Board Staff Supplemental Interrogatories
2009 Electricity Distribution Rates
Northern Ontario Wires Inc. (NOW)
EB-2008-0238

OPERATING COSTS

Other Interest Expense

1. Ref: E4/T2/S1 – OM&A costs table, E/6/T1/ S3 – Cost of Debt table
Board staff IR #3, #12, #41 (a)

In response to Board staff IR #3 and #12, NOW explained that it has included the following amounts in OM&A:

Other Interest Expense

IESO Letter of Guarantee Fee ($525/month)	$	6,300
Regulatory Interest (on Variance Accounts)		50,943
Truck Loan Interest – Digger Truck (purchased in 2007)		11,000
Truck Loan Interest – Bucket Truck (purchased in 2008)		13,214
Customer Deposit Interest Expense		6,119
	$	87,576

a. Please explain the nature of the interest charges identified above for the truck loans and the variance accounts.

The interest in the truck loans are normal interest cost associated with a non-cash purchase (credit purchase) of a vehicle. As responded to in parts b) and c) of this question the vehicles are part of rate base and NOW agrees that these interest costs should not be a part of “Other Interest Costs”.

With respect to Regulatory Interest (on Variance Accounts), this is an expense that is associated with the amounts owing to rate payers for the over collection of RSVA expenses.

b. Please confirm that the trucks in question are included in rate base.

As discussed in part a) of this question, the vehicles are in the rate base the identified interest costs should not be a part of "Other Interest".

c. If so, please confirm that as all other rate base items, NOW will be earning a return on the capital investment to purchase the trucks, which return includes both the deemed equity return and the deemed interest on the debt portion.

NOW agrees, and submits that our other Interest value should be reduced by $24,214

d. If so, does NOW agree that including the truck loan interest amounts in "Other Interest Expense" would lead to double recovery of the interest expense? If not, please explain.

Yes, NOW agrees that this would be double counting of interest and should not occur.

e. Please confirm whether or not the variance account balances provided in response to Board staff IR #41 a) includes the $50,943 amount shown above for regulatory interest on variance accounts.

The balances in BS IR #41a) do include carrying charges (interest).

f. If so, does NOW agree that including the $50,943 amount in "Other Interest Expense" would lead to double counting once the variance accounts are disposed?

No, NOW does not agree this would lead to double counting. As this other interest is an expense (owing to customers) NOW will be returning the principle and interest portions of the variances without any recovery for the interest expense (unless recovered here). As NOW does not have any control over the timing of disposition of these accounts or any control over the WMS or COP retail rates, NOW submits that these expenses are legitimate business costs and should be recoverable via the revenue requirement. Regulatory Interest (carrying charges) currently included in revenue requirements will need to be adjusted to reflect any approval of all or part of NOW's deferral and variance accounts.

For Reference the new "Other Interest Expense" should be as follows:

IESO Letter of Guarantee Fee ($525/month)	$ 6,300
Regulatory Interest (on Variance Accounts)	$50,943
Customer Deposit Interest Expense	$ 6,119
Total Other Interest Expense	***$ 63,362***

Impacts of proposed change to NOW's governance structure

2. Ref: E4/T2/S4/p1 – Shared services table, Board staff IR #8, EB-2008-0339 – MAADs application by the Town of Cochrane

On October 17, 2008, the Town of Cochrane, which currently owns 67% of the shares of both NOW and its street lighting affiliate Northern Ontario Energy (NOE), applied under section 86 (2) of the OEB Act to acquire the remaining shares of both NOW and NOE from the Town of Iroquois Falls. The purchase price is $1M. Notice of Application was issued on January 12, 2009. The deadline for submissions on the application is ten days from the last publication date.

The Town of Cochrane currently owns 100% of Cochrane Telecom Services (CTS), which provides all labour and certain facilities services to NOW (with the exception of five management personnel recently transferred from CTS to NOW).

In response to Board staff IR#8, NOW indicated that CTS is the only affiliate from which NOW purchases significant services and that there are no corporate services allocated to NOW.

a. Please confirm whether or not the status of the activities as described by NOW in response to Board staff IR #8 changes once the proposed transaction in the MAADs case is completed and the new governance structure is implemented, assuming Board approval.

NOW does not anticipate any changes in the near future to the services agreement with CTS resulting from the proposed change in shares ownership.

b. If NOW or its affiliates are planning changes to shared services or corporate cost allocation, as a result of the share purchase, if approved, please identify what they are and the purpose for the changes.

See response to a) above –therefore not applicable.

c. Please identify any impacts on any other aspects of the subject rate application, such as cost of debt, capital structure, debt / equity, etc.

NOW does not anticipate any impact on any aspects of the rate application resulting from the proposed change in shares ownership

Revision to NOW's Regulatory Costs Claim

3. Ref: E4/T2/S1/p2 – OM&A Costs Table, E4/T2/S6 – Purchase of Services, Board staff IR #11

In response to Board Staff IR #11, NOW indicated that it will add $5,000 in Intervenor costs in its final submission in this application. NOW realized that it had not included any costs for Intervener activities in its original filing. In reviewing other 2008 cost awards NOW estimated $15,000 in costs from intervenors. NOW stated that it will be including $5,000 as an annual cost, in the final submission for this application.

With respect to the regulatory related costs NOW is proposing to recover in 2009, it is unclear which expense items are for the full amount and which costs are amortized.

In terms of the annual rate application costs, it appears that NOW records those in another account under Purchases of Services. All regulatory costs to be recovered in 2009 should be recorded in account 5655, Regulatory Expenses.

It is also unclear whether the $24,000 included for RDI consulting in 2009 as "purchased services" is the total cost of the 2009 rate application, or if it is 1/3 of the total amount amortized over three years (i.e. 1/3 of about $72,000).

a. Please confirm that NOW is (i) requesting an increase in 2009 regulatory expenses in account 5655 from $17,875 to $22,875, (ii) that this $5,000 increase equates to1/3 of $15,000 in projected Intervenor costs related to the 2009 rates proceeding, and (iii) that the $17,875 pertains only to OEB quarterly and annual fees.

i) NOW confirms the request to increase 2009 regulatory expenses by $5,000 to account for intervener costs

ii) We estimated $15,000 and did allocate it for 3 years = $5,000 annually.

iii) Yes - See schedule with b) below for details of $17,875.

b. Please provide a schedule itemizing all the regulatory related costs, including consultant and legal, that NOW proposes to recover in its 2009 revenue requirement (including costs that have not been included under Account 5655); the schedule should (i) identify the account number the itemized costs are recorded in and (ii) indicate whether the amount to be recovered in 2009 is the full amount or an amortized portion (e.g the first year of a three year amortization period).

See chart below:

A/C#5630-0000 - Outside Services

		2009 TEST
Legal Fees	$	10,000
Actuarial Services	$	1,500
EDA Membership	$	12,500
ESA Contractor License	$	400
Management Fees	$	94,884
Audit Fees	$	22,500
Consulting Fees - Regulatory (RDI)	$	24,000
TOTAL as submitted per Original Filing	**$**	**165,784**
Add Negotiation Consulting Costs omitted from original application	$	2,500
TOTAL Revised Outside Services	**$**	**168,284**

A/C#5655-0000 Regulatory Expenses

		2009 TEST
OEB Quarterly Assessments	$	16,000
OEB Annual License	$	800
OEB Cost Awards	$	1,075
TOTAL as submitted per Original Filing	**$**	**17,875**
Estimate of Intervenor Costs - not considered in original, suggested 3 year amortization in response to first round of interogatories	$	5,000
revise Intervenor Costs to four year amortization period	$	(1,250)
TOTAL REGULATORY EXPENSES	**$**	**21,625**

NOW erroneously excluded contract negotiation consultant costs from the application. Usually $10,000 every three years. We just settled a four year deal. $10,000/ 4 = $2,500/year. See summary of changes to revenue requirements.

