Hawkesbury Hydro Inc.
850 Tupper Street
Hawkesbury, ON
K6A 3S7

November 4, 2009
Ms. Kirstin Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Re: EB-2009-0186 Hawkesbury Hydro Inc. 2010 Cost of Service Application

Dear Ms. Walli:

Please find attached Hawkesbury Hydro Inc's application for revenue requirements and corresponding rates for rate year commencing May 1, 2010 and ending April 30, 2011. This application is being filed pursuant to the Board's e-Filing Services. Two hard copies of the Application will be delivered to the Board over the next few days.

Should there be any questions, please do not hesitate to contact me at the number below.

Yours truly,

Michel Poulin, General Manager
Hawkesbury Hydro Inc.
850 Tupper Street
Hawkesbury, ON
K6A 3S7
(613)632-6689

Hydro Hawkesbury Inc.

2010 EDR Application

EB-2009-0186

Submitted 4 November, 2009

Hydro Hawkesbury Inc.
850 Tupper Street
Hawkesbury
ON K6A 3S7

<u>EXHIBIT 1</u>:

ADMINISTRATIVE DOCUMENTS

Exhibit 1: Administrative Documents

Tab 1 (of 4): Application Summary

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Rate Application

IN THE MATTER OF THE Ontario Energy Board Act, 1998, S.O 1998, c 15 (Sched.B);

AND IN THE MATTER OF an Application by HYDRO HAWKESBURY INC., to the Ontario Energy Board for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2010;

Introduction

The Applicant Hawkesbury Hydro Inc. ("HHI") is a corporation incorporated pursuant to the Ontario Business Corporation Act, and carries on business of distributing electricity within the Town of Hawkesbury.

HHI hereby applies to the Ontario Energy Board (the "OEB" or "The Board") pursuant to section 78 of the Ontario Energy Board Act, 1998 as amended (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2010.

Except where specifically identified in the Application, HHI followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated May 27, 2009 (the "Filing Requirements") as well as the "Electricity Distribution Rate Handbook" where applicable. The material being filed in support of HHI's applications sets out HHI approach to its 2010 distribution rates and charges.

The Schedule of Rates and Charges proposed in HHI's application is presented at Exhibit 8, Tab 4, Schedule 4, Attachment 1, the bill impact is found in Exhibit 8, Tab 4, Schedule 4, Attachment 2

HHI requests that the OEB make its Rate Order effective May 1, 2010 in accordance with the Filing Requirements. HHI requests that, if for any reason, final rates are not approved and effective May 1, 2010 that the current rates be approved as interim rates effective May 1, 2010 until final rates are approved by the Board.

The Proposed Distribution Rates and Other Charges are Just and Reasonable on the following grounds:

- the proposed rates for the distribution of electricity have been prepared in accordance with the Board's filing requirements;

- the proposed rates are necessary to provide a fair return on investment, and meet the company's Payments in Lieu of Taxes ("PILS") requirements;

- The proposed rates and charges are required to recover the ongoing costs incurred to provide electricity distribution services to its customers at an appropriate level of quality.

- Including the proposed rate riders, the proposed rates will result in a monthly total bill decrease of 6.8% or $5.58 per residential customer consuming 800 kWh.

- For a residential customer consuming 800 kWh, without the impact of the proposed rate riders, the proposed rates would result in a monthly total bill decrease of $1.10 or 1.3%.

Dated in Hawkesbury, Ontario on this 4th day of November 2009

Michel Poulin, General Manager
Hawkesbury Hydro Inc.
850 Tupper Street
Hawkesbury, ON
K6A 3S7

Summary of Application and Approvals Requested

HHI is applying to the Ontario Energy Board (the "Board") for distribution rates to be effective from May 1, 2010 to April 30, 2011. The approved rates will form the base year for subsequent rate adjustments under the Board's incentive rate mechanism.

Amongst the approval requested, HHI seeks Board authorization to;

- Charge increased electricity distribution rates effective May 1, 2010 while ensuring that they remain just and reasonable
- Charge rates that allow the recovery of the prudently incurred ongoing costs of providing distribution service to the Inhabitants of the Town of Hawkesbury at an appropriate level of safety and quality.
- Charge rates that permit an opportunity to earn the allowed rate of return
- Allow the disposition of the balances recorded in certain variance and deferral accounts.

HHI seeks approval of its capital structure change involving the decrease of the deemed common equity component from 43.3% to 40.0% and the increase of the debt component from 56.7% to 60.0% based on 56.0% long-term debt and 4% short-term debt (Exhibit 5) consistent with the report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006.

The key points supporting HHI's application are discussed below.

In its application, HHI seeks to recover a Base Revenue Requirement of $1,304,216 which includes a Gross Revenue Deficiency in the amount of $394,455 arising from changes in OM&A, Amortization, Rate of Return and PILS. HHI seeks a disposal of balances of Deferral and Variance Accounts in the amount of $ 1,885,598 over a period of two years, as proposed in the "*Board's Report on Electricity Distributors' Deferral and Variance Account Review Initiative*" issued on the 31st of July 2009. HHI also seeks approval of a utility specific smart meter adder of $1.51 per month. HHI is also seeking approval of its revised loss adjustment factor as well as its revised Retail Transmission Service Rates.

HHI has been assisted in preparing its application by Elenchus Research Associates ("ERA") who provided the 2010 EDR model used in the determination of proposed 2010 Distribution Rates. In order to facilitate the review of this application, HHI has voluntarily included a locked version of the model for the Board and Interveners convenience. The model has been filed as an addendum to the application.

In order to file the application in English, HHI was assisted in the drafting of the application by a bilingual staff at ERA.

HHI has based its application on forecasted results for the 2010 Test Year. As required by the Board's minimum filing requirements, HHI is also presenting the historical actual information for fiscal 2006, 2007 and 2008; information for the 2009 Bridge Year and 2010 Test Year.

The financial information supporting the Test Year for HHI Application will be a forecast of HHI's fiscal year ending December 31, 2010 (the "2010 Test Year").

DRAFT ISSUES LIST

There are a number of issues, some generic and some specific to HHI that could be examined in this application.

CAPITAL STRUCTURE

HHI's current deemed capital structure is 56.7% debt and 43.7% equity. In its December 20, 2006 Report on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors, the OEB mandated a shift to a 60% debt and 40% equity for all distributors. Consequently, HHI is requesting a change in its deemed capital structure. Specifically, HHI is requesting a decrease in the deemed equity ratio from 43.3% to 40.00% and increase the debt ratio from 56.7% to 60.0% consistent with the 3 year phase-in of HHI's capital structure to a 60/40 debt to equity ratio.

