Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		**2017**		
Total Metered excluding WMP	C = A+B	196,959,263	kWh	100%
RPP	A	110,282,244	kWh	56.0%
Non RPP	B = D+E	86,677,019	kWh	44.0%
Non-RPP Class A	D	2,849,283	kWh	1.4%
Non-RPP Class B*	E	83,827,736	kWh	42.6%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the Actual

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month ☐

Note 4 **Analysis of Expected GA Amount**

Year **2017**

Calendar Month	**Non-RPP Class B Including Loss Factor Billed Consumption (kWh)**	**Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)**	**Add Current Month Unbilled Loss Adjusted Consumption (kWh)**	**Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)**	**GA Rate Billed ($/kWh)**	**$ Consumption at GA Rate Billed**	**GA Actual Rate Paid ($/kWh)**	**$ Consumption at Actual Rate Paid**	**Expected GA Variance ($)**
	F	**G**	**H**	**I = F-G+H**	**J**	**K = I*J**	**L**	**M = I*L**	**=M-K**
January	6,578,474	- 7,876,297	7,615,726	22,070,497	0.08227	$ 1,815,740	0.08227	$ 1,815,740	$ -
February	7,801,969	- 7,615,726	6,189,745	21,607,439	0.08639	$ 1,866,667	0.08639	$ 1,866,667	$ -
March	6,828,217	- 6,189,745	6,801,524	19,819,486	0.07135	$ 1,414,120	0.07135	$ 1,414,120	$ -
April	7,426,063	- 6,801,524	6,513,551	20,741,139	0.10778	$ 2,235,480	0.10778	$ 2,235,480	$ -
May	6,573,087	- 6,513,551	6,381,009	19,467,647	0.12307	$ 2,395,883	0.12307	$ 2,395,883	$ -
June	7,026,155	- 6,381,009	6,180,641	19,587,804	0.11848	$ 2,320,763	0.11848	$ 2,320,763	$ -
July	7,392,165	- 6,180,641	7,446,295	21,019,101	0.11280	$ 2,370,955	0.11280	$ 2,370,955	$ -
August	7,979,082	- 7,446,295	7,137,680	22,563,057	0.10109	$ 2,280,899	0.10109	$ 2,280,899	$ -
September	8,526,624	- 7,137,680	7,012,331	22,676,634	0.08864	$ 2,010,057	0.08864	$ 2,010,057	$ -
October	7,443,719	- 7,012,331	7,104,920	21,560,969	0.12563	$ 2,708,705	0.12563	$ 2,708,705	$ -
November	7,089,848	- 7,104,920	6,318,863	20,513,631	0.09704	$ 1,990,643	0.09704	$ 1,990,643	$ -
December	6,905,261	- 6,318,863	7,478,661	20,702,785	0.09207	$ 1,906,105	0.09207	$ 1,906,105	$ -
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**87,570,663**	**- 82,578,582**	**82,180,945**	**252,330,190**		**$ 25,316,017**		**$ 25,316,017**	**$ -**

Calculated Loss Factor **3.0101**

Note 5 **Reconciling Items**

	Item	Amount	Explanation
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)		-$ 448,573	
1a	True-up of GA Charges based on Actual Non-RPP Volumes - prior year		
1b	True-up of GA Charges based on Actual Non-RPP Volumes - current year		
2a	Remove prior year end unbilled to actual revenue differences	-$ 231,901	Reversal of 2016 unbilled revenue difference. Amount was not included in 2018 IRM request for disposition
2b	Add current year end unbilled to actual revenue differences	$ -	2017 unbilled revenues were true-up to actual amounts at year end
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers		
3b	Add difference between current year accrual/forecast to actual from long term load transfers		
4	Remove GA balances pertaining to Class A customers		
5	Significant prior period billing adjustments recorded in current year	$ 29,813	($72,100) - reversal of 2016 adjustment due to some customers were billed the June GA rate on their July consumption. This resulted in higher GA revenue since the June rate was higher than the July rate. These
6	Differences in GA IESO posted rate and rate charged on IESO invoice	$ 47,862	Difference between the actual invoiced GA amount and the amount calculated was on NOTL Hydro's proportion of the total GA.
7	Differences in actual system losses and billed TLFs	$ 69,662	Difference between kWh used to calculate GA expense and actual amount billed to customers
8	Others as justified by distributor	$ 498,348	$493,306 was move to A/R in 2017 due to settlement of the NOD with the IESO. $5,042 in legal fees included the
9	Generation Estimates	$ 42,891	Monthly generation numbers reported as part of our 1598 submission to IESO are based on estimates from
10	OEB Approved Disposition	$ 12,943	Approved in NOTL Hydro's 2018 IRM