There was not an increased value in the purchased services from RDI consulting relating to the 2009 rebasing costs. The value of $24,000 is an ongoing expense that has been consistent over the last 4 years. In 2008 / 2009 NOW utilized the purchased services for rate application projects as opposed to other business consulting.

As there are no incremental costs relating to 2009 rebasing, there has not been any amortization of the costs.

c. If certain costs related to the 2009 rates proceeding are not amortized please explain why such amounts are not amortized over three years as per NOW's approach to Intervenor costs for 2009.

See Summary of Proposed Changes to Revenue Requirements – NOW has reflected the change from a three year rate period to a four year rate period. We have attempted to identify any costs that occur every few years and amortize them over the rate period.

d. Please explain whether or not NOW's regulatory costs should be amortized over four years rather than three in light of the Board's determination in its July 14, 2008 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* that the plan term for 3rd generation incentive regulation will be fixed at three years (i.e. rebasing year plus three years).

As explained in part c) of this question, NOW submits that regulatory costs (relating to the RDI purchased services) should not be amortized, however, we do agree that if a 3 year IRM process will be utilized than the $15,000 for intervener costs should be amortized over 4 years.

e. Please explain why NOW does not appear to be conforming to the described treatment as outlined in the Board's *Accounting Procedures Handbook*, Article 220, Account 5655 (p.183-184).

The only explanation is for consistency of annual reporting.

As the outside services purchased from RDI relate to the 2009 rate application, NOW submits it may be appropriate to amortize the $24,000 over 4 years, however, this $6,000 annual reduction in "Outside Service Employed (5630)" will move to "Regulatory Expenses (5655)" and leave the remaining $18,000 annual costs in 5630, resulting in the same distribution requirement.

The rationale is that the RDI / NOW contract will remain at a constant cost level throughout the next 4 year rate setting window, and NOW will need to recover the entire portion year over year.

RATE BASE, SMART METERS AND PILS

Capital Expenditures

4. Ref: Board Staff IR #2, SEC IR #6

NOW's capital expenditures and annual depreciation for 2003 to 2009 are shown in the table below. For 2003 to 2006, NOW's capital spending was significantly less than its annual depreciation expense. Beginning in 2007, NOW's capital spending is close to annual depreciation.

Year		Capital Expenditures	Annual Depreciation Expense	Capex / Depreciation
2003		$ 63,390	$ 371,004	17.1%
2004		$ 113,179	$ 372,597	30.4%
2005		$ 167,266	$ 363,348	46.0%
2006		$ 183,655	$ 329,835	55.7%
2007		$ 404,275	$ 337,216	119.9%
2008	bridge	$ 615,250	$ 363,270	169.4%
2009	forecast	$ 391,000	$ 404,740	96.6%
Total		$ 1,938,015	$ 2,542,010	76.2%

a. In response to Board staff IR#2 and SEC IR#6, NOW indicated that it's capital spending for 2003 to 2006 was significantly less than its annual depreciation expense. In response to SEC IR#6, NOW stated that it "had to limit its capital expenditure from 2003 to 2006 for financial reasons". Please explain what NOW means by this statement. How has NOW's situation changed from 2007 onwards?

2002 Market deregulation had a significant impact on our financial stability. Increased costs related to deregulation preparation followed by cash flow issues resulting from delays in customer billings forced NOW into a tight budget while weathering the storm. NOW continued to be very conservative in its spending for a few years in order to maintain a secure financial footing. NOW has since regained its financial stability and is up to date on all aspects of its business requirements. With regards to capital spending we are transitioning to a more proactive planning effort in maintaining and upgrading infrastructure.

b. In response to Board staff IR #2, NOW stated that it “is continually inspecting and assessing its system to determine deteriorating components that require maintenance or replacement.” Staff notes that NOW’s proposed 2009 capital expenditures are in line with its 2009 annual deprecation expense. Does NOW foresee that it will eventually have to undertake a significant rehabilitation of its network?

NOW does not foresee at this time that it will eventually have to undertake a significant rehabilitation of its network. Please note that the implementation of the Smart Meters Infrastructure will provide NOW with more diagnostics information to assess system performance and reliability. This information may indicate the need for rehabilitation efforts over and above our current capital spending levels.

c. Based on information that NOW has from its regular assessment of its system, does NOW believe that if it maintains its capital spending at the levels of its annual deprecation expense going forward, that this will be sufficient to maintain system replacement and reliability?

NOW has not identified the need at this time to increase its capital spending above that of annual depreciation expense. Current capital spending levels are considered sufficient to maintain the system.

d. What role, if any, does NOW’s low growth in customers or load, contribute to it being able to maintain and operate its distribution system safely and reliably, while under-spending on capital for a number of years?

The communities serviced by NOW have not had significant (if any at all) development to which NOW would have to extend its infrastructure. As a result our capital expenditure for the past number years essentially consists of maintaining and upgrading old plant. Needless to say that under spending on capital for an extended period of time is costly in the long term.

PILs Rate Adder

5. Ref: E4/T3/S1 – Tax Calculations, Board staff IR#20, VECC IR#15, #17c

In response to Board staff IR#20, NOW provided the table below identifying the annual amounts for Other Additions and Other Deductions used in calculating Income Taxes.

	Other Addition		Other Deduction	
	Value	Details	Value	Details
2006 Approved	$ 131,461	Deemed interest to be recovered (calculated by OEB Tax Model)	$ 205,891	Anticipated Interest (from OEB 2006 Tax model)
2006 Actual	$ 131,461	Deemed interest	$ 101,338	Actual Interest
2007 Actual	$ 127,037	Deemed Interest	$ 103,161	Actual Interest
2008 Bridge	$ 143,906	Deemed Interest (short & long term combined)	$ 114,122	Forecast interest expense
2009 Test	$ 156,466	Deemed Interest (short & long term combined)	$ 105,262	Forecast interest expense

a. Please explain why NOW is using actual interest for “Other Deductions” but deemed interest for “Other Additions”. As per the 2008 Cost of Service applications, these were not allowable adjustments to the PILs proxy. For reference, see the October 27, 2008 Erie Thames Decision and Order (EB-2007-0928) where on page 13 the Board stated:

> Interest expense additions and deductions should not be included in the PILs tax calculations, since this does not comply with the Board’s method.

Would NOW be willing to remove the adjustments?

NOW if fully committed to getting the appropriate PILS value in rates. If it is the OEB Panels view that these adjustment lines should be removed then NOW will oblige.

It is NOW’s belief that the PILS proxy should mirror the actual tax filing as close as possible and since taxes are paid on actual interest, these adjustments may be appropriate.

b. In response to VECC IRs #15 and #17, NOW referred to several changes / corrections that it has made to the calculation of its PILs proxy. In response to VECC IR #17 d), NOW shows an "updated" PILs adder of $60,503. Yet, this amount is the same as in the original filing. In addition to the corrections related to part a) above for Other Additions and Deductions, please identify and explain any other changes or corrections that NOW has made to the calculation of the PILs proxy. Please provide updated calculations as per E4/T3/S1 to S3 identifying any changes made and the reasons for those changes and an updated PILs proxy.