RETURN ON EQUITY

In addition, HHI has assumed a return on equity of 8.01% consistent with the rate of return on equity approved by the OEB for 2010 cost of service applications. HHI understands the OEB will be finalizing the return on equity for 2010 rates based on January 2010 market interest rate information.

REVISION TO THE COST ALLOCATION

HHI, assisted by Elenchus Research Associates ("ERA"), proposes an appropriate cost allocation study for its 2010 cost of service rate application. In the context of a cost of service rate application based on a 2010 forward test year, the primary purpose of the cost allocation study is to determine the proportions of a distributor's total revenue requirement that are the "responsibility" of each rate class.

For the purpose of this application, a "Prospective Year CA Study" approach was used: This approach ensures compliance with the Board's direction in the Filing Requirements that the CA Study should "reflect future loads and cost". The proposed 2010 Cost

Allocation also addresses the correction of the treatment of the Transformer Ownership Allowance. This evidence is presented at Exhibit 7

LOAD FORECAST

As part of this application, HHI proposes a weather normal load forecast. Weather normalization involves removing the year-to-year variations in consumption due to weather. This is achieved by estimating a statistical relationship between observed monthly weather and observed monthly consumption. Details of this evidence can be found at Exhibit 3, Tab 1.

OPERATING AND MAINTENANCE COSTS

As can be seen from the evidence at Exhibit 4, due to the benefits of ownership and democratic control, HHI has managed to maintain its operating and maintenance costs at a reasonable level. The major cost driver behind the increase is the cost of complying with regulatory requirements. The increase in OM&A expenses in 2010 over the 2006 EDR is $147,059.

SMART METER INFRASTRUCTURE

HHI is requesting, as part of its 2010 Rate Application, a utility specific funding adder of $1.51 for its smart metering infrastructure. Evidence related to this request can be found at Exhibit 9, Tab 3.

TRANSMISSION RATES

As per the Board’s Decision and Rate Order in the EB-2008-0272 proceeding, the new UTRs were made effective July 1, 2009. In accordance with the Board’s minimum filing requirements, HHI proposes to revise its retail transmission service rates (“RSTR”). Historical transmission costs and revenues as well as calculation of proposed RSTR are presented at Exhibit 8, Tab 3, Schedule 1, Attachment 1.

EXCEPTIONAL CIRCUMSTANCES:

HHI' s only Large Use Customer in its service area will cease operation in November of 2009. This lost of this customer will adversely affect HHI's ability to meet its obligations unless the loss of distribution revenue is offset by an adjustment to the distribution rates applicable to HHI's remaining classes. Details of this event and its impact on HHI's revenues are presented at Exhibit 8, Tab 2, Schedule 3.

FIXED TO VARIABLE SPLIT

HHI is proposing to change the existing fixed to variable split by increasing the fixed component percentage. This shift will bring HHI's billings closer to the split used by its cohorts and neighbouring utilities. Details of the proposed variable/fixed split as well as its arguments supporting this split can be found at Exhibit 8, Tab 2, Schedule 1, Attachment 2.

UTILITY REPRESENTATIVES & WITNESSES

Michel Poulin
General Manager
Hydro Hawkesbury Inc.
850 Tupper St
Hawkesbury, Ontario
K6A 3S7

Tel: 613-632-6689
Fax: 613-632-8603
E-Mail: poulinmi@hawk.igs.net

Linda Parisien
Assistant Manager
Hydro Hawkesbury Inc.
850 Tupper St
Hawkesbury, Ontario
K6A 3S7

Tel: 613-632-6689
Fax: 613-632-8603
E-Mail: lindapar@hawk.igs.net

Consultants
Elenchus Research Associates Inc.
34 King Street East, Suite 600
Toronto, ON M5C 2X8
Tel: 416.710-2704

- Manuela Ris-Schofield
- James Cochrane

- Stephen Motluk
- Andrew Frank

Deloitte & Touche
300 McGill
Hawkesbury, ON K6A 1P8
Tel: 613-632-4178
Gerald Gauthier

Michel Poulin, B.A.

513 Chartrand
Hawkesbury, Ontario K6A 3P4
Res: 613-632-8713 E-mail:poulinmi@hawk.igs. net
Business: 613-632-6689

BUSINESS EXPERIENCE

Hawkesbury Hydro Inc. Hawkesbury, Ontario *2004 – Present*
General Manager

Responsible for reporting to the Hawkesbury Hydro Inc. board of directors. Responsible for overseeing the operations and capital budget for Hawkesbury Hydro Inc. Ensure system reliability through maintenance and capital project. Responsible for day to day operations. Preparation of reports required by the OEB and the IESO for maintenance of electricity distribution license, electricity distribution rate applications, participates in the annual budget process, preparation and analysis of year end working papers for the finance department, participates in service agreements management. Apply our conditions of service to protect our customer's interest. Oversee all operations to maintain a solid infrastructure and maintain cost to a reasonable level for our customer base.

United Counties of Prescott & Russell *2003-2004*
Maintenance Suppervisor

Responsible for maintenance and operations withing the social housing department. Maintain operational and capital budgets. Report to housing supervisor. Prepare, elaborate maintenance plans and allow contracts to entrepreneurs.

Hydro One *2001 – 2003*
Part of the Amalgamation team

Report to supervisor of performed work of newly acquired employees across Ontario. Organise training sessions for those employees at remote distance. Provide work load and support to office employees across Ontario.

I was part of the Amalgamation team whose role was to acquire more LDC'S.

Champlain Hydro Inc. Champlain, Ontario *1998 –2003*
General Manager

Responsible for reporting to the Champlain Board of directors. Responsible for overseeing the operations and capital budget for Champlain Hydro. Ensure system reliability through maintenance and capital project. Responsible for day to day operations. Comply with all government bodies. Prepare electricity distribution rate applications, annual budget process, preparation and analysis of year end working papers and all financials. Oversee all operations on a daily basis to maintain a solid infrastructure and maintain cost to a reasonable level for our customer base. Participate in the amalgamation process of L'Orignal, Vankleek Hill, West Hawkesbury and Longueuil Township.

L 'Orignal Hydro. L 'Orignal, Ontario *1991 –1998*
General Manager

Responsible for reporting to the L'Orignal Hydro. Responsible for overseeing the operations and capital budget for L'Orignal Hydro. Ensure system reliability through maintenance and capital project. Responsible for day to day operations. Comply with all government bodies. Prepare electricity distribution rate applications, annual budget process, preparation and analysis of year end working papers and all financials. Oversee all operations on a daily basis to maintain a solid infrastructure and maintain cost to a reasonable level for our customer base.

