76
5114 · Mtce-Distrib Station Equipment - Other	0.00		0.00
Total 5114 · Mtce-Distrib Station Equipment	**23,581.31**	**26,423.89**	**2,842.58**
5120-50 · Labour	21,537.62	19,143.89	-2,393.73
5120-51 · Truck Time	8,352.50	8,000.00	-352.50
5120-52 · Materials	1,283.86	1,500.00	216.14
5120-99 · Overhead Charges	17,230.03	15,315.11	-1,914.92
Total 5120 · Mtce-Poles,Towers & Fixtures	**48,404.01**	**43,959.00**	**-4,445.01**
Best estimate for pole top maintenance.			
5125-50 · Labour	28,832.03	34,778.55	5,946.52

Account Description	2007	2008	2008 vs 2007
5125-51 · Truck Time	3,787.50	8,000.00	4,212.50
5125-52 · Materials	990.02	1,000.00	9.98
5125-99 · Overhead Charges	23,065.56	27,822.84	4,757.28
Total 5125 · Mtce-O/H Conductors & Device	**56,675.11**	**71,601.39**	**14,926.28**
Best estimate for pole top maintenance.			
5130-50 · Labour	5,502.65	5,823.00	320.35
5130-51 · Truck Time	1,602.50	4,000.00	2,397.50
5130-52 · Materials	-74.46	500.00	574.46
5130-99 · Overhead Charges	4,402.08	4,658.40	256.32
Total 5130 · Mtce-O/H Services	**11,432.77**	**14,981.40**	**3,548.63**
Annual O/H maintenance, Change out Old open wire services			
5135-50 · Labour	34,033.02	23,292.00	-10,741.02
5135-51 · Truck Time	16,649.47	16,000.00	-649.47
5135-52 · Materials	16.84	200.00	183.16
5135-60 · Contractors	250.00	9,000.00	8,750.00
5135-99 · Overhead	27,226.37	18,633.60	-8,592.77
Total 5135 · O/H Dist Lines & Feeders-R.O.W.	**78,175.70**	**67,125.60**	**-11,050.10**
5145-50 · Labour	397.88	2,795.04	2,397.16
5145-51 · Truck Time	180.00	560.00	380.00
5145-99 · Overhead Charges	318.30	2,236.03	1,917.73
Total 5145 · Mtce-U/G Conduit	**896.18**	**5,591.07**	**4,694.89**
5150-50 · Labour	2,233.24	2,317.60	84.36
5150-51 · Truck Time			
5150-52 · Materials	402.28	400.00	-2.28
5150-99 · Overhead Charges	1,672.97	1,854.08	181.11
5150 · Mtce-U/G Conductors & Devices - Other	0.00		0.00
Total 5150 · Mtce-U/G Conductors & Devices	**4,723.49**	**5,571.68**	**848.19**
5155-50 · Labour	2,287.73	2,720.00	432.27
5155-51 · Truck Time	1,155.00	1,000.00	-155.00
5155-52 · Materials	0.79	300.00	299.21
5155-99 · Overhead Charges	1,943.79	2,176.00	232.21
Total 5155 · Mtce-U/G Services	**5,387.31**	**6,196.00**	**808.69**
PED Replacements on Secondary Conductors.			
5160-03 · Waste Disposal	175.34	13,228.00	13,052.66
5160-50 · Labour	5,464.70	7,347.98	1,883.28
5160-51 · Truck Time	2,636.50	2,499.00	-137.50
5160-52 · Materials	460.92	6,000.00	5,539.08
5160-99 · Overhead Charges	4,371.75	5,878.38	1,506.63
Total 5160 · Maintenance-Line Transformers	13,109.21	34,953.36	21,844.15

Account Description	2007	2008	2008 vs 2007
5175-50 · Labour	7,117.44	8,000.00	882.56
5175-51 · Truck Time	1,120.00	1,200.00	80.00
5175-58 · Insurance	60.12	65.00	4.88
5175-99 · Overhead Charges			
Total 5175 · Mtce-Meters	**5,693.92**	**6,400.00**	**706.08**
5190 · Water Heater Controls - Labour	13,991.48	15,665.00	1,673.52
5190-02 · Communications - W/H controls	4,476.12		-4,476.12
5190-50 · Labour	15.72	4,594.00	4,578.28
5190-51 · Truck Time	90.00		-90.00
5190-99 · Overhead Charges	12.57		-12.57
5190 · Water Heater Controls - Labour - Other	0.00		0.00
Total 5190 · Water Heater Controls - Labour	**4,594.41**	**4,594.00**	**-0.41**

Water Heater Control Activation for DSM Purposes

1 **2007 Actual to 2008 Bridge Year – Cont'd (Account #5310 to #6205)**

Account Description	2007	2008	2008 Vs 2007
5310-Meter Reading Expense	**47,648**	**47,991**	**343**

- 5310- account has remained consistent.

5315-Customer Billing	**190,826**	**266,256**	**75,431**

- 5315- labour and overhead increased by $57,500 because of a re-allocation of staff to billing plus a 3% increase in wages and a $17,000 increase in training costs to upgrade our billing system to the current platform. The balance of the change is minor variances in other accounts.

5320-Collecting	**108,645**	**70,971**	**-37,675**

- 5320- This decrease is explained as follows: as explained in 5315 a re-allocation of staff from Collecting to Billing plus a 3% wage increase and an estimated increase in credit bureau costs of $2500 make up the balance.

5325-Collecting- Cash Over and Short	**-30**	**-**	**30**

5335-Bad Debt Expense	**-4,398**	**8,822**	**13,220**

- 5335- management is attempting to create a write-off policy and process to ensure consistency in the write-off and Allowance for Doubtful Accounts procedure. An in-depth review of aged accounts resulted in the budgeted amount.

5410-Community Relations - Sundry	**13,368**	**14,505**	**1,137**

- 5410- the 2008 bridge year projections are primarily based on historical averages with an inflationary adjustment of 3% to labour and overhead. All other costs are primarily historical averages adjusted in inflation.

5415-Energy Conservation	**75,485**	**51,200**	**-24,285**

- 5415- the decrease is caused by the balance of 3rd tranche money being spent in 2008.

5420-Community Safety Program	**948**	**2,760**	**1,812**

5605-Executive Salaries and Expenses	**8,147**	**12,015**	**3,868**

- 5606- the $3900 increase is a budgeted amount for planned attendance to seminars in the 2008 calendar year.

5615-General Administrative Salaries and Expenses	**170,034**	**176,875**	**6,841**

- 5615- an inflation adjustment of 3%, the budgeted amount for bridge year essentially causes the increase.

5620-Office Supplies and Expenses	32,062	31,167	-896

- 5620- this account remains consistent.

Account Description	2007	2008	2008 Vs 2007
5630-Outside Services Employed	**124,227**	**132,303**	**8,076**

- a budgeted increase in outside consulting costs of $8000 caused by the rebasing exercise.

5640-Injuries and Damages	**1,000**	**-**	**-1,000**

- 5640 - no estimated amount for 2008.

5655-Regulatory Expenses	**12,110**	**12,319**	**209**

- 5655 - the bridge year budget amount remains consistent with past years.

5670-Rent	**-**	**46,500**	**46,500**

- 5670- this cost is directly related to fair-market appraisal being conducted in Jan 2008 of the office building we occupy. This cost is explained in further detail in section 4.2.4.

6205-Donations	**100**	**0**	**-100**

1 **2008 Bridge to 2009 Test (Accounts #5005 to #5190)**

Account Description	2008	2009	2009 vs 2008
5005 · Operations Supervision & Eng	**22,542.20**	**24,796.42**	**2,254.22**
Inflation Adjustment			
5016-50 · Labour	800.00	1,000.00	200.00
5016-51 · Truck Time	600.00	600.00	0.00
5016-99 · Overhead	640.00	800.00	160.00
Total 5016 · DS Equip-Operations Labour	**2,040.00**	**2,400.00**	**360.00**
Inflation Adjustment			
5017-55 · Bell Line Cost Primary Meters	2,990.53	3,289.59	299.06
5017-56 · Property Tax	4,175.18	4,175.18	0.00
Total 5017 · DS Equip-Oper Supplies & Expens	**7,165.71**	**7,464.77**	**299.06**
Inflation Adjustment			
5020-50 · Labour	1,500.00	1,800.00	300.00
5020-51 · Truck Time	900.00	1,000.00	100.00
5020-99 · Overhead	1,200.00	1,440.00	240.00
5020 · O/H Dist Lines/Feed-Oper Labour – Other	0.00	0.00	0.00
Total 5020 · O/H Dist Lines/Feed-Oper Labour	**3,600.00**	**4,240.00**	**640.00**
Inflation Adjustment			
5025 · O/H Dist Line/Feed-Oper Supplie	**55.00**	**55.00**	**0.00**
5035 · O/H Dist. Transformer-Operation			0.00
5035-50 · Labour	500.00	500.00	0.00
5035-51 · Truck Time	400.00	400.00	0.00
5035-99 · Overhed Charges	400.00	400.00	0.00
Total 5035 · O/H Dist. Transformer-Operation	**1,300.00**	**1,300.00**	**0.00**
5040-50 · Labour	3,500.00	3,675.00	175.00
5040-51 · Truck Time	1,200.00	1,260.00	60.00
5040-99 · Overhead	2,800.00	2,940.00	140.00
5040 · U/G Dist Lines/Feed-Oper Labour – Other			0.00
Total 5040 · U/G Dist Lines/Feed-Oper Labour	**7,500.00**	**7,875.00**	**375.00**
Inflation Adjustment			
5055-50 · Labour	225.00	240.00	15.00
5055-99 · Overhead Charges	180.00	192.00	12.00
Total 5055 · U/G Dist Transformers - Operati	**405.00**	**432.00**	**27.00**
Inflation Adjustment			

Account Description	2008	2009	2009 vs 2008
5065-50 · Labour	6,424.96	7,067.45	642.49
5065-51 · Truck Time	2,100.00	2,200.00	100.00
5065-63 · Contractors			0.00
5065-69 · Testing, Calibrating, Sealing	2,300.00	2,500.00	200.00
5065-70 · MSP- Primary Meters	3,600.00	3,960.00	360.00
5065-99 · Overhead Charges	5,139.97	5,653.96	513.99
Total 5065 · Meter Expense	**19,564.93**	**21,381.41**	**1,816.48**
Inflation Adjustment			
5095-01 · Pole Attachment Rental	801.08	801.08	0.00
Total 5095 · O/H Lines/Feed-Rental Paid	**801.08**	**801.08**	**0.00**
5096-02 · Bell Joint Use of Poles Rental	5,943.63	5,943.63	0.00
Total 5096 · Other Rent	**5,943.63**	**5,943.63**	**0.00**
5105 · Mtce Supervision & Engineering	**6,994.34**	**7,693.77**	**699.43**
5114-01 · Transformer Oil Testing	2,700.00	2,800.00	100.00
5114-50 · Labour	4,500.00	4,725.00	225.00
5114-51 · Truck Time	1,750.00	1,850.00	100.00
5114-52 · Materials	450.00	500.00	50.00
5114-58 · Insurance	12,523.89	13,776.29	1,252.40
5114-62 · Maintenance	900.00	1,000.00	100.00
5114-99 · Overhead Charges	3,600.00	3,780.00	180.00
5114 · Mtce-Distrib Station Equipment - Other			0.00
Total 5114 · Mtce-Distrib Station Equipment	**26,423.89**	**28,431.29**	**2,007.40**
Used Three year Ave. as this GL stays fairly constant			
5120-50 · Labour	19,143.89	21,058.27	1,914.38
5120-51 · Truck Time	8,000.00	8,500.00	500.00
5120-52 · Materials	1,500.00	1,800.00	300.00
5120-99 · Overhead Charges	15,315.11	16,846.62	1,531.50
Total 5120 · Mtce-Poles,Towers & Fixtures			
Annual Pole maintenance, Patrols, repairs to Poles & fixtures			
Used Average of last two years			
5125-50 · Labour	34,778.55	38,256.41	3,477.86
5125-51 · Truck Time	8,000.00	9,000.00	1,000.00
5125-52 · Materials	1,000.00	1,000.00	0.00
5125-99 · Overhead Charges	27,822.84	30,605.13	2,782.29
Total 5125 · Mtce-O/H Conductors & Device	**71,601.39**	**78,861.54**	**7,260.15**
2008 Used Average of last three years., 2009 =2008 + 10%			

Account Description	2008	2009	2009 vs 2008
5130-50 · Labour	5,823.00	6,405.30	582.30
5130-51 · Truck Time	4,000.00	4,400.00	400.00
5130-52 · Materials	500.00	500.00	0.00
5130-99 · Overhead Chargs	4,658.40	5,124.24	465.84
Total 5130 · Mtce-O/H Services	**14,981.40**	**16,429.54**	**1,448.14**
Annual O/H maintenance, Change out Old open wire services			
2 Men X 100 hours =58.23 X 100= 5823.00, 2009 =5823.00 X 10%=6405.30			
2008, 100 Hrs X 40 = 4000, 2009 =4000 X 10% =4400			
5135-50 · Labour	25,621.20	23,292.00	2,329.20
5135-51 · Truck Time	17,600.00	16,000.00	1,600.00
5135-52 · Materials	220.00	200.00	20.00
5135-60 · Contractors	10,000.00	9,000.00	1,000.00
5135-99 · Overhead	20,496.96	18,633.60	1,863.36
Total 5135 · O/H Dist Lines & Feeders-R.O.W.	**73,938.16**	**67,125.60**	**6,812.56**
325 Hour of Tree Trimming Trucks 400X 40=16000, 2009 =16000X10%=17600			
Trimming of 44 KV Line - Contractors			
5145-50 · Labour	2,795.04	2,934.79	139.75
5145-51 · Truck Time	560.00	616.00	56.00
5145-99 · Overhead Charges	2,236.03	2,347.83	111.80
Total 5145 · Mtce-U/G Conduit	**5,591.07**	**5,898.62**	**307.55**
5150-50 · Labour	2,317.60	2,549.36	231.76
5150-51 · Truck Time	1,000.00	1,100.00	100.00
5150-52 · Materials	400.00	450.00	50.00
5150-99 · Overhead Charges	1,854.08	2,039.49	185.41
Total 5150 · Mtce-U/G Conductors & Devices	**5,571.68**	**6,138.85**	**567.17**
5155-50 · Labour	2,720.00	2,800.00	80.00
5155-51 · Truck Time	1,000.00	1,100.00	100.00
5155-52 · Materials	300.00	350.00	50.00
5155-99 · Overhead Charges	2,176.00	2,240.00	64.00
Total 5155 · Mtce-U/G Services	**6,196.00**	**6,490.00**	**294.00**
Same as last year with mark-up			
5160-03 · Waste Disposal	13,228.00	0.00	-13,228.00
5160-50 · Labour	7,347.98	1,397.52	-5,950.46
5160-51 · Truck Time	2,499.00	1,560.00	-939.00
5160-52 · Materials	6,000.00	12,000.00	6,000.00
5160-99 · Overhead Charges	5,878.38	1,118.02	-4,760.37

Account Description	2008	2009	2009 vs 2008
Total 5160 · Maintenance-Line Transformers	**34,953.36**	**16,075.54**	**-18,877.83**
Last of PCB's in system should be removed in 2008, 2009 Upgrade of six Transformers @$2000.00			
2008 Replace 3 Tx for upgrade @$2000.00 2009 Upgrade of six Transformers @$2000.00			
5175-50 · Labour	8,000.00	8,250.00	250.00
5175-51 · Truck Time	1,200.00	1,200.00	0.00
5175-58 · Insurance	65.00	70.00	5.00
5175-99 · Overhead Charges	6,400.00	6,600.00	200.00
Total 5175 · Mtce-Meters	**15,665.00**	**16,120.00**	**455.00**
Approximately the same amount of changes as 2007			
5190-50 · Labour	4,594.00	4,594.00	0.00
5190-51 · Truck Time			0.00
5190-99 · Overhead Charges			0.00
Total 5190 · Water Heater Controls - Labour	**4,594.00**	**4,594.00**	**0.00**
used 2007 value most cost covered by OPA			

2008 Bridge to 2009 Test – Cont'd (Accounts #5310 to #6205)

Account Description	2008	2009	2009 vs 2008
5310-Meter Reading Expense	**47,991**	**48,872**	**881**

The 2009 test year budget for meter reading expense is based on historical labour averages adjusted for a 3% inflationary increase. The other cost drivers remain consistent with prior years averages.

5315-Customer Billing	**266,256**	**276,999**	**10,742**

The 2009 test year budget for Customer Billing is based on historical labour averages adjusted for a 3% inflationary increase. The other cost drivers remain consistent with prior years averages. The customer billing costs were increased slightly due to a small amount of customer growth.

5320-Collecting	**70,971**	**75,610**	**4,639**

The 2009 test year budget for meter reading expense is based on historical labour averages adjusted for a 3% inflationary increase. The other cost drivers remain consistent with prior years averages.

5325-Collecting- Cash Over and Short	**-**	**-**	**-**

5335-Bad Debt Expense	**8,822**	**8,822**	**-**

management is attempting to create a write-off policy and process to ensure consistency in the write-off and Allowance for Doubtful Accounts procedure. An in-depth review of aged accounts resulted in the budgeted amount.

5340-Miscellaneous Customer Accounts Expenses	**-**	**-**	**-**

5410-Community Relations - Sundry	**14,505**	**15,538**	**1,033**

The 2009 test year budget for meter reading expense is based on historical labour averages adjusted for a 3% inflationary increase. The other cost drivers remain consistent with prior years averages.

5415-Energy Conservation	**51,200**	**-**	**-51,200**

there is no further 3rd tranche CDM spending

5420-Community Safety Program	**2,760**	**2,760**	**-**

the budget amount remains consistent with historial averages

5425-Miscellaneous Customer Service and Informational Expenses	**-**	**-**	**-**

5605-Executive Salaries and Expenses	**12,015**	**12,015**	**-**

Account Description	2008	2009	2009 vs 2008

the budget amount remains consistent with historical averages. Directors Salaries are not budgeted for inflation.

Account Description	2008	2009	2009 vs 2008
5610-Management Salaries and Expenses	**-**	**-**	**-**
5615-General Administrative Salaries and Expenses	**176,875**	**188,967**	**12,093**

The 2009 test year budget for meter reading expense is based on historical labour averages adjusted for a 3% inflationary increase. The other cost drivers remain consistent with prior years averages.

Account Description	2008	2009	2009 vs 2008
5620-Office Supplies and Expenses	**31,167**	**31,689**	**523**

the budgeted amount remains consistent with historical averages.

Account Description	2008	2009	2009 vs 2008
5630-Outside Services Employed	**132,303**	**132,612**	**309**

the budgeted amount remains consistent with historical averages.

Account Description	2008	2009	2009 vs 2008
5635-Property Insurance	**-**	**-**	**-**
5640-Injuries and Damages	**-**	**-**	**-**
5655-Regulatory Expenses	**12,319**	**45,653**	**33,333**

this increase is caused from the estimated cost of the 2009 Rebasing Application of $100,000 being allocated over three years.

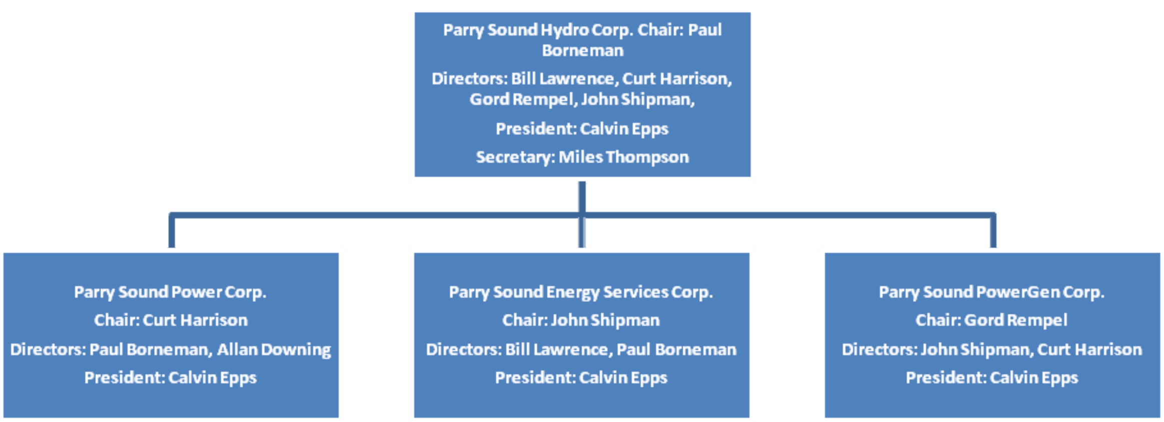
Account Description	2008	2009	2009 vs 2008
5660-General Advertising Expenses	**-**	**-**	**-**
5665-Miscellaneous General Expenses	**-**	**-**	**-**
5670-Rent	**46,500**	**46,500**	**-**
5685-Independent Market Operator Fees and Penalties	**-**	**-**	**-**
6105-Taxes Other Than Income Taxes	**-**	**-**	**-**
6205-Donations	**0**	**0**	**0**

Shared Services

Overview

PSP as shown in the Corporate Entities chart below Parry Sound Power is 100% owned by the parent corporation Parry Sound Hydro Corporation PSHC). PSP has two sister corporations: Parry Sound PowerGen (PGEN) and Parry Sound Energy Services (PSES). PSPS has “Service Agreements” with the PSHC, PSES and PGen. These agreements detail the arrangements and services provided and are attached in the following section Ex 4 Tab 2. The detailed analysis of the corporate relationship follows the organization chart preceding this section, the detail is offered to provide the reader with a better understanding of the corporate relationship the benefits created by this relationship and the pricing structure currently in place. PSHC, PSP, PSES and PGen have intended this information to assist the reader without dwelling into the competitive business practices of the affiliate corporations.

Parry Sound Hydro Corporate Entities Chart



Detailed Analysis

Parry Sound Hydro Corporation

PSHC being the corporate company owns the building that houses the administration and operations staff. This building located at 125 William Street Parry Sound Ontario includes office space, storage/warehouse area and large garage to house the transportation equipment. The agreement for rental space is between PSHC and PSES, the historical rent was based on the value of property tax paid during the year and allocate to PSES. PSES allocated the rental costs (along with other costs detailed later) to the other affiliates based on approximate area of use PSP 75% & PGen 10%. Management was of the opinion that the former agreement did not lend itself to “Fair Market” practice based on the rental agreement. Therefore in late 2007 PSHC had a market value assessment done of the premises at 125 William Street to determine what the fair market rental rate would be. This assessment was conducted by a certified commercial real estate appraiser. The formal report results in an increase of the rental space to $62,000 (75% PSP, 15%PSES & 10% P:Gen) per year from the former costs of $4,679 in 2007. This increase now reflects fair value of the office space used by PSP. This area was described in the OMA variance in the prior section. PSHC also allocates the costs of the board of directors to each of the subsidiary companies based on the number of directors that sit the subsidiary board from the holding company board. PSP has two directors form the PSHC board that hold directors’ positions on the Power board. These expenses are allocated at cost. Any further costs incurred by the parent company that are to be shared between the subsidiary corporations are invoiced at cost to PSES and PSES deals with these expenses accordingly.

Parry Sound PowerGen Corporation

PGen is an electrical generation company licensed by the Ontario Energy Board. PGen produces hydraulic generation and charges PSP using the actual “Spot” price determined by the IESO. A copy of the connection agreement is located in the next section.

Parry Sound Energy Services Corporation

PSES "The Services Corporation" retains all the employees and assets, vehicles, equipment, computers, etc., needed to provide the services to operate the LDC and Generation Company. The services are charged at cost. PSES is also involved in "Other" competitive" business endeavors. PSES is NOT an electrical retailer operating in the electricity market nor does it portray itself as such.

PSES invoices PSP for services rendered by operations department on a biweekly (payroll) basis. These costs are tracked by the hour using 15 minute increments for both operations staff and equipment time involved. The rates invoiced are at the direct hourly cost of the employee with an added overhead burden.

The equipment time is invoiced at a set hourly rate depending on the vehicle size.

Table 2 PSES' Equipment Rental Rates

Equipment:

Single Bucket Truck	$30.00
Digger Derrick	$35.00
Double Bucket Truck	$45.00
½ Ton Truck	$10.00
Chain Saw etc.	$10.00

The Operations and Equipment costs are invoiced and allocated on a gl account level to capital, operations, maintenance and any other relative cost centers.

The admin staff is invoiced on the same time table as operations and equipment. The costs are true admin wage costs including a payroll burden percentage. These costs are allocated to various cost pools based on the staff member: General Admin, Regulatory, Customer Billing, Collecting etc. on a percentage of time spent basis. This allocation is reviewed periodically by management and changed when considered needed.

This costing approach was created by management using historical time allocation and management best opinions.

PSP also purchases other services from PSES that allows us to operate effectively by sharing costs to achieve synergies that in other ways would not be possible. These expenses are transferred at cost on a percentage of use methodology. The table below lists the cost centers and allocation percentages.

Table 3 PSES Allocation of Costs

			PSP 75%	**PGen 10%**	**PSES 15%**
Other administration & general					
	5620	General admin – other			
	01	Office Equipment Maintenance			
	02	Computer software maintenance			
	03	Photocopier lease and maintenance			
	04	Fax machine			
	05	Postage meter rental & mailing machine			
	06	Postage			
	10	Advertising			
	11	Fees memberships			
	14	Service pins & dinner			
	16	Internet access			
	17	Courier charges			
	18	Bank charges			
	20	Rent from Parry Sound Hydro			
	21	Gen Admin from Parry Sound Hydro			
	57	Conventions/seminars			
	58	Insurance			
	59	Telephone			
	67	Cleaning & other maintenance			
	68	Stationery supplies			
	70	Mileage & Messenger			
	72	Office Supplies Other			
	5630	Outside services employed			
	01	Audit			
	02	Legal			
	03	Other			
	63	Contractors			
	5640	Damages			
	5675	Maintenance of general plant			
	01	Grounds & Custodial			
	02	Snow plowing			
	03	Waste disposal			
	04	Security system			
	50	Labour			
	51	Truck Time			
	53	Elect., water, sewage, gas			
	58	Insurance			

99	Maintenance
6215	Penalties and donations
9085	Trades Training

Amortization of capital assets

5705-12	Office furniture and equipment
5705-13	Computer equipment
5705-16	Communications equipment
5705-18	Load management controllers

The amortization expense allocated is only the amortization on the assets used for shared services.