Note 6

Adjusted Net Change in Principal Balance in the GL	$	21,045
Net Change in Expected GA Balance in the Year Per Analysis	$	-
Unresolved Difference	$	21,045
Unresolved Difference as % of Expected GA Payments to IESO		0.1%

Appendix A

GA Methodology Description
Questions on Accounts 1588 & 15891

NOTE: Questions shown in **BLACK**. Answers shown in **BLUE**. Charts may be shown in black.

1. **In booking expense journal entries for Charge Type (CT) 1142 and CT 148 from the IESO invoice, please confirm which of the following approaches is used:**
   a. CT 1142 is booked into Account 1588. CT 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589 respectively.
   b. *CT 148 is booked into Account 1589. The portion of CT 1142 equaling RPP minus HOEP for RPP consumption is booked into Account 1588. The portion of CT 1142 equaling GA RPP is credited into Account 1589.*
   c. If another approach is used, please explain in detail.

   Niagara-on-the-Lake Hydro uses approach B

2. **Questions on CT 1142**
   a. **Please describe how the initial RPP related GA is determined for settlement forms submitted by day 4 after the month-end (resulting in CT 1142 on the IESO invoice).**
   Refer to Appendix 2B

   b. **Please describe the process for truing up CT 1142 to actual RPP kWh, including which data is used for each TOU/Tier 1&2 prices, as well as the timing of the true up.**
   Refer to Appendix 2C

   c. **Has CT 1142 been trued up for with the IESO for all of 2017?**
   Yes

   d. **Which months from 2017 were trued up in 2018?**
   None

   e. **Have all of the 2017 related true-up been reflected in the applicant's DVA Continuity Schedule in this proceeding?**
   Yes
   f. **Please quantify the amount reflected in the DVA Continuity Schedule, and the column where it is included.**

Credit to account 4705 in the amount of $525,938 is included in the DVA Continuity Schedule in Sheet 2a column BD – Transactions Debit/(Credit) during 2017.

3. **Questions on CT 148**
   a. **Please describe the process for the initial recording of CT 148 in the accounts (i.e. 1588 and 1589)**
   Refer to Appendix 2B

   b. **Please describe the process for true up of the GA related cost to ensure that the amounts reflected in Account 1588 are related to RPP GA costs and amounts in 1589 are related to only non-RPP GA costs.**
   Refer to Appendix 2C

   c. **What data is used to determine the non-RPP kWh volume that is multiplied with the actual GA per kWh rate (based on CT 148) for recording as expense in Account 1589 for initial recording of the GA expense?**
   The initial amount recorded in account 1589 is the total GA (excluding Class A customers) less Estimated RPP GA

   d. **Does the utility true up the initial recording of CT 148 in Accounts 1588 and 1589 based on estimated proportions to actuals based on actual consumption proportions for RPP and non-RPP?**
   Yes

   e. **Please indicate which months from 2017 were trued up in 2018 for CT 148 proportions between RPP and non-RPP.**
   None

   f. **Are all true-ups for 2017 consumption reflected in the DVA Continuity Schedule under 2017.**
   Yes

   g. **Please quantify the amount reflected in the DVA Continuity Schedule, and the column where it is included.**
   Debit to account 4707 in the amount of $678,907.98 is included in the DVA Continuity Schedule in Sheet 2a column BD – Transactions Debit/(Credit) during 2017.