E D U C A T I O N

Bachelor's Degree in Administration from the Ottawa University

L I N D A D E N I S P A R I S I E N

POSITION

Assistant Manager & CFO

COMPETENCE

- Responsible for the financial management of Hydro Hawkesbury
- **More than 14 years experience** within the electricity sector
- Excellent computer knowledge
- Multi-task administrator
- Excellent communicator
- Perfectly bilingual, French and English, spoken & written

EDUCATION

Fall 2001 St-Lawrence College Cornwall ON

Accounting 1 & 2

~ Completed.

1980 - 1985 E.S.R.H. ***High School Diploma*** Hawkesbury ON

~ Completed (1985)

EXPERIENCE

1998 to today Hydro Hawkesbury Inc. Hawkesbury ON

Assistant Manager & CFO

Responsible of budgetary items, accounting and financial activities of the Corporation. Management of all financial aspects, payroll, invoicing, accounts payable, accounts receivable, cost analysis, budget & rate preparation. Responsible for all regulatory reporting for Ontario Energy Board. Responsible of all public relations aspects, including customer complaints, recovery of bad debts and approval of disconnections for non-payment.

Responsible of all human resources aspects.

905, L' AVENUE ROYAL • HAWKE SBURY ON K6A 3J 8
TÉL. (613) 632- 1078 • TÉ LÉ C. (613) 632-7429 • COURRIEL : LINDAPAR@HAWK.IGS.NET

Manage a team of three clerks and upon absence of the Manager, supervise a line crew of three men.
Responsible for the preparation of the year end Financial Statements of the Corporation for presentation to the Board of Directors.

Achievements

- Transition from Commission to Corporation
- Completed deregulation successfully
- Implantation of two new billing systems

TRAINING

- Attended many billing seminars
- Attended accounting seminars
- Attended Pension Plan seminars (O.M.E.R.S.)
- Attended a seminar on work relation/contract negotiation
- Attended a communication seminar
- Attended a collection techniques seminar
- Attended a customer service seminar

PROFESSIONNEL KNOWLEDGE

- **Computing (experienced user)**

Good knowledge of operating systems **Windows XP,** of **Advanced & Northstar** billing software, **MS Office 2003, Outlook, Internet Explorer, Word et Excel et ACCPAC Business Edition.**

COMMUNITY ACTIVITIES

- Canadian cancer society

JAMES J. COCHRANE

PROFILE

- ♦ Seasoned financial professional with practical business sense and strong results-orientation
- ♦ Diversified and accomplished academic background (Bachelor of Computer Science, MBA)
- ♦ Extensive expertise and successful track record on highly complex commercial and strategic transactions
- ♦ Well-versed in accounting, legal and regulatory principles, standards and practices
- ♦ Broad experience in financial and corporate strategy, reporting, analysis, planning, systems and controls
- ♦ High capacity to adapt, reprioritize objectives and initiate action in a changing environment
- ♦ Effective leader of multidisciplinary project teams and respected manager of a finance function
- ♦ Keen understanding of technology issues derived from academic and industry experience
- ♦ Proven financial modelling and presentation skills
- ♦ Fluently bilingual (English/French) with superior verbal and written communication abilities

PROFESSIONAL EXPERIENCE

ERA Inc.
Toronto, ON
2007 – present

Senior Consultant – Providing expertise and support to energy industry stakeholders on regulatory matters, with a focus on rate regulation of electricity distributors under the Ontario Energy Board (OEB).

- Advised over 25 electricity distributors on their 2008 and 2009 cost of service rate applications. Advisory work spanned project planning, application strategy, support for rate modeling and formulating evidence on key issues and risks.
- Delivered presentations in monthly conference calls with clients, to provide updates and analysis of key developments and decisions from the OEB.
- Designed and developed a toolkit for electricity distributors' cost of service rate applications, including *Rat eMaker,* the only fully integrated commercialized model to address all key areas of the OEB 's filing requirements.
- Performed Total Resource Cost analysis in support of two electricity distributors' Conservation and Demand Management (CDM) programs, and quantitative analysis of smart meter pilot project data for the OEB's distribution rate design initiative.
- Drafted reports and regulatory submissions for several Ontario electricity stakeholders (Ontario Energy Association, Electricity Distributors Association, Power Workers Union and the Association of Power Producers of Ontario).
- Authored a research report and presentation on electricity market surveillance, which was delivered at a conference in Vietnam sponsored by the Canadian International Development Agency.

Toronto Hydro
Toronto, ON
2002 – 2006

***Director, Corporate Planning* –** Key leader overseeing the corporation's business and financial planning functions, delivering support services to corporate and utility business units: coordinating the development and alignment of company strategies, projections and budgets; implementing appropriate measurements with periodic benchmarking, reporting and analysis of performance against objectives, evaluating business initiatives from both strategic and financial perspectives, and supporting the execution of strategic transactions.

- Re-engineered the corporation's strategic and financial planning processes. Lead the preparation of annual budgets and five-year business plans for presentation to the Board of Directors and submission to shareholder
- Managed the development of financial models to evaluate a $60 million acquisition and developed negotiation positions for all financial elements of the transaction, including a 30-year services agreement.
- Delivered written and oral evidence, under direct and cross examination, in support of the utility's application before the OEB for electricity distribution rates based on a Forward Test Year..
- Provided comprehensive support to the utility's $40 million CDM initiative for regulatory reporting requirements, cost tracking mechanisms and a governance framework for business case reviews.
- Managed the implementation of Hyperion Planning as the corporate standard for collaborative financial planning, and standard web-based toolkits for management reporting and variance analysis. Managed the Finance-stream work plan for the Corporation's ERP system.
- Oversaw the development and implementation of the corporation's delivery and costing model for Shared Services

Nortel Networks
Brampton, ON
2000 – 2001

***Senior Manager, Finance, Major Accounts* –** Team leader providing comprehensive financial support to a large sales organization delivering over $1.2 billion in annual revenue, with Profit & Loss and Balance Sheet performance accountability. Duties included structuring of commercial terms, financial impact analyses and advice, planning, reporting, financing, balance sheet management, governance and control. Received several awards for contributions to business growth.

- Primed financial support on a competitive bid to a global optical backbone provider, yielding a $600 million incremental volume commitment to Nortel.
- Structured key terms for a vendor-financed $200 million turnkey network build.
- In a breakthrough initiative, successfully worked with a customer and a financing company to structure an operating lease on a $50 million network equipment sale.
- Adopted and managed processes for the review and approval of sales proposals, and initiated measures to improve financial planning and reporting.

Nortel Networks
Toronto, ON
1999 – 2000

***Senior Manager, Finance, Wireless Solutions* –** Finance team leader supporting wireless equipment sales in Canada. Responsible for evaluation of sales proposals, assessment of financing requests, control, results reporting and planning. Team received recognition award for outstanding performance and contributions.

~ Worked with marketing personnel and customers to structure commercial terms, closing several significant sales transactions up to $10 million

~ Tasked spending targets by department as a timely reaction to expected revenue shortfall – selling expense as a percent of revenue remained on target.