Other

PSP is currently a member of Cornerstone Hydro Electric Concepts Group "CHEC". As a shareholder, PSP is very involved with the development of policy processes and shared agreements amongst the group. As a CHEC group member we have accomplished many things as a group that as individual LDCs we could not have done without great cost to our customers. The shared costs of a Finance Coordinator has enabled our group to ensure the many if not ALL facets of finance are well managed and up-to-date. Board Staff are well aware of our activities and have attended many of our finance meetings, resulting in better relationship with the LDC and Board Staff, a very favorable result for both parties. A CDM coordinator is also shared among our group enabling us to achieve synergies and find programs to offer our customers that we could not accomplish on our own. The "CHEC" organization is well known throughout the industry and very well respected. Parry Sound participates in this group to its full potential; we have representation on the CHEC board of directors and the CHEC Finance Steering Committee.

PSP in late 2006 became a 25% share holder in "Utility Collaborative Services Inc." This company provides billing, EBT and reporting services to its members. The operating premise is based on standards and group efforts to share costs relating to "Back Office" task that would otherwise be handled by the utility itself or other "Billing" contractors. The simple business case is shared services with a return of costs based on annual company performance. As UCS grows, our discounts relating to costing drop in proportion to the number of customers we represent.

Summary

Management understands the need to ensure the cost allocation among affiliate companies and within each organization is fair and equitable. The current methodology is under review and PSP with its affiliate PSES will endeavor to obtain a documented procedure/process. The costing models are also under review including payroll burdens and overhead allocation. The advantages of shared type mechanism we currently have in place far exceed the pitfalls. The cross training affords ALL staff an understanding of the entire system mechanics from billing to operations. The ability to obtain full-time on-call workers for emergencies (fires, etc.) power outages, keeps our system up and running smoothly. This type of “shared” service is effective because jobs are not delayed due to tending or agreements. Our customers’ receive the best service, care and dependable service offered from well educated staff because of the current business model. A segregation completely of the services would not be cost effective to any of the businesses and any one business would have difficulty operating on a one to one basis. Parry Sound Power will conduct a comprehensive review to develop an action plan to ensure compliance with the Affiliate Relationship Code. PSP understands our existing model may not be compliant with the changes to the ARC last November that will take effect Aug 2008. We have hired an outside consultant and will be seeking legal opinions prior to changing our model. The action plan and review will be shared with the” Board” should this become necessary. This cost of service process has afforded management the opportunity to review in great detail the cost drivers and methodology used to examine related management activities. As finance quickly becomes the backbone to any well managed business it is imperative to a regulated entity such as PSP to evolve its business practices to remain viable. Management does understand the need to strive for further reductions in costs will become the industry standard throughout the rate setting future. PSP also understand that its’ current business practices are outdated and need to be brought into line with current management and financial trends. The membership to CHEC and the investment in UCS will definitely aid PSP in its future endeavors to control costs.

Service Agreement(s)

Service Agreements between PSP and its Corporate Entities are attached on the following pages.

ATTACHMENT 1

MASTER SERVICE AGREEMENT

BETWEEN

PARRY SOUND ENERGY SERVICES CORP.

AND

PARRY SOUND POWER CORP.

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this 28 day of Nov , 2001

BETWEEN:

PARRY SOUND ENERGY SERVICES CORPORATION

(hereinafter referred to as "Servco")

OF THE FIRST PART

- and -

PARRY SOUND POWER CORPORATION

(hereinafter referred to as "Wiresco")

OF THE SECOND PART

WHEREAS each of Servco and Wiresco are duly incorporated pursuant to Section 142 of the *Electricity Act, 1998;*

AND WHEREAS the Parties have agreed that Servco will maintain and repair Wiresco's electrical distribution system on a fee-for-service basis and Servco shall provide such and other products and services as may be agreed by the Parties from time to time;

AND WHEREAS the Parties acknowledge and agree that in providing goods and services Servco acts as an independent contractor and not, except as expressly provided herein, as an agent, partner, or servant;

AND WHEREAS the Parties shall consult as frequently as may be desirable to ensure that Wiresco and its customers receive adequate, economical, safe and effective electrical distribution and ancillary services;

NOW THEREFORE IN CONSIDERATION of mutual covenants and agreements as set forth herein, and for other good and valuable consideration (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties do hereby covenant and agree with each other, as follows:

1. **Definitions**

1.01 "**Capital Cost**" means the cost incurred for materials, equipment, overhead, and labour to provide capital works.

1.02 **"Capital Works"** has the meaning set out in Section 3.03.

1.03 "**Customer Service Costs**" means the cost incurred by a Party to bill and collect and to provide related customer services.

1.04 "**Customer Services**" means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing collection of unpaid accounts, and customer relations, etc.

1.05 "**Easements**" means any permissions, concessions, permits, licenses, interests, ways, privileges, easements and right-of-way to install, operate and maintain part or parts of the electrical distribution system over real property.

1.06 **"Effective Date"** means November 7, 2000.

1.07 "**Extraordinary Costs** has the meaning set out in Section 4.04.

1.08 **"IMO"** means the Independent Electricity Market Operator for Ontario.

1.09 "**OM&A Costs**" means operations, maintenance, and administration costs incurred by Servco to distribute electric power within the areas serviced by Wiresco from time to time and includes costs for the services described in Section 3.01.

1.10 **"Parties"** means Servco and Wiresco.

2. **Term**

2.01 Unless terminated in accordance with Article 9 of this Agreement, the term of this Agreement shall be from the Effective Date to and including December 31, 2003 and the term shall be extended automatically for further periods of two years each, unless either Party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. **Covenants of Servco**

3.01 Servco agrees to maintain in a good and workmanlike manner Wiresco's electrical distribution system in all of the areas serviced by Wiresco from time to time.

3.02 In providing electrical distribution system maintenance services for Wiresco, Servco shall maintain at least the same performance standards as were delivered prior to the Effective Date within Wiresco's licensed service area and shall not discriminate in its performance between any parts of Wiresco's licensed service area. Servco shall render performance of the services to be provided hereunder in a competent and professional manner.

3.03 Servco shall expand or upgrade in a timely and in a good and workmanlike manner Wiresco's electrical distribution system at Wiresco's request, which shall hereinafter be referred to as "Capital Works", provided that such Capital Works have been designed in accordance with good engineering principles applicable in the Province of Ontario.

3.04 Subject to the obligations of Servco hereunder, Servco shall be free to offer services to any other person.

3.05 Servco shall be responsible for obtaining all necessary licences and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the services hereunder and Servco shall when requested provide Wiresco with adequate evidence of its compliance with this Section 3.05.

3.06 Servco shall comply, while on the premises used by Wiresco, with all the rules and regulations of Wiresco from time to time in force which are brought to its notice or of which it could reasonably be aware.

3.07 Servco shall pay for and maintain for the benefit of Servco appropriate insurance concerning the operations and liabilities of Servco relevant to this Agreement including, without limiting the generality of the foregoing, workers' compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by Servco to any employees of Servco and public liability and property damage insurance.

3.08 Servco shall indemnify and save Wiresco harmless from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which Wiresco or its officers, employees or agents may suffer as a result of the negligence or breach of Servco in the performance or non-performance of this Agreement.

3.09 Servco shall not (either during the term of this Agreement or at any time thereafter) disclose any information relating to the private or confidential affairs of Wiresco or relating to any secrets of Wiresco to any person other than with the consent of Wiresco

4. **Costs**

4.01 Wiresco shall pay Servco the fees and charges more particularly outlined in Schedule "A" for OM&A Costs.

4.02 Wiresco shall reimburse Servco for its actual Capital Works costs, which without limiting the generality of the foregoing, shall include all Servco's direct labour and material costs, engineering design and review costs, plus a margin calculated as a percentage of the actual costs to be notified to Wiresco by Servco from time to time.

4.03 Wiresco agrees to reimburse Servco for any costs ("Extraordinary Costs") over and above OM&A and Capital Works costs, plus a margin as a percentage of the actual costs to be notified to Wiresco from time to time, which Servco may incur resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, acts of God and the like, provided such equipment failures are not caused by negligence on the part of Servco to provide routine service and maintenance of the electrical distribution system or breach by Servco of this Agreement.

4.04 Upon renewal of the term of this Agreement and any subsequent renewals, Servco may adjust the OM&A, Capital Works Costs and Extraordinary Costs upon ninety (90) days prior notice in writing to Wiresco provided that, if Wiresco does not accept the adjusted costs and the Parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Article 9 of this Agreement.

5. **Invoicing**

5.01 Servco shall submit an invoice within 5 days from the end of each month to Wiresco for payment for all costs incurred by Servco in performing its services. All monthly invoices shall provide sufficient detail of the costs incurred and the description of the services undertaken by Servco. All invoices shall be paid by Wiresco within ten (10) days from the date of receipt.

5.02 Servco will submit details of any Extraordinary Costs to Wiresco for review before invoicing.

6. **Easements**

6.01 Wiresco represents that it has secured all requisite Easements necessary for the delivery of electrical services for the distribution of electric power throughout the Wiresco licensed service area as at the Effective Date.

6.02 Wiresco shall indemnify and save Servco harmless from any claims, demands, actions and applications brought against Servco arising from the failure of Wiresco to have secured the requisite Easements or from any defect or deficiency in the Easements secured by Wiresco prior to the Effective Date.

6.03 Servco shall act on behalf of Wiresco, and Wiresco appoints Servco its agent for the purposes of this Section 6.03, to secure all Easements required for the performance of the expansion or upgrade of electrical distribution services pursuant to this Agreement. Any costs related to the acquisition of Easements, including without limitation appraisal and legal costs, shall be paid by Wiresco.

7. **Customer Billing**

7.01 Servco shall provide billing services to Wiresco as requested from time to time but all bills shall be issued in Wiresco's name.

7.02 Wiresco shall be responsible for all costs related to any billing errors and uncollectible bills incurred on or before the commencement of this Agreement and shall indemnify and save Servco harmless in respect thereof.

7.03 Servco shall assume responsibility for any billing errors arising after the commencement of this Agreement only to the extent that the costs arising from the billing errors are unrecoverable from Wiresco's customer and only if the billing error is attributable to Servco's negligence or the negligence of its servants, agents or representatives or breach of this Agreement by Servco.

8. **Arbitration**

8.01 The Parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either Party may have relating to the interpretation, application or implementation of this Agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the Parties agree to resolve their disputes by arbitration as provided in this Article 8.

8.02 Arbitration of a dispute shall be commenced by written notice by a Party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each Party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the *Arbitration Act*, R.S.O. 1991, c. A.17.

8.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitration panel. The provisions of the *Arbitration's Act*, R.S.O. 1991, c. A.17, as amended or any successor legislation shall apply to the arbitration.

8.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

8.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the Parties agree to share the fees of the Chair and other related costs equally.

9. **Termination**

9.01 In the event of non-performance by either Party of its obligations under this Agreement, the other Party may at its sole option elect to terminate this Agreement provided that the defaulting Party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

9.02 Notwithstanding any termination of this Agreement for any reason whatsoever and with or without cause, the provisions of Sections 3.08 and 3.09 and any other provisions of this Agreement necessary to give efficacy thereto shall continue in full force and effect following any such termination.

10. **Warranty**

10.01 Servco provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

11. **Notices**

11.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

(a) in the case of Servco, to:

Parry Sound Hydro Corporation
125 William Street,
Parry Sound, Ontario P2A 1V9

Attention: President

Telephone: (705) 746-5866
Fax: (705) 746-7789

(b) in the case of Wiresco, to:

Parry Sound Power Corporation
125 William Street,
Parry Sound, Ontario P2A 1V9

Attention: President

Telephone: (705) 746-5866
Fax: (705) 746-7789

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and it sent by prepaid post, on the third day after mailing.

12. **Regulatory Changes**

12.01 The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the Parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 8.

13. **Relationship and Agency**

13.01 Servco's obligations in connection with this Agreement are contractual in nature only. The legal relationship between the Parties established by this Agreement is that of Servco serving solely as an independent contractor providing specified services to Wiresco on an arm's length basis and, without limitation, the relationship is not intended to be, and shall not, unless specifically provided herein, be deemed or considered to be, one of, joint venture, co-venture or trustee-beneficiary and therefore neither Party will owe any fiduciary or similar duty, other than pursuant to Section 13.02, to the other Party under this Agreement, all of which are expressly disclaimed.

13.02 Wiresco appoints Servco as its agent for the following purposes:

(a) the purposes set out in Section 6.03;

(b) purchasing and procurement, in accordance with the guidelines and policies of Wiresco in effect from time to time as notified to Servco;

(c) entering into agreements or other arrangements with builders, developers and similar parties with respect to the provision of electricity distribution and ancillary services, including without limitation agreements or other arrangements in respect of capital contribution;

(d) any other commercial arrangements as may be agreed to by the Parties from time to time for the purposes of carrying out this Agreement

14. **General Provision**

14.01 This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

14.02 For the purposes of this Agreement, whenever the term Servco or Wiresco is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

14.03 The division of this Agreement into Articles and Sections and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof and include any agreement or instrument supplemental or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

14.04 In this Agreement words importing the singular number only include the plural and plus overhead administration costs calculated at a percentage of the actual costs to be notified to Wiresco from time to time vice versa, words importing any gender include all genders and words importing persons include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and vice versa.

14.05 This Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof and cancels and supersedes any prior understanding and agreements between the Parties hereto with respect thereto. There are no representations, warranties, forms, conditions, undertakings or collateral agreements, express implied or statutory between the Parties other than as expressly set forth in this Agreement.

14.06 No amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the Parties hereto. No waiver of any breach of any term or provision of this Agreement shall be effective or binding unless made in writing and signed by the Party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

14.07 Except as may be expressly provided in this Agreement, neither Party hereto may assign his or its rights or obligations under this Agreement without the prior written consent of the other Party hereto.

14.08 If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof shall continue in full force and effect.

14.09 Each Party must from time to time execute and deliver all such further documents and instruments and do all acts and things as the other Party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement

14.10 This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written.

PARRY SOUND ENERGY SERVICES CORPORATION

Per: William Sheridan

Title:

PARRY SOUND POWER CORPORATION

Per: Joseph N Robinson

Title:

SCHEDULE "A"

Fees and Charges

Administration:	$Cost

All the following costs are per hour:

Field Employees:

Foreman	$60.00
Lead Crew Leader	$45.00
Journeyman	$40.00
Customer Service	$40.00
Plant Operator	$40.00

Equipment:

Single Bucket Truck	$30.00
Digger Derrick	$35.00
Double Bucket Truck	$45.00
½ Ton Truck	$10.00
Chain Saw etc.	$10.00

Extraordinary Services:	$ As Agreed
Ancillary:	$ As Agreed

*

* Saved As: servco-genco-wiresco, fees, schedule a

ATTACHMENT 2

CONNECTION AGREEMENT

BETWEEN

PARRY SOUND POWER CORP.

AND

PARRY SOUND POWERGEN CORP.

CONNECTION AGREEMENT

Between

PARRY SOUND POWER CORPORATION

And

PARRY SOUND POWERGEN CORPORATION

December 11th, 2001

DRAFT: November 9, 2001

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<u>Draft</u>
<u>November 9, 2001</u>

Connection Agreement

This Connection Agreement is made this ________day of _________, 2001

BETWEEN Parry Sound Power Corporation (the "Distributor"), a corporation incorporated pursuant to the laws of the Province of Ontario and licensed by the Ontario Energy Board Board.

PARTY OF THE FIRST PART;

and

Parry Sound Powergen Corporation (the "Generator"), a corporation incorporated pursuant to the laws of the Province of Ontario and licensed by the Ontario Energy.

PARTY OF THE SECOND PART.

From time to time, the Distributor and the Generator shall be individually referred to in this Agreement as "Party" and collectively as "Parties"".

RECITALS

Whereas the Generator is an embedded generator as that term is defined in the Code.

And Whereas, in accordance with its licence and the Market Rules, the Distributor has agreed to offer, and the Generator has agreed to accept, connection service to the Distributor's facilities ("Connection Service"), on the terms and subject to the conditions of this Agreement.

AGREEMENT

NOW THEREFORE in consideration of the foregoing, and of the mutual covenants, agreements, terms and conditions herein contained, the Parties, intending to be legally bound, hereby agree as follows:

1. DEFINITIONS

1.1 All defined terms that appear in this Connection Agreement (this "Agreement") that are not defined herein shall have the meanings ascribed thereto in the Distribution System Code ("the Code") issued by the Board in effect at the relevant time. All capitalized terms in the this Agreement shall have the same meaning as their capitalized counterparts as defined in the Code;

liquidation, dissolution, winding up, termination of existence, declaration of bankruptcy or insolvency or similar relief under any present or future law relating to bankruptcy, insolvency or other relief for or against debtors generally, and such order, judgment or decree remains unvacated and unstayed for 60 days (whether or not consecutive) from the day of entry; or if any trustee in bankruptcy, receiver, receiver and manager, liquidator or any other officer with similar powers is appointed for the Generator with its consent or acquiescence and that appointment remains unvacated and unstayed for 60 days (whether or not consecutive); or

1.11.3 The Distributor or the Generator becomes insolvent.

1.12 “non-defaulting Party" means a Party that is not a defaulting Party;

1.13 “non-financial Default’ means the following:

1.13.1 any breach of a term or condition of the Code or the Connection Agreement other than a financial default unless the breach occurs as a direct result of an emergency,

1.13.2 a licensed Party’s ceasing to hold a licence; and

1.13.3 an Insolvency Event.

1.14 "Distribution Services” means services related to the distribution of electricity and the services the Board has required distributors to carry out, for which a charge or rate has been approved by the board under section 78 of the Act;

2. PURPOSE OF AGREEMENT

This Agreement sets out the terms and conditions upon which the Distributor has agreed to offer, and the Generator has agreed to accept Connection Service.

3. DISTRIBUTION SYSTEM CODE

The Distribution System Code (the "Code") and this Agreement establish minimum testing, inspection, operational and maintenance standards for the Generator and the Distributor. The Parties hereto hereby agree to be bound by, and to act at all times in accordance with the Code which is hereby incorporated in its entirety by reference into, and which hereby forms part of this Agreement.

the Information solely for the requirements of the work as specified;

4.3.3 Information shall not be used for any commercial purpose of any kind whatsoever other than contemplated herein.

4.4 The Parties shall make the Information available to each other in a timely and co-operative manner.

4.5 The Information disclosed by the Parties in accordance with this section shall only be used by the recipient of the Information for the requirement of the work being performed including, but not limited to, planning or operating the Parties' facilities and shall not be used for any other purpose or disclosed to a third Party. All Information disclosed hereunder shall be confidential information except as provided in subsection 4.2 above.

4.6 A Party (Party "A") shall indemnify and save harmless the other Party (Party "B"), from and against any and all claims occasioned or suffered by Party "B" as a result of Party "A" disclosing any of the Information contrary to the provisions of this Agreement.

4.7 The Information ("Information") shall include, but not be limited to, the types set out below:

4.7.1 equipment capacities and ratings;

4.7.2 situations when equipment limits are being approached;

4.7.3 changes in the configuration of each Party's facilities (either permanent or temporary) that may affect each Party's system security, load distribution, protective relay settings, and other parameters;

4.7.4 details of defective equipment or hazardous conditions that may become known to one controlling authority but not to the other,

4.7.5 the date and time at which the Generator's facility was connected to or disconnected from the Distributor's distribution facilities;

4.7.6 megawatt and megavar readings, excluding revenue-metered quantities;

4.7.7 the date and time at which the supply circuit breaker or high voltage interrupting(HVI) switch of the Generator's facility automatically trips;

4.7.8 automatic relay protection operation at the Generator's facility impacting the the Distributor distribution facilities;

5. EQUIPMENT STANDARDS

5.1 The Distributor and the Generator shall ensure that their respective new or altered equipment connected to the distribution system: (1) meets requirements of the Ontario Electrical Safety Authority; (2) conform to relevant industry standards including, but not limited to, CSA International, the Institute of Electrical and Electronic Engineers (IEEE), the American National Standards Association (ANSI), and the International Electrotechnical Commission (IEC); (3) conforms to good utility practices.

5.2 The minimum inspection requirements for all equipment connected to the distribution system are set out in Appendix C of the Code. The Distributor shall provide the technical parameters to assist the Generator to ensure that the design of the Generator's equipment connected to the distribution system shall coordinate with the distribution system to achieve compliance with the Code and this Agreement.

5.3 The Distributor at its discretion, may participate in commissioning, inspecting, and testing the Generator's facilities to ensure that equipment connected to the distribution system will not materially reduce or adversely affect the current level of reliability of the distribution system.

5.4 The Generator shall permit the Distributor to participate in any necessary commissioning, inspection and testing of its generation facilities to ensure that their equipment connected to the distribution system will not adversely affect the reliability of the distribution system.

6. OPERATIONAL STANDARDS, REPORTING PROTOCOL AND LOAD FORECAST PROTOCOL

6.1 Equipment connected to the distribution system shall be operated and maintained in accordance with the Code and this Agreement.

6.2 The Generator shall promptly report to the Distributor any changes in its equipment that could materially affect the Connection Services provided.

6.3 The Distributor shall promptly report to the Generator any changes in its equipment that could materially affect the performance of the distribution system.

6.4 The Generator shall provide prompt notice to the Generator in accordance with the Code or as agreed in Schedule C to this Agreement before disconnecting its equipment from the distribution system.

6.5 Upon the Distributor's request, the Generator shall promptly report to the Distributor any and all incidents involving the automatic operation of the Generator's facility protective relaying that affect the Distributor's distribution facilities.

7.2 Involuntary Disconnection

The Distributor may disconnect the Generator's facilities at any connection point at any time throughout the term of this Agreement in any of the following circumstances:

i. in accordance with subsection 40(5) of the *Electricity Act*, applicable law, its licence, the Market Rules, or provisions set out in the Code and this Agreement;

ii. in obedience to a decision by an arbitrator or court in accordance with the dispute resolution procedure set out in this Agreement.

iii. during an emergency in accordance with the provisions of the Code, this Agreement, and the Market Rules;

iv. if required by an order or direction from the IMO in accordance with the Market Rules;

v. if the Generator is a defaulting Party; or

vi. upon termination of this Agreement.

7.3 Disconnection - General

7.3.1 The Generator shall continue to pay the applicable distribution rates during the notice period leading up to a disconnection.

7.3.2 The Generator shall pay all costs that are directly attributable to an involuntary disconnection, and decommissioning of its facilities, including the cost of removing any of the Distributor's equipment from the Generator's property and shall cooperate in establishing appropriate procedures for such decommissioning.

7.3.3 For the duration of the disconnection the Distributor shall not be obliged to fulfill any agreement to convey electricity to or from the Generator's facilities.

7.4 Reconnection after Involuntary Disconnection

7.4.1 The Distributor shall reconnect the Generator's facilities to its distribution facilities following an involuntary disconnection when it is reasonably satisfied that the emergency which was the cause of the disconnection has ceased or has been rectified and all other requirements and obligations contained in the Code and this Agreement have been complied with.

7.4.2 The Distributor shall reconnect the Generator's facilities to its distribution system following a non-emergency disconnection

9. REPRESENTATIONS AND WARRANTIES

9.1 Generator's Representations and Warranties

9.2.1 The Generator represents and warrants to the Distributor as follows, and acknowledges that the Distributor has relied upon such representations and warranties in entering into this Agreement:

i. that it has all the necessary corporate power, authority, and capacity to enter into this Agreement and to perform its obligations hereunder;

ii. that it has authorized by all required corporate action, the execution, delivery and performance of the terms, conditions, covenants and obligations contained in this Agreement;

iii. that its facilities meet the technical requirements of the Code and this Agreement, and

iv. that all required licences including but not limited to its Distributor or Generator licences, where one is required to carry out its business such as a Distributor and Generator licences, are in full force and effect.

9.2 Distributors' Representations and Warranties

9.2.1 The Distributor represents and warrants to the Generator as follows and acknowledges that the Generator is relying upon such representations and warranties in entering into this Agreement:

i. that it has all the necessary corporate power, authority .and capacity to enter into this Agreement and to perform its obligations hereunder;

ii. that its facilities meet the technical requirements of the Code and this Agreement:

iii. that it has authorized by all required corporate action, the execution, delivery and performance of the terms, conditions, covenants and obligations contained in this Agreement; and

iv. that its licence is in full force and effect.

10.4.2 The Distributor and the Generator shall comply with all requests by the other Party's controlling authority in accordance with this Agreement and the Code.

10.5 Communication Between the Parties

10.5.1 All communications between the Parties about day-to-day operating and maintenance matters shall at all times go through the controlling authorities, or those other persons to whom a controlling authority has delegated the communication authority.

10.5.2 Each Party shall provide the other with the name of a current 24 - hour contact to respond to operating and maintenance matters, which shall be listed in a schedule to the Agreement.

10.5.3 The Generator shall provide the Distributor with all necessary instructions for emergency responses, including reporting procedures and the names of site emergency co - ordinators.

10.5.4 The Distributor shall provide the Generator with all necessary instructions for emergency responses, including reporting procedures and the names of site emergency co-ordinators.

10.5.5 Either Party shall provide the other with all required work protection documentation and notices in writing, by facsimile distribution, or by such other means as they may agree on in writing.

10.5.6 Where one Party's work requires the other's participation or cooperation, or in the other's opinion could adversely affect normal operation of its facilities, the Parties shall establish procedures and cost sharing criteria for the work and adhere to them in performing the work unless they agree otherwise in writing.