4. Questions regarding principal adjustments and reversals on the DVA Continuity Schedule:

Questions on Principal Adjustments - Accounts 1588 and 1589

a. Did the applicant have principal adjustments in its 2018 rate proceeding which were approved for disposition?

Yes

b. Please provide a break-down of the total amount of principal adjustments that were approved (e.g. true-up of unbilled (for 1589 only), true up of CT 1142, true up of CT 148 etc.).

1588

2016 Adjustments

1. True-up of unbilled revenue for Dec 2016: ($237,386.16).
2. Estimate for impact of 2016 IESO Notice of Dispute (NOD): ($6,947.29)
3. Adjust 2015 NOD from estimate to settlement amount: $12,445.39
4. Adjust 2016 NOD from estimate to settlement amount: ($892.44)

Total 2016 Principal Adjustments: -$237,386.16 - $6,947.29 + $12,445.39 - $892.44 = -$232,780.50

2015 Adjustments

1. Estimate for impact of 2015 NOD: ($35,790.65)

1589

2016 Adjustments

1. True-up of unbilled revenue for Dec 2016: $231,902.02
2. Estimate for impact of 2016 NOD: ($125,029.94)
3. Adjust 2015 NOD from estimate to settlement amount: $64,312.16
4. Adjust 2016 NOD from estimate to settlement amount: $2,822.86
5. Remove legal fees related to NOD included in balance: ($5,042.37)
6. Adjustment for billing error in July 2016: $72,099.66
7. Adjustment for Generation Estimates provided to IESO: $35,661.43

Total 2016 Principal Adjustments: $231,902.02 - 125,029.94 + 64,312.16 + $2,822.86 - $5,042.37 + $72,099.66 + 35,661.43 = $276,725.82

2015 Adjustments

1. Estimate for impact of 2015 NOD: ($435,410.61)

c. Has the applicant reversed the adjustment approved in 2018 in its current proposed amount for disposition?

1588

Yes, the total 2016 amount of $232,780.50 and 2015 amount of $35,790.65 are reversed in 2017 for a total of $268,571.15.

1589

No, the amounts related to Generation Estimates are not reversed in 2017. At the conclusion of our Cost of Service application NOTL Hydro will undertake a historical review of generation estimates provided to IESO to determine the total impact.

All other amounts were reversed. 2016 amount of ($241,063.39) (total $276,724.82 less Generation Estimates $35,661.43) and total 2015 amount of $435,410.61 for a total of $194,347.22

d. Please provide a breakdown of the amounts shown under principal adjustments in the DVA Continuity Schedule filed in the current proceeding, including the reversals and the new true up amounts regarding 2017 true ups.

1588

2017 Adjustments

1. Reversal of True-up of unbilled revenue for Dec 2016: $237,386.16
2. Reversal of Estimate for impact of 2016 IESO Notice of Dispute (NOD): $6,947.29
3. Reversal of Adjustment for 2015 NOD from estimate to settlement amount: ($12,445.39)
4. Reversal of Adjustment 2016 NOD from estimate to settlement amount: $892.44
5. Reversal of Estimate for impact of 2015 NOD: $35,790.65

Total 2017 Principal Adjustments: $237,386.16 + $6,947.29 - $12,445.39 + $892.44 + $35,790.65 = $268,571.15

1589

2017 Adjustments

1. Reversal of True-up of unbilled revenue for Dec 2016: ($231,902.02)
2. Reversal of Estimate for impact of 2016 NOD: $125,029.94
3. Reversal of Adjustment for 2015 NOD from estimate to settlement amount: ($64,312.16)
4. Reversal of Adjustment for 2016 NOD from estimate to settlement amount: ($2,822.86)

