December 21, 2007

Ms. Kirsten Walli
Board Secretary
P.O Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli,

Re: Halton Hills Hydro Inc. 2008 Electricity Distribution Rates Application
Board File Number EB 2007-0696
Second Round Interrogatory Responses to OEB Staff

Please find the second round of interrogatory responses to OEB Staff questions, dated December 7, 2007 and as directed in Procedural Order #1 dated October 23, 2007 in proceeding EB-2007-0696.

These responses have been filed through the OEB RESS, couriered to the OEB offices and emailed to all intervenors.

Yours truly,

Arthur A. Skidmore CMA
Corporate Vice-President and
Chief Financial Officer
Halton Hills Hydro Inc.
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c. Dan Guatto, President Halton Hills Hydro Inc.
Interested Parties EB-2007-0696

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1. Ref: Exhibit 4, Tab 1, Schedule 2, Page 1

Board Staff Table 1 was prepared by Board staff to review Halton Hills OM&A expenses. The 2006 Board Approved value was previously confirmed by Halton Hills in Phase 1 OEB Staff Interrogatories. Please note rounding differences may occur, but are immaterial to this question.

Board Staff Table 1

	2006 Board Approved	Variance 2006/2006	2006 Actual	Variance 2007/2006	2007 Bridge	Variance 2008/2007	2008 Test	Variance 2008/2006
Operation	495,098	205,455	700,553	14,447	715,000	69,000	784,000	83,447
		4.5%		*0.3%*		*1.4%*		*1.8%*
Maintenance	560,579	133,973	694,552	46,448	741,000	80,000	821,000	126,448
		2.9%		*1.0%*		*1.7%*		*2.8%*
Billing & Collecting	835,191	73,658	908,849	14,151	923,000	116,000	1,039,000	130,151
		1.6%		*0.3%*		*2.4%*		*2.8%*
Administrative & General Expenses	1,961,445	127,314	2,088,759	81,241	2,170,000	277,000	2,447,000	358,241
		2.8%		*1.8%*		*5.8%*		*7.8%*
Taxes other than income taxed	71,132	117,888	189,020	980	190,000	5,000	195,000	5,980
		2.6%		*0.0%*		*0.1%*		*0.1%*
Other Operating Costs	0	2,901	2,901	17,099	20,000	13,000	33,000	30,099
		0.1%		*0.4%*		*0.3%*		*0.7%*
Total OM&A	3,923,445	661,189	4,584,634	174,366	4,759,000	560,000	5,319,000	734,366
		14.4%		*3.8%*		*11.8%*		*16.0%*

Board Staff Table 2

Board Staff Table 2 was compiled by Board staff to summarize Halton Hills OM&A expenses cost drivers. Board Staff have used for example the drivers as provided by Halton Hills on Exhibit 4, Tab 1, Schedule 2, Page 1. Please note rounding differences may occur, but are immaterial to this question.

	2006	2007	2008
Opening Balance	$ 3,923,445	$ 4,584,634	$ 4,759,000
Settlement Analyst			$ 56,000
Staff Training - MBA Designation			$ 45,000
Regulatory Affairs Officer			$ 30,000
Annual Management Salary Increase			$ 10,000
Disaster Recovery Contract Renewal			$ 8,500
Engineering Technologist			$ 73,800
Annual General Administrative Salary Increase			$ 7,500
Annual Benefit Cost Increase			$ 6,500
Scada Maintenance Contract			$ 7,500
Unexplained Variance	$ 661,189	$ 174,366	$ 315,200
Closing Balance	$ 4,584,634	$ 4,759,000	$ 5,319,000

i. Please confirm that Halton Hills agree with the tables as prepared by Board staff. If Halton Hills does not agree please advise why not.

ii. Please complete a Cost Drivers by Year analysis table similar to the Board Staff Table 2 above identifying the cost drivers that make up the changes to Halton Hill's annual controllable expenses. The objective is to identify all significant expense cost drivers that reduces the "Unexplained Difference" to an amount no greater or no less than WNPI calculated OM&A materiality limit as found on Exhibit 4/Tab 2/ Schedule 2.

Please ensure that each identified driver is followed with a more detailed discussion with information the applicant feels the Board would require more detail. For example Staff Training – MBA Designation would benefit from some discussion on employment contract with employee post graduation. Another Discussion would provide reason for need of Settlement analyst.

iii. Halton Hills identifies that the company is planning to expend $45,000 for Staff Training – MBA Designation.

a) Please confirm that the 2008 Staff Training – MBA Designation is a one-time cost of $45,000.

b) If this cost is a one-time cost, please explain why this one-time amount should be recovered by way of Halton Hills annual revenue requirement in light of the fact that the 2008 revenue requirement, once approved will not be adjusted until 2011.

c) If the cost is not a one-time cost, please explain why Halton Hills expects to incur the level of staff training costs reported for the 2008 test year on an annual basis going forward.

d) Has Halton Hills identified any other one time costs that should be addressed in a similar manner as above? If yes please provide similar discussions.

iv. What cost saving/efficiency initiatives or activities has the applicant implemented after the last 2006 EDR application? In addition what other plans does the applicant have to increase cost saving and efficiency, that that have not already been discussed in the application?

i. Halton Hills Hydro Inc. agrees with Table 1 as prepared by OEB Staff. Table 2 has been amended to update the cost drivers per year as per ii).

ii. Please refer to Table 2A and Table2B for an analysis of cost drivers by year. The unexplained difference has been reduced to below the materiality limit as calculated per Exhibit 4, Tab 2, Schedule 2.

Table 2A- OEB Staff Table 2 Updated for Cost Drivers by Year

	2006	2007	2008
Opening balance	3,923,445	4,584,634	4,759,000
Cost drivers as detailed below	609,200	144,500	515,500
Unexplained variance	51,989	29,866	44,500
	4,584,634	4,759,000	5,319,000
Materiality level per Exhibit 4, Tab 4, Schedule 2, Page 1	65,142	68,704	74,787

Table 2B-Cost Drivers

1. Staffing costs:	**2006**	**2007**	**2008**
a) Annual salary cost increases:			
Annual engineering staff salary increase - 2005	6,800		
Annual engineering staff salary increase - 2006	8,200		
Annual engineering staff salary increase - 2007		7,800	
Annual engineering staff salary increase - 2008			8,000
Annual operations staff salary increase - 2005	12,600		
Annual operations staff salary increase - 2006	14,300		
Annual operations staff salary increase - 2007		13,600	
Annual operations staff salary increase - 2008			14,000
Customer care supervisory & staff salary increase - 2005	24,900		
Customer care supervisory & staff salary increase - 2006	19,100		
Customer care supervisory & staff salary increase - 2007		18,200	
Customer care supervisory & staff salary increase - 2008			18,800
Annual management salary increase - 2005	6,400		
Annual management salary increase - 2006	6,800		
Annual management salary increase - 2007		6,500	
Annual management salary increase - 2008			10,000
Annual general administrative salary increase - 2005	7,200		
Annual general administrative salary increase - 2006	9,700		
Annual general administrative salary increase - 2007		9,200	
Annual general administrative salary increase - 2008			7,500
Annual executive salary increase - 2005	9,600		
Annual executive salary increase - 2006	11,700		
Annual executive salary increase - 2007		11,200	
Annual executive salary increase - 2008			11,500
b) Staffing additions:			
Regulatory affairs officer			30,000
Settlement analyst			56,000
Engineering technologist			73,800
c) Staff benefit costs:			
Pension cost increase	46,200		5,800
Group insurance cost increase	17,800		20,500
Payroll tax cost increase	4,900		6,800
d) Other staff costs:			
Engineering staff overtime	4,000		
Substation operations staffing cost	26,500		
Overhead line maintenance - staff overtime	33,500		
Underground line maintenance staffing cost	21,600		
Underground line maintenance - staff overtime	12,100		
Union contract signing bonus	14,000		
Vacation accrual	35,300		
Management incentive	66,800		
Staff development	3,300		17,500
Staff training - MBA designation			45,000

Table 2B (cont'd)

2. Contractor costs:	**2006**	**2007**	**2008**
Tree trimming	15,000		30,000
Meter reading contract cost increase	12,200		15,100
PCB transformer maintenance / removal cost	7,600		
Underground line maintenance	4,200		
Substation shutdown maintenance		22,500	
Customer care contract staff		12,800	
Wholesale meter maintenance		9,700	
SCADA maintenance contract			7,500
Safety training			10,000
Information technology contract staff			30,000
3. Communications costs:			
MV90 meter communications			23,000
MV90 software maintenance			10,500
4. Other costs:			
Regulatory	29,000		
Bad debts		13,000	10,000
Corporate donations program		20,000	10,000
Governance costs			11,500
Disaster recovery contract renewal			8,500
Liability and property insurance			8,200
Professional fees			4,000
Utilities cost increase			3,400
Building maintenance			2,600
5. Taxes			
Capital taxes	100,200		1,400
Property tax increase	17,700		4,600
	609,200	144,500	515,500

Further discussion:

1. Staffing costs:
   A. Annual salary cost increases – these annual salary cost increases correspond to collective agreement annual increases as follows:
      2006 – 2.75%
      2007 – 3.25%
      2008 – 3.00%
      2009 – 3.00%
      Management and executive annual salary increases are similar to the collective agreement increases.
   B. Staffing additions:
      I) Regulatory affairs officer – the regulatory affairs officer was hired to address the requirements of ongoing regulatory activities. The 2008 test year amounts bring the new hire to full year salary.

II) Settlement analyst - the settlement analyst will be hired to address the requirements of settlements related to smart metering. The 2008 test year is projected as the initial year of hire for this individual.

III) Engineering technologist – the engineering tech is hired to address ongoing growth in layout requirements. The 2008 test year represents the full year salary of this new hire.

C. Staff benefit costs: Benefit costs continue to increase for Halton Hills Hydro Inc. Group insurance costs have been renegotiated in the latest round of collective bargaining in an attempt to minimize experience increases. Pension cost and payroll tax cost increases are small percentage increases based on the aggregate of these costs respectively.

D. Other staff costs:

I) 2006 – Operational requirements necessitated actual costs in excess of Board Approved for overhead and underground line maintenance, as well as substation operations. Staff budgeted to capital activities were reassigned to operational and maintenance activities as required. Other staff costs also included a signing bonus related to the new union collective agreement, a vacation accrual to bump the accrued vacation payable costs to actual, and the 2006 management incentive accrual.

II) 2008 – A continual effort in staffing development ensures Halton Hills Hydro Inc. staff augments industry expertise and assists in minimizing staff turnover. Current and ongoing training cost increases include substation training, customer care, metering and line staff. The MBA designation cost is addressed in iii) below.

2. Contractor costs:

I) 2006 – Actual contractor costs increased on a minimal basis compared to 2006 Board Approved. Tree trimming and meter reading contractor costs were the major sources of the increase, which was based on operational requirements.

II) 2007 – Similarly for 2007, actual contractor costs increases were minimal. An augmented substation maintenance program was engaged in 2007, with testing and maintenance tailored to specific substation components. Substations are maintained on a three-year rotational basis, with one-third of the substations shutdown each year. Substation contractors are retained for specialized tasks and repairs. Customer care contractor costs were incurred to support ongoing customer contact and billing activities. Wholesale meter maintenance costs reflect the continuing maintenance costs resulting from acquisition of all service area wholesale meters.

III) 2008 – Additional tree trimming program costs are necessitated to ensure safety and reliability of the overhead distribution system on an ongoing basis. Heavily treed areas of rural North Acton and urban areas of Georgetown and Acton have been scheduled over the upcoming years. Meter reading contract costs are projected to increase based on service area customer growth, both residentially and commercially. Telephone line reading point maintenance costs will also be incurred for meter reading in 2008. An upgraded SCADA maintenance contract will be incurred in the Test year, ensuring the reliability of our data collection and control infrastructure. Safety training costs are enhanced to include ongoing annual school safety training. Information technology contract staff will be retained to support required technology programs: system modifications, maintenance and upgrades and office support.

3. Communications costs: most communications costs are projected to remain relatively static over the periods in question. The increases in communications costs are related to MV90; specifically telephone line charges for the increase in customer reads using the MV90 system and software maintenance fees for the system.
4. Other costs:
   I) 2006 – One other cost item differed significantly from 2006 Board Approved: regulatory costs.
   II) 2007 – Bad debts are projected to increase for 2007 but still remain a small percentage of overall receivables. A corporate donations program was undertaken in 2007 to further community projects undertaken in our service area.
   III) 2008 – A number of other cost items are projected to increase for the Test year, most them at a minimal amount. More significant projected increases relate to governance costs, the corporate donations program and bad debts. Governance costs are projected to increase based on the prior year's experience with Board of Directors fees. The corporate donations program in 2007 to further community projects will be expanded. Bad debts are also projected to increase for 2008 but still remain a small percentage of overall receivables.
5. Taxes: For 2006, capital taxes were included in the PILs segment of the rate filing. The only item listed in 2006 Board Approved was property taxes. All comparative years include capital taxes in the taxes other than income taxes line. Property taxes are projected to increase at a moderate rate for the 2008 Test year.

iii. MBA designation:
   a) The 2008 staff training is not a one-time cost. The program is a two-year program at a cost of $45,000 per annum.
   b) Although this is not a one-time cost, the 2010 rate year cost recovery is still in question. In 2010, these funds will go towards further staff training in the functional areas of Engineering, Regulatory, IT, Administration and Tax. Halton Hills Hydro Inc. is committed to providing training to ensure we have professional and knowledgable staff.
   c) As stated, this is not a one-time cost.
   d) Halton Hills Hydro Inc. has not identified other costs that are on a one-time basis in the 2008 test year.

iv. Cost Saving/efficiency initiatives:

a. Implemented a Prudential reduction with the IESO, therefore saving Letter of Credit charges.
b. Issued a Banking RFP and changed financial institutions to achieve costs savings and operational efficiencies.
c. Implemented new telephone system to provide enhanced customer service.
d. Implemented on-line account access for our customers to access their account information.
e. Implemented E-Meter.com as a value added service for our large interval metered customer. This web-site provides daily HOEP pricing, graphical analysis of consumption and previous day consumption by hour.
f. Issued an Audit RFP and proceeded with a change to the auditing company.
g. Use of internal staff for 2008 Rate Application process.
h. Acted as a Beta site for operating software to reduce overall software fees.
i. Negotiated new software pricing.
j. Staff efficiencies were maximized resulting in cost savings.
    - Accounting workflow documentation
    - Staff development programs
    - MSDS management
k. Scanning all documents into electronic format to allow for easy and quick archival and retrieval of data.
l. Improved SCADA system with direct relay communications to substations.
m. Implemented ICCP link for direct Master to Master communication with Hydro One Networks Inc.
n. Continued voltage conversions along Steeles Avenue.

2. Ref: Exhibit 4, Tab 1, Schedule 2, Page 1

> ***Has Halton Hills presented the 2007 Bridge Forecast of $4.759 million and 2008 Test Year Budget of $5.319 million to its Board of Directors and received final approval and committed management to these budget expenditures? If so, please confirm Board of Directors approval the OM & A expenditures. If not please provide information as to when Halton Hills will be presenting these budgets for approval by its Board.***

The Board of Directors of Halton Hills Hydro Inc. considers the budget process a key component of its responsibilities. Management is required to present the budget for review for the approval of the Board of Directors and the process is normally conducted and completed as part of the Board of Directors' activities during the final quarter of the pre-budget year. Management presented the 2007 budget for approval during the fall of 2006 and the budget was approved on December 14, 2006. Management has reported at each of the Board of Directors meetings throughout 2007 regarding the financial status of the corporation and this report includes a review of budget accomplishment.

In addition, it is noted that prior to approving the rate application to be filed with the Ontario Energy Board at the Board of Directors' meeting in August, the Board of Directors had discussed the financial and project needs for both capital and OM&A expenditures in order to provide direction to management that enabled the completion of the 2008 rate application in as accurate a manner as possible, including allocation of costs to customer classes.

As part of its continuing responsibilities to monitor financial performance and financial management of the Corporation, the Board of Directors is reviewing the budget for 2008 operations and has reviewed management's budget proposals as they pertain to expenditures for the test year. In this review, the Board of Directors will be mindful of the content and context of the submitted 2008 Rate Application approved by the Board of Directors in August 2007. Although the Board of Directors will complete its review of the budget in early January 2008, Halton Hills Hydro Inc. does not expect this review to alter, in any material way, the customer impacts as reflected in the rates and charges identified in the rate application, since the Board of Directors has been kept fully informed during the development of the rate application.

3. Ref: Exhibit 4, Tab 1, Schedule 2, Page 1

> ***Please prepare a comprehensive listing of all operational costs by work unit for smart meter included in the 2008 budgets. Include in this listing the work unit where the smart meter cost is accounted for in the budgets, description of activity, and amount budgeted. In particular please identify for each of the reported budget amount whether Halton Hills considers the cost to be a component of minimum functionality or if the amount is incidental/incremental to minimum functionality.***

Halton Hills Hydro Inc. did not include any smart metering costs in the 2008 Budget included as part of the original application. Exhibit 1, Tab 1, Schedule 6, Page 1 states:

> *"In the rate application, Halton Hills Hydro Inc. has not included any costs related to Smart Metering dated April 12, 2007. Halton Hills Hydro Inc. applied for $1.18 to embark on its Smart Metering Investment Plan filed with the Ontario Energy Board December 15, 2006. However, the Ontario Energy Board only approved $0.26 due to Regulation 153/07."*

Halton Hills Hydro Inc. expects that a further provincial directive will be necessary in order to extend the current Smart Meter initiative and this will likely require Halton Hills Hydro Inc. and other Local Distribution Companies to adjust their current planning.

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

Board staff IR#3 asked Halton Hills to "Please provide a detailed description of the assumptions underlying the allocation of Halton Hills' corporate costs to its business units, if applicable. Please include relevant documentation of the overall methodology and policy. If not applicable, please explain why."

In response, Halton Hills appears to have provided information on how costs are allocated within its group of companies, which dealt with the information requested in Board staff IR# 6.

However, on page 8 of the Board's filing requirements of November 14, 2006, corporate cost allocation is described as "an allocation of costs for corporate and miscellaneous shared services from the parent to the utility."

Page 16 of the filing requirements list the requirements for corporate cost allocation as the provision of a detailed description of the assumptions underlying the allocation of these services and documentation of the overall methodology and policy.

Please confirm that Halton Hills' response covers the information referenced in the filing requirements, or if not, please provide this information.

The information filed by Halton Hills Hydro Inc. in response to Round 1 OEB Staff Interrogatory #3 does not provide the information requested by the OEB Staff. Halton Hills Hydro Inc. does not have a parent company to the LDC and therefore, there are no corporate cost allocations to the business units. All costs are incurred within Halton Hills Hydro Inc. Exhibit 1, Tab 3, Schedule 5, Page 1 indicates that Halton Hills Hydro Inc. corporate structure does not have a holding company.

5. Ref: Exhibit 4/Tab 2/Schedule 4 and Appendix B Financial Statements

In response to Board staff IR#3, Halton Hills discusses services which it performs for its affiliate Halton Hills Fibre Optics Inc.

In Appendix B, Financial Statements, Audited Financial Statements at December 31, 2006, page 9 of 16, Note 5, there appears to be reference to additional services performed for Halton Hills Fibre Optics Inc. which are not discussed in the response. These services relate to advances for capital initiatives.

The relevant portion of Note 5 is reproduced below:

> ***"Repayments of advances to Halton Hills Fibre Optics Inc. for capital initiatives amounted to $250,000 during the year (2005 - $100,000 advanced). The net amount advanced for capital initiatives of $350,000 (2005 - $600,000) is unsecured, bears interest at the prime rate less ½% and has no specific repayment terms.***
>
> ***Other than the above, these receivables are unsecured and have no specific interest or repayment terms."***

i. Please provide a detailed explanation as to the nature of the arrangements Halton Hills Hydro has with its affiliate regarding these advances and why this approach was chosen.

ii. Please state whether or not the arrangements described in the Financial Statements notes in above are expected to continue and unchanged in 2007 and 2008 period or whether or not Halton Hills Hydro made any new financial arrangements with Halton Hills Fibre Optics Inc. for 2007 and 2008 and if so, why.

iii. Please state whether or not Halton Hills has similar arrangements with any other of its affiliates and, if so, please provide equivalent information.

iv. Please state whether or not the rates which are being paid for these services by Halton Hills Hydro's affiliates are considered to be market rates, and if so, how they were determined to be so. If not, please comment on whether or not, in Halton Hills Hydro's view, there is an element of cross subsidy from the utility to its affiliated companies contained in these rates and if not, why not.

i. Halton Hills Hydro Inc. advanced (lent) its affiliate Halton Hills Fibre Optics Inc. monies for Capital Initiatives as stated in the Financial Statements. This approach was taken to assist Halton Hills Hydro Inc.'s affiliate in growth opportunities. The loan is a commercial arrangement as indicated in the financial statements and "bears interest at the prime rate less ½%".

ii. The existing arrangements will continue in 2007 and 2008 with further repayments by Halton Hills Fibre Optics Inc. to Halton Hills Hydro Inc. in both 2007 and 2008. It is the intention of Halton Hills Fibre Optics Inc. to have the monies fully repaid by 2009. Halton Hills Hydro Inc. does not anticipate any new financial arrangements in 2007 or 2008.

iii. Halton Hills Hydro Inc. has no similar arrangements with any other affiliates.

iv. Further to the answer to (i) above, Halton Hills Hydro Inc. considers the rates to be market value. The rate is determined by Halton Hills Hydro Inc.'s Credit Facility with its financial institution.

6. Ref: Exhibit 4/Tab 2/ Schedule 5

In response to Board staff IR#4, Halton Hills provides more detailed descriptions of the specific methodologies used to determine the price for services which it has purchased from other organizations. Please provide the following additional information:

- ***i. Please state how Halton Hills determines which services should be acquired through which approach (i.e. tendering, cost approach or quotation)***
- ***ii. For tendering, it is stated that tenders are sent to "qualified organizations." Please state how such organizations are determined. Please also state whether there are any criteria other than ability to meet the requirements and being the lowest priced organization in determining the awarding of work through the tender process.***
- ***iii. (iii) For the cost approach, please provide more detail with respect to the following statement "Typically we have worked with vendors in the past and set up budgetary restrictions on the amount to be spent." Please discuss specifically how budgetary restrictions on the amount to be spent have been established.***
- ***iv. (iv) For quotation, please state how "selected vendors" are determined. Please also state whether there are any criteria other than ability to meet the requirements and being the lowest priced organization in determining the awarding of work through the tender process.***

i. Halton Hills Hydro Inc. has attached its Purchasing Policy (Appendix A) that sets out the guidelines for Management and Staff to follow to establish amounts, requirements and approval for acquired services.

ii. Qualified organizations are determined from the following criteria:
   a. Well known in their field of expertise
   b. Industry references
   c. Previous work history
   d. Proof of training/competency and safety record
   e. Availability of qualified personnel and appropriate equipment

   Other criteria used in determining the successful proposal would be the assurance that the project timeline can be achieved.

iii. Budgetary targets are determined based on the amount of work that needs to be completed.
   - Example: Pole inspections – Halton Hills Hydro Inc. determines that 1,000 poles need to be inspected @$10/pole set by the budgetary amount @$10,000 (this is an example only and does not refer back to any budget line item).

iv. Selected vendors are determined from the following criteria:
   a. Well known in their field of expertise
   b. Industry references
   c. Previous work history
   d. Proof of training/competency and safety record
   e. Availability of qualified personnel and appropriate equipment

   Other criteria used in determining the successful proposal would be the assurance that the project timeline can be achieved.

7. Wheeling Rates

In the Board's 2004 Decision and Order regarding rates for Halton Hills Hydro Inc. (RP-2004-0153/EB-2004-0235) the Board stated:

"On April 30, 2004, Hydro One responded and confirmed that the rates attached as Appendix B to the Minister's letter are the rates which were charged to Hydro One by Halton Hills for wheeling and transformation services from January 1, 2002 to April 30, 2002. Hydro One also noted that it supported the proposed rates only as transitional rates until Halton Hills' rates could be re-based, as these rates were not reflective of the cost to provide the services. Hydro One further stated that in preparation for the re-basing of its 2006 rates, Halton Hills should be required to conduct a cost of service study and specifically develop a separate rate class to deal with wheeling power.

The Board finds Hydro One's request that Halton Hills develop a separate wheeling power rate class to be reasonable and expects Halton Hills to propose such a rate class as part of the 2006 rate-setting process."

Did Halton Hills Hydro apply for wheeling rates as part of its 2006 application? If not, why has Halton Hills Hydro not applied for such rates as directed in the (RP-2004-0153/EB-2004-0235) decision and order?

Halton Hills Hydro Inc. did not apply for wheeling rates as part of its 2006 application. Effective on, or about, May 1, 2006 at the request of Hydro One Networks Inc., Halton Hills Hydro Inc. made changes to the distribution system removing the necessity for calculating wheeling charges. At that time, Hydro One Networks Inc. became a GS 1,000 to 4,999kW commercial class customer of Halton Hills Hydro Inc. Therefore, due to this occurrence, Halton Hills Hydro Inc. did not file a request to create a "separate wheeling power rate class".

8. Ref: Response to Board staff IR#12

a) On page 2 under (a) iii the income tax number shown as $836,500 includes Ontario Capital Tax of $65,419. Does the amount of $1,181,000 under ii for 2007 include capital tax as well?

b) The application supports a return on equity of $1,585,346 according to the table shown for Question 37, "Revenue Sufficiency/Deficiency Calculation 2008 Test Year". There is an amount of $3,546,537, shown on the reply to Question 12, page 2, (a) iii, for 2008 pro-forma net income before PILs/ taxes.

• Please explain if the Applicant intends to over-earn in 2008 based on this evidence.

• Please explain why the income before PILs Taxes on E4/T3/S1/P1 is not the return amount of $1,585,346 shown above.

c) Under the regulatory framework, the distributor is allowed to recover an amount for interest on rate base. This amount may be the deemed amount or a lower amount based on projected actual interest to be incurred. The equity return on rate base occurs after the deduction of interest. Only excess interest is included as a penalty, or a deduction, in the PILs calculations. Please refer to schedule 7-3 in the 2006 EDR Handbook.

Board staff notes that the interest amount of $1,242,620, shown in the deficiency calculations in Question 37, is not the same amount used in the PILs calculations in E4/T3/S1/P1 and E4/T3/S2/P1.

Board staff suggests that the proposed interest add-back and deduction in the PILs calculation is not appropriate and is not supported by the Board's PILs/ tax methodology. Please explain why the Applicant feels it is appropriate.

If the distributor intends to pay more interest to its shareholder than allowed by the Ministry of Finance in completing the annual tax returns, why does the distributor expect the ratepayers to fund the PILs/ tax excess cost?

a) The 2007 PILs amount of $1,181,000 includes capital tax in the amount of $65,419 as well.

b) Halton Hills Hydro Inc. does not intend to over-earn in 2008. The 2008 Test year pro-forma income statement was created using placeholders in income sources and was not updated once these revenues were generated through our model.

The net income before PILs Taxes on Exhibit 4, Tab 3, Schedule 1, Page 1, is stated at a different value than per the Revenue Sufficiency / Deficiency Calculation in Round 1 OEB Staff Interrogatory #37 because a slightly different regulated rate of return was used in the Interrogatory response. A short term debt rate of 6% was used in the original rate application, whereas a 6.14% short term debt rate was used in the Interrogatory response.

c) On review of schedule 7-3 of the 2006 EDR Handbook and theory behind why excess interest is deducted from net income in the PILs calculations, Halton Hills Hydro Inc. agrees that the add-back of interest expense in excess of deemed is not appropriate.

Halton Hills Hydro Inc. does not expect ratepayers to fund the PILs Tax excess cost of interest paid to the shareholder in excess of that allowed by the Ministry of Finance.

Capital Budget
9. Ref: Response to Board Staff IR#17

> ***Please provide an economic evaluation of the Halton Hills Hydro/Brampton Hydro Load Transfer Project "Winston Churchill - 5SDRD to Steeles" using the generic Economic Evaluation Model referenced in response to Board staff IR#16.***

Halton Hills Hydro Inc. wants to emphasize that the Winston Churchill -5SDRD to Steeles capital project is driven by the road widening of Winston Churchill Boulevard. The project has been active for over six years but has not been constructed due to the inability to obtain easements. The load transfer component of this project is zero cost as all of the costs are associated with the road widening.

The work performed in this project will eliminate all load transfers between Halton Hills Hydro and Hydro One Brampton in the affected area since the result will be that each utility will own its own feeders on a common pole line.

Halton Hills Hydro Inc. has an obligation under provincial legislation to co-operate with any road widening activities. The combined concerted efforts of both Halton Hills Hydro Inc. and Hydro One Brampton staff to have the foresight to seek the Load Transfer extension from the Ontario Energy Board enabled the LDCs to cost share the project and to avoid any unnecessary costs.

Excerpt from "*Public Service Works on Highways Act*"

Notice to operating corporation to take up works

2. *(1) Where in the course of constructing, reconstructing, changing, altering or improving a highway it becomes necessary to take up, remove or change the location of appliances or works placed on or under the highway by the operating corporation, the road authority may by notice in writing served personally or by registered mail require the operating corporation, without prejudice to their respective rights under section 3, so to do on or before the date specified in the notice. R.S.O. 1990, c. P.49, s. 2 (1).*

Excerpt from "*Distribution System Code*"

3.4.1 *When requested to relocate distribution plant, a distributor shall exercise its rights and discharge its obligations in accordance with existing legislation such as the* Public Service Works on Highways Act*, regulations, formal agreements, easements and common law. In the absence of existing arrangements, a distributor is not obligated to relocate the plant. However, the distributor shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner shall include a response to the requesting party that explains the feasibility of infeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.*

The generic economic evaluation model referenced is intended to be used for subdivision analysis and not for road widening project analysis.

10. Ref: Response to Board Staff IR#17

Reference to "load transfer arrangements":
In regard to load transfer arrangements, please provide:
a) a listing of all load transfer arrangements in operation mentioning:

- ***i. the utility involved and which party is the geographical supplier and which the physical supplier***
- ***ii. the number of customers, the nature of the load, and the amount of load served***
- ***iii. the expenditure which it is expected will be required by Halton Hills to eliminate the arrangement***
- ***iv. the method of eliminating the transfer i.e. will Halton HIlls transfer service area and customers in or out***
- ***v. to what extent the arrangement has been influenced by the perception that the area is going to be a load growth area and therefore profitable to serve.***

b) For the load transfer arrangement with Brampton Hydro which was approved by the Board recently, please provide:

- ***i. for the record, a copy of all interim decisions and the final decision issued by the Board***
- ***ii. any qualitative and operational justifications, which demonstrate that the decision was the most economical for the two utilities***
- ***iii. any net present value or other economic studies which demonstrate that the decision made was the most economical for the two utilities.***

a) Please refer to Table 3.

b)

i. See Appendix B for interim and final decisions issues by the Board.
ii. Please refer to Round 2 OEB Staff Interrogatory #9.
iii. Please refer to Round 2 OEB Staff Interrogatory #9.

Table 3

Load Transfer Arrangement	Geographic Supplier	Physical Supplier	Number of customers	Nature of load	Amount of Load (kWh) - Sum of Highest kWh in 12 month period	Expenditure needed to eliminate arrangement (Rough Cost Estimate)	Method of Elimination	Arrangement influenced by perception of growth
Winston Churchill Blvd 17 SDRD through Old Pine Crest Rd.	HOB	HHHI	11	Res.		N/A HOB Customers	N/A Retail metering installation at 17sdrd & Winston Churchill Blvd - become retail customer of Hydro One	N/A
Winston Churchill Blvd 17 SDRD through Wanless Dr.	HHHI	HONI	6	Res. & Comm.	64831	$ 10,000.00		N/A
Winston Churchill Blvd Steeles to Norval Metering Point	HHHI	HOB	58	Res. & Comm.	268473	$ 1,100,000.00	Construction of Joint-Use Pole Line	Major Growth (Commercial)
Winston Churchill Blvd 32 Sideroad to 17 SDRD	HHHI	HONI	40	Res	4334	N/A	HHH customer to Hydro One	N/A
5 SDRD	HHHI	MILT	4	Res	12035	N/A	Joint use pole line built approximately 15 years ago.	N/A
Townline	HHHI	MILT	3	Res	8265	N/A	Customers to Milton	Perception of growth insignificant
9th Line (O/H)	HHHI	HONI	20	Res	113353	N/A	Pole line already built	N/A
10th Line (U/G)	HHHI	HONI	7	Res	54244	N/A	Built underground primary to join HHH to HONI Feeder.	N/A
32nd Sideroad Winston Churchill Blvd. to Town Line	HHHI	HONI	9	Res	17882	N/A	HO customers become HHHI customers	N/A

HHHI	Halton Hills Hydro Inc.
HOB	Hydro One Brampton
HONI	Hydro One Networks Inc.
MILT	Milton Distribution

11. Ref: Exhibit 2/ Tab 1/ Schedule 1

Reference to performance of an assessment of the condition of an asset.
In regard to asset condition assessment procedures, please provide:

a) a detailed description of the procedures, and documentation which has to be completed by assessors before capital expenditure is committed
b) the schedule according to which the assessments are to be or have been conducted to determine replacements required in each of the historical, bridge and test years
c) any evidence of third party assistance in making assessments, including any assessment reports provided
d) evidence on how the utility uses reliability indicators to assist in maintenance and replacement activity, and
e) evidence indicating that asset replacement is specifically addressing areas with lower than target reliability.

a) Please see Appendix C for an example of procedures and documentation used by Halton Hills Hydro Inc. in the assessment of asset conditions. These documents are completed and reviewed; contributing to the decision of any capital expenditure commitment where necessary.

b) Please see Appendix D for an example of asset assessment schedules.

c) Halton Hills Hydro Inc. uses internal personnel for distribution system assessments. Building assessment for 43 Alice St, Acton was conducted by IRC Building Sciences Group Inc. A copy of the assessment is located in Appendix E.

d) Halton Hills Hydro Inc. uses reliability indicators to assess priority tree trimming and animal contact. Halton Hills Hydro Inc. has also used the reliability indicators in an effort to determine potentially faulty equipment by analyzing areas affected and determining if equipment was the cause of a reliability issue. Phone call indices indicate that customer calls have lengthened. Halton Hills Hydro Inc. has used this index to determine the information system is operating at a slower than desired speed.

e) Halton Hills Hydro Inc. has used customer complaints about noisy transformers and power outages to determine that certain Distribution Stations need to be repaired or replaced. In Exhibit 2, Tab 3, Schedule 1, Page 6, listed under Substation Capital, the River Street DS transformer and Cross Street switchgear projects are the direct result of these indicators. In addition, outage calls have brought the issue of backyard replacements to the attention of Halton Hills Hydro Inc. As a result of phase to phase contact due to older, broken backyard poles, Halton Hills Hydro Inc. is addressing the replacement of all backyard poles over the coming years. Halton Hills Hydro Inc. has attempted to use reliability indicators to determine faulty equipment that results in lower than target reliability. However, in analyzing the data, Halton Hills Hydro Inc. has not been able to specifically target any one type or batch of equipment that has proven faulty. As a result, repairs and replacements have been conducted as problems have arisen, hence, using the reliability indicators in this case will not specifically address these areas with lower than target reliability. In addition, the upgrade to the AS-400 will increase the speed at which the information system retrieves data and will help decrease the time customers spend speaking with Customer Care Representatives thereby providing a reduced response time to customer inquiries.

12. Ref: Exhibit 2/ Tab 1/ Schedule 1

Please provide:
a) a list of service reliability indices which are maintained by the utility
b) their target values for 2006 and 2007 and their actual achieved values for 2006 and 2007 (to date)
c) capital expenditure activity (specific budget items) which is intended to address poor performance in specific areas

a) The following Service Reliability Indices are maintained by Halton Hills Hydro Inc.:
- New Connections-Low Voltage
- New Connections-High Voltage
- Emergency Response-Urban
- Emergency Response-Rural
- SAIDI
- SAIFI
- CAIDI
- Outage Tracking
- Cable Locates
- Phone Calls
- Annual Appointments
- Annual Written Response

b) All target values are 100% each year. These targets were reached for most indices. The indices that did not have a 100% value are listed in Table 4. All Service Reliability Indices are within acceptable limits as set by the Ontario Energy Board.

Table 4

	2006	**2007 (to November 30)**
Cable Locates	97%	100%
Phone Calls**	67%	87%
Written Responses	100%	99%
SAIDI	1.19	1.21
SAIFI	1.53	0.65
CAIDI	0.78	1.86

**Please note that Halton Hills Hydro Inc. installed a new phone system in 2006.

c) The following represent capital expenditure activity that is intended to address poor performance:
i. Upgrade existing rear yard equipment
-Budgeted in Operations pole replacement.
ii. DS transformer replacement and/or switchgear to address customer outage calls and noise complaints
-Cross Street switchgear and River Street transformer replacement budgeted in Capital Projects.
iii. AS-400 upgrade
-Budgeted in Capital Projects.

13. Ref: Exhibit 2/ Tab 1/ Schedule 1

a. Please provide Halton Hills' Code of Business Conduct.

b. For the years 2002 to 2008 inclusive, please provide a table listing the following (use actual dollars in years where available, or expected or planned or projected dollars, or % where indicated):

i. Net income

ii. Actual Return on Equity (%)

iii. Allowed Return on Equity (%)

iv. Retained Earnings;

v. Dividends to shareholders;

vi. Sustainment Capital expenditures excluding smart meters;

vii. Development Capital Expenditures excluding smart meters;

viii. Operations Capital Expenditures;

ix. Smart meters Capital Expenditures;

x. Other Capital Expenditures (identify)

xi. Total Capital Expenditures including and excluding smart meters;

xii. Depreciation

a) Please see Appendix F.

b) Please see Table 5 for the listing of items as requested for years 2002 – 2008.

Table 5

	2002	2003	2004	2005	2006	2007	2008
Net income	1,422,281	1,170,989	989,906	670,842	1,165,491	1,582,680	1,934,320
Actual return on equity	8.27%	6.66%	5.48%	3.55%	5.88%	(forecast) 7.47%	n/a
Allowed return on equity	9.88%	9.88%	9.88%	9.88%	9%	9%	8.93%
Retained earnings	233,887	1,404,876	2,394,782	3,065,624	4,231,115	5,813,795	7,748,115
Dividends to shareholders	-	-	-	-	-	-	749,577
Sustainment capital expenditures (excl. smart meters)	827,529	617,217	978,677	1,436,827	1,221,511	3,037,361	2,112,500
Development capital expenditures (excl. smart meters)	828,231	685,014	754,741	1,081,895	1,545,851	1,753,718	1,886,110
Operations capital expenditures	211,612	183,863	645,982	238,592	509,996	635,137	832,400
Smart meters capital expenditures	-	-	-	-	-	-	-
Other capital expenditures	-	-	-	-	-	-	-
Total capital expenditures (excl. smart meters)	1,867,372	1,486,094	2,379,400	2,757,314	3,277,358	5,426,216	4,831,010
Total capital expenditures (incl. smart meters)	1,867,372	1,486,094	2,379,400	2,757,314	3,277,358	5,426,216	4,831,010
Depreciation	1,768,391	1,682,297	1,814,270	1,884,106	1,930,209	2,129,369	2,190,723

14. Ref: Exhibit 6 / Tab 1 / Schedule 2, Exhibit 6 / Tab 1 / Schedule 3 and Response to Board staff IR#26 – Cost of Short Term Debt

In its response to Board staff IR#26, Halton Hills Hydro shows an effective rate for Short-Term Debt of 6.00%. This corresponds to what Halton Hills Hydro has listed as "Prime – 2%" as the effective rate for "Deposits" and "TD Bank Deposits" in the referenced schedules.

The Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism for Ontario's Electricity Distributors (the "Board Report"), issued December 20, 2006, states the following in section 2.2.2:

> ***"The Board has determined that the deemed short-term debt rate will be calculated as the average of the 3-month bankers' acceptance rate plus a fixed spread of 25 basis points. This is consistent with the Board's method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts. The Board will use the 3-month bankers' acceptance rate as published on the Bank of Canada's website, for all business days in the same month as used for determining the deemed long-term debt rate and the ROE." [Emphasis in original]***

a) Please provide the source of the 6.00%, including showing all calculations, source data and identifying the sources of data used.
b) Is Halton Hills Hydro proposing that the 6.00% rate be used instead of the deemed rate calculated as documented in the Board Report?
c) If Halton Hills Hydro is proposing a short-term rate other than that which would be calculated per the methodology in section 2.2.2 of the Board Report, please provide Halton Hill Hydro's explanation for deviating from the methodology in the Board Report.

a) The Short-Term debt rate was set as a place holder in the Halton Hills Hydro Inc.'s 2008 Rate Setting Model.

b) Halton Hills Hydro Inc. is not proposing to use the 6.00% rate but use the deemed rate calculated as documented in the Board Report.

c) See (b) above

15. Ref: Response to Board Staff IR#29.

In Response to Board Staff IR#29, Board Staff asked a ten-part interrogatory (i.e. parts (a) to (j)). The Applicant responded by presenting a number of updated tables which assisted in addressing subsequent interrogatories but which did not specifically address any of the ten sub-interrogatories.