10.6 Switching

10.6.1 A Party's controlling authority shall be responsible for establishing in writing for agreement by the other Party, the appropriate conditions for and the co-ordination of switching on the equipment under its control from time to time throughout the term of this Agreement.

10.6.2 When the Parties have so agreed in writing, one Party may appoint an employee of the other as its designate for switching-purposes.

10.6.3 The Generator shall comply with all switching instructions issued by the Distributor's controlling authority to maintain the security and reliability of the distribution system. The two controlling

10.8.2 The condition guarantee shall identify the Distributor's assigned equipment operating designations.

10.9 Alternative Method of Isolation

10.9.1 Either Party may establish its own work protection in place of a condition guarantee.

10.9.2 The controlling authority of the facilities required to establish the work protection shall provide the other Party with access to such facilities.

10.9.3 Establishing work protection shall be limited to hanging tags and locking of devices.

10.10 Forced Outage

10.10.1 When a forced outage by one Party adversely affects the other's facilities, the first Party's controlling authority shall give prompt notice to the controlling authority of the second Party.

10.10.2 Each Party's controlling authority shall have sole authority to identify the need for and initiate a forced outage on equipment under its control.

10.11 Scheduling of Planned Work

10.11.1 The Generator shall schedule all planned work with the Distributor's controlling authority to co-ordinate outages that directly affect the Distributor's distribution facilities.

10.11.2 The Generator shall, take all reasonable steps to ensure that its anticipated and planned outages for the upcoming year are submitted to the Distributor by October 1st of each year.

10.11.3 At least four days in advance of planned work that requires a feeder breaker to be opened or operated and at least ten days in advance of planned work that requires operations of multiple feeder breakers, station bus or a whole transformer station, the Generators controlling authority shall fax requests to the appropriate Distributor contact identified in the operations schedule of this Agreement.

10.11.4 At least four days in advance of planned work, the Generator's controlling authority shall fax requests to the appropriate Distributor contact identified in the operations schedule if the planned work involves:

i. any disconnection from the Distributor's distribution facilities of less than 50 kV e.g. disconnection from a

10.13.3 The Distributor may be required from time to time to implement load shedding as outlined in this Agreement, Schedule C, section 7.

10.13.4 The Generator shall identify the loads (and their controllable devices) to be included on the rotational load shedding schedules to achieve the required level of emergency preparedness.

10.13.5 The Distributor may review the rotational load-shedding schedule with the Generator annually or more often as required.

10.13.6 The Generator shall comply with all requests by the Distributor's controlling authority to shed load. Such requests shall be initiated to protect distribution system security and reliability in response to a request by the IMO.

10.13.7 When the Distributor's distribution facilities return to normal, the Distributor's controlling authority shall notify the Generator's controlling authority to re-energize the Generator's facilities.

10.13.8 The Distributor may be required from time to time to interrupt supply to the Generator during an emergency to protect the stability, reliability, and integrity of its own facilities and equipment, or to maintain its equipment availability. The Distributor shall advise the Generator as soon as possible/practical of the distribution system's emergency status and when to expect normal resumption and reconnection to the distribution system.

10.14 Access and Security of Facilities

10.14.1 Each Party shall co-operate with the other to ensure that its respective facilities and assets are secure at all times.

10.14.2 Each Party shall follow all applicable procedures and staff training procedures required for expeditious access to the other Party's equipment or premises, including, without limitation, any procedures regarding access codes and keys.

10.14.3 Certain of each Party's facilities may, at the date of this Agreement or later, be on one or more of the other Party's sites, in accordance with each Party's policies and procedures.

10.14.4 Either Party and its representatives shall be entitled to access to the other's facilities or site, and the host Party shall grant such access, to carry out work at all reasonable times on reasonable prior notice to the host Party, subject to each Party's policies and procedures.

10.14.5 If either Party or its representatives wishes to have access to the other's facilities, the accessing Party shall notify the host Party of

11.2 Termination by a Non-Defaulting Party

A non-defaulting Party may terminate the Agreement at anytime during the term or any renewal thereof by giving the other Party six months prior written notice setting out the termination date. Termination in the event of a default shall follow the procedures set out in section 12.4 of this Agreement.

11.3 Right to Disconnect

If a non-defaulting Party gives notice to terminate the Agreement under section 12.2.1, the Distributor shall disconnect the connection point on the termination date specified in that notice or on another date that the Parties have agreed upon in writing.

11.4 Right to Remove Assets

11.4.1 When a non-defaulting Party has terminated the Agreement under section 8.2.1, the Distributor may disconnect the connection point and shall be entitled to de-commission and remove any of its assets associated with the connection and the connection point.

11.4.2 The Distributor shall notify the Generator in writing of the days the de-commissioning and removal of its assets shall occur, and the Generator shall provide the Distributor with any and all access to the Generator's site, provided such dates and times are reasonable to both Parties, that may be required by the Distributor to de-commission and remove its assets.

12. EVENTS OF DEFAULT AND TERMINATION

12.1 Occurrence of an Event of Default

If an event of default occurs, the non-defaulting Party may (without prejudice to its other rights and remedies as provided for in this Agreement) serve the defaulting Party with a default notice specifying the event of default that has occurred.

12.2 Cure Periods

12.2.1 In the event of a non-financial default and upon service of a default notice, the defaulting Party shall be entitled to remedy the default specified in the default notice either:

i. within the Cure Period specified in Schedule B of this Agreement from the date of receiving the specified default notice; or

12.4 Right to Terminate and Disconnect when an Event of Default Occurs

12.4.1 A non-defaulting Party may, without prejudice to other rights and remedies provided for in this Agreement with respect to an Event of Default, which has not been remedied within the periods set forth below, terminate this Agreement by written notice to the defaulting Party:

12.4.2 For an unremedied non-financial default, by giving twenty business days' notice in writing to the defaulting Party, stating its intention to terminate by the expiry of that notice period; or

12.4.3 For an unremedied financial default, subject to giving seven business days notice in writing to the defaulting Party, stating its intention to terminate by the expiry of that notice period.

12.5 Effect of Termination and Remedies

12.5.1 Neither the Distributor nor the Generator may terminate the Agreement except in accordance with the applicable provisions set out in the Code or this Agreement.

12.5.2 If either the Distributor or the Generator chooses to terminate this Agreement pursuant to its rights under section 12.4, then upon termination the Agreement will, subject to section 12.5.3, be of no further force and effect.

12.5.3 The termination of this Agreement shall not affect any rights or obligations of either Party that may have accrued before termination, nor affect either Party's rights or obligations as set out in section 4, section 8 and section 13 of this Agreement, which will continue in full force and effect notwithstanding the termination of the Agreement.

12.5.4 Subject to section 13, upon termination of this Agreement, the non-defaulting Party choosing to terminate may pursue all available remedies including:

i. sue the defaulting Party to recover damages for that event of default and, if it is a financial default, to recover the amounts owed including interest to be calculated using the Distributor's approved debt rate at the relevant time;

ii. exercise all available legal and equitable remedies including, without limitation, injunctive relief or such other relief as it deems appropriate; and chosen by the Generator and to a designated representative chosen by the Distributor for resolution on an informal basis.

13.2.2 Such designated representatives shall attempt in good faith to resolve the dispute within thirty days of the date when the dispute was referred to them, except that the Parties may extend such period upon which they agree in writing.

13.2.3 Any resolution of the dispute by the designated representatives shall be in writing and shall be executed by an authorized signing officer of each Party. The resolution shall bind the Parties and their respective successors and assigns, and shall not, except for either Party's subsequent failure to abide by the resolution, from then on be subject to arbitration or challenge in any court or other tribunal.

14. FORCE MAJEURE

14.1 Definition

14.1.1 For the purposes of this section,"Force Majeure" or "an event or circumstance of Force Majeure" means any act of God, labour disturbance, act of a public enemy, war, insurrection, riot, fire, storm or flood, earthquake, or explosion; any curtailment, order, regulation, or restriction imposed by govern•mental, military or lawfully established civilian authorities; or any other cause beyond a party's reasonable control.

14.2 Limitation

14.2.1 Subject to section 14.3, neither Party shall be held to have committed an event of default in respect of any obligation under this Agreement if prevented from performing that obligation, in whole or in part, because of a force majeure event.

14.3 Obligations in the Event of a Force Majeure

14.3.1 If a force majeure event prevents a Party from performing any of its obligations under the Code and this Agreement, that Party shall:

i. promptly notify the other Party of the force majeure event and its assessment in good faith of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practicable.

ii. not be entitled to suspend performance of any of its obligations under this Agreement to any greater extent or

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that could reasonably be expected to affect [illegible] distribution system. The Generator shall [illegible] reasonable costs associated with such tes[illegible] the Distributor, the Generator shall pr[illegible] approval, or exemption, from the On[illegible] Authority.

15.1.6 The Distributor has the right to specify by addendums to this Agreement the types of changes that require prior approval of the Distributor before the Generator implements such changes. Such changes, that require prior approval of the Distributor, shall be set out in Schedule A of this Agreement, and shall be limited to those that can have material adverse effect(s) on the Distributors' distribution facilities or facilities of its other generators.

15.2 Right of Entry

15.2.1 The Generator shall allow the Distributor access to its facilities subject to the Code and this Agreement to assess compliance, or to investigate any possible past or potential threat to the security of the distribution system.

16. GENERAL TECHNICAL REQUIRMENTS

The Distributor and the Generator shall follow the general technical requirements set out in Schedule D of this Agreement.

17. TECHNICAL REQUIREMENTS FOR GENERATORS

The Distributor and the Generator shall follow the technical requirements for Generators set out in Schedule E of this Agreement.

18. PROTECTION SYSTEM REQUIREMENTS

The Distributor and the Generator shall follow the protection system requirements set out in Schedule F of this Agreement.

19. OWNERSHIP OF FACILITIES

19.1 The Distributor has ownership of **[28 KV & 44 kV?]** feeders from the flexible connection at Parry Sound station terminations. Specifically, the Distributor owns the **[describe feeder and give details of what other facilities at Generator's site are owned by the distributor].**

19.2 The Generator owns all equipment at the Generator's site with the exception of equipment specifically identified above.

20. DISTRIBUTION SERVICE

The Distributor hereby agrees to provide the distribution service to the Generator, and the Generator hereby agrees to accept the distribution services as outlined in the

(a) to the Distributor: **Parry Sound Power Corporation**
125 William Street,
Parry Sound, Ontario P2A 1V9

Attention: President
Fax: (705) 746-7789

(b) to the Generator: **Parry Sound Powergen Corporation**
125 William Street,
Parry Sound, Ontario P2A 1V9

Attention: President
Fax: (705) 746-7789

Notice sent in accordance with this section shall be deemed to have been delivered and received:

(a) if delivered by hand, upon receipt,

(b) if delivered by electronic transmission, 48 hours after the time of transmission, excluding from the calculation weekends and public holidays;

(c) if delivered by registered mail, six (6) days after the mailing thereof, provided that if there is a postal strike such notice shall be delivered by hand.

24. ASSIGNMENT

The rights and obligations under this Agreement may not be assigned by the Generator to any other person without the prior written consent of the Distributor which consent shall not be unreasonably withheld.

25. FURTHER ASSURANCES

Each Party shall, upon the reasonable request of the other, do or cause to be done all further lawful acts, deeds, assurances whatever in order to more effectively carry out the intent and purpose of this Agreement.

26. WAIVER

The failure of any Party to exercise any right, power or option or to enforce any remedy or to insist upon the strict compliance with the terms, conditions and covenants of this Agreement shall not constitute a waiver of the terms, conditions and covenants herein with respect to that or any other or subsequent breach thereof nor a waiver by the Party at any time thereafter to require strict compliance with all terms, conditions and covenants hereof, including the terms, conditions and covenants with respect to which the Party has failed to exercise such right, power or option. Nothing shall be construed

SCHEDULE B

CURE PERIODS FOR NON-FINANCIAL DEFAULT EVENTS

Areas of Impact	Cure Period
Safety - Immediate	Promptly
Environment - Immediate	Promptly
Asset Integrity	Promptly
Security	*(not applicable - IMO accountability addressed in Market Rules)*
Adequacy	*(not applicable - IMO accountability addressed In Market Rules)*
Safety - Potential	10 DAYS
Power Quality	30 DAYS
Environment - Potential	30 DAYS
Maintenance	60 DAYS
Any Other Areas of Impact	**30 DAYS**

Areas of Impact

Safety - Immediate: Any aspect that could result in immediate injury or loss of life (e.g. exposed Wires, destroyed station fence, etc.).

Environment - Immediate: Any aspect that could result in immediate impact on the natural system of land air, water, plants, and animals, including humans and their social, economic and cultural interactions with the system.

Asset Integrity: The extent to which an asset is operated within prescribed ratings (voltage, thermal, short circuit) and maintained to required standards to prolong asset life-span and satisfy safety and environmental requirements.

Security: The ability of the transmission system to withstand sudden disturbances such as short circuits or unanticipated loss of system facilities.

Adequacy: The ability of the transmission system to supply the aggregate electrical demand and energy requirements of the Customer's at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements or components.

Safety - Potential: The threat to human life depends on the occurrence of a single contingency (e.g. substandard grounding)

Power Quality: Any variation in electric power service resulting in misoperation or failure of end-use equipment such as voltage sag, over-voltage, transients, harmonic distortion and electrical noise.

SCHEDULE C

DETAILS OF SPECIFIC OPERATIONS

1. **Telephone Contacts**

Either Party has the right to change the position designations and telephone numbers listed below with immediate effect at any time by notice in writing delivered to the other Party by fax or other telegraphic means. Any employee of a Party with apparent authority may deliver such a notice to the other Party.

Day-to-Day Operations
For the operation of the Distributor's distribution facilities and the Generator's facilities.

	Distributor	Generator
Operating Contacts:		
Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		
Outage Planning:		
Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		
Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		
Position:		
Name:		
Location:		
Phone Number:		
Fax Number		

Notes:

(d) Notification of any changes to the controlling authority shall be exchanged between the Distributor and the Generator as follows:

Distributor	The Generator
Director - Distribution Operations Division	General Manager [Appropriate level of Management to be identified by the Generator]
All affected Controlling Authorities and Distribution Operations Management Centre	All affected Controlling Authorities

The Generator owns:

The Generator has operating control of:

The Distributor owns:

The Distributor has operating control of:

4. **Single Line Diagram**

This diagram is based on the operating diagram.

5. **Metering Facilities Diagram**

This diagram is based on the protection, control, and metering diagram.

6. **Normal Operations**

This Schedule shall include Generator-specific Information during normal operations.

7. **Emergency Operations**

This Schedule would include Generator specific Information during Emergency operations.

(a) **Scope:**
This instruction assigns authority and defines responsibilities for manual primary load shedding that may be required to correct abnormal conditions on the IMO-controlled grid or the Distributor's distribution facilities. Procedures are also outlined for conducting simulation of rotational load shedding.

(b) **Information:**
From time to time the IMO-controlled grid or the Distributor's distribution facilities may experience abnormal conditions. To minimize their impact, and to restore and maintain security of operations, prompt control action

The Distributors controlling authority will confirm the request and both operators will remain on line to review procedure and collect Information.

8. **Re-verification Schedules-Protection and Control (sample only)**

1. The Generator shall re-verify its station protections and control systems that can impact on the Distributor's distribution system.. The maximum verification or re-verification interval is: four (4) years for most of the 115 kV distribution system elements including transformer stations and distribution lines, and certain 230 kV distribution system elements; and two (2) years for all other high voltage elements. The maintenance cycle can be site specific.

2. The Generator shall advise the Distributor at least fourteen (14) business days' notice of its intention to conduct a re-verification test, so that the Distributor's protection and control staff and system performance staff (if required) can observe.

   a) re-verification of protection equipment settings specified in this Agreement.

   b) relay recalibration

   c) test tripping of station breakers that impact on the Distributor/Generator interface measurement and analysis of secondary AC voltages and currents to confirm measuring circuit integrity as well as protection directioning.

   d) measurement and analysis of secondary AC voltages and currents to confirm measuring circuit integrity.

   Note: All tests must be coordinated and approved ahead of time through the normal outage planning process.

3. The following specific actions are required:

   a) observe all station protections that trip and open the "enter the devices that interface with the Distributor" for proper operation

   b) confirm that settings approved by the Distributor are applied to the following protections:

      i. over and under voltage;
      ii. transformer differential;
      iii. transformer phase and ground backup protection;
      iv. line protections;
      v. breaker or HVI failure protection; and
      vi. transfer and remote trip protections.

e) Reverification Schedule

Routine Maintenance on communication equipment and the communication channels must be performed every two years.

f) Inventory of Communication Equipment

The provision of spare communication equipment is the Generators' responsibility and will be located at its site.

g) Failure of Communication Equipment

If a communication failure affects either the transfer trip channels or the blocking channels:

The Distributor will decide whether or not the Generator should remain connected to the high-voltage system. The Distributor must advise the Generator, through the appropriate communication protocol outlined in this code, of the situation, the choices available to the Generator and the risks involved. Since the Distributor will take the decision according to its own interests, the Generator can choose to remain or separate from the high-voltage system at its own risk.

h) Mean Time for Repairs

The mean time for repairs will be within two working days, dependent on the availability of staff of Bell Telephone and the Distributor.

i) Provision of Purchase Order by Generator to Distributor

The Generator will provide the Distributor's designated leader with a purchase order, so that the Distributor may apply appropriate charges to the Generator.

iv. if equipment owned by either Party interferes with the operation of the distribution system; or as directed by the IMO.

1.3 Protection and Control

1.3.1 The protection systems, which protects distribution system elements, shall be capable of minimizing the severity and extent of disturbances to the distribution system while themselves experiencing a first-order single contingency such as the failure of a relay protection em to operate or the failure of a breaker to trip. In particular

i. the elements designated by the Distributor as essential to system reliability and security shall be protected by two protection systems. Each system shall be independently capable of detecting and isolating all faults on those elements. These elements shall have breaker failure protection, but breaker failure protection need not be duplicated. Both protection systems shall initiate breaker failure protection;

ii. to reduce the risk of both systems being disabled simultaneously by a single contingency, the protection system designs shall not use components;

iii. the use of two identical protection systems is not generally, recommended, because it increases the risk of simultaneous failure of both systems due to design deficiencies or equipment problems;

iv. the protection systems shall be designed to isolate only the faulted element. For faults outside the protected zone, each protection system shall be designed either not to operate or to operate selectively in coordination with other protection systems;

v. Generator protection settings for protections affected by conditions on the distribution system shall be coordinated with those of the distribution system;

vi. protection systems shall not operate to trip for stable power swings following contingencies that are judged by protection system designers as not harmful to the distribution system or its Generators;

vii. the components and software used in all protection systems shall be of proven quality for effective utility application and following good utility practice;

viii. critical features associated with the operability of protection systems and the high voltage interrupting device (HVI) shall be annunciated or monitored;

1.5.2 Each transformer, switching, or generating station shall have structures, metallic equipment and non-energized metallic eg. type and requirements for the ground grid are site-specific, ck station size, and short-circuit level.

1.5.3 The Distributor shall review the ground potential rise (GPR) Generators cost. The Generator shall comply with the Bell System Practices as they may be amended or modified from time to time and the IEEEb standard 487 as it may be amended or modified from time to time for providing special high-voltage protection devices on metallic communication cables. The Distributor assumes no responsibility for the adequacy of design or correctness of the operation of any equipment or apparatus associated with the Generator's installation.

1.5.4 The placement of any additional grounding points on the distribution system shall require the approval of the Distributor. The Distributor shall give its approval if it is satisfied that the reliability of its distribution system is not affected.

1.6 Telemetry, Monitoring, and Telecommunications

1.6.1 The Distributor shall advise the Generator of the performance and serve them. Some requirements depend on the size and specific location of the connection to the distribution system. As a minimum, telemetry shall be required for the flow of real and reactive power through circuits and transformers, the voltages at selected points, and the status (open or closed) of switching elements.

1.6.2 A Distributor may require a Generator to install monitoring equipment to track the performance of its facilities, identify possible protection system problems, and provide measurements of power quality. As required, the monitoring equipment shall perform one or several of the following functions:

i. sequence of events recording (SER) to record protection related events at a connection

ii. digital fault recording (DFR) to permit analysis of distribution system performance under normal and abnormal conditions; or

iii. power quality monitoring (PQM) to record voltage transient surges, voltage sags and swells, voltage unbalance, supply interruptions, frequency variations and other voltage and current waveform monitoring;

1.6.3 The Generators' telecommunications facilities shall be compatible with those of the Distributor and have similar reliability and performance characteristics. At the Distributor's discretion, some or all of the following functions may require telecommunication: protection systems, system control and data acquisition (SCDA) voice communication, and special protection systems (e.g. generation rejection or runback)

1.7.6 If the Distributor requires changes, then the Parties shall act in good faith to reach agreement and finalize the commissioning program within a reasonable period.

1.7.7 The Generator shall submit the results of the commissioning tests to the Distributor and must demonstrate that all its equipment complies with the Code and this Agreement.

1.7.8 If the commissioning test reveals non-compliance with none or more requirements of the Code or this Agreement, the Generator whose equipment was tested shall promptly meet with the Distributor and agree on a process aimed at achieving compliance.

1.7.9 The Distributor may withhold permission to complete the commissioning and subsequent connection of the Generator to the distribution system if the relevant equipment fails to meet any technical requirement stipulated in the Code or this Agreement.

1.7.10 All reasonable costs incurred or associated with Distributor's witnessing of the verification tests shall be borne by the Generator.

1.8 Procedures for Maintenance and Periodic Verification

1.8.1 The Distributor may at its sole discretion specify the maintenance criteria and the maximum time intervals between verification cycles for those parts of Generators facilities that may materially adversely affect the distribution system. The obligations for maintenance and performance re-verification shall be stipulated in the appropriate schedule to this Agreement.

1.8.2 Test switches shall be provided to isolate current and potential transformer input to the relays as well as a set of switches to isolate the relays tripping outputs from the power equipment control circuitry.

1.8.3 The reasonable cost of conducting maintenance and verification tests shall be borne by the Generator.

1.8.4 The Distributor may appoint a representative to witness relevant maintenance and verification tests and the Generator shall permit the representative to be present while those tests are being conducted.

1.8.5 To ensure that the Distributor's representative can witness the proposed test procedures and a test schedule to the Distributor not less than ten business days before it proposes to carry out the test. Following receipt of the technical reasons the testing for as long as ten business day.

1.8.6 The reasonable costs associated with the witnessing of verification tests by the Distributor's representative shall be borne by the Generator.

1.8.7 If a verification test reveals that the electrical equipment or operations schedule does not comply oath requirements, the

Schedule D (Cont'd)

Exhibit D.1 Protection System Symbols and Devices

[insert diagram]

The Customer must be able to isolate (self-contain) his internal problems without having a major impact on the transmission system. Under certain circumstances, HV breakers may not transformers, provided that a motorized disconnect switch and redundant provided to isolate the transformer at the terminal stations if a fault occurs in I

Medium-voltage buses require either duplicated differential protection or a single differential protection with an overcurrent backup.

1.5.2 Following a protection operation on a distribution line, the network switching and/or transformation stations, shall reclose shall provide a reliable means of disconnecting its equipment responsible for protecting its own equipment and the Transmitter is not liable for damage to the Generator's equipment. The Generator may request a means of supervising the transmission reclosure prior to the disconnection of its equipment e.g. changes in protection logic at one or both stations to reduce the risk of such events.

1.5.3 A Generator's distribution system breaker shall not autoreel

1.5.4 Manual energization of a Distributor's line by a Generatoes Distributor's direction.

1.2 Test Schedule for Relaying Communication Channels

1.2.1 Communication channels associated with protective relaying shall be tested at periodic intervals to verify that the channels are operational and that their characteristics lie within specific tolerances. The testing consists of signal adequacy tests and channel performance tests.

i. signal adequacy test intervals are:

(a) Channels - for Protection (unmonitored) at one(l)-month intervals

(b) Channels for Protection (monitored) at twelve(12)-month intervals

ii. channel performance testing on leased communication circuits shall be conducted at 24-month intervals, while intervals for testing power line carrier equipment shall be equipment-specific.

1.3 Verification and Maintenance Practices

1.3.1 Generators shall perform routine verifications of protection systems on a scheduled basis as specified by the Distributor in accordance with applicable reliability standards. The maximum verification interval is four years for most 11 5-kV elements, most transformer stations, and certain 230-kV elements and two years for all other high- voltage elements. All newly commissioned protection systems shall be verified within six months of the initial in-service date of the system.

1.3.2 Routine verification shall ensure with reasonable certainty that the protections respond correctly to fault conditions.

1.3.3 An electrically initiated simulated-fault clearing check is mandatory to verify new protections, after any varying or component changes are made to a protection, and for routine verification *of* a protection.

1.3.4 The Generator shall ensure that the functional testing of protection and metering can be properly performed and that all verification readings are obtainable.

1.3.5 The Distributor shall co-ordinate the initial verification upon receipt of the approved and final set *of* drawings. The initial verification shall be used during the final commissioning phase of the station and shall be used as a basis for future periodic verifications.

1.3.6 the Distributor and Customers shall agree upon the final functional test procedures before the tests begin. If they cannot agree, the supply or continuity of supply shall depend on the performance of the tests that the Distributor shall require.

1.6.5 Interconnected current transformer secondary wiring and voltage transformer secondaries shall each be grounded at only a single point.

1.7 Battery Banks and Direct Current Supply

1.7.1 When station battery banks are used, as a minimum requirement the Generator shall ensure that if either the battery charger fails or the AC supply source fails, the station battery bank shall have enough capacity to allow the station to operate for at least eight hours.

1.7.2 Critical DC supplies shall be monitored and annunciated such as relay protection circuits and high voltage interrupters (HVIs).