~ Undertook an exhaustive review of balance sheet accruals and exposures, resulting in the delivery of significant incremental earnings.

~ Supported internal audit and implemented key recommendations, improving control procedures and governance processes.

Nortel Networks,
Brampton, ON
1996 – 1999

***Manager, Mergers and Acquisitions* -** Corporate prime on strategic transaction initiatives. Key responsibilities included valuation, due diligence coordination, negotiations and management of legal and other functions to execute transactions.

- Managed two significant divestitures, generating $85 million in cash proceeds, working with line and legal executives. Prepared documentation to secure executive and Board approvals. Directed preparation of financial statements, information packages and due diligence materials. Evaluated offers and participated in the negotiation of all substantive issues. Received special award for leadership and support.
- Corporate prime on strategic partnership and equity investments in a micro-cellular technology provider, working with business leaders, the line Finance team and legal counsels. Eight final agreements were executed within two weeks of a preliminary term sheet. Completed follow-on investments including a capital restructuring, after which investee completed a successful IPO.
- Negotiated memorandum of understanding and final agreements on the merger of Nortel's cable data business with an existing joint venture, which later became a publicly-traded, integrated end-to-end provider of broadband access networks.
- Lead and/or supported a number of other initiatives, including acquisitions and spinouts. Drafted key recommendations to improve execution of acquisitions.

Nortel Networks
Mississauga, ON
1995 – 1996

***Senior Financial Analyst, Corporate Reporting* -** Consolidation, reconciliation, presentation and analysis of management financial results for Nortel's senior executives, Board of Directors and then-parent corporation, BCE Inc. Implemented numerous process improvements and enhanced analytical reporting.

Other
Montreal, QC
1986 - 1995

Manager, Business Analysis (BCE Inc.)
Manager, Budget and Results (Bell Canada)
Application Systems Development (BCE Inc., UAB Ltd.)

EDUCATION

M.B.A. McGill University, Montreal, 1992
B.Comp.Sc. Concordia University, Montreal, 1986 *(awarded With Distinction)*

Numerous professional programs e.g. Niagara Institute *(2002),* Wharton Business School *(1996)*

Stephen A. Motluk

Stephen Motluk has over 15 years experience in economic policy analysis, both in the public and private sectors, and has worked extensively in the regulated and unregulated electricity sector. During his tenure at Elenchus Research Associates (ERA), representative engagements include:

- Evaluation of electric utility performance under incentive rates;
- Evaluation of, and advice on, proposed electric utility rate plans;
- Analysis of, and advice on, various utility cost indices;
- Economic evaluation of electricity generation options in Ontario;
- Research, evaluation and analysis of regulatory regimes for electricity markets in various jurisdictions in North America, Europe, and other OECD areas;
- Cost modelling and price simulation of the Ontario interconnected electricity system using simulation models;
- Development of avoided cost estimates for natural gas and electricity distribution systems.

Before joining ERA, Stephen spent several years working for the Ontario Energy Board (the Ontario electricity and natural gas regulator), primarily responsible for analytical and strategic input for decisions relating to the Performance-Based Regulation (PBR) Plans for both electricity and natural gas. He was also involved in projects regarding transmission rate design, mergers, acquisitions, and divestitures, as well as formulaic ROE determination, amongst others. He also has several years experience with an electricity wholesale and merchant group, responsible for market analytics, analytical support for business development initiatives, real-time trading operations, electricity pricing models, and project analysis for affiliate companies.

He also has significant government experience working in the Policy Branches of several Ontario Government Ministries, including education finance and social services. Prior to joining the Ontario Public Service, Mr. Motluk worked as an Economic Forecaster for the Conference Board of Canada in Ottawa, where he was part of the team responsible for producing the Conference Board's quarterly Provincial Outlook. He was also Senior Economist and Senior Research Analyst at the Ontario Medical Association, responsible for analytics in support of negotiations on behalf of physicians in fee-for-service and alternative payment plans.

EDUCATION

MA (and PhD studies), Economics, Dalhousie University (Halifax, NS)
MBA, Management Science, Clarkson University (Potsdam, NY, USA)
BA, Economics, University of Waterloo (Ontario)

PROFESSIONAL BACKGROUND

2004 - Senior Consultant, Elenchus Research Associates

2002 - 2004 Senior Portfolio Analyst, EPCOR Merchant & Capital, L.P.

1999 - 2002 Research/Policy Staff, Ontario Energy Board

1998 Consultant, Price Waterhouse Coopers

1997 - 1998 Senior Data Analyst, Education Finance Branch, Ontario Ministry of Education and Training

1995 - 1997 Economic Policy Analyst, Ontario Ministry of Community and Social Services, Child Care Branch

1991 - 1995 Senior Economist/Senior Research Analyst, Ontario Medical Association

1989 - 1991 Research Associate, Forecasting and Analysis Group, Conference Board of Canada

1987 - 1988 Teaching Master, Business and Human Studies, St. Lawrence College of AA & T.

SELECTED PAPERS AND PRESENTATIONS

'Flawed Competition Policies: Designing 'Markets' with Biased Costs and Efficiency Benchmarks,' (with F.J. Cronin), Review of Industrial Organization, forthcoming'

Reviewing Electric Distribution Restructuring in Ontario: Policy Without Substance or Commitment,' (with F.J. Cronin), Utilities Policy, forthcoming

'The Road Not Taken: Revisiting performance-based rates with endogenous market designs,' (with F.J. Cronin), Public Utilities Fortnightly, March 2004, pp. 52-57.

'Restructuring Monopoly Regulation with Endogenous Market Designs,' (with F.J. Cronin), paper presented to Michigan State University Institute of Public Utilities

35th Annual Regulatory Policy Conference, Dec. 8-10 2003, Charleston, South Carolina.

'Examining the (Mis)Specification of Peer Group Performance Benchmarking,' (with F.J. Cronin) presentation to the North American Productivity Workshop II, Union College, Schenectady, N.Y., June, 2002.

'Inter Utility Cost and Efficiency Differences Among Electric Distribution Utilities in Ontario,' presentation at 35th Annual Meeting of the Canadian Economics Association, May 31 - June 3, 2001, McGill University, Montreal, Quebec. (With F.J. Cronin).

'PBR for Ontario Electric Distribution Utilities,' PBR Rate Making Conference, KEMA Consulting, November 8 - 9 2000, Denver, Colorado.