Please answer the original IR#29, specifically addressing each of the ten parts in turn and, in order to minimize confusion, numbering each response (a) to (j) as appropriate. If the Applicant should make reference to any previously filed documents, please identify that precisely (including page number) so as to minimize confusion.

In answering Round 2 OEB Staff Interrogatory #15, the original interrogatory from Round 1 OEB Staff Interrogatory #29 was completed as follows:

Refs: Exhibit 3/ Tab 2/ Schedule 1/ Page 1 and Exhibit 3/ Tab 2/ Schedule 2/ Page 1

In Schedule 1, page 1, the Applicant explains that it is providing normalized historical and forecast throughput data and, where required, weather-normalized throughput data for 2004. In Schedule 2, page 1, the Applicant states that it has not used "weather sensitive load in the calculation of the Load Forecast" though in the table immediately following this statement, "Normalized Consumption" data is provided.

In Schedule 1, page 1, the Applicant explains that weather-normalized throughput was generated by Hydro One for the Applicant. However, the Applicant explains that, upon review, it concluded that the Hydro One-produced weather-normalized data provided "skewed results that did not present a realistic forward scenario. For this reason we developed our Load Forecast based on actual consumption data."

Please explain:

a) What does the Applicant mean by "normalized" data as distinct from "weather-normalized" data?

"Normalized" data means data that has been forecasted by Halton Hills Hydro Inc. without any weather normalization. Please refer to Round 2 OEB Staff Interrogatory #16 (b).

b) If "normalized" data have not been the result of a weather-conversion process, what were the "base" data that existed prior to the normalization process?

Halton Hills Hydro Inc. created its data based on historical data. Please refer to Round 2 OEB Staff Interrogatory #17 (a)(i).

c) What was the process used to convert the base data to normalized data?

There is no difference between base data and normalized data.

d) What were the conversion values (for each year) used to convert from base data to normalized data, and what was the source(s) of these conversion values?

Refer to (c) above.

e) Why did the Applicant only, apparently, produce weather-normalized data for 2004 and not for every historical year upon which the Applicant would have relied to develop a forecast?

Halton Hills Hydro Inc.'s forecast is not weather normalized which means weather normalization was not produced or used for any year.

f) What does the Applicant mean by "skewed results"; is the term skewed being used in the statistical sense or in some other sense?

The term "skewed" is used to describe the increasing differences between weather normalized wholesale consumption and actual wholesale consumption as described in Table 6.

g) The characteristics of the results produced by Hydro One that caused the Applicant to disregard these results.

Table 19 from Round 1 OEB Staff Interrogatories #29, page 3 is reproduced as Table 6 below and is used by Halton Hills Hydro Inc. to disregard the weather normalized results.

Table 6

	Weather Normalized Wholesale Consumption	Actual Wholesale Consumption	Difference
2004	470,617,571	468,337,202	.49%
2005	500,786,563	495,175,531	1.13%
2006	533,118,653	493,166,270	8.10%

The Weather Normalized consumption for 2004 compared to 2004 Actual is relatively close. However the margin of difference increases in 2005 to 1.13% and then jumps to 8.10%.

h) Since it is normal load forecasting practice to base the forecast on weather-corrected data, if the Applicant found the Hydro One results quite unacceptable, why did the Applicant not develop its own weather-corrected historical data?

Halton Hills Hydro Inc. expected to use the weather normalized load forecast but as the application was prepared, found it produces a result that did not appear reasonable and realistic. For this reason, Halton Hills Hydro Inc. chose not to use the weather normalized data.

i) What degree of confidence the Applicant has in its load forecast for a "weather-corrected" year (as the year 2008 and any future year can only be regarded) if the forecast is based on non-weather-corrected data?

Halton Hills Hydro Inc. has a great degree of confidence in its load forecast in the Phase 1 OEB Staff Interrogatory #29 answer amended below in Table 7:

Table 7

	Residential	General Service less than 50 kW	General Service 50 to 999 kW	General Service 1,000 to 4,999 kW	Un-metered Scattered Load	Street Lighting	Sentinel Lighting	Total
2008 Weather Normalized consumption	227,461,500	66,272,923	101,340,612	148,399,628	972,554	2,830,936	374,772	547,649,128
Proposed Loss Factor 4.99%	11,350,329	3,307,019	5,056,897	7,405,141	48,531	141,264	18,701	27,327,691
2008 Revised Weather Normalized consumption	216,111,171	62,965,904	96,283,715	140,994,486	924,023	2,689,672	356,071	520,321,437
2008 Load Forecast of Halton Hills Hydro	220,790,841	58,287,111	126,131,349	94,784,230	1,018,946	2,689,946	323,275	504,025,698
Difference - %	+2.2%	-7.4%	+31%	-32.8%	+10.3	0%	-9.25	-3.1%
Billing determinant	kWh	kWh	kW	kW	kWh	kW	kW	

The internal forecast is only 3.1% different than the weather normalized forecast after adjusting for the applied loss factor. Further, if you only look at customer classes where the variable distribution revenue is derived from kWhs, the difference is .03% reflected in Table 8 below:

Table 8

	Residential	General Service less than 50 kW	Un-metered Scattered Load	Total
2008 Weather Normalized consumption	227,461,500	66,272,923	972,554	294,706,977
Proposed Loss Factor 4.99%	11,350,329	3,307,019	48,531	14,705,879
2008 Revised Weather Normalized consumption	216,111,171	62,965,904	924,023	280,001,098
2008 Load Forecast of Halton Hills Hydro	220,790,841	58,287,111	1,018,946	280,096,898
Difference - %	+2.2%	-7.4%	+10.3	+.003%
Billing determinant	kWh	kWh	kWh	

j) What tests did the Applicant conduct to verify the reasonableness of its forecast?

Table 9 verifies the reasonability of Halton Hills Hydro Inc.'s forecast.

Table 9

	Residential	General Service less than 50 kW	Un-metered Scattered Load	Total
2008 Weather Normalized consumption	227,461,500	66,272,923	972,554	294,706,977
Proposed Loss Factor 4.99%	11,350,329	3,307,019	48,531	14,705,879
2008 Revised Weather Normalized consumption	216,111,171	62,965,904	924,023	280,001,098
2008 Load Forecast of Halton Hills Hydro	220,790,841	58,287,111	1,018,946	280,096,898
Difference - %	+2.2%	-7.4%	+10.3	+.003%
Billing determinant	kWh	kWh	kWh	

16. Ref: Exhibit 3/ Tab 2/ Sch 1 to 5, and
Response to Board Staff IR# 30 to 32.

In Schedules 1 to 5, the Applicant very briefly explains how it developed its 2008 load forecast. Further elaboration is provided by the Applicant's responses to Board Staff IR# 30 to 32. While parts of the explanation are missing, the Applicant appears to have used the same approach as some other applicants. On this understanding, it appears that the Applicant:
o determined the 2008 forecasted customer count for each customer class,
o determined the weather-normalized retail energy for each customer class for 2004,
o determined the 2004 retail normalized average use per customer ("NAC") by dividing each of these weather-normalized retail energy values by the number of customers/connections in each class existing in 2004,
o applied the 2004 retail NAC to the 2008 Test Year without modification, and
o determined the 2008 Test Year energy forecast for each customer class by multiplying the applicable 2004 retail NAC value by the 2008 forecasted customer count in that class.

Please:
a) verify that the above is the essence of the Applicant's load forecasting methodology, and
b) fully correct any errors in the above explanation.

a) The bullets above do not capture the essence of Halton Hills Hydro Inc.'s load forecasting methodology.

b) The Load Forecasting methodology used by Halton Hills Hydro Inc. consists of the following process:
    a. Determine the 2008 Forecasted customer count for each customer class.
    b. Determine the 2008 Load forecast by obtaining:
        I. Municipal Subdivision information
        II. Ongoing residential subdivision occupancy
        III. Load projections by feeder
        IV. New residential subdivision development
        V. New Commercial Subdivision development
        VI. Residential/Commercial "in-fill" information

17. Ref: Exhibit 3/ Tab 2/ Schedules 1 to 5, and Response to Board Staff IR# 30 to 32.

In Schedules 1 to 5, the Applicant determines the 2004 retail normalized average use per customer ("NAC") and apparently uses this value for other years in the 2002 to 2008 period. This does not appear to adequately weather-normalize the energy usage in historical years and does not allow for the possible change in energy usage per customer over the 2002 – 2008 period. The use of a constant NAC is also evident in the Applicant's responses to interrogatories Numbers 30 to 32. The minimal weather normalization and the constant retail energy assumption could potentially lead to forecasting errors. Further information would be helpful in understanding expected load growth.

a) Please file a data table for the historical years 2002 to 2006 that shows:
- ***i. the actual retail kWh for each customer class in each year,***
- ***ii. the weather normalized retail kWh for each customer class in each year (where, for the customer classes that the Applicant has identified as weather sensitive, the weather normalization process should, as a minimum, involve the direct conversion of the actual load to the weather normalized load using a multiplier factor for that year and not rely on results for any other year),***
- ***iii. the values of the weather conversion factors used,***
- ***iv. the customer count for each class in each year,***
- ***v. the Average retail kWh / Customer for each class in each year based on the weather corrected retail kWh data in item ii. above, and***
- ***vi. as a footnote to the table, the source(s) of the weather correction factors.***

b) Please file a data table for the 2002 to 2008 period:
- ***i. utilizing the weather corrected Average retail kWh / Customer values for each class in each year obtained in a) v. above for the historical years 2002 to 2006,***
- ***ii. including 2007 and 2008 projections for the weather corrected Average retail kWh / Customer values (where, for each of the weather-sensitive classes, this is based on trends in the data) in each year, and for each of the weather-sensitive classes, describe in detail the trend analysis performed in ii. above.***

c) Please file an updated version of the table in Exhibit 3, Tab 2, Schedule 1, page 2, utilizing the weather corrected and other data determined in b) above.

a) Please find below the requested information.
   i. Table 10 represents historical retail kWh consumption.

Table 10

	2002	2003	2004	2005	2006
Residential	178,343,104	192,540,833	188,074,010	203,400,642	208,116,543
GS less than 50 kW	51,373,082	56,015,810	55,919,613	55,852,414	54,412,911
GS 50 to 999 kW	100,160,966	104,746,656	114,744,205	115,964,615	120,056,489
GS 1000 to 4999 kW	90,188,362	89,034,146	100,892,638	95,819,357	87,641,451
Street Lighting	1,786,014	2,401,021	2,495,616	2,753,868	2,535,532
Sentinel Lighting	381,133	351,162	363,744	315,881	313,546
Un-metered Scattered Load					979,473
Residential TOU					55,028

ii. Table 11 was calculated using the information from (i) above and multiplying by the weather conversion factor shown in (iii).

Table 11 – Weather Normalized Retail kWhs

	2002	2003	2004	2005	2006
Residential	174,169,875	191,231,555	188,318,506	200,471,673	209,719,040
GS less than 50 kW	50,170,952	55,634,902	55,992,308	55,048,139	54,831,890
GS 50 to 999 kW	100,160,966	104,746,656	114,744,205	115,964,615	120,056,489
GS 1000 to 4999 kW	90,188,362	89,034,146	100,892,638	95,819,357	87,641,451
Street Lighting	1,786,014	2,401,021	2,495,616	2,753,868	2,535,532
Sentinel Lighting	381,133	351,162	363,744	315,881	313,546
Un-metered Scattered Load	-	-	-	-	979,473
Residential TOU	-	-	-	-	55,452

iii. The weather conversion factors shown in Table 12 come from the IESO website (see (vi) below). The worksheet labeled Table 2.2 (Appendix G) from the IESO website was modified from the original format so individual year's information could be added to determine the conversion factor. Halton Hills Hydro Inc. considers Residential, General Service less than 50kW and Residential TOU classes as weather sensitive classes denoted by "***".

Table 12 – Weather Conversion Factors

	2002	2003	2004	2005	2006	
Residential	97.66%	99.32%	100.13%	98.56%	100.77%	***
GS less than 50 kW	97.66%	99.32%	100.13%	98.56%	100.77%	***
GS 50 to 999 kW	100 %	100 %	100 %	100 %	100 %	
GS 1000 to 4999 kW	100 %	100 %	100 %	100 %	100 %	
Street Lighting	100 %	100 %	100 %	100 %	100 %	
Sentinel Lighting	100 %	100 %	100 %	100 %	100 %	
Un-metered Scattered Load	100 %	100 %	100 %	100 %	100 %	
Residential TOU	97.66%	99.32%	100.13%	98.56%	100.77%	***

iv. Table 13 is replicated from Exhibit 3, Tab 2, Schedule 2, Page 2.

Table 13 – Actual Customer Count

	2002	2003	2004	2005	2006
Residential	16,312	16,787	17,004	18,413	18,201
GS less than 50 kW	1,340	1,400	1,295	1,301	1,482
GS 50 to 999 kW	166	168	163	168	178
GS 1000 to 4999 kW	10	10	10	10	12
Street Lighting	3,739	3,804	3,944	4,289	4,289
Sentinel Lighting	175	181	121	177	178
Un-metered Scattered Load					136
Residential TOU					2

v. Table 14 was calculated by dividing the information in (ii) above by the information in (iv) above.

Table 14 – Average Weather Normalized Retail kWhs per Customer

	2002	2003	2004	2005	2006
Residential	10,677.41	11,391.65	11,074.95	10,887.51	11,522.39
GS less than 50 kW	37,441.01	39,739.22	43,237.30	42,312.17	36,998.58
GS 50 to 999 kW	603,379.31	623,492.00	703,952.18	690,265.57	674,474.66
GS 1000 to 4999 kW	9,018,836.20	8,903,414.60	10,089,263.80	9,581,935.70	7,303,454.25
Street Lighting	477.67	631.18	632.76	642.08	591.17
Sentinel Lighting	2,177.90	1,940.12	3,006.15	1,784.64	1,761.49
Un-metered Scattered Load	-	-	-	-	7,202.01
Residential TOU	-	-	-	-	27,725.86

vi. http://www.ieso.ca/imoweb/pubs/marketReports/18Month_ODF_2007dec.xls

b) Please find below the requested information:

i. Table 15 is the average weather normalized retail kWh/customer values calculated by averaging the 5 years 2002 to 2006.

Table 15 - Average weather normalized retail kWh/customer

	2002	2003	2004	2005	2006	Average
Residential	10,677	11,392	11,075	10,888	11,522	11,111
GS less than 50 kW	37,441	39,739	43,237	42,312	36,999	39,946
GS 50 to 999 kW	603,379	623,492	703,952	690,266	674,475	659,113
GS 1000 to 4999 kW	9,018,836	8,903,415	10,089,264	9,581,936	7,303,454	8,979,381
Street Lighting	478	631	633	642	591	595
Sentinel Lighting	2,178	1,940	3,006	1,785	1,761	2,134
Un-metered Scattered Load	-	-	-	-	7,202	1,440
Residential TOU	-	-	-	-	27,726	5,545

ii. Forecasted Customer Counts shown in Table 16 come from Exhibit 3, Tab 2, Schedule 1, page 2. Table 17 multiplies the weather normalized consumption by the 2007 and 2008 customer count for weather sensitive customer classes.

Table 16 - Forecasted Customer Count

	2007	2008	
Residential	18,335	18,900	*** Weather Sensitive Classes
GS less than 50 kW	1,550	1,600	*** Weather Sensitive Classes
GS 50 to 999 kW	179	180	
GS 1000 to 4999 kW	12	12	
Street Lighting	4,444	4,450	
Sentinel Lighting	179	179	
Un-metered Scattered Load	136	136	
Residential TOU	2	2	*** Weather Sensitive Classes
	24,837	25,459	

Table 17 – Weather Normalized Retail kWh per Customer

	2007	2008
Residential	203,716,170	209,993,762
GS less than 50 kW	61,915,767	63,913,050
Residential TOU	55,452	55,452

c) Table 18 represents the recalculated weather information plus existing information contained in Exhibit 3, Tab 2, Schedule 2, Page 2.

Table 18

		Historical Board Approved	Historical Actual	Bridge Year Forecast – Normalized	Test Year Forecast - Normalized
Customer Class		**2006**	**2006**	**2007**	**2008**
Residential	#	17,006	18,201	18,335	18,900
	kWh	188,015,331	208,116,543	203,716,170	209,993,762
Residential Time of Use	#	2	2	2	2
	kWh	58,679	55,028	55,452	55,452
General Service less than 50 KW	#	1,154	1,482	1,550	1,600
	kWh	54,999,273	54,412,911	61,915,767	63,913,050
General Service 50 to 999 kW	#	153	178	179	180
	kWh	111,923,177	120,056,489	123,658,184	126,131,349
	kW	489,420	442,181	444,000	454,000
General Service 1,000 to 4,999 kW	#	10	12	12	12
	kWh	95,926,614	87,641,451	90,270,695	94,784,230
	kW	257,863	257,481	306,000	316,000
Un-metered Scattered Load	#	141	136	136	136
	kWh	920,340	979,473	1,008,857	1,018,946
Sentinel Lighting	#	121	178	179	179
	kWh	343,839	313,546	322,952	323,275
	kW	956	768	800	800
Street Lighting	#	3944	4289	4444	4450
	kWh	2,495,616	2,535,532	2,611,598	2,689,946
	kW	6794	6808	7400	7500

The weather normalized test year consumption for weather sensitive customers is 273, 962,264kWhs compared with the test year forecast in Exhibit 3, Tab 2, Schedule 2, Page 2, of 279,149,952kWhs or a 1.89% difference.

18. Please provide a revised version of Tables 21 and 22, filed in response to Board Staff IR#35 b) and c), based on the following re-wording of # 35 b), part ii.

Please provide a table that shows:

- ***i. the proposed customer classes,***
- ***ii. the class revenue requirements in Sheet O2, row 35, expressed as a percentage of the total revenue requirement,***
- ***iii. the proposed 2008 revenue requirement from distribution rates (ie total revenue requirement, net of revenue from specific service charges) X the percentages calculated in column ii,***
- ***iv. the proposed revenue at proposed rates per Exhibit 10 Tab 1 Schedule 8.***

Please provide a table that shows:

- ***i. the revenue to cost ratios from the preferred version of the informational filing,***
- ***ii. the ratio of column d to column c in the preceding part of this interrogatory.***

Please note: Halton Hills Hydro Inc. could not locate Sheet O2, row 35. Sheet O1, row 35 was used in answering ii above.

Please find below revised tables in the same format as per Round 1 OEB Staff Interrogatory #35 (b) & (c) shown as Table 19 and Table 20 respectively.

Table 19

	(ii)	(iii)	(iv)
Proposed Customer Classes (i)	**Information Filing Class Revenue Requirements Sheet O1 Row 35**	**2008 Proposed Revenue Requirement times (ii) ($)**	**Exhibit 10/ Tab 1/ Schedule 8 ($)**
Residential	60.66 %	6,771,363	6,066,295
Residential TOU	-	-	1,122
General Service less than 50 kW	12.21 %	1,362,414	1,288,536
General Service 50 kW to 999 kW	12.52 %	1,397,459	2,187,968
General Service 1,000 kW to 4,999 kW	9.56 %	1,067,063	1,469,242
Un-metered Scattered Load	.31 %	34,657	32,212
Sentinel Lighting	.19 %	20,940	10,642
Street Lighting	4.55 %	508,344	106,223
Total	100%	$11,162,240	$11,162,240

Table 20

Proposed Customer Classes	Revenue to Costs Ratios from Informational Filing (ii)	Column (iv) /Column (iii) from item b above
Residential	88.34%	89.59%
Residential TOU	-	-
General Service less than 50 kW	81.75%	94.58%
General Service 50 kW to 999 kW	156.93%	156.57%
General Service 1,000 kW to 4,999 kW	164.17%	137.69%
Un-metered Scattered Load	106.77%	92.93%
Sentinel Lighting	15.14%	50.82%
Street Lighting	36.74%	20.90%

19. Ref: Ontario Energy Board Report on the Application of Cost Allocation for Electricity Distributors, EB-2007-0667.

On November 28, 2007, the Board released its report on the application of allocated costs to specific matters in rate design. In chapter 5, it states: "The cost allocation policies reflected in this Report should be followed by distributors whenever they apply for rates on a cost of service basis."

Please describe any adjustments to the proposed rates that you would make to implement the policies in this Report.

Halton Hills Hydro Inc. does not propose any adjustments based upon the Application of Cost Allocation for Electricity Distributors, EB-2007-0667. The reason for this decision is found in section 2.3.4 of the report which states:

> ***"2.3.4 Managing the movement of rates closer to allocated costs:*** *A principle of rate making is that rate stability in most instances is desirable. Rates should not be constructed in a manner that leads to subsequent counter directional changes. The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process.*
> *Another principle of rate making is the avoidance of rate shock. Proposed rate changes should consider the ability of consumers to react to their new costs. In aligning rate levels closer to costs, reducing a high revenue-to-cost ratio for any one class requires an offsetting increase to one or more other classes. Such realignments could result in large rate increases, particularly when combined with other plans that affect the distributor's revenue requirement.*
> *The Board expects to address these concerns as and when they arise in the context of individual rate applications. Distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. However, if a large increase is required to move closer to one, rate mitigation plans should be proposed by the distributor. Distributors should not move their revenue-to-cost ratios further away from one. "*

Halton Hills Hydro Inc.'s proposed cost allocation meets the criteria as set out in the above noted section of the report.

20. Ref: Exhibit 7 Tab 1 Schedule 1 Page 1

Response to Board Staff IR#37 a) and b)

Phase 1 OEB Staff Interrogatories
APPENDIX F
2008Test Year Distribution Revenue
Question: 37

DETERMINATION OF NET UTILITY INCOME AND CALCULATION OF REVENUE DEFICIENCY

	2008 Test using 2007 Existing Rates ($)	Comments
Revenue		
Distribution Revenue	9,672,375	Exhibit 3, Tab 1, Schedule 2
Other Operating Revenue (Net)	960,000	Exhibit 3, Tab 1, Schedule 2
Total Revenue	10,632,375	

Halton Hills noted in its Phase 1 OEB Staff Interrogatories that a corrected amended schedule is shown as Appendix F. Please explain why $9,672,375 and $960,000 are still showing as Distribution Revenue and Other Operating revenue (Net) when this appears to be the 2007 amount.

Halton Hills Hydro Inc. has recalculated its revenue sufficiency / deficiency separately per the response to Round 1 OEB Staff Interrogatory #37 (i) – Table 27. Please refer to this table for a recalculation of the test year revenue sufficiency / deficiency. Appendix F in the Round 1 OEB Staff Interrogatories presented 2007 rates compared to 2008 operating expenses.

21. Ref: Response to Board staff IR#39

Halton Hills has provided duration levels by program and class (Table 30), however this appears to be the equipment life, and not the duration of program delivery. For each program, please provide the length of time in years or months for which Halton Hills is claiming LRAM and SSM in this current application.

Halton Hills Hydro Inc. is claiming LRAM and SSM from the time the equipment was installed to the end of 2006.

Water Heater Load Control-	An on-going project with monthly installation beginning in the third quarter of 2005.
Capacitor Installation-	A one-time project installed in quarter 4 of 2005.
Lighting-	A one-time project installed in quarter 1 of 2006.
Equipment Replacement-	A one-time project installed in quarter 4 of 2006.

22. Ref: Response to Board staff IR#40

In the response to Board staff IR#40, Halton Hills stated that the "free rider rate was assumed to be 0% based on the requirement to sell this project on a cost/benefit basis including the HHHI incentive".

a) Please clarify the statement regarding the "HHHI incentive" since the Board stated in the Total Resource Cost Guide that:

Incentive payments from the LDC to a customer for participation in a program are not a component of the TRC analysis. The incentive merely represents a transfer payment between two parties involved in the program to support the purchase of energy efficient equipment.

a) The free rider rate was assessed as 0% due to the benefits of this project to the participant which included Halton Hills Hydro Inc.'s incentive. However, the incentive itself was not included in the TRC calculation.

23. Ref: Response to Board staff IR#45

Halton Hills has stated that it is "claiming SSM amounts on utility side programs". Please explain why Halton Hills finds this appropriate when the Board, in its Report of the Board on the 2006 EDR Handbook, issued May 11, 2005, stated:

"There has been considerable discussion in this proceeding as to whether CDM expenditures on the utility side should be differentiated from customer-side expenditures. The Board recognizes that conservation programs should have a balance between the two. It is important to recall however, the Board's earlier finding that the SSM incentive does not apply to utility-side investments. The Board previously ruled with respect to the 2005 SSM that the inclusion of capitalised assets into rate base provides sufficient incentives. The Board continues to hold that view."

Please provide a revised SSM amount with SSM amounts for utility-side programs removed.

Please find below (Table 21, Table 22 and Table 23) revised SSM amounts with utility-side programs removed.

Table 21

Residential - SSM	TRC	TRC Rate	SSM
2005	12,034	5%	$602
2006	93,993	5%	$4,700
Total			$5,302

Table 22

General Service <50 kW - SSM	TRC	TRC Rate	SSM
2005	48,609	5%	$2,430
2006	9,914	5%	$ 496
Total			$2,926

In Halton Hills Hydro Inc.'s response to Round 1 OEB Staff Interrogatory #42 (b), Halton Hills Hydro Inc. has recalculated the rate rider calculation in Table 33 as follows:

Table 23

Rate Class	Amounts (2005 + 2006)		Billing Units (2006)		Rate Riders		
	LRAM	SSM			LRAM	SSM	Total
	$	$			$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)
Residential	$ 1,163	$ 5,302	208,116,543	kWh	0.00000	.00003	.00003
General Service less than 50 kW	$ 6,818	$ 2,926	54,412,911	kWh	0.00013	.00005	.00018
Total	**$ 7,981**	**$ 8,228**					

24. Ref: Responses to Board staff IRs# 55 & 56.

With respect to the Retail Transmission Rate – Network Service Rates, given the fact that the wholesale rate will decrease 18%, please provide the background data and calculations to justify a reduction to existing rates ranging from 5.8% to 7% that meets the revenue neutral criteria identified in question 55.

With respect to the Retail Transmission Rate – Line and Transformation Connection Service Rates, given the fact that the wholesale rates will decrease 28% for Line Connection and increase 7% for Transformation Connection, please provide the background data and calculations to justify a reduction to existing rates ranging from 6% to 6.8% that meets the revenue neutral criteria identified in question 56."

See Table 24 for Retail Transmission Rate – Network Service Rates.

See Table 25 for Retail Transmission Rate – Line and Transformation Connection Service Rates.

Halton Hills Hydro Inc. has recalculated its proposed Retail Transmission Rates. The transmission grid supplying Halton Hills Hydro Inc. contains two IESO delivery points and five Hydro One Networks Inc. (HONI) delivery points. From our discussions with HONI, we understand that the proposed rates for embedded delivery points, submitted to the OEB by HONI December 17, 2007, are $2.02 and $1.90 respectively for the Network and Connection Service Charges. This is a decrease from $2.52 and $2.09, or 19.8% and 9.1% respectively from the current HONI embedded rates. Combining these changes with the declines in IESO Retail Transmission Rates, Halton Hills Hydro Inc. has revised its proposed revenue-neutral rates as below:

Table 24 – Revised Proposed Retail Transmission Rates - Network

Rate Class	Existing	Proposed
Residential	**$0.0057**	**$0.0037**
Residential TOU	**$0.0057**	**$0.0037**
General Service less than 50 kW	**$0.0052**	**$0.0034**
General Service 50 to 4,999 kW	**$2.2535**	**$1.4743**
Street Lighting	**$1.6002**	**$1.0469**
Sentinel Lighting	**$1.6083**	**$1.0522**
Un-metered Scattered Load	**$0.0052**	**$0.0034**

Table 25 – Revised Proposed Retail Transmission Rates - Connection

Rate Class	Existing	Proposed
Residential	**$0.0050**	**$0.0036**
Residential TOU	**$0.0050**	**$0.0036**
General Service less than 50 kW	**$0.0045**	**$0.0033**
General Service 50 to 4,999 kW	**$1.9603**	**$1.4168**
Street Lighting	**$1.3824**	**$0.9991**
Sentinel Lighting	**$1.4113**	**$1.0200**
Un-metered Scattered Load	**$0.0045**	**$0.0033**

Halton Hills Hydro Inc. will revise the proposed transmission rates in Table 24 and Table 25 if the proposed Hydro One Networks Inc. transmission rates are not approved by the Ontario Energy Board.

25. Ref: Response to Board Staff IR# 49e, Appendix H

a) Please provide a detailed explanation of the cause and timing of the over-recovery in 1570 and 1571.
b) Why was this adjustment not brought forward in the 2006 EDR when accounts 1570 and 1571 were dispositioned?
c) Please provide regulatory precedent for approval of disposition of accounts in this application that were closed during 2006 EDR.

a) Explanation of cause and timing of over-recovery in 1570 and 1571:
   i. 1570 – Over-recovery total is interest of $2,038. The reconciliation of this account needed to be revised. The amounts written-off based on minimum review of the transition cost recovery calculation were included in the principal amount recovered, appearing as if there was an over-recovery on the principal balance. This is not the case. There is no over-recovery of the principal balance. The over-recovery is based on actual versus accrued interest. Total interest accrued in the 2006 rate filing was $90,208 compared to actual interest booked of $88,170. Interest on this account was booked December 2006, subsequent to the 2006 EDR filing.
   ii. 1571 – Over-recovery total is $26,067, less interest of $5,464 for a credit balance of $20,603. These over-recoveries relate to back-billings in 2006 to the pre-market opening period for charges that were neither billed nor accrued to the pre-market opening period. Specifically these back-billings were charged as follows: Residential customers in the amount of $7,257 in the 2nd quarter of 2006 and a general service > 50 kWh customer in the amount of $18,810 in the 4th quarter of 2006.

b) These adjustments were not available at the time the Regulatory asset recovery segment of the 2006 EDR was filed and therefore, were not disposed of at that time.

c) Halton Hills Hydro Inc. is not aware of any regulatory precedent of approval for disposition of accounts that were closed during the 2006 EDR.

26. Ref: Response to Board Staff IR#48

a) Why is Halton Hills using account 1562 for the PILs variance costs subsequent to April 30, 2006 considering the guidance provided in the Accounting Procedures Handbook which states "Account 1562 relates to the rate periods that ended on or before April 30, 2006."

b) What would the balances be in 1562 and 1563 if Halton Hills was following the guidance provided in the Accounting Procedures Handbook?

a) Halton Hills Hydro Inc. has utilized account 1562 for the period subsequent to April 30, 2006 in oversight.

b) Following the guidance in the Accounting Procedures Handbook, the April 30, 2006 balances in the accounts would be:

Account 1562	$(115,260)
Account 1563	$ 115,260

27. Ref: Response to Board staff IR#49 Appendix H, Ex 5/Tab 1/Sch 2& 3, 2008 Rate Rider Calculation Appendix A

a) The individual and total balances under "Total Claim" column in Appendix H do not match the individual and total balances in Ex5/Tab 1/Sch 2 & 3 or in Appendix A. Components of Table 36 in IR 49 d) also do not match Appendix A or Appendix H or Ex5/Tab 1/Sch 2 & 3. Which balances are correct?

b) Please update either Appendix H, Table 36 in IR 49 d) or Ex 5/Tab 1/Sch 2 & 3, or Appendix A as necessary to detail the balances claimed for disposition.

a) The continuity schedule provided by OEB Staff was a useful analysis that allowed for an improved review of the deferral and variance account balances.

The original Appendix H represents the updated balances for all accounts, except for the following amendments:

- Account 1562 was excluded from the original Appendix H schedule. The April 30, 2006 balance in 1562 is ($115,260).
- Account 1555 is included in the original Appendix H, however, it is proposed that this account not be settled. As well, interest for account 1508 should be adjusted by $2,120 per response to Round 2 OEB Staff Interrogatory #31.
- Accounts 1555, 1565 and 1566 were included in the original Appendix H, but Halton Hills Hydro Inc. is not proposing to settle these accounts.

b) Please see Appendix H for updated schedules of the following:

- Appendix H
- Exhibit 5, Tab 1, Schedule 2
- Exhibit 5, Tab 1, Schedule 3 & Appendix A
- Table 36

28. Response to Board Staff IR#49 Appendix H

Why was there no opening balance for account 1590 in 2005?

There is no opening balance in account 1590 in 2005 as the starting point for the schedule is the 2006 EDR regulatory asset schedule. Account 1590 transactions that were not included in the opening balance are included in the 2005 transactions.

29. Response to Board Staff IR#50

Halton Hills is tracking a forecasted balance of ($40,516) in the Continuity Schedule in Appendix H under account 1508 sub-account Other.

a) Please provide a description of the deferral or variance being tracked in this sub-account.
b) Please provide a sample journal entries used to track variance in this sub-account.
c) Were carrying charges calculated on this balance throughout the life of the sub-account?
d) What period was the deferral or variance balance being tracked (e.g. Since July 200XX to August 20XX)
e) Please provide the regulatory authority for Halton Hills to use this sub-account of 1508.

a) The forecasted balance in the 1508 sub-account of ($40,516) represents the offset, plus interest, for the approved recovery of Hydro One Networks other regulatory assets in the 2006 EDR. The actual charges from Hydro One Networks for these have been recorded through account 1586.

b) There are no journal entries other than the reclassification of the recovery from 1508 to 1590.

c) Carrying charges were booked beginning with the reclassification of the approved recovery to account 1590.

d) This balance was tracked beginning with the reclassification of the approved recovery to account 1590. These were approved to be reclassified May 1, 2006.

e) Regulatory authority for the use of this sub-account of 1508 comes from the approved recovery of these charges in the 2006 EDR.

30. Ref: Response to Board Staff IR#51

Halton Hills indicates that it implemented prescribed interest rate for Board-approved deferral and variance accounts as of April 1, 2006. However, prescribed interest rate for Board-approved deferral and variance accounts were not effective until May 1, 2006, per the Board's November 28, 2006 Letter to LDCs.

a) Why did Halton Hills implement prescribe interest rates earlier than the approved Board date?

b) What would the impact on the deferral and variance accounts being requested for disposition if Halton Hills implemented prescribed interest rates as of May 1, 2006?

a) Halton Hills Hydro Inc. implemented prescribed interest rates in accordance with the approved OEB date. The response to Round 1 OEB Staff Interrogatory #51 should have read May 1, 2006 rather than April 1, 2006.

b) There is no impact on the deferral and variance account balances as a result of Halton Hills Hydro Inc. implementing prescribed rates effective May 1, 2006.

31. Ref: Response to Board Staff IR#51

Halton Hills indicates that the only difference in interest rate application for applicable deferral and variance accounts is 1508, which has carrying costs charged at 3.88% for January to December 2005. However, there are two different interest rates used for account 1508 sub-account OEB Cost Assessments and OMERS Pension Contributions, as per December 20, 2004 Letter to LDCs and APH FAQs December 2005. In addition there are different interest rates used for accounts 1565 and 1566 as per the APH, and carrying charges are applicable only to February 28, 2005, for these two accounts.

a) What would the impact be on the deferral and variance accounts being requested for disposition if Halton Hills implemented interest rates as per the direction from the Board, as discussed above?

a) Halton Hills Hydro Inc. has investigated interest rate application to the deferral and variance account and the following represents the impact of interest rates as discussed:
   i. 2004 interest on 1508 accounts per December 20, 2004 Letter to LDCs:
      - 5.75% per annum on 1508 accounts for 2004
      - interest for 2004 was not applied to 1508 accounts. Additional interest would be $1,495.
   ii. APH FAQs December 2005
      - 3.88% applies to OEB cost assessments as well as OMERS pension contributions. A rate of 7.25% was applied to OEB cost assessments for 2005 and the first quarter of 2006. Reduction in interest would be $3,615.
   iii. APH – 1565 and 1566 interest to February 28, 2005
      - 5.75% - no interest was applied to these accounts as no CDM expenditures or funding was in place prior to February 28, 2005.

The net impact of the interest adjustments is to reduce interest due on deferral account 1508 by $2,120. This impact has been taken into account for the resolution of Round 2 OEB Staff Interrogatory #27.

Appendix A

Halton Hills Hydro Inc. Purchasing Policy

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HALTON HILLS HYDRO INC.

POLICIES, PROCEDURES AND DIRECTIVES

SECTION TITLE: *ACCOUNTING* ***DATE ISSUED:*** *JULY 1993*

SUBJECT: PURCHASING POLICY **DATE REVISED:** OCTOBER 2004

REFERENCE #: ACC 001 **ORIGINATOR**: ART SKIDMORE

PURPOSE

The Purchasing Policy is a guideline for Management and Staff to establish amounts, requirements and approvals.

GUIDING PRINCIPLE

It is the intention of the Corporation to maintain an adequate level of inventory in order to properly maintain the reliability of our distribution system

ACQUISITION (PURCHASING) METHODS

In determining the value of goods and services to ascertain the appropriate method of acquisition, the following criteria will be used:
1) The expenditure must be related to a whole or complete job, item or service in the Corporation's approved budget, both operating and capital.

KNOWN QUANTITIES/REQUIREMENTS

Quotations – known quantities/requirements

a) Quotations will be administered by the Purchasing Department.
b) The Purchasing Department may obtain up to three quotes from qualified suppliers in the most expeditious manner possible either by phone, fax, e-mail, EDI or correspondence.

Negotiations

The Purchasing Department may negotiate where:

a) there is only one source of supply for the goods or services, or
b) there is merit in purchasing at a public auction, or
c) all tenders or quotations received fail to meet specifications or terms and conditions and it is unreasonable to recall tenders or quotations.

The negotiation procedures shall be those accepted as standard negotiating procedures that employ fair and ethical practices.

Sole Supplier

A vendor may be identified by the Corporation as a sole supplier where:

a) the vendor is the only manufacturer of the particular product, or
b) in order to maintain warranties or system integrity, the vendor is the preferred or only choice for replacement parts or services for an original product or service purchased from this vendor, or
c) there is a requirement that repeated purchases be consistent in operation and manufacture, or
d) there is a need for additions to the original purchase and the additions are to form an integral part of the original purchase.

Where a vendor has been identified as a sole supplier to the Corporation by virtue of a previous purchase, all subsequent purchases shall be made by the "Negotiation" method if the price was not established as part of the original purchase.

Consideration should be given to the timely review of the sole supplier where a new or alternate product(s) or service(s) become available in the marketplace.

Partnerships

Halton Hills Hydro Inc. believes that it can obtain greater benefits by adopting a strategic procurement alliance for the purchase of goods and services rather than treating individual purchases in isolation. The benefits accruing to the Board are:

1. reduced total inventory levels arising from closely matching production schedules with actual requirements;
2. reduced administrative burden and overall costs due to streamlining the procurement process and taking advantage of economies of scale;
3. improved service levels;
4. better project estimates and improved ability to control final project costs;
5. improved ability to meet project schedules;
6. reduced expediting and inspection costs;
7. innovation will be encouraged and,
8. adoption of agreed terms and conditions and specifications will reduce time required in both engineering and purchasing to ascertain expressions of interest from the marketplace. The ability to add and delete products or services to the agreement will be a requirement of the agreement.

Cooperative Purchasing

The Corporation encourages cooperative purchasing with other Corporation or public agencies whenever the best interests of the Corporation will be served.

Exceptions

This Policy does not apply to the following items:

1. Power purchases from the IMO;
2. Transmission charges from Hydro One;
3. Petty cast items;
4. Training and education;
5. Refundable employee expenses;
6. Refunds;
7. Payroll related expenditures;
8. Other expenditures
   a) debenture payments
   b) insurance payments
   c) damage claims
   d) tax remittances
9. Utilities

A purchase order is not required for the following:

1. Professional services
   a) Counseling fees
   b) Auditing
   c) Consulting fees
   d) Banking
   e) Insurance premiums

Selection Criteria

The selection criteria for goods shall be based on the following where relevant:

a) specifications or requirements
b) quality
c) service
d) delivery
e) place
f) life cycle costs and,
g) Price.

In support of the Corporate Vision, life cycle costs or price shall be the determining selection criteria for goods when the above criteria are satisfied.

The selection criteria for services shall be based on the following where relevant:

a) the ability, capacity and skill of the vendor to perform the contract;
b) the ability, capacity and skill of the vendor to perform the contract in a safe manner;
c) whether the vendor can perform the service promptly within the time specified without delay or interference;
d) the character, integrity, reputation, judgement, experience and efficiency of the vendor and the proposed staff for this service;
e) the quality of performance provided n previous contracts or services, and
f) all cost to the utility that would result from selecting the vendor.

Disposals

Senior management shall have the authority to sell exchange or otherwise dispose of all goods declared as surplus to the needs of the Corporation. Where it is in the best interest of the Corporation, items or groups of items may:

a) be offered to other public agencies;
b) be sold by external advertisement, formal request, auction or public sale;
c) be advertised by public offering for sale and sealed bids will be received with the award to the highest bidder;

In the event that all efforts to dispose of goods by sale are unsuccessful, these items may be offered for refuse or donated to a charity.