1.7.3 Where the use of a single battery bank is allowed, the following conditions shall be met:

i. it can be tested and maintained without removing it from service;

ii. where two separate protective systems are required, each protection system shall be supplied from physically separated and separately fused direct current circuits; and

iii. no single contingency other than failure of the battery bank itself shall prevent successful tripping for a fault.

SCHEDULE H

DATA THAT DISTRIBUTOR MUST SUBMIT TO GENERATOR

(a) The following Information shall be made available to the Generator, provided that:

(1) such data is available; (2) the confidentiality of Information process and safeguards are not violated:

feeder amperes per phase,
bus voltage,
real and reactive power flow per feeder (where available; otherwise per bus level),
feeder breaker open/close status,
feeder breaker recloser blocked/not blocked status,
bus tie breaker open/close status,
capacitor bank breaker open/close status,
energy pulse output in kW.h and kvar.h per Generator feeder.
energy pulse output in kW.h and kvar.h per station bus.
transformer/bus breaker open/close status.

(b) Other Information: to be specified based on site specific considerations.

RESOLUTION OF THE BOARD OF DIRECTORS

OF

PARRY SOUND POWER CORPORATION

RESOLVED that the Corporation accept the Connection Agreement between the Corporation and Parry Sound PowerGen Corporation.

The undersigned being the Board Members of the Corporation hereby sign the foregoing Resolution pursuant to the Business Corporations Act (Ontario) as of the 11th Day of December, 2001.

Joseph R. Robinson

Joseph Robinson

Bill Sheridan

Bill Sheridan

Ted Knight

Ted Knight

RESOLUTION OF THE BOARD OF DIRECTORS

OF

PARRY SOUND POWERGEN CORPORATION

RESOLVED that the Corporation accept the Connection Agreement between the Corporation and Parry Sound PowerGen Corporation.

The undersigned being the Board Members of the Corporation hereby sign the foregoing Resolution pursuant to the Business Corporations Act (Ontario) as of the 11th Day of December, 2001.

Joseph N Robinson

Joseph Robinson

Bill Sheridan

Bill Sheridan

Ted Knight

Ted Knight

ATTACHMENT 3

SERVICE AGREEMENT

BETWEEN

PARRY SOUND HYDRO CORP.

AND

PARRY SOUND POWER CORP.

SERVICES AGREEMENT

THIS AGREEMENT made this 28 day of Nov , 2001

BETWEEN:

PARRY SOUND HYDRO CORPORATION

(hereinafter referred to as "Holdco")

OF THE FIRST PART

- and -

PARRY SOUND POWER CORPORATION

(hereinafter referred to as "Wiresco")

OF THE SECOND PART

WHEREAS each of Holdco and Wiresco are duly incorporated pursuant to Section 142 of the *Electricity Act, 1998*;

AND WHEREAS the Parties have agreed that Holdco shall provide such services as may be agreed by the Parties from time to time;

AND WHEREAS the Parties acknowledge and agree that in providing services Holdco acts as an independent contractor and not as an agent, partner, or servant;

NOW THEREFORE IN CONSIDERATION of mutual covenants and agreements as set forth herein, and for other good and valuable consideration (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties do hereby covenant and agree with each other, as follows:

1. **Definitions**

1.01 **"Effective Date"** means November 7, 2000.

1.02 **"Parties"** means Holdco and Wiresco.

1.03 **"Services"** means the administrative and corporate services that Holdco shall agree to provide and Wiresco shall agree to purchase from time to time.

2. **Term**

2.01 Unless terminated in accordance with Article 6 of this Agreement, the term of this Agreement shall be from the Effective Date to and including December 31, 2003 and the term shall be extended automatically for further periods of two years each, unless either Party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. **Covenants**

3.01 Holdco agrees to provide and Wiresco agrees to purchase the Services.

3.02 Holdco shall indemnify and save Wiresco harmless from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which Wiresco or its officers, employees or agents may suffer as a result of the negligence of Holdco in the performance or non-performance of this Agreement.

3.03 Holdco shall not (either during the term of this Agreement or at any time thereafter) disclose any information relating to the private or confidential affairs of Wiresco or relating to any secrets of Wiresco to any person other than with the consent of Wiresco.

4. **Fees**

4.01 Wiresco shall pay to Holdco fees equal to the cost to Holdco of providing the Services.

5. **Invoicing**

5.01 Holdco shall submit an invoice within five (5) days from the end of each month to Wiresco for payment for all estimated costs incurred by Holdco in providing the Services for such month. All monthly invoices shall provide sufficient detail of the estimated costs incurred and the description of the Services undertaken by Holdco. All invoices shall be paid by Wiresco within ten (10) days from the date of receipt.

6. **Termination**

6.01 In the event of non-performance by either Party of its obligations under this Agreement, the other Party may at its sole option elect to terminate this Agreement provided that the defaulting Party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

6.02 Notwithstanding any termination of this Agreement for any reason whatsoever and with or without cause, Sections 3.02 and 3.03 and any other provisions of this Agreement necessary to give efficacy thereto shall continue in full force and effect following any such termination.

7. **Notices**

7.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

(a) in the case of Holdco, to:

Parry Sound Hydro Corporation
125 William Street,
Parry Sound, Ontario P2A 1V9

Attention: President

Telephone: (705) 746-5866
Fax: (705) 746-7789

(b) in the case of Wiresco, to:

Parry Sound Power Corporation
125 William Street,
Parry Sound, Ontario P2A 1V9

Attention: President

Telephone: (705) 746-5866
Fax: (705) 746-7789

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and it sent by prepaid post, on the third day after mailing.

8. **Regulatory Changes**

8.01 The Parties acknowledge that substantial changes to legislation and regulations and government policies may occur during the term of this Agreement which may affect the nature of the relationship between them, and as consequence the Parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment.

9. **Relationship**

9.01 Holdco's obligations in connection with this Agreement are contractual in nature only. The legal relationship between the Parties established by this Agreement is that of Holdco serving solely as an independent contractor providing specified services to Wiresco on an arm's length basis and, without limitation, the relationship is not intended to be, and shall not be deemed or considered to be one of agency, joint venture, co-venture, or trustee-beneficiary and therefore neither Party will owe any fiduciary or similar duty to the other Party under this Agreement, all of which are expressly disclaimed.

10. **General Provisions**

10.01 This Agreement shall enure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

10.02 The division of this Agreement into Articles and Sections and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof and include any agreement or instrument supplemental or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

10.03 In this Agreement words importing the singular number only include the plural and vice versa, words importing any gender include all genders and words importing persons include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and vice versa.

10.04 This Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof and cancels and supersedes any prior understanding and agreements between the Parties hereto with respect thereto. There are no representations, warranties, forms, conditions, undertakings or collateral agreements, express implied or statutory between the Parties other than as expressly set forth in this Agreement.

10.05 No amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the Parties hereto. No waiver of any breach of any term or provision of this Agreement shall be effective or binding unless made in writing and signed by the Party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

10.06 Except as may be expressly provided in this Agreement, neither Party hereto may assign his or its rights or obligations under this Agreement without the prior written consent of the other Party hereto.

10.07 If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof shall continue in full force and effect.

10.08 Each Party must from time to time execute and deliver all such further documents and instruments and do all acts and things as the other Party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement

10.09 This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written.

PARRY SOUND HYDRO CORPORATION

Per:

Name:
Title:

PARRY SOUND POWER CORPORATION

Per:

Joseph N Robinson.

Name:
Title:

Purchase of Services

Table 4 Purchase of Services List

Company	Description	Contract/Cost	Total Cost
AESI Acumen Engineered Solutions	2007 ESA Audit	Cost	1,804.32
Bell Canada	Primary Metering	Contract	13,517.29
Bell Canada Special Billing	Pole Rentals	Contract	11,788.93
Cam Tran Co. Ltd	Operations Supplies	Cost	3,882.84
Canada Brokerlink(Ontario)Inc	Insurance renewal 2007-2008	Contract	12,140.28
Canada Post Corporation	Postage	Cost	19,991.24
CHEC	Membership Dues	Contract	4,452.88
Collus Power Corp.	Load Management Services	Contract	384.67
Cull, Gordon & Gingrich	Audit fees	Contract	7,950.00
De Lage Landen Financial Services Canada	Lease Pymt-Postage Machine	Contract	2,857.03
Dearness Enviromental Society	DC Academic Program	Cost	9,817.45
Electrical Safety Authority	2007 Regulatory Oversight Cost Recovery Acct#27660	Cost	2,655.89
Elster Metering	Meters	Cost	10,041.29
Environment Network	Supplies	Cost	14,917.14
General Electric Canada Inc	Oil samples & Analysis; Transformer Rental & Inspections	Contract	85,527.94
Gord Eamer Enterprises	Third Tranche CDM-Jun/07 Assistance	Contract	2,227.43
Grafton Utility Supply	Transfomers and Supplies	Contract	36,759.28
Green Group	conservation activities/programs	Contract	13,960.30
Harris	Remote Consulting Services with Carrie Allen	Cost	1,160.52
HD Supply Utilities	Transformers and Supplies	Cost	36,020.80
Home Hardware	Miscellaneous Supplies	Cost	8,151.20
Hydro One Networks Inc	Connection & Network Charges	Contract	1,102,821.32
Independent Electricity System Operator	Power Purchased	Contract	6,795,861.21
Metroland NorthMedia	Newspaper Ads	Cost	2,920.30
MINISTER OF FINANCE-CORP TAX	2007 PIL Installment	Cost	8,151.00
Minuteman Press	Envelopes, Bill Inserts, misc forms,	Cost	1,383.16
Nedco	Operations Supplies	Cost	1,411.32
North Star/Beacon Star	Newspaper Ads	Cost	5,436.74
Olameter Inc	Meter Testing	Cost	4,287.54
Ont Electricity Finance Corp-Pils	Payments in Lieu of Tax	Cost	165,844.95
Ontario Electricity Financial Corporation	Debt Retirement Charge	Cost	575,948.64
Ontario Energy Board	Assessments	Cost	12,705.25

Company	**Description**	**Contract/Cost**	**Total Cost**
Parry Sound Area Chamber of Commerce	Membership Dues & Home Show Booth Registration Cost	Cost	1,157.20
Parry Sound District Housing	Purchase of Refrigerators & Light Replacements	Cost	14,105.60
Parry Sound Energy Services Corporation	Labour, equipment, admin and office costs purchased from Affiliate	Contract	966,109.24
Parry Sound Powergen Corporation	Cost of Power purchased from affiliate	Contract	291,234.68
Parry Sound Hydro	Director's Fees Invoiced from Holding Company	Cost	6,467.68
Peterborough Utilities Services Inc	MSP Billing	Contract	3,498.00
Receiver General	GST	Cost	218,058.07
Savage Data Systems Ltd	Settlement Services	Contract	33,512.96
T.D.Canada Trust	Miscellaneous Payments-retailers, visa, pap etc	Cost	1,034,034.80
T.D.Visa	Visa Charges	Cost	13,547.61
The ITM Group	Network Management, Spare Router, Email Access etc	Contract	3,201.41
The SPI Group	EBT Hub Services	Contract	3,848.23
Tiltran Services	Test Transformer at MS3	Cost	2,280.00
Town of Parry Sound	Property Taxes, Interest on Promissory Note, CDM	Cost	200,619.06
URB, Division of Olameter Inc	Meter Reading and Data Collecting Services	Contract	39,585.16
Util-Assist	Smart Meter Consulting Services	Contract	18,692.00
Utility Collaborative Services	Billing Services	Contract	76,570.86
Utility Financial Concepts Inc	IRM/Cost Allocation Work	Cost	4,437.50
Westburne/Ruddy	Misc Supplies - conduit/sleeves…	Cost	2,164.58
			11,909,904.79

Employee Description

As outlined above, in Shared Services, the PSES (services company) provides us with services for labour.

Loss Adjustment Factor Calculation

Overview

The table below identifies PSP's loss factor calculation over a four year period. PSP is not seeking an adjustment to the current approved loss factor of 5.86%. As the table indicates the calculated distribution loss factor average over four years is 4.86%. The supply facility loss factor is 3.24%. Therefore PSP's Total Loss Factor (DLF X SFLF) is 8.26%. The retail kWh are based on prior usage pro-rated from the last read date to the month-end. This application process has involved an in-depth look at several aspects of our system, the loss factor being one of them. PSP believes a more reliable calculation can be done once smart meters are in place as the data will be readily available. PSP is looking the option of conducting a loss study over the next year in an effort to reduce line losses.

Table 5 Loss Adjustment Factor

	2004	2005	2006	2007
"Wholesale" kWh Qty at the Meter	82,366,827	88,169,677	83,591,580	87,972,204
Net "Wholesale" kWh	82,366,827	88,169,677	83,591,580	87,972,204
Retail kWh (Distributor) Qty at the Meter	78,688,561	84,112,093	79,702,356	83,724,368
Net "Retail" kWh	78,688,561	84,112,093	79,702,356	83,724,368
Distribution Loss Factor [(A)/(B)]	1.0467	1.0482	1.0488	1.0507
			4 Yr Average	1.0486

Total Utility Loss Adjustment Factor	LAF
Supply Facility Loss Factor From 2006 EDR	1.03244
Total Loss Factor	
Secondary Metered Customer	
Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0826
Total Loss Factor - Secondary Metered Customer > 5,000kW	n/a
Primary Metered Customer	
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0718
Total Loss Factor - Primary Metered Customer > 5,000kW	n/a

Retail Transmission Adjustment Calculations

PSP notes that on May 30, 2008, Hydro One Networks Inc. (Hydro One) filed an application before the Ontario Energy Board (the Board) to adjust uniform transmission rates (EB-2008-0113) effective January 1, 2009. Hydro One stated that the requested rates would result in a 9.2% average increase when applied to the uniform transmission rates. This application is presently before the Board and the Board has not reached any decision in this regard. Hydro One Networks is also expected to file a cost of service application in August 2008, which is a separate proceeding that could affect its final rates. PSP has not made any proposed changes to the Retail Transmission Rates in this application pending the Board's decision on Hydro One Networks Application regarding the proposed increase in retail transmission rates.

Income and Capital Taxes

Included with this rate application is an electronic copy of PSP's PILs calculations used in the calculation of the Service Revenue Requirement.

The Tables below have been extracted from the electronic model and copied here to provide a summary of the tax calculations.

Table 6 below shows the projected PILs expense for the Bridge Year 2008 at $39,931 and the 2009 Test Year at $63,173.

Table 6 Projected PILs Expenses

	2008 Projection	2009 Test
Regulatory Taxable Income/(Loss)	242,006	319,692
Combined Income Tax Rate	16.50%	16.50%
Total Income Taxes	39,931	52,749
Investment & Miscellaneous Tax Credits		
Income Tax Payable	**39,931**	52,749
Large Corporations Tax (LCT)		
Ontario Capital Tax (OCT)		
Grossed-up Income Tax		63,173
Grossed-up LCT		
Total PILs Expense	**39,931**	**63,173**

Table 7 shows the calculation of taxable income from the 2006 EDR approved year to the 2009 Test year.

Table 7 Calculation of Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Total entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting)		249,352		249,352	149,985	137,143	196,132
Additions: Amortization of tangible assets	104	330,093		330,093	335,514	345,916	345,916
Amortization of intangible assets	106	6,976		6,976	48,588	48,588	48,588
Actual Debt Interest				0	176,445	176,445	
Other Interest Expense	290	3,189		3,189			0
Total Additions		**340,258**	**0**	**340,258**	**560,547**	**570,949**	**394,504**
Deductions: Capital cost allowance from Schedule 8	403	221,331		221,331	224,938	243,621	243,621
Cumulative eligible capital deduction from Schedule 10 CEC	405	36,526		36,526	29,380	27,323	27,323
Deemed Debt Interest				0	214,208	211,132	
Total Deductions		**257,857**	**0**	**257,857**	**468,526**	**482,077**	**270,944**
NET INCOME (LOSS) FOR TAX PURPOSES		**331,753**	**0**	**331,753**	**242,006**	**226,016**	**319,692**
TAXABLE INCOME (LOSS)		**331,753**	**0**	**331,753**	**242,006**	**226,016**	**319,692**

Federal T2 Tax Return

Federal Tax Return is attached on the following page.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2008-12-31

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made either to an authorized financial institution or filed with form T9 (instalment form) and addressed to the appropriate Revenue Canada Taxation Centre.

Quarterly instalment workchart

Date	Quarterly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2008-03-31				
2008-06-30				
2008-09-30				
2008-12-31				
Total				

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2008-01-31	6,813			6,813
2008-02-29	6,813			6,813
2008-03-31	6,813			6,813
2008-04-30	6,813			6,813
2008-05-31	6,813			6,813
2008-06-30	6,813			6,813
2008-07-31	6,813			6,813
2008-08-31	6,813			6,813
2008-09-30	6,813			6,813
2008-10-31	6,813			6,813
2008-11-30	6,813			6,813
2008-12-31	6,806			6,806
Total	81,749			81,749

Indicate instalment method chosen [1-3] 1

1st Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.). 1

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

1 – Is the corporation a Canadian-controlled private corporation (CCPC)? [X] Yes [ ] No

2 – Did the corporation claim the small business deduction, during either the current or previous year? [X] Yes [ ] No

3 – Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to $400,000? [ ] Yes [ ] No

4 – Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to $10,000,000? [ ] Yes [ ] No

5 – Does the corporation have a perfect compliance history in the last 12 months? [ ] Yes [ ] No

If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments. [ ]

1 – 1st Instalment base method

1st Instalment base amount (amount I below)	81,749	÷ 12	=	6,813	
Monthly instalments required				6,813	
Quarterly tax instalments required	81,749	÷ 4	=		

2 – Combined 1st and 2nd instalment base method

2nd Monthly instalment base amount

Indicate: Part I tax		70,640				
Part I.3, VI & VI.I tax	+					
Provincial tax, other than Alberta, Québec and Ontario	+					
Ontario tax	+					
Total	=	70,640	÷ 12	=	5,887	**A**
1/12 of estimated current year credits (M below /12)				–		
Each of the first two instalment payments				=	5,887	**B**
Total tax from N below		81,749				
Amount B above x 2	–	11,774				
	=	69,975	÷ 10	=	6,998	
Each of the remaining ten instalment payments				=	6,998	

2nd Quarterly instalment base amount

Indicate: Part I tax		70,640				
Part I.3, VI & VI.I tax	+					
Provincial tax, other than Alberta, Québec and Ontario	+					
Ontario tax	+					
Total	=	70,640	÷ 4	=	17,660	**A**
1/4 of estimated current year credits (M below /4)				–		
The first instalment payment				=		**B**
Total tax from N below		81,749				
Amount B above	–					
	=	81,749	÷ 3	=	27,250	
Each of the remaining three instalment payments				=		

3 – Estimated tax method

Instalment base amount (amount N below)		÷ 12	=	
Monthly instalments required				
Quarterly tax instalments required		÷ 4	=	

Instalment base calculation

		1st instalment base method		Estimated tax method	
Taxable income		511,160			
Calculation of tax payable					
Federal part I tax		194,241			
Federal surtax	+	5,725	+		
Refundable tax on a CCPC's investment income	+		+		
Subtotal	=	199,966	=		**A**
Small business deduction		55,680			
Investment corporation deduction	+		+		
Federal tax abatement	+	51,116	+		
Manufacturing and processing profits deduction	+		+		
Non-business foreign tax credit	+		+		
Business foreign tax credit	+		+		
Tax reduction, general and accelerated	+	11,421	+		
Logging tax credit	+		+		
Federal political contribution tax credit	+		+		
Investment tax credit per Schedule 31 and resource deduction	+		+		
Qualifying environmental trust tax credit	+		+		
Subtotal	=	118,217	=		**B**
Total part I tax payable (A minus B)		81,749			**C**
Part I.3 tax	+		+		**D**
Part VI tax	+		+		**D**
Part VI.I tax	+		+		**E**
Total					
Parts I, I.3, VI and VI.I		81,749			**F**
Adjustment for short taxation years x 365 ÷ number of days in year if less than 365 — 365	÷	365	365 ÷	365	
		81,749			**G**
Provincial/territorial tax, other than Alberta, Québec and Ontario	+		+		**H**

Use this section only to calculate instalments payable with regard to taxation years ending in 2009 and after (for other tax years, see the *Ontario Tax Instalments* schedule (Jump Code: **ION**)):

Ontario tax	Income tax	+					
	Capital tax	+					
	Corporate minimum tax paid	+					
	Total Ontario tax*	=		+		+	**I**

		1st instalment base method		Estimated tax method	
Total harmonized provincial tax					
Harmonized provincial tax (H + I)	+		+		**J**
Adjustment for short taxation years x 365 ÷ number of days in year if less than 365 — 365	÷	365	365 ÷	365	
					K
Total of tax before refundable credits (G + K)**	=	81,749	=		**L**

Instalment base calculation (continued)

Estimated current year credits					
Investment tax credit refund					
Dividend refund	+		+		
Federal capital gains refund	+		+		
Provincial and territorial capital gains refund	+		+		
NRO allowable refund per Schedule 26	+		+		
Tax withheld at source	+		+		
Other estimated credits	+		+		
Total estimated current year credits	=		=		**M**
Instalment base amount (L minus M)		81,749			**N**

*Ontario tax corresponds to the amount before the application of specified Ontario tax credits.

**For instalments payable for tax years beginning before 2008, the amount on line G is not added to line L unless it exceeds 1,000. The same rule applies to line K. For instalments payable for tax years beginning after 2007, the amount on line G is not added to line L unless it exceeds $3,000. The same rule applies to line K.

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the *T2 Corporation – Income Tax Guide* (T4012).

Identification

Business Number (BN) **001** 89055 3811 RC0001

Corporation's name

002 PARRY SOUND POWER CORPORATION

Has the corporation changed its name since the last time you filed your T2 return? **003** 1 Yes [ ] 2 No [X]

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** ..... **004** 1 Yes [ ] 2 No [ ]

Address of head office

Has this address changed since the last time you filed your T2 return? .... **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018)

011 125 WILLIAM ST.

012

City: **015** PARRY SOUND

Province, territory, or state: **016** ON

Country (other than Canada): **017**

Postal code/Zip code: **018** P2A 1V9

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? .... **020** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028)

021 c/o

022

023

City: **025**

Province, territory, or state: **026**

Country (other than Canada): **027**

Postal code/Zip code: **028**

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? .... **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038)

031 125 WILLIAM ST.