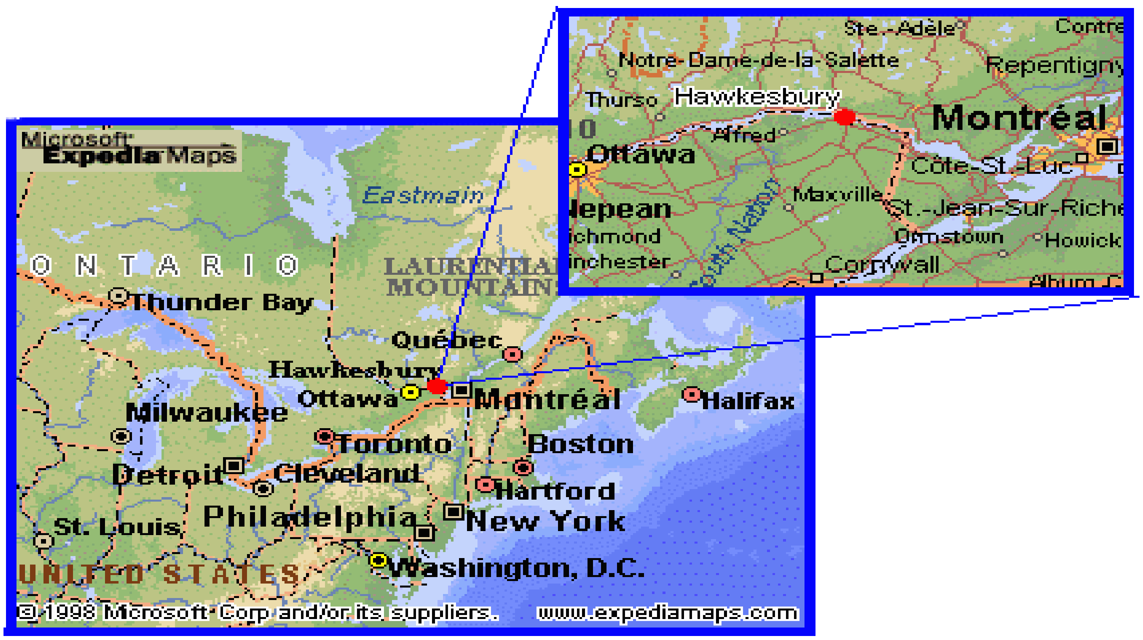
Exhibit 1: Administrative Documents

Tab 2 (of 4): Company Overview

DESCRIPTION SUMMARY

HHI is licensed by the Ontario Energy Board to distribute electricity to the inhabitants of the Town of Hawkesbury. HHI is incorporated under the Business Corporation Act on October 25th 2000. The sole Shareholder of HHI is the town of Hawkesbury.

The population of the Municipality of Hawkesbury is approximately 10,500. The distribution service area within the Town of Hawkesbury is bounded by the township of Champlain, East Hawkesbury, and the province of Quebec. The total service area covered by HHI is approximately 8.6 SQ.KM of urban area. HHI does not serve the rural area, nor do they have seasonal customers.



NEIGHBORING UTILITIES

HHI is surrounded by Hydro One Networks Inc. On the North side of Hawkesbury, the Ottawa River is the boundary between Hawkesbury Hydro Inc and Hydro Quebec. HHI is not connected to the Quebec Hydro Grid.

HHI is directly connected to Hydro One's transmission system at 115 KV and 44KV and is not an embedded LDC that takes delivery of electricity from another LDC.

HHI does not host any utilities within its service area, nor have any embedded utilities within its service area.

HHI is a registered Market Participant dealing directly with the IESO.

ANNUAL REPORT (2008) AND INTERIM REPORT (2009)

HHI does not produce an annual report.

DISTRIBUTION SYSTEM

HHI relies on approximately 66 km of circuits deliver 185,033,775 kWh of energy and 307570 kW of power to approximately 5,500 customers. The circuits can be broken down into roughly 57 km of overhead lines and 9 km of underground conductor. The distribution system is comprised of 43 km of 3-phases circuits and 23 km of single phase circuits.

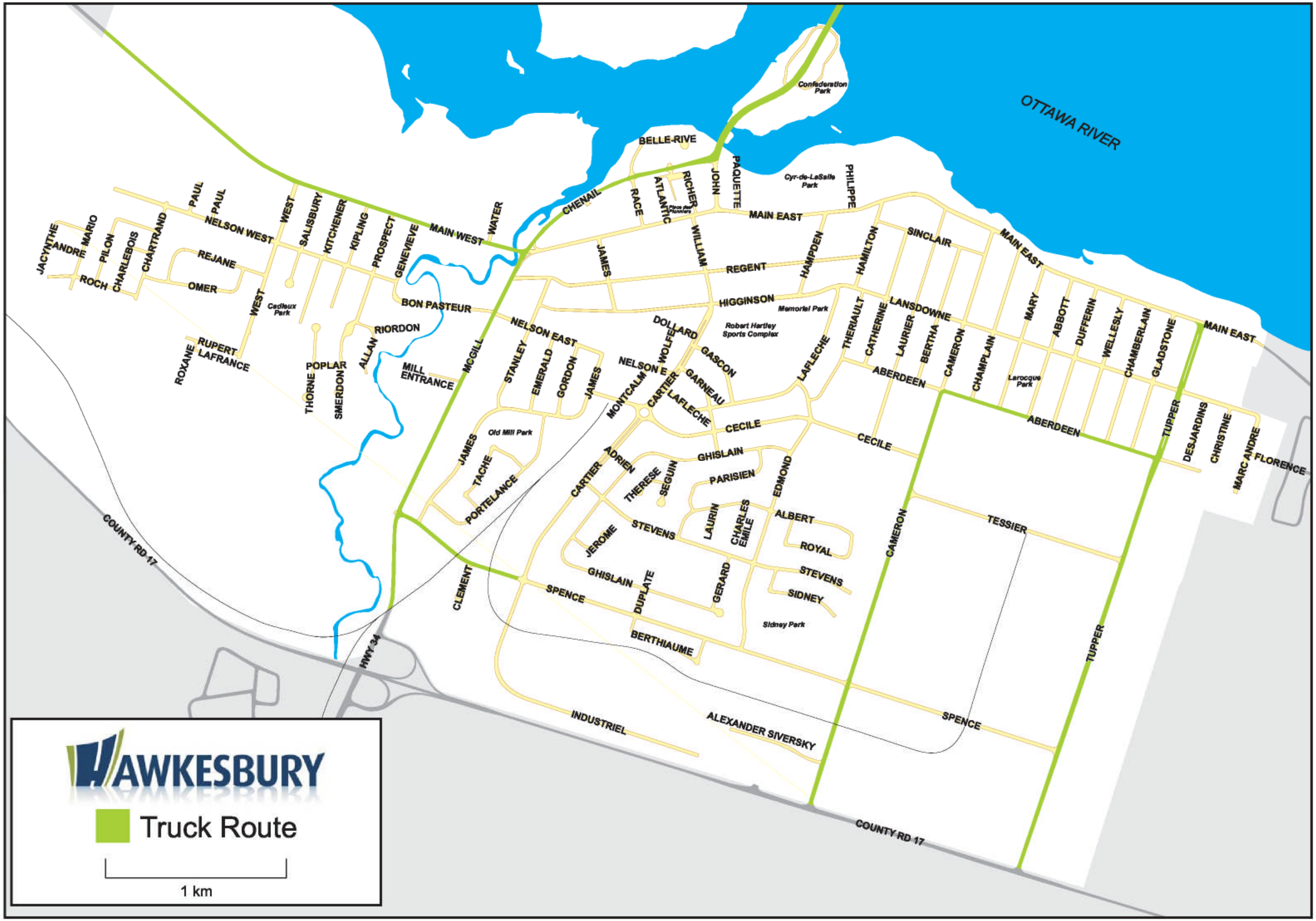
The total service area covered by HHI is approximately 8.6 SQ.KM of urban area. HHI does not serve any rural area, nor does it service seasonal customers.