Prohibitions

1) Disposals – no employee for the Corporation having responsibility for declaring goods surplus to the needs of the Corporation or for disposing of such items, may acquire these goods.
2) Personal benefit – any elected official, appointed official, officer, employee or member of their immediate family of the Corporation is expressly prohibited from accepting, directly or indirectly from any person, company or corporation to which any purchase order or contract is, or might be, awarded, any rebate, gift or money.

3) The Corporation shall be advised, prior to the award of business, if goods or services are being purchased by Halton Hills Hydro Inc. from an employee. A purchase is deemed to be made from an employee when it is made either directly or indirectly from the employee, their spouse or an immediate family member, a company owned or operated by an employee, their spouse or an immediate family member.

_____, President

Appendix B

Hydro One Brampton and Halton Hills Hydro Inc.
Load Transfer Interim and Final OEB Decisions

Ontario Energy Board
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2300 Yonge Street
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Commission de l'Énergie de l'Ontario
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Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY PRIORITY POST

December 16, 2005

Gary Ebersberger
Vice President
Halton Hills Hydro
43 Alice Street
Acton ON L7J 2A9

Dear Mr. Ebersberger:

Re: Application by Halton Hills Hydro for deferral of the requirement to comply with section 6.5.4 of the Distribution System Code
Board File No. EB-2005-0513

The Board has now issued its Notice of Application with respect to the above-noted Application, and a copy is enclosed.

You are directed to immediately deliver to Hydro One Brampton and to each affected load transfer customer a copy of the Notice of Application together with a copy of the letter entitled "Dear Customer of Halton Hills Hydro" attached to this Letter of Direction.

Yours truly,

Peter H. O'Dell
Assistant Board Secretary

Encl.

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
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2300, rue Yonge
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Téléphone; 416- 481-1967
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Numéro sans frais: 1-888-632-6273

Ontario

Dear Customer of Halton Hills Hydro

The Ontario Energy Board has received an application from Halton Hills Hydro which would allow for the continuation of an electrical supply arrangement that has existed between Halton Hills Hydro and Hydro One Brampton. You are **not required** to do anything in response to this letter but you may wish to let the Ontario Energy Board know of any concerns you may have about the application filed by Halton Hills Hydro.

You are a customer of Halton Hills Hydro and are located within Halton Hills Hydro's service area but you are provided electricity from Hydro One Brampton's distribution system.

You are currently billed for electricity by Halton Hills Hydro at their approved rates, and your service calls, queries and complaints are also handled by Halton Hills Hydro. This arrangement by which the electricity which you use is supplied through the distribution system of Hydro One Brampton is referred to as a "load transfer".

The Ontario Energy Board requires that, after May 1, 2007 utilities cease to hold such load transfer arrangements.

Halton Hills Hydro has requested that the Ontario Energy Board allow it to continue the current transfer arrangement beyond May 1, 2007 to allow for road construction along Winston Churchill Boulevard (scheduled for 2007 and 2008).

Following completion of the road construction, Halton Hills Hydro intends to extend its electrical distribution system so that Halton Hills Hydro would physically supply the electricity that you use. Halton Hills Hydro would continue to serve your electricity needs, at the rates that are approved for Halton Hills Hydro, as is the case at present.

You will find attached to this letter a copy of the Notice of Application that relates to Halton Hills Hydro's application. The Notice contains important information about how to participate in the proceeding associated with the application. If you wish to make a submission to the Board in this matter, please follow the direction set out in the Notice.

DATED at Toronto December 16, 2005

ONTARIO ENERGY BOARD

Peter H. O'Dell
Assistant Board Secretary

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0513

NOTICE OF APPLICATION

Halton Hills Hydro: Application for a Deferral of Section 6.5.4 of the Distribution System Code

Halton Hills Hydro has filed an application dated October 21, 2005 and clarified December 6, 2005 with the Ontario Energy Board ("the Board") requesting exemption from or a deferral of the application of section 6.5.4 of the Distribution System Code. The deferral would, if granted, require an amendment to Halton Hills Hydro's electricity distributor licence under section 74 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Sched. B. The Board has assigned file number EB-2005-0513 to this application.

Section 6.5 of the Distribution System Code deals with load transfer customers, who are customers located in the licensed service area of one distributor (the "geographic distributor") but are physically served by another distributor (the "physical distributor"). Under section 6.5.4 of the Code, load transfer situations are required to be eliminated by May 1, 2007. This can be done by either negotiating the transfer of the customers to the physical distributor, or by the geographic distributor extending its system to connect the customers.

The load transfer customers affected by this application are located in Halton Hills Hydro's licensed service area but are connected to the distribution system of Hydro One Brampton. Halton Hills Hydro intends to connect the load transfer customers to Halton Hills Hydro's distribution system following road construction work along Winston Churchill Boulevard scheduled for 2007 and 2008. It is therefore asking for approval to continue the existing load transfer arrangements beyond May 1, 2007 in order to await completion of road construction before building the new line connecting the existing load transfer customers.

Copies of the application and associated information filed with the Board are available for inspection at the Board's office and from the office of Halton Hills Hydro, at the addresses indicated below.

The Board intends to proceed with this application by written hearing unless a party satisfies the Board that there is good reason for not proceeding by written hearing. The Board invites submissions regarding the application. **Submissions, quoting file number EB-2005-0513, must be filed with the Board Secretary within 7 days of receipt of this Notice, and a copy must also be provided simultaneously to the applicant.**

The applicant may submit a response to submissions by **filing the response with the Board Secretary within 14 days of delivery of the date on which the last person required to be served with this Notice was so served**. A copy of the response must also be provided simultaneously to all persons that file submissions with the Board.

IF YOU DO NOT PROVIDE A SUBMISSION IN ACCORDANCE WITH THIS NOTICE, THE BOARD MAY PROCEED WITHOUT YOUR PARTICIPATION AND YOU WILL NOT BE ENTITLED TO FURTHER NOTICE IN THIS PROCEEDING.

ADDRESSES

Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto ON M4P 1E4
E-mail: boardsec@oeb.gov.on.ca
Fax # 416-440-7656

Halton Hills Hydro
Attention Mr. Gary Ebersberger
Vice President
43 Alice Street
Acton ON L7J 2A9
E-mail: gebersberger@haltonhillshydro.com

DATED at Toronto December 16, 2005

ONTARIO ENERGY BOARD

Peter H. O'Dell
Assistant Board Secretary

Ontario Energy Board
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Numéro sans frais: 1-888-632-6273

BY E-MAIL

July 18, 2006

Mr. Gary Ebersberger
Vice President
Halton Hills Hydro
43 Alice Street
Acton ON L7J 2A9

Re: Application by Halton Hills Hydro for exemption from section 6.5.4 of the Distribution System Code
Board File No. EB-2005-0513

The Board has reviewed the information submitted by Halton Hills Hydro indicating the existence of an agreement between Halton Hills Hydro and Hydro One Brampton.

The Board has determined there is a need for additional information before a decision on the application can be made. The Board therefore directs that Halton Hills Hydro respond to the interrogatories attached to this letter as Attachment A. Given that the parties are participating in an Agreement, the response should have the concurrence of Hydro One Brampton.

The responses to these interrogatories must be filed with the Board Secretary on or before 4:45pm on July 28, 2006.

Yours truly,

Peter H. O'Dell
Assistant Board Secretary

c. Scott Miller, Hydro One Brampton

Attachment.

Attachment A
Staff Interrogatories

EB-2005-0513
Halton Hills Hydro Load Transfer Application for Exemption

1. Is the letter provided on June 13, 2006 the only agreement signed between Halton Hills Hydro and Hydro One Brampton? If not, please provide the full agreement.
2. If no other agreement was negotiated or if the filed agreement does not include the following, please provide this information:
    a. The specific date to which the parties agreed to extend the load transfers (i.e. the date after which Brampton does not agree to continue service)
    b. A statement as to which party is responsible for investment (including maintenance and capital additions and new connections) made to the load transfer assets after May 1, 2007;
    c. Identification of any assets located in the service territory of Hydro One Brampton which will not be the responsibility of Hydro One Brampton to operate or maintain during the period of the proposed exemption;
    d. A statement as to the agreement among the parties as to the payment for any non-salvageable stranded assets found after the period of the exemption.
3. Did Halton Hills Hydro consider negotiating to transfer on a permanent basis the services in questions? If not, please provide the reasons and specifically address why Halton Hills Hydro and/or Hydro One Brampton believe the most efficient solution is to have Halton physically make a connection to these customers.

-End of document-

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0513

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

AND IN THE MATTER OF an application by Halton Hills Hydro for deferral of the requirement to comply with section 6.5.4 of the Distribution System Code.

By delegation before: Mark C. Garner

DECISION AND ORDER

THE APPLICATION

Halton Hills Hydro ("Halton") filed an application dated October 21, 2005 with the Ontario Energy Board (the "Board") requesting an exemption from the application of section 6.5.4 of the Distribution System Code (the "Code"). The Board assigned file number EB-2005-0513 to this application.

An Interim Decision and Order was issued on May 5, 2006 which denied the application but allowed for its reconsideration if Halton and Hydro One Brampton Networks Inc. ("Brampton") reached an agreement regarding service to the load transfer customers. By letter dated June 13, 2006, Halton informed the Board that such an agreement had been reached, although no agreement was provided to the Board.

An exemption is granted up to the earlier of December 31, 2008 or completion of the road works more fully described below.

REVIEW

Pursuant to subsection 6(1) of the *Ontario Energy Board Act, 1998*, (the "Act") I have been delegated the powers and duties of the Board with respect to the determination of applications made under section 74 of that Act.

Section 6.5 of the Code deals with load transfers. A load transfer occurs where customers are located in the licensed service area of one distributor (the "geographical distributor") but are physically served by another distributor (the "physical distributor"). Sixty-three load transfer customers are affected by this application. They are located in Halton's licensed service area along Winston Churchill Boulevard. While they are billed and notionally served by Halton, the customers are physically connected to the electricity distribution system of Brampton. Winston Churchill Boulevard forms the border between the service areas of the two distributors and there are plans to widen the road in 2007 and 2008. The application does not apply to load transfer customers in other areas of Halton's service area.

Halton's original application was deficient in three ways. The first was that Halton had not come to a formal agreement with Brampton and therefore could not provide clear evidence in respect to the obligations and liabilities of each of the utilities during the period of the exemption. The second was that the original application lacked a clear request for the term of the exemption. The third matter was whether the proposal to extend the load transfer was the most efficient way to proceed.

Section 6.5.4 of the Code provides a temporary period in which the geographic distributor has time to resolve the load transfer arrangement. The code states that all load transfer arrangements will be ended by May 1, 2007. At that time the geographic distributor, in this case Halton, either must resume all obligations for service or negotiate with the physical distributor, in this case Brampton, for the continuation of distribution services to the customers. In order for this exemption to be granted, it is the responsibility of Halton to come to terms agreeable to Brampton for the continuation of the load transfer arrangement.

Halton re-filed their application on June 19, 2006. The entire application consisted of a single letter which indicated that an agreement had been reached between the two utilities. No agreement was filed. When asked by Board staff, Halton indicated that they had an Operating Agreement with Brampton, but stated that it does not address

the issue of load transfers. The rather informal way in which Halton approached the matter has required that Board staff distil the various elements of an agreement, apparently not put to paper, but in the minds of both utilities. Based on the responses to Board staff's interrogatories the understanding between the parties appears to be as set out below:

After May 1, 2007, the original date when the load transfers were to be eliminated, any investment (including maintenance, capital additions and new connections) will be made by the physical distributor. The only exception to that general rule will be if the physical distributor deems that the existing facilities cannot accommodate new customers. If this occurs then Halton and Brampton will negotiate to determine whether any capital contributions are required or whether alternative service arrangements can be made. Responsibility for operation and maintenance of assets associated with distribution feeders and equipment will rest with the physical distributor during the exemption period. Stranded assets will be written off by their respective owner.

While I am discomforted by the lack of a written agreement, I believe that there is a sufficient meeting of the minds of Halton and Brampton upon which to be satisfied that electricity distribution service will be maintained without interruption. The parties have defined who shall bear responsibility for upgrades and new connections and have agreed to maintain the arrangement regardless of how long the road work takes. I interpret this to mean that Brampton is willing to bear the responsibility for investment required except where plant additions or upgrades are required for additional new load transfer customers. In that case Brampton will seek a capital contribution from Halton. I note that no terms or conditions under which such a contribution would be calculated have been agreed upon.

In respect to the period of the exemption, Halton seeks a term defined by the completion or substantial completion of road work on Winston Churchill Boulevard. Halton expects this work to be completed by the end of 2008. I am not prepared to allow the arrangement to continue indefinitely and will require that the parties seek renewal of the arrangement if the roadwork is delayed beyond the anticipated date of construction.

In the original submission Halton did not provide reasons why this load transfer could not be eliminated more efficiently by a sale and transfer of assets as between the utilities. However, Halton subsequently gave a written presentation which demonstrates

that the distribution plant work that will be done in conjunction with the anticipated road work will eliminate multiple line crossings of the road and provide for a more reliable distribution system.

IT IS ORDERED THAT:

1. Halton Hills Hydro is exempt from compliance with section 6.5.4 of the Distribution System Code in relation to the existing load transfer customers identified in Attachment A to this Decision and Order in accordance with the June 13, 2006 letter indicating agreement between Halton Hills Hydro and Hydro One Brampton and in accordance with the agreement indicated in the July 28, 2006 response to staff interrogatories.

2. The exemption granted in number 1 above is for the period described in Halton Hills Hydro's licence amendment (number 3 below).

3. Halton Hills Hydro's electricity distribution licence is amended by adding the following paragraph to Schedule 3:

> The Licensee is exempt from the requirements of section 6.5.4 of the Distribution System Code until the earlier of December 31, 2008 or completion of the road works on Winston Churchill Boulevard, as specified in the Board's Decision and Order dated November 6, 2006 in proceeding EB-2005-0513, in relation to the 63 load transfer customers served by Hydro One Brampton Networks Inc. The names of the customers are set out in attachment A to the aforementioned Board Decision and Order.

Under section 7(1) of the *Ontario Energy Board Act, 1998*, this decision may be appealed to the Board within 15 days.

Dated at Toronto, November 6, 2006

ONTARIO ENERGY BOARD

Original signed by

Mark C. Garner
Managing Director, Market Operations

APPENDIX "A"

TO DECISION AND ORDER

BOARD FILE NO. EB 2005-0513

DATED: November 6, 2006

AFFECTED LOAD TRANSFER CUSTOMERS

No.	Cust ID	Loc ID	CUSTOMER NAME	ADDRESS			CONSUMPTION	METER NO.
1	7149	6054	GOMES, FERNANDO	9046	WINSTON CHURCHILL	BLVD	960	HH19229
2	7151	6056	WHALEY, RAYMOND	9120	WINSTON CHURCHILL	BLVD	2861	HH23690
3	7153	6058	WHALEY, KENNETH E	9148	WINSTON CHURCHILL	BLVD	4281	HH21681
4	7155	6060	MAY, LARRY	9182	WINSTON CHURCHILL	BLVD	7823	HH19356
5	62771	6062	WEATHERBEE, JOHN	9194	WINSTON CHURCHILL	BLVD	2050	HH5594
6	7159	6064	MARINUCCI, ANTONIETTA	9214	WINSTON CHURCHILL	BLVD	4624	HH8922
7	7161	6066	HANSMA, JOHN	9232	WINSTON CHURCHILL	BLVD	4611	HH19228
8	7165	6070	PERRY, KENNETH	9340	WINSTON CHURCHILL	BLVD	2030	HH15824
9	7167	6072	MANZON, PRIMO	9484	WINSTON CHURCHILL	BLVD	6824	HH24596
10	44567	6074	SIGELOW, ENSOR	9490	WINSTON CHURCHILL	BLVD	2319	HH24997
11	7171	6076	COLLIER, SYD	9504	WINSTON CHURCHILL	BLVD	14840	HH22454
12	7173	6078	KALBARSKI, JOHN	9602	WINSTON CHURCHILL	BLVD	2381	HH19227
13	7175	6080	LAIDLAW, WILLIAM F	9656	WINSTON CHURCHILL	BLVD	13720	HH13635
14	7177	6082	LAIDLAW, WILLIAM	9688	WINSTON CHURCHILL	BLVD	10710	HH19226
15	7179	6084	GOLOW, MR H	9722	WINSTON CHURCHILL	BLVD	8473	HH26542
16	7181	6086	GASPARO, JOSEPH	9748	WINSTON CHURCHILL	BLVD	652	HH22400
17	35357	6088	SCHENDAL, ELVA	9748	WINSTON CHURCHILL	BLVD	1935	HH16902
18	42945	6094	GODIN, VINCE	9836	WINSTON CHURCHILL	BLVD	2048	HH25216
19	7191	6096	CROATION S&C CTR, HR SREDISTE	9118	WINSTON CHURCHILL	BLVD	6856	HH25385
20	7193	6098	MCLAUGHLIN ESTATE, CLAUDE	9190	WINSTON CHURCHILL	BLVD	1050	HH11487
21	7195	6100	CROATION S&C CTR HR SREDISTE	9218	WINSTON CHURCHILL	BLVD	4520	HH8568
22	7199	6104	MOGAN, JOHN	9250	WINSTON CHURCHILL	BLVD	880	HH6695
23	42769	6106	BOZEK, PWA	9260	WINSTON CHURCHILL	BLVD	1985	HH21982
24	7203	6108	KUDRASOVS, ALEX	9278	WINSTON CHURCHILL	BLVD	778	HH21983
25	7205	6110	JOLLY, DAVID	9294	WINSTON CHURCHILL	BLVD	2424	HH15939
26	7207	6112	GOMSKI, MR S	9296	WINSTON CHURCHILL	BLVD	4568	HH16224
27	56259	6114	ROWLEY, IBM	9362	WINSTON CHURCHILL	BLVD	6589	HH11497
28	7211	6116	WIGLEY, ALBERT	9368	WINSTON CHURCHILL	BLVD	684	HH6461
29	56269	6118	HOWETT, KRISTEN	9420	WINSTON CHURCHILL	BLVD	1759	HH24587
30	56427	6120	LORRAINE TRUEMAN	9438	WINSTON CHURCHILL	BLVD	1308	HH11530
31	58303	6122	STINSON, CHANNING	9446	WINSTON CHURCHILL	BLVD	3479	HH8161
32	7225	6124	BRANDER, HENRY W	9446	WINSTON CHURCHILL	BLVD	5469	HH16486
33	43365	6126	RANDALL, WAYNE	9550	WINSTON CHURCHILL	BLVD	4189	HH19423
34	7231	6128	FIRTH, NORMAN	9564	WINSTON CHURCHILL	BLVD	3521	HH19222
35	7233	6130	SMELLIE, J C	9580	WINSTON CHURCHILL	BLVD	3140	HH11495
36	36551	6132	KEASTRA, DREW	9584	WINSTON CHURCHILL	BLVD	5735	HH21963

37	7237	6134	VANDENBERG, SOPHIE	9590	WINSTON CHURCHILL	BLVD	2901	HH26543
38	45045	6136	COULSON CONTRACTING INC	9610	WINSTON CHURCHILL	BLVD	0	HH11579
39	45047	6138	COULSON CONTRACTING INC	9610	WINSTON CHURCHILL	BLVD	2019	HH26944
40	7243	6140	OWENS, MR L	9616	WINSTON CHURCHILL	BLVD	6258	HH18908
41	45153	6142	WEBB, ESTATE OF KEITH F	9618	WINSTON CHURCHILL	BLVD	3510	HH11396
42	56261	6144	FRANTER, NINA	9626	WINSTON CHURCHILL	BLVD	2484	HH20943
43	7249	6146	BRAUN, WOLFRAM	9636	WINSTON CHURCHILL	BLVD	3360	HH11494
44	7251	6148	MCHAFFIE, BRUCE	9652	WINSTON CHURCHILL	BLVD	4170	HH11513
45	7253	6150	ROGERS, KIERAN	9680	WINSTON CHURCHILL	BLVD	2834	HH11539
46	40757	6152	MCKEOGH, BEATRIX	9714	WINSTON CHURCHILL	BLVD	5590	HH11698
47	58033	6154	MARLEAU, CLEMENT	9734	WINSTON CHURCHILL	BLVD	1783	HH18907
48	58033	6154	MARLEAU, CLEMENT	9734	WINSTON CHURCHILL	BLVD	1625	HH26739
49	7261	6156	HANNAHSON, BRUCE	9738	WINSTON CHURCHILL	BLVD	2786	HH21934
50	7263	6158	ARNOLD, IAN KENNETH	9754	WINSTON CHURCHILL	BLVD	4879	HH11503
51	7265	6160	ARNOLD, IAN KENNETH	9774	WINSTON CHURCHILL	BLVD	10307	HH15221
52	7267	6162	LEE, GLENNA	9792	WINSTON CHURCHILL	BLVD	1736	HH21933
53	54025	6172	SUCCO, JOHN	9924	WINSTON CHURCHILL	BLVD	2328	HH10963
54	7279	6174	SMITH, DON	9933	WINSTON CHURCHILL	BLVD	5629	HH9938
55	8047	6850	CROATIAN S&C CRT	9118	WINSTON CHURCHILL	BLVD	16709	HH8950
56	8047	6850	CROATIAN S&C CRT	9118	WINSTON CHURCHILL	BLVD	3216	HH18125
57	8079	6880	BRITTO, FRANK	10212	OLD PINE CREST	RD	2516	HH11997
58	8157	6956	WING WO LUNG CANADA LTD	8564	WINSTON CHURCHILL	BLVD	1446	HH26152
59	22675	19998	SHERIDAN NURSERIES LTD	9674	WINSTON CHURCHILL	BLVD	0	HH1297
60	22675	19998	SHERIDAN NURSERIES LTD	9674	WINSTON CHURCHILL	BLVD	0	HH2129
61	22675	19998	SHERIDAN NURSERIES LTD	9674	WINSTON CHURCHILL	BLVD	27769	HH12141
62	22757	20076	SHERIDAN NURSERIES LTD	9674	WINSTON CHURCHILL	BLVD	9253	HH22335
63	22983	20256	LEE'S NURSERY INC	8564	WINSTON CHURCHILL	BLVD	19398	HH1249

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2005-0513

NOTICE OF APPLICATION

Halton Hills Hydro: Application for a Deferral of Section 6.5.4 of the Distribution System Code

Halton Hills Hydro has filed an application dated October 21, 2005 and clarified December 6, 2005 with the Ontario Energy Board ("the Board") requesting exemption from or a deferral of the application of section 6.5.4 of the Distribution System Code. The deferral would, if granted, require an amendment to Halton Hills Hydro's electricity distributor licence under section 74 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Sched. B. The Board has assigned file number EB-2005-0513 to this application.

Section 6.5 of the Distribution System Code deals with load transfer customers, who are customers located in the licensed service area of one distributor (the "geographic distributor") but are physically served by another distributor (the "physical distributor"). Under section 6.5.4 of the Code, load transfer situations are required to be eliminated by May 1, 2007. This can be done by either negotiating the transfer of the customers to the physical distributor, or by the geographic distributor extending its system to connect the customers.

The load transfer customers affected by this application are located in Halton Hills Hydro's licensed service area but are connected to the distribution system of Hydro One Brampton. Halton Hills Hydro intends to connect the load transfer customers to Halton Hills Hydro's distribution system following road construction work along Winston Churchill Boulevard scheduled for 2007 and 2008. It is therefore asking for approval to continue the existing load transfer arrangements beyond May 1, 2007 in order to await completion of road construction before building the new line connecting the existing load transfer customers.

Copies of the application and associated information filed with the Board are available for inspection at the Board's office and from the office of Halton Hills Hydro, at the addresses indicated below.

The Board intends to proceed with this application by written hearing unless a party satisfies the Board that there is good reason for not proceeding by written hearing. The Board invites submissions regarding the application. **Submissions, quoting file number EB-2005-0513, must be filed with the Board Secretary within 7 days of receipt of this Notice, and a copy must also be provided simultaneously to the applicant.**

The applicant may submit a response to submissions by **filing the response with the Board Secretary within 14 days of delivery of the date on which the last person required to be served with this Notice was so served**. A copy of the response must also be provided simultaneously to all persons that file submissions with the Board.

IF YOU DO NOT PROVIDE A SUBMISSION IN ACCORDANCE WITH THIS NOTICE, THE BOARD MAY PROCEED WITHOUT YOUR PARTICIPATION AND YOU WILL NOT BE ENTITLED TO FURTHER NOTICE IN THIS PROCEEDING.

ADDRESSES

Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto ON M4P 1E4
E-mail: boardsec@oeb.gov.on.ca
Fax # 416-440-7656

Halton Hills Hydro
Attention Mr. Gary Ebersberger
Vice President
43 Alice Street
Acton ON L7J 2A9
E-mail: gebersberger@haltonhillshydro.com

DATED at Toronto December 16, 2005

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

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Appendix C

Procedures and Documentation for Asset Assessment

[This page left intentionally blank]

Substation Monthly Inspection Form

Asset Condition & loading record

Substation Name: _____ *Date:* _____

Inspected By: _____ *Work Order:* _____

Transformer Readings

Oil Level (tx) _____
Oil Level (OLTC) _____
Oil Pressure _____
Liquid Temp. _____
Winding Temp. _____

Gauges Reset? _____

On Load Tap Changer
High Tap _____
Low Tap _____
Present Tap _____
Operation Count _____

Station Bus Readings

Peak kW Demand: _____
Peak kVA Demand: _____
kWhr (do not reset): _____

Peak Amp Demand (Red): _____
Peak Amp Demand (White): _____
Peak Amp Demand (Blue): _____

All peaks reset? _____

Bus Volts (kV)

Phase	Max.	Min.
Red		
White		
Blue		

Station Battery:
Volts _____
Amps _____

Feeder Readings

Feeder	F1		F2		F3	
Phase	Peak Demand Amps	Breaker Operation Count	Peak Demand Amps	Breaker Operation Count	Peak Demand Amps	Breaker Operation Count
3 Phase						
Red						
White						
Blue						
Neutral						

Relay Targets			
SF6 Pressure			
Trip Cap Unit			
Control Battery			

Targets Reset? _____
Peak Amp Demands Reset? _____
Max/Min Reset? _____

Substation Monthly Inspection Form

Asset Condition & loading record

Visual Checks	√	*Comments*
Warning Signs		
Weeds/vegetation		
Fence, Grounding Condition		
Adjacent Objects/Structures to Station		
Incoming Structure		
HV Air Break Switch		
Insulator Condition		
Lightning Arresters		
Power Transformer		
Oil Leaks		
Transformer Cooling Fans		
Bushings		
Paint Condition		
LV Disconnects		
Cable Condition		
Spare Fuses		
Station Service		
Station Battery		
Ventilation Fans		
Heaters		
Interior Lighting		
Fire Extinguisher		

New Action Items:

.....

.....

Other Work Done / Additional Comments / System condition, Switching Changes:

.....

.....

Voltage Regulator Monthly Inspection Form and Settings Record

Location: _____

Inspected By: _____ *Date:* _____

Regulator Number	Operation Counter	Voltage Check	Raise/ Lower Check (4 Taps)	Max Tap	Min Tap	Current Tap	Drag Hands Reset?	Time Delay (Sec.)		Line Drop Compensation		Polarity	Voltage		Vari-Amp	
								R	L	R	X		Band-width	Level	R	L
Red:	Found:		R Volts:													
	Left:		L Volts:													
White:	Found:		R Volts:													
	Left:		L Volts:													
Blue:	Found:		R Volts:													
	Left:		L Volts:													

Comments:

.....

.....

Single Phase Regulator Ratio Test Sheet

Regulator No./Location: _____
Manufacturer: _____
Model: _____
S/N: _____
Date Tested: _____
Tested By: _____
Voltage Rating: _____
Current Rating: _____

Ratiometer
Manufacturer: _____
model: _____
S/N: _____
Date Calibrated: _____

Megger Reading: _____ Temp: _____ Corrected Megger Reading: _____
Winding Resistance S-L: _____ S-SL: _____ L-SL: _____

	Tap #	Ratio Formula	Calculated Ratio	Measured Ratio	Phase Angle
BOOST	16				
	15				
	14				
	13				
	12				
	11				
	10				
	9				
	8				
	7				
	6				
	5				
	4				
	3				
	2				
	1				
	0				
BUCK	1				
	2				
	3				
	4				
	5				
	6				
	7				
	8				
	9				
	10				
	11				
	12				
	13				
	14				
	15				
	16				

Single Phase Regulator Ratio Test Sheet

Comments:

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.....
.....

Temperature Correction Factors For Megger Readings:

Temperature		Multiplier	
°C	°F	Oil Immersed	Solid Insulation
0	32	0.25	0.40
5	41	0.36	0.50
10	50	0.50	0.63
15	59	0.75	0.81
20	68	1.00	1.00
25	77	1.40	1.25
30	86	1.98	1.58
35	95	2.80	2.00
40	104	3.95	2.50
45	113	5.60	3.15
50	122	7.85	3.98
55	131	11.20	5.00
60	140	15.85	6.30
65	149	22.40	7.90
70	168	31.75	10.00
75	167	44.70	12.60
80	176	63.50	15.80
85	185	89.79	20.00
90	194	127.00	25.20
95	203	180.00	31.60
100	212	254.00	40.00
105	221	359.15	50.40
110	230	509.00	63.20
-5	23	0.180	0.32
-10	14	0.125	0.25

Halton Hills HYDRO

SUB04 R1
Revised: Aug 2007
M. Wright

Transformer Test Form

Three Phase Ratio, Insulation & Winding Resistance

Station:	Transformer Designation:	Date:
Work Order:	Tested By:	Voltage Class:

Nameplate Data

kVA		Temp. Rise		Bushing Arrangement
Type (ONAN,ONAF)		H Voltage		
Phase (1, 3)		X Voltage		
Manufacturer		Y Voltage		
Serial No.		Tertiary Voltage		
Mfg. Date				
BIL HV				
BIL LV				
As Found Tap Pos.				
% Imp.				

Test Equipment

Test Set	Make	Model	Serial No.	Calibration Date
Ratiometer				
Insulation Resistance				
Winding Resistance				

Condition Checks

Liquid Temperature		Manhole/Handholes	
Gas Detector Relay		Oil Leaks	
Breather		Oil Level	
Primary Bushings		Tap Changer Switch	
Secondary Bushings		Aux. Piping	
Cooling Radiators		Aux. Wiring	
Main Tank		Gaskets	
Conservator Tank		Primary/Secondary Throat	
LTC Tank			
Valves			
Explosion Vent			

Halton Hills HYDRO

SUB04 R1
Revised: Aug 2007
M. Wright

Transformer Test Form

Three Phase Ratio, Insulation & Winding Resistance

Corrected Insulation Resistance Readings

Test No.	Test Volts	Test Time	Temp.	Correct. Factor	Phase Insulation Resistance			
					H-LG	L-HG	HL-G	Core-G
1								
2								
3								
4								
5								
6								

Ratio and Winding Resistance Readings

Phasor Diagram				Phase 1					Phase 2					Phase 3				
				Winding Resistance	H1 - H		Winding Resistance	H2 - H		Winding Resistance	H3 - H	
					X - X			X - X			X - X	
				H1 – H / X - X	Jumper -			H2 – H / X - X	Jumper -			H3 – H / X - X	Jumper -			
Tap Pos.*	HV	LV	Calc. Ratio H/L	Mult	Dev. Dial	Phase Angle	Resu-ltant Ratio	Amps	Mult	Dev. Dial	Phase Angle	Resu-ltant Ratio	Amps	Mult	Dev. Dial	Phase Angle	Resu-ltant Ratio	Amps
1																		
2																		
3																		
4																		
5																		

* Circle "As Left Tap"

Comments

ABS/Load Interrupter Maintenance Form

Including High Side Fuses and Lightning Arresters

Site: _____ Switch No.:_____ Tested By: _____ Date: _____

Switch Nameplate Data

Manufacturer: _____ Cat No: _____ Serial No.: _____ Date of Manufacture: _____

kV Nom: _____ kV Max: _____ Cont. /Interrupt Amps: _____/_____ Momentary Amps: _____

Fuse Amp Max: _____ Fuse Type: _____

Lightning Arrester Data

Type: _____ Manufacturer: _____ Year: _____ Cat. No. _____ Serial No. _____ Class: _____

Rating (kV): _____ Duty Cycle Rating: _____ MCOV Rating: _____

Fuse Data

Manufacturer: _____ kV: ___ Type: _____ Cat. No.: _____ Amps: _____ TCC: _____

Low-Resistance Measurements

Device	Phase A			Phase B			Phase C		
	Resistance			Resistance			Resistance		
	Amp Scale	Before	After	Amp Scale	Before	After	Amp Scale	Before	After
Switch									
Power Fuses									

Insulation Resistance Measurements

Device	Phase A			Phase B			Phase C		
	Insulation Resistance			Insulation Resistance			Insulation Resistance		
	Volts	Ohms	Leakage	Volts	Ohms	Leakage	Volts	Ohms	Leakage
Lightning Arresters									

Temp.: _____ Megger Correction Factor: _____

ABS/Load Interrupter Maintenance Form

Including High Side Fuses and Lightning Arresters

Switch Operation/Inspection Checklist
** Note any deficiencies/corrections*

___ Main Contacts
___ Arcing Contacts
___ Snuffers
___ Alignment
___ Sequence of Operation
___ Interlock
___ Insulators Cleaned
___ LA's Cleaned
___ Insulators Meggered

Micro-Ohmmeter
Make: _____ Model No.: _____
Serial No.: _____ Calibration Date: _____

Megger
Make: _____ Model No.: _____
Serial No.: _____ Calibration Date: _____

Comments:

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.....
.....
.....

Temperature Correction Factors For Megger Readings:

Temperature		Multiplier	
°C	°F	Oil Immersed	Solid Insulation
0	32	0.25	0.40
5	41	0.36	0.50
10	50	0.50	0.63
15	59	0.75	0.81
20	68	1.00	1.00
25	77	1.40	1.25
30	86	1.98	1.58
35	95	2.80	2.00
40	104	3.95	2.50
45	113	5.60	3.15
50	122	7.85	3.98
55	131	11.20	5.00
60	140	15.85	6.30
65	149	22.40	7.90
70	168	31.75	10.00
75	167	44.70	12.60
80	176	63.50	15.80
85	185	89.79	20.00
90	194	127.00	25.20
95	203	180.00	31.60
100	212	254.00	40.00
105	221	359.15	50.40
110	230	509.00	63.20
-5	23	0.180	0.32
-10	14	0.125	0.25

Bus Maintenance Form

Integrity Testing

Site: _____ Bus Designation: _____ Tested By: _____ Date: _____

Bus Nameplate Data

Manufacturer: _____ Material: _____ Date of Manufacture: _____

kV Nom: _____ kV Max: _____ Cont. Amps: _____ Momentary Amps: _____

Corrected Megger Readings A-B: _____ A-C: _____ B-C: _____ ABC-G: _____ Temp: ____ Correction Factor: ____

Low-Resistance Measurements

Section		Phase A			Phase B			Phase C		
		Resistance			Resistance			Resistance		
From	To	Amp Scale	Before	After	Amp Scale	Before	After	Amp Scale	Before	After

Bus Maintenance Form

Integrity Testing

Bus Integrity Checklist
** Note any deficiencies/corrections*

___ Boots intact
___ Corona Evidence
___ Overheating Evidence
___ Bolted connections secure & torqued

Micro-Ohmmeter
Make: _____ Model No.: _____
Serial No.: _____ Calibration Date: _____

Megger
Make: _____ Model No.: _____
Serial No.: _____ Calibration Date: _____

Comments:

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.....

Temperature Correction Factors For Megger Readings:

Temperature		Multiplier	
°C	°F	Oil Immersed	Solid Insulation
0	32	0.25	0.40
5	41	0.36	0.50
10	50	0.50	0.63
15	59	0.75	0.81
20	68	1.00	1.00
25	77	1.40	1.25
30	86	1.98	1.58
35	95	2.80	2.00
40	104	3.95	2.50
45	113	5.60	3.15
50	122	7.85	3.98
55	131	11.20	5.00
60	140	15.85	6.30
65	149	22.40	7.90
70	168	31.75	10.00
75	167	44.70	12.60
80	176	63.50	15.80
85	185	89.79	20.00
90	194	127.00	25.20
95	203	180.00	31.60
100	212	254.00	40.00
105	221	359.15	50.40
110	230	509.00	63.20
-5	23	0.180	0.32
-10	14	0.125	0.25

AC High Potential Withstand Test Form

G&W Viper & Viper ST Reclosers

Withstand Test Voltage and Ratings Information

Recloser Rating			Withstand Rated Voltage	Withstand Test Voltage
50 Hz	60 Hz	Impulse (BIL)	Power Frequency	75% of Rated Power Frequency Voltage
12 kV	15.5 kV	110 kV	50 kV	37.5 kV
24 kV	27 kV	125 kV	60 kV	45.0 kV
36 kV	38 kV	150 kV	70 kV	52.5 kV

Comments

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AC High Potential Tester

Make: _____ Model No.: _____

Serial No.: _____ Calibration Date: _____

AC High Potential Withstand Test Form

G&W Viper & Viper ST Reclosers

Site: _____ Recloser No.:_____ Tested By: _____ Date: _____

Recloser Nameplate Data

Manufacturer: _____ Cat No: _____ Serial No.: _____ Date of Manufacture: _____
kV Nom: _____ kV Max: _____ Cont. Amps: _____ Interrupting Amps: _____
kV BIL: _____ Weight: _____

High Potential Test Results

	Test 1	**Test 2**	**Test 3**	**Test 4**
	Phase To Ground	Phase To Phase	Open Contact - Source	Open Contact - Load
	* De-Energize Reclosers and ensure frames are grounded - Recloser contacts Closed - Short Source Side S1, S2, S3 - Apply AC test voltage to S1, S2, S3	* De-Energize Reclosers and ensure frames are grounded - Recloser contacts Closed - Ground Load Side L1 and L3 - Apply AC test voltage to S2 only	* De-Energize Reclosers and ensure frames are grounded - Recloser contacts Open - Ground Load Side L1, L2, L3 - Short Source Side S1, S2, S3 - Apply AC test voltage to S1, S2, S3	* De-Energize Reclosers and ensure frames are grounded - Recloser contacts Open - Ground Source Side S1, S2, S3 - Short Load Side L1, L2, L3 - Apply AC test voltage to L1, L2, L3
Applied AC Test Voltage (kV)				
Duration (Sec.)				
Leakage Current (mA)				

Recloser Test Form

Oil & Vacuum Types

Site: _____ Recloser No.:_____ Tested By: _____ Date: _____

Recloser Nameplate Data

Manufacturer: _____ Cat No: _____ Serial No.: _____ Date of Manufacture: _____
kV Nom: _____ kV Max: _____ Cont. Amps: _____ Interrupting Amps: _____
kV BIL: _____ Weight: _____

Resistance Measurements

	Phase A			Phase B			Phase C		
	Volts	Amps	Ohms	Volts	Amps	Ohms	Volts	Amps	Ohms
Insulation Resistance									
Contact Resistance									

Temp.: _____ Megger Correction Factor: _____

Recloser Test Form

Oil and Vacuum Types

Switch Operation/Inspection Checklist
** Note any deficiencies/corrections*

___ Case Condition
___ Bushings Cleaned
___ Interlocks
___ Trip Counters

Micro-Ohmmeter

Make: _____ Model No.: _____
Serial No.: _____ Calibration Date: _____

Meg-Ohmmeter

Make: _____ Model No.: _____
Serial No.: _____ Calibration Date: _____

Comments:

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Temperature Correction Factors For Megger Readings:

Temperature		Multiplier	
°C	°F	Oil Immersed	Solid Insulation
0	32	0.25	0.40
5	41	0.36	0.50
10	50	0.50	0.63
15	59	0.75	0.81
20	68	1.00	1.00
25	77	1.40	1.25
30	86	1.98	1.58
35	95	2.80	2.00
40	104	3.95	2.50
45	113	5.60	3.15
50	122	7.85	3.98
55	131	11.20	5.00
60	140	15.85	6.30
65	149	22.40	7.90
70	168	31.75	10.00
75	167	44.70	12.60
80	176	63.50	15.80
85	185	89.79	20.00
90	194	127.00	25.20
95	203	180.00	31.60
100	212	254.00	40.00
105	221	359.15	50.40
110	230	509.00	63.20
-5	23	0.180	0.32
-10	14	0.125	0.25

Halton Hills HYDRO

SUB12 R0
Revised: June 2007
M. Wright

Circuit Breaker Test Form

Routine Testing and Preventative Maintenance for Vacuum, SF6 & Air

Station:	Circuit Breaker Designation:	Date:
Work Order:	Tested By:	Nominal Circuit Voltage:

Nameplate Data

Type (Vac/SF6/Air)		Rated Sym S/C Current	
Manufacturer		Rated Sym MVA	
Model		Asym Rating Factor	
Serial No.		Duty	
Voltage Rating		Weight	
Rated Cont. Current		Mfg. Year	
Frequency		Trip/Close/Charge Volts	/ /
BIL		Control Drawing No.	