032

City: **035** PARRY SOUND

Province,territory, or state: **036** ON

Country (other than Canada): **037**

Postal code/Zip code: **038** P2A 1V9

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ____ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2007-01-01 (YYYY MM DD)

Tax year-end **061** 2007-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? .... **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired .... **065** ____ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? .... **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? .... **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? .... **070** 1 Yes [ ] 2 No [X]

Amalgamation? .... **071** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? .... **072** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? .... **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? .... **078** 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and **complete and attach** Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? .... **082** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Was the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234		———
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177

Attachments – continued from page 2

		Yes	Schedule
Is the corporation subject to Part XIII.1 tax?	255		92 *
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

*** We do not print this schedule.**

Additional information

		1 Yes	2 No
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? (Only complete if **yes** was entered at line 281) **282**

If the major business activity involves the resale of goods, show whether it is wholesale or retail **283** 1 Wholesale [ ] 2 Retail [X]

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Elect. dist./retail	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	511,160	A
Deduct: Charitable donations from Schedule 2	311				
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Gifts of medicine from Schedule 2	315				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction *	325				
Non-capital losses of previous tax years from Schedule 4	331				
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal			▶		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				511,160	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	511,160	
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				511,160	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	511,160	A
Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax	405	511,160	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000	x	Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year	/ 365	=		1
400,000	x	Number of days in the tax year after 2006 / Number of days in the tax year	365 / 365	=	400,000	2
		Add amounts at lines 1 and 2			400,000	4

Business limit (see notes 1 and 2 below)	410	348,000	C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C	348,000	x	415 *** ______ D / 11,250	=		E
Reduced business limit (amount C **minus** amount E) (if negative, enter "0")				425	348,000	F

Small business deduction

Amount A, B, C, or F whichever is the least	348,000	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	16 %	= 55,680	5
Amount A, B, C, or F whichever is the least	348,000	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	17 %	=	6
Amount A, B, C, or F whichever is the least	348,000	x	Number of days in the tax year after December 31, 2008 / Number of days in the tax year	/ 365	x	17 %	=	7
			Total of amounts 5, 6, and 7 – enter on line 9			430	55,680	G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)]						435		H
Amount H		x	Number of days in the tax year in 2005 / Number of days in the tax year	/ 365	x	3 %	=	I
Amount H		x	Number of days in the tax year in 2006 / Number of days in the tax year	/ 365	x	5 %	=	J
Amount H		x	Number of days in the tax year in 2007 / Number of days in the tax year	365 / 365	x	7 %	=	K
Resource deduction – total of amounts I, J and K						438		L

Enter amount L on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			511,160	A
Amount Z1 from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Taxable resource income from line 435		D		
Amount used to calculate the credit union deduction (from Schedule 17)		E		
Amount from line 400, 405, 410, or 425, whichever is the least	348,000	F		
Aggregate investment income from line 440		G		
Total of amounts B, C, D, E, F, and G	348,000	▶	348,000	H
Amount A **minus** amount H (if negative, enter "0")			163,160	I

Amount I	163,160	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 %	=	11,421 J
Amount I	163,160	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	K
Amount I	163,160	x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	K1
Amount I	163,160	x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	K2

General tax reduction for Canadian-controlled private corporations – total of amounts J, K, K1, and K2 .... 11,421 L
Enter amount L on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)				M
Amount Z1 from Part 9 of Schedule 27		N		
Amount QQ from Part 13 of Schedule 27		O		
Taxable resource income from line 435		P		
Amount used to calculate the credit union deduction (from Schedule 17)		Q		
Total of amounts N, O, P, and Q		▶		R
Amount M **minus** amount R (if negative, enter "0")				S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	U1
Amount S		x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	U2

General tax reduction – total of amounts T, U, U1, and U2 V
Enter amount V on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7) **440**		x 26 2/3 % =		A
Foreign non-business income tax credit from line 632				
Deduct: Foreign investment income (from Schedule 7) **445**		x 9 1/3 % =		
		(if negative, enter "0")	►	B
Amount A **minus** amount B (if negative, enter "0")				C
Taxable income from line 360			511,160	
Deduct:				
Amount from line 400, 405, 410, or 425, whichever is the least	348,000			
Foreign non-business income tax credit from line 632		x 25 / 9 =		
Foreign business income tax credit from line 636		x 3 =		
	348,000 ►		348,000	
			163,160	
			x 26 2/3 % = 43,509	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)			81,749	
Deduct: Corporate surtax from line 600			5,725	
Net amount			76,024 ►	76,024 E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least **450**				F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year **460**			
Deduct: Dividend refund for the previous tax year **465**			
	►		G
Add the total of:			
Refundable portion of Part I tax from line 450 above			
Total Part IV tax payable from Schedule 3			
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation **480**			
	►		H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H **485**			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3	x 1 / 3		I
Refundable dividend tax on hand at the end of the tax year from line 485 above			J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)			

Part I tax

Base amount of Part I tax – taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . **550** 194,241 A

Corporate surtax calculation

Base amount from line A above	194,241	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	51,116	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360		a		
28.00 % of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		

Total of lines 2 to 6	51,116	7
Net amount (line 1 **minus** line 7)	143,125	8

Corporate surtax*

Line 8 143,125 x Number of days in the tax year before January 1, 2008 / Number of days in the tax year 365 / 365 x 4 % = **600** 5,725 B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . **602** C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360	511,160		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least	348,000		
Net amount	163,160 ▶	163,160	ii

Refundable tax on CCPC's investment income – 6 2/3 % of whichever is less: amount i or ii . . . . **604** D

Subtotal (**add** lines A, B, C, and D) 199,966 E

Deduct:

Small business deduction from line 430		55,680	9
Federal tax abatement	**608**	51,116	
Manufacturing and processing profits deduction from Schedule 27	**616**		
Investment corporation deduction	**620**		
(taxed capital gains **624**)			
Additional deduction – credit unions from Schedule 17	**628**		
Federal foreign non-business income tax credit from Schedule 21	**632**		
Federal foreign business income tax credit from Schedule 21	**636**		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount L	**638**	11,421	
General tax reduction from amount V	**639**		
Federal logging tax credit from Schedule 21	**640**		
Federal political contribution tax credit	**644**		
Federal political contributions **646**			
Federal qualifying environmental trust tax credit	**648**		
Investment tax credit from Schedule 31	**652**		
Subtotal		118,217 ▶	118,217 F

Part I tax payable – Line E **minus** line F . . . . 81,749 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	81,749
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		81,749

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
Total tax payable	770		81,749 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	54,127	
Total credits	890	54,127	54,127 B

Refund code 894 Overpayment

Balance (line A **minus** line B) 27,622

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid 27,622

Enclosed payment 898 27,622

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No X

Certification

I, 950 EPPS (Last name in block letters) 951 CALVIN (First name in block letters) 954 PRESIDENT (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2008-07-28 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (705) 746-5866 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes X 2 No ☐

958 ______ Name in block letters 959 ______ Telephone number

Language of correspondence – Langue de correspondance

990 Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

1 English / Anglais X 2 Français / French ☐

Schedule of Instalment Remittances

Name of corporation contact

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
2007-12-31	INSTALMENTS FOR 2006	54,127

Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	54,127	**A**
Total instalments credited to the taxation year per T9	54,127	**B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
PARRY SOUND POWER CORPORATION	89055 3811 RC0001	2007-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements			236,358 A
Add:			
Provision for income taxes – current	101	138,155	
Interest and penalties on taxes	103	1,216	
Amortization of tangible assets	104	332,645	
Amortization of intangible assets	106	48,588	
Subtotal of additions		520,604 ►	520,604
Other additions:			
Miscellaneous other additions:			
Subtotal of other additions	199	0 ►	0
Total additions	500	520,604 ►	520,604
Deduct:			
Capital cost allowance from Schedule 8	403	214,211	
Cumulative eligible capital deduction from Schedule 10	405	31,591	
Subtotal of deductions		245,802 ►	245,802
Other deductions:			
Miscellaneous other deductions:			
Total	394		
Subtotal of other deductions	499	0 ►	0
Total deductions	510	245,802 ►	245,802
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			511,160

* For reference purposes only

T2 SCH 1 E (06)

Canada

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
PARRY SOUND POWER CORPORATION	89055 3811 RC0001	2007-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1	1	Stations,lines, etc.	5,256,026	150,312		0	75,156	5,331,182	4	0	0	213,247	5,193,091
2	10	Computer equipment	3,212			0		3,212	30	0	0	964	2,248
		Total	5,259,238	150,312			75,156	5,334,394				214,211	5,195,339

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (06)

Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		150,312		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
	+			
Total additions per books	=	150,312	►	150,312
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
	+			
Total proceeds per books	=		– ►	
Depreciation and amortization per accounts – Schedule 1			–	332,645
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	-182,333

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		3,884,567
Opening net book value	–	4,066,900
Net change per financial statements	=	-182,333

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
PARRY SOUND POWER CORPORATION	89055 3811 RC0001	2007-12-31

This schedule is to be completed by a corporation having one or more of the following:
– related corporation(s)
– associated corporations(s)

	Name	Country of residence (if other than Canada)	Business Number (Canadian corporation only) (see note 1)	Relationship code (see note 2)	Number of common shares owned	% of common shares owned	Number of preferred shares owned	% of preferred shares owned	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	PARRY SOUND HYDRO CORPORATI(		86370 8996 RC0001	1					2,436,727
2.	PARRY SOUND ENERGY SERVICES (		86370 9192 RC0001	3					1,000
3.	PARRY SOUND POWERGEN CORPOF		86371 6395 RC0001	3					1,000

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

T2 SCH 9(99)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
PARRY SOUND POWER CORPORATION	89055 3811 RC0001	2007-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") . . . 200 — 451,301 A

Add:
- Cost of eligible capital property acquired during the taxation year . . . 222 ____
- Other adjustments . . . 226 ____
- Subtotal (line 222 plus line 226) ____ x 3 / 4 = ____ B
- Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . 228 ____ x 1 / 2 = ____ C
- amount B minus amount C (if negative, enter "0") ____ ► ____ D
- Amount transferred on amalgamation or wind-up of subsidiary . . . 224 ____ E
- Subtotal (add amounts A, D, and E) 230 — 451,301 F

Deduct:
- Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . 242 ____ G
- The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . 244 ____ H
- Other adjustments . . . 246 ____ I
- (add amounts G,H, and I) ____ x 3 / 4 = 248 ____ J

Cumulative eligible capital balance (amount F minus amount J) . . . 451,301 K
(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . 249 ____

amount K 451,301
less amount from line 249 ____

Current year deduction . . . 451,301 x 7.00 % = 250 — 31,591 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 31,591 ► 31,591 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . 300 — 419,710 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

T2 SCH 10 (04)

Canada

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		**400**	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)		**401**	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	**402** 3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	**408** 4			
Line 3 minus line 4 (if negative, enter "0")	►		5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400	7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000	8			
Subtotal (line 7 plus line 8)	**409** ►		9	
Line 6 minus line 9 (if negative, enter "0")			►	O
Line N minus line O (if negative, enter "0")				P
Line 5			x 1 / 2 =	Q
Line P minus line Q (if negative, enter "0")				R
Amount R			x 2 / 3 =	S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)			**410**	

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . **050** Year 2007

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	PARRY SOUND POWER CORPORATION	89055 3811 RC0001	1	400,000	87.0000	348,000	
2	PARRY SOUND HYDRO CORPORATION	86370 8996 RC0001	1	400,000	0.7500	3,000	
3	PARRY SOUND ENERGY SERVICES CORP.	86370 9192 RC0001	1	400,000	12.2500	49,000	
4	PARRY SOUND POWERGEN CORPORATION	86371 6395 RC0001	1	400,000			
				Total	100.0000	400,000	**A**

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
PARRY SOUND POWER CORPORATION	89055 3811 RC0001	2007-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	Parry Sound Hydro Corporation	86370 8996 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

T2 SCH 50 (06)

Canada

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
PARRY SOUND POWER CORPORATION	89055 3811 RC0001	2007-12-31

On: 2007-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . [ ] Yes [X] No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . [X] Yes [ ] No
   If the answer to question 3 is yes, complete Part 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . [X] Yes [ ] No
5. Corporations that become a CCPC or a DIC . . . . . [ ] Yes [X] No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . [ ] Yes [X] No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . [ ] Yes [ ] No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . [ ] Yes [ ] No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . [ ] Yes [X] No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . [ ] Yes [ ] No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . [ ] Yes [ ] No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

	Line	Amount		Line	Amount	
GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")				050		A
GRIP at the end of the previous tax year				100	108,866	B
Taxable income for the year (DICs enter "0")*	110	511,160	C			
Income for the credit union deduction* (amount E in Part 3 of Schedule 17) — 120						
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less* — 130: 348,000						
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income* — 140						
Subtotal (**add** lines 120, 130, and 140) 348,000 ▶		348,000	D			
Income taxable at the general corporate rate (line C **minus** line D)	150	163,160				
After-tax income (line 150 **multiplied** by 68 %)				190	110,949	E
Eligible dividends received in the tax year	200					
Dividends deductible under section 113 received in the tax year	210					
Subtotal (**add** lines 200 and 210) ▶						F
GRIP addition:						
Becoming a CCPC (line PP from Part 4)	220					
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230					
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240					
Subtotal (**add** lines 220, 230, and 240) ▶				290		G
Subtotal (**add** lines A or B (as applicable), E, F, and G)					219,815	H
Eligible dividends paid in the previous tax year	300					
Excessive eligible dividend designations made in the previous tax year	310					
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.						
Subtotal (line 300 **minus** line 310) ▶						I
GRIP before adjustment for specified future tax consequences (line H **minus** line I) (amount can be negative)				490	219,815	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)				560		
GRIP at the end of the year (line 490 **minus** line 560) Enter this amount on line 160 on Schedule 55.				590	219,815	

*** Note:** For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year		428,597 J1		
Enter the following amounts before specified future tax consequences from the current tax year:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	268,500 L1			
Aggregate investment income (line 440 of the T2 return)	M1			
Subtotal (**add** lines K1, L1, and M1)	268,500 ▶	268,500 O1		
Subtotal (line J1 **minus** line O1) (if negative, enter "0")		160,097 ▶	160,097	P1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ________ Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ________ S1

Aggregate investment income (line 440 of the T2 return) . . . . ________ T1

Subtotal (**add** lines R1,S1, and T1) ________ ▶ ________ V1

Subtotal (line Q1 **minus** line V1) (if negative, enter "0") ________ ▶ ________ W1

Subtotal (line P1 **minus** line W1) (if negative, enter "0") ________ X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 **multiplied by** 68 %) . . . **500** ________

Second previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year 171,056 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less 171,056 L2

Aggregate investment income (line 440 of the T2 return) . . . . ________ M2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . ________ N2

Subtotal (**add** lines K2, L2, M2, and N2) 171,056 ▶ 171,056 O2

Subtotal (line J2 **minus** line O2) (if negative, enter "0") ________ ▶ ________ P2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ________ Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ________ S2

Aggregate investment income (line 440 of the T2 return) . . . . ________ T2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . ________ U2

Subtotal (**add** lines R2, S2, T2, and U2) ________ ▶ ________ V2

Subtotal (line Q2 **minus** line V2) (if negative, enter "0") ________ ▶ ________ W2

Subtotal (line P2 **minus** line W2) (if negative, enter "0") ________ X2

GRIP adjustment for specified future tax consequences to second previous tax year (line X2 **multiplied by** 68 %) **520** ________

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2004-12-31

Taxable income before specified future tax consequences from the current tax year J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) M3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** N3

Subtotal (**add** lines K3, L3, M3, and N3) ▶ O3

Subtotal (line J3 **minus** line O3) (if negative, enter "0") ▶ P3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences Q3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S3

Aggregate investment income (line 440 of the T2 return) T3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** U3

Subtotal (**add** lines R3, S3, T3, and U3) ▶ V3

Subtotal (line Q3 **minus** line V3) (if negative, enter "0") ▶ W3

Subtotal (line P3 **minus** line W3) (if negative, enter "0") X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 **multiplied by** 68 %) . . . **540**

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . Y

Enter amount Y on line 560.

***Note**: The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . AA

Eligible dividends paid by the corporation in its last tax year . . . . BB

Excessive eligible dividend designations made by the corporation in its last tax year CC

Subtotal (line BB **minus** line CC) ▶ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)
(line AA **minus** line DD) . . . . EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ______ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ______ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ______
Net capital losses . . . . ______
Farm losses . . . . ______
Restricted farm losses . . . . ______
Limited partnership losses . . . . ______

Subtotal ______ ► ______ HH

Subtotal (**add** lines FF, GG, and HH) ______ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ______ JJ

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ______ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ______ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ______ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ______ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ______ ► ______ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . ______ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . PARRY SOUND POWER CORPORATION

Taxation Year . . . . 2007-01-01 to 2007-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 3

Type of corporation . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* 27,622

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	511,160
Taxable income	511,160
Donations	
Calculation of income from an active business carried on in Canada	511,160
Dividends paid	
Balance of the low income rate pool at the end of the year	
Balance of the general rate income pool at the end of the year	219,815
Part I tax (base amount)	194,241
Surtax	5,725

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction	55,680	Part I	81,749	ITC refund	
M&P deduction		Part I.3		Dividends refund	
Foreign tax credit		Part IV		Instalments	54,127
Political contributions		Part III.1		Surtax credit	
Investment tax credits		Other*		Other*	
Abatement/Other*	62,537	Provincial or territorial tax			
				Balance due/refund (–)	27,622

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts

Investment tax credits	
Non-capital loss	
Capital loss	
Farm loss	
Restricted farm loss	
Surtax credit	
Part I tax credit (Schedule 42)	
Federal foreign non-business income tax credit	

Carryforward balances

RDTOH	
Charitable donations	
Gifts to Canada, a province or a territory	
Gifts of certified cultural property	
Gifts of certified ecologically sensitive land	
Gifts of medicine	

Summary of federal carryforward/carryback information (continued)

Investment tax credits	
Non-capital losses	
Capital/L.P.P. losses	
Farm losses	
Restricted farm losses	
Current year's balance of SR&ED expenditures (T661)	
Foreign business tax credit	
Unused surtax credit (Schedule 37)	12,069
Capital dividend amount	
Part I tax credit (Schedule 42)	
Cumulative eligible capital	419,710
Capital gains reserves	
Financial statement reserve	
Other reserves	
Balance of patronage dividends	
Continuity of exemption of accumulated income	

Summary of provincial information – provincial income tax payable

	Ontario (CT-23)	**Québec (CO-17)**	**Alberta (AT1)**
% Allocation	100.00		
Attributed taxable income	511,160		
Surtax	6,583	N.A.	N.A.
Tax payable before deduction*	71,562		
Deductions and credits	29,580		
Net tax payable	48,565		
Attributed taxable capital	6,936,181		N.A.
Capital tax payable**			N.A.
Total tax payable***	48,565		
Instalments and refundable credits	48,565		
Balance due/Refund (-)			

* For Québec, this includes special taxes.
** For Québec, this includes compensation tax and registration fee.
*** For Ontario, this includes corporate minimum tax and premium tax.

	British Columbia	**Saskatchewan**	**Manitoba**
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			
Attributed taxable capital			
Capital tax payable			
Instalments and refundable credits			
Balance due/Refund (-)			

Summary of provincial information – provincial income tax payable (continued)

	Newfoundland and Labrador	Prince Edward Island	Nova Scotia	New Brunswick
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				
Attributed taxable capital				
Capital tax payable				
Instalments and refundable credits				
Balance due/Refund (-)*				

* Only applies in the case of bank, a loan corporation or a trust corporation.

	Yukon	Northwest Territories	Nunavut
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			

Summary of provincial carryforward amounts

	Ontario	Québec	Alberta
Non-capital losses			
Net capital/L.P.P. losses			
Farm losses			
Restricted farm losses			
Donations			
Capital gains reserves			
Financial statement reserves			
Other reserves			
Eligible capital	419,710	419,710	419,710

Other carryforward amounts

Scientific research and experimental development – Schedule 425	
Manufacturing and processing – Schedule 426	
Research and development – Schedule 380	
Manufacturing investment – Schedule 381	
Co-operative education – Schedule 384	
Odour control – Schedule 385	
Manufacturing and processing investment – Schedule 402	
Research and development – Schedule 403	
Direct equity tax – Schedule 303	
Investment – Schedule 321	
Energy efficiency tax credit – Schedule 342	
Manufacturing and processing investment – Schedule 344	
Research and development – Schedule 360	
Investment – Schedule 480	
R&D expenditures not deducted at the end of the year – RD-222	
Foreign non-business income tax credits – CO-17S.39	
Development work expenses – FM220.3	
Excess development work expenses – FM220.3	
Unclaimed SR&ED expenditure pool deduction balance – A16	
Continuity of other eligible CMT losses – Filling Corporation – OCMT101	
Predecessor corporations only – Amalgamation – OCMT101	
Predecessor corporations only – Wind-up – OCMT101	
CMT credit carryovers workchart – Filling Corporation – OCMT101	
CMT credit carryovers workchart – Predecessor corporations only – Amalgamation	
CMT credit carryovers workchart – Wind-up – OCMT101	
Ontario current taxation year closing balance in pool of deductible SR&ED expenditures – O161	
Continuity Schedule for Federal ITC relating to SR&ED Expenditures for the Preceding Taxation Year – O161	
Continuity Schedule for the Amount of Federal ITC from SR&ED Expenditures relating to QORD for the Preceding Taxation Year – O161	

Diagnostics : All

Type	Group	Jurisd...	Diagnostic
Filing	GIFI	Federal	F1 — Please attach a copy of the notes to the financial statements together with the RSI schedules to the federal income tax return.
Missing infor...	CCH	Ontario	M2 — CT23 - Electrical Generating Corporation may be eligible for deduction from paid-up capital.
Missing infor...	CCH	Ontario	M38 — Return set for DFILE, but CT23 DFILE not yet built.
Missing infor...	CCH	Ontario	M147 — CT23 - Ontario Net Income Reconciliation - Electrical Generating Corporation may be eligible for deduction from net income.
Possi... input error	CCH	Federal	E19 — Identification - Year end of the corporation is after the release date of this version. Verify for any tax changes after 2007-11-15.
Possi... input error	CCH	Ontario	E158A — CT23 - Certain types of income must not be included in the corporation's revenue. Press F1 when the form is displayed and review 'Definition of sales figure'.
Forms with overr... cells	CCH	Federal	O103 — Overridden data - You can see the list by using the "Overridden data" filter in Xpress.
Possi... input error	CCH	Federal	E799 — Schedule 9 Workchart - Since the corporation is associated, ensure that the amount of taxable capital employed in Canada from the last taxation year has been entered. This amount is used in the calculation of the business limit reduction.
Possi... input error	CCH	Federal	E799 — Schedule 9 Workchart - Since the corporation is associated, ensure that the amount of taxable capital employed in Canada from the last taxation year has been entered. This amount is used in the calculation of the business limit reduction.
Possi... input error	CCH	Federal	E799 — Schedule 9 Workchart - Since the corporation is associated, ensure that the amount of taxable capital employed in Canada from the last taxation year has been entered. This amount is used in the calculation of the business limit reduction.
Possi... input error	CCH	Federal	E799 — Schedule 9 Workchart - Since the corporation is associated, ensure that the amount of taxable capital employed in Canada from the last taxation year has been entered. This amount is used in the calculation of the business limit reduction.
Possi... input error	CCH	Federal	E813 — Schedule 9 Workchart - Verify if you must enter the taxable capital employed in Canada for the year.
Possi... input error	CCH	Federal	E813 — Schedule 9 Workchart - Verify if you must enter the taxable capital employed in Canada for the year.
Possi... input error	CCH	Federal	E813 — Schedule 9 Workchart - Verify if you must enter the taxable capital employed in Canada for the year.

Diagnostics : All

Type	Group	Jurisd...	Diagnostic
Error	T2 Data Conn...	Federal	D3 — The location and the name of the linked file are invalid.
Error	T2 Data Conn...	Federal	D3 — The location and the name of the linked file are invalid.

Ontario CT23 Tax Return

Provincial Tax Return is attached on the following page.

Ontario Tax Instalments

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

Ontario tax instalments

For the taxation year ended: 2008-12-31

The following is a list of Ontario instalments payable for the current taxation year. The last column indicates the instalments payable to the Ontario Ministry of Revenue. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Minister of Finance. Payment may be made either to a chartered bank in Ontario or filed with an instalment form and addressed to:

Ministry of Revenue (Ontario)
Corporation Tax
33 King Street West
P.O. Box 620
Oshawa Ontario
L1H 8E9

Quarterly instalment

Date	Instalments required	Instalments paid	Cumulative difference	Instalments payable
Total				

Date	Instalments required	Instalments paid	Cumulative difference	Instalments payable
2008-01-31	4,048			4,048
2008-02-29	4,048			4,048
2008-03-31	4,048			4,048
2008-04-30	4,048			4,048
2008-05-31	4,048			4,048
2008-06-30	4,048			4,048
2008-07-31	4,048			4,048
2008-08-31	4,048			4,048
2008-09-30	4,048			4,048
2008-10-31	4,048			4,048
2008-11-30	4,048			4,048
2008-12-31	4,037			4,037
Total	48,565			48,565

Indicate instalment method chosen [1-3]: 1

1st Instalment base method

Do not use the quarterly payment even if applicable "X" to continue montly payments

If instalments are starting late, indicate the MONTH in which you want them to start (1=January, 2=February, etc.) 1

1 – 1st Instalment base method

1st instalment base amount (amount I below)	48,565 ÷ 12 =	4,048
Monthly instalments required		4,048
Quarterly instalments required		

2 – Combined 1st and 2nd instalment method

2nd instalment base amount:

Indicate:	Income tax, C.M.T		32,052				
	Capital tax, prem. tax	+					
	Total	=	32,052	÷	12 =	2,671	A
Each of the first two instalment payments						2,671	B
Total tax from I below			48,565				
Amount A above x 2		–	5,342				
		=	43,223	÷	10 =	4,323	
Each of the remaining ten instalment payments						4,323	
Quarterly instalments required							

3 – Estimated tax method

Instalment base amount (amount I below)		÷	12 =	
Monthly instalments required				
Quarterly instalments required				

Instalment base calculation

		1st instalment base method			Estimated tax method	
Ontario taxable income		511,160				
Calculation of tax payable						
Gross Ontario tax		71,562				A
Incentive deduction for an S.B.C., net of surtax		22,997				
Manufacturing and processing profits credit	+			+		
Additional deduction for credit unions	+			+		
Credit for foreign taxes paid	+			+		
Credit for investment in S.B.D.C.	+			+		
Specified credits applied against income tax	+			+		
Total deduction and credits	=	22,997		=		B
Income tax (A - B)		48,565				C
Capital tax	+			+		D
Corporate minimum tax paid (credited)	+			+		E
Premium tax	+			+		F
Total income tax and other taxes (C + D + E + F)	=	48,565		=		G
Adjustment for short taxation years x 365 ÷ number of days in year if less than 365	365 ÷	365	365	÷	365	
		48,565				H
Total estimated current year credits	–			–		
		48,565				I

Ontario Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No

Corporation's Legal Name *(including punctuation)*: PARRY SOUND POWER CORPORATION

Ontario Corporations Tax Account No. (MOF): 1800162

Mailing Address:
125 WILLIAM ST.
PARRY SOUND
ON CA P2A 1V9

This Return covers the Taxation Year
Start (year month day): 2007-01-01
End (year month day): 2007-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes — Date of Change (year month day):

Date of Incorporation or Amalgamation (year month day): 2000-10-31

Registered/Head Office Address:
125 WILLIAM ST.
PARRY SOUND
ON CA P2A 1V9

Ontario Corporation No. (MGS): 1448207

Location of Books and Records:
125 WILLIAM ST.
PARRY SOUND
ON CA P2A 1V9

Canada Revenue Agency Business No. — If applicable, enter: 89055 3811 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
CALVIN EPPS	(705) 746-5866	

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced (year month day):
Ceased (year month day):
[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Preferred Language / *Langue de préférence*: [X] English *anglais* [ ] French *français*

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). No. of Schedule(s):

Ministry Use

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). [X] **No Change**

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*: CALVIN EPPS

Title D [ ] Director O [X] Officer P [ ] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) **box(es) and complete required information.**

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired — year / month / day

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
	X	Was the corporation inactive throughout the taxation year?
X		Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
	X	the Carry-back of a Loss?
	X	an Overpayment?
	X	a Specified Refundable Tax Credit?
	X	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

Municipal electrica

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	511,160
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax ______ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses	–	From 704	
Net capital losses (page 16) From 715 ______ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	511,160

Addition to taxable income for unused foreign tax deduction for federal purposes	+	11	
Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11)	=	20	511,160

Taxable Income

Number of Days in Taxation Year

	Taxable income		Ontario Allocation		Rate		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days			
From 10 (or 20 if applicable)	511,160	x 30	100.0000 %	x	12.5 %	x 33		÷ 73	365	= +	29	

	Taxable income		Ontario Allocation		Rate		Days after Dec. 31, 2003		Total Days			
From 10 (or 20 if applicable)	511,160	x 30	100.0000 %	x	14 %	x 34	365	÷ 73	365	= +	32	71,562

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 71,562

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X)

X Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))				50	511,160
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+	51	511,160		
Add: Losses of other years deducted for federal purposes (fed.s.111)	+	52			
Subtract: Losses of other years deducted for Ontario purposes (s.34)	–	53			
	=		511,160	54	511,160
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	348,000		

Ontario Business Limit Calculation

320,000 x	Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ______	÷ ** 365	= +	46		
400,000 x	Days after Dec. 31, 2003: 34 365	÷ ** 365	= +	47	400,000	

Business Limit for Ontario purposes 46 + 47 = 44 400,000 x 48 87.0000 % (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) = 45 348,000

Income eligible for the IDSBC From 30 100.0000 % (***Ontario Allocation) x 56 348,000 (Least of 50 , 54 or 45) = 60 348,000

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

			Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
Calculation of IDSBC Rate	7 %	x	31	÷ 73	365	= + 89	.
			Days after Dec. 31, 2003		Total Days		
	8.5 %	x	34 365	÷ 73	365	= + 90	8.5000
IDSBC Rate for Taxation Year 89 + 90						= 78	8.5000
Claim	From 60 348,000	x	From 78 8.5000 %			= 70	29,580

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** From 10 (or 20 if applicable) + 80 511,160

If you are a member of an associated group (X) 81 X (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
PARRY SOUND HYDRO CORPORATION	1800161	2007-12-31	+ 82	2,619
PARRY SOUND ENERGY SERVICES CORP.	1800160	2007-12-31	+ 83	48,368
PARRY SOUND POWERGEN CORPORATION	1800163	2007-12-31	+ 84	
Aggregate Taxable Income 80 + 82 + 83 + 84 , etc.			= 85	562,147

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
320,000	x	31	÷ 73	365	= + 115	
		Days after Dec. 31, 2003		Total Days		
400,000	x	34 365	÷ 73	365	= + 116	400,000

115 + 116 = 400,000 – 114 400,000

(If negative, enter nil) = 86 162,147

Number of Days in Taxation Year

			Days after Dec. 31, 2002		Total Days		
Calculation of Specified Rate for Surtax	4.6670 %	x	38 365	÷ 73	365	= + 97	4.6670

From 86 162,147 x From 97 4.6670 % = 87 7,567

From 87 7,567 x From 60 348,000 ÷ From 114 400,000 = 88 6,583

Surtax Lesser of 70 or 88 = 100 6,583

**** Note: Short Taxation Years –*** Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

DOLLARS ONLY

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)*

110 .