NOW regrets not providing an updated Tax calculation and revenue sufficiency / deficiency for VECC # 15 and 17, this was an omission on our part. Revised schedules are included below that represents the changes in the CCA categories discussed in VECC IR # 15.

With respect to other changes, NOW will await an official decision by the OEB panel prior to revising the PILS calculation for the items identified in part a) above.

	2006 Board Approved	2006 Actual	2007Actual	2008 Bridge	2009 Test
Determination of Taxable Income					
Regulatory Net Income (before tax)	$250,137	$153,531	$175,819	$217,283	$206,121
Book to Tax Adjustments					
Additions to Accounting Income:					
Depreciation and amortization	$331,372	$317,199	$299,135	$363,270	$404,740
Meals & entertainment / Mileage					
Other Additions	$131,461	$131,461	$127,037	$143,858	$156,415
Total Additions	$462,832	$448,659	$426,172	$507,128	$561,155
Deductions from Accounting Income:					
Capital Cost Allowance	$247,569	$249,668	$270,962	$388,552	$404,768
Cumulative eligible capital deductions					
Gain on Disposal					
Other Deductions	$205,891	$101,338	$103,161	$114,122	$105,262
Total Deductions	$453,460	$351,006	$374,123	$502,674	$510,030
Regulatory Taxable Income	$259,509	$251,184	$227,867	$221,738	$257,247
Corporate Income Tax Rate	18.62%	18.62%	18.62%	17.00%	17.00%
Ontario Capital Tax Rate					
Subtotal					
Less: R&D ITC (0.3)					
Regulatory Income Tax	$48,321	$46,770	$42,429	$37,695	$43,732
Calculation of Utility Income Taxes					
Income Taxes (Line 23)	$48,321	$46,770	$42,429	$37,695	$43,732
Ontario Capital Tax	$0	$0	$0	$0	$0
Large Corporation Tax (Line 14, page 2)					
Total Taxes	$48,321	$46,770	$42,429	$37,695	$43,732
Gross UP factor (1-tax rate)	81.38%	81.38%	81.38%	83.00%	83.00%
Total taxes with Gross up (taxes/gross up factor)	$59,376	$57,472	$52,137	$45,416	$52,689

Determination of Net Utility Income

	Existing Rates	Proposed Rates	Revenue (Surplus) or Defficiency
Revenue Deficiency		$374,344	
Distribution Revenue	$2,459,426	$2,459,426	$0
Other Operating Revenue (Net)	$297,503	$297,503	$0
Total Revenue	$2,756,929	$3,131,273	$374,344
Costs and Expenses			$0
Distribution Costs	$1,672,302	$1,672,302	$0
Operation & Maintenance	$639,005	$639,005	$0
Depreciation & Amortization	$404,740	$404,740	$0
Deemed Interest	$156,415	$156,415	$0
Total Costs and Expenses	$2,872,463	$2,872,463	$0
Utility Income Before Income Taxes	-$115,534	$258,810	$374,344
Income Taxes	$52,689	$52,689	$0
Utility Income (loss) After Taxes	-$168,223	$206,121	$374,344
Rate Base	$5,480,429	$5,480,429	
Equity Portion	43.3300%	43.3300%	
Equity Component of Rate Base	$2,374,670	$2,374,670	
Target Return on Equity	8.68%	8.68%	
Return on Rate Base	$206,121.35	$206,121.35	
Revenue Deficiency	-$374,344.10	$0.00	

Reconciliation to Revenue Requirement (colour coded)

OM&A	$2,311,307
Amortization	$404,740
Return	$362,536
PILS	$52,689
Revenue Off-Set (Other operating revenu	-$297,503
Base Revenue Requriement	**$2,833,770**
Transformer Allowance (input)	$49,168
Revenue Requirement	**$2,882,938**

Smart Meter Costs

6. Ref: E1/T1/S6 – Draft Issues List, Board staff IR#19, 41, SEC IR#2, VECC IR#4b

In its original application, NOW indicated that it had not included any smart meter costs in its application. However, in response to Board staff IR #19 b) and VECC IR #4 b), NOW confirmed that its proposed rates included the currently approved $0.26 rate adder.

In response to Board staff IR #19, NOW revised its smart meter funding request by adjusting its smart meter adder from $0.26 to $1.00 per metered customer per month. NOW confirmed that it is approved for smart meter spending under the London Hydro RFP.

NOW stated that full recovery for smart meters when installation is completed (expected in 2009) would be $4.05 per month per metered customer. NOW indicated that it will be installing 6,140 meters at an estimated total cost of meters installed to be $1,468,196. Minimum functionality only.

In a schedule provided in response to SEC IR #2 b), NOW indicated that it will have incurred $31,427 in smart meter operating costs from 2007 to December 31, 2008. Since NOW only just became authorized to engage in smart metering activity, it is unclear what these costs represent.

a. Please confirm the date that NOW became authorized to engage in smart meter activity under the London Hydro RFP.

Please see attached letters which indicate the timing in which we received authority to move forward with the Smart Meter Initiative. The letters are dated June 3, 2007 and June 10, 2007.

PRP International, Inc.

Fairness Commissioner Services

June 2, 2008

Mr. Gary Rains, P.Eng.
Project Director, AMI Procurement Initiative
London Hydro
111 Horton Street, PO Box 2700
London, ON N6A 4H6

Dear Mr. Rains:

Subject: Supplementary Quotation Submission to RFQ No. Q2007-N-7
Fairness Commissioner Services
Advanced Meter Infrastructure (AMI) – Second LDC Group, 2008

PRP International, Inc. is pleased to submit its supplementary quotation for this noted requirement, as requested. This additional work will be performed as an extension to the existing Purchase Order (E.07-019) issued by London Hydro Inc. It is understood that the Fairness Commissioner duties and services will be consistent with the initial work for the London Hydro & Consortium RFP #T2007-N-6, issued on August 14, 2007, to wit: another group of approximately 35 Local Distribution Companies (LDCs) will be processed through the evaluation process to determine the two (2) highest ranked Proponents for each LDC or group of LDCs. It is expected that this work will commence on or about June 2, 2008.

1. Estimated Fees per LDC: $500.00
2. Estimated Travel Expenses: 3 Trips - $5,000.00
3. Optional Fairness Services during negotiations / contracting stage: $175/hour plus associated travel expenses

Based on both work packages for approximately 67 LDCs, the average fees (including expenses but excluding fees and expenses for services during negotiations) for Fairness Services is estimated to be $1,400.00 per LDC.

I look forward to working with you and the new group of LDCs. If there is any clarification that you require on any part of this supplementary quotation, please do not hesitate to contact me.

Yours very truly,

Peter Sorensen
President

203 - 8 QUEEN STREET, SUMMERSIDE, PEI C1N 0A6
TELEPHONE: 902.436.3930 FAX: 604-677-5409
EMAIL: fairness@telus.net

Department:	Energy Management
Attention:	G.H. Rains
Telephone:	661-5800 Ext. 4870

June 10, 2008

North Bay Hydro
74 Commerce Crescent
P.O. Box 3240
North Bay, Ontario
P1B 8Y5

Attention: Mr. Dave Miller

Re: London Hydro RFP for Advanced Metering Infrastructure (AMI)
Mechanism for Other LDC's to Piggy-Back on RFP Results

Further to our meeting of Friday, May 30th at the Ministry of Energy offices, London Hydro and the designated Fairness Commissioner are pleased to assist the remaining LDC's in the Province in their selection of a "*best value*" AMI vendor based on the parameters and methodology set out in Section 7.3.2, *Basis of Award*, of the London Hydro RFP and recognized in the draft amendment to Ontario Regulation 427/06, *Smart Meters: Discretionary Metering Activity and Procurement Principles*.