Test Equipment

Test Set	Make	Model	Serial No.	Calibration Date
Micro Ohm Resistance				
Insulation Resistance				

Condition Checks

Enclosure Inspection □	Manual Close □	Electrical Trip □	Lube Mechanical □
Arc Contacts □	Manual Trip □	Operation count found	Wipe Down □
Arc Chutes □	Manual Charge □	Operation Count left	
Truck Inspection □	Electrical Close □	SF6 pressure contacts □	

Micro Ohm Contact Test

	Phase Contact Resistance		
	Red	Yellow	Blue
Before Cleaning			
After Cleaning			

Insulation Resistance

Test No.	Test Volts	Test Time	Phase Insulation Resistance		
			R to Y,B,G	Y to B,R,G	B to R,Y,G
Breaker Open, Load Side Grounded					
1					
2					
Breaker Closed					
1					
2					
Arc Chutes					
1					
2					

Circuit Breaker Test Form

Routine Testing and Preventative Maintenance for Vacuum, SF6 & Air

Breaker Function Verification

	Circuit Device	Operation Verified?	Comments
Close Initiation			
Close Seal-in			
Close Cut-off			
Anti-Slam			
Anti-Pump			
Trip Initiation			
Trip Cut-off			
Trip Free			
Trip Circuit Fuses			
Close Circuit Fuses			
Trip Close Monitor			
SF6 Monitor			
Under Voltage Relay			
Trip Capacitive Device			
Slow Close			

Measurements & Adjustments

	Expected	Measured	% Error	% Tolerance	Pass/Fail
Contact Wipe					
Trip Coil Resistance					
Trip Circuit Resistance					
Close Coil Resistance					
Close Circuit Resistance					
Minimum trip voltage					

Comments

Halton Hills HYDRO

SUB13 R0
Revised July 2007
M. Wright

Relay Test Sheet
Feeder Protection

Station:	Protection Designation:	Date:
Work Order:	Tested By:	Nominal Circuit Voltage:

Relay Test Equipment

Make:	Model:
Serial No.:	Calibration Date:

Relay Nameplate Data

Manufacturer:	Part No.:
Serial No.:	FID:

Settings Group	Settings File & Date	
CT Ratio Programmed	CT Ratio From One Line	CT Ratio Verified? Correct?
PT Ratio Programmed	PT Ratio From One Line	PT Ratio Verified? Correct?

Over-Current Element Settings

IEEE Element	Relay Element	Pickup	Curve	Time Dial
51				
51N				

IEEE Element	Relay Element	Pickup	Delay	Reset Delay
50A				
50B				
50NA				
50NB				

Notes

Halton Hills HYDRO

SUB13 R0
Revised July 2007
M. Wright

Relay Test Sheet
Feeder Protection

Metering Verification

Phase	Applied Volts	Applied Amps	I lags V (angle)
R			
Y			
B			

Phase	Calc Primary V	Measured V	% Error	% Tolerance	Pass/Fail
R				0.5 %	
Y				0.5 %	
B				0.5 %	

Phase	Calc Primary A	Measured A	% Error	% Tolerance	Pass/Fail
R				0.25	
Y				0.25	
B				0.25	

Phase	Calc. MW	Measured MW	% Error	% Tolerance	Pass/Fail
R				1	
Y				1	
B				1	

Phase	Calc. MVAR	Meas. MVAR	% Error	% Tolerance	Pass/Fail
R				1	
Y				1	
B				1	

Instantaneous Over-current Tests

Phase	IEEE Element	Relay Element	PU Setting	Calc. Amps	Measured PU	% Error	% Tolerance	Pass/Fail
R	50A						5	
Y	50A						5	
B	50A						5	
N	50NA						5	
R	50B						5	
Y	50B						5	
B	50B						5	
N	50NB						5	

Timed Over-current Tests - Pick Up

Phase	IEEE Element	Relay Element	Pickup Setting	Calc. Amps	Measured Pickup (A)	% Error	% Tolerance	Pass/Fail
R	51						5	
Y	51						5	
B	51						5	
N	51N						5	

Timed Over-Current Tests - Timing

Timing	IEEE Element	Relay Element	Mult. of PU	Amps	TD Mult.	Expected Time	Measured Time	% Error	% Tolerance	Pass/ Fail
R	51		1.5						5	
	51		2						5	
	51		3						5	
Y	51		1.5						5	
	51		2						5	
	51		3						5	
B	51		1.5						5	
	51		2						5	
	51		3						5	
N	51N		1.5						5	
	51N		2						5	
	51N		3						5	

Timing Elements

Timer	PU/DO	Timer	Setting (ms)	Start/Stop Elements	Measured Time	% Error	% Tolerance	Pass/Fail
79 Open Interval							5	
79 Reset							5	
79 Reset From Lockout							5	

Function Tests

Function	Expected Response	Tested Response	Pass/Fail
Lo Set Block			
Reclose Block			
Remote Block			
Ground Block			
Reclose Sequence			

Halton Hills HYDRO

SUB14 R0
Revised July 2007
M. Wright

Relay Test Sheet
Electronic Recloser Control

Station:	Protection Designation:	Date:
Work Order:	Tested By:	Nominal Circuit Voltage:

Relay Test Equipment

Make:	Model:
Serial No.:	Calibration Date:

Relay Nameplate Data

Manufacturer:	Part No.:
Serial No.:	FID:

Settings Group	Settings File & Date	
CT Ratio Programmed	CT Ratio From One Line	CT Ratio Verified? Correct?
PT Ratio Programmed	PT Ratio From One Line	PT Ratio Verified? Correct?

Over-Current Element Settings

IEEE Element	Relay Element	Pickup	Curve	Time Dial
51 Fast				
51 Slow				
51N Fast				
51N Slow				

Metering Verification

Phase	Applied Volts	Applied Amps	I lags V (angle)
R			
W			
B			

Phase	Calc Primary V	Measured V	% Error	% Tolerance	Pass/Fail
R				0.5 %	
W				0.5 %	
B				0.5 %	

Phase	Calc Primary A	Measured A	% Error	% Tolerance	Pass/Fail
R				0.25	
W				0.25	
B				0.25	

Phase	Calc. MW	Measured MW	% Error	% Tolerance	Pass/Fail
R				1	
W				1	
B				1	

Phase	Calc. MVAR	Meas. MVAR	% Error	% Tolerance	Pass/Fail
R				1	
W				1	
B				1	

Timed Over-Current Tests
Pick Up

Phase	IEEE	Relay Element	Pickup Setting	Calc. Amps	Measured Pickup (A)	% Error	% Tolerance	Pass/Fail
R	51 (Fast)						5	
W	51 (Fast)						5	
B	51 (Fast)						5	
N	51N (Fast)						5	
R	51 (Slow)						5	
W	51 (Slow)						5	
B	51 (Slow)						5	
N	51N (Slow)						5	

Timing

Timing	IEEE	Relay Element	Mult. of PU	Amps	TD Mult.	Expected Time	Measured Time	% Error	% Tolerance	Pass/ Fail
R (Fast)	51		1.5						5	
	51		2						5	
	51		3						5	
W (Fast)	51		1.5						5	
	51		2						5	
	51		3						5	
B (Fast)	51		1.5						5	
	51		2						5	
	51		3						5	
N (Fast)	51N		1.5						5	
	51N		2						5	
	51N		3						5	
R (Slow)	51		1.5						5	
	51		2						5	
	51		3						5	
W (Slow)	51		1.5						5	
	51		2						5	
	51		3						5	
B (Slow)	51		1.5						5	
	51		2						5	
	51		3						5	
N (Slow)	51N		1.5						5	
	51N		2						5	
	51N		3						5	

Timing Elements

Timer #	PU/DO	Timer	Setting (ms)	Start/Stop Elements	Measured Time	% Error	% Tolerance	Pass/Fail

Notes

Halton Hills HYDRO

SUB16 R0
Revised: June 2007
M. Wright

Ground Impedance Test Sheet

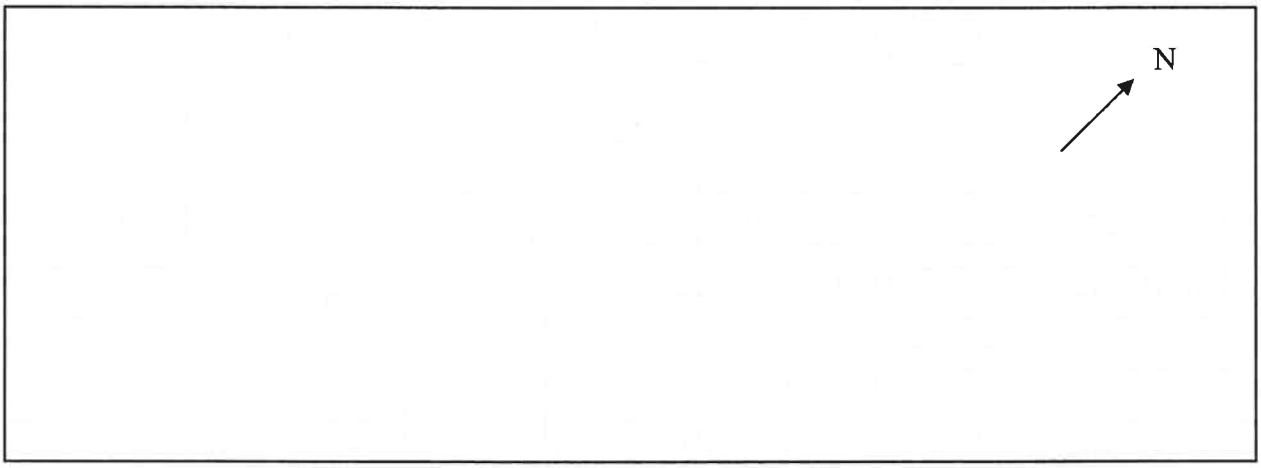
Substation Ground Grid Impedance and Integrity

Station:	Designation:	Date:
Work Order:	Tested By:	Voltage Class:

Test Equipment

Test Set	Make	Model	Serial No.	Calibration Date
Ground Tester				

Substation Layout



Measurements

Distance "P" (m)	Distance "C" (m)	Reading (Ohms)

Comments

Appendix D

Asset Assessment Schedules

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Substation Maintenance

Station Name	Equipment Type	Equipment Designation	Maintenance Schedule		
			Year		
			2006	2007	2008
Mountainview DS	HV Incoming, Bus	E03T1-L			X
	Transformers	E03T1			X
	LV SWGR, Bus	EB1			X
	Feeder C/B, Protection	E-F1			X
		E-F2			X
		E-F3			X
	Grounding				X
	Yard (Spraying)		X	X	X
	Stn. Battery				X
Cross DS	HV Incoming, Bus	C03T1-L			X
	Transformers	C03T1			X
	LV SWGR, Bus	CB1			X
	Feeder C/B, Protection	C-F1			X
		C-F2			X
		C-F3			X
	Grounding				X
	Yard (Spraying)		X	X	X
	Stn. Battery				X
River DS	HV Incoming, Bus	Q03T1-L			X
	Transformers	Q03T1			X
	LV SWGR, Bus	QB1		X	
	Feeder C/B, Protection	Q-F1		X	
		Q-F2		X	
		Q-F3		X	
	Grounding				X
	Yard (Spraying)		X	X	X
	Stn. Battery			X	
Armstrong DS	HV Incoming, Bus	AR03T1-L			X
	Transformers	AR03T1			X
	LV SWGR, Bus	ARB1			X
	Feeder C/B, Protection	AR-F1			X
		AR-F2			X
		AR-F3			X
	Grounding				X
	Yard (Spraying)		X	X	X
	Stn. Battery				X

Station Name	Equipment Type	Equipment Designation	Maintenance Schedule		
			Year		
			2006	2007	2008
Queen DS	HV Incoming, Bus	B03T1-L		X	
	Transformers	B03T1		X	
	LV SWGR, Bus	BB1		X	
	Feeder C/B, Protection	B-F1		X	
		B-F2		X	
		B-F3		X	
	Grounding			X	
	Yard (Spraying)		X	X	X
	Stn. Battery				X
Willow DS	HV Incoming, Bus	A03T1-L		X	
	Transformers	A03T1		X	
	LV SWGR, Bus	AB1		X	
	Feeder C/B, Protection	A-F1		X	
		A-F2		X	
		A-F3		X	
	Grounding			X	
	Yard (Spraying)		X	X	X
	Stn. Battery				X
Beardmore DS	HV Incoming, Bus	HA03T1-L		X	
	Transformers	HA03T1		X	
	LV SWGR, Bus	HAB1		X	
	Feeder C/B, Protection	HA-F1		X	
		HA-F2		X	
	Grounding			X	
	Yard (Spraying)		X	X	X

Station Name	Equipment Type	Equipment Designation	Maintenance Schedule		
			Year		
			2006	2007	2008
Silver Creek DS	HV Incoming, Bus	SC03T1-L	X		
	Transformers	SC03T1	X		
	LV SWGR, Bus	SCB1	X		
	Feeder C/B, Protection	SC-F1			X
		SC-F2			X
		SC-F3			X
	Grounding		X		
	Yard (Spraying)		X	X	X
	Stn. Battery		X		
	Line Voltage Regulators	B03W262	X		
		B03W264	X		
		B03W266	X		
Ashgrove DS	HV Incoming, Bus	4244T1-L	X		
	Transformers	4244T1	X		
	LV SWGR, Bus	4244B1	X		
	Feeder C/B, Protection	4244F1			X
		4244F2			X
		4244F3			X
	Grounding		X		
	Yard (Spraying)		X	X	X
	Line Voltage Regulators	D03W013		X	
		D03W015		X	
		D03W017		X	
Ballinafad DS	HV Incoming, Bus	4246T1-L	X		
	Transformers	4246T1	X		
	LV SWGR, Bus	4246B1	X		
	Feeder C/B, Protection	4246F1	X		
		4246F2	X		
		4246F3	X		
	Grounding		X		
	Yard (Spraying)		X	X	X

Station Name	Equipment Type	Equipment Designation	Maintenance Schedule		
			Year		
			2006	2007	2008
Glen Williams DS	HV Incoming, Bus	4231T1-L		X	
	Transformers	4231T1		X	
	LV SWGR, Bus	4231B1		X	
	Feeder C/B, Protection	4231F1	X		
		4231F2	X		
		4231F3	X		
	Grounding			X	
	Yard (Spraying)		X	X	X
Norval DS	HV Incoming, Bus	4245T1-L	X		
	Transformers	4245T1	X		
	LV SWGR, Bus	4245B1	X		
	Feeder C/B, Protection	4245F1	X		
		4245F2	X		
		4245F3	X		
	Grounding		X		
	Yard (Spraying)		X	X	X

Halton Hills Hydro Inc.
Pole Testing Schedule

Year	Proposed Quantity of Poles to be Tested	Assigned Pole Numbers	Location(s)	Notes
			Guelph Street/ along C.N.R. Tracks (Crewson's Corners to Eastern Avenue Substation)	
2004	500	1000 - 1267	Steeles Avenue (James Snow Parkway to Winston Churchill Blvd.)	Poles numbers to be affixed to poles.
			Highway #7/ Guelph Street (Acton to Norval)	
			Main Street, Georgetown (HWY #7 to Guelph Street)	
			Trafalgar Road (27 SDRD to HWY #7)	
			Trafalgar Road (HWY #7 to 10 SDRD)	
			27 SDRD (Trafalgar Road to Dead-end at West)	
2005	500	268 - 767	Lindsay Court, Georgetown	Poles numbers to be affixed to poles.
			32nd SDRD (Trafalgar Road to 8th Line)	
			Guelph Street (Acton to Crewson's Corners - Poles on south side of Guelph Street	
			Trafalgar Road (10 SDRD to Steeles Avenue)	
			Highway #25 (32nd SDRD to Approx. 10 SDRD)	Budget allowed for additional testing above 500.
2006	500	768 - 999, 1268 - 1551	Hornby Road (All)	Additional pole numbers to be affixed to poles.
			4th Line (32nd SDRD to south of 10 SDRD)	
			10 SDRD (Ashgrove Substation to west of 3rd Line)	
			15 SDRD (East of 6th Line to HWY #25)	
			17 SDRD (Trafalgar Road to 4th Line)	
			3rd Line (South of 15 SDRD)	
			5th Line (10 SDRD to 17 SDRD)	
			6th Line (10 SDRD to 16 SDRD)	
			Private Road of Trafalgar Road (C08F272)	
			Winston Churchill Blvd. (17 SDRD through Old Pine Crest Road)	
			8th Line (Ballinafad Substation to 27 SDRD)	
			9th Line (32nd SDRD to 27 SDRD)	
			10th Line (32nd SDRD to 27 SDRD)	
			27 SDRD (8th Line to 9th Line)	Budget allowed for additional testing above
2007	1000	1552 - 2647	Reid Court, Georgetown	1000. Order additional pole tags if needed.
			Dublin Line (32nd SDRD to 25 SDRD) - 85 poles.	
			Town Line (north of 22nd SDRD to St. Helena's Road) - 90 poles.	
			17 SDRD (Town Line to HWY #25) - 56 poles.	
			22nd SDRD (Town Line to HWY # 25) - 34 poles.	
			3rd Line (32nd SDRD to Tx. A03Z036) - 54 poles.	
			Dublin Line (17 SDRD to north of 22nd SDRD) - 78 poles.	
			5th Line (17 SDRD to HWY #7) - 91 poles.	
			22nd SDRD (5th Line to HWY #7) - 54 poles.	
			6th Line (22nd SDRD north to Blue Phase Dead-End) - 30 poles.	
			6th Line (HWY #7 to 32nd SDRD) - 56 poles.	
			8th Line (10 SDRD to Steeles Avenue) - 102 poles.	Budgeted to Test 1000 poles. Proposed only,
			9th Line (10 SDRD to Steeles Avenue) - 97 poles.	actual poles tested may vary, additional poles
			5 SDRD (West of 6th Line to West of 10th Line) - 122 poles.	may be added, locations may change. Order
2008	1000	2648 - 3648	** Additional 51 poles to be added. Possible list of poles to retest.	Pole Tags.

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Appendix E

IRC Building Sciences Group Inc.
Building Assessment for 43 Alice St., Acton

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CONDITION ANALYSIS REPORT

Prepared for: **Halton Hills Hydro Inc.**
43 Alice Street
Acton, Ontario

Attention: Mr. Chris Tenant

Project: **Halton Hills Hydro Building**
43 Alice Street Acton, Ontario

IRC Number: IRC-5100

W.O. Number: M06-172CR

Report Date: October 31, 2006

Consultants: **IRC Building Sciences Group Inc.**
7565 Danbro Crescent
Mississauga, ON, L5N 6P9

Roof
Consultants
Institute

ISO 9001:2000 REGISTERED

Professional Engineers
Ontario

Table of Contents

1 Introduction

1.1 Terms of Reference

In October 2006, IRC Building Sciences Group Inc. was authorized by Halton Hills Hydro Inc. to conduct a visual assessment of the roof assembly components of the following property:

Halton Hills Hydro Building
43 Alice Street,
Acton, Ontario

The objective of this analysis is to review the condition of the roof assemblies and related components, to assess their existing condition and to make recommendations on future repair and/or replacement.

The site investigation consisted of a thorough visual examination of the visible roofing components, their current condition in addition to identifying areas requiring remedial attention. Perimeter flashing details, caulking, drainage, and surface anomalies were visually examined to identify signs of failure and potential future problem areas.

A roof plan was prepared showing all the designated roof areas, rooftop equipment, roof penetrations, etc., deficiencies, locations of test cuts, and other pertinent information. The roof plan is provided at the end of the report.

Budgetary costing estimates for corrective/replacement work identified from the visual inspection are also provided at the end of the report.

1.2 Scope of Work

The scope of work includes the following elements and techniques:

.1 On-site visual inspection of all roof areas. Visual record of all potential sites for water entry into the building. Interior visual walk through survey to ascertain location of leakage into the building.

.2 Interviews with appropriate building occupants and managers, in conjunction with document review, if available.

.3 Core-cut testing, relating to roofing system configuration and analysis.

.4 Moisture analysis utilizing the Delmhorst Moisture Metre for the purpose of moisture verification at the following locations:

i) Roof Interply System

ii) Insulation within the sub roof system.

1.3 Site Visit

The date of the site investigation was October 27, 2006 and the outside weather conditions during the visit were overcast and cool with a temperature of 5 degrees Celsius. The site assessment was conducted by Dave Ross and Raymond McNulty.

1.4 Building Description and Roof Area Identification

For the purposes of this report, the west elevation of the building fronts along Alice Street in Acton Ontario. The existing building is a multi storey steel frame and metal clad structure extensively renovated and rebuilt in 1989. All roofs with the exception of a small area above the staff lunchroom (roof area 1.2) consist of built up bituminous assemblies installed in 1989.

For the purposes of the reporting and data assembly, each roof area was divided into identifiable sections according to the boundaries set out by such termination features as edges, height changes, control joints and/or expansion joints.

1.5 Maintenance History and Reported Leaks

Relatively few repairs and minimal maintenance appears to have been performed on the existing roof areas. Interior review of the building and interviews with building occupants revealed numerous locations where water leakage was actively occurring or had occurred in the past.

The following table outlines reported leak locations:

Leak No.	Roof Area (Refer to Roof Plan)	Leak Details
1	Roof Area 1.1 (Garage)	Leaks reported below the north exhaust duct opening. Water stains evident around spiral duct.
2	Roof Area 1.1 (Garage)	Leaks reported below the west HVAC curb.
3	Roof Area 2.2 (Stairwell leading from second floor to Engineering)	Water damaged drywall ceiling directly under sloped metal cladding. Suspected sealant failure and inadequate waterproofing under cladding.
4	Roof Area 2.1 (Engineering)	Water stained ductwork below HVAC unit.
5	Roof Area 2.1 (East wall of Engineering)	Water stained ceiling tile below east parapet. Suspected membrane flashing failing.
6	Roof Area 2.1 (Corridor leading from engineering to payroll)	Water stained drywall at base of soil stack penetration. Suspect membrane flashing failure at north highwall transition. Existing grommet flashings at soil stack pipe are also loose.
7	Roof Area 2.1 (Engineering)	Water stained ceiling tile over workstation in northeast corner. Suspect sealant failure at highwall transition.

8	Roof Area 2.1 (Engineering)	Water stained ceiling tile adjacent to north skylights. Suspect membrane flashing failure at north highwall transition.
9	Roof Area 3.1 (Engineering)	Water stained ceiling tile along north wall of Manager of Engineering office. Investigation revealed splits in membrane flashing above this location.
10	Roof Area 3.1 (Payroll)	Reported history of leaking along base of skylight in southwest corner. Suspect membrane flashing and sealant deterioration along base of skylight.
11	Roof Area 1.2 (Lunch Room)	Reported history of leaking above west bay window. Suspect sealant failure at metal panel joints.

1.6 Limitations of the Study

The study was limited to those elements within the scope of work and based on existing conditions. The assessments obtained are based on observed defects and our experience with similar types of roof systems. Deficiencies may exist in areas not referenced in this report and may not have been visually apparent, given the level of study requested by the client. Therefore, IRC Building Sciences Group cannot accept liability for any costs incurred by the subsequent discovery of deficiencies not identified in this report.

2 Roof Compositions

Roof Area	Estimated Age	Deck Type	Vapour Retarder	Insulation	Membrane System	Surface	Perimeter Details	Approximate Thermal Resistance Above Deck (Insulation Dry)
1.1	17	½" Gypsum board on Metal	1 ply kraft paper	2.5" Fiberglass	4 Ply Asphalt B.U.R.	Pea Gravel	Parapet	9.63
1.2	17	Metal	Undetermined		Metal Panels	Painted	Drip Edge	Undetermined
2.1	17	½" Gypsum board on Metal	1 ply kraft paper	2.5" Fiberglass	4 Ply Asphalt B.U.R.	Pea Gravel	Parapet	9.63
2.2	17	Metal	Undetermined		Metal Panels	Painted	Drip Edge	Undetermined
3.1	17	½" Gypsum board on Metal	1 ply kraft paper	2.0" Fiberglass	4 Ply Asphalt B.U.R.	Pea Gravel	Parapet	7.70
4.1	17	Wood	1 ply kraft paper	2.0" Fiberglass	4 Ply Asphalt B.U.R.	Pea Gravel	Parapet	7.70
4.2	17	½" Gypsum board on Metal	1 ply kraft paper	2.5" Fiberglass	4 Ply Asphalt B.U.R.	Pea Gravel	Parapet	9.63

3 Visual Survey

Photograph 1: Northwest elevation of the Halton Hills Hydro Building in Acton. The existing building is a multi storey steel frame and metal clad structure extensively renovated and rebuilt in 1989.

Photograph 2: Southwest elevation of the Halton Hills Hydro Building in Acton.

Photograph 3: Roof Area 1.1 – Overall view looking northeast at roof area 1.1 situated over the Garage in the east end of the facility The existing roof consists of a built up bituminous membrane system installed in 1989.

Photograph 4: Roof Area 1.1 – Overall view of roof area 1.1 looking northwest. Drainage patterns appear to be generally good due to a slightly sloping structural substrate.

Photograph 5: Roof Area 1.1 – Localized ponding is evident along the central portion of the roof area primarily due to debris obstructing the roof drains.

Photograph 6: Roof Area 1.1 – Core cuts revealed that the membrane is exhibiting top ply deterioration, increased brittleness and poor interply adhesion. These observations would suggest that the existing membrane is in poor condition with limited service life remaining. Probes taken at the core cut locations revealed no moisture present in the insulation layer or within the membrane interply.

Photograph 7: Roof Area 1.1 – Generally heavy bitumen bleedthrough and blueberry accumulation was noted throughout the area. These anomalies are associated with weathering and aging of the roof system.

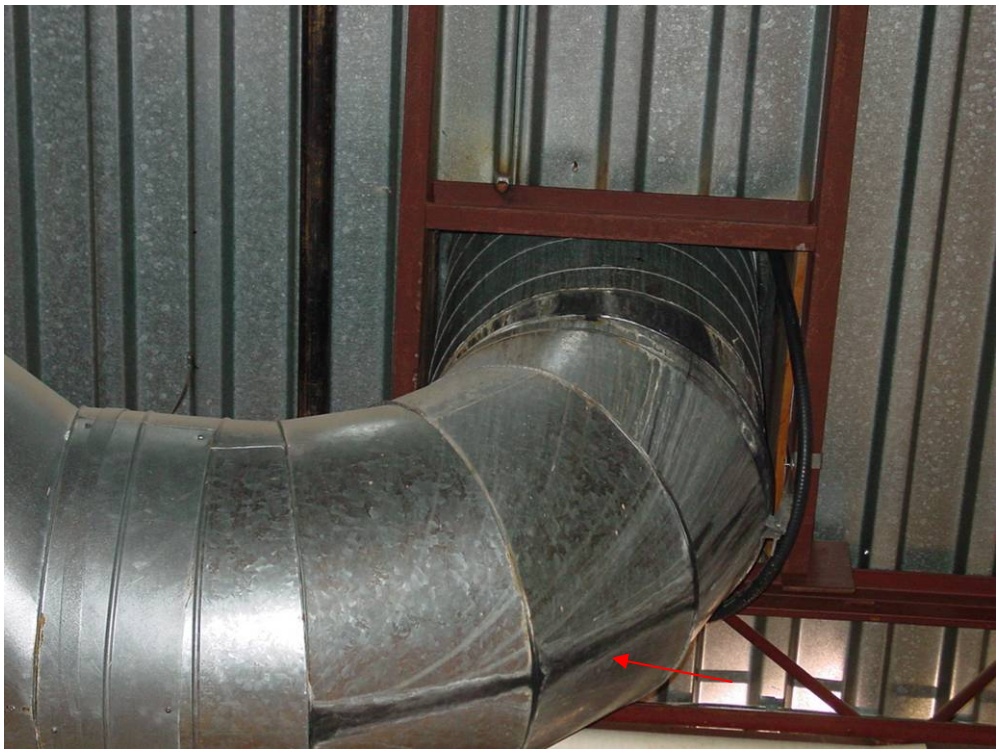
Photograph 8: Roof Area 1.1 - Heavy moss growth and organic debris exists along the south perimeter due to adjacent trees overhanging the roof. Moss is a form of vegetation that can grow on a roof surface. A roof surface with moss cover tends to deteriorate at an accelerated rate.

Photograph 9: Roof Area 1.1 – Heavy membrane blistering and ridging is evident in localized areas throughout the roof.

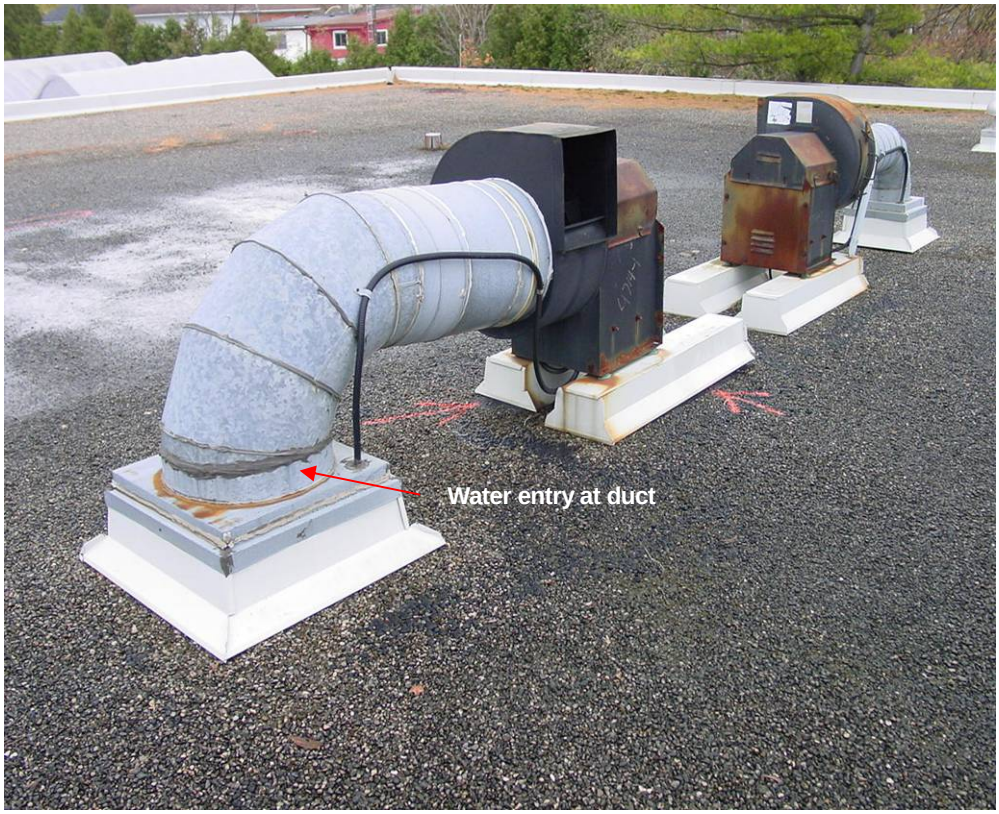
Photograph 10: Roof Area 1.1 - Existing membrane flashings at perimeter parapets are exhibiting developing deterioration, delamination and embrittlement.

Photograph 11: Roof Area 1.1 – No membrane protection has been provided at the base of the access ladder along the west wall. The membrane at this area typically experiences additional stress and potential damage from foot traffic, impact loading and erosive forces. Walkway pads or concrete pavers are appropriate elements for such areas.

Photograph 12: Roof Area 1.1 - Sealant deterioration exists at metal flashing joints and transitions, adding to the potential for wind blown moisture to enter the building.

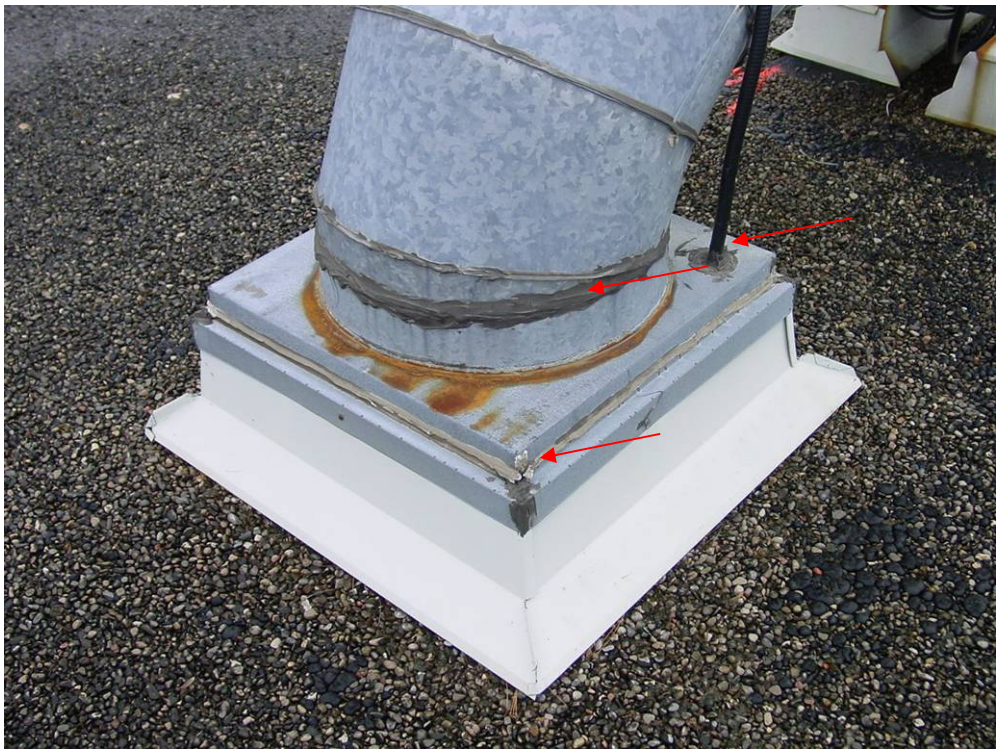


Photograph 13: Roof Area 1.1 – Ongoing leaks were reported below the north exhaust duct opening. Water stains are evident around spiral duct.

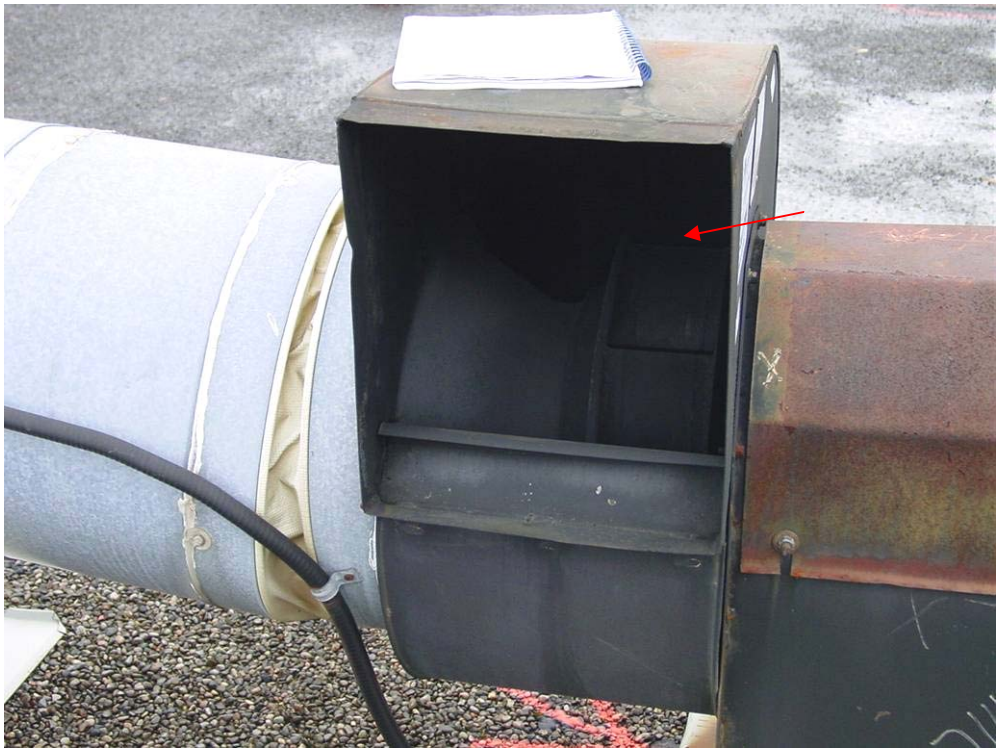


Photograph 14: Roof Area 1.1 – Photograph showing the duct penetrations (area of leaks) above the garage.

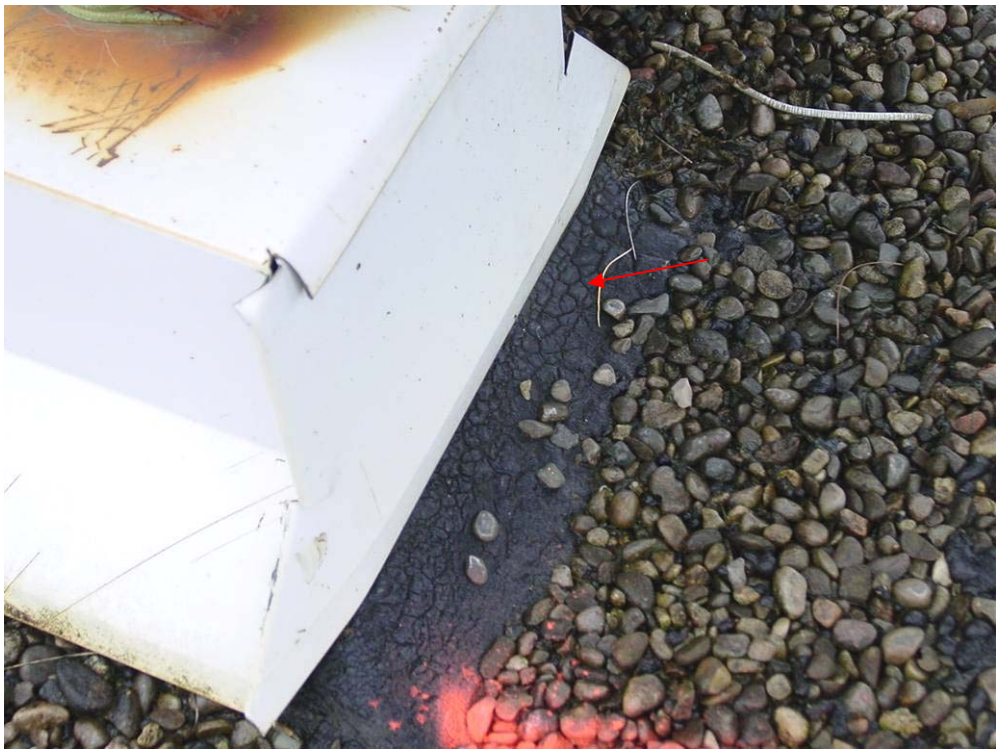
Photograph 15: Roof Area 1.1 – Water entry is likely at the deteriorated flexible duct connections.



Photograph 16: Roof Area 1.1 – Sealant deterioration and a lack of proper rain collars could be contributing to water entry.



Photograph 17: Roof Area 1.1 – Existing exhaust openings lack protective rain hoods.



Photograph 18: Roof Area 1.1 - Membrane flashing deterioration at sleeper supports and curbs could be contributing to water entry.

Photograph 19: Roof Area 1.2 - This small roof area is situated over the lunchroom bay window along the west perimeter of the building. The existing roof consists of prepainted metal panels, installed in 1989.

Photograph 20: Roof Area 1.2 - Ongoing leaks were reported below this roof area particularly during periods of snow accumulation and melting. Investigation revealed that significant deterioration of the sealant applied to panel joints is the likely cause of water entry.

Photograph 21: Roof Area 2.1 - Overall view looking south at roof area 2.1 situated over the Engineering Department in the central portion of the building. The existing roof consists of a built up bituminous membrane system installed in 1989.

Photograph 22: Roof Area 2.1 – Overall view of roof area 2.1 looking north.

Photograph 23: Roof Area 2.1 – Probes taken at the core cut locations revealed no moisture present in the insulation layer or within the membrane interply.

Photograph 24: Roof Area 2.1 – The membrane at the core cut on this area exhibits very poor interply adhesion. The individual membrane plies were very easily delaminated.

Photograph 25: Roof Area 2.1 – Drainage patterns appear to be generally good with evidence of ponding due to debris accumulation around drains.

Photograph 26: Roof Area 2.1 – Localized membrane ridging and blistering was evident throughout the roof area.

Photograph 27: Roof Area 2.1 – A broken blister was evident in the northwest corner and may be a source of leakage.

Photograph 28: Roof Area 2.1 – Existing membrane flashings at perimeter parapets and curb penetrations are exhibiting developing deterioration and exposure (photograph 15). Cracking of the membrane flashings along the base of the north wall is a potential source of the reported leaks over the north end of the Engineering Department.