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits	+	120	.
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	– From	56	348,000 .

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 6,583 . ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 77,447 .

*Ontario Allocation

Lesser of 56 or 121	+	122	77,447 .
120 – 56 + 122	=	130	.
Taxable Income	+ From	10	511,160 .
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	– From	56	348,000 .
Add: Adjustments for Surtax on Canadian-controlled private corporations	+ From	122	77,447 .
Subtract: Taxable Income 10 511,160 X Allocation % to jurisdictions outside Canada	–	140	.
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses	–	141	.
10 – 56 + 122 – 140 – 141	=	142	240,607 .

Claim

Number of Days in Taxation Year

143 . (Lesser of 130 or 142) x From 30 100.0000 % (Ontario Allocation) x 1.5 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 33 ÷ 73 365 (Total Days) = + 154 .

143 . (Lesser of 130 or 142) x From 30 100.0000 % (Ontario Allocation) x 2 % x (Days after Dec. 31, 2003) 34 365 ÷ 73 365 (Total Days) = + 156 .

M&P claim for taxation year 154 + 156 = 160 .

*** Note:** *Ontario Allocation for M&P Credit purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations

= 161 .

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity

= 162 .

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* 170 .

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 . Credit Claimed 180 .

Subtotal of Income Tax

40 – 70 + 100 – 110 – 160 – 161 – 162 – 170 – 180 = 190 48,565 .

continued on Page 7

DOLLARS ONLY

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.

Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.

Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)

Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. 204 Name of Production

Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 193

Graduate Transitions Tax Credit (GTTC) (s.43.6)

Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. No. of Graduates From 6596 194

Eligible Credit From 6598 CT23 Schedule 115 (*Attach Schedule 115*) + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)

Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.

Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)

Applies to labour relating to computer animation and special effects on an eligible production.

Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)

Applies to qualifying R&D expenditures under an eligible research institute contract.

Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10)

Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.

Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)

Applies to qualifying labour expenditures of eligible products for the taxation year.

Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)

Applies to qualifying expenditures in respect of eligible Canadian sound recordings.

Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13)

Applies to employment of eligible apprentices. No. of Apprentices From 5896 202

Eligible Credit From 5898 CT23 Schedule 114 (*Attach Schedule 114*) + 203

Other (specify) + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220

Specified Tax Credits ***Applied to reduce Income Tax*** = 225

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 48,565

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation	+ 240	9,289,016	
Total Revenue of the corporation	+ 241		2,047,670

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 **X** (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Total Assets		Total Revenue
PARRY SOUND HYDRO CORPORATION	1800161	2007-12-31	+ 243	3,606,180	+ 244	309,523
PARRY SOUND ENERGY SERVICES CORP.	1800160	2007-12-31	+ 245	1,045,049	+ 246	1,026,820
PARRY SOUND POWERGEN CORPORATION	1800163	2007-12-31	+ 247	746,968	+ 248	266,505
Aggregate Total Assets 240 + 243 + 245 + 247 , etc.			= 249	14,687,213		
Aggregate Total Revenue 241 + 244 + 246 + 248 , etc.					= 250	3,650,518

Determination of Applicability

Applies if ***either*** Total Assets 249 exceeds $5,000,000 ***or*** Total Revenue 250 exceeds $10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101**.

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - - CMT Base From Schedule 101 2136 374,513 (If negative, enter zero) x From 30 100.0000 % (Ontario Allocation) X 4 % = 276 14,981

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	– 277	
Subtract: Income Tax	– From 190	48,565
Net CMT Payable (If negative, enter Nil on Page 17.)	= 280	-33,584

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From 2333

Application of CMT Credit Carryovers

A.	Income Tax (before deduction of specified credits)			+ From 190	48,565
	Gross CMT Payable	+ From 276	14,981		
	Subtract: Foreign Tax Credit for CMT purposes	– From 277			
	If 276 – 277 is negative, enter NIL in 290	=	14,981	– 290	14,981
	Income Tax eligible for CMT Credit			= 300	33,584
B.	Income Tax (after deduction of specified credits)			+ From 230	48,565
	Subtract: CMT credit used to reduce income taxes			– 310	
	Income Tax			= 320	48,565

Transfer to page 17

If A & B apply, 310 ***cannot exceed the lesser of*** 230 **,** 300 ***and your CMT credit carryover available*** 2333 **.**

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333 **.**

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	2,433,727
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	735,826
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	1,332,900
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	2,433,728
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	6,936,181
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	6,936,181
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	–	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	–	382	
Net Paid-up Capital	=	390	6,936,181

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	

continued on Page 10

Total Assets (Int.B. 3015R)

DOLLARS ONLY

Total Assets per balance sheet	+	420	9,289,016
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	9,289,016
Amounts in 360 and 361 (if deducted from assets)	+	440	
Subtract: Amounts in 371, 372 and 381	–	441	
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	9,289,016

Investment Allowance (410 ÷ 450) x 390 — **Not to exceed** 410	=	460	
Taxable Capital 390 – 460	=	470	6,936,181

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	2,047,670
Total Assets (as adjusted)	From 430	9,289,016

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

Amount		Days			Total Days			
7,500,000	x	36 (Days after Dec. 31, 2004 and before Jan. 1, 2006)		÷ 73	365	= +	501	
10,000,000	x	37 (Days after Dec. 31, 2005 and before Jan. 1, 2007)		÷ 73	365	= +	502	
12,500,000	x	38 (Days after Dec. 31, 2006 and before Jan. 1, 2008)	365	÷ 73	365	= +	504	12,500,000
15,000,000	x	39 (Days after Dec. 31, 2007)		÷ 73	365	= +	505	

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 12,500,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

Rate		Days			Total Days			
0.3 %	x	556 (Days before Jan. 1, 2007)		÷ 73	365	= +	511	%
0.285 %	x	557 (Days after Dec. 31, 2006 and before Jan. 1, 2009)	365	÷ 73	365	= +	512	0.2850 %

Capital Tax Rate 511 + 512 = 516 0.2850 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+ From 470 ________
− From 503 ________
= 471 ________ x From 30 100.0000 % Ontario Allocation x From 516 0.2850 % Capital Tax Rate x Days in taxation year 555 365 / 365 (366 if leap year) = + 523 ________

If floating taxation year, refer to Guide.

Transfer to 543 on page 12 and complete the return from that point

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. [ ] 509 (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. [X] 524 (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation
Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - - - + From 470 6,936,181

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
PARRY SOUND HYDRO CORPORATION	1800161	2007-12-31	+ 531	238,509
PARRY SOUND ENERGY SERVICES CORP.	1800160	2007-12-31	+ 532	729,111
PARRY SOUND POWERGEN CORPORATION	1800163	2007-12-31	+ 533	709,939
Aggregate Taxable Capital 470 + 531 + 532 + 533, etc.			= 540	8,613,740

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E below, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From 470 6,936,181 ÷ From 540 8,613,740 x From 503 12,500,000 = 541 10,065,577

Transfer to 542 *in Section E below*

Ss.69(2.1) Election Filed

☐ 591 (X if applicable) **Election filed**. *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

+	From 470	6,936,181
–	542	10,065,577
=	471	

471 x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) x 555 365 (Days in taxation year) / * 365 (366 if leap year) = + 523 (**Total Capital Tax for the taxation year**)

Transfer to 543 *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From 470 x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) - - - = + 561

– Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - – From 995

= 562

Capital Tax - - - 562 x 555 365 (Days in taxation year) / * 365 (366 if leap year) - - - = 563 (**Total Capital Tax for the taxation year**)

Transfer to 543 *and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits - - - = 543

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - – 546

Capital Tax 543 – 546 *(amount cannot be negative)* - - - = 550

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes 565 and 570. Do not submit with this tax return.)

565 ______ x 567 ______% x From 30 100.0000 % x 555 365 / * 365 (366 if leap year) = + 569 ______
Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1 | Capital Tax Rate (1) *(Refer to Guide)* | Ontario Allocation | Days in taxation year

570 ______ x 571 ______% x From 30 100.0000 % x 555 365 / * 365 (366 if leap year) = + 574 ______
Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount | Capital Tax Rate (2) *(Refer to Guide)* | Ontario Allocation | Days in taxation year

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) 569 + 574 = 575 ______

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments – 585 ______

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions 575 – 585 = 586 ______

Transfer to 543 on Page 12

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements 587 ______ x 2 % = 588 ______
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in 588 and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in 588.)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – 589 ______

Premium Tax 588 – 589 = 590 ______
Transfer to page 17

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± 600 511,160
Transfer to Page 15

Add:

Federal capital cost allowance	+	601	214,211
Federal cumulative eligible capital deduction	+	602	31,591
Ontario taxable capital gain	+	603	
Federal non-allowable reserves. Balance beginning of year	+	604	
Federal allowable reserves. Balance end of year	+	605	
Ontario non-allowable reserves. Balance end of year	+	606	
Ontario allowable reserves. Balance beginning of year	+	607	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+	608	
Federal resource allowance *(Refer to Guide)*	+	609	
Federal depletion allowance	+	610	
Federal foreign exploration and development expenses	+	611	
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+	617	

Management fees, rents, royalties and similar payments to non-arms' length non-residents

Number of Days in Taxation Year

612 ______ x 5 / 12.5 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ______ ÷ Total Days: 73 365) = + 633 ______

612 ______ x 5 / 14 x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 634 ______

Total add-back amount for Management fees, etc. 633 + 634 = ______	+	613	
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	+	615	
Add any negative amount in 473 from Ont. CT23 Schedule 161	+	616	
Federal allowable business investment loss	+	620	
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	+	614	

Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614 = 245,802 ▶ 640 245,802
Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+	650	214,211
Ontario cumulative eligible capital deduction	+	651	31,591
Federal taxable capital gain	+	652	
Ontario non-allowable reserves. Balance beginning of year	+	653	
Ontario allowable reserves. Balance end of year	+	654	
Federal non-allowable reserves. Balance end of year	+	655	
Federal allowable reserves. Balance beginning of year	+	656	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+	657	
Ontario depletion allowance	+	658	
Ontario resource allowance *(Refer to Guide)*	+	659	
Ontario current cost adjustment *(Attach schedule)*	+	661	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+	675	

Subtotal of deductions for this page 650 to 659 + 661 + 675 681 245,802
Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1	From ±	600	511,160
Total of Additions on page 14	From =	640	245,802
Sub Total of deductions on page 14	From =	681	245,802

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - 662 ________

ONTTI Gross-up deduction calculation:

Gross-up of CCA

From 662 ________ x 100 / (From 30 100.0000 Ontario Allocation) – From 662 ________ = 663 ________

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 665 ________ x 30 % x 100 / (From 30 100.0000 Ontario allocation) = 666 ________

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 667 ________ x 100 % x 100 / (From 30 100.0000 Ontario allocation) = 668 ________

Number of Employees accommodated 669 ________

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: 670 ________ x 30 % x 100 / (From 30 100.0000 Ontario allocation) = 671 ________

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 672 ________ x 15 % x 100 / (From 30 100.0000 Ontario allocation) = 673 ________

Ontario allowable business investment loss + 678 ________

Ontario Scientific Research Expenses claimed in year in 477 **from Ont. CT23 Schedule 161** + 679 ________

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003) + 677 ________

Total of other deductions allowed by Ontario *(Attach schedule)* + 664 ________

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 245,802 ► 680 245,802

Net income (loss) for Ontario Purposes 600 + 640 – 680 = 690 511,160
Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	720 (2)	730	740	750
Add:	Current year's losses (7)	701	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703	713	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707	717	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day		Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800	9th preceding taxation year 1999-09-30	817 (9)	860 (9)		850	870
801	8th preceding taxation year 2000-09-30	818 (9)	861 (9)		851	871
802	7th preceding taxation year 2001-09-30	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2001-12-31	820	830	840	853	873
804	5th preceding taxation year 2002-12-31	821	831	841	854	874
805	4th preceding taxation year 2003-12-31	822	832	842	855	875
806	3rd preceding taxation year 2004-12-31	823	833	843	856	876
807	2nd preceding taxation year 2005-12-31	824	834	844	857	877
808	1st preceding taxation year 2006-12-31	825	835	845	858	878
809	Current taxation year 2007-12-31	826	836	846	859	879
Total		829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance**.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2004-12-31	911	921	931	941
ii) 2nd preceding	902	2005-12-31	912	922	932	942
iii) 1st preceding	903	2006-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+ From 230 or 320		48,565
Corporate Minimum Tax	+ From 280		
Capital Tax	+ From 550		
Premium Tax	+ From 590		
Total Tax Payable	=	950	48,565
Subtract: Payments	–	960	48,565
Capital Gains Refund (s.48)	–	965	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	–	985	
Specified Tax Credits *(Refer to Guide)*	–	955	
Other, specify	–		
Balance	=	970	
If payment due Enclosed *		990	
If overpayment: Refund *(Refer to Guide)*	=	975	
Apply to (year month day)		980	

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*: CALVIN EPPS

Title: PRESIDENT

Full Residence Address:
4 HILLCREST AVENUE
PARRY SOUND
ON CA P2A 1L4

Signature

Date: 2008-07-28

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP)			± 2100	236,358
Subtract (to the extent reflected in net income/loss):				
Provision for recovery of income taxes / benefit of current income taxes	+ 2101			
Provision for deferred income taxes (credits) / benefit of future income taxes	+ 2102			
Equity income from corporations	+ 2103			
Share of partnership(s)/joint venture(s) income	+ 2104			
Dividends received/receivable deductible under fed.s.112	+ 2105			
Dividends received/receivable deductible under fed.s.113	+ 2106			
Dividends received/receivable deductible under fed.s.83(2)	+ 2107			
Dividends received/receivable deductible under fed.s.138(6)	+ 2108			
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) ______ x 3	+ 2109			
Subtotal	=		– 2110	
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	+ 2111	138,155		
Provision for deferred income taxes (debits) / cost of future income taxes	+ 2112			
Equity losses from corporations	+ 2113			
Share of partnership(s)/joint venture(s) losses	+ 2114			
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	+ 2115			
Subtotal	=	138,155	+ 2116	138,155

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

	Add		Subtract	
** Fed.s.85	+ 2117		or – 2118	
** Fed.s.85.1	+ 2119		or – 2120	
** Fed.s.97	+ 2121		or – 2122	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+ 2123		or – 2124	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	+ 2125		or – 2126	
** Amounts relating to s.57.10 election/regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years	+ 2127		or – 2128	
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income			– 2150	
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)			– 2155	

Subtotal (Additions) =		+ 2129	
Subtotal (Subtractions) =		– 2130	
** Other adjustments		± 2131	
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131		= 2132	374,513
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss		± 2133	
Adjusted net income (loss) (if loss, transfer to 2202 in *Part 2: Continuity of CMT Losses Carried Forward*.)		= 2134	374,513
Deduct: * CMT losses: pre-1994 Loss	+ From 2210		
* CMT losses: other eligible losses	+ 2211		
	=	– 2135	

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this schedule.*

CMT Base	= 2136	374,513

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)			+ 2201	
Add: Current year's losses	+ 2202			
Losses from predecessor corporations on amalgamation NOTE (3)	+ 2203			
Losses from predecessor corporations on wind-up NOTE (3)	+ 2204			
Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes				
Subtotal	=		+ 2207	
Adjustments (attach schedule)			± 2208	
CMT losses available 2201 + 2207 ± 2208			= 2209	
Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income	+ 2210			
Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)	+ 2211			
Losses expired during the year	+ 2212			
Subtotal	=		– 2213	
Balances at End of Year NOTE (5) 2209 – 2213			= 2214	

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.

(5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 1999-09-30	2260	2280
2241	8th preceding taxation year 2000-09-30	2261	2281
2242	7th preceding taxation year 2001-09-30	2262	2282
2243	6th preceding taxation year 2001-12-31	2263	2283
2244	5th preceding taxation year 2002-12-31	2264	2284
2245	4th preceding taxation year 2003-12-31	2265	2285
2246	3rd preceding taxation year 2004-12-31	2266	2286
2247	2nd preceding taxation year 2005-12-31	2267	2287
2248	1st preceding taxation year 2006-12-31	2268	2288
2249	Current taxation year 2007-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290 ***must equal amount in*** 2214.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) . . . . . + 2301

Add: Current year's CMT Credit (280 on page 8 of the CT23 or 347 on page 6 of the CT8. If negative, enter NIL) + From 280 or 347

Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8. (Life Insurance corporations only. Others enter NIL.) . . . . . + From 312

Subtract Income Tax (190 on page 6 of the CT23 or page 4 of the CT8) . . . . . – From 190

Subtotal (If negative, enter NIL) . . . = ► – 2305

Current year's CMT credit (If negative, enter NIL) 280 or 347 – 2305 . . . = ► + 2310

CMT Credit Carryovers from predecessor corporations NOTE (3) . . . . . + 2325

Amalgamation (X) 2315 ☐ Yes Wind-up (X) 2320 ☐ Yes

Subtotal 2301 + 2310 + 2325 . . . . . = 2330

Adjustments *(Attach schedule)* . . . . . ± 2332

CMT Credit Carryover available 2330 ± 2332 . . . . . = 2333

Transfer to Page 8 of the CT23 or Page 6 of the CT8

Subtract: CMT Credit utilized during the year to reduce income tax (310 on page 8 of the CT23 or 351 on page 6 of the CT8.) + From 310 or 351

CMT Credit expired during the year . . . . . + 2334

Subtotal . . . . . = ► – 2335

Balance at End of Year NOTE (4) 2333 – 2335 . . . . . = 2336

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))

(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).

(3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(4) Amount in 2336 must equal sum of 2370 + 2390 .

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 1999-09-30	2360	2380
2341	8th preceding taxation year 2000-09-30	2361	2381
2342	7th preceding taxation year 2001-09-30	2362	2382
2343	6th preceding taxation year 2001-12-31	2363	2383
2344	5th preceding taxation year 2002-12-31	2364	2384
2345	4th preceding taxation year 2003-12-31	2365	2385
2346	3rd preceding taxation year 2004-12-31	2366	2386
2347	2nd preceding taxation year 2005-12-31	2367	2387
2348	1st preceding taxation year 2006-12-31	2368	2388
2349	Current taxation year 2007-12-31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390 ***must equal amount in*** 2336 .

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year (max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

(ii) Continuity of Other Eligible CMT Losses – Filing Corporation (for losses occurring in tax years commencing after 1993)

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1998-09-30					
9th Prior Year	1999-09-30					
8th Prior Year	2000-09-30					
7th Prior Year	2001-09-30					
6th Prior Year	2001-12-31					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	**Opening Balance**	**Add**	**Adjustment**	**Deduction**	**Expired**	**Closing Balance**
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1998-09-30					
9th Prior Year	1999-09-30					
8th Prior Year	2000-09-30					
7th Prior Year	2001-09-30					
6th Prior Year	2001-12-31					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Ontario Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

TOWN OF PARRY SOUND	+	2,433,728
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	2,433,728

Ontario Ministry of Finance
Corporations Tax
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PO Box 620
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

Is the corporation electing under regulation 1101(5q)? 1 [ ] Yes 2 [X] No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	5,256,026	150,312		0	5,406,338	75,156	5,331,182	4	0	0	213,247	5,193,091
10	3,212			0	3,212		3,212	30	0	0	964	2,248
Totals	5,259,238	150,312			5,409,550	75,156	5,334,394				214,211	5,195,339

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario Ministry of Finance
Corporations Tax
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Ontario Cumulative Eligible Capital Deduction

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year *(if negative, enter zero)*			= +	451,301 **A**
Add: Cost of eligible capital property acquired during the taxation year	+ **B**			
Other adjustments	+ **C**			
B + C	=	x 3 / 4 =	**D**	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002		x 1 / 2 = –	**E**	
D minus E *(if negative, enter zero)*		=		+ **F**
Amount transferred on amalgamation or wind-up of subsidiary				+ **G**
Subtotal A + F + G				= 451,301 **H**
Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	+ **I**			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada)	+ **J**			
Other adjustments	+ **K**			
I + J + K	=	x 3 / 4		= – **L**
Ontario cumulative eligible capital balance H minus L				= 451,301 **M**

*If **M** is negative, enter zero at line **Q** and proceed to **Part 2**, page 2.*

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			**N**	
From **M**	451,301			
From **N**	–			
Current year deduction **M minus N**	= 451,301	x 7 % = +	31,591 **O**	
N + O		=	31,591	– 31,591 **P**

Note: *The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.*

Enter amount in box 651 *of the CT23*

Ontario cumulative eligible capital - closing balance M minus P *(if negative, enter zero)* = 419,710 **Q**

See page 2 - Part 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
PARRY SOUND POWER CORPORATION	1800162	2007-12-31

Part 2 – Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. *Show this as a positive amount; not negative*. . . . . ________ **R**

Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988 . . . . + ________ **1**

Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA . . . . + ________ **2**

Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988 . . . . + ________ **3**

Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988 . . . . – ________ **4**

Deduct line 4 from line 3 *(if negative, enter zero)* . . . . = ________ + ________ **5**

Total lines 1 + 2 + 5 . . . . = ________ **6**

Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line **1** . . . . ________ **7**

Amounts at **Line Z** from Ontario Schedule 10 of previous taxation years ending after February 27, 2000
*(This will be **Line T** in earlier versions of this schedule.)* . . . . + ________ **8**

Total lines 7 + 8 . . . . = ________ – ________ **9**

Deduct line 9 from line 6 *(if negative, enter zero)* . . . . = ________ – ________ **S**

R minus S *(if negative, enter zero)* . . . . = ________ **T**

From Line **5** ________ x 1 / 2 . . . . = – ________ **U**

T minus U *(if negative, enter zero)* . . . . = ________ **V**

From **V** ________ x 2 / 3 . . . . = ________ **W**

Lesser of **R** and **S** . . . . = + ________ **Z**

Amount to be included in income W + Z . . . . = ________

Description of Deferral and Variance Accounts

This Schedule contains descriptions of Deferral and Variance Accounts ("DVAs") used by Parry Sound Power.

Commodity accounts are classified as follows:

1588 Retail Settlement Variance Account – Power

Description: This account is used to recover the net difference between the energy amount billed to customers and the energy charged to Parry Sound Power using the settlement invoice from the Independent Electricity System Operator [IESO], host distributor and embedded generator.

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustments

Description: This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to Parry Sound Power using the settlement invoice from the Independent Electricity System Operator [IESO].

Non-commodity accounts are classified in two categories as follows:

Wholesale and Retail Market Variance Accounts:

1518 Retail Cost Variance Account – Retail

Description: This account is used to record the net of revenues derived from establishing retailer services agreements, distributor-consolidated billing, retailer-consolidated billing and spilt billing and the costs of entering into retailer service agreements and related contract administration, as well as incremental costs to provide distributor-consolidated and split billing and any avoided costs credit arising from retailer-consolidated billing.

1548 Retail Cost Variance Account – STR

Description: This account is used to record the net of revenues derived from service transaction requests charged by Parry Sound Power in the form of a request fee, processing fee, information request fee, default fee and other associated costs and the incremental cost of labour, internal information system maintenance costs and delivery costs related to the provision of retail transaction services.

Low Voltage Variance Account

Description: This account is used to record the amounts charged to customers based on the OEB approved low voltage rate rider and Low Voltage charges billed by Hydro One Networks Inc. (H.O.N.I.) on the Power bill.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Description: This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, the amount charged by a host distributor, and the amount billed to customers using the OEB approved Wholesale Market Service Rate.

Retail Settlement Variance Account - One-time Wholesale Market Service

Description: This account is used to record the net of non-recurring amounts not included in the Wholesale Market Service Rate charged by the IESO based on the settlement invoice and the amount charged to customers for the same services using the OEB-approved rate.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

Description: This account is used to record the net of the amount charged by the IESO, based on the settlement invoice, for transmission network services, the amount charged by the host distributor and the amount billed to customers using the Board Approved Transmission Network Charge.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Description: This account is used to record the net of the amount charged by the IESO, based on the settlement invoice, for transmission connection services, the amount charged by the host distributor and the amount billed to customers using the OEB-approved Transmission Connection Charge.