As you may recall, the analysis options available to LDC's are:

(i) a service model offering in which the LDC owns, operates and maintains the meters and LAN communications facilities (i.e. regional collectors) but the vendor (or a third-party) hosts the master station versus an ownership model in which the LDC owns, operates and maintains the meters, LAN communications facilities, and master station.

(ii) an individual LDC model wherein the "*best value*" supplier is determined for that LDC based on LDC-specific technical weighting factors, LDC-specific meter populations, and LDC-specific cost factors (meter exchange rates, labour costs, etc.) versus a collective model wherein the "*best value*" supplier is determined for a defined group of LDC's where a common AMI solution is preferred. The collective model assumes that one of the LDCs in the group would have the master station on its premises and provide hosting services for the other LDCs in the group.

Note: Within London Hydro's consortium of 32 LDC's, those that wished a collective solution fortunately had also had common LDC-specific technical weighting factors. Those LDC's wishing to entertain a collective solution will either have to have common LDC-specific technical weighting factors, or alternatively your consultant will have to provide guidance where differences in LDC-specific technical weighting factors are encountered (e.g. determination of an average based on individual LDC-specific factors, etc.).

Note: I recall that there are unique circumstances surrounding one of the LDC's wherein the municipality has already invested in AMI technology for their domestic water meters, and the LDC wishes to leverage the municipality's investment in AMI technology to also support electric meters. Although the London Hydro analysis model contemplated sunk investments (generally arising from third-tranche pilot projects), these circumstances are different and this particular case may require analysis outside the London Hydro model.

Nonetheless, provided the spirit of a fair and transparent process is maintained, it is understood that the Ministry of Energy is willing to engage in a discussion with those distributors considering leveraging previous municipal water AMI procurements for the purpose of electricity AMI to see if they may be accommodated through regulation.

From a fairness perspective, participating LDC's can either (i) declare their preferred go-forward option (e.g. identify the best value supplier for LDC X under an ownership model for this as a stand-alone LDC), or (ii) declare the decision logic by which they would choose between an *individual* LDC model and a *collective* model and between a *service* model and an *ownership* model. Recall that the "*most probable life-cycle system cost*" model provides only two outputs, namely (i) net present value of the system, and (ii) effective end-point cost (which is simply the net present value divided by the total number of revenue meters). As such, the decision logic needs to be based on one or both of these monetary parameters.

With respect to deliverables, each LDC or collective of LDC's will receive:

(i) a letter of attestation from Peter Sorensen, the designated Fairness Commissioner for this project, identifying the "*best value*" bidder and the "*second best value*" bidder for the pre-identified circumstances or decision logic;

(ii) copies of the proposals received from the identified "*best value*" bidder and "*second best value*" bidder. Portions of some proposals are covered by existing Confidentiality Agreements (between London Hydro and the bidder), so in such cases, the confidentiality provisions will have to be transferred to LDCs receiving these proposals.

(iii) a copy of the "*most probable life-cycle system cost*" analysis for the top two bidders.

Pursuant to Section 7.5.14, *Final Contract Negotiations*, of the London Hydro RFP, it is expected that LDC's would initiate good faith contract negotiations with their identified "best value" bidder, and only if these negotiations stall or fail, the second best value bidder would be invited to negotiate a procurement contract.

I have attached a letter from the Fairness Commissioner which estimates the cost of his services. Pat Hewlett of London Hydro and John Temporal of EnWin Powerlines will populate the "*most probable life-cycle system cost*" analysis spreadsheets, and handle all the administrative details (preparing LDC-specific outcome pages, customizing the Powerpoint presentation used within our consortium for Board endorsements, disseminating proposals, etc.) on a cost recovery basis. London Hydro can invoice each LDC for services provided at the end of the process.

As you are aware, to start this process, every participating LDC will have to submit three (3) spreadsheets (of which James Douglas already possesses copies), namely:

(i) LDC-specific technical weighting factors;

(ii) LDC-specific meter population information (including particulars of any pilot projects); and

(iii) LDC-specific cost, productivity, and other factors.

Note: If there are specific conditions that require special analysis within any of the service territories of participating LDC's, you will have to advise us of these special conditions and how you would like them considered.

I trust this letter adequately covers or clarifies all the discussion items arising at our meeting.

I am creating a "statement of work" template for the 32 LDC's in the London Hydro consortium with the expectation that we will start formal negotiations with the three (3) successful AMI suppliers in perhaps another two weeks. I'll try and structure the statement of work so that there will be an opportunity up to mid-August for other LDC's to join in and take advantage of greater purchasing volumes. In any case, time is now of the essence to complete the "best value" analysis and for LDC's receiving this letter to be in a position to commit to procuring AMI systems.

I trust this letter adequately covers or clarifies all the discussion items arising at our meeting.

Yours truly,

LONDON HYDRO INC

Gary Rains, P.Eng.
Director of Energy Management Programs

GHR/ghr

Encl: Letter from Peter Sorensen, dated June 2nd, re: *Supplementary Quotation Submission to RFQ No. Q2007-N-7; Fairness Commissioner Services; Advanced Meter Infrastructure (AMI) – Second LDC Group, 2008*

cc: Usman Syed	Senior Advisor – Smartmeters, Ontario Ministry of Energy
Peter Sorensen	PRP International Inc.
James Douglas	Util-Assist Inc.

b. Assuming that NOW only just became authorized under the London Hydro RFP recently, please explain why NOW shows OM&A costs for 2007 totalling $15,850, and 2008 costs of $15,577.

See response in part c) below.

c. Please explain the nature of these costs and why they are treated as OM&A costs being recorded in Account 1556 (and subject to future review and disposition).

Responses to b and c

OEB Q#6

b and c

Smart Meters OM&A Costs

	2007 Actual	2008 Forecast
Consulting Fees - Utilassist	$ 9,788	$ 9,585
Travel Costs	$ 6,062	$ 5,992
Total OM&A Smart Meters	**$ 15,850**	**$ 15,577**

In early 2007 NOW retained Util-Assist to provide consulting services regarding the Ontario Smart Meter Initiative. NOW is party to a collaborative approach to this project whereby we have partnered with other Northern Ontario Utilities, referred to as District 9 Utilities. The consulting costs booked to 1556 in 2007 and 2008 are consulting fees paid to Util-Assist. A copy of our agreement and quarterly invoices are available as required. The travel costs booked to 1556 are costs incurred by NOW staff to travel to periodic meetings with the consultants and other District 9 Utilities group members.

NOW has booked these costs to OM&A, in reviewing the nature of these costs, it seems appropriate to include these as smart meter capital costs.

LOAD AND REVENUE FORECAST

2009 Revenue Forecast

7. Ref: E3/T1/S2/p1 – Summary of Operating Revenue Table, E1/T3/S2/p2 – Pro Form Statement of Income for 2009, Board staff IR#26, VECC IR#9

Both Board staff and VECC requested that NOW provided a derivation of its forecasted distribution revenue for 2009. In response, NOW showed a derivation for 2008 but not 2009. NOW indicated that "the 2009 distribution revenue is derived through the application and ends up at the $2,890,752 indicated in Exhibit 1, Tab 3, Schedule 2, page 2". Staff notes that this reference is for the 2009 pro forma statements. The above number is the requested revenue requirement for 2009.