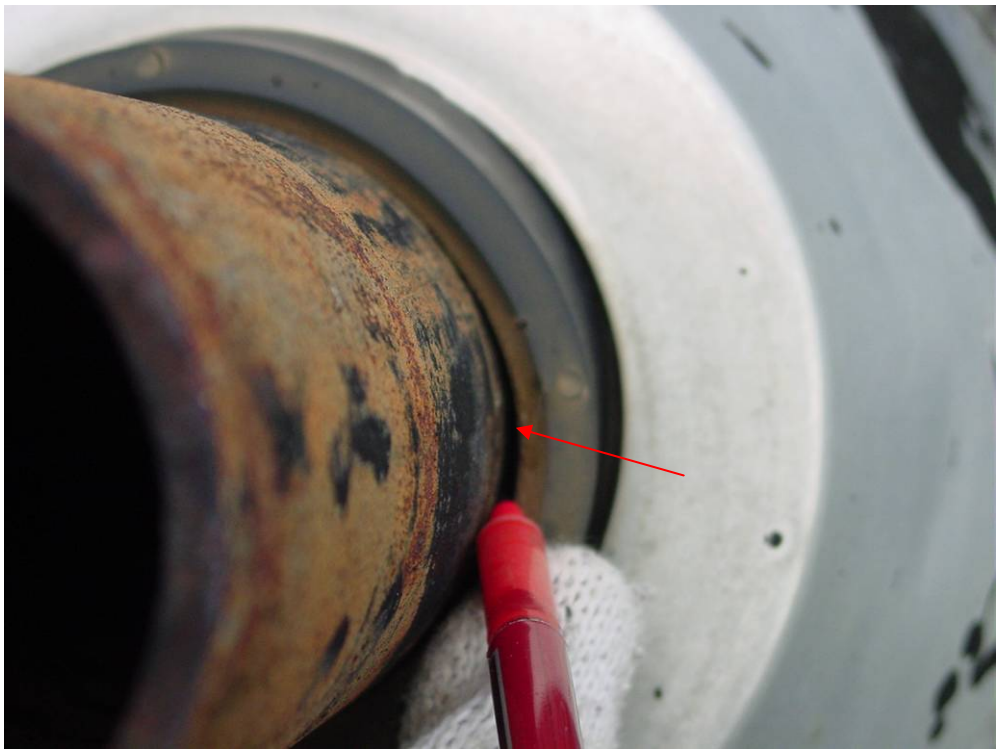
Photograph 29: Roof Area 2.1 – Localized moss growth and organic debris exists at corner transitions.

Photograph 30: Roof Area 2.1 – No membrane protection has been provided at the base of access ladders. Membrane blistering and delamination was evident at the base of the east roof ladder. Active roof leaks were reported below the ladder along the east parapet shown above.

Photograph 31: Roof Area 2.1 – Water stained ceiling tile was noted over workstation in northeast corner.

Photograph 32: Roof Area 2.1 – Sealant deterioration exists at the metal flashing and cladding joints in the northwest corner. Reported leaks below this location (see photo 31 above) could be due to wind blown moisture entering through the failed sealant.

Photograph 33: Roof Area 2.1 – Water stained drywall was noted at a leak location above the corridor leading to the payroll department.

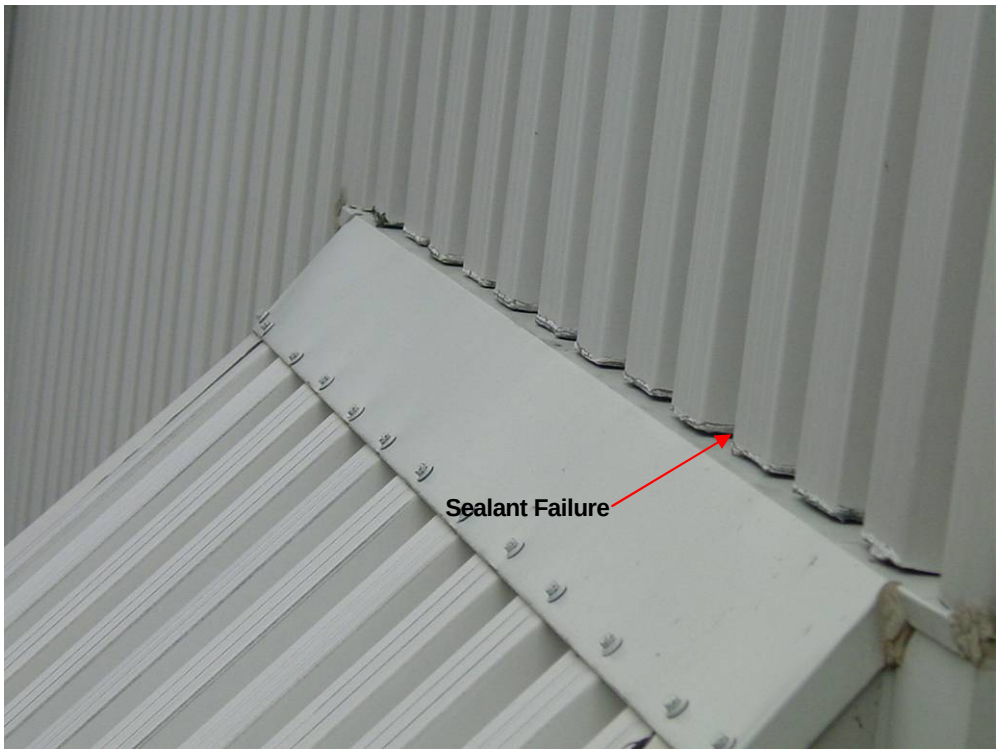


Photograph 34: Roof Area 2.1 – The existing grommet flashing around the north soil stack pipe penetration is loose and is a potential source of leakage.

Photograph 35: Roof Area 2.1 – There is evidence of long-term moisture accumulation between the panes of the skylights and it is likely that the seal between the panes has failed. This condition may be contributing to the reported water entry into the space below.

Photograph 36: Roof Area 2.2 – This small roof area is situated over the stairwell leading from the second floor level to the Engineering Department at the southeast portion of the building. The existing roof consists of prepainted metal panels installed in 1989.

Photograph 37: Roof Area 2.2 – Interior view. Ongoing leaks were evident in the stairwell below this roof area particularly along the perimeter wall transitions.



Photograph 38: Roof Area 2.2 – Investigation revealed that sealant failure along the upper west wall transition is a possible source of water entry. If inadequate membrane waterproofing was installed under the metal panels, then any water entering through failed sealant could more readily enter the building.

Photograph 39: Roof Area 3.1 – Overall view looking west. This roof area is situated over the Finance Department at the northwest portion of the facility. The existing roof consists of a built up bituminous membrane system installed in 1989.

Photograph 40: Roof Area 3.1 – Overall view looking south.

Photograph 41: Roof Area 3.1 – Core cuts revealed that the membrane is exhibiting top ply deterioration in addition to weak interply adhesion due to inadequate asphalt application quantities. Probes taken at the core cut locations revealed no moisture present in the insulation layer or within the membrane interply

Photograph 42: Roof Area 3.1 – Photo showing evidence of poor floodcoat coverage and adhesion. This condition leads to premature wear and deterioration of the top membrane plies.

Photograph 43: Roof Area 3.1 - Localized moss growth exists at corner transitions and along the base of the south skylight.

Photograph 44: Roof Area 3.1 – Localized membrane blistering is evident.

Photograph 45: Roof Area 3.1 – Water stained ceiling tile was observed along north wall of Manager of Engineering office.

Photograph 46: Roof Area 3.1 – Photo of the north parapet in the vicinity of the leaks above Manager of Engineering office.

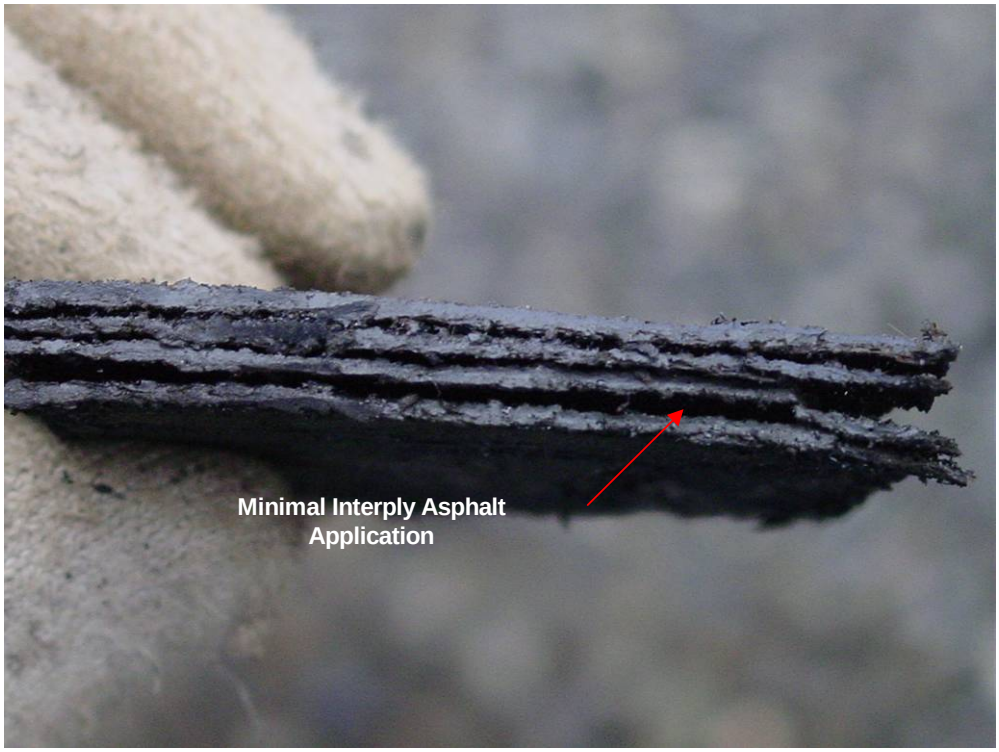
Photograph 47: Roof Area 3.1 North Wall – Investigation revealed splits in membrane flashing above the leak location.

Photograph 48: Roof Area 3.1 – A history of leaking was reported along the base of the south skylight.

Photograph 49: Roof Area 3.1 - Visual review of this skylight indicated that sealant deterioration could be resulting in water entry. In addition, deterioration of the membrane flashings along the base of the skylight could be contributing to the water entry. Previous caulking repairs were evident throughout the skylight.

Photograph 50: Roof Areas 4.1 and 4.2 – These uppermost roof areas are situated over the southwest corner of the building and consist of built up bituminous membrane systems installed in 1989.

Photograph 51: Roof Area 4.1 - Probes taken at the core cut locations revealed no moisture present in the insulation layer or within the membrane interply.



Photograph 52: Roof Area 4.1 – The existing membrane exhibits very poor interply adhesion.

Photograph 53: Roof Area 4.1– Localized membrane blistering is evident.

Photograph 54: Roof Area 4.1- Membrane exposure was identified along the transition between roof area 4.1 and 4.2.

4 Summary of Observations

4.1 Roof Area 1.1 (Garage)

This roof area (photographs 3 and 4) is situated over the Garage at the east end of the facility. The existing roof consists of a built up bituminous membrane system installed in 1989. Investigation revealed the following:

1. The existing roof system on this area is assessed to be in weathered condition in the latter stages of its serviceable life cycle.
2. Core cuts revealed that the membrane is exhibiting top ply deterioration, increased brittleness and reduced interply adhesion. These observations would suggest that the existing membrane is in poor condition with limited service life remaining. Probes taken at the core cut locations revealed no moisture present in the insulation layer or within the membrane interply (photograph 6).
3. Drainage patterns appear to be generally good due to a slightly sloping structural substrate. Localized ponding is evident along the central portion of the roof area primarily due to debris obstructing the roof drains (photograph 5).
4. Generally heavy bitumen bleedthrough and blueberry accumulation was noted throughout the area (photograph 7). These anomalies are associated with weathering and aging of the roof system.
5. Heavy moss growth and organic debris exists along the south perimeter due to adjacent trees overhanging the roof (photograph 8). Moss is a form of vegetation that can grow on a roof surface. A roof surface that has organic felts with moss cover tends to rot and deteriorate at an accelerated rate.
6. Heavy membrane blistering and ridging is evident in localized areas throughout the roof (photograph 9). Given the time of year this review was done (late fall during colder temperatures), it is suspected that blistering of the membrane would be more intense during warmer weather.
7. Existing membrane flashings at perimeter parapets are exhibiting developing deterioration, delamination and embrittlement (photograph 10).
8. No membrane protection has been provided at the base of the access ladder along the west wall (photograph 11). The membrane at this area typically experiences additional stress and potential damage from foot traffic, impact loading and erosive forces. Walkway pads or concrete pavers are appropriate elements for such areas.
9. Sealant deterioration exists at metal flashing joints and transitions, adding to the potential for wind blown moisture to enter the building (photograph 12).
10. Investigation of the leak at the HVAC unit in the west end of the roof was inconclusive but it is suspected that the water entry could be related to membrane flashing deterioration around the curb opening.

11. Investigation of the leaks around the truck exhaust duct penetrations (photograph 13) revealed that the source of water entry could be one of the following:
    - Existing flex connectors on ductwork are open to water entry (photograph 15),
    - Lack of proper rain collars around ductwork photograph 16),
    - Lack of rain hoods over duct exhaust openings (photograph17),
    - Failed sealant at duct penetrations,
    - Membrane flashing deterioration at sleeper supports and curbs (photograph 18).

4.2 Roof Area 1.2

This small roof area (photograph 19) is situated over the lunchroom bay window along the west perimeter of the building. The existing roof consists of prepainted metal panels, installed in 1989. Investigation revealed the following:

1. Ongoing leaks were reported below this roof area particularly during periods of snow accumulation and melting. Investigation revealed that significant deterioration of the sealant applied to panel joints is the likely cause of water entry (photograph 20).

4.3 Roof Area 2.1

This roof area (photographs 21 and 22) is situated over the Engineering Department in the central portion of the building. The existing roof consists of a built up bituminous membrane system installed in 1989. Investigation revealed the following:

1. The existing roof system on this area is assessed to be in weathered condition in the latter stages of its serviceable life cycle.

2. Core cuts revealed that the membrane is exhibiting top ply deterioration, increased brittleness and very poor interply adhesion (photograph 24). Probes taken at the core cut locations revealed no moisture present in the insulation layer or within the membrane interply (photograph 23).

3. Drainage patterns appear to be generally good with evidence of ponding due to debris accumulation around drains (photograph 25).

4. Generally heavy bitumen bleedthrough and blueberry accumulation was noted throughout the area. These anomalies are associated with weathering and aging of the roof system.

5. Localized membrane ridging (photograph 26) and blistering was evident throughout the roof area. A broken blister was evident in the northwest corner and may be a source of leakage (photograph 27).

6. Existing membrane flashings at perimeter parapets and curb penetrations are exhibiting developing deterioration and exposure. Cracking of the membrane flashings along the base of the north wall (photograph 28) is a potential source of the reported leaks over the north end of the Engineering Department.

7. Localized moss growth and organic debris exists at corner transitions (photograph 29).

8. No membrane protection has been provided at the base of access ladders. Membrane blistering and delamination was evident at the base of the east roof ladder (photograph 30).

9. Sealant deterioration exists at the metal flashing and cladding joints in the northwest corner (photograph 32). Reported leaks below this location (photograph 31) could be due to wind blown moisture entering through the failed sealant.

10. The existing grommet flashing around the north soil stack pipe penetration is loose and is a potential source of leakage (photograph 34).

11. Water stained ceilings were evident below the east parapet wall and investigation revealed that leakage may be due to membrane flashing deterioration along the parapet.

12. There is evidence of long-term moisture accumulation between the panes of the skylights (photograph 35), which is likely the result of a failed edge seal, and the build up of condensation between the domes. Over time, the build up of water and freezing during the winter may result in the cracking of the domes.

4.4 Roof Area 2.2

This small roof area (photograph 36) is situated over the stairwell leading from the second floor level to the Engineering Department at the southeast portion of the building. The existing roof consists of prepainted metal panels installed in 1989. Investigation revealed the following:

1. Ongoing leaks were evident in the stairwell below this roof area particularly along the perimeter wall transitions (photograph 37). Investigation revealed that sealant failure along the upper west wall transition is a possible source of water entry (photograph 38). If inadequate membrane waterproofing was installed under the metal panels, then any water entering through failed sealant could more readily enter the building.

4.5 Roof Area 3.1

This roof area (photographs 39 and 40) is situated over the Finance Department at the northwest portion of the facility. The existing roof consists of a built up bituminous membrane system installed in 1989. Investigation revealed the following:

1. The existing roof system on this area is assessed to be in weathered condition in the latter stages of its serviceable life cycle.

2. Core cuts revealed that the membrane is exhibiting top ply deterioration due to a very thin asphalt floodcoat (photograph 42) in addition to weak interply adhesion. Probes taken at the core cut locations revealed no moisture present in the insulation layer or within the membrane interply (photograph 41).

3. Localized moss growth exists at corner transitions and along the base of the south skylight (photograph 43).

4. Localized membrane blistering is evident (photograph 44).

5. Existing membrane flashings at perimeter parapets are exhibiting exposure and developing deterioration, cracking and splitting. The membrane flashings along the

north parapet are split, resulting in active leaks into the office below (photographs 45 and 47).

6. No membrane protection has been provided at the base of the access ladder in the southeast corner.

7. Existing skylights exhibit evidence of previous caulking repairs. A history of leaking was reported along the base of the south skylight (photograph 48). Visual review of this skylight indicated that sealant deterioration could be resulting in water entry (photograph 49). In addition, deterioration of the membrane flashings along the base of the skylight could be contributing to the water entry.

4.6 Roof Areas 4.1 and 4.2

These uppermost roof areas (photograph 50) are situated over the southwest corner of the building and consist of built up bituminous membrane systems installed in 1989. Investigation revealed the following:

1. The existing roof system on these areas is assessed to be in weathered condition in the latter stages of its serviceable life cycle.

2. Core cuts revealed that the membrane is exhibiting top ply deterioration, increased brittleness and very poor interply adhesion (photograph 52). Probes taken at the core cut locations revealed no moisture present in the insulation layer or within the membrane interply (photograph 51).

3. Localized membrane blistering and vegetation growth is evident (photograph 53).

4. Membrane exposure was identified along the transition between roof area 4.1 and 4.2 (photograph 54).

5. No membrane protection has been provided at the base of the access ladder or at the roof hatch.

5 Recommendations

The average life expectancy of a typical built-up roof 12 to 20 years depending on materials and levels of maintenance. The life expectancy of 20 years is a benchmark commonly used when planning future roof replacement strategies and life cycle costing. The existing built up roof systems reviewed at the Halton Hills Hydro Building in Acton are 17 years old and exhibit signs of deterioration consistent with systems nearing the end of their service life. Core cut testing indicated that the asphalt between membrane plies was failing which will tend to further reduce anticipated service life. Due to their age, condition and the evidence of ongoing water infiltration, the roof systems at this building cannot be expected to provide adequate long-term moisture protection, and replacement within one to three years can be expected.

In the immediate term, in order to control active water infiltration, the following corrective maintenance repair is recommended:

5.1 Roof Area 1.1 (Garage)

1. Clean debris and vegetation from roof surface. Ensure all drains are unobstructed.
2. Cut back overhanging tree along south perimeter.
3. Repair membrane blistering and ridging.
4. Install membrane protection at the base of the access ladder along the west wall.
5. Seal metal flashing joints and transitions.
6. Perform water test to determine source of the leak at the HVAC unit in the west end of the roof.
7. Replace flex connectors on exhaust ductwork.
8. Install rain collars at spiral ductwork.
9. Install rain hoods over duct exhaust openings.
10. Reseal duct penetrations.
11. Repair membrane flashings at sleeper supports and curbs.

5.2 Roof Area 1.2

1. Seal all metal panel joints.

5.3 Roof Area 2.1

1. Clean debris and vegetation from roof surface. Ensure all drains are unobstructed.
2. Repair membrane ridging and blistering.
3. Repair membrane flashings at north, east and west perimeters.
4. Install membrane protection at the base of access ladders.
5. Seal the metal flashing and cladding joints in the northwest corner.

6. Seal grommet flashing around the north soil stack pipe penetration. Check membrane flashings around soil stack and repair as required.
7. Replace skylight domes. This item is more cost effective to complete during roof replacement.

5.4 Roof Area 2.2

1. Remove existing metal panels, apply membrane waterproofing to substrate and install new metal panels.

5.5 Roof Area 3.1

1. Clean debris and vegetation from roof surface. Ensure all drains are unobstructed.
2. Repair localized membrane blistering.
3. Repair cracked membrane flashings along north parapet (above leak area).
4. Repair membrane flashings along base of south skylight.
5. Perform water testing and further investigation on skylight components to determine source of water entry.
6. Install membrane protection at the base of the access ladder in the southeast corner.

5.6 Roof Areas 4.1 and 4.2

1. Clean debris and vegetation from roof surface. Ensure all drains are unobstructed.
2. Repair localized membrane blistering.
3. Repair membrane exposure and reinforce transitional tie-in between roof area 4.1 and 4.2.
4. Install membrane protection at the base of the access ladder and roof hatch.

6 Budgetary Costing

The budgetary costing for the recommended remedial repairs is presented in the table below. The figures are in current dollars and can be considered accurate to within 25% on a plus or minus basis. The costs of these repairs are based upon the deterioration present at the time of the investigation and average unit prices. It is important to realize that the prices are not based on prepared specifications, but instead on general approaches and assumed quantities.

Please note that the listed prices do not include GST or engineering fees associated with the preparation of specifications. In addition, we would suggest that the budget allow for standard 10% contingency to compensate for any unforeseen complications that may arise during construction.

Halton Hills Hydro Building

43 Alice Street, Acton, Ontario
Budgetary Costing

Roof Area	Recommended Action	Budgetary Cost
Roof Area 1.1 (Garage)	Short Term Maintenance and Leak Repair	$ 3,500
Roof Area 1.2	Seal all metal panel joints	$ 500
Roof Area 2.1	Short Term Maintenance and Leak Repair	$ 5,000
Roof Area 2.2	Remove/replace metal panels apply waterproofing membrane	$ 2,500
Roof Area 3.1	Short Term Maintenance and Leak Repair	$ 3,500
Roof Areas 4.1 and 4.2	Short Term Maintenance	$ 1,000
Built Up Roof Areas 1.1, 2.1, 3.1, 4.1 and 4.2	Roof Replacement - 2008	$ 285,000
Estimated Total – Short Term Maintenance and Repair		**$ 16,000**
Estimated Total – Roof Replacement		**$285,000**

Appendix A

Roof Plan

Appendix B

Glossary of Terms

Glossary of Terms

Bare Felts:

Exposed membrane felts due to the gravel and top pour bitumen that have worn away. The exposed felts will eventually deteriorate and breakdown allowing water to migrate into the roofing system and eventually ending up in the building interior.

Blisters:

Blisters are produced when air, or air and moisture that is trapped between the roofing plies is heated by solar radiation. The pockets of gas will expand and contract with the changes in pressure and temperature. The concern of this anomaly is that the pressure in the blister builds up during the day, when heated, and may stretch the soft membrane, but with the cooling prevalent during the night, the stretched blister becomes hard and negative pressure or suction may be created. The concern then being that if the depth of the interply blister reaches the fourth ply of the inter-ply felt, the growth of the blister where air and/or moisture vapour is readily available, will grow over time to a very large size. The concern at that point is that the exposed bitumen located at the top of the blister begins to dry out due to the process of photo-oxidation and eventually this section of the blister will split. The end result being that the moisture then has free access to infiltrate the rest of the roofing system.

Bleedthrough:

Bitumen that when heated rises up through the gravel surface. This occurs as a result of roof ageing.

Blueberries:

Blueberries are formed as a part of the natural ageing of the top pour coat of the roof membrane that forms the main waterproofing of the roof system. They are formed when the heating effects of the sun act upon the bitumen in the roof membrane. When heated the bitumen will exhibit a slight lowering of viscosity and the subsequent movement results in small amounts of bitumen detaching itself from the main membrane. If this is carried to the extreme, this process will result in the loss of the top pour coat and exposure of the roofing felts. When the process has reached this point, the roof membrane is incapable of providing a reliable, watertight covering.

Caulking Splits:

This may be defined as cohesive splitting which is developing in the caulking. This anomaly is a regular occurrence along reglet joints at wall flashings, metal perimeter details, chimney flashings and various other areas. These joints require regular maintenance and renewal of the sealant. If left unattended, this situation will allow water access to the upper leading edge of the bituminous flashings. If the same condition exists there, water then has clear access to the sub-roofing system.

Deck:

The structural infill between main structural supports to the top surface of which a roofing system is applied.

Delamination:

Separation of the felt plies in a built up roofing membrane.

Degranulation:

Removal or wearing of the protective granulated surfacing of the modified bitumen cap membrane by erosive or abrasive forces. Degranulation leads to accelerated deterioration of the modified membrane by U.V. elements.

Embrittlement:

The loss of flexibility, elasticity or ductility of a material. The transition of a flexible material to a brittle material. This occurs as a natural ageing process in most roofing materials.

Towards the end of a roofing material's life expectancy, embrittlement can result in rupture or splitting of the material, as it can no longer resist the naturally occurring thermal cycling from day to night or summer to winter.

Flashing:

A building device used to prevent water from penetrating the exterior surface of a building element or material, or to intercept and lead water out of it. Flashing can be considered as a continuation of the roofing membrane to protect and weatherproof any element of the building or roof deck that departs from the roof deck or incline.

Base Flashing:	The extension over a cant strip and up the vertical surface of the roofing membrane at the base of a vertical wall or item intersecting or penetrating the roof.
Cap Flashing:	The sheet metal coping for the top of a higher wall such as a parapet, or the cover over a detail such as an expansion joint.
Counter Flashing:	The material, usually sheet metal, protecting the top edge and covering or partially covering the base flashing. This is sometimes also called a cap flashing.
Gravel Stop:	A formed strip of metal at the edges of a gravel surfaced roof to prevent the gravel from rolling or washing off. Usually combined with eaves flashing to add a crisp finished appearance to the roof edge.
Step Flashing:	Individual pieces of flashing material used to counterflash chimneys, dormers and such projections along steep sloping roofs. The individual pieces are overlapped and stepped up the vertical surface.

Lap:

That part of a roofing unit that covers the preceding course in any overlapping roofing application. Applied to shingles, built up roofing felts and most other types of roofing.

Mastic:

Flexible bituminous paste made by adding mineral fillers to concentrated cutbacks. This may also be called plastic or flashing cement.

Pitch Pocket:

A flanged metal collar placed over penetrating items on roofing and filled with pitch or mastic.

Ponding

Ponding is another term for standing water. At these locations the water may remain for many hours and possibly days. If there are any weaknesses in the membrane around the edges of the ponded area, water can penetrate the system. The amount of penetration will be directly dependent on the amount of time that the water lies in this area. In addition, the excess weight load created by ponding may pose a threat to the structural integrity of the building.

Since ponds occur in low areas of a roof, a pond becomes a repository for debris, sediment, and chemical emissions. Ponding encourages micro organism and bacterial degradation, roof deflection, magnified ultraviolet exposure and ultimate premature failure of the roof system.

Reglet:

A horizontal groove or slot in a wall or other vertical surface projecting above a roof surface into which flashing can be secured and sealed.

Ridging:

This may also be referred to as wrinkling or buckling. Majority of ridges are located over the insulation joints. Moisture can only be considered as one contributing factor to this roof anomaly. Movement from cyclical temperature change and slippage between felt layers is the main contributor to insulation-joint ridging. Ridges can occur very early in the life of a membrane and will often grow to a height of 25mm or more. Basically over time these ridges will breakdown as a result of movement and exposure, they usually crack along the upper top of the ridge. The end result being the migration of moisture again into the membrane and roof system ending up eventually in the interior building space.

Roof System - (B.U.R.):

The roof systems on this building consist of a conventional built up roof system (B.U.R.) installed over various insulations. This roof membrane system is manufactured on site via the use of hot kettles etc. Asphalt by itself is the main waterproofing material but must be reinforced. Layers of felts or plies are laid down and adhered together with hot asphalt. These felts are used to reinforce the asphalt. By alternating layers of felts and asphalt the roof system is built up. The plies of the felt are in the reality comprised of asphalt impregnated cardboard and have identical properties to the common cardboard box, the most applicable property is

the ability to absorb water. In a built up roof system, it is not the built up mat of asphalt and felts that forms the waterproofing barrier but the thin top pour of asphalt that forms the main barrier to moisture penetration in this type of roof system. This top pour coat is also used to adhere the gravel ballast that protects the membrane from the deteriorating effects of the ultraviolet light. The top pour coat undergoes natural weathering and ageing. If the top pour coat should be allowed completely weather away, then the roof membrane system will fail. Another point to consider is that a roof system is not just a piece of built up roof membrane but a whole system of interacting components such as curb flashing, expansion joints, caulking, drain details, etc., that have been brought together in a functional design. Should any one of these components fail then the entire system is in jeopardy as they are all interdependent. Furthermore all of these components, including the membrane, must receive regular maintenance in a preventative maintenance procedure. A leak is not a sign that there is going to be a problem with a roof but is evidence that damage has been done to the roof system.

Splitting:

The formation of long cracks usually completely through a built up roofing membrane representing a tension failure in the membrane.

Substrate:

The underlying surface of a roofing membrane. The surface of the deck or the insulation that is the supporting base for the roofing.

Surface Erosion:

The protective gravel surfacing may be washed or blown away leaving the top pour of bitumen exposed. When the bitumen is exposed to sunlight, moisture absorption and further water erosion, it becomes breached and will rapidly deteriorate if water is impinging on the area. This will result in the breakdown of the membrane system and ultimately water is allowed to migrate through the entire roofing system and find its way into the building interior.

Thermal Resistivity:

The basic property of a material's resistance to heat flow through a unit area of unit thickness for unit temperature difference between the faces.

Wood Supports:

Wood base supports have been positioned directly over the membrane surface and due to the amount of traffic and constant weight, the supports depress into the membrane system. Over time, this detail will generate splitting of the interply felt layers and once this anomaly has developed, moisture is then allowed to enter the felt layers and eventually end up in the building space.

Building Envelope
Condition Review
43 Alice St.
Acton, Ontario

Prepared for:
Halton Hills Hydro
43 Alice Street
Acton, Ontario
L7J 2A9

Attention: Mr. Kurt Durski

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June 6, 2007
IRC 5100-M07-039CR

Roof
Consultants
Institute

ISO 9001:2000 REGISTERED

Professional Engineers
Ontario

Table of Contents

1 Introduction

1.1 Terms of Reference

IRC Building Sciences Group Inc. (IRC) was authorized by Mr. Kurt Durski of Halton Hills Hydro to perform a Building Envelope Condition Review of the building located at 43 Alice Street, Acton, Ontario.

The purpose of the condition assessment was to review the exterior concrete block masonry, metal cladding and window systems to assess each component's existing condition and remaining service life, to quantify and determine the cause of any deterioration noted, and to provide recommendations for replacement/repair complete with budget estimates.

In particular, comment was requested on the cold indoor conditions at the second floor area at the overhang area at the main entrance to the building

1.2 Scope of Work

The assessment was performed as per IRC's proposal 03567P dated December 15, 2007 and the scope of work was as follows:

.1 Visual inspection of the exterior precast masonry, siding and windows systems. The visual review was performed from ground and roof levels. Record of all potential sites for air and water entry into the building. Interior visual walk through survey to ascertain location of leakage into the building.

.2 Interviews with appropriate building occupants and managers, in conjunction with document review, if available.

.3 Thermographic Scan to identify any potential areas of thermal bridging or air leakage.

.4 Recording of the Ambient Air Temperature at various locations analysis utilizing a REED LM-800 Thermometer to verify interior and exterior temperature differences.

.5 Recording of the Surface Temperature at various locations utilizing a RAYTEK RAYNGER ST Thermometer to verify surface temperatures of the window frames and glazing units.

.6 Air leakage analysis utilizing a smoke pencil to identify air leakage to and from the interior of the building.

.7 No analysis, destructive, non-destructive or invasive testing, other than has been described above, was completed.

.8 Based on the findings of the field investigation and review of other available documentation, a written report will be provided.

.9 The report will provide recommendations for the future repair/replacement options.

.10 Budgetary costing will be provided for all of the recommended repair options.

2 Methodology

The visual review of the exterior walls and related components was conducted on March 7, 2007. Observations of the exterior wall assemblies were made from the ground and roof levels.

Mr. Bill Denison performed the thermographic scan.

Mr. Darren Leung, B. Arch. Sc. performed the site review portion of the investigation.

Photographs were taken during the course of the investigation and are presented in Appendices A (Exterior Walls) and B (Thermographic Scans) and are referenced throughout the report.

For the purposes of this report, the elevation of the building facing Alice Street faces west.

3 Documentation

3.1 Drawings

The following drawings were provided to IRC for review as a part of this condition assessment. All drawings were prepared by Nichol and Johnston Architects.

3.1.1 Architectural

Drawings A1 to A18, dated June 8, 1998.

3.1.2 Structural

Drawings S1 to S6, dated June 1988.

3.1.3 Landscape

Drawings L1 to L2, dated June 8, 1988.

3.1.4 Details of Culvert and Gabions

Drawing C1, dated May 11, 1988.

3.1.5 Mechanical

Drawings M1 to M5, dated May 1988.

3.1.6 Electrical

Drawings E1 to E3, dated June 8, 1988.

4 Component Review

4.1 Building Description

The building is comprised of the warehouse/shop area at the rear of the building and the attached two storey office building. The original building included the warehouse/shop area with several offices along the south side. In 1988, the office building addition was constructed around the existing offices and extended towards Alice Street.

Based on the drawings and site review, the warehouse/shop portion of the building is composed of split-faced architectural concrete block with siding accents to match the new addition constructed in 1988 (Photograph 1). The addition is a steel framed structure with prefinished steel siding supported on concrete footings with concrete block foundation walls (Photograph 2). At the interior of the building, metal studs/wood studs, fiberglass batt insulation, a polyethylene vapour barrier and gypsum board have been installed at the interior face of the plywood sheathing adjacent the exterior steel siding.

The windows and doors are generally comprised of aluminum frames with insulated glass units (IGU). Prefinished metal garage doors and man doors have been provided at the warehouse portion of the building.

4.2 Exterior Masonry

In general, the exterior masonry walls are in good to fair condition with minor localized deterioration observed (Photograph 3). This was generally in the form of deteriorated mortar joints or poor masonry construction (Photograph 4). The split-face concrete blocks were not aligned correctly and various mortar joints were not completely filled with mortar (Photograph 5).

Cracked and separated mortar joints were typically observed at the corners of the building. No masonry control joints were provided at the corners of the building.

Cracked concrete blocks were only visible at one (1) location, above a stepped foundation wall at the east elevation (Photograph 6).

4.3 Metal Cladding

The prefinished metal cladding was generally in good condition, with no significant deterioration of the cladding observed (Photograph 7). Some chalking of the coating was typically observed.

The metal parapet cap flashings were in very good condition as well except at one (1) location, at the sloped parapet at the south elevation (Photograph 8), where surface corrosion of the cladding was noted.

4.4 Sealants

The sealant joints at all elevations were typically noted to be failed (hardened and split). This included all sealants at the following locations;

.1 between the siding and the split-faced concrete block (Photograph 9),

.2 the control joints at the full height of the concrete block walls (Photograph 10),

.3 the window perimeter sealant joints (Photograph 11),

.4 sealant at masonry penetrations (Photograph 12),

.5 all metal-to-metal joints at the windows (Photograph 13), and

.6 at all glass-to-metal sealant joints at the windows (Photograph 14).

Overbeading of the sealant joints at the skylights was evident at various locations (Photograph 15), most probably executed due to water leakage at the skylight locations. Failed sealants create an entry point for water penetration and air leakage into the building.

4.5 Window and Doors

Aluminum framed windows have been provided around the building. A window wall system has generally been used with insulated glass unit (IGUs) installed from the interior.

Metal man doors have been provided at the rear warehouse/shop area. Metal overhead doors have been provided at the vehicle bays.

At the main entrance to the building, an aluminum framed store front glazing system has been installed. The store front system glazing consists of both IGUs at the main portion of the walls area and metal panels at the floor level. The IGUs and metal panels appear to be glazed from the interior, although some removable stops were present on the exterior face of the glazing as well.

The vestibule, lobby and 2nd floor offices at the southwest corner of the building (Photographs 16 and 17) have been reported to be very cold during the winter months.

The following was observed:

.1 The aluminum framed windows at the front offices at the 1st and 2nd floors facing the southwest corner appear to be original to the building addition construction in 1989. The glazing has been provided in the form of IGUs installed from the interior. No broken or failed IGUs were observed during the review.

.2 Aluminum sills have been provided at the base of the 2nd floor windows. This was observed from the interior of the building (Photograph 18).

.3 Various installed glazing stops were undersized, leaving large gaps between them. (Photograph 19).

.4 Water leakage or condensation at various locations at the interior window sills/frames was evident (Photograph 20).

.5 All other aluminum framed windows provided at the 1st and 2nd floors were apparently installed from the exterior. No failed IGUs were observed during the review.

.6 At the east elevation, it was observed that no sill flashings were installed below the ground floor windows; there seemed to be plywood strips beneath, some of them being loose (Photographs 21 and 22).

.7 Various glazing snap caps at the exterior glazed windows seemed to have separated from the window frame (Photograph 23).

.8 Within the vestibule, Halton Hills Hydro has installed a 'Night Deposit Box', a steel panel in lieu of the window at this location (Photograph 24). The steel panel is not insulated and there are obvious holes at the corners of the window frame.

.9 No significant deterioration was noted at the steel man doors and overhead doors at the rear warehouse/shop portion of the building.

4.6 Skylights

Several aluminum framed skylights were noted at the roof levels. The skylights are glazed from the exterior with pressure plates securing the glazing. The pressure plates are of an exposed type, without decorative cover caps to conceal the fasteners. Extensive remedial repairs have been performed involving the surface application of sealant at the pressure plates, flashings and exposed fasteners. No broken or failed glazing units were observed in the review. No active water penetration was reported.

4.7 Interior Areas

A visual review of the interior office areas near the front entrance was performed. The following was noted:

.1 At the exposed soffit area, below the second floor and outside the main entrance area, a soffit panel was removed to permit examination of the space. Based on the drawings and site observations, the soffit construction is as follows:

a) prefinished metal vented soffit,

b) 300 mm cavity (allowance for recessed pot lights),

c) 13 mm plywood sheathing,

d) batt insulation within steel C-channel framing,

e) polyethylene vapour retarder

f) cantilevered structural steel I-beams,

g) 2nd floor composite floor slab (concrete on steel deck).

.2 Within the soffit space, the insulation and air/vapour barrier was generally hidden by the plywood sheathing. At locations where the plywood was cut out around the structural steel framing, it did not appear that the polyethylene air/vapour barrier was sealed (Photograph 27).

.3 At the ground floor area within the ceiling space, it appears that the vertical divider between the soffit space and the interior has been upgraded with the installation of spray applied polyurethane foam insulation covered with a cementitious thermal barrier. In one location, it was noted that electrical cable has been installed/modified and the opening in the foam was not sealed (Photograph 28). All areas of this exterior wall in the ceiling space were not accessible so it could not be determined if other discontinuities were present.

.4 Using an ambient air temperature gauge, it was observed that the 2nd floor area, the 2nd floor ceiling space and the ground floor area were relatively the same temperatures. However, the ground floor ceiling space did show an approximate 9◦C decrease in temperature in comparison to the other areas.

.5 For reference, the exterior temperature on March 7, 2007 was -4◦C. This can be compared to an average interior surface temperature of the window frames and glazing units of approximately 5◦C, with the window frames being colder than the glazing units.

.6 Using a smoke pencil, it was observed at various locations at the window framing gaps and openings, that air leakage was evident (Photographs 25 and 26). The gaps or openings and the lack of sealant between the window framing components allows cold air to enter the building at these locations.

4.8 Thermographic Scans

Thermographic scanning of the entire building perimeter was performed. Copies of the thermographic images are provided in Appendix B – Thermographic Scans. Increased surface temperatures were observed at the following locations:

.1 the window frames, glazing units and their connection to their adjacent wall systems.

.2 sheet metal siding overlapping.

.3 intersection between the metal parapet cap flashings and the sheet metal siding.

.4 door perimeters and,

.5 insulated masonry wall areas.

Increased thermal temperatures would be expected to some degree in these locations due to changes in wall construction and materials.

As noted in images A15, A16, B02 to B05, increased surface temperatures were noted at areas above the windows at the office area of the building. The inconsistent nature of the increased surface temperature suggest that there may be air leakage or thermal bridging at these locations.

5 Conclusions and Recommendations

5.1 Exterior Masonry

In general, the exterior split face concrete block masonry is in good condition with no significant deterioration noted. Over the long term, the localized cracked, separated or otherwise deteriorated mortar joints should be repointed to prevent further deterioration of the masonry. Consideration should be given to the introduction of control joints (or other means of controlling the movement) at the corners of the building to minimize future cracking/separations due to expansion and contraction of the masonry.

5.2 Metal Cladding

The prefinished metal cladding found at the building was generally in good condition with no significant deterioration noted. Chalking of the finishes were observed, which is normal for exterior metal finishes exposed to ultra-violet radiation. The light colour of the cladding will minimize the overall effect of the chalking on the cladding aesthetics.