5. Reversal of legal fees related to NOD included in balance: $5,042.37
6. Reversal of Adjustment for billing error in July 2016: ($72,099.66)
7. Reversal of Estimate for impact of 2015 NOD: $435,410.61
8. Adjustment for Generation Estimates provided to IESO 2017: $42,891.11

Total 2017 Principal Adjustments: -$231,902.02 + 125,029.94 - 64,312.16 - $2,822.86 + $5,042.37 - $72,099.66 + 435,410.61 + 42,891.11 = $237,237.33.

e. Do the amount calculated in part d. above reconcile to the applicant's principal adjustments shown in the DVA Continuity Schedule for the current proceeding? If not, please provide an explanation.
Yes

f. Please confirm that the principal adjustments approved for disposition in 2018 were not recorded in the applicant's GL as adjustments (they would be recorded as OEB approved dispositions in the GL and shown as such on the DVA Continuity Schedule under 2018).
Confirmed

Appendix 2A – RPP Settlement

Determine Estimated RPP kWh for the reporting month

Actual amounts consumed by RPP customers for the reporting month are not available at the time that the 1598 submission is due to the IESO. Due to this fact, NOTL Hydro estimates RPP consumption by applying a scaling factor to the kWhs billed to RPP customers in the reporting month. This is calculated as follows:

1. Scaling Factor

a. 'Totalized Meter Data with losses for MMP' reports for each day are downloaded from the IESO Reports website. Daily information is consolidated for NOTL Hydro's 2 transformer stations to determine the Total Grid Supplied Consumption.

b. Actual Embedded Generation for the month is added to the Total Grid Supplied Consumption to determine the Total System Consumption for the reporting month.

Example: June 2018		
Grid Supplied Consumption	Embedded Generation	**Total System Consumption**
16,351,107	1,640,550	**17,991,657**

c. The total kWhs billed for all customers (RPP and non-RPP) for the reporting month is obtained from NOTL Hydro's Harris Northstar billing system. The Total System Consumption / Total Billed kWh = Scaling Factor

Example: June 2018		
Total System Consumption	Total Billed kWh	**Scaling Factor**
17,991,657	13,172,187	**1.3660**

2. Energy billed for the reporting month to RPP customers (kWh) in Block 1 and 2 for conventional meters OFF/MID/ON PEAK periods for smart meters are obtained from Northstar. Since these are the billed amounts and not the actual consumption for the month, the scaling factor is applied to estimate the RPP Block 1 & 2 and ON/OFF/MID Peak consumption for the reporting month.

	Billed kWh (Northstar) a	Scaling Factor b	**Consumption Estimate** c = a x b
Block 1	247,313	1.3660	337,830
Block 2	441,012	1.3660	602,422
Off Peak	5,133,449	1.3660	7,012,291
Mid Peak	1,612,397	1.3660	2,202,534
On Peak	1,729,682	1.3660	2,362,746
Total RPP	9,163,853	1.3660	12,517,823

Determine Estimated Weighted Average Price for the reporting month

1. At the time of submission, pricing is normally available in Northstar for the first 19 – 22 days of the reporting month.

a. For the period that pricing is available in Northstar an estimate of the IESO invoice is generated utilizing a 3rd party software provided by Kinetiq. This software uses NOTL Hydro's load, net system load shape and pricing for the period to determine IESO Charge Type 101 – Net energy market settlement for non-dispatchable load. In the example below, pricing in Northstar was available up to and including June 21, 2018. Therefore the estimate invoice cover the period from June 1 – 21, 2018.