HHI receives its electricity supply from Hydro One at two delivery points. A substation at 115KV with two distribution transformers at the West end of town and a 44KV station at the East end of Hawkesbury. Primary voltage is 12.47/7.2KV. The equipment within the Hawkesbury Hydro substations is listed below, along with the ratings that are used to evaluate each component for various loading scenarios.

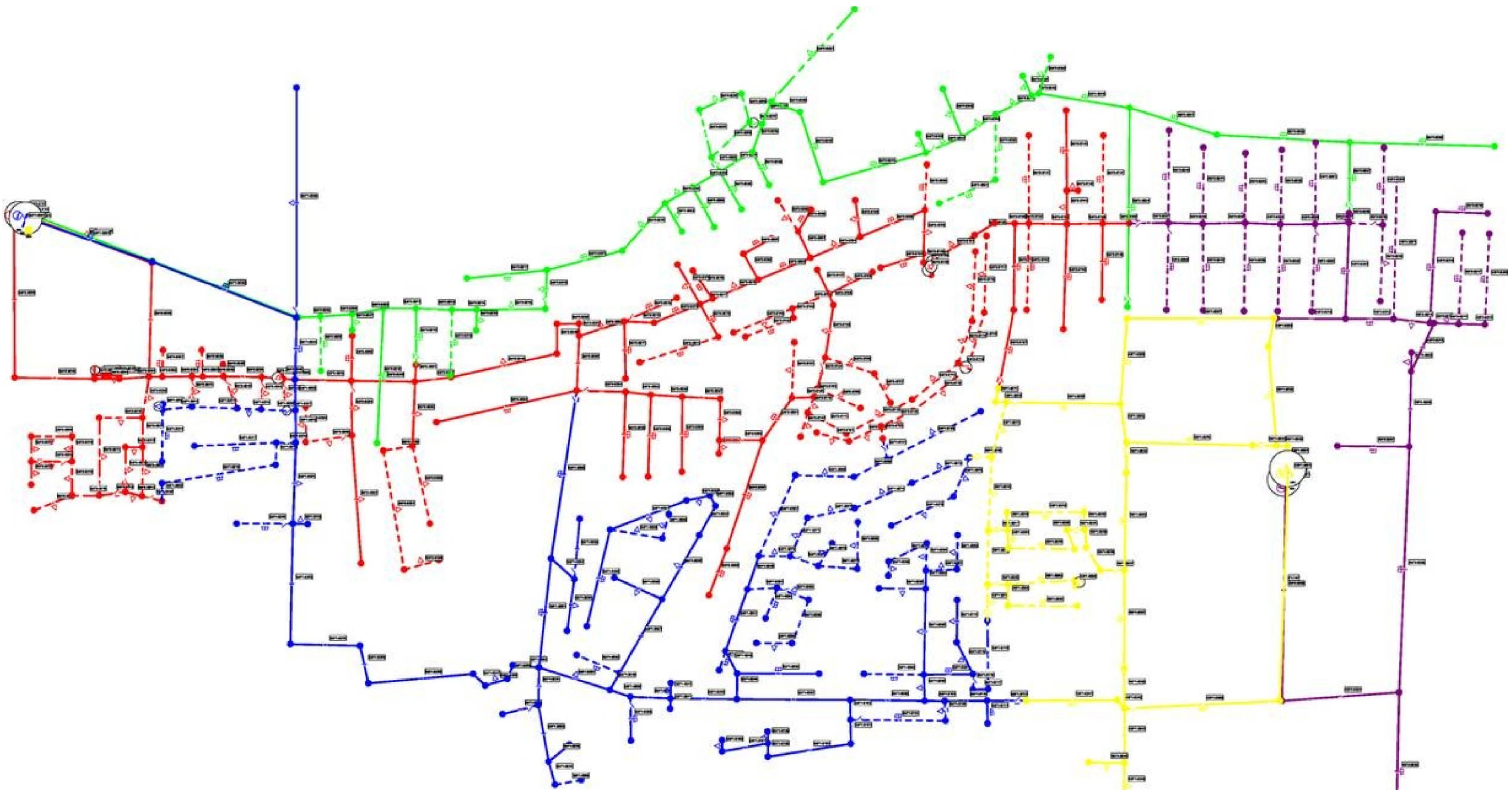
110kV Substation West # 55		
System Component	**Rating**	**Amps @ 12.48kV (110kV)**
110kV Primary Fuses **S&C Electric SMD-2B, 80E** **Standard Speed, TCC 153-1**	Continuous Amps Daily 4 hour peak Emergency 4 hour peak	1 163A (132A) 1181A (134A) 1 181A (134A)
1 10,000/12,480V Transformer **Delta/Wye (Grnd.), 7.5/10/12.5 MVA** (ONS/ONP/ONPP) **Z = 8.9%**	Continuous Amps ONS Continuous Amps ONP Continuous Amps ONPP	347A (39.4A) 462A (52.4A) 578A (65.6A)
12,480V Secondary Switchgear	Continuous Amps	1200A*
12,480V Hydraulic Oil Circuit Reclosers **McGraw Edison Type 'L' with 560A Trips**	Continuous Amps	560A
1 2,480V Recloser Bypass Fuses **S&C Electric SM-5, 300E*** **Slow or Standard Speed, TCC 119-1 or 153-1**	Continuous Amps Daily 4 hour peak Emergency 4 hour peak	300A 310A 330A
Recloser Load Side Isolation Cutouts	Continuous Amps	800A*
F1/F2/F3 Lines, 336 MCM ACSR	Continuous Amps (min)	647A
F1/F2/F3 Lines, 3/0 AWG ACSR	Continuous Amps (min)	370A