5.3 Sealants

At all locations around the building, it was evident that the majority of the sealant joints require replacement. The sealants were generally noted to have exceeded their expected service life, with hardened and split materials observed. Deterioration of the sealant joints will allow water penetration into the wall assemblies with the potential for deterioration of the building components, both exterior and interior. Replacement is recommended at all locations. Work should include removal of all existing sealants prior to replacement.

5.4 Windows

The aluminum framed windows generally appear to be in fair condition considering their age. Staining was observed on the interior sills at various locations, however it is unclear if this is due to water penetration or condensation. Given the complaints of cold conditions within the office area, lack of reported water penetration and lack of damage at interior finishes adjacent to the windows, it can be concluded that the staining is due to the formation of condensation in the winter.

As noted in the Sealants section above, all of the sealants installed at the windows were noted to be failed, including sealant at window frame joints and sealants between the frame and glass. It is recommended that all of the sealants be replaced.

Air leakage around/through the window frames was detected with the use of a smoke pencil. This air leakage may be through joints in the frame or originating from between the frame and the rough wall opening. Consideration should be given to the injection of polyurethane foam insulation into all of the frame cavities and into the space between the window frames and rough wall openings to prevent uncontrolled air flow into the building. This can be accomplished by removing the interior stops and drilling through the frame at regular intervals.

Alternately, consideration could be given to the replacement of the window systems, although the costs may be prohibitive.

5.5 Skylights

It appears that the aluminum framed sloped glazing (skylights) were face sealed with sealant in the past in an attempt to stop ongoing water penetration issues. Typically, skylights of this design incorporate internal drainage systems to channel any water that may penetrate past the exterior seals, back to the exterior. A face sealed system relies on exterior sealants for the weather seal. Once the exterior seals fail, water penetration may occur. It is recommended that the exterior sealants be renewed along with the replacement of the exterior glazing tapes to ensure the exterior seals are effective over the next 2 to 5 years.

Alternately, consideration could be given to the replacement of the skylights with a new system incorporating internal drainage to reduce the requirements for maintenance.

5.6 Interior Areas

It appears likely that uncontrolled air leakage is ongoing at the soffit space below the second floor office area at the main entrance. Discontinuities were observed at the polyethylene sheet that acts as the air barrier. This would tend to cool the floor space above.

The difference in temperatures between the ground floor ceiling space and the floor area can be accounted for by the connection of the ceiling space to the overhang of the 2nd floor over the southwest corner of the building. Although spray applied foam insulation was observed within the ground floor ceiling space, a discontinuity was observed at a newer electrical conduit. It could also not be confirmed that the insulation is continuous at all areas around the soffit.

It should be ensured that all portions of the soffit are insulated and air sealed at the second floor level and the main floor ceiling space. At the floor slab, polyurethane insulation could be spray applied from the exterior onto the plywood substrate with an appropriate thermal barrier applied over the insulation. At the ceiling space, all discontinuities (such as at the electrical conduit) should be sealed. This work, in conjunction with the air sealing of the windows, should reduce the uncontrolled air leakage and heat loss and warm up the second floor office areas.

At test opening of the metal cladding may be considered around the window systems above the soffit to confirm adequate insulation and air sealing.

Consideration should be given to a review of the building heating systems. At the entrance vestibule, additional heat may be required to counter act the repeated introduction of cold air whenever someone enters the building. Warming of the vestibule will reduce the heat loss from the main floor area around the entrance.

Consideration could be given to provide an addition heat source below the windows along the reception area/second floor offices at the exterior wall. Typically, a heating source is located directly below a window to direct hot air towards the glass. This helps to heat the surface of the interior glass thereby counteracting convection currents and raising reducing radiant heat transfer between the glass and the occupants.

The air sealing/ insulation work should be completed prior to adding any additional heating equipment. Reducing air infiltration into the office area may be sufficient in improving interior conditions. The provision of additional perimeter heating should be considered only if the other remedial measures fail.

It should be noted that second floor office areas over the main entrance will always be colder than other areas of the building given the large window areas (thermal resistance of 2 compared to 15 to 20 for the typical wall assembly) and the exterior floor exposure over the main entrance.

6 Budgetary Costing

Based on the site review, various repairs are required at the building. For an inclusive budget estimate a " 25% variance should be allocated to costs provided in the table below for the recommended remedial repairs. It must be noted that in preparing the budgets for individual items, it has been assumed that a group of repairs will be completed at the same time. If individual repairs are completed increases should be expected.

The repair items listed have also been prioritized into "immediate', representing items of structural, of life safety significance or a liability, "estimated life", representing our estimation of the remaining serviceable life of the element and "optional" which represents repair items that can be considered as aesthetic or technical upgrades in comparison to the existing construction.

The cost of repairs is based upon the deterioration present at the time of the investigation and average unit prices obtained from our experience on similar projects in Southern Ontario. It is important to realize that the prices are not based on tendered specifications, but instead on general approaches and assumed quantities. The actual repair costs will depend on the prices received at the time of tendering and/or the actual quantities removed during the repair contract. Please note that the listed prices do not include GST or engineering fees associated with the preparation of specifications, and inspections for conformance with same.

Item	Description of Work	Budget Cost	Priority
1.0 Masonry			
1	Localized repairs	$ 15,000	2-5 years
2.0 Sealant Replacement			
1	At masonry joints	$ 2,500	1-2 years
2	At metal cladding	$ 12,500	1-2 years
3	At windows	$ 50,000	1-2 years
3.0 Windows			
1	Air sealing of frames at area above soffit area	$ 15,000	1-2 years
2	Air sealing of frames at remaining windows	$ 30,000	Optional
3	Replacement	$ 125,000	Optional
4.0 Skylights			
1	Replacement of sealants and glazing tapes	$ 10,000	2-5 years
2	Replacement	$ 20,000	Optional
5.0 Interior Areas			
1	Air sealing / insulating at soffit areas	$ 25,000	1-2 years
2	Metal cladding test opening	$ 4,000	optional
Budget Costing (Excl. of GST)			
1-2 years			$ 105,000
2-5 years			$ 25,000
Optional			$ 179,000

7 Limitations

IRC prepared this report solely for the client named. The responsibilities of IRC are as described in the Terms of Reference and The Scope of Work. The material in this report reflects the opinion of IRC at the time of preparation and within the terms of reference as agreed. Any use, which a Third Party makes of this report, or any reliance on decisions based on it, are the responsibility of such Third Parties.

IRC does warrant the accuracy of the identified information provided to IRC at the time of the report preparation. Unless provided in writing, but not limited to, mistakes, contacts, insufficient information or certification of such information is not the responsibility of IRC.

Only the specific information or locations noted in the report have been reviewed. Although every reasonable effort was taken to identify defects, latent and hidden defects may affect the accuracy of this report. No physical or destructive testing and no design calculations have been performed unless indicated elsewhere in this report.

We trust that the above is satisfactory for your purposes. If you have any questions or comments concerning the above please do not hesitate to contact our office.

Yours very truly,

IRC Building Sciences Group Inc.

Darren Leung, B. Arch Sc.
Project Coordinator

Mark Bechthold, P.Eng.
Manager of Engineering

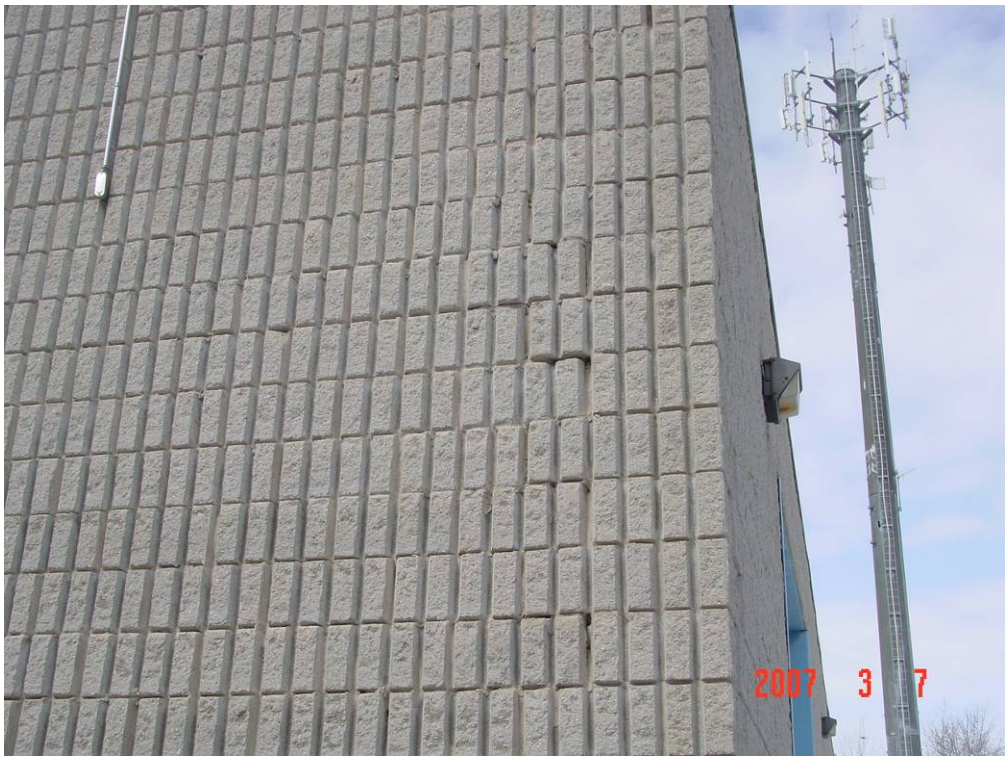
Appendix A

Photographs - Exterior Walls

Photograph 1: Original warehouse portion of the building constructed with split-faced concrete block with siding accents to match newer addition.

Photograph 2: The addition is a steel structure with prefinished steel siding supported on concrete footings with concrete block foundation walls.

Photograph 3: In general, the exterior masonry walls are in good to fair condition with very minor deterioration observed.



Photograph 4: Deterioration was identified in the form of deteriorated mortar joints or poor masonry construction.

Photograph 5: The split-face concrete blocks were not aligned correctly and various mortar joints were not completely filled with mortar.

Photograph 6: Cracked concrete blocks were only visible at one (1) location, above a stepped foundation wall at the East elevation.

Photograph 7: The exterior prefinished steel siding was generally in good condition.

Photograph 8: The metal parapet cap flashings were in very good condition as well except at one (1) location, at the sloped parapet at the South elevation.

Photograph 9: All observed sealant joints at all elevations were in very poor condition, which included all sealant joints between the siding and the split-faced concrete block.

Photograph 10: Sealant deterioration at the control joints at the full height of the concrete block walls.

Photograph 11: Sealant deterioration at the window perimeters.

Photograph 12: Sealant deterioration at wall penetrations.

Photograph 13: Sealant deterioration at all metal-to-metal sealant joints.

Photograph 14: Sealant deterioration at all glass-to-metal sealant joints.

Photograph 15: Improper overbeading repairs to the sealant joints at the skylights.

Photograph 16: The vestibule and lobby at the Southwest corner of the building have been reported to be very cold during the winter months.

Photograph 17: The 2nd floor offices at the Southwest corner of the building have been reported to be very cold during the winter months.

Photograph 18: Aluminum sills have been provided at the base of the 2nd floor windows. This was observed from the interior of the building.

Photograph 19: Various installed glazing stops were undersized.

Photograph 20: Water leakage at various locations at the interior window sills/frames was evident.

Photograph 21: The windows at the East elevation**.**

Photograph 22: At the East elevation, it was observed that no sill flashings were installed below the ground floor windows; there seemed to be plywood strips beneath, some of them being loose.

Photograph 23: Some glazing cover caps were noted to be loose.

Photograph 24: Within the vestibule, Halton Hills Hydro has installed a 'Night Deposit Box', a steel panel en lieu of the window at this location. The steel panel is not insulated and there are obvious holes at the corners of the window frame

Photograph 25: Using a smoke pencil, it was observed at various locations at the window framing gaps and openings, that air leakage was evident.

Photograph 26: The gaps or openings and the lack of sealant between the window framing components allows cold air to enter the building at these locations.

Photograph 27: At soffit locations where the plywood was cut out around the structural steel framing, it did not appear that the polyethylene air/vapour barrier was sealed.

Photograph 28: At one location between the soffit and the main floor ceiling space, an opening in the polyurethane foam was noted at an electrical conduit.

Appendix B

Photographs – Thermographic Scans

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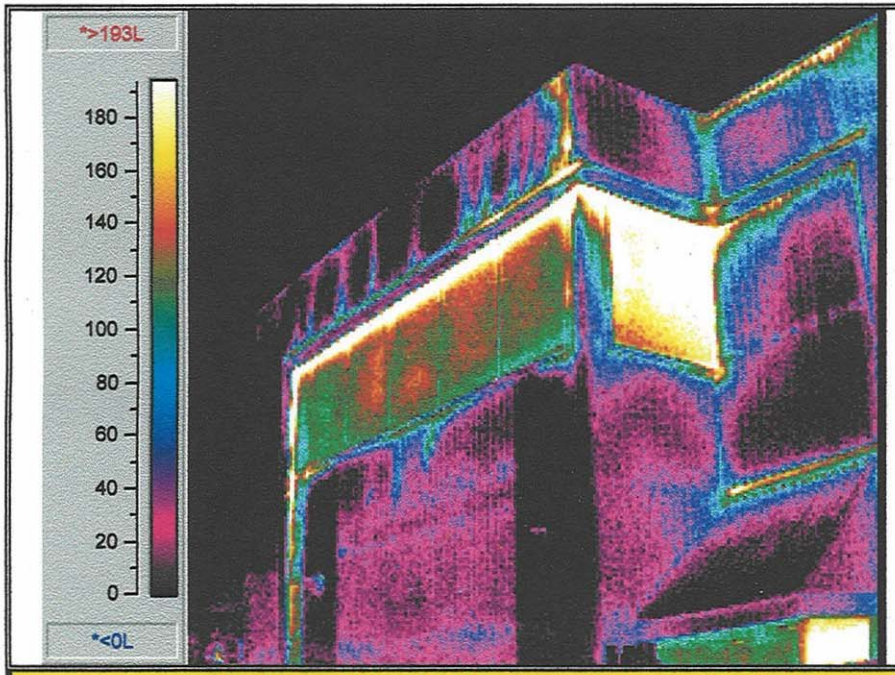
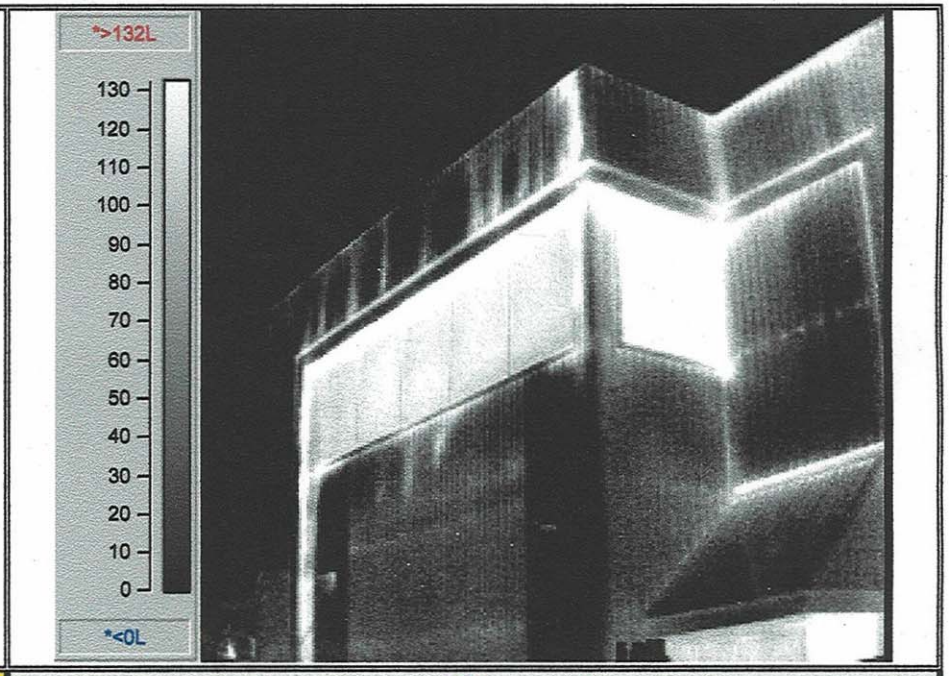
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**South Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Thermal Anomaly**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-05 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal image of upper floor Southwest corner scanned Northwest from back yard of private residence.

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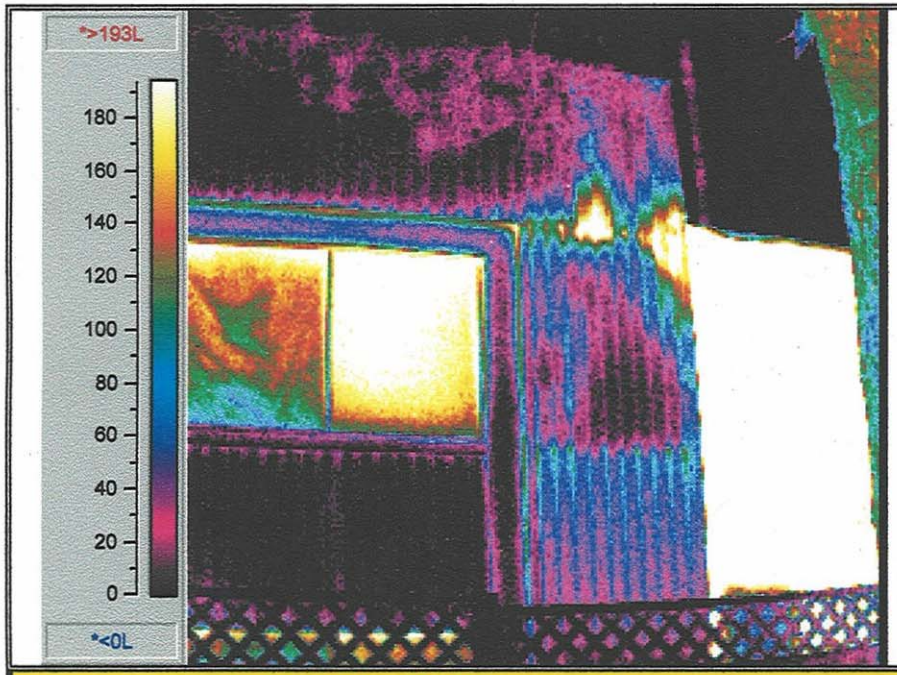
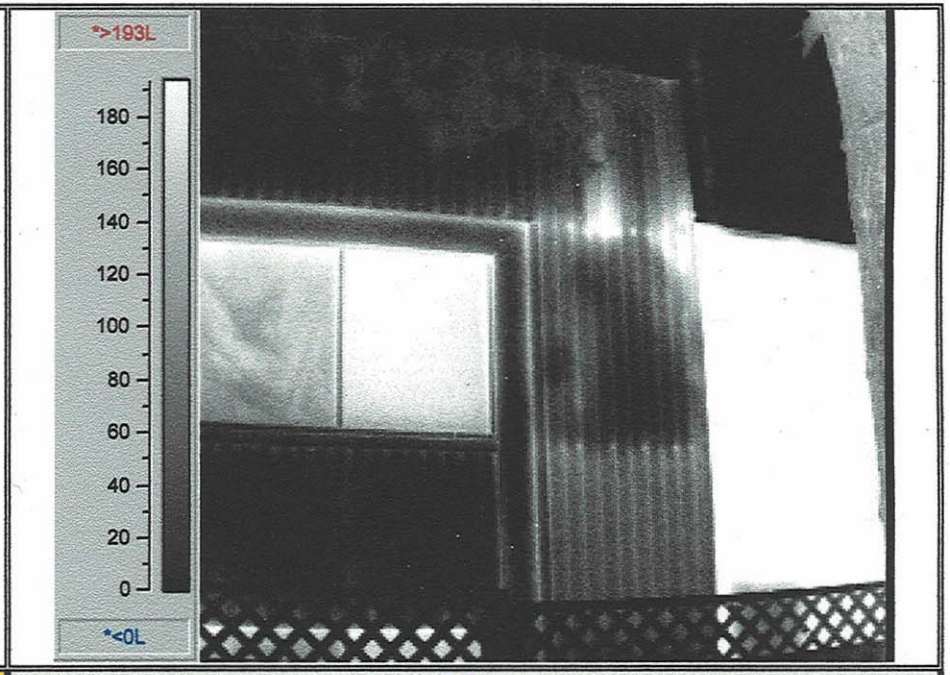
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**South face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Thermal Anomaly**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-06 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal image of anomaly on South face where garage and office building join. Scanning North from yard of private residence.

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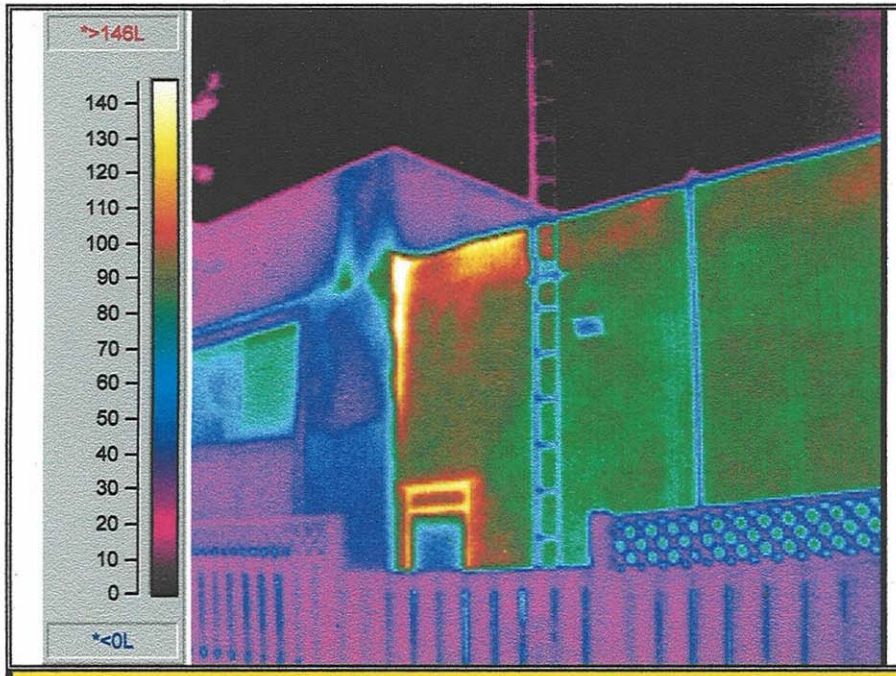
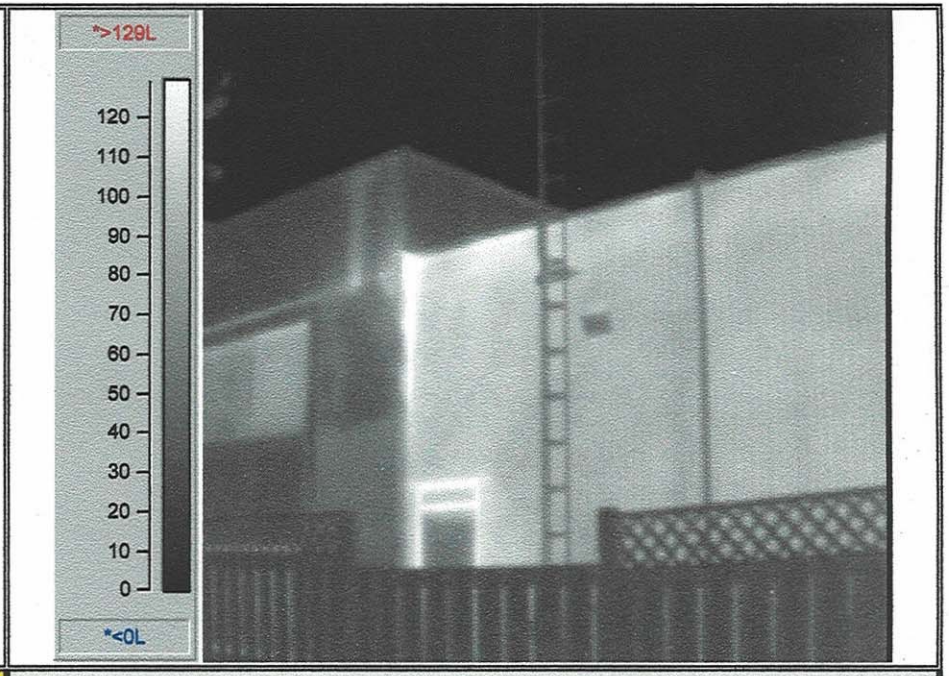
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**South face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Thermal Anomaly**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-07 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal image of anomaly on South face where garage and office building join. Scanning Northwest from yard of private residence.

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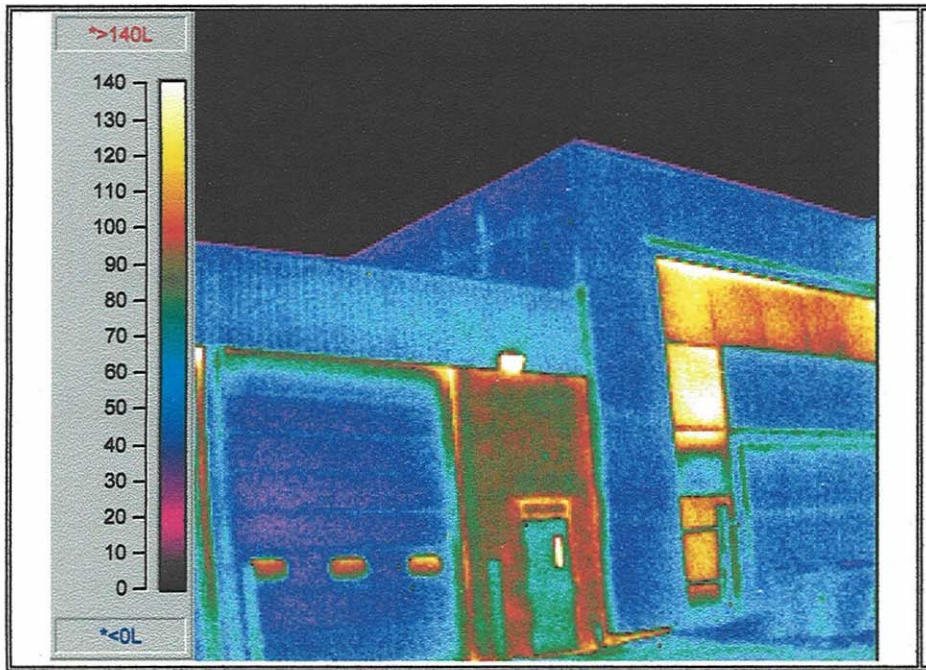
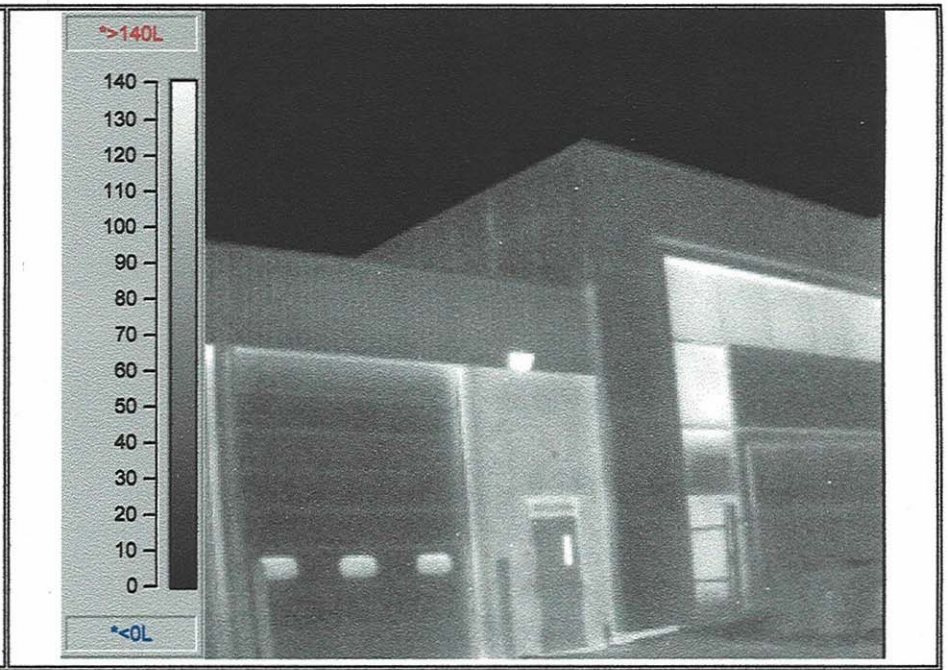
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**North Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**General Image**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-08 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal image of North face, East side, scanning Southwest from in front of garage.

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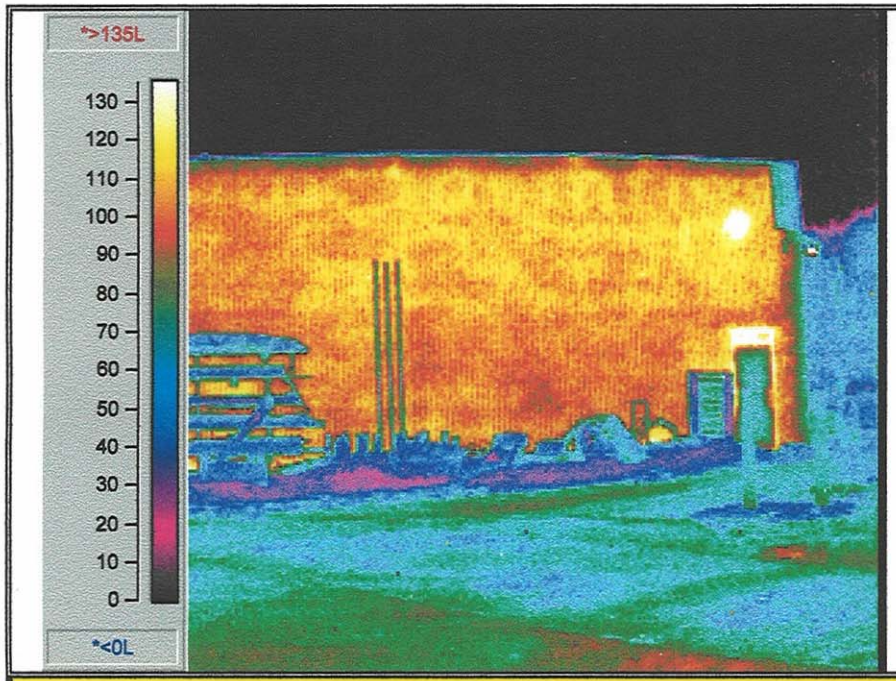
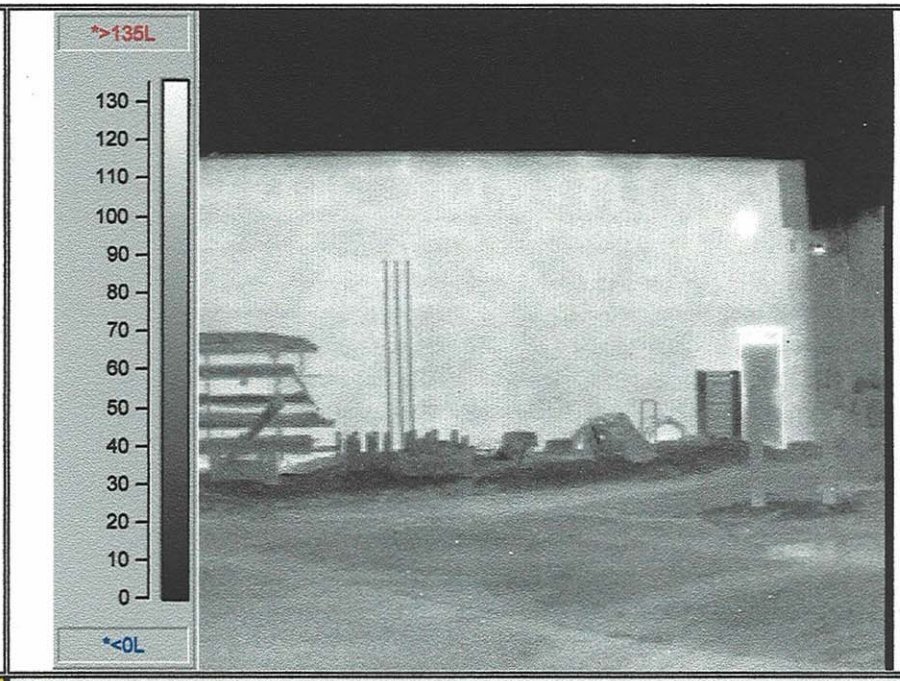
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**East Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**General Image**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-09 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal image of East face, North half of garage wall scanning West from yard area.

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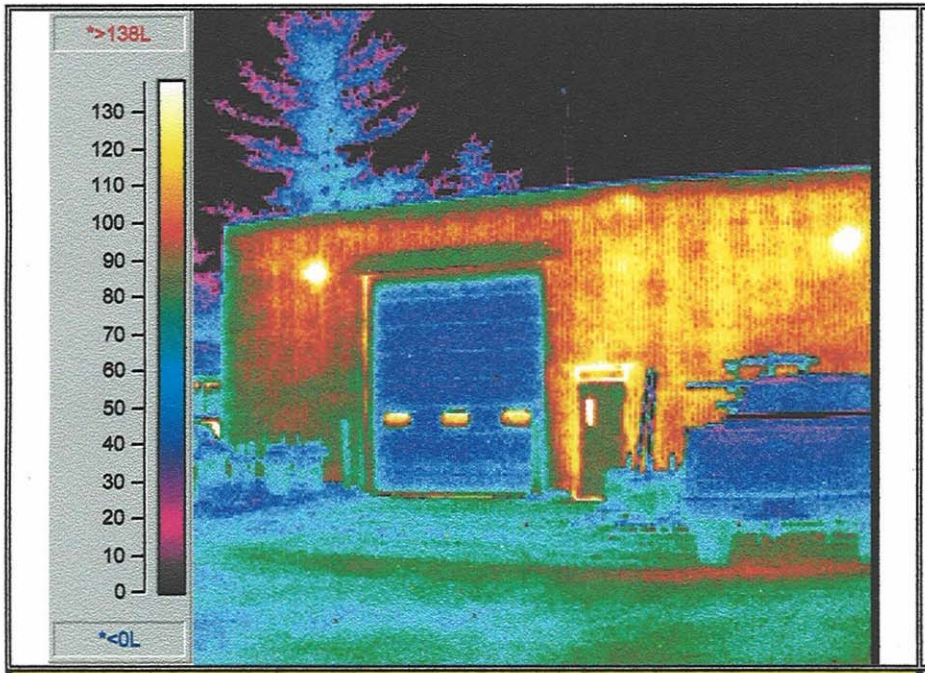
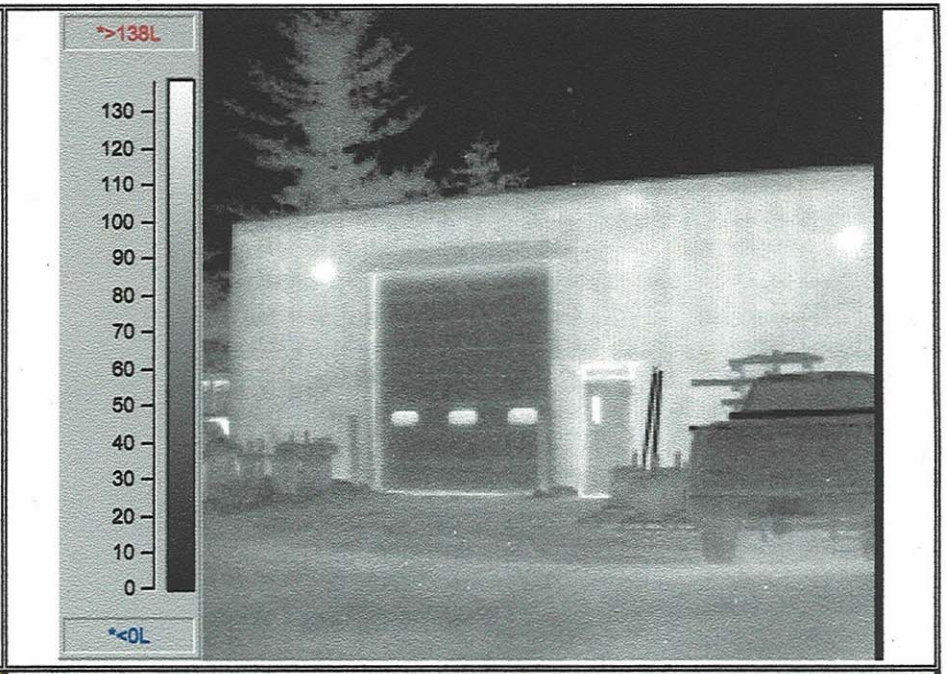
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**East Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**General Image**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-10 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal image of East face, South half of garage wall scanning West from yard area.

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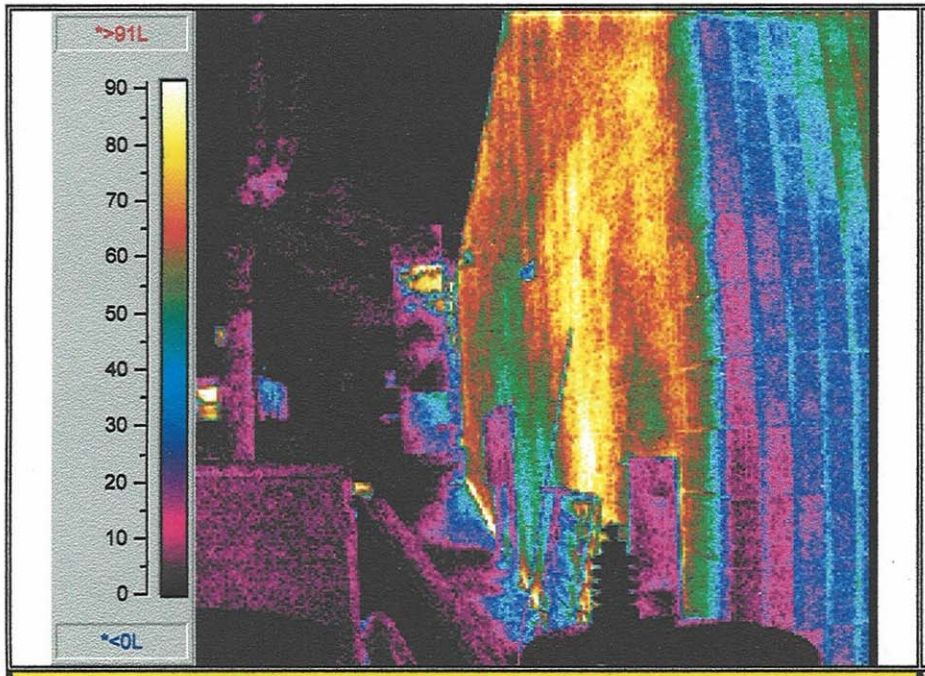
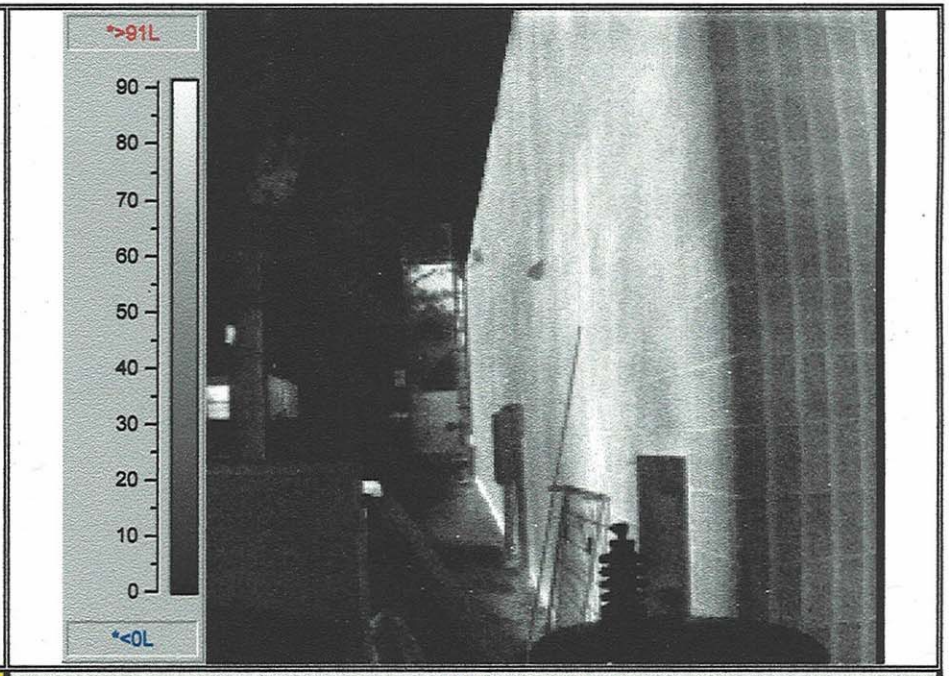
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**South Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**General Image**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-11 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal image of Southeast corner of South face scanned West from back of garage area.