Final Start Date	01-Jun-18
Final End Date	07-Jun-18
Preliminary Start Date	08-Jun-18
Preliminary End Date	21-Jun-18

IESO Charge Code	Description	Total Cost
101	Net Energy Market Settlement for Non-dispatchable Load	$209,083.68
102	TR Clearing Account Credit	-$0.40
148	Class B Global Adjustment Settlement Amount	-$2.92
150	Net Energy Market Settlement Uplift	$6,531.42
155	Congestion Management Settlement Uplift	$11,977.95
169	Station Service Reimbursement Debit	$2.70
170	Local Market Power Rebate	-$0.01
183	Generation cost guarantee recovery debt	$0.07
186	Intertie Failure Charge Rebate	-$136.89
250	10-Minute Spinning Market Reserve Hourly Uplift	$2,518.74
252	10-Minute Non-Spinning Market Reserve Hourly Uplift	$1,852.82
254	30-Minute Operating Reserve Market Hourly Uplift	$1,266.54
451	New Code	$1,100.44
452	Reactive Support And Voltage Control Settlement Debit	$0.01
454	Regulation Service Settlement Debit	$0.09
900	GST Credit	-$26.01
950	GST Debit	$30,889.23
1350	Capacity Based Recovery Amount for Class A Loads	$24.09
1351	Capacity Based Recovery Amount For Class B Loads	$827.61
1550	Day-Ahead Production Cost Guarantee Recovery Debit	$2,361.57
		$268,270.73

2. For the remainder of the reporting month when pricing is not available in Northstar pricing is determined using the following method:

a. kWhs are obtained from the 'Totalized Meter Data with losses for MMP' reports mentioned above and Ontario Zone HOEP On Peak and Off Peak prices are obtained from the Daily Market Summary reports available on the IESO website. A sample of the Daily Market Summary is provided below.

Daily Market Summary

Friday June 22 2018

ONTARIO ZONE MARKET QUANTITIES

(MW)	DAILY			ON PEAK[1]			OFF PEAK		
	Ave	Max	Min	Ave	Max	Min	Ave	Max	Min
Market Demand	16,859	18,665	13,896	17,866	18,665	16,664	14,846	16,446	13,896
Ontario Demand	14,551	16,202	11,884	15,509	16,202	14,149	12,635	14,383	11,884
Imports	356	663	233	385	663	248	299	374	233
Exports	2,365	2,736	2,043	2,411	2,736	2,167	2,273	2,566	2,043
Unavailable Capacity	7,896	8,403	7,098	7,764	8,302	7,098	8,161	8,403	7,874

ONTARIO ZONE MARKET PRICES[2]

Energy Prices ($/MWh)	DAILY			ON PEAK			OFF PEAK		
	Ave	Max	Min	Ave	Max	Min	Ave	Max	Min
HOEP	2.89	8.07	-4.35	5.14	8.07	1.87	-1.62	1.80	-4.35
5 Minute MCP	2.89	14.33	-4.40	5.14	14.33	0.00	-1.62	5.78	-4.40
Operating Reserve Prices ($/MWh/hr)									
10 Minute Sync	6.34	21.51	0.20	9.36	21.51	0.32	0.32	1.38	0.20
10 Minute Non-Sync	5.66	21.51	0.20	8.40	21.51	0.28	0.20	0.20	0.20
30 Minute	5.66	21.51	0.20	8.40	21.51	0.28	0.20	0.20	0.20

b. For the purpose of determining the Net energy market settlement for non-dispatchable load for each day that pricing is not available it is assumed that 75% of the consumption is at the ON Peak price and 25% is at the OFF peak price.

Date	kWh - Totalized Meter Data with Losses	ON Peak price / kWh - Daily Market Summary	OFF Peak price / kWh - Daily Market Summary	Daily Total Cost Estimate
	a	b	c	d = (a x 75% x b) + (a x 25% x c)
6/22/18	486,044	$ 0.00514	$ (0.00162)	$ 1,676.85
6/23/18	503,249	$ 0.01135	$ 0.01135	$ 5,711.88
6/24/18	473,543	$ 0.01096	$ 0.01096	$ 5,190.03
6/25/18	493,407	$ 0.01492	$ 0.00393	$ 6,006.00
6/26/18	515,451	$ 0.01728	$ 0.00112	$ 6,824.57
6/27/18	567,863	$ 0.02658	$ 0.00311	$ 11,761.87
6/28/18	637,833	$ 0.03977	$ 0.01694	$ 21,726.17
6/29/18	724,141	$ 0.03904	$ 0.01675	$ 24,235.17
6/30/18	793,124	$ 0.02437	$ 0.02437	$ 19,328.42
	5,194,654			$ 102,460.97