Utility Deferral Accounts:

1508 Other Regulatory Assets

Description: This account includes amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the Board

1525 Miscellaneous Deferred Debits

Description: This account includes all debits not elsewhere provided for which will benefit future periods are carried forward and charged to expense over the term of the benefit. Specifically, Customer Information System expenses with respect to Ontario Price Credit [OPC] rebate cheques are tracked in this account.

1555 Smart Meter Capital and Recovery Offset Variance

Description: This account records the net of the amounts paid for capitalized direct costs related to the smart meter program and the amounts charged to customers using the OEB approved smart meter rate rider.

1556 Smart Meter OM&A Variance

Description: This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters.

1562 Deferred Payments in Lieu of Taxes

Description: This account records the amount resulting from the OEB-approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent periods ending April 30, 2006.

1563 PILs contra account

Description: This account records the amounts relating to the third accounting method approved for recording entries in Account 1562 in accordance with the OEB's accounting instructions for PILs as set out in the April 2003 Frequently Asked Questions on the AP Handbook.

1565 Conservation and Demand Management Expenditures and Recoveries

Description: This account records the net of amounts incurred for conservation and demand management (CDM) activities and expenditures, the revenue proxy amount equivalent to the third tranche of market adjusted revenue requirement (MARR) and the amount charged to customers using the OEB approved CDM rate rider as well as 2006 CDM revenues and costs.

1566 CDM Contra

Description: This account records the offsetting entry for amounts recorded in account 1565, CDM Expenditures and Recoveries, pertaining to third tranche CDM programming for the reversal of entries to the accounts of original entries.

1570 Qualifying Transition Costs

Description: This account was used to record transition costs meeting the criteria established by the OEB.

1571 Pre-Market Opening Energy Variances

Description: This account was used to record the difference between the utility's purchased cost of power based on time-of-use and amounts billed to non-time-of-use customers charged at an average rate for the same period. Amounts recorded in this account started January 1, 2001 and ended on April 30, 2002.

1572 Extraordinary Event Losses

Description: This account is used to record extraordinary event costs that meet the qualifying criteria established by the OEB.

1574 Deferred Rate Impact Amounts

Description: This account is used to record amounts equal to rate impacts associated with market-based rate of return, transition costs and extraordinary costs that are determined to be excessive and decided to defer to future periods.

1590 Recovery of Regulatory Asset Balances

Description: This account records the net of amounts collected from or repaid to customers using the OEB approved regulatory asset recovery rate riders and the account balances of other regulatory assets approved on a final basis for recovery or repayment in rates when directed by the OEB. In November 2006, LDCs were advised by the OEB to reallocate the 2006 EDR approved regulatory asset balances from their account of origin to the 1590 recovery accounts effective May 1, 2006.

PILs & Tax Variance [Deferred PILs]

Description: Effective May 1, 2006 this account will be used to record the tax impact of any of the following differences:

- any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB tax model
- any differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretive bulletins by relevant federal or provincial tax authorities
- any differences in 2006 PILs that result in changes in a distributor's "opening" 2006 balances for tax accounts due to changes in debits and credits to those accounts arising from a tax re-assessment.

2425 Other Deferred Credits

Description: This account includes advance billings and receipts and other deferred credits not provided for elsewhere including amounts, which cannot be entirely cleared or disposed of until additional information has been received.

Calculation of Balances by Account

Requested for disposition

Parry Sound Power is requesting disposition of the following Deferral accounts:

- 1508 Other Regulatory Assets
- 1525 - Miscellaneous Deferred Debits
- 1550 - LV Variance Account

Parry Sound Power is requesting disposition of the 2007 year-end balances in the three accounts plus interest calculated to April 30, 2009. Interest is calculated at the available OEB prescribed rates.

Table 1 Calculation of Account Balances

	Basis for Allocation to Customer Classes	Bal @ Dec 31 07		2008	2009 Interest Jan 1 - Apr 30	Account Balance for Disposition
		Principal	Interest	Interest		
1508 - Other Regulatory Assets	Distribution Revenue	$17,214	$1,265	$702	$234	$19,416
1525 - Miscellaneous Deferred Debits	Provincial Rebate Cheques	$870	$163	$35	$12	$1,080
1550-LV Variance Account	kWh	$154,487	$4,175	$6,303	$2,101	$167,066
Total for Disposition		**$172,571**	**$5,604**	**$7,041**	**$2,347**	**$187,563**

Method of Recovery and Rate Rider

The methods proposed to dispose of the DVA balances, together with a summary of proposed rates and bill impacts, are set out in this Schedule.

1508 Other Regulatory Assets

Disposal of the year end 2007 balance plus interest to April 30, 2009 over a three year period is requested.

Method of recovery: Allocation to rate classes on basis Distribution Revenue at existing rates

1525 Miscellaneous Deferred Debits

Disposal of the year end 2007 balance plus interest to April 30, 2009 over a three year period is requested.

Method of recovery: Allocation to rate classes on basis of number of Provincial rebate cheques per customer class

1550 Low Voltage Charges

Disposal of the year end 2007 balance plus interest to April 30, 2009 over a three year period is requested.

Method of recovery: Allocation to rate classes on basis of 2009 kWh.

The proposed allocators are provided in the following table:

Table 2 Proposed Allocators

Allocators	Total	Residential	GS < 50kW	GS 50 - 4,999kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
Distribution Revenue	$1,886,774	$1,014,959	$345,983	$500,941	$8,622	$603	$15,666
Provincial Rebate Cheques	$3,215	$2,680	$535	$0	$0	$0	$0
kWh	$89,919,820	$32,856,430	$16,622,806	$39,438,481	$118,251	$16,006	$867,846

Proposed DVA Rate Riders

The proposed rate Riders resulting from the Account Balances and proposed Allocators are set out in the table below.

Table 3 Proposed DVA Rate Riders

Allocation by Customer Class	Account Balance for Disposition	Residential	GS < 50kW	GS 50 - 4,999kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
1508-Other Regulatory Assets	$19,416	$10,444	$3,560	$5,155	$89	$6	$161
1525 - Miscellaneous Deferred Debits	$1,080	$901	$180	$0	$0	$0	$0
1550-LV Variance Account	$167,066	$61,046	$30,884	$73,275	$220	$30	$1,612
Total	$187,563	$72,391	$34,624	$78,430	$308	$36	$1,774
Annual Recovery Amount	$62,521	$24,130	$11,541	$26,143	$103	$12	$591
Proposed Rate Rider *(based on 2009 volumes)*		**$0.0007**	**$0.0007**	**$0.2723**	**$0.0009**	**$0.2922**	**$0.2439**

Overview of Cost of Capital and Return

The purpose of this evidence is to summarize the method and cost of financing Parry Sound Power's capital requirements for the 2009 test year.

Capital Structure

Parry Sound Power has a current a current capital structure of 53.3% debt, 46.7%, and a return on equity of 9.00%, consistent with the capital structure and return specified in the OEB's Decision in EB-2007-0825, dated 14th March, 2008. Parry Sound Power is requesting Board approval of a capital structure of 56.67% debt, 43.33% equity including an equity return of 8.57%.

Parry Sound Power is requesting this change in capital structure and associated return on equity primarily to comply with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated August 15, 2006. That Report requires all licensed Ontario electricity distributors to move toward a 60% debt/40% equity ratio. Details are provided in Exhibit 6, Tab 1, Schedule 2. Parry Sound Power believes the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Cost of Debt

Exhibit 6, Tab 1, Schedule 2 provide the details of Parry Sound Power's forecast long-term debt cost of 7.25% for 2009.

Return on Equity

Parry Sound Power is requesting an equity return for the 2009 Test year of 8.57%. PSP understands that the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information. PSP's use of an ROE of 8.57% is without prejudice to any revised ROE that may be adopted by the OEB in early 2009.

Table 1 Capital Structure

	Current Application				***2006 EDR Approved***		
	Deemed Portion	***Effective Rate***	***Return Amount***		***Deemed Portion***	***Effective Rate***	***Return Amount***
Short-Term Debt	4.00%	4.47%			0.00%		
Long-Term Debt	52.67%	7.25%			50.00%	7.25%	
Total Equity	43.33%	8.57%			50.00%	9.00%	
Regulated Rate of Return	**100%**	**7.71%**			**100%**	**8.13%**	
Rate Base			$5,281,770				$5,540,217
Regulated Return on Capital			**$407,264**				**$450,143**
Deemed Interest Expense			*$211,132*				*$200,833*
Deemed Return on Equity			*$196,132*				*$249,310*

Cost of Debt

Table 2 Cost of Debt

Description	Amount	Issue Date (dd-mmm-yyyy)	Term Date (dd-mmm-yyyy)	Interest Rate (a)	Other Costs (b)	Due to Affiliate?	Annual Cost (c)
Note Payable to Shareholder	2,433,728	1-Nov-2000	no term	7.25%		YES	176,445

Description	Effective Rate	Days o/s in 2009	Average Balance	2009 Cost	2009 Ending Balance	Debt o/s USA #	Int. Expense USA #
Note Payable to Shareholder	7.25%	365	2,433,728	176,445	2,433,728	2520	6005
TOTAL	**7.25%**		**2,433,728**	**176,445**	**2,433,728**		

(a) For debt held issued prior to 12-Apr-2006 (prior Test Year approval, per sheet A1), represents the previously approved rate.
(b) Annual charges other than interest (e.g. commitment fees, amortization of issuance costs, etc.)
(c) For debt issued to an affiliate since 12-Apr-2006, represents the lower of (i) actual cost and (ii) cost based on the deemed debt rate (5.25%)

Return on Equity

The calculations used to determine the ROE and the debt are taken from the OEB's "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors" issued August 15, 2006.

The following are extracts from Appendix A and B to the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors.

Method to Update the Deemed Long-term Debt Rate

The Board will use the Long Canada Bond Forecast plus an average spread with "A/BBB" rated corporate bond yields to determine the updated deemed debt rate.

The following approach is consistent with the ROE method. As per the approach adopted in the 2006 EDR, the ROE and the long-term debt rates are based on the same risk-free rate forecast. Therefore, they differ only through the risk premiums that reflect their distinct natures and for which lenders/investors seek commensurate returns. This approach simplifies the calculations and aims to make it easier to understand the numbers. Specifically, the Long Canada Bond Forecast (LCBFt) used will be the same as that used for updating the ROE. The average spread between "A/BBB" rated corporate bond yields and 30-year (long) Government of Canada Bond yields will be calculated as the average spread over the weeks of the month corresponding to the Consensus Forecasts.

The deemed Long-Term Debt Rate (LTDRt) will be calculated as follows:

$$LTDR_t = LCBF_t + \frac{\sum_w (CorpBonds_{w,t} - {}_{30}CB_{w,t})}{n}$$

Where:

- ***CorpBonds w,t*** is the average long-term corporate bond yield from Scotia Capital Inc. for week *w* of period *t* [Series V121761];
- ***30CBw,t*** is the 30-year (long) Government of Canada bond yield for week *w* of period *t* [Series V121791]; and
- ***n*** is the number of weeks in the month for which data are reported.

Method to Update ROE - ROE Update for any Period

Using March 1999 as the starting calculation and substituting for the initial ROE and Long Canada Bond Forecast approved by the Board in the Decision RP-1998-0001 the following is the adjustment formula for calculating the ROE at time *t*:

$$ROE_t = 9.35\% \ + 0.75 \times (LCBF_t - 5.50\%)$$

The ROE must be set in advance of the approved rates. The final ROE will be factored into rates using the Long Canada Bond Forecast based on *Consensus Forecasts* (as detailed below) and Bank of Canada data three months in advance of the effective date for the rate change. Therefore, for May 1 rate changes, the ROE will be based on January data – effectively *Consensus Forecasts* published during that month and Bank of Canada data for all business days during the month of January. The necessary data is available within the first or second business days after the end of the month and thus poses no delay for determining rates.

Long Canada Bond Forecast for any Period

For any period *t* the Long Canada Bond Forecast *LCBFt* can be expressed as:

$$LCBF_t = \left[\frac{{}_{10}CBF_{3,t} + {}_{10}CBF_{12,t}}{2} \right] + \frac{\sum_i ({}_{30}CB_{i,t} - {}_{10}CB_{i,t})}{I_t}$$

Where:

- **10CB3,T** is the 3-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;
- **10CB12,t** is the 12-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;
- **30CBi,t** is the actual rate for the 30-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39056] during the month (this is the previous month data, the same as used for updating the ROE for natural gas distribution) corresponding to time *t*;
- **10CBi,t** is the actual rate for the 10-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39055] during the month corresponding to time *t*; and
- ***It*** is the number of business days for which published 10- and 30- Government of Canada bond yields are published during the month corresponding to time *t*.

Overview of Utility Revenue

This exhibit presents an overview of the revenue deficiency or surplus calculations used to project the deficiency of revenue for the 2009 Test year. The steps used in this process are:

- Calculate the Service Revenue using the Rate Base (Exhibit 2), OM & A and Amortization Expenses calculated in Exhibit 4 and the Return on Capital calculated in Exhibit 6.

- Calculate the Base Revenue requirement using the PILs calculation and the Revenue Offsets from Exhibit 3.

- Use the existing rates and load projections to calculate Utility Income - Net of Taxes and PILs

- Use those Calculated Revenues and the Base Revenue requirement to determine Revenue Deficiency or Sufficiency.

Parry Sound Power projects that it will need to recover a Service Revenue Requirement of $2,129,732 in the 2009 Test Year through distribution rates and other regulated charges. This includes:

- $ 1,941,997 recovered through fixed and variable distribution rates plus a projected Transformer allowance of $14,119 and LV charges of $183,000 for a total of $2,139,116;

- $ 187,735 recovered through Administration, Specific Service Charges and Other Miscellaneous Revenue.

At the existing distribution rates, Parry Sound Power's 2009 Test Year gross revenue deficiency is calculated as $133,170. It is derived from the chart in Exhibit 7, Tab 1, Schedule 2.

Determination of Revenue Deficiency or Surplus

Table 1 Revenue Sufficiency / Deficiency (2008 and 2009)

	2009 Projection	**2008 Projection**
Utility Income	299,974	309,189
Utility Rate Base	5,281,770	5,289,237
Indicated Rate of Return	5.68%	5.85%
Requested / Approved Rate of Return	7.71%	7.71%
Sufficiency / (Deficiency) in Return	(2.03%)	(1.87%)
Net Revenue Sufficiency / (Deficiency)	**-107,290**	**-98,651**
Provision for PILs/Taxes *	-25,880	-14,630
Gross Revenue Sufficiency / (Deficiency)	**-133,170**	**-113,281**
Deemed Overall Debt Rate	*7.05%*	*7.25%*
Deemed Cost of Debt	*211,132*	*191,735*
Utility Income less Deemed Cost of Debt	*88,842*	*117,455*
Return On Deemed Equity	*3.88%*	*5.12%*
UTILITY INCOME		
Total Net Revenues	1,996,562	1,988,294
OM&A Expenses	1,264,790	1,255,072
Depreciation & Amortization	394,504	384,102
Taxes other than PILs / Income Taxes	0	0
Total Costs & Expenses	1,659,295	1,639,173
Utility Income before Income Taxes / PILs	337,267	349,120
PILs / Income Taxes	37,293	39,931
Utility Income	**299,974**	**309,189**

The forecasted revenue deficiency is mainly attributable to the fact that the 2006 EDR rates do not reflect forecasted increases in OM & A costs and Capital Investments.

The 2006 EDR was based on historic (average of 2003 &2004) net fixed assets balances, and the 2004 additions were subject to the half year rule.

Parry Sound Power has continued to make capital investments through the period 2004 – 2007 and will continue to invest in Capital projects in 2008 and 2009.

This increase in investments, results in an increase in return on capital, depreciation expense and in working capital.

The recovery of Regulatory Assets is not included in the revenue requirement. Regulatory Assets are recovered through a separate rate rider. Regulatory Assets, deferral accounts and recoveries are explained in Exhibit 5.

COST ALLOCATION

Proposed Method

Introduction

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. Parry Sound Power prepared a cost allocation information filing consistent with Parry Sound Power's understanding of the Directions, the Guidelines, the Model and the Instructions. Parry Sound Power submitted this filing to the OEB in early 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications.

Current Cost Allocation Study

On the advice of ERA, PSP assessed the need to complete an updated cost allocation study on the basis of stability of PSP's infrastructure, operations, customer count and the class shares of billed kWh and kW. The premise underlying this approach is that if the underlying costs and allocators are stable, the proportional allocation of costs to the rate classes will not have changed significantly from the results of the 2006 Cost Allocation Model. In that case, it will be reasonable to use the percentage allocations to the rate classes that were derived in the 2006 cost allocation as a suitable proxy for the 2009 allocators.

The information on PSP's rate base (Exhibit 2) and operating and maintenance costs (Exhibit 4) show that the underlying infrastructure and operations have been quite stable through the intervening years. Further Exhibit 3, Tab 2, Schedule 4 shows that the customer count has also been stable. Tables 1 and 2, below, show the 2006 EDR Approved and 2009 forecast class shares of billed kWh and kW. These tables show that the usage is also stable.

PSP concurs with ERA's advice that PSP's infrastructure, operations, customer count and the class shares of billed kWh and kW are sufficiently stable relative to the acceptable revenue-to-cost ratio ranges recommended by the Board in Application of Cost Allocation for Electricity Distributors, Report of the Board (EB-2007-0667) that it would not be prudent to incur the cost of completing an full cost allocation study for the 2009 test year. The factors that were considered in making this determination were:

- the proportions of kWh and kW attributable to each rate class have not changed significantly between the 2006 EDR approved shares and the 2009 forecast, hence, the share of costs attributable to each class will not have changed significantly;
- PSP's capital and operating cost do not exhibit any significant discontinuities;
- the revenue-to-cost ratios for all classes are within the Board-approved ranges; hence small changes in the calculated revenue-to-ratios would not require changes in the proposed rates;
- PSP will be implementing smart meters in the near future, which will provide a significantly improved basis (e.g., a direct measure of the hourly demand of each rate class) for quantifying the allocators used in the cost allocation study than the Hydro One estimates that must be relied on at this time; hence, it is prudent to defer updating PSP's cost allocation study until this information is available;
- time of use commodity pricing can be expected to alter demand and, as a result, some key allocators used in cost allocation studies; hence, it would be prudent to defer updating PSP's cost allocation study until the new patterns of use can be reflected in the study; and
- it is expected that the Board's current Rate Design Review will result in changes to rate classes necessitating new cost allocation studies; hence, an updated cost allocation study will be required in the near-future in any case.

Updating PSP's cost allocation would require a significant investment of time and money to obtain an updated hourly load shape by class, and then update the cost allocation model with 2009 forecast cost information. If PSP were to conduct a cost allocation study for the 2009 test year, it would be quickly out-of-date due to the imminent industry and regulatory changes noted above. For these reasons, PSP determined that it was prudent to defer updating its cost allocation study until its next cost of service rate application is filed.

Table 1 Class kWh and Share: 2006 EDR vs. 2009 forecast

Customer Class Name	2006 EDR Approved kWh	Share by Class	2009 Normalized	Share by Class
Residential	13,198	2.84%	12,260	1.89%
General Service Les Than 50 kW	35,602	7.67%	31,071	4.79%
General Service 50 to 4,999 kW	409,174	88.16%	597,553	92.19%
Unmetered Scattered Load	4,629	1.00%	5,375	0.83%
Sentinel Lighting	806	0.17%	1,067	0.16%
Street Lighting	716	0.15%	864	0.13%
TOTAL	**464,125**	**100.00%**	**648,190**	**100.00%**

Table 2 Class kW and Share: 2006 EDR vs. 2009 forecast

Customer Class Name	2006 EDR Approved kW	Share by Class	2009 Normalized	Share by Class
General Service 50 to 4,999 kW	1338	99.68%	1455	99.65%
Sentinel Lighting	2	0.17%	3	0.19%
Street Lighting	2	0.15%	2	0.17%
TOTAL	**1,342**		**1,460**	

Summary of Results and Proposed Changes

Results of the Cost Allocation Study:

The data used in the Cost Allocation Model was consistent with Parry Sound Power's cost data that supported its 2006 OEB-approved distribution rates. Consistent with the Guidelines, Parry Sound Power assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to all Utilities, its engineering records, and its customer and financial information systems.

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The following table outlines the revenue to cost ratios from the Cost Allocation Informational Filing submitted by Parry Sound Power. In addition, the dollar amount by which each rate classification is being subsidized or over-contributing is provided. The calculations are based on Parry Sound Power's OEB-approved 2006 electricity distribution rates.

Table 3 Revenue to Cost Ratios (Informational Filing)

Rate Classification	Revenue to Cost Ratio	$ Being Subsidized / $ Over-Contributing
Residential	104.74%	$46,809
GS <50 kW	86.33%	$(59,578)
GS>50 – 4,999 kW	140.74%	$118,185
Unmetered Scattered Load	66.30%	$(5,139)
Sentinel Lighting	33.60%	$(1,212)
Street Lighting	13.56%	$(99,065)
Total	**--**	**$0**

Proposed Adjustment to Cost Allocation:

On November 28, 2007, the OEB issued its “Report on Application of Cost Allocation for Electricity Distributors” (the “Cost Allocation Report”). In the Cost Allocation Report, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 2 below. As can be seen from the table, Parry Sound Power Cost Allocation Filing Results, only the Residential, GS <50kW, and GS > 50-4,999 are the customer classes currently falling within the revenue to cost ratio ranges established by the OEB. The table also provides the Proposed 2009 R/C ratios for comparison purposes. The calculations providing the proposed ratios will be discussed later in this Exhibit.

Table 4 OEB Proposed R/C Ratio Ranges & PSP Filing Results

Customer Class	OEB Low	OEB High	Cost Allocation Filing Results	Proposed 2009 R/C Ratios
Residential	85%	115%	104.74%	103.85%
GS <50 kW	80%	120%	86.33%	91.37%
GS>50 – 4,999 kW	80%	180%	140.74%	124.12%
Unmetered Scattered Load	80%	120%	66.30%	90.68%
Sentinel Lighting	70%	120%	33.60%	73.03%
Street Lighting	70%	120%	13.56%	41.80%

As can be seen in Table 5 below, Parry Sound Power is proposing to re-align its revenue to cost ratios in this application by adjusting the allocations of its Base Revenue Requirement, before Transformer Allowance and Low Voltage, among its rate classes in order to reduce the cross-subsidization. Transformer Allowance and Low voltage is then added to the resulting class revenues to arrive at the Gross Base Revenue Requirement.

Table 5 Allocation of Base Revenue Requirement

- Customer Class Name	- Outstanding Base Revenue Requirement %	-		- Outstanding Base Revenue Requirement $[3]	-		Directly	Total Base
	Cost Allocation	Existing Rates	Rate Application	Cost Allocation	Existing Rates	Rate Application	Assigned Revenues	Revenue Requirement
Residential	52.96%	53.79%	55.000%	1,028,459	1,041,939	1,068,098	-	1,068,098
General Service Les Than 50 kW	23.72%	18.34%	21.675%	460,685	356,308	420,928	-	420,928
General Service 50 to 4,999 kW	16.00%	26.55%	19.855%	310,660	518,001	385,584	-	385,584
Unmetered Scattered Load	0.77%	0.46%	0.700%	14,991	8,919	13,594	-	13,594
Sentinel Lighting	0.103%	0.03%	0.075%	1,994	624	1,456	-	1,456
Street Lighting	6.447%	0.83%	2.695%	125,208	16,206	52,337	-	52,337
TOTAL	100.00%	100.00%	100.000%	1,941,997	1,941,997	1,941,997	-	1,941,997

- Customer Class Name	Total Base Revenue Requirement	Transformer Allowance Recovery[4]	Low Voltage Revenue Required[5]	Gross Base Revenue Requirement
Residential	1,068,098	-	74,170	1,142,268
General Service Les Than 50 kW	420,928	-	34,033	454,961
General Service 50 to 4,999 kW	385,584	14,119	73,103	472,806
Unmetered Scattered Load	13,594	-	242	13,836
Sentinel Lighting	1,456	-	25	1,481
Street Lighting	52,337	-	1,427	53,763
TOTAL	1,941,997	14,119	183,000	2,139,116

Parry Sound Power is proposing to move in the direction of the revenue to cost ratio of 100% in this rate application for all customer classes. However, since the revenue to cost ratios for Street Lighting was so low in the Cost Allocation Filing, Parry Sound Power is proposing to move this class approximately half way to the lower revenue to cost band of 70% in this application and proposes to move to revenue to cost ratios of 70% during the 2 year IRM period

2010 and 2011. The intent of this proposal is to reduce the rate impact for the customer in this class.

Table 6 provides a comparison of the 2009 Allocated Revenue versus the 2009 Allocated Cost to arrive at the proposed Revenue to cost ratios. The Allocated Cost is calculated by multiplying the Base Revenue Requirement times the revenue proportions from the cost allocation filing. As noted earlier the R/C ratio for all customer classes are moving in the direction of a R/C ratio of 100%.

Table 6 Parry Sound Power Revenue to Cost Ratios

Customer Class Name	Rate Application			Cost Allocation	Variance
	Allocated Revenue [8]	Allocated Cost [8]	Revenue to Cost Ratio	Revenue to Cost Ratio [9]	
Residential	1,068,098	1,028,459	1.04	1.05	-0.01
General Service Les Than 50 kW	420,928	460,685	0.91	0.86	0.05
General Service 50 to 4,999 kW	385,584	310,660	1.24	1.41	-0.17
Unmetered Scattered Load	13,594	14,991	0.91	0.66	0.24
Sentinel Lighting	1,456	1,994	0.73	0.34	0.39
Street Lighting	52,337	125,208	0.42	0.14	0.28
TOTAL	1,941,997	1,941,997	1.00	1.00	

Cost Allocation Summary

The discussion and tables above support Parry Sound Power's proposed reallocation of distribution revenues across customer classes, in order to begin moving toward revenue to cost ratios of 100% and reduce cross-subsidization. Parry Sound Power submits that the proposed reallocation of distribution revenue is fair and reasonable for the following reasons:

- Customer class revenues will more closely reflect the actual costs of providing distribution service to that class;
- Partial reallocation provides time for further refinement of the cost allocation model and movement between classes;
- The further reallocation to the Street Lighting customer class continue in 2010 and 2011 with proposed offsets to those classes who are still above the revenue to cost ration of 1.0.