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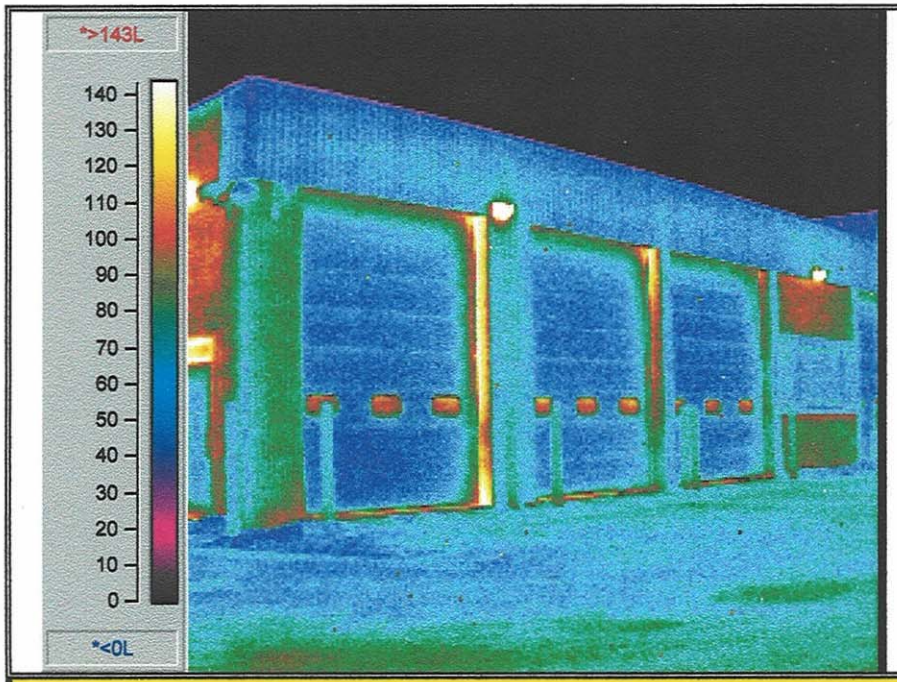
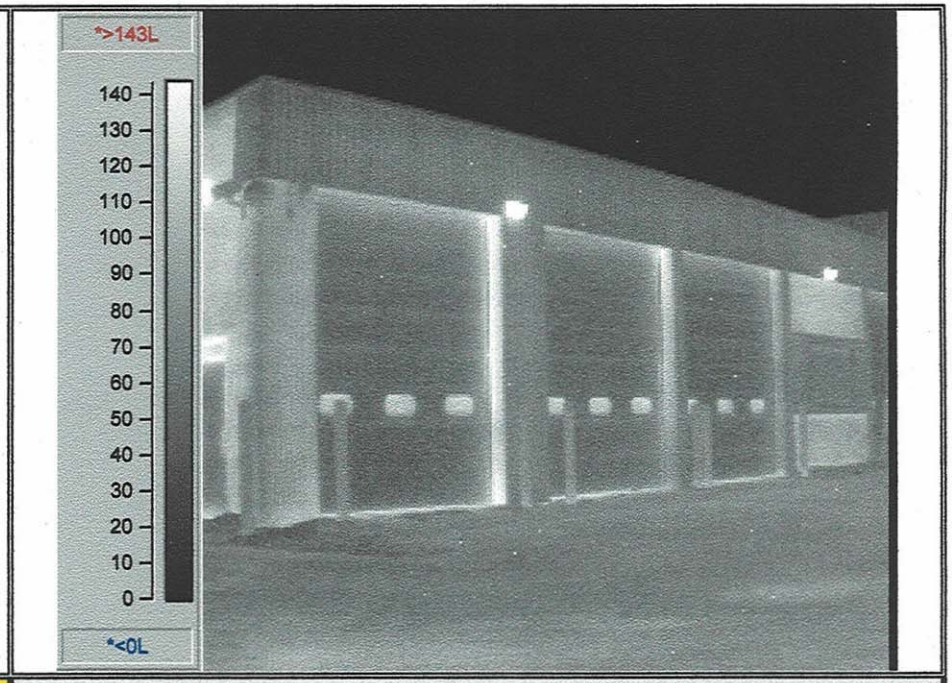
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**North Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**General Image**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-12 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal image of North face, East side, scanning Southwest from vehicle yard area.

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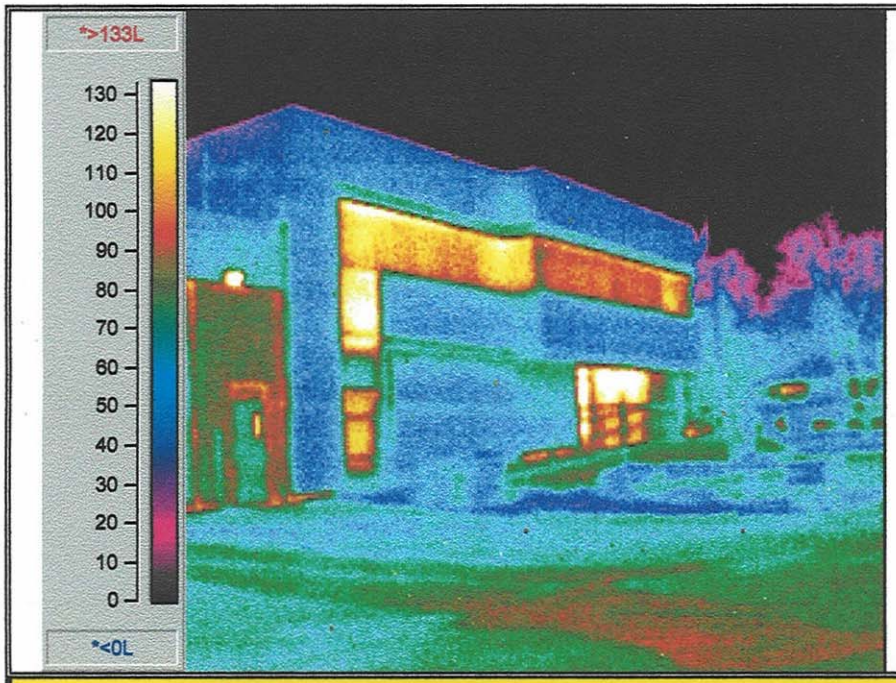
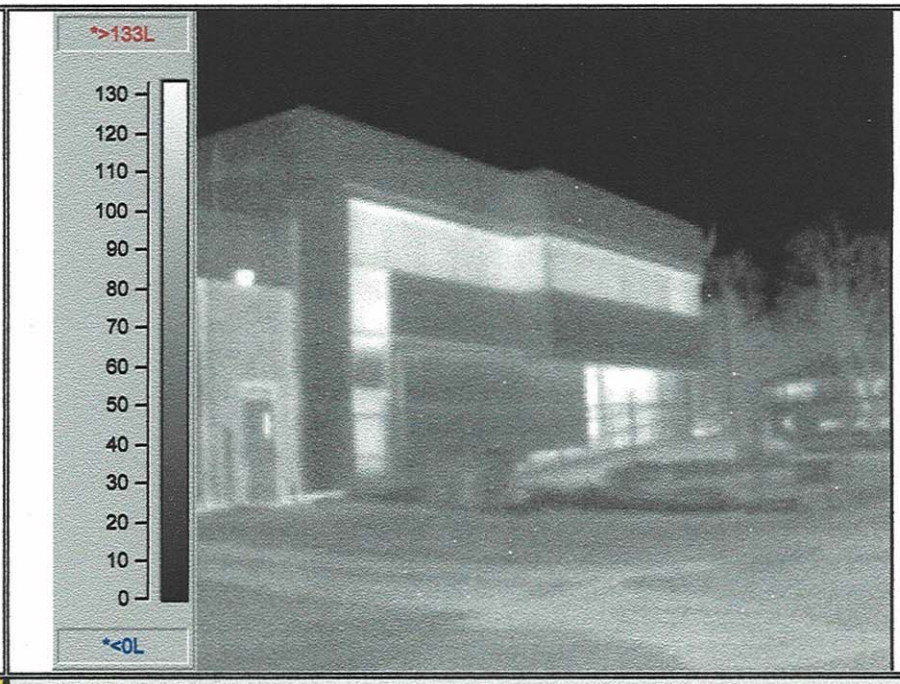
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**North Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Overview**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-13 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal Image of the North face. Scanning Southwest from vehicle yard.

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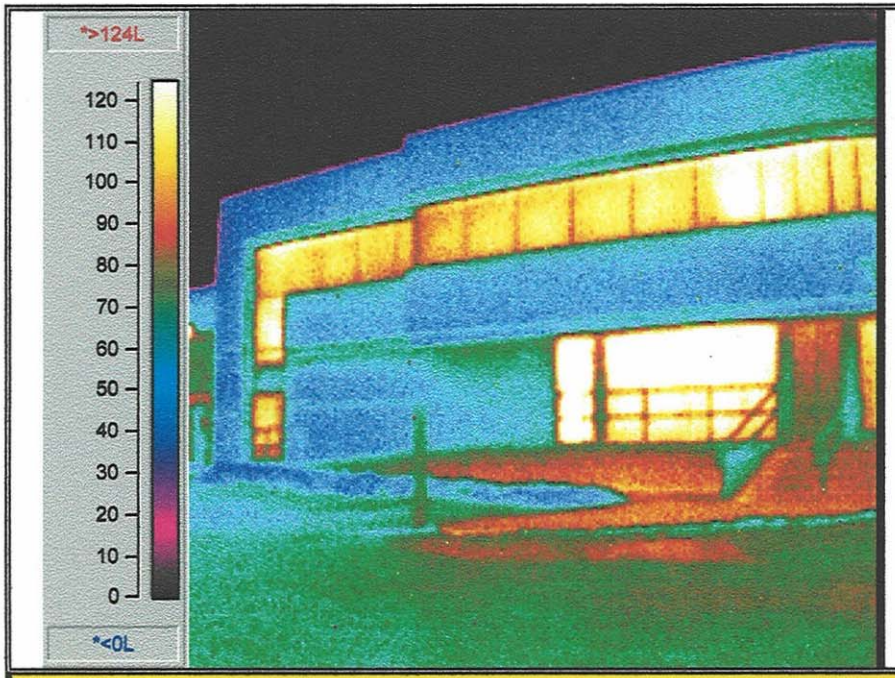
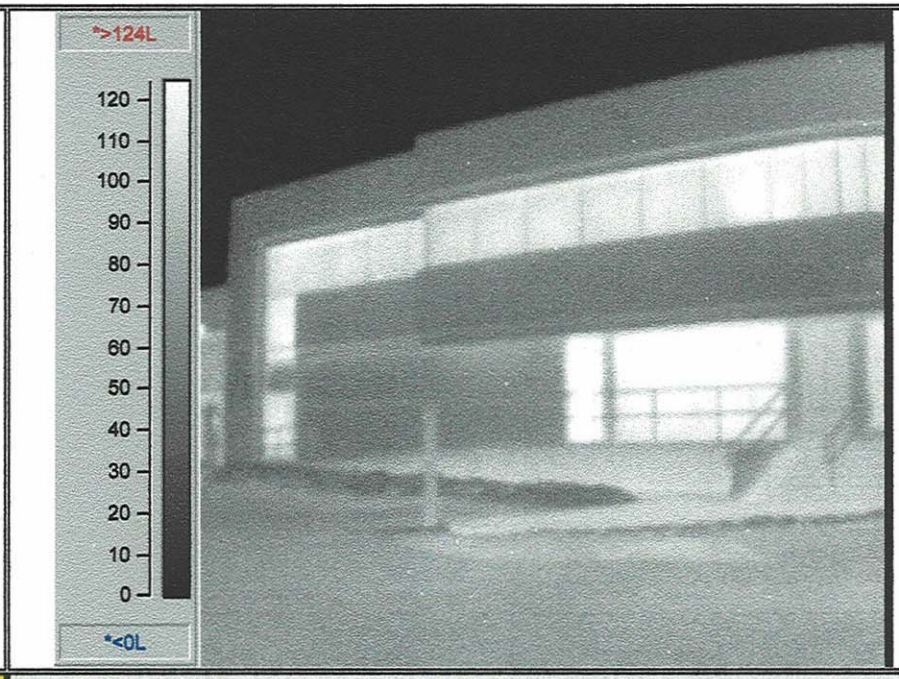
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**North Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Overview**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-14 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal Image of North face of the building. Scanning Southeast from Alice Street.

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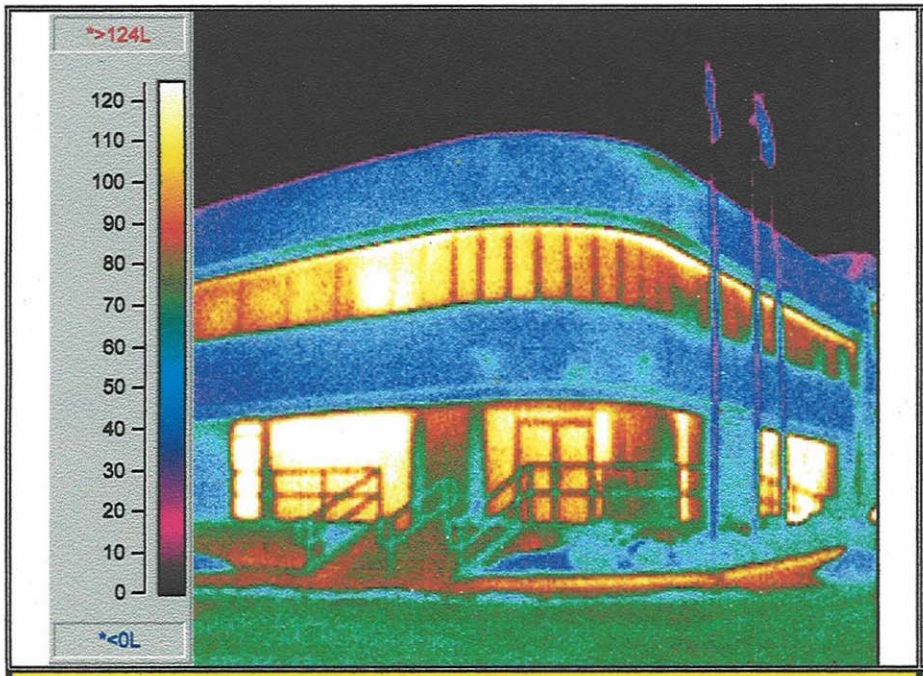
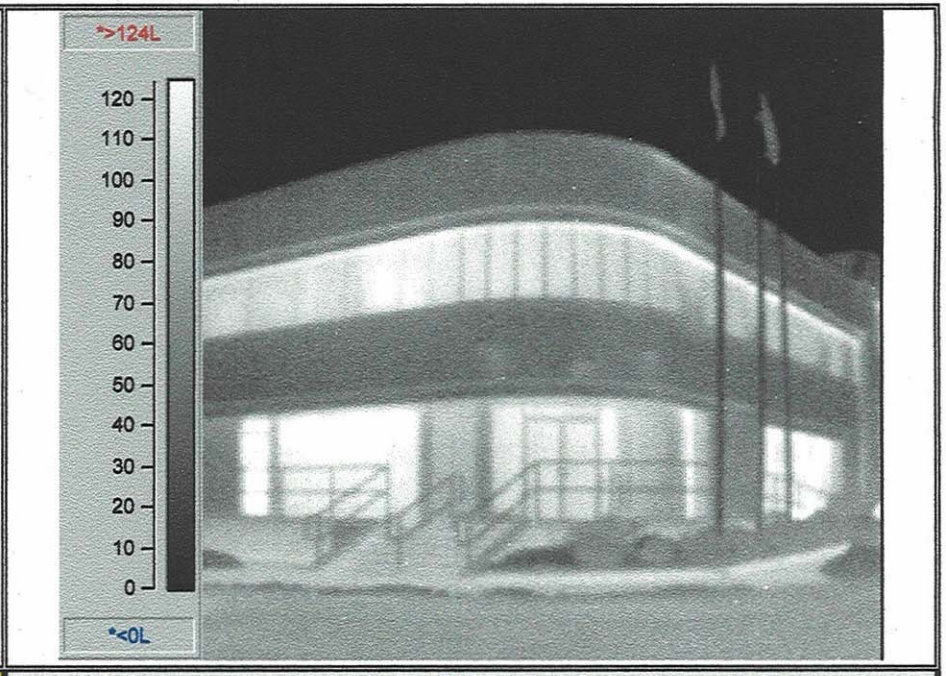
Mississauga, Ontario, L5N 6P9

INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**Northwest Corner**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Overview**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-15 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal Image of the Northwest corner of the building. Scanning Southeast from Alice Street.

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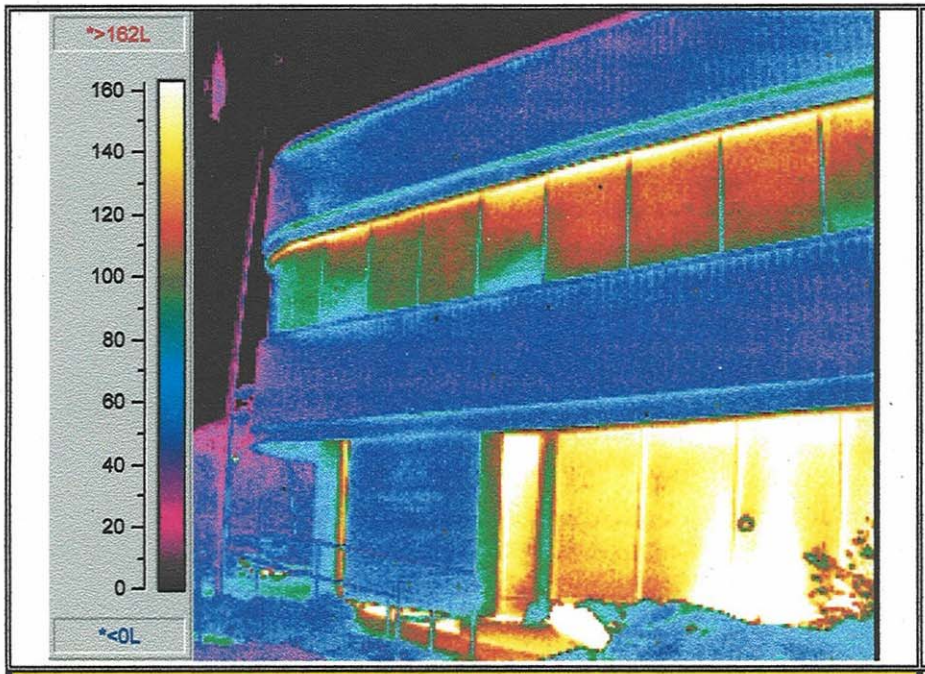
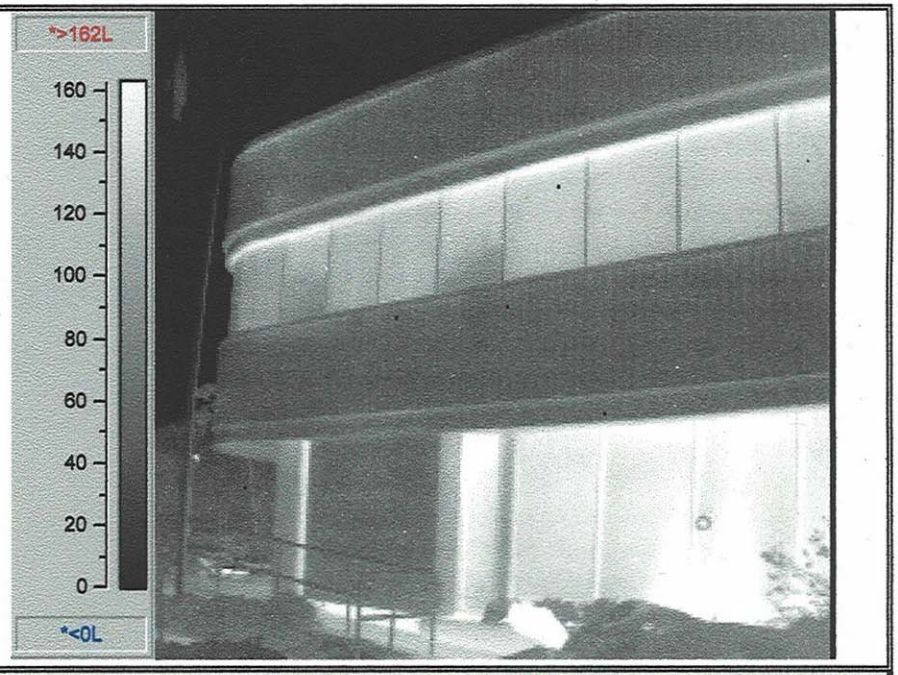
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**West Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Overview**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**A-16 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal Image of the North half of the West face. Scanning Southeast from Alice Street.

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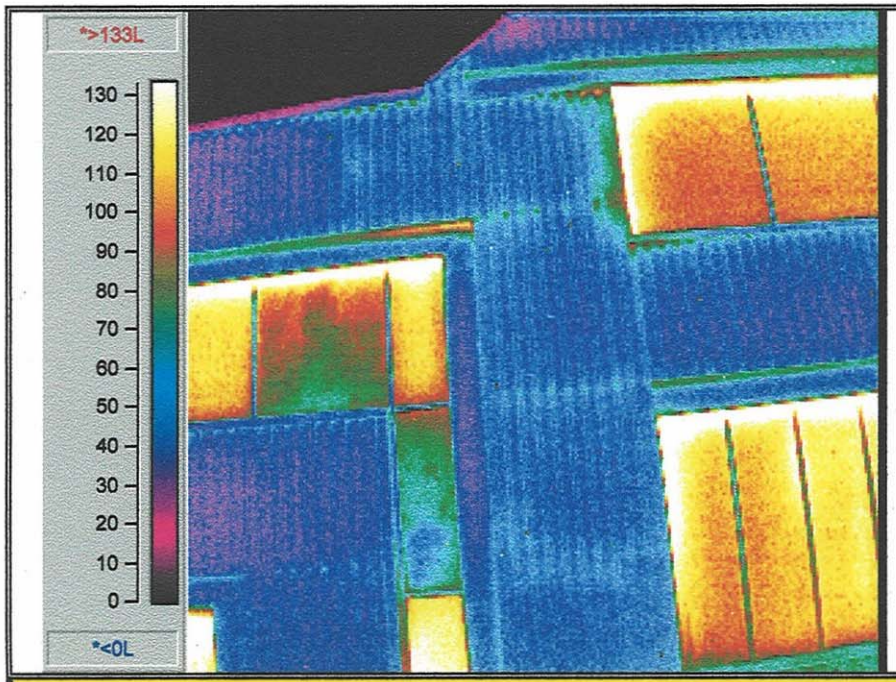
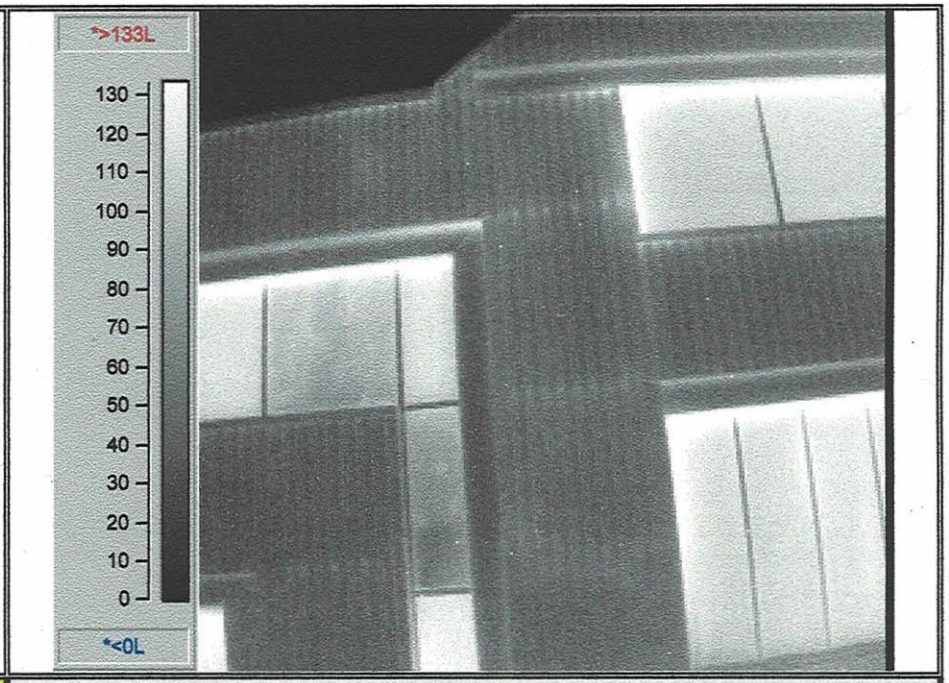
INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**West Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Thermal Anomaly**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**B-01 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

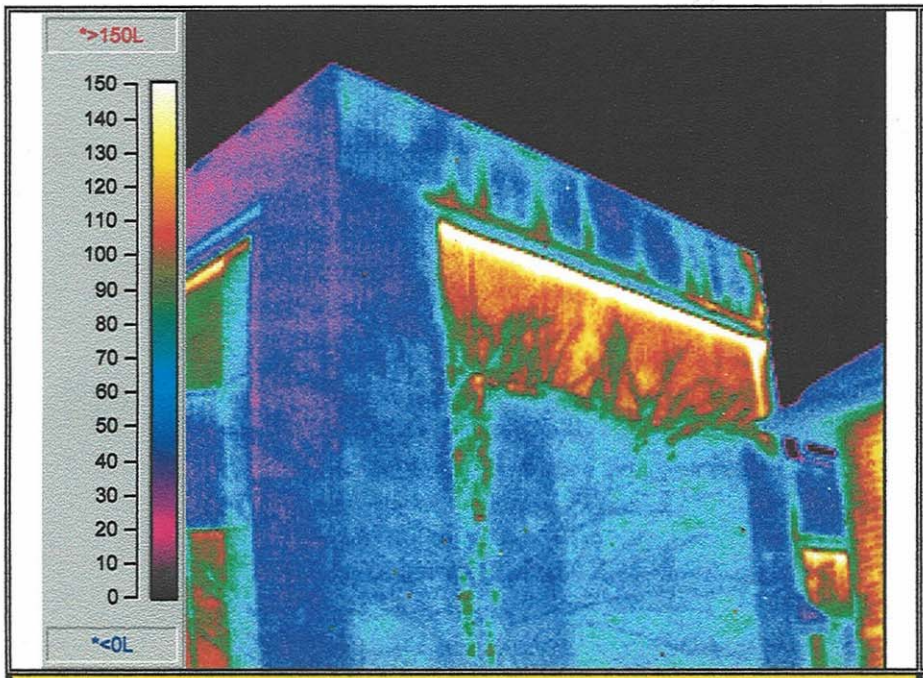
Comments:	
Description of Image	Thermal Image of the upper floor on the South half of the West face. Scanning Eastt from Alice Street.

IRC Building Sciences Group Inc.

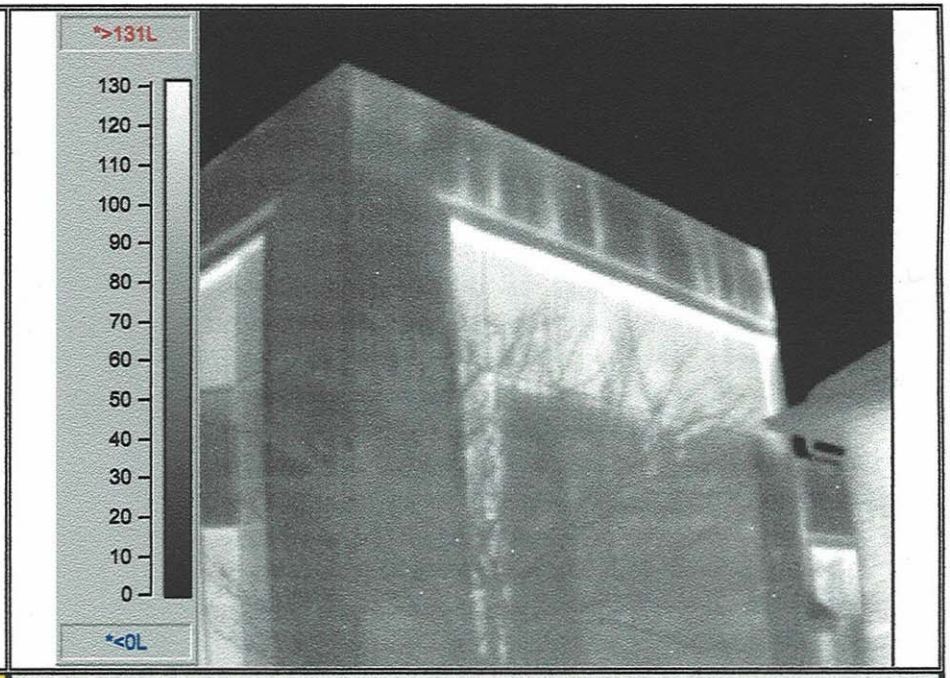
7565 Danbro Crescent
Mississauga, Ontario, L5N 6P9

INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**South Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Thermal Anomaly**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**B-02 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

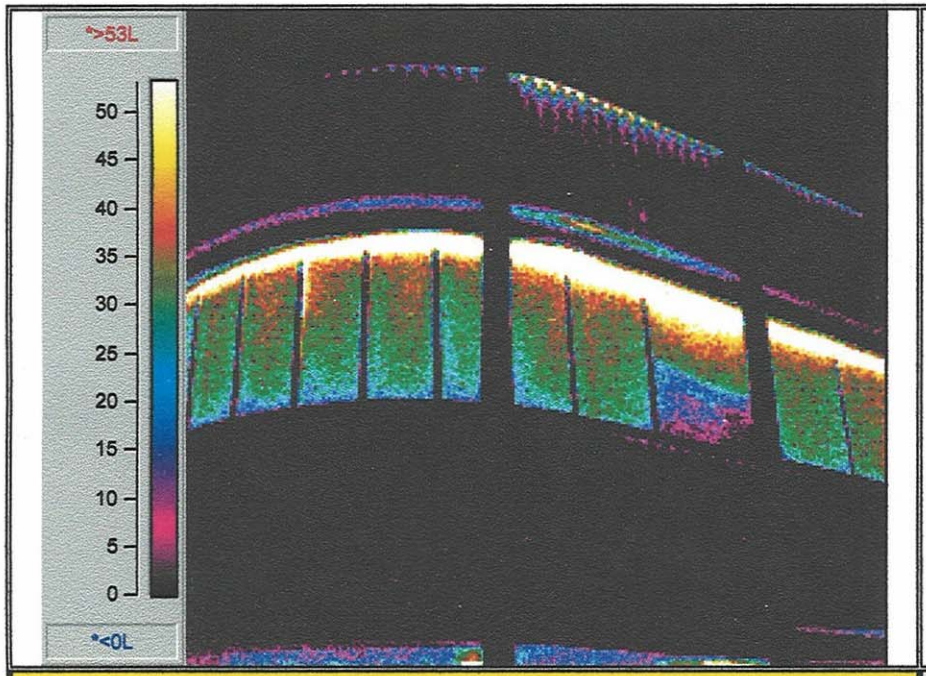
Comments:	
Description of Image	Thermal image of the upper floor of the Southwest corner. Scanning North from Alice Street.

IRC Building Sciences Group Inc.

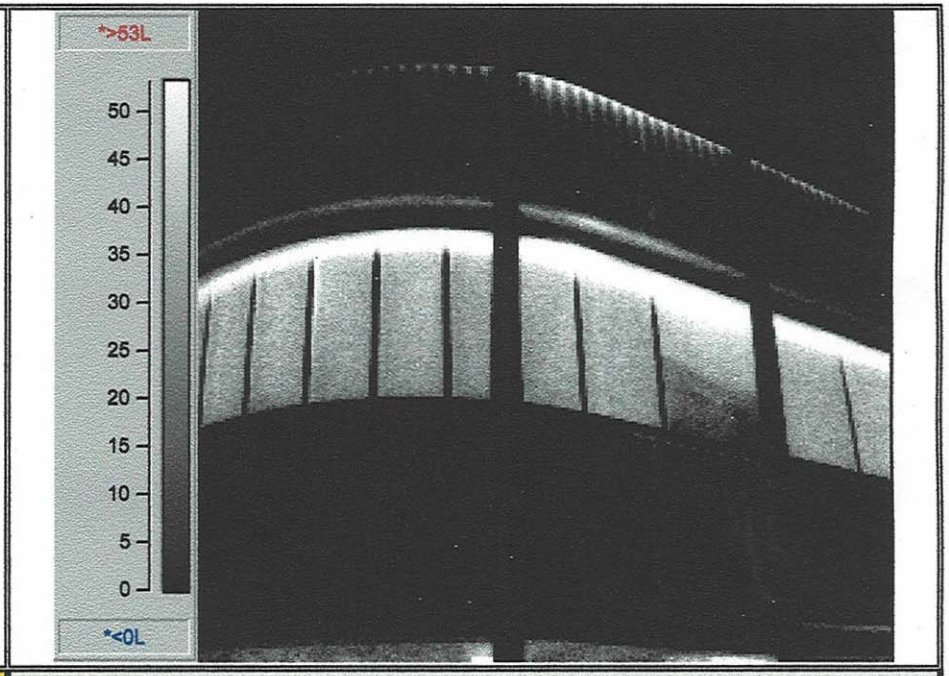
7565 Danbro Crescent
Mississauga, Ontario, L5N 6P9

INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**Northwest Corner**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Thermal Anomaly**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**B-03 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

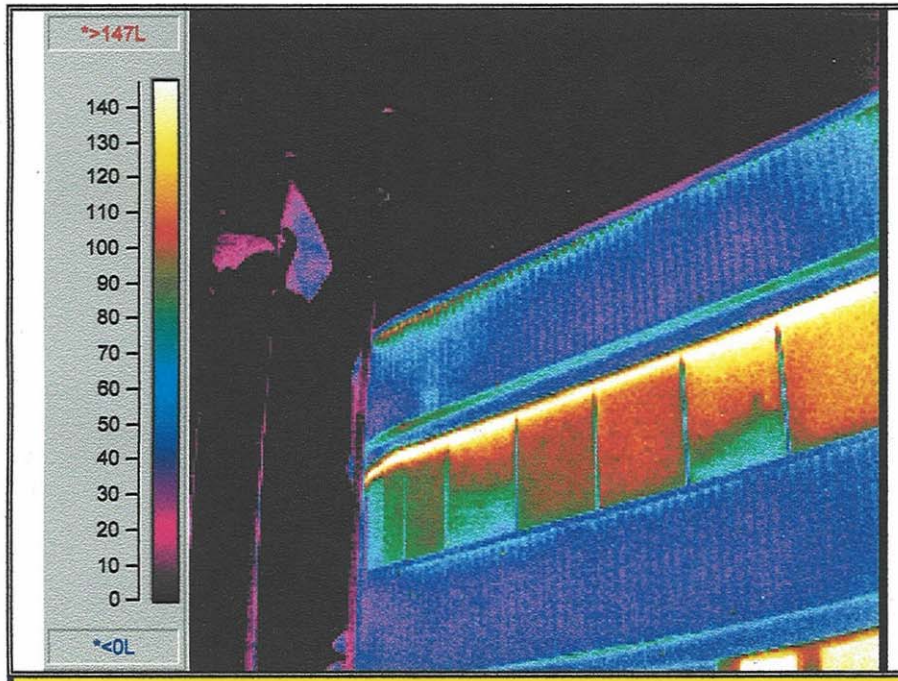
Comments:	Note: close up of area seen in B-04.
Description of Image	Thermal image of the upper floor on the Northwest corner. Scanning Southeast from Alice Street.

IRC Building Sciences Group Inc.

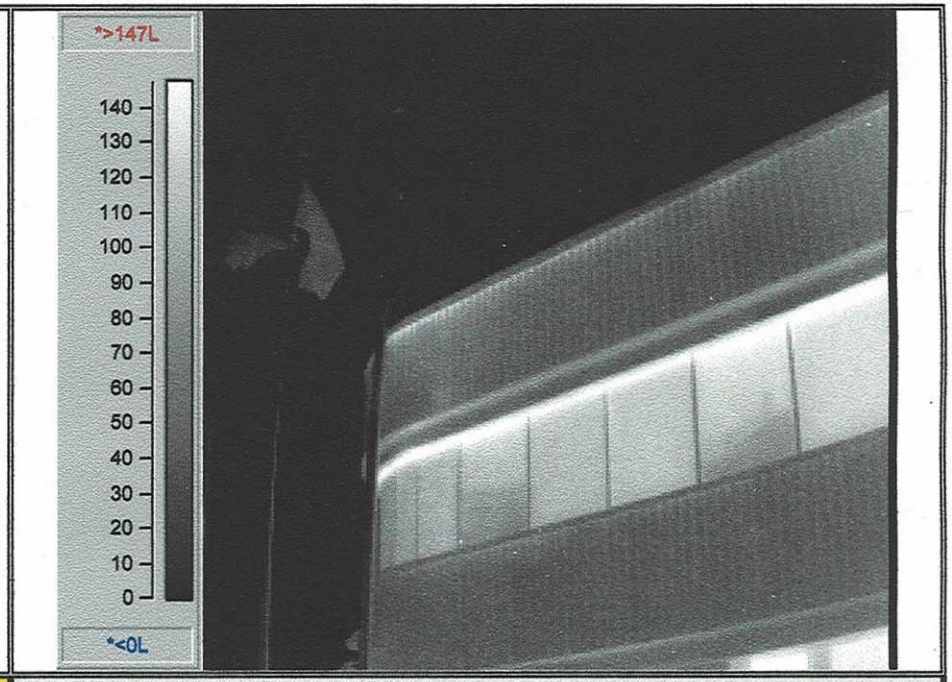
7565 Danbro Crescent
Mississauga, Ontario, L5N 6P9

INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**West Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Thermal Anomaly**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**B-04 (5100-07-001-SC)**



Colour Scale Thermal Image



Grey Scale Thermal Image

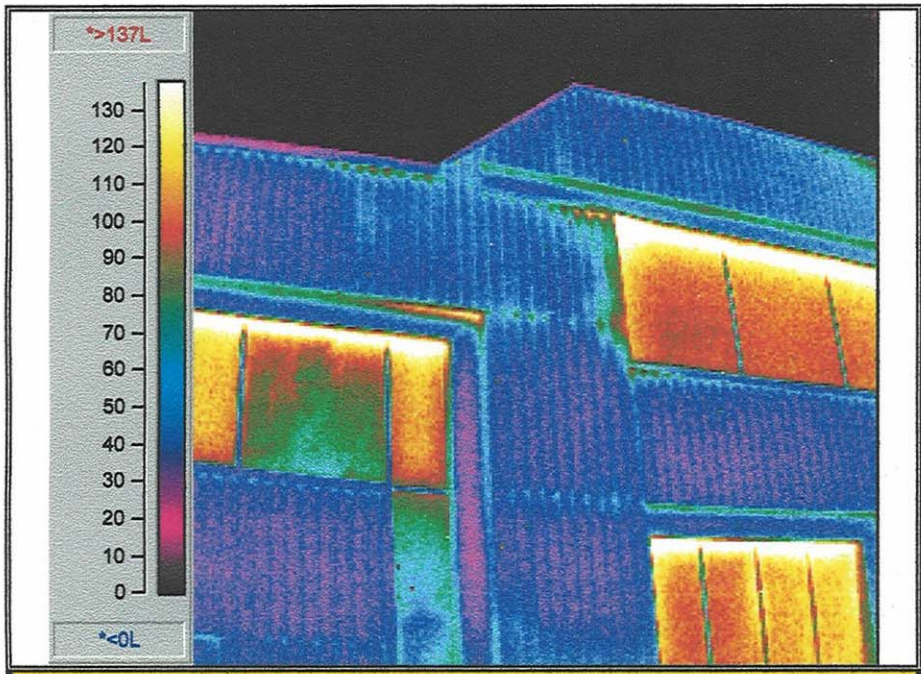
Comments:	
Description of Image	Thermal image of the upper floor on the West face at the Northwest corner. Scanning Northeast from Alice Street.

IRC Building Sciences Group Inc.