44kV Substation East # 43		
System Component	**Rating**	**Amps @ 12.48kV (44kV)**
44kV Primary Fuses **S&C Electric SMD-2C*, 250E** **Standard Speed*, TCC 153-1 ***	Continuous Amps Daily 4 hour peak Emergency 4 hour peak	970A (275A) 1005A (285A) 11 52A (327A)
44,000/12,480V Transformer **Delta/Wye(Grnd), 10/13.3/16.7MVA** **(ONAN/ONAF/ONAF')**	Continuous Amps ONAN Continuous Amps ONAF Continuous Amps ONAF'	463A (131A) 615A (174A) 773A (219A)
1 2,480V Secondary Switchgear	Continuous Amps	800A*
12,480V Hydraulic Oil Circuit Reclosers **Kyle type 'WE' with 560A Trips**	Continuous Amps	560A (280A Ground Trip)
1 2,480V Recloser Bypass Fuses **S&C Electric SM-5, 300E*** **Slow or Standard Speed, TCC 119-1 or 153-1**	Continuous Amps Daily 4 hour peak Emergency 4 hour peak	300A 310A 330A
F1/F2/F3 Lines, 336 MCM ACSR	Continuous Amps (min)	647A
F1/F2/F3 Lines, 3/0 AWG ACSR	Continuous Amps (min)	370A

1


OTTAWA RIVER
Confederation Park
BELLE-RIVE
PAQUETTE
Cyr-de-LaSalle Park
PHILIPPE
JOHN
RICHER
ATLANTIC
RACE
CHENAIL
MAIN EAST
MAIN WEST
WATER
WILLIAM
JAMES
REGENT
HAMPDEN
HAMILTON
SINCLAIR
MAIN EAST
HIGGINSON
Memorial Park
Robert Hartley Sports Complex
LANSDOWNE
MAIN EAST
PAUL
PAUL
NELSON WEST
WEST
SALISBURY
KITCHENER
KIPLING
PROSPECT
GENEVIEVE
MARIO
JACYNTHE
ANDRE
PILON
CHARLEBOIS
CHARTRAND
REJANE
ROCH
OMER
WEST
Cadieux Park
BON PASTEUR
RIORDON
RUPERT
LAFRANCE
ROXANE
POPLAR
ALLAN
THORNE
SMERDON
MILL ENTRANCE
MCGILL
NELSON EAST
DOLLARD
GASCON
WOLFE
NELSON E
GARNEAU
STANLEY
EMERALD
GORDON
JAMES
MONTCALM
CARTIER
LAFLECHE
LAFLECHE
THERIAULT
CATHERINE
LAURIER
BERTHA
CAMERON
MARY
ABBOTT
DUFFERIN
WELLESLY
CHAMBERLAIN
GLADSTONE
ABERDEEN
CHAMPLAIN
Larocque Park
ABERDEEN
TUPPER
DESJARDINS
CHRISTINE
MARC ANDRE
FLORENCE
CECILE
CECILE
Old Mill Park
JAMES
TACHE
PORTELANCE
ADRIEN
CARTIER
THERESE
SEGUIN
GHISLAIN
PARISIEN
EDMOND
LAURIN
CHARLES EMILE
ALBERT
ROYAL
STEVENS
STEVENS
JEROME
GHISLAIN
DUPLATE
GERARD
SIDNEY
Sidney Park
CAMERON
TESSIER
CLEMENT
SPENCE
BERTHIAUME
INDUSTRIEL
ALEXANDER SIVERSKY
SPENCE
TUPPER
COUNTY RD 17
HWY 34
COUNTY RD 17
HAWKESBURY
Truck Route
1 km

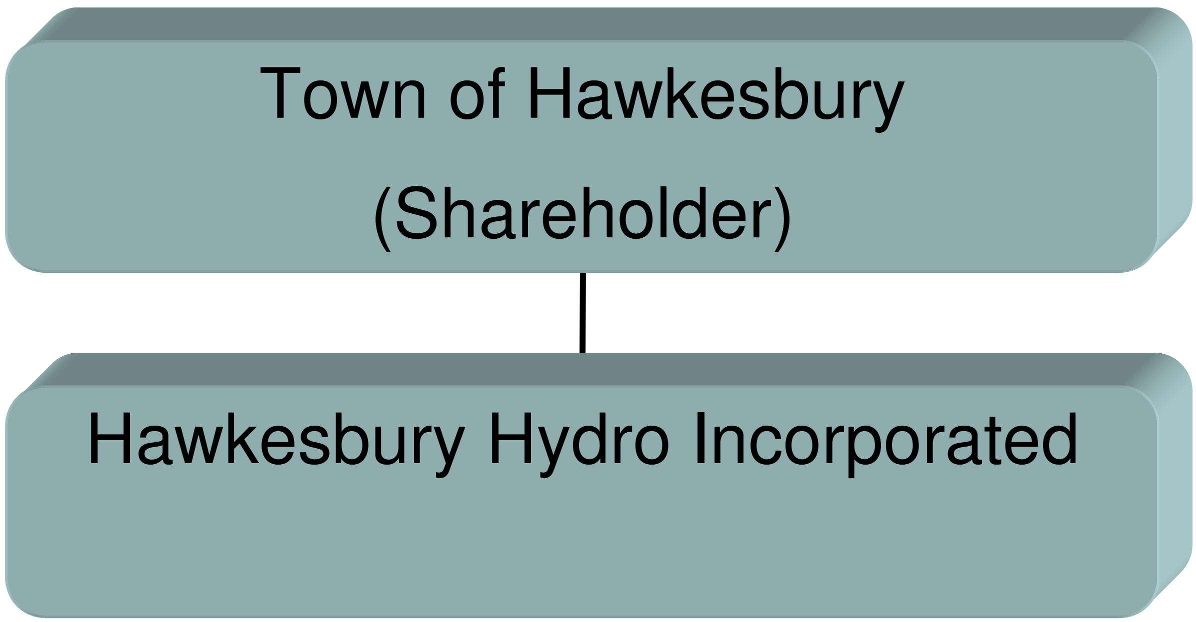
filar :