Rate Design Overview

This exhibit documents the calculation of Parry Sound Power's proposed distribution rates by rate class for the 2009 test year, based on the rate design as proposed in this Exhibit.

Parry Sound Power has determined its total 2009 service revenue requirement to be $2,129,732. The total revenue offsets in the amount of $187,735 reduces Parry Sound Power's total service revenue requirement to a base revenue requirement to $1,941,997 excluding transformer allowance and LV charges. The base revenue requirement is derived from Parry Sound Power's 2009 capital and operating forecasts, weather normalized usage, forecasted customer counts, and Parry Sound Power's regulated return on rate base. The revenue requirement is summarized in the table below:

Table 1 Calculation of Base Revenue Requirement

	2009 Projection
OM&A Expenses	1,264,790
3850-Amortization Expense	394,504
Total Distribution Expenses	1,659,295
Regulated Return On Capital	407,264
PILs (with gross-up)	63,173
Service Revenue Requirement	**2,129,732**
Less: Revenue Offsets	187,735
Base Revenue Requirement	**1,941,997**

The outstanding Base Revenue Requirement is allocated to the various rate classes using the following proposed apportionment of revenue as outlined in Exhibit 8 – Cost Allocation and repeated below on Table 2.

Table 2 Proposed Apportionment of Revenue to Rate Classes

Rate Classification	Proposed Proportion of Revenue
Residential	55.000%
GS<50 kW	21.675%
GS>50 – 4,999 kW	19.855%
Unmetered Scattered Loads	0.700%
Sentinel Lights	0.075%
Street Lights	2.695%
Total	**100.00%**

The following table outlines the results of this allocation which is then adjusted for Transformer allowance Recovery and Low Voltage Revenue required to arrive at Gross Base Revenue Requirement.

Table 3 Allocation of Outstanding Base Revenue Requirement Plus Transformer Allowance and Low Voltage

Customer Class Name	Total Base Revenue Requirement	Transformer Allowance Recovery	Low Voltage Revenue Required	Gross Base Revenue Requirement
Residential	1,068,098		74,170	1,142,268
General Service Les Than 50 kW	420,928		34,033	454,961
General Service 50 to 4,999 kW	385,584	14,119	73,103	472,806
Unmetered Scattered Load	13,594		242	13,836
Sentinel Lighting	1,456		25	1,481
Street Lighting	52,337		1,427	53,763
TOTAL	**1,941,997**	**14,119**	**183,000**	**2,139,116**

Determination of Monthly Fixed Charges

Parry Sound Power's current OEB-approved monthly fixed charges based on its 2008 IRM application by customer class are included in Table 4 below.

Using the existing approved fixed charges applied to the forecasted number of customers for 2009, the following table outlines the current split between fixed and variable distribution revenue.

Table 4 Existing Fixed Variable Split using Existing Monthly Service Charge

Customer Class Name	Existing Rates		
	Rate	Fixed %	Variable %
Residential	$16.71	53.35%	46.65%
General Service Les Than 50 kW	$25.17	46.91%	53.09%
General Service 50 to 4,999 kW	$170.31	26.94%	73.06%
Unmetered Scattered Load	$8.92	27.31%	72.69%
Sentinel Lighting	$1.74	51.93%	48.07%
Street Lighting	$0.41	31.53%	68.47%

In September 2006 the OEB completed its Cost Allocation Review and issued the Board Directions on Cost Allocation Methodology for Electricity Distributors, RP-2005-0317. The results of this Board report stem from at least three years of discussions and work groups which included OEB staff, electricity distributors, interveners and experts at various stages of the review process. Subsequently, in November of 2006, the OEB issued the Cost Allocation Informational Filing Guidelines for Electricity Distributors ("the Guidelines") and the Cost Allocation Model. The Guidelines and Model provided LDCs the framework to complete their cost allocation studies, which were filed in early 2007.

In its follow-up to the review of the cost allocation filings, the OEB issued a “Board Staff Discussion Paper on the Implications Arising from a Review of the Electricity Distributors’ Cost Allocation Filings” (EB-2008-0667), in which OEB staff requested comments on proposed ranges for revenue to cost ratios and well as ranges for the fixed distribution charges.

Board staff made the suggestion in Section 3.5 of the Discussion Paper (Implications Arising from the Determination of class Specific Revenue to Cost Ratios) that “no distributor’s revenue to cost ratios should be outside the ranges, without significant justification…” and further that “Any distributor with a class ratio that falls outside the suggested ranges should re-align its distribution rates so that all classes fall with the respective ranges.” OEB staff further recognizes throughout this section that “for some customer classes, there could be higher than average rate adjustments.” and that “Any significant adjustments to rates must consider the range of factors associated with rate changes which may not allow for immediate full adjustments.”

In Section 4 of the Discussion Paper, OEB staff provided an analysis of fixed distribution charges and suggested an upper and lower range based on the minimum system concept. This concept has been a long-standing methodology for cost allocation studies, however OEB staff proposed that each distributor set fixed rates within these ranges “at the time of its next rebasing rate application.”

In its November 28, 2008 Report on Application of Cost Allocation for Electricity Distributors, referred to in Exhibit 8 above, the OEB addressed a number of “Other Rate Matters”, including the treatment of the fixed rate component (the Monthly Service Charge, or “MSC”) of the bill. At page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is defined in the September 29, 2006 report of the OEB entitled “Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors”. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB’s Rate Review proceeding (EB-2008-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time.

Parry Sound Power is proposing in this application to change the Monthly Service Charges, while keeping within the boards November 28, 2007 guidelines, which results in a change to the fixed variable proportions. The following Table provides Parry Sound Power's calculations of its proposed monthly fixed distribution charges for the 2009 Test Year and the resulting Fixed Variable splits.

Table 5 Proposed Monthly Service Charges and Fixed Variable Splits

Existing Fixed/Variable Split				Rate Application		
Customer Class Name	Rate	Fixed %	Variable %	Rate	Fixed %	Variable %
Residential	$18.95	53.35%	46.65%	$17.88	50.34%	49.66%
General Service Less Than 50 kW	$33.25	46.91%	53.09%	$31.33	44.21%	55.79%
General Service 50 to 4,999 kW	$160.81	26.94%	73.06%	$153.03	25.63%	74.37%
Unmetered Scattered Load	$14.31	27.31%	72.69%	$13.37	25.51%	74.49%
Sentinel Lighting	$4.27	51.93%	48.07%	$3.99	48.49%	51.51%
Street Lighting	$1.41	31.53%	68.47%	$1.25	28.01%	71.99%

Proposed Volumetric Charges

The variable distribution charge is calculated by dividing the variable distribution portion of the Gross Base Revenue Requirement by the appropriate 2009 Test Year usage, kWh or kW, as the class charge determinant.

The following Table 6 provides Parry Sound Power's calculations of its proposed variable distribution charges for the 2009 Test Year assuming the same fixed/variable split used in designing the current approved rates.

Table 6 Variable Distribution Charge Calculation

Customer Class	Gross Base Revenue Requirement	Variable Revenue Proportion	2009 Test Volumetric Billing Determinant	Proposed Volumetric Distribution Charge
Residential	1,142,268	49.66%	32,856,430	$ 0.0173
General Service Les Than 50 kW	454,961	55.79%	16,622,806	$ 0.0153
General Service 50 to 4,999 kW	472,806	74.37%	96,015	$ 3.6620
Unmetered Scattered Load	13,836	74.49%	118,251	$ 0.0872
Sentinel Lighting	1,481	51.51%	41	$ 18.6082
Street Lighting	53,763	71.99%	2,424	$ 15.9668
Total	**2,139,116**			

Proposed Distribution Rates

The following table sets out Parry Sound Power's proposed 2009 electricity distribution rates based on the foregoing calculations. Although Parry Sound Power has not included any forecast for Smart Meters as a result of not currently being included in the Ministry regulations, Parry Sound Power is asking for $1.00 per metered customer per month as seen in many of the 2008 cost of service decisions. The final proposed rates therefore include the Base Revenue Requirement, adjusted for Transformer Allowance Recovery, LV Revenue Required, and the Smart Meter rate adder.

Table 7 Proposed 2009 Electricity Distribution Rates

Customer Class	Calculated Fixed Charge	Smart Meters	Proposed Total Fixed Charge	Proposed Volumetric Charge
Residential	$17.88	$1.00	$18.88	$0.0173
General Service Les Than 50 kW	$31.33	$1.00	$32.33	$0.0153
General Service 50 to 4,999 kW	$153.03	$1.00	$154.03	$3.6620
Unmetered Scattered Load	$13.37		$13.37	$0.0872
Sentinel Lighting	$3.99		$3.99	$18.6082
Street Lighting	$1.25		$1.25	$15.9668

Total Loss Factor	
Secondary Metered Customer < 5,000kW	1.0586
Primary Metered Customer < 5,000kW	1.0480
Transformer Ownership Allowance ($/kW)	$ (0.6000)

Rate Mitigation

Parry Sound Power submits that the bill impacts of its proposed 2009 electricity distribution rates are in line with the Board's November 28, 2007 Cost Allocation Report with the exception of the Street Light Class.

As mentioned previously in Exhibit 8 - Cost Allocation, Parry Sound Power is proposing to move the revenue to cost ratios for the Street Light class from the existing Cost Allocation R/C ratio by one-half of the difference between the existing ratio and the R/C ratio of 70% in an effort to mitigate the increase to those customers. Parry Sound Power proposes the R/C ratios move to 70% over the 2 years of the 3rd Generation IRM process following this cost of service rate application.

Existing Rate Classes

Residential

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase.

General Service Less Than 50kW

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 – 4,999 kW

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Unmetered Scattered Load

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Existing Rate Schedule

Residential

Service Charge	$	16.95
Distribution Volumetric Rate	$/kWh	0.0143
Regulatory Asset Recovery	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.41
Distribution Volumetric Rate	$/kWh	0.0110
Regulatory Asset Recovery	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	170.55
Distribution Volumetric Rate	$/kW	3.8105
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.8937
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6161
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.2535
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9603
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	8.92
Distribution Volumetric Rate	$/kWh	0.0530
Regulatory Asset Recovery	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	1.74
Distribution Volumetric Rate	$/kW	7.0713
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.4354
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2755
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.41
Distribution Volumetric Rate	$/kW	4.4250
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.4282
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2493
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.001
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	15
Account history	$	15
Credit reference/credit check (plus credit agency costs	$	15
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30
Returned Cheque (plus bank charges)	$	15
Charge to certify cheques	$	15

Legal letter charge	$	15
Special meter reads	$	30
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30
Non-Payment of Account		
Late Payment - per month	%	1.5
Late Payment - per annum	%	19.56
Collection of account charge – no disconnect	$	30
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65
Disconnect/Reconnect Charge - At pole During Regular Hours	$	185
Install/Remove load control device – during regular hours	$	65
Service call – customer owned equipment	$	30
Temporary Service install & remove – overhead – no transformer	$	500
Temporary Service install & remove – underground – no transformer	$	300
Temporary Service install & remove – overhead –with transformer	$	1000
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.6
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0586
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.048
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Proposed Rate Classes

Parry Sound Power is not requesting any changes to the existing rate classes.

Proposed Rate Schedule

Residential

Service Charge	$	18.88
Distribution Volumetric Rate	$/kWh	0.0173
Regulatory Asset Recovery	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Les Than 50 kW

Service Charge	$	32.33
Distribution Volumetric Rate	$/kWh	0.0153
Regulatory Asset Recovery	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	154.03
Distribution Volumetric Rate	$/kW	3.6620
Regulatory Asset Recovery	$/kW	<u>0.2724</u>
Retail Transmission Rate – Network Service Rate	$/kW	1.5528
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	<u>1.5353</u>
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge	$	13.37
Distribution Volumetric Rate	$/kWh	0.0872

Regulatory Asset Recovery	$/kWh	0.0009
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	3.99
Distribution Volumetric Rate	$/kW	18.6082
Regulatory Asset Recovery	$/kW	0.2925
Retail Transmission Rate – Network Service Rate	$/kW	1.1770
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2117
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.25
Distribution Volumetric Rate	$/kW	15.9668
Regulatory Asset Recovery	$/kW	0.2440
Retail Transmission Rate – Network Service Rate	$/kW	1.1711
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1868
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Arrears Certificate	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge / change of occupancy charge	$	30.00
Special Meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Late Payment - per month	%	1.50

Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Install / remove load control device – during regular hours	$	65.00
Service call – customer-owned equipment	$	30.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Service Transaction Request -- request fee (per request)	$	0.25

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor -Secondary Metered Customer < 5,000 KW	1.0586
Total Loss Factor -Secondary Metered Customer > 5,000 KW	
Total Loss Factor-Primary Metered Customer <5,000 KW	1.0480
Total Loss Factor-Primary Metered Customer >5,000 KW	

Rate Impacts

This Schedule presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are derived using the applicable May 1, 2008 rates and the proposed 2009 distribution rates (including Rate Rider for the recovery of Deferral and Variance Accounts), proposed 2009 Retail Transmission Service Rates, and Parry Sound Power's proposed Loss Factor.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

Table 8 Residential Bill Impact – 600 kWh's

Residential **RPP:** **Summer**

600 kWh's		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$16.95			$18.88	$1.93	11.4%
Distribution	kWh	600	$0.0143	$8.58	600	$0.0173	$10.38	$1.80	21.0%
Sub-Total (Distribution)				**$25.53**			**$29.26**	**$3.73**	**14.6%**
Deferral/Variance Dispositions	kWh	600			600	$0.0007	$0.42	$0.42	
Electricity (Commodity)	kWh	635	RPP-Summer	$32.07	635	RPP-Summer	$32.07		
Transmission - Network	kWh	635	$0.0042	$2.67	635	$0.0042	$2.67		
Transmission - Connection	kWh	635	$0.0043	$2.73	635	$0.0043	$2.73		
Wholesale Market Service	kWh	635	$0.0052	$3.30	635	$0.0052	$3.30		
Rural Rate Protection	kWh	635	$0.0010	$0.64	635	$0.0010	$0.64		
Debt Retirement Charge	kWh	600	$0.0065	$3.90	600	$0.0065	$3.90		
TOTAL BILL				**$70.84**			**$74.99**	**$4.15**	**5.9%**

Table 9 Residential Bill Impact – 1,000 kWh's

Residential **RPP:** **Winter**

1,000 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$16.95			$18.88	$1.93	11.4%
Distribution	kWh	1,000	$0.0143	$14.30	1,000	$0.0173	$17.30	$3.00	21.0%
Sub-Total (Distribution)				**$31.25**			**$36.18**	**$4.93**	**15.8%**
Deferral/Variance Dispositions	kWh	1,000			1,000	$0.0007	$0.70	$0.70	
Electricity (Commodity)	kWh	1,059	RPP-Winter	$53.46	1,059	RPP-Winter	$53.46		
Transmission - Network	kWh	1,059	$0.0042	$4.45	1,059	$0.0042	$4.45		
Transmission - Connection	kWh	1,059	$0.0043	$4.55	1,059	$0.0043	$4.55		
Wholesale Market Service	kWh	1,059	$0.0052	$5.50	1,059	$0.0052	$5.50		
Rural Rate Protection	kWh	1,059	$0.0010	$1.06	1,059	$0.0010	$1.06		
Debt Retirement Charge	kWh	1,000	$0.0065	$6.50	1,000	$0.0065	$6.50		
TOTAL BILL				**$106.77**			**$112.40**	**$5.63**	**5.3%**

Table 10 General Service (<50 kW) Bill Impact – 2,000 kWh's

General Service Less Than 50 kW **RPP:** **Winter**

2,000 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$25.41			$32.33	$6.92	27.2%
Distribution	kWh	2,000	$0.0110	$22.00	2,000	$0.0153	$30.60	$8.60	39.1%
Sub-Total (Distribution)				**$47.41**			**$62.93**	**$15.52**	**32.7%**
Deferral/Variance Dispositions	kWh	2,000			2,000	$0.0007	$1.40	$1.40	
Electricity (Commodity)	kWh	2,117	RPP-Winter	$115.91	2,117	RPP-Winter	$115.91		
Transmission - Network	kWh	2,117	$0.0038	$8.05	2,117	$0.0038	$8.05		
Transmission - Connection	kWh	2,117	$0.0039	$8.26	2,117	$0.0039	$8.26		
Wholesale Market Service	kWh	2,117	$0.0052	$11.01	2,117	$0.0052	$11.01		
Rural Rate Protection	kWh	2,117	$0.0010	$2.12	2,117	$0.0010	$2.12		
Debt Retirement Charge	kWh	2,000	$0.0065	$13.00	2,000	$0.0065	$13.00		
TOTAL BILL				**$205.76**			**$222.68**	**$16.92**	**8.2%**

Table 11 General Service (<50 kW) Bill Impact – 4,000 kWh’s

General Service Less Than 50 kW **RPP:** **Summer**

4,000 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$25.41			$32.33	$6.92	27.2%
Distribution	kWh	4,000	$0.0110	$44.00	4,000	$0.0153	$61.20	$17.20	39.1%
Sub-Total (Distribution)				**$69.41**			**$93.53**	**$24.12**	**34.8%**
Deferral/Variance Dispositions	kWh	4,000			4,000	$0.0007	$2.80	$2.80	
Electricity (Commodity)	kWh	4,234	RPP-Summer	$244.43	4,234	RPP-Summer	$244.43		
Transmission - Network	kWh	4,234	$0.0038	$16.09	4,234	$0.0038	$16.09		
Transmission - Connection	kWh	4,234	$0.0039	$16.51	4,234	$0.0039	$16.51		
Wholesale Market Service	kWh	4,234	$0.0052	$22.02	4,234	$0.0052	$22.02		
Rural Rate Protection	kWh	4,234	$0.0010	$4.23	4,234	$0.0010	$4.23		
Debt Retirement Charge	kWh	4,000	$0.0065	$26.00	4,000	$0.0065	$26.00		
TOTAL BILL				**$398.69**			**$425.61**	**$26.92**	**6.8%**

Table 12 General Service (>50 kW) Bill Impact – 31,250 kWh’s

General Service 50 to 4,999 kW **RPP:** **n/a**

31,250 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
103 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$170.55			$154.03	($16.52)	(9.7%)
Distribution	kW	103	$3.8105	$392.48	103	$3.6620	$377.19	($15.30)	(3.9%)
Sub-Total (Distribution)				**$563.03**			**$531.22**	**($31.82)**	**(5.7%)**
Deferral/Variance Dispositions	kW	103			103	$0.2724	$28.06	$28.06	
Electricity (Commodity)	kWh	33,081	$0.0545	$1,802.93	33,081	$0.0545	$1,802.93		
Transmission - Network	kW	103	$1.5528	$159.94	103	$1.5528	$159.94		
Transmission - Connection	kW	103	$1.5353	$158.14	103	$1.5353	$158.14		
Wholesale Market Service	kWh	33,081	$0.0052	$172.02	33,081	$0.0052	$172.02		
Rural Rate Protection	kWh	33,081	$0.0010	$33.08	33,081	$0.0010	$33.08		
Debt Retirement Charge	kWh	31,250	$0.0065	$203.13	31,250	$0.0065	$203.13		
TOTAL BILL				**$3,092.27**			**$3,088.52**	**($3.76)**	**(0.1%)**

Table 13 General Service (>50 kW) Bill Impact – 1,332 kW's

General Service 50 to 4,999 kW **RPP:** **n/a**

632,000 kWh's

1,332 kW's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$170.55			$154.03	($16.52)	(9.7%)
Distribution	kW	1,332	$3.8105	$5,075.59	1,332	$3.6620	$4,877.78	($197.80)	(3.9%)
Sub-Total (Distribution)				**$5,246.14**			**$5,031.81**	**($214.32)**	**(4.1%)**
Deferral/Variance Dispositions	kW	1,332			1,332	$0.2724	$362.84	$362.84	
Electricity (Commodity)	kWh	669,035	$0.0545	$36,462.42	669,035	$0.0545	$36,462.42		
Transmission - Network	kW	1,332	$1.5528	$2,068.33	1,332	$1.5528	$2,068.33		
Transmission - Connection	kW	1,332	$1.5353	$2,045.02	1,332	$1.5353	$2,045.02		
Wholesale Market Service	kWh	669,035	$0.0052	$3,478.98	669,035	$0.0052	$3,478.98		
Rural Rate Protection	kWh	669,035	$0.0010	$669.04	669,035	$0.0010	$669.04		
Debt Retirement Charge	kWh	632,000	$0.0065	$4,108.00	632,000	$0.0065	$4,108.00		
TOTAL BILL				**$54,077.93**			**$54,226.44**	**$148.52**	**0.3%**

Table 14 General Service (>50 kW) Bill Impact – 494 kW's

General Service 50 to 4,999 kW **RPP:** **n/a**

177,610 kWh's

494 kW's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$170.55			$154.03	($16.52)	(9.7%)
Distribution	kW	494	$3.8105	$1,882.39	494	$3.6620	$1,809.03	($73.36)	(3.9%)
Sub-Total (Distribution)				**$2,052.94**			**$1,963.06**	**($89.88)**	**(4.4%)**
Deferral/Variance Dispositions	kW	494			494	$0.2724	$134.57	$134.57	
Electricity (Commodity)	kWh	188,018	$0.0545	$10,246.98	188,018	$0.0545	$10,246.98		
Transmission - Network	kW	494	$1.5528	$767.08	494	$1.5528	$767.08		
Transmission - Connection	kW	494	$1.5353	$758.44	494	$1.5353	$758.44		
Wholesale Market Service	kWh	188,018	$0.0052	$977.69	188,018	$0.0052	$977.69		
Rural Rate Protection	kWh	188,018	$0.0010	$188.02	188,018	$0.0010	$188.02		
Debt Retirement Charge	kWh	177,610	$0.0065	$1,154.47	177,610	$0.0065	$1,154.47		
TOTAL BILL				**$16,145.62**			**$16,190.31**	**$44.69**	**0.3%**

Table 15 USL Bill Impact – 447 kWh's

Unmetered Scattered Load **RPP:** **Summer**

447 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$8.92			$13.37	$4.45	49.9%
Distribution	kWh	447	$0.0530	$23.69	447	$0.0872	$38.98	$15.29	64.5%
Sub-Total (Distribution)				**$32.61**			**$52.35**	**$19.74**	**60.5%**
Deferral/Variance Dispositions	kWh	447			447	$0.0009	$0.40	$0.40	
Electricity (Commodity)	kWh	473	RPP-Summer	$23.66	473	RPP-Summer	$23.66		
Transmission - Network	kWh	473	$0.0038	$1.80	473	$0.0038	$1.80		
Transmission - Connection	kWh	473	$0.0039	$1.85	473	$0.0039	$1.85		
Wholesale Market Service	kWh	473	$0.0052	$2.46	473	$0.0052	$2.46		
Rural Rate Protection	kWh	473	$0.0010	$0.47	473	$0.0010	$0.47		
Debt Retirement Charge	kWh	447	$0.0065	$2.91	447	$0.0065	$2.91		
TOTAL BILL				**$65.76**			**$85.90**	**$20.14**	**30.6%**

Table 16 Sentinel Lighting Bill Impact – 88 kWh's

Sentinel Lighting **RPP:** **Summer**

88 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
0.23 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$1.74			$3.99	$2.25	>100%
Distribution	kW	0.23	$7.0713	$1.61	0.23	$18.6082	$4.24	$2.63	>100%
Sub-Total (Distribution)				**$3.35**			**$8.23**	**$4.88**	**>100%**
Deferral/Variance Dispositions	kW	0.23			0.23	$0.2925	$0.07	$0.07	
Electricity (Commodity)	kWh	93	RPP-Summer	$4.66	93	RPP-Summer	$4.66		
Transmission - Network	kW	0.23	$1.1770	$0.27	0.23	$1.1770	$0.27		
Transmission - Connection	kW	0.23	$1.2117	$0.28	0.23	$1.2117	$0.28		
Wholesale Market Service	kWh	93	$0.0052	$0.48	93	$0.0052	$0.48		
Rural Rate Protection	kWh	93	$0.0010	$0.09	93	$0.0010	$0.09		
Debt Retirement Charge	kWh	88	$0.0065	$0.57	88	$0.0065	$0.57		
TOTAL BILL				**$9.70**			**$14.65**	**$4.95**	**51.0%**

Table 17 Street Lighting Bill Impact – 72 kWh's

Street Lighting **RPP:** **Summer**

72 **kWh's**

0.20 **kW's**

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$0.41			$1.25	$0.84	>100%
Distribution	kW	0.20	$4.4250	$0.89	0.20	$15.9668	$3.21	$2.32	>100%
Sub-Total (Distribution)				**$1.30**			**$4.46**	**$3.16**	**>100%**
Deferral/Variance Dispositions	kW	0.20			0.2012	$0.2440	$0.05	$0.05	
Electricity (Commodity)	kWh	76	RPP-Summer	$3.81	76	RPP-Summer	$3.81		
Transmission - Network	kW	0.20	$1.1711	$0.24	0	$1.1711	$0.24		
Transmission - Connection	kW	0.20	$1.1868	$0.24	0	$1.1868	$0.24		
Wholesale Market Service	kWh	76	$0.0052	$0.40	76	$0.0052	$0.40		
Rural Rate Protection	kWh	76	$0.0010	$0.08	76	$0.0010	$0.08		
Debt Retirement Charge	kWh	72	$0.0065	$0.47	72	$0.0065	$0.47		
TOTAL BILL				**$6.54**			**$9.75**	**$3.21**	**49.1%**