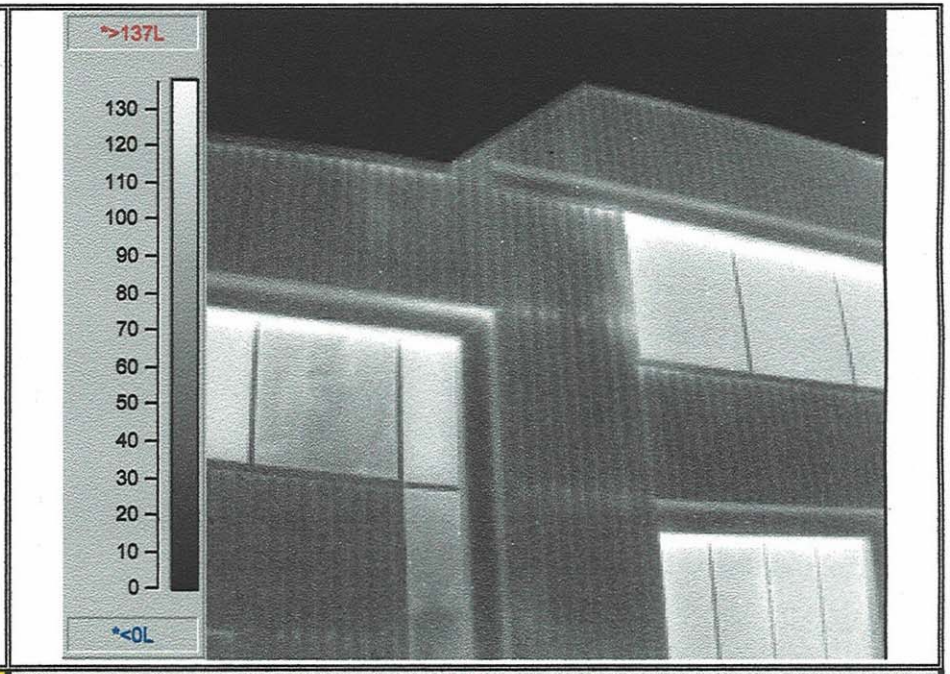
7565 Danbro Crescent
Mississauga, Ontario, L5N 6P9

INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Site Location	**Halton Hills Hydro, Acton, Ontario**	**Wall Scan Location**	**West Face**
Thermographer	William Denison, Certified Level II	**Scan Conditions**	Temperature -4°C / Wind 13 km/h
Date & Time	**Friday February 23, 2007 / Time 20.00**	**Image Type**	**Thermal Anomaly**
Scan Manager	**Walter Murray, IRC**	**Image Reference Number**	**B-05**



Colour Scale Thermal Image



Grey Scale Thermal Image

Comments:	
Description of Image	Thermal Image of the upper floor on the South half of the West face. Scanning Southeast from Alice Street.

Appendix F

Halton Hills Hydro Inc. Code of Conduct

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ADM 001

HALTON HILLS HYDRO INC.
CODE OF CONDUCT

OVERVIEW

- The Code of Conduct serves as a guide to Board Members and staff in the conduct of their duties.
- Directors and staff are to work together for the common good of Halton Hills Hydro Inc.
- When representing Halton Hills Hydro Inc., you need to maintain high standards of personal and professional conduct. You must preserve the trust and confidence placed in you by the Corporation and the community by conducting yourself with integrity, competency and impartiality.
- This Code represents general standards. It clarifies the Hydro's expectations. It does not replace laws or personal ethics.
- The onus is on the individual Director and/or staff member to ensure that they adhere to the Code of Conduct.

CUSTOMER RELATIONS

- All communications shall be handled in a courteous and respectful manner. An objective and impartial attitude shall be maintained in dealing with all citizens as they have a right to present their views.
- Directors and staff should exercise care when communicating with the media on utility matters.

CONFIDENTIAL INFORMATION

- The President shall be designated the Freedom of Information Head.
- Directors and staff have access to confidential information by virtue of their position with Halton Hills Hydro Inc.
- Confidential information must not be disclosed or released, by any means, either in verbal or written form, to any person other than to those who are properly entitled to this information.
- Where a Director is unsure of the status of information, before making any disclosure they shall discuss it with the President.
- Where staff is unsure of the status of information, before making any disclosure they shall discuss it with their Supervisor. The President may also need to be consulted.
- Where a member of the public requests information regarded as confidential by Halton Hills Hydro Inc., they must be referred to the President, who will advise them of the formal procedures in accordance with The Municipal Freedom of Information and Protection of Privacy Act.

CONFLICT OF INTEREST

- A conflict of interest exists where the civic objectives of a Director or member of staff are in conflict with their private goals.
- Directors and staff shall not:

a) engage in any business transactions or have financial or other personal interests which are inconsistent with the impartial discharge of their Board/Corporation objectives.
b) Place themselves in a position where they are under obligation to any person who might benefit from special consideration or favour on their part.
c) Deal with any application, agreement, or contract with Halton Hills Hydro Inc. for any loan, grant, award, land matter or other benefit in which they, their relatives, affiliated organizations or their employer have a pecuniary interest.
d) Gain personal benefit, directly or indirectly, from any knowledge about hydro-related matters.
e) Disclose or release, by any means, confidential information which they have acquired by virtue of their position with the utility for personal or private gain, or for the gain of their relatives, affiliated organizations or their employer.

- When a conflict of interest exists, Directors and staff must withdraw from direct involvement and refrain from any comment on the issue which might influence the decision.
- Directors must publicly declare their direct or indirect pecuniary interest. They must refrain from influencing and discussing this matter with their colleagues. They are not eligible to vote on this matter. If this issue is a confidential matter, they should also retire from the meeting.
- Staff should consult their respective Supervisor if they have or sense a possible conflict.

GIFTS AND HOSPITALITY

- In order to preserve the image and integrity of Halton Hills Hydro Inc., business gifts should be discouraged. The Directors recognize that moderate hospitality is an accepted courtesy of a business relationship. However, Directors and staff should not accept any gifts or hospitality which could create, or be seen to create, any obligation or special consideration to an individual or business.
- There shall be no solicitation of gifts or acts of hospitality in recognition of the fulfillment of Board duties.
- When in doubt of what is acceptable in terms of gifts or hospitality, the offer should be declined.
- If the refusal of any gift or act of hospitality will strain the Hydro's business relationship, the Chairman or President may accept it on behalf of the Board of Directors with the appropriate acknowledgement.

BOARD RESOURCES

- Unless otherwise approved by the respective Supervisor, Directors and staff shall only use hydro property, facilities, equipment, supplies and services, or other property, for activities associated with the discharge of their hydro duties.
- Directors and staff shall not utilize the Hydro's purchasing activities for the acquisition of personal goods or services.

ENFORCEMENT

- The provisions of The Municipal Act, The Municipal Conflict of Interest Act and, The Municipal Elections Act apply to instances of improper conduct of officials.
- The President and all Supervisors shall ensure that all employees are aware of this Code of Conduct, and to the best of their ability, that it is followed by all staff.
- Any member of staff who has direct knowledge of a breach of the Code of Conduct shall approach the President in confidence.
- Where it is determined that a member of staff has committed a breach of the Code of Conduct, disciplinary action shall be taken in accordance with the relevant disciplinary procedures.

- Where it is determined that a Board member has committed a breach of the Code of Conduct, disciplinary action may be taken by the appointed authority.

INTERPRETATION

- If any clarification is required on the Code of Conduct of Halton Hills Hydro Inc., Directors are requested to consult with the President.

Staff may wish to seek clarification about the Code of Conduct from their respective Supervisor. The Chairman and the President are also available for consultation.

_____

President

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Appendix G

Weather Conversion Data from the IESO

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Table 2.2 - Actual and Weather Corrected Weekly Energy Demand

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
5-May-02	2,701	2,653	-47	18	
12-May-02	2,670	2,632	-38	19	
19-May-02	2,680	2,585	-95	20	
26-May-02	2,598	2,571	-27	21	Victoria Day
2-Jun-02	2,746	2,703	-43	22	
9-Jun-02	2,686	2,675	-11	23	
16-Jun-02	2,784	2,852	68	24	
23-Jun-02	2,890	2,811	-79	25	
30-Jun-02	3,113	2,944	-169	26	
7-Jul-02	3,189	2,904	-285	27	Canada Day
14-Jul-02	2,998	2,991	-8	28	
21-Jul-02	3,269	3,174	-95	29	
28-Jul-02	3,079	3,031	-48	30	
4-Aug-02	3,348	3,048	-300	31	
11-Aug-02	2,946	2,944	-2	32	Civic Holiday
18-Aug-02	3,438	3,117	-321	33	
25-Aug-02	2,949	2,940	-10	34	
1-Sep-02	2,952	2,924	-28	35	
8-Sep-02	3,017	2,826	-191	36	Labour Day
15-Sep-02	3,050	2,869	-181	37	All-Time September Peak
22-Sep-02	2,986	2,830	-156	38	
29-Sep-02	2,742	2,749	7	39	
6-Oct-02	2,812	2,776	-36	40	All-Time October Peak
13-Oct-02	2,715	2,757	42	41	
20-Oct-02	2,725	2,671	-55	42	Thanksgiving
27-Oct-02	2,856	2,784	-72	43	
3-Nov-02	2,921	2,769	-152	44	
10-Nov-02	2,898	2,903	5	45	
17-Nov-02	2,935	2,925	-10	46	Rememberance Day
24-Nov-02	2,960	2,979	19	47	
1-Dec-02	3,066	2,980	-86	48	
8-Dec-02	3,219	3,133	-86	49	
15-Dec-02	3,142	3,185	43	50	
22-Dec-02	3,128	3,137	9	51	
29-Dec-02	2,768	2,796	28	52	Christmas & Boxing Day
	102,974	100,568	97.66%		

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
5-Jan-03	2,911	2,952	41	1	New Years Day
12-Jan-03	3,163	3,174	11	2	
19-Jan-03	3,338	3,261	-78	3	
26-Jan-03	3,435	3,275	-160	4	
2-Feb-03	3,270	3,268	-2	5	
9-Feb-03	3,250	3,251	1	6	
16-Feb-03	3,437	3,210	-227	7	All-Time February Peak
23-Feb-03	3,207	3,193	-15	8	
2-Mar-03	3,254	3,136	-118	9	
9-Mar-03	3,249	3,090	-159	10	All-Time March Peak
16-Mar-03	3,113	3,038	-75	11	
23-Mar-03	2,907	3,020	113	12	
30-Mar-03	2,851	2,904	53	13	
6-Apr-03	3,058	2,904	-153	14	All-Time April Peak
13-Apr-03	2,903	2,834	-69	15	
20-Apr-03	2,688	2,716	28	16	Good Friday
27-Apr-03	2,718	2,687	-31	17	Easter Monday
4-May-03	2,656	2,683	27	18	
11-May-03	2,659	2,705	45	19	
18-May-03	2,625	2,641	17	20	
25-May-03	2,562	2,571	9	21	Victoria Day
1-Jun-03	2,638	2,666	29	22	
8-Jun-03	2,654	2,670	16	23	
15-Jun-03	2,676	2,730	54	24	
22-Jun-03	2,749	2,794	45	25	
29-Jun-03	3,088	2,870	-218	26	
6-Jul-03	2,993	2,814	-179	27	Canada Day
13-Jul-03	2,846	2,878	32	28	
20-Jul-03	2,843	2,980	137	29	
27-Jul-03	2,883	2,882	-1	30	
3-Aug-03	2,893	2,886	-7	31	
10-Aug-03	3,015	2,862	-153	32	Civic Holiday
17-Aug-03	2,723	2,605	-118	33	Blackout
24-Aug-03	2,749	2,625	-124	34	Conservation Appeals
31-Aug-03	2,845	2,829	-17	35	
7-Sep-03	2,689	2,722	33	36	Labour Day
14-Sep-03	2,868	2,762	-107	37	

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
21-Sep-03	2,772	2,772	1	38	
28-Sep-03	2,679	2,698	19	39	
5-Oct-03	2,731	2,661	-71	40	
12-Oct-03	2,695	2,737	42	41	
19-Oct-03	2,667	2,655	-12	42	Thanksgiving
26-Oct-03	2,794	2,766	-28	43	
2-Nov-03	2,796	2,829	33	44	
9-Nov-03	2,891	2,833	-59	45	
16-Nov-03	2,918	2,932	14	46	Rememberance Day
23-Nov-03	2,871	3,035	165	47	
30-Nov-03	2,973	3,021	48	48	
7-Dec-03	3,146	3,120	-26	49	
14-Dec-03	3,162	3,150	-12	50	
21-Dec-03	3,135	3,138	3	51	
28-Dec-03	2,703	2,873	170	52	Christmas & Boxing Day
	151,341	150,310	99.32%		
4-Jan-04	2,707	2,886	178	1	New Years Day
11-Jan-04	3,369	3,217	-152	2	
18-Jan-04	3,445	3,331	-113	3	All-Time January Peak
25-Jan-04	3,446	3,285	-161	4	
1-Feb-04	3,419	3,309	-110	5	
8-Feb-04	3,239	3,271	32	6	
15-Feb-04	3,215	3,203	-13	7	
22-Feb-04	3,158	3,157	-1	8	
29-Feb-04	3,039	3,126	87	9	
7-Mar-04	2,961	3,107	147	10	
14-Mar-04	3,027	3,027	0	11	
21-Mar-04	3,069	2,982	-88	12	
28-Mar-04	2,921	2,940	18	13	
4-Apr-04	2,847	2,871	24	14	
11-Apr-04	2,746	2,675	-71	15	Good Friday
18-Apr-04	2,741	2,754	13	16	Easter Monday
25-Apr-04	2,692	2,706	14	17	
2-May-04	2,726	2,719	-7	18	
9-May-04	2,706	2,659	-47	19	
16-May-04	2,746	2,704	-42	20	All-Time May Peak
23-May-04	2,670	2,678	8	21	

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
30-May-04	2,607	2,648	41	22	Victoria Day
6-Jun-04	2,661	2,691	30	23	
13-Jun-04	2,893	2,821	-72	24	
20-Jun-04	2,894	2,877	-17	25	
27-Jun-04	2,774	2,926	152	26	
4-Jul-04	2,757	2,827	69	27	Canada Day
11-Jul-04	2,792	2,831	39	28	
18-Jul-04	2,913	2,936	23	29	
25-Jul-04	2,983	2,988	4	30	
1-Aug-04	2,933	2,955	22	31	
8-Aug-04	2,843	2,884	40	32	Civic Holiday
15-Aug-04	2,828	2,947	119	33	
22-Aug-04	2,809	2,853	44	34	
29-Aug-04	3,029	2,932	-97	35	
5-Sep-04	2,949	2,874	-75	36	
12-Sep-04	2,847	2,805	-42	37	
19-Sep-04	2,878	2,809	-68	38	
26-Sep-04	2,893	2,812	-81	39	
3-Oct-04	2,780	2,835	55	40	
10-Oct-04	2,745	2,784	39	41	
17-Oct-04	2,716	2,752	35	42	Thanksgiving
24-Oct-04	2,826	2,844	18	43	
31-Oct-04	2,796	2,900	104	44	
7-Nov-04	2,859	2,888	29	45	
14-Nov-04	2,964	2,942	-21	46	Rememberance Day
21-Nov-04	2,885	3,044	159	47	
28-Nov-04	3,005	3,055	50	48	
5-Dec-04	3,096	3,170	74	49	
12-Dec-04	3,170	3,217	47	50	
19-Dec-04	3,258	3,169	-88	51	
26-Dec-04	3,229	3,084	-146	52	All-Time Winter Peak, Christmas & Boxing Day
	152,501	152,703	100.13%		
2-Jan-05	2,906	3,008	103	53	New Years Day
9-Jan-05	3,186	3,226	39	1	
16-Jan-05	3,215	3,294	79	2	
23-Jan-05	3,529	3,334	-195	3	All-Time Weekend Peak

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
30-Jan-05	3,422	3,338	-85	4	
6-Feb-05	3,164	3,302	139	5	
13-Feb-05	3,140	3,248	107	6	
20-Feb-05	3,213	3,236	23	7	
27-Feb-05	3,226	3,146	-81	8	
6-Mar-05	3,169	3,156	-13	9	
13-Mar-05	3,206	3,117	-89	10	
20-Mar-05	3,041	3,032	-9	11	Good Friday
27-Mar-05	2,884	2,907	24	12	Easter Monday
3-Apr-05	2,869	2,919	50	13	
10-Apr-05	2,772	2,899	128	14	5% Voltage Reduction April 7
17-Apr-05	2,706	2,774	68	15	
24-Apr-05	2,738	2,766	28	16	
1-May-05	2,756	2,694	-62	17	
8-May-05	2,662	2,648	-14	18	
15-May-05	2,676	2,674	-2	19	
22-May-05	2,637	2,648	11	20	
29-May-05	2,617	2,633	16	21	Victoria Day
5-Jun-05	2,827	2,744	-84	22	
12-Jun-05	3,348	2,935	-413	23	
19-Jun-05	2,964	2,874	-90	24	
26-Jun-05	3,090	2,964	-126	25	Power Warning June 24
3-Jul-05	3,207	2,996	-211	26	Power Warning June 28-29, Canada Day
10-Jul-05	3,050	2,943	-107	27	
17-Jul-05	3,486	3,120	-366	28	All-Time Peak Demand
24-Jul-05	3,353	3,193	-160	29	Power Warning July 18-21
31-Jul-05	3,069	3,070	0	30	
7-Aug-05	3,312	3,090	-223	31	Power Warning & 5% Voltage Reduction August 3-4
14-Aug-05	3,309	3,117	-192	32	Power Warning August 9-10
21-Aug-05	3,051	3,042	-8	33	
28-Aug-05	2,968	2,946	-22	34	
4-Sep-05	3,016	2,988	-28	35	
11-Sep-05	2,901	2,872	-29	36	Labour Day
18-Sep-05	3,058	2,888	-170	37	
25-Sep-05	2,916	2,847	-68	38	
2-Oct-05	2,772	2,774	2	39	
9-Oct-05	2,805	2,726	-80	40	All-Time October peak
16-Oct-05	2,660	2,699	39	41	Thanksgiving

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
23-Oct-05	2,757	2,745	-13	42	
30-Oct-05	2,838	2,817	-21	43	
6-Nov-05	2,780	2,894	114	44	
13-Nov-05	2,809	2,859	50	45	Rememberance Day
20-Nov-05	2,910	2,903	-7	46	
27-Nov-05	3,061	2,936	-125	47	All-Time November peak
4-Dec-05	3,020	3,017	-4	48	
11-Dec-05	3,205	3,145	-60	49	
18-Dec-05	3,287	3,171	-116	50	
25-Dec-05	3,107	3,096	-11	51	Christmas Day
	156,671	154,408	98.56%		
1-Jan-06	2,801	2,846	45	52	Boxing Day & New Year's Day
8-Jan-06	3,064	3,138	74	1	
15-Jan-06	3,051	3,222	171	2	
22-Jan-06	3,136	3,306	170	3	
29-Jan-06	3,080	3,259	179	4	
5-Feb-06	3,002	3,200	199	5	
12-Feb-06	3,173	3,167	-6	6	
19-Feb-06	3,183	3,177	-6	7	
26-Feb-06	3,138	3,124	-14	8	
5-Mar-06	3,166	3,121	-45	9	
12-Mar-06	2,959	3,087	129	10	
19-Mar-06	2,996	2,975	-21	11	
26-Mar-06	2,973	2,955	-17	12	
2-Apr-06	2,785	2,888	103	13	
9-Apr-06	2,839	2,899	60	14	
16-Apr-06	2,619	2,666	47	15	Good Friday
23-Apr-06	2,652	2,702	49	16	Easter Monday
30-Apr-06	2,675	2,726	51	17	
7-May-06	2,605	2,594	-11	18	
14-May-06	2,625	2,649	23	19	
21-May-06	2,604	2,612	8	20	Victoria Day
28-May-06	2,630	2,656	25	21	
4-Jun-06	3,032	2,881	-151	22	
11-Jun-06	2,792	2,774	-18	23	
18-Jun-06	2,959	2,951	-8	24	

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
25-Jun-06	3,024	3,003	-21	25	
2-Jul-06	2,981	2,939	-42	26	
9-Jul-06	2,901	2,803	-98	27	Canada Day
16-Jul-06	3,156	3,023	-134	28	
23-Jul-06	3,190	3,086	-105	29	
30-Jul-06	3,303	3,186	-117	30	
6-Aug-06	3,372	3,265	-107	31	Peak Demand record set
13-Aug-06	2,892	2,907	15	32	Civic Holiday
20-Aug-06	2,991	2,998	8	33	
27-Aug-06	2,892	2,900	8	34	
3-Sep-06	2,773	2,811	38	35	
10-Sep-06	2,694	2,736	43	36	Labour Day
17-Sep-06	2,718	2,743	25	37	
24-Sep-06	2,700	2,737	36	38	
1-Oct-06	2,663	2,665	2	39	
8-Oct-06	2,649	2,657	8	40	
15-Oct-06	2,639	2,615	-24	41	Thanksgiving
22-Oct-06	2,718	2,685	-33	42	
29-Oct-06	2,798	2,777	-20	43	
5-Nov-06	2,824	2,852	28	44	
12-Nov-06	2,785	2,847	62	45	
19-Nov-06	2,843	2,890	47	46	
26-Nov-06	2,865	2,911	46	47	
3-Dec-06	2,921	3,008	86	48	
10-Dec-06	3,122	3,227	105	49	
17-Dec-06	2,945	3,036	91	50	
24-Dec-06	2,899	3,001	101	51	
31-Dec-06	2,671	2,768	97	52	Christmas & Boxing Day
	153,470	154,651	100.77%		
7-Jan-07	2,783	2,913	131	1	New Years Day
14-Jan-07	3,047	3,112	65	2	
21-Jan-07	3,212	3,262	50	3	
28-Jan-07	3,260	3,302	42	4	
4-Feb-07	3,289	3,252	-37	5	
11-Feb-07	3,347	3,248	-100	6	
18-Feb-07	3,341	3,238	-103	7	Winter Peak Demand

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
25-Feb-07	3,162	3,071	-91	8	
4-Mar-07	3,075	3,036	-40	9	
11-Mar-07	3,174	3,133	-41	10	
18-Mar-07	2,950	2,972	22	11	
25-Mar-07	2,947	2,954	6	12	
1-Apr-07	2,769	2,813	44	13	
8-Apr-07	2,839	2,764	-75	14	Good Friday
15-Apr-07	2,891	2,838	-53	15	Easter Monday
22-Apr-07	2,695	2,716	21	16	
29-Apr-07	2,651	2,677	26	17	
6-May-07	2,591	2,576	-15	18	
13-May-07	2,615	2,618	3	19	
20-May-07	2,620	2,621	1	20	
27-May-07	2,696	2,693	-3	21	
3-Jun-07	2,932	2,860	-72	22	
10-Jun-07	2,745	2,713	-32	23	
17-Jun-07	3,065	2,942	-123	24	
24-Jun-07	2,890	2,834	-56	25	
1-Jul-07	3,070	3,018	-52	26	
8-Jul-07	2,778	2,826	48	27	Canada Day
15-Jul-07	2,919	2,947	28	28	
22-Jul-07	2,837	2,886	49	29	
29-Jul-07	3,014	3,050	37	30	
5-Aug-07	3,293	3,238	-54	31	
12-Aug-07	3,091	2,983	-108	32	Civic Holiday
19-Aug-07	2,880	2,838	-43	33	
26-Aug-07	2,934	2,863	-71	34	
2-Sep-07	2,936	2,888	-49	35	
9-Sep-07	2,956	2,879	-77	33	Labour Day
16-Sep-07	2,693	2,695	2	34	
23-Sep-07	2,762	2,728	-34	35	
30-Sep-07	2,789	2,746	-43	36	
7-Oct-07	2,748	2,834	87	34	
14-Oct-07	2,652	2,699	47	35	Thanksgiving Day
21-Oct-07	2,656	2,689	33	36	
28-Oct-07	2,666	2,686	21	37	
4-Nov-07	2,693	2,684	-8	35	
11-Nov-07	2,821	2,797	-24	36	

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
18-Nov-07	2,831	2,811	-20	37	
25-Nov-07	2,967	2,944	-23	38	
	136,572	135,888	99.50%		

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Appendix H

Updated Schedules for Round 2 OEB Staff Interrogatory #27

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REVISED APPENDIX H

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	HALTON HILLS HYDRO INC.	**LICENCE NUMBER**	ED-2002-0552
NAME OF CONTACT	ARTHUR SKIDMORE	**DOCID NUMBER**	EB-2007-0696
E-mail Address	askidmore@haltonhillshydro.com		
VERSION NUMBER	v3.0	**PHONE NUMBER**	519-853-3700
Date	13-Nov-07	**(extension)**	ext 225

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

			2005								2006							
Account Description		**Account Number**	**Opening Principal Amounts as of Jan-1-05** [1]	**Transactions (additions) during 2005, excluding interest and adjustments** [4]	**Transactions (reductions) during 2005, excluding interest and adjustments** [4]	**Adjustments during 2005 - instructed by Board** [2]	**Adjustments during 2005 - other** [3]	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**	**Opening Principal Amounts as of Jan-1-06**	**Transactions (additions) during 2006, excluding interest and adjustments** [4]	**Transactions (reductions) during 2006, excluding interest and adjustments** [4]	**Adjustments during 2006 - instructed by Board** [2]	**Adjustments during 2006 - other** [3]	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Principal Balance as of Dec-31-06**	**Opening Interest Amounts as of Jan-1-06**
RSVA - Wholesale Market Service Charge		1580	$ 140,097	$ 799,639				$ 939,736	$ 41,280	$ 31,904	$ 73,184	$ 939,736	$ (573,941)				$ (169,333)	$ 196,462	$ 73,184
RSVA - One-time Wholesale Market Service		1582	$ 56,885	$ 28,000				$ 84,885	$ 3,715	$ 5,192	$ 8,907	$ 84,885	$ 22,591				$ (59,015)	$ 48,461	$ 8,907
RSVA - Retail Transmission Network Charge		1584	$ 849,912	$ (99,554)				$ 750,358	$ 50,853	$ 35,729	$ 86,582	$ 750,358	$ (146,740)				$ (567,993)	$ 35,625	$ 86,582
RSVA - Retail Transmission Connection Charge		1586	$ 411,478	$ 347,113				$ 758,591	$ 30,297	$ 32,681	$ 62,978	$ 758,591	$ (166,240)				$ (1,140,363)	$ (548,012)	$ 62,978
	Sub-Totals		$ 1,458,372	$ 1,075,198		$ -	$ -	$ 2,533,570	$ 126,145	$ 105,506	$ 231,651	$ 2,533,570	$ (864,330)		$ -	$ -	$ (1,936,704)	$ (267,464)	$ 231,651
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	$ -	$ 75,121	$ -			$ 75,121	$ -	$ 5,183	$ 5,183	$ 75,121						$ 75,121	$ 5,183
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	$ -	$ 170,947	$ -			$ 170,947	$ -	$ 4,775	$ 4,775	$ 170,947						$ 170,947	$ 4,775
Other Regulatory Assets - Sub-Account - Other[7]		1508	$ -	$ -	$ -			$ -			$ -	$ -					$ (38,179)	$ (38,179)	$ -
Retail Cost Variance Account - Retail		1518	$ (485)	$ 7,291	$ -			$ 6,806			$ -	$ 6,806	$ 4,244				$ 485	$ 11,535	$ -
Retail Cost Variance Account - STR		1548	$ 6,952	$ -	$ (2,464)			$ 4,488			$ -	$ 4,488	$ 174				$ (6,952)	$ (2,290)	$ -
Misc. Deferred Debits		1525	$ -	156,802			$ (80,539)	$ 76,263	$ -	$ 17,886	$ 17,886	$ 76,263		$ (14,968)			$ (21,785)	$ 39,510	$ 17,886
LV Variance Account		1550	$ -					$ -			$ -	$ -	$ 21,076					$ 21,076	$ -
Qualifying Transition Costs[5]		1570	$ 311,056	n/a	n/a	$ (40,126)		$ 270,930	$ 60,137	$ 20,402	$ 80,539	$ 270,930	n/a	n/a			$ (270,930)	$ -	$ 80,539
Pre-Market Opening Energy Variances Total[6]		1571	$ 265,377	n/a	n/a		$ 1,200	$ 266,577	$ 51,306	$ 19,283	$ 70,589	$ 266,577	n/a	n/a		$ (27,267)	$ (265,377)	$ (26,067)	$ 70,589
	Sub-Totals		$ 582,900	$ 410,161	$ (2,464)	$ (40,126)	$ (79,339)	$ 871,132	$ 111,443	$ 67,529	$ 178,972	$ 871,132	$ 25,494	$ (14,968)	$ -	$ (27,267)	$ (602,738)	$ 251,653	$ 178,972
Deferred Payments in Lieu of Taxes		1562	$ 64,637		$ (157,410)			$ (92,773)	$ (4,242)	$ (1,492)	$ (5,734)	$ (92,773)		$ (14,270)				$ (107,043)	$ (5,734)
2006 PILs & Taxes Variance		1592	$ -					$ -			$ -	$ -						$ -	$ -
	Sub-Totals		$ 64,637	$ -	$ (157,410)	$ -	$ -	$ (92,773)	$ (4,242)	$ (1,492)	$ (5,734)	$ (92,773)	$ -	$ (14,270)	$ -	$ -	$ -	$ (107,043)	$ (5,734)
	Total		$ 2,105,909	$ 1,485,359	$ (159,874)	$ (40,126)	$ (79,339)	$ 3,311,929	$ 233,346	$ 171,543	$ 404,889	$ 3,311,929	$ (838,836)	$ (29,238)	$ -	$ (27,267)	$ (2,539,442)	$ (122,854)	$ 404,889
RSVA - Power (including Global Adjustment)		1588	$ 2,135,535	$ 348,310				$ 2,483,845	$ 147,331	$ 84,945	$ 232,276	$ 2,483,845	$ 628,053				$ (2,135,535)	$ 976,363	$ 232,276
Recovery of Regulatory Asset Balances		1590			$ (1,413,047)			$ (1,413,047)			$ -	$ (1,413,047)		$ (1,504,395)			$ 4,715,103	$ 1,797,661	$ -
	Sub-Totals		$ 2,135,535	$ 348,310	$ (1,413,047)	$ -	$ -	$ 1,070,798	$ 147,331	$ 84,945	$ 232,276	$ 1,070,798	$ 628,053	$ (1,504,395)	$ -	$ -	$ 2,579,568	$ 2,774,024	$ 232,276
	Overall Total		$ 4,241,444	$ 1,833,669	$ (1,572,921)	$ (40,126)	$ (79,339)	$ 4,382,727	$ 380,677	$ 256,488	$ 637,165	$ 4,382,727	$ (210,783)	$ (1,533,633)	$ -	$ (27,267)	$ 40,126	$ 2,651,170	$ 637,165

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

REVISED APPENDIX H

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	HALTON HILLS HYDRO INC.
NAME OF CONTACT	ARTHUR SKIDMORE
E-mail Address	askidmore@haltonhillshydro.com
VERSION NUMBER	v3.0
Date	13-Nov-07

Account Description		**Account Number**	**Interest Jan-1 to Dec31-06**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-06**	**Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 [4]**	**Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 [4]**	**Claim before Forecasted Transactions**	**Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007**	**Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008**	**Projected Interest from Jan 1, 2007 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007**	**Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008**	**Total Claim**
RSVA - Wholesale Market Service Charge		1580	$ 24,231	$ (54,823)	$ 42,592	$ 9,018	$ 3,006	$ 251,077					$ 251,077
RSVA - One-time Wholesale Market Service		1582	$ 3,583	$ (9,214)	$ 3,276	$ 2,224	$ 741	$ 54,703					$ 54,703
RSVA - Retail Transmission Network Charge		1584	$ 28,391	$ (133,012)	$ (18,039)	$ 1,635	$ 545	$ 19,766					$ 19,766
RSVA - Retail Transmission Connection Charge		1586	$ 8,694	$ (70,073)	$ 1,599	$ (25,154)	$ (8,385)	$ (579,951)					$ (579,951)
	Sub-Totals		$ 64,899	$ (267,122)	$ 29,428	$ (12,277)	$ (4,092)	$ (254,405)	$ -	$ -	$ -	$ -	$ (254,405)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	$ 3,423	$ -	$ 8,606	$ 3,448	$ 1,149	$ 88,324					$ 88,324
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	$ 7,791		$ 12,566	$ 7,846	$ 2,615	$ 193,975					$ 193,975
Other Regulatory Assets - Sub-Account - Other[7]		1508			$ -	$ (1,752)	$ (584)	$ (40,516)					$ (40,516)
Retail Cost Variance Account - Retail		1518		$ 47	$ 47	$ 529	$ 176	$ 12,288					$ 12,288
Retail Cost Variance Account - STR		1548		$ (672)	$ (672)	$ (105)	$ (35)	$ (3,102)					$ (3,102)
Misc. Deferred Debits		1525		$ -	$ 17,886	$ 1,814	$ 605	$ 59,814					$ 59,814
LV Variance Account		1550	$ (1,202)		$ (1,202)	$ 967	$ 322	$ 21,164					$ 21,164
Qualifying Transition Costs[5]		1570	$ 7,631	$ (90,208)	$ (2,038)	$ -	$ -	$ (2,038)					$ (2,038)
Pre-Market Opening Energy Variances Total[6]		1571	$ 13,429	$ (76,959)	$ 7,059	$ (1,196)	$ (399)	$ (20,603)					$ (20,603)
	Sub-Totals		$ 31,072	$ (167,792)	$ 42,252	$ 11,551	$ 3,850	$ 309,306	$ -	$ -	$ -	$ -	$ 309,306
Deferred Payments in Lieu of Taxes		1562	$ (2,483)		$ (8,217)			$ (115,260)					$ (115,260)
2006 PILs & Taxes Variance		1592			$ -			$ -					$ -
	Sub-Totals		$ (2,483)	$ -	$ (8,217)	$ -	$ -	$ (115,260)	$ -	$ -	$ -	$ -	$ (115,260)
	Total		$ 93,488	$ (434,914)	$ 63,463	$ (726)	$ (242)	$ (60,359)	$ -	$ -	$ -	$ -	$ (60,359)
RSVA - Power (including Global Adjustment)		1588	$ 156,545	$ (353,766)	$ 35,055	$ 44,815	$ 14,938	$ 1,071,171	$ 506,834	$ 44,719	$ 31,018	$ 684	$ 1,654,427
Recovery of Regulatory Asset Balances		1590	$ (157,394)	$ 748,554	$ 591,160	$ 70,736	$ 6,467	$ 2,466,024	$ (1,738,274)	$ (597,240)			$ 130,510
	Sub-Totals		$ (849)	$ 394,788	$ 626,215	$ 115,551	$ 21,405	$ 3,537,195	$ (1,231,440)	$ (552,521)	$ 31,018	$ 684	$ 1,784,937
	Overall Total		$ 92,639	$ (40,126)	$ 689,678	$ 114,825	$ 21,163	$ 3,476,837	$ (1,231,440)	$ (552,521)	$ 31,018	$ 684	$ 1,724,578

HALTON HILLS HYDRO INC.
CALCULATION OF BALANCES BY ACCOUNT
DEFERRAL AND VARIANCE ACCOUNT BALANCES
REVISED EXHIBIT 5 / TAB 1 / SCHEDULE 2 / PAGE 1

Commodity accounts:	Opening balances Dec 31/06	Carrying Costs	Accruals	Proposed recovery balance
1588	976,363	94,808	583,256	1,654,427
Non-commodity accounts:				
1518	11,535	753		12,288
1548	(2,290)	(812)		(3,102)
1580	196,462	54,615		251,077
1582	48,461	6,242		54,703
1584	35,625	(15,859)		19,766
1586	(548,012)	(31,939)		(579,951)
Utility deferral accounts:				
1508	207,889	33,894		241,783
1525	39,510	20,304		59,814
1550	21,076	88		21,164
1562	(107,043)	(8,217)		(115,260)
1570	-	(2,038)		(2,038)
1571	(26,067)	5,464		(20,603)
1590	1,797,661	668,363	(2,335,514)	130,510
				1,724,578

Account Description	Account Number	Proposed recovery Balance	Allocation Basis	Residential	GS < 50 KW	GS 50-999 kW	GS 1000-4999	Unmetered Scattered Load	Sentinel	Street Light	Residential TOU	Totals
Other Regulatory Assets	1508	241,783	KWh	105,899	27,957	60,497	45,462	489	155	1,290	35	241,783
Retail Cost Variance Account - Retail	1518	12,288	# Customers	11,054	936	105	7	80	105	1	1	12,288
Misc. Deferred Debits - incl. Rebate Cheques	1525	59,814	Rebate cheques	59,814	-	-	-	-	-	-	-	59,814
Retail Cost Variance Account - STR	1548	(3,102)	# Customers	(2,790)	(236)	(27)	(2)	(20)	(26)	(0)	(0)	(3,102)
LV Variance Account	1550	21,164	KWh	9,270	2,447	5,295	3,979	43	14	113	3	21,164
Deferred Payments in Lieu of Taxes	1562	(115,260)	KWh	(50,483)	(13,327)	(28,839)	(21,672)	(233)	(74)	(615)	(16)	(115,260)
Qualifying Transition Costs	1570	(2,038)	# Customers	(1,833)	(155)	(17)	(1)	(13)	(17)	(0)	(0)	(2,038)
Pre-Market Opening Energy Variances Total	1571	(20,603)	KWh for Non TOU Customers	(11,198)	(2,956)	(6,397)	-	(52)	-	-	-	(20,603)
RSVA - Wholesale Market Service Charge	1580	251,077	KWh	109,970	29,031	62,823	47,209	508	161	1,340	36	251,077
RSVA - One-time Wholesale Market Service	1582	54,703	KWh	23,959	6,325	13,687	10,286	111	35	292	8	54,703
RSVA - Retail Transmission Network Charge	1584	19,766	KWh	8,657	2,285	4,946	3,717	40	13	105	3	19,766
RSVA - Retail Transmission Connection Charge	1586	(579,951)	KWh	(254,014)	(67,058)	(145,111)	(109,047)	(1,172)	(372)	(3,095)	(83)	(579,951)
RSVA - Power	1588	1,654,427	KWh	724,626	191,296	413,958	311,078	3,344	1,061	8,828	236	1,654,427
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08	**1,594,068**		**732,931**	**176,545**	**380,920**	**291,016**	**3,123**	**1,053**	**8,259**	**222**	**1,594,068**
Clear residual 1590 balance as of April 30/08?	YES	**130,533**		67,596	15,990	16,314	29,568	144	153	745	23	**130,533**
Total to Dispose at May1/08		**1,724,601**	**- 23 diff = rounding**	**800,526**	**192,535**	**397,234**	**320,584**	**3,267**	**1,207**	**9,004**	**244**	**1,724,601**
Disposal period?	3 YEARS			266,842	64,178	132,411	106,861	1,089	402	3,001	81	**574,867**
Test year consumption				220,790,841 kWh	58,287,111 kWh	454,000 kW	316,000 kw	2,443 kWh	800 kW	7,500 kW	72,000 kWh	
Projected 2008 Rate Riders				**0.0012**	**0.0011**	**0.2917**	**0.3382**	**0.0011**	**0.5027**	**0.4002**	**0.0000**	
Rate Determinant				kWh	kWh	kW	kW	kWh	kW	kW		

Test Year (2008) Allocations

Customer Class	Metric	KWh	# Customers	KWh for Non TOU Customers	Dx Revenue	# Customers w/Rebate Cheques	Rebate cheques
Residential	kWhs	44%	90%	54%			100%
GS < 50 KW	kWhs	12%	8%	14%			0%
GS 50-999 kW	kW	25%	1%	31%			0%
GS 1000-4999	kW	19%	0%				0%
Intermediate	kW	0%	0%				0%
Large Users	kW	0%	0%				0%
Unmetered Scattered Load	kWhs	0%	1%	0%			0%
Standby Power	kW	0%	0%				0%
Sentinel	kW	0%	1%				0%
Street Light	kW	1%	0%				0%
Residential TOU	kWhs	0%	0%				0%
Additional Customer Class 2		0%	0%				0%
Additional Customer Class 3		0%	0%				0%
Additional Customer Class 4		0%	0%				0%
Totals		**100%**	**100%**	**100%**	**0%**	**0%**	**100%**

HALTON HILLS HYDRO INC.
REGULATORY ASSET RECOVERY ACCOUNT 1590
CONTINUITY

i) Update to Exhibit 5 / Tab 1 / Schedule 2 / Page 1

Calculation of balances by account

		Opening December 31, 2006 Balance	Carrying Costs	Accruals	Proposed recovery Balance
1590	Recovery of regulatory asset balances	1,797,661	668,363	(2,335,514)	130,510
Totals		2,651,170	825,666	(1,752,258)	1,724,578

ii) Update to Exhibit 5 / Tab 1 / Schedule 3 / Page 1

		Ending April 30, 2 Balance	Allocation Basis	Residential	GS<50kW	GS 50-999kW	GS1000-4999kW	UMSL	Sentinel	Street Light	Res TOU	Total
1590	Recovery of regulatory asset balances	130,510	kWh	67,596	15,990	16,314	29,568	144	153	745	23	130,533
Total		1,724,578		800,526	192,535	397,234	320,584	3,267	1,207	9,004	244	1,724,601
Disposal period - 3 years				266,842	64,178	132,411	106,861	1,089	402	3,001	81	574,867
Projected 2008 rate riders				0.0012 kWh	0.0011 kWh	0.2917 kW	0.3382 kW	0.0011 kWh	0.5027 kW	0.4002 kW	0.0000 kWh	