Please produce a derivation of the 2009 distribution revenue build up in a format similar to what NOW produced for 2008 in response to Board staff IR #26.

Please see chart below.

2009 Distribution Reveue Build-Up

	2009 Customer Counts	Number of Bills	Fixed Rate (excl.Smart Meters)	Fixed Revenue	Annual kWh / kW	Variable Rate	Variable Revenue	Total Revenue
Residential	5,200	12	$ 17.50	$ 1,092,000	41,161,457	0.01788	$ 735,862	**$ 1,827,862**
GS < 50 kW	785	12	$ 23.00	$ 216,660	21,858,575	0.01564	$ 341,781	**$ 558,441**
GS > 50 kW	69	12	$ 205.00	$ 169,740	173,388	0.945	$ 163,852	**$ 333,592**
Unmetered Load	15	12	$ 12.00	$ 2,160	121,104	0.04095	$ 4,959	**$ 7,119**
Street Light	1,737	12	$ 6.25	$ 130,275	5,014	6.6742	$ 33,464	**$ 163,739**
Total								**$ 2,890,752**

COST ALLOCATION, RATE DESIGN AND VARIANCE ACCOUNTS

2009 Low Voltage Costs

8. Ref: E2/T4/S1/p3 – Working Capital Calculation by Account, Board staff IR #34 b), c)

Hydro One recently received their 2008 Cost of Service decision which approved updated LV rates for its embedded distributors.

NOW's response to Board staff IR# 34 c) derives an estimate of LV cost based on updated LV rates @ $175k, in place of $219k as per the application. NOW's response to Board Staff IR# 37 c) calculates rate adders that would recover $219k. NOW offers to update the rate adder when a new cost forecast is calculated.

a. Total LV billing demand for 2007 is 46,224.48 kW. This amount multiplied by the Hydro One rate for HVDS(low) @ $3.797 per kW comes to approximately $175k. The forecast cost is $219k, and is based on these same quantities. Please confirm that there is some other cost component in addition to the rate for HVDS(low). (For example, was the Shared Line rate also applicable, at a rate of $0.633 and a cost of approximately $40k?)

NOW does pay for Shared Line as well. The 2008 and 2009 estimated value was based on the actual 2007 costs. As discussed in earlier IR responses, NOW understands the need to move this value to the actual approved rates as the time of approval.

b. The revised cost forecast includes the updated rate for HVDS(low) which is $2.66 per kW, and a new fixed charge of $188 per delivery point. If the Shared Line rate was charged by Hydro One in 2007 (i.e. if confirmed in part a), please update the forecast in Board staff IR#34 c) to include the updated rate for Common ST line (approved at $0.58 per kW).

See updated schedule:

Month	Year	Units	Variable Rate	Variable Charge	Fixed Charge	Total Charge
Nov	**2007**	3,505.78	$ 3.24	$ 11,358.73	$ 376.00	$ 11,734.73
Dec	**2007**	3,776.33	$ 3.24	$ 12,235.31	$ 376.00	$ 12,611.31
Jan	**2008**	4,369.80	$ 3.24	$ 14,158.15	$ 376.00	$ 14,534.15
Feb	**2008**	4,444.23	$ 3.24	$ 14,399.31	$ 376.00	$ 14,775.31
Mar	**2008**	4,458.77	$ 3.24	$ 14,446.41	$ 376.00	$ 14,822.41
Apr	**2008**	4,130.65	$ 3.24	$ 13,383.31	$ 376.00	$ 13,759.31
May	**2008**	3,752.66	$ 3.24	$ 12,158.62	$ 376.00	$ 12,534.62
June	**2008**	3,517.82	$ 3.24	$ 11,397.74	$ 376.00	$ 11,773.74
July	**2008**	3,337.59	$ 3.24	$ 10,813.79	$ 376.00	$ 11,189.79
Aug	**2008**	3,097.18	$ 3.24	$ 10,034.86	$ 376.00	$ 10,410.86
Sept	**2008**	2,759.66	$ 3.24	$ 8,941.30	$ 376.00	$ 9,317.30
Oct	**2008**	3,705.29	$ 3.24	$ 12,005.14	$ 376.00	$ 12,381.14
12 Month Total						$ 149,844.66

Assumes:

- Monthly Service Charge of $188.00 per delivery point
- Variable charges of $2.66 per kW plus $0.58 for shared LV

The value of $149,844.66 (if based on final and implemented rates) should be the new value of the LV included in the NOW rate application before the board.

In reviewing the most recent Hydro One invoice (Dec 2008) the old charges are still applying. NOW submits that once the new rates are implemented by Hydro One, NOW will reproduce the estimated expenses and amend the application to reflect the 2009 estimated expenses.

9. Ref: E9 / T1 / S8 – Rate Impacts,
Board staff IR # 38 b), VECC IR #21 b)

In NOW's rate impact calculations, it is evident that the proportion of revenue from the fixed charge would decrease for the Residential class, because the Monthly Service Charge would be increased by 6.6% while the volumetric rate would be increased by 65.5%. The same is true for the GS<50 kW class, where the increases would be 6.7% and 53.3% respectively. For the GS 50-4999 class, the opposite would occur, because the Monthly Service Charge is decreased by only 1.9% while the volumetric would be decreased by 54.0%.

The Monthly Service Charge is higher than the ceiling in the cost allocation filing, and the Board's usual approach in the 2008 Decisions was to leave the proportions unchanged from the status quo in this situation.

a. In response to Board taff IR#38 b), NOW states that "the rationale for the proposed fixed charge was based on a goal to keep fixed charges relatively close to current fixed charges approved". Please explain the rationale that a relatively small change in all monthly service charges is desirable.

It is not necessarily desirable. As discussed in earlier correspondence, the fixed charges were set to balance revenue stability, rate stability and OEB guidelines. A minor change in fixed charges was not seen by NOW as a trouble spot in the approval process.

If the Board or Board Staff feel that the fixed charges must remain constant, then NOW does not object.

b. Please explain why such a small change is a goal for fixed charges, rather than applying equally to both fixed and variable charges.

See comment in response a) above.

Retail Transmission Service (RTS) Rates

10. Guideline G-2008-0001 - Electricity Distribution Retail Transmission Rates, Board staff IR #40 c), #41 a)

The response to Board staff IR# 40 c) includes a new calculation of RTS rates to reflect the Uniform Transmission Rates (wholesale) that come into effect January 1, 2009. The proposed RTS rates match the change in the wholesale rates but will not halt the persistent growth of the variance account balances1584 and 1586. The balances as of December 31, 2007 are negative $87,347 and negative $1,431,220 (these balances include interest to April 30, 2009). The Board's guidelines on RTS rates states, "The pattern over time of the amounts being recorded in these accounts can guide the distributor as to what adjustments may be needed to maintain the balance of the deferral accounts at a reasonable level." (page 3, second paragraph)

a. Please confirm that the proposed RTS rates are designed to reflect the most recent changes in the Uniform Transmission Rates (UTRs), and that the 2008 changes in RTS rates were designed to reflect the change in UTRs in November 2007.

NOW confirms the above.

b. Please confirm that neither change in RTS rates was designed to correct the tendency for NOW's RTS rates to over-collect (i.e. surpluses identified in response to Board staff IR#40 a) of approximately $70k over two years when passing through each of Network and Connection cost).

NOW confirms the above.

c. Please submit revised RTS rates that addresses the tendency in NOW's RTS rates to over collect.