c. The amount found on Line 101 of the estimated invoice plus the daily total cost estimate are used as the estimate of the commodity cost for the month purchased from the grid. This amount is then divided by the Grid Supplied Consumption to arrive at the weighted average price for the month.

Estimated Invoice Line 101	June 1 - 21	$ 209,083.68
Daily Totals	June 22 - 30	$ 102,460.97
Total Commodity Cost (a)		$ 311,544.65
Grid Supplied Consumption (kWh) (b)	June 1 - 30	16,351,107
Average Price per kWh (a / b)	June 1 - 30	$ 0.0191

3. Since the actual Global Adjustment rate for the month is not available at the time of the submission, the 2nd Estimate of the Global adjustment rates for Class B customers for the month is used for estimating RPP cost of power. The rate is obtained from the IESO website.

Global Adjustment Estimates and Actual Rates

The 1st, 2nd estimate and actual rates for Class B customers are posted below in MWh.

2018	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1st Estimate ($/MWh)	87.77	73.33	78.77	98.10	93.92	133.36	85.02	77.90				
2nd Estimate ($/MWh)	63.70	77.05	85.95	100.74	131.99	102.39	81.23					
Actual Rate ($/MWh)	67.36	81.67	94.81	99.59	107.93	118.96						

Average Price per kWh	$	0.01905
GA 2nd Estimate per kWh	$	0.10239
Total	$	0.12144

Estimate and submit RPP Variances

The estimated/scaled RPP energy consumption is multiplied by the RPP rates to estimate the amount NOTL Hydro will receive from RPP customers for the reporting month.

	Billed kWh (Northstar) a	Scaling Factor b	Consumption Estimate c = a x b	RPP Rates d	Revenue e = c x d
Block 1	247,313	1.3660	337,830	$ 0.077	$ 26,012.88
Block 2	441,012	1.3660	602,422	$ 0.089	$ 53,615.59
Off Peak	5,133,449	1.3660	7,012,291	$ 0.065	$ 455,798.94
Mid Peak	1,612,397	1.3660	2,202,534	$ 0.094	$ 207,038.22
On Peak	1,729,682	1.3660	2,362,746	$ 0.132	$ 311,882.42
Total RPP	9,163,853	1.3660	12,517,823		$ 1,054,348.05

The estimated/scaled RPP energy consumption is multiplied by the estimated weighted average price and GA 2nd estimate to determine the total cost of power.

	Billed kWh (Northstar) a	Scaling Factor b	Consumption Estimate c = a x b	Estimated Weighted Average Price d	GA 2nd Estimate e	Cost per kWh f = d + e	Total Cost e = c x d
Block 1	247,313	1.3660	337,830	$ 0.0191	$ 0.102	$ 0.12149	$ 41,042.91
Block 2	441,012	1.3660	602,422	$ 0.0191	$ 0.102	$ 0.12149	$ 73,188.30
Off Peak	5,133,449	1.3660	7,012,291	$ 0.0191	$ 0.102	$ 0.12149	$ 851,923.27
Mid Peak	1,612,397	1.3660	2,202,534	$ 0.0191	$ 0.102	$ 0.12149	$ 267,585.89
On Peak	1,729,682	1.3660	2,362,746	$ 0.0191	$ 0.102	$ 0.12149	$ 287,049.96
Total RPP	9,163,853	1.3660	12,517,823				$ 1,520,790.34

The differences between dollars received and cost for each of blocks 1 and 2 for conventional meters and OFF/MID/ON PEAK periods for smart meters are the RPP variances submitted to the IESO in the Form 1598.