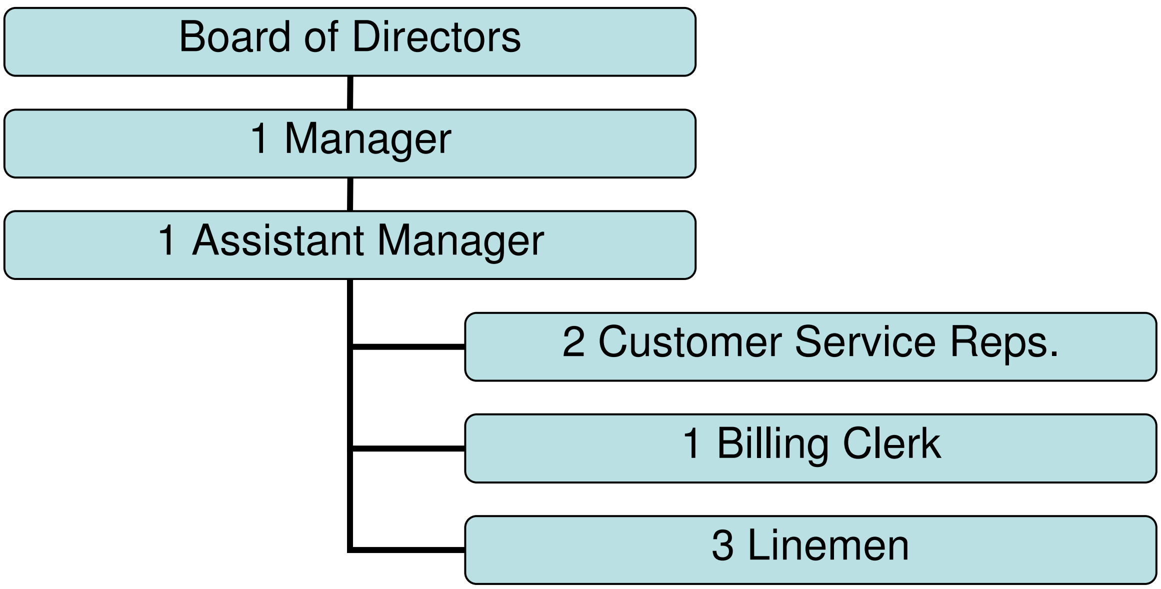
CORPORATE ORGANIZATION

HHI is not planning any changes to its corporate or operational structure. The current Corporate Entities and Organizational Chart can be found in at Exhibit 1, Tab2, Schedule 3, Attachment 1 and 2.

Corporate Entities Relationships Chart



Utility Organizational Chart



AFFILIATE TRANSACTIONS

HHI does not have any affiliates.

Exhibit 1: Administrative Documents

Tab 3 (of 4): Board Directions

BOARD DIRECTIONS FROM PREVIOUS EDR DECISIONS

Please find below a summary of the directions from previous Board decisions.

2006 EDR

In its 2006 EDR application, HHI reported line losses in excess of 5%. A subsequent Report of the Board dated May 11, 2005 stated that any distributor whose losses are higher than 5% would be required to report on those losses and provide an action plan as to how the distributor intends to reduce the level of losses. HHI hired Stantec Consulting Ltd. to perform a Utility Load Flow and Line Loss Evaluation Study. The Study was completed in 2006 and the findings were presented in a report dated February 16th 2007. The Santec Consulting Report can be found in Attachment 2 of this schedule.

In order to minimize printing costs, copies of the report will be made available upon request.

2007 IRM

The Board found that Hydro Hawkesbury's rate application was consistent with the Board approved guidelines and no specific direction was received from the OEB.

2008 IRM

The Board found that Hydro Hawkesbury's rate application was consistent with the Board approved guidelines and no specific direction was received from the OEB.

2009 IRM

The Board found that Hydro Hawkesbury's rate application was consistent with the Board approved guidelines and no specific direction was received from the OEB.
HHI offers the following notes on the Decision and Order.

Rural or Remote Electricity Rate Protection Adjustment

HHI has complied with the Board's decision regarding the Rural or Remote Electricity Rate Protection Adjustment and the model was consequently adjusted to reflect the new RRRP charge.

Smart Meter Funding Adder

On October 22, 2008 the Board issued a Guideline for Smart Meter Funding and Cost Recovery ("Smart Meter Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

Hydro Hawkesbury was granted the standard smart meter funding adder of $1.00 per metered customer per month, and the adder was reflected in the Tariff of Rates and Charges appended to the Decision and Order. Hydro Hawkesbury's variance accounts for smart meter program implementation costs, previously authorized by the Board, were continued.

Retail Transmission Service Rates

In the RTSR Guideline the Board directed all electricity distributors to propose an adjustment to their RTSRs to reflect the new UTRs for Ontario transmitters effective January 1, 2009. The objective of resetting the rates was to minimize the prospective balances in deferral accounts 1584 and 1586. Hydro Hawkesbury proposed not to adjust to its RTSR – Network Service Rates and RTSR – Line and Transformation Connection Service Rates. Hydro Hawkesbury indicated that this proposal would decrease the balance in deferral accounts 1584 and 1586. The Board found that this approach was reasonable and therefore approved these adjustments.

ACCOUNTING ORDERS

At the date of this application, no accounting orders were issued to HHI.

Generally Accepted Accounting Principles in Canada will be transitioned to International Financial Reporting Standards ("IFRS") effective January 1, 2011. To assist in the transition to IFRS, HHI is aware that the Board has initiated a consultation regarding the Transition of Regulatory Accounting to IFRS (the "IFRS Consultation").

The IFRS Consultation will provide an opportunity for Board staff to work with interested industry participants on an informal basis with a view to identifying issues associated with this transition as well as suggestions for how those issues might be addressed. This will provide input to Board staff's transition plan for the Board's regulatory accounting instruments and processes.

At the time of this application, HHI applies the generically authorized accounting orders and concepts but intends on complying fully with IFRS requirements and government imposed deadlines.

HHI has not sought and does not seek any specific accounting orders.

COMPLIANCE ORDERS

At the date of this application, no compliance orders have been issued to HHI.

OTHER BOARD DIRECTIONS

As previously mentioned, all of HHI's applications were consistent with the Board's approved guidelines. Consequently there are no specific directions from the OEB at this time. Board Direction from previous EDR decisions can be found at Exhibit 1, Tab 3, Schedule 1.

Exhibit 1: Administrative Documents

Tab 4 (of 4): Finance

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of business

The corporation was incorporated under the laws of Ontario on October 25, 2000 and is licensed by the Ontario Energy Board ("OEB" or “the Board”) as an electricity distributor. The incorporation was a requirement of the Electricity Act, 1998. The principal activity of the corporation is to distribute electricity to the Town of Hawkesbury. The corporation is regulated by the OEB and adjustments to the distribution and power rates require OEB approval.

Basis of Accounting

The financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles (“GAAP”) with rate regulation specifications described under the other assets heading for electricity distributors as required by the OEB and set forth in the Board’s "Accounting Procedures Handbook":

Accounting policies

Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company’s designation of such instruments. Settlement date accounting is used.

<u>Classification</u>

- Cash and term deposits/Held for trading
- Accounts receivable/Loans and receivables
- Unbilled revenue/Loans and receivables
- Accounts payable and accrued liabilities/Other liabilities
- Other current liabilities/Other liabilities
- Long-term liabilities/Other liabilities
- Note payable/Other liabilities

Held for trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other income.

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Transaction Costs