Please see summary trend analysis below:

Network

	2007	2008 (Jan to Sept)	Total	
Expenses	689,730	404,964	1,094,694	
Revenues	711,868	450,919	1,162,787	
$ Difference	(22,138)	(45,955)	(68,093)	note negative equal over recovery
% Difference	-3.2%	-11.3%	-6.2%	

Connection

	2007	2008 (Jan to Sept)	Total	
Expenses	689,730	333,850	1,023,580	
Revenues	711,868	386,667	1,098,535	
$ Difference	(22,138)	(52,818)	(74,956)	note negative equal over recovery
% Difference	-3.2%	-15.8%	-7.3%	

As discussed in response to BS IR # 40, NOW is not opposed to a 5% reduction in both RTR Network and Connection charges. NOW does not believe that a 21 month snapshot in time can accurately reflect the future direction of these accounts, however, does understand the need to not over collect in excess.

Below you will see an updated schedule that includes the 2009 projected increase to the wholesale rates and also incorporate a 5% reduction in the retail charges.

Northern Ontario Wires
Retail Transmission Rates Adjustment Model

Network

	2008	2009	% Change
Wholesale Rate	2.31	2.57	11.26%

Retail Rates

	Current Rate	Adjustment Factors Wholesale	Retail Trend	Net	Proposed 2009 Rate
Residential	0.0044	11.26%	-5.00%	6.26%	0.0047
GS < 50 kW	0.0040	11.26%	-5.00%	6.26%	0.0043
GS > 50 kW	1.6425	11.26%	-5.00%	6.26%	1.7452
Unmetered Load	0.0040	11.26%	-5.00%	6.26%	0.0043
Street Light	1.2388	11.26%	-5.00%	6.26%	1.3163

Connection

	2008	2009	% Change
Wholesale Line	0.59	0.70	
Wholesale Tranformation	1.61	1.62	
Wholesale Total	2.2	2.32	5.45%

Retail Rates

	Current Rate	Adjustment Factors Wholesale	Retail Trend	Net	Proposed 2009 Rate
Residential	0.0042	5.45%	-5.00%	0.45%	0.0042
GS < 50 kW	0.0038	5.45%	-5.00%	0.45%	0.0038
GS > 50 kW	1.4944	5.45%	-5.00%	0.45%	1.5012
Unmetered Load	0.0038	5.45%	-5.00%	0.45%	0.0038
Street Light	1.1553	5.45%	-5.00%	0.45%	1.1606

Deferral and Variance Accounts

11. Ref: Board staff IR #41 a), b)

NOW has not requested disposition of any deferral or variance accounts. In Board staff IR #41 b), staff asked NOW to calculate a rate rider for each class based on clearing most non-RSVA accounts, but NOW did not do so. NOW provided only the total projected variance balance as at April 30, 2009 ($655,945 credit).

a. Account 1571 (Pre-Market Opening Energy Variance) was cleared in 2006 EDR when NOW received final approval for its variance account balances to December 31, 2004 plus interest to April 30, 2006. For account 1571 the approved principal balance that was disposed was $263,662 and interest approved was $25,487. The full principle and interest balances approved were transferred to account 1590, Regulatory Assets recovery account at that time as per the Board's instructions. However, NOW's continuity schedule shows an additional interest balance of $50,975 that has remained in account 1571. There is no explanation as to what this amount represents or whether NOW expects to recover this amount when all of its variance accounts are disposed. The 2006 Regulatory Assets recovery model (filed by NOW in response to Board staff IR #41) does not show this amount. Please explain what the $50,975 represents and confirm if NOW expects to recover this amount.

The $50,975 represents carrying charges on Account 1571 (Pre-Market Opening Energy Variance)for the Period May 2002 to Dec 31, 2004. NOW did not calculate and report interest for this period with the Dec 31, 2004 variance balances used for approval and determination of the 2006 regulatory asset recovery rates. This was an error on NOW's part. A detailed Account 1571 schedule for 2002 to 2006 is available if required. We have summarized the interest for the entire period as follows:

On $263,662 Variance for	**Carrying Charges**
May 2002 to April 2006	$76,642
Reported with Dec 31/04 balances for the 2006 regulatory asset recovery rates and recovered accordingly	(25,487)
Balance of Carrying Charges not recovered	**$50,975**

b. Is there a reason based in a Board Decision or direction that allowed NOW to revise its interest calculations for account 1571?

This was an error on NOW's part. NOW either did not realize that this account was subject to carrying charges or erroneously failed to calculate it.

c. For account 1580 (RSVA – Wholesale Market Service Charges), NOW is showing a balance of negative $296,878. Please describe the costs that are recorded in account 1580. Does NOW have an estimate in percentage terms of how much its revenues have exceeded its costs in an average month or year?

Please see chart below:

Costs recorded in A/C 1580 - Wholesale Market Service Charges

		IESO Charge Type
150	Net Energy Market Settlement Uplift	4708-0000
155	Congestion Management Settlement Uplift	4708-0000
163	Market Suspension Additional Compensation Settlement	4708-0000
164	Outage Cancellation/Deferral Debit	4708-0000
167	Emergency Energy and EDRP Debit	4708-0000
169	Station Service Reimbursement Debit	4708-0000
170	Local Market Power Rebate	4708-0000
182	Hour Ahead Dispatchable Load Offer Guarantee Debit	4708-0000
183	Generation cost Guarantee Recovery Debit	4708-0000
184	Demand Response Debit	4708-0000
186	Intertie Failure Charge Rebate	4708-0000
250	10-minute Spinning Market Reserve Hourly Uplift	4708-0000
251	10- minute Spinning Market Reserve Hourly Uplift	4708-0000
252	10-minute Non-Spinning Market Reserve Hourly Uplift	4708-0000
253	10-minute Non-Spinning Market Reserve Hourly Uplift	4708-0000
254	30-munute Operating Reserve Market Hourly Uplift	4708-0000
255	30-minute Operating Reserve Market Shortfall Debit	4708-0000
450	Black Start Capability Settlement Debit	4708-0000
452	Reactive Support and Voltage Control Settlement Debit	4708-0000
454	Regulation Service Settlement Debit	4708-0000
550	Must Run Contract Settlement Debit	4708-0000
704	OPA Adminstration Credit	4708-0000
753	Rural Rate Settlement Charge	4708-0000
754	OPA Adminstration Charge	4708-0000
9990	IMO Administration Charge	4708-0000

1580 - Wholesale Market Services
Cash Basis Schedule (Difference to Continuity Schedule is timing - one month)

	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Balance at Beginning of Year	$ -	$ 237,110	$ 163,758	$ 160,002	$ 222,457	$ (101,989)
IMO Charges	$ 605,702	$ 863,216	$ 857,167	$ 984,395	$ 739,977	$ 682,001
Billed to Customers	$ (368,592)	$ (936,568)	$ (860,923)	$ (921,940)	$ (894,422)	$ (871,535)
NET current year (*)	$ 237,110	$ (73,352)	$ (3,756)	$ 62,455	$ (154,445)	$ (189,534)
Adjustments (prior year coding error)					$ (4,677)	
Recovery					$ (165,324)	
Net Change for the year	$ 237,110	$ (73,352)	$ (3,756)	$ 62,455	$ (324,446)	$ (189,534)
Balance at Year End	**$ 237,110**	**$ 163,758**	**$ 160,002**	**$ 222,457**	**$ (101,989)**	**$ (291,523)**
% Revenues in excess of Charges (* - Net Current Year)		7.8%	0.4%	-6.8%	17.3%	21.7%

Billed to Customers includes WMS rate of $0.0052/kWh and Rural Rate Assistance $.0010/kWh and is based on adjusted kWh.

d. Account 1590, Recovery of Regulatory Asset Balances: In its continuity schedule, NOW forecasts transactions in 2008 to be negative $480k. This appears to be the recoveries in 2008 flowing from the 2006 EDR approved rate riders. However, these rate riders ceased to apply effective May 1, 2008. For comparison purposes, the amount of recoveries recorded for the entire 2007 calendar year were $322,910 (cell AB44). Please explain why NOW is forecasting such a large recovery amount for the 2008 stub period (Jan 1 to Apr 30).