	Revenue a	Total Cost b	Due to / (from) IESO c = a - b
Block 1	$ 26,012.88	$ 41,042.91	$ (15,030.04)
Block 2	$ 53,615.59	$ 73,188.30	$ (19,572.70)
Off Peak	$ 455,798.94	$ 851,923.27	$ (396,124.34)
Mid Peak	$ 207,038.22	$ 267,585.89	$ (60,547.67)
On Peak	$ 311,882.42	$ 287,049.96	$ 24,832.46
Total RPP	$ 1,054,348.05	$ 1,520,790.34	$ (466,442.29)

Determine Accounting Entries

When the IESO invoice for the reporting month is received, an accounting entry is made to reflect the components of the total RPP variance amount in Charge Type 1142. For each of blocks 1 and 2 for conventional meters and OFF/MID/ON PEAK periods for smart meters, the entry to OEB Account 4705 is to reflect passing on to the IESO the RPP dollars received by NOTL Hydro from customers less NOTL Hydro's energy cost at the weighted average price. The entry to Account 4707 is to reflect NOTL Hydro's energy cost at the GA rate for non-RPP customers.

	Due to (from) IESO	GA - RPP Account 4707	Cost of Power Account 4705
Block 1	$ (15,030.04)	$ (34,590.37)	$ 19,560.33
Block 2	$ (19,572.70)	$ (61,682.03)	$ 42,109.33
Off Peak	$ (396,124.34)	$ (717,988.51)	$ 321,864.17
Mid Peak	$ (60,547.67)	$ (225,517.49)	$ 164,969.82
On Peak	$ 24,832.46	$ (241,921.52)	$ 266,753.98
Total RPP	$ (466,442.29)	$ (1,281,699.92)	$ 815,257.63

	Consumption Estimate a	Estimated Weighted Average Price d	Cost of Power c = a x b	GA 2nd Estimate d	GA e	Total Cost e = c x d
Block 1	337,830	$ 0.019	$ 6,452.54	$ 0.102	$ 34,590.368	$ 41,042.91
Block 2	602,422	$ 0.019	$ 11,506.27	$ 0.102	$ 61,682.029	$ 73,188.30
Off Peak	7,012,291	$ 0.019	$ 133,934.76	$ 0.102	$ 717,988.510	$ 851,923.27
Mid Peak	2,202,534	$ 0.019	$ 42,068.41	$ 0.102	$ 225,517.487	$ 267,585.89
On Peak	2,362,746	$ 0.019	$ 45,128.44	$ 0.102	$ 241,921.523	$ 287,049.96
Total RPP	12,517,823		$ 239,090.42		$ 1,281,699.92	$ 1,520,790.34

Appendix 2c - 1598 True-up Process

1. The true-up process is completed once all billings for the reporting period have been processed through the billing system. The last billings for 2017 were completed in mid-February 2018. While the true-up was competed in 2018 all entries were booked in 2017.
2. Actual billed usage data and weighted average price is extracted from the NOTL Hydro's Northstar Reporting Database using SQL Server Management Studio. Data includes:
    a. Read from Date
    b. Read to Date
    c. Billed Days
    d. Usage (kwh)
    e. Rate
    f. Rate Type (Block 1, Block 2, On, Off, Mid Peak)
    g. Weighted Average Price (WAP)
3. The data is consolidated and sorted to determine the following by Rate Type and month of consumption:
    a. kWh consumed (including losses)
    b. RPP amount received
    c. Cost (WAP) amount.
    d. Global Adjustment (GA) Cost is calculated by multiplying kWh consumed is multiplied by the actual GA for each month to determine the total GA attributable to RPP customers
4. Actual settlement amounts are calculated for 4705 and 4707:
    a. 4705 = RPP Received – Cost (WAP)
    b. 4707 = GA Cost
5. The Actual settlement amounts are compared to the monthly 1598 submissions
    a. The variance between the 2 amounts is the True-up entry.