NOW received approval in July 2006 for its 2006 rates including regulatory asset recovery rate rider to be effective July 16,2006. NOW did not include the regulatory recovery rate rider in the customers billings at this time by error. This was discovered in September 2007. A retroactive calculation was performed and billed to our customers over a 4 month period from November 2007 to February 2008. Furthermore a few of our larger customers requested the retroactive adjustment be spread over the next 12 months starting in November 2007. Therefore we continue to show some regulatory asset recovery until November 2008, although the majority of it was recovered to April 30, 2008. Essentially NOW's recovery of approved regulatory asset balances as per 2006 EDR was collected between November 2007 and April 2008

e. Please provide a response to the part of Board staff IR #41 b) that refers to rate riders.

Due to the size of the spreadsheet, it is not available within these responses, however, is included electronically as appendix A to these responses.

We have calculated the rate rider using a 4 year recovery period as are shown below.

Rate Riders with out RSVA

NORTHERN ONTARIO WIRES INC
SUMMARY OF VARIANCE ACCOUNTS AND RATE RIDER CALCULATION
OEB Interog 41 b) response - Variance accounts excluding RSVA's

ALLOCATORS >>>

	Residential	GS < 50 KW	GS > 50 Non TOU	Small Scattered Load	Street Lighting	Total
Summary of Allocators = 2009 FORECAST						
KW			173,388		5,014	**178,402**
KWH	41,161,457	21,858,575	68,558,740	121,104	1,778,469	**133,478,345**
# of Customers	5,200	785	69	15	3	**6,072**
Distribution Revenue	1,827,862	558,441	333,592	7,119	163,739	**$ 2,890,753**
Allocator Percentages						
KW	0.0%	0.0%	97.2%	0.0%	2.8%	100.0%
KWH	30.8%	16.4%	51.4%	0.1%	1.3%	100.0%
# of Customers	85.6%	12.9%	1.1%	0.2%	0.0%	100.0%
Distribution Revenue	63.2%	19.3%	11.5%	0.2%	5.7%	100.0%
2006 EDR Reg Asset Alloc	40.7%	17.7%	40.4%	0.3%	0.9%	100.0%

BALANCE AND RATE RIDER CALCULATION

A/C Description	A/C#	Forecast Balance April 30, 2009	ALLOCATOR	Residential	GS < 50 KW	GS > 50 Non TOU	Small Scattered Load	Street Lighting	Total
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0.00							
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$84,988.41	Dx Revenue	$53,739.31	$16,418.22	$9,807.64	$209.30	$4,813.94	$84,988.41
Other Regulatory Assets - Sub-Account - Other 6	1508	$0.00							
Other Regulatory Assets - Sub-Account - Other 6	1508	$0.00							
Other Regulatory Assets - Sub-Account - Other 6	1508	$0.00							
Retail Cost Variance Account - Retail	1518	($31,696.20)	# of Customers	($27,144.31)	($4,097.75)	($360.18)	($78.30)	($15.66)	($31,696.20)
Misc. Deferred Debits	1525	$4,679.23	# of Customers	$4,007.25	$604.94	$53.17	$11.56	$2.31	$4,679.23
Retail Cost Variance Account - STR	1548	$21,816.17	# of Customers	$18,683.15	$2,820.44	$247.91	$53.89	$10.78	$21,816.17
Qualifying Transition Costs 4	1570	$0.00							
Pre-Market Opening Energy Variances Total 4	1571	$50,975.00	KWH	$15,719.44	$8,347.73	$26,182.39	$46.25	$679.19	$50,975.00
Extra-Ordinary Event Costs	1572	$0.00							
Deferred Rate Impact Amounts	1574	$0.00							
RSVA -- One-time Wholesale Market Service	1582	$10,739.00	KWH	$3,311.64	$1,758.63	$5,515.89	$9.74	$143.09	$10,739.00
2006 PILs & Taxes Variance	1592	$0.00							
Other Deferred Credits	2425	$0.00							
Smart Meter Capital and Recovery Offset	1555								
Smart Meter Operaqtion, Maintenance and Administration	1556								
Deferred Payments in Lieu of Taxes	1562								
Deferred PILs Contra Account 8	1563								
CDM Expenditirues and Recoveries	1565								
CDM Contra Account	1566								
Recovery of Regulatory Asset Balances	1590	$152,495.00	% of Previous Allocation	$62,115.69	$26,919.51	$61,589.44	$505.62	$1,364.74	$152,495.00
TOTAL NON-RSVA's balances per above		**$293,996.61**		**$130,432.18**	**$52,771.72**	**$103,036.25**	**$758.06**	**$6,998.39**	**$293,996.61**
Recovery over a 4 year period		$73,499.15		$32,608.05	$13,192.93	$25,759.06	$189.52	$1,749.60	$73,499.15
RATE RIDERS CALCULATION									
Regulatory Asset Rate Rider				$0.0008	$0.0006	$0.1486	$0.0016	$ 0.35	
Billing Determinants				**KWH**	**KWH**	**KW**	**KWH**	**KW**	

Rate Riders with RSVA recovery

NORTHERN ONTARIO WIRES INC

SUMMARY OF VARIANCE ACCOUNTS AND RATE RIDER CALCULATION

OEB Supplem Interog 11 f) response - Variance accounts including RSVA's

ALLOCATORS >>>

	Residential	GS < 50 KW	GS > 50 Non TOU	Small Scattered Load	Street Lighting	Total
Summary of Allocators = 2009 FORECAST						
KW			173,388		5,014	**178,402**
KWH	41,161,457	21,858,575	68,558,740	121,104	1,778,469	**133,478,345**
# of Customers	5,200	785	69	15	3	**6,072**
Distribution Revenue	1,827,862	558,441	333,592	7,119	163,739	**$ 2,890,753**
Allocator Percentages						
KW	0.0%	0.0%	97.2%	0.0%	2.8%	100.0%
KWH	30.8%	16.4%	51.4%	0.1%	1.3%	100.0%
# of Customers	85.6%	12.9%	1.1%	0.2%	0.0%	100.0%
Distribution Revenue	63.2%	19.3%	11.5%	0.2%	5.7%	100.0%
2006 EDR Reg Asset Alloc	40.7%	17.7%	40.4%	0.3%	0.9%	100.0%

BALANCE AND RATE RIDER CALCULATION

A/C Description	A/C#	Forecast Balance April 30, 2009	ALLOCATOR	Residential	GS < 50 KW	GS > 50 Non TOU	Small Scattered Load	Street Lighting	Total
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0.00							
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$84,988.41	Dx Revenue	$53,739.31	$16,418.22	$9,807.64	$209.30	$4,813.94	$84,988.41
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Misc. Deferred Debits	1525	$4,679.23	# of Customers	$4,007.25	$604.94	$53.17	$11.56	$2.31	$4,679.23
Retail Cost Variance Account - STR	1548	$21,816.17	# of Customers	$18,683.15	$2,820.44	$247.91	$53.89	$10.78	$21,816.17
Qualifying Transition Costs 4	1570	$0.00							
Pre-Market Opening Energy Variances Total 4	1571	$50,975.00	KWH	$15,719.44	$8,347.73	$26,182.39	$46.25	$679.19	$50,975.00
Extra-Ordinary Event Costs	1572	$0.00							
Deferred Rate Impact Amounts	1574	$0.00							
RSVA -- One-time Wholesale Market Service	1582	$10,739.00	KWH	$3,311.64	$1,758.63	$5,515.89	$9.74	$143.09	$10,739.00
2006 PILs & Taxes Variance	1592	$0.00							
Other Deferred Credits	2425	$0.00							
Smart Meter Capital and Recovery Offset	1555								
Smart Meter Operaqtion, Maintenance and Administration	1556								
Deferred Payments in Lieu of Taxes	1562								
Deferred PILs Contra Account 8	1563								
CDM Expenditirues and Recoveries - no Bal $ therefore did not include	1565								
CDM Contra Account -no Bal $ therefore did - no Bal$ therefore did not include	1566								
Recovery of Regulatory Asset Balances	1590	$152,495.00	% of Previous Allocation	$62,115.69	$26,919.51	$61,589.44	$505.62	$1,364.74	$152,495.00
Low Voltage Variance Account	1550	$46,139.63	KWH	$14,228.33	$7,555.88	$23,698.79	$41.86	$614.77	$46,139.63
RSVA - Wholesale Market Service Charge	1580	($398,650.56)	KWH	($122,934.08)	($65,283.50)	($204,759.66)	($361.69)	($5,311.63)	($398,650.56)
RSVA - Retail Transmission Network Charge	1584	($184,669.83)	KWH	($56,947.66)	($30,241.75)	($94,852.32)	($167.55)	($2,460.55)	($184,669.83)
RSVA - Retail Transmission Connection Charge	1586	($1,526,335.29)	KWH	($470,684.47)	($249,954.51)	($783,974.54)	($1,384.83)	($20,336.93)	($1,526,335.29)
RSVA - Power (including Global Adjustment)	1588	$1,113,574.00	KWH	$343,398.99	$182,360.22	$571,967.16	$1,010.34	$14,837.29	$1,113,574.00
RSVA - Power - Sub-Account - Global Adjustment	1588	$0.00	KWH	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL NON-RSVA's balances per above		**($655,945.44)**		**($162,506.71)**	**($102,791.94)**	**($384,884.32)**	**($103.81)**	**($5,658.67)**	**($655,945.44)**
Overall % allocated				***24.8%***	***15.7%***	***58.7%***	***0.0%***	***0.9%***	**100.0%**
Recovery over a 4 year period		($163,986.36)		($40,626.68)	($25,697.98)	($96,221.08)	($25.95)	($1,414.67)	($163,986.36)
RATE RIDERS CALCULATION									
Regulatory Asset Rate Rider				($0.0010)	($0.0012)	($0.5549)	($0.0002)	($0.2821)	
Billing Determinants				**KWH**	**KWH**	**KW**	**KWH**	**KW**	

f. Please calculate an alternative set of rate riders that would dispose the net balance of the accounts identified in part e) above plus all RSVA accounts, 1580, 1582, 1584, 1586, 1588 and 1550.

Please see attached schedule. Again we have calculated the rate rider using a 4 year recovery period.

Regulatory Interest (carrying charges) included in revenue requirements will need to be adjusted to reflect any approval for disposition of all or part of NOW’s deferral and variance accounts.

Transformer Ownership Allowance

12. Ref: Board staff IR #38 a) - NOW's cost allocation model – Information Filing, VECC IR#19

In VECC IR #19, VECC requested an alternative run of the cost allocation model in which the "cost" of the transformer ownership allowance would be omitted from the allocation, because the model (in its original run) incorrectly allocated the cost only amongst those classes that receive service through distributor-owned line transformers.

NOW failed to produce the requested output, with the explanation that errors were caused in the model when NOW attempted this modification.

Please note that the Board, in its decision, may require NOW to produce revenue to cost ratios that exclude both the costs and revenues related to transformer ownership allowance. If this is the case, NOW must have the ability to produce these ratios accurately. Please expand on what happened when NOW attempted to respond to VECC's request for a new run of the Cost Allocation model, and explain why NOW believes that the outcome may not be reliable.

As both OEB and VECC has asked follow up questions regarding the CA runs, NOW has attempted (successfully) to revisit the original request.

Please see requested Output in response to VECC # 35 in the second round of IR's.

Rural or Remote Electricity Rate Protection

13. Ref: E9/T1/S5 – Proposed Rate Schedule for 2009, Board's December 17, 2008 Letter to All Licensed Electricity Distributors and Retailers Re: Rural or Remote Electricity Rate Protection

In its December 17, 2008 letter, the Board announced a change to the RRRP rate from 0.10 cents per kWh to 0.13 cents per kWh. The Board also directed all distributors that have current rate applications before the Board to submit the Board's December 17, 2008 letter as an update to their evidence along with a request that the RRRP change in their tariff sheet be revised to 0.13 cents per kWh effective May 1, 2009. As of this date, NOW has not updated its application for this change.

Does NOW wish to update its application to reflect the change to the RRRP rate?

Yes we do, please find letter attached as requested in other rate applications.

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
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
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

December 17, 2008

To: All Licensed Electricity Distributors and Retailers

Re: Rural or Remote Electricity Rate Protection

Ontario Regulation 442/01, Rural or Remote Electricity Rate Protection ("RRRP") (made under the *Ontario Energy Board Act, 1998*) requires the Ontario Energy Board (the "Board") to calculate the amount to be charged by the Independent Electricity System Operator ("IESO") with respect to the RRRP for each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid.

Amount to be charged by the IESO for RRRP

Based on the demand forecast provided by the IESO, the Board has determined that the amount to be charged by the IESO with respect to the RRRP shall remain at the current level of 0.1 cents per kilowatt-hour effective January 1, 2009. Effective May 1, 2009, the IESO's RRRP charge shall be 0.13 cents per kilowatt-hour.

Amount to be Charged by Distributors and Retailers for RRRP

Effective January 1, 2009, the RRRP charge shall remain at the current level of 0.1 cents per kilowatt-hour.

Effective May 1, 2009, the RRRP charge shall be 0.13 cents per kilowatt-hour.

After May 1, 2009 the RRRP charge shall remain at 0.13 cents per kilowatt-hour until such time as the Board revises it.

Distributors that currently have a rate application before the Board shall file this letter as an update to their evidence along with a request that the RRRP charge in their tariff sheet be revised to 0.13 cents per kilowatt-hour effective May 1, 2009.

Where a distributor does not have a rate application before the Board, the distributor shall make an application to the Board to alter the RRRP charge in its tariff sheet effective May 1, 2009 to 0.13 cents per kilowatt-hour.

In the collection of this amount from customers, the customer's metered energy consumption shall be adjusted by the Total Loss Factor as approved by the Board.

The Board wishes to remind all distributors and retailers that in accordance with subsection 5(6) of the Regulation:

> A distributor or retailer who bills a consumer for electricity shall aggregate the amount that the consumer is required to contribute to the compensation required by subsection 79(3) of the Act with the wholesale market service rate described in the Electricity Distribution Rate Handbook issued by the Board, as it read on October 31, 2001.

Yours Truly,

Original Signed By

Kirsten Walli
Board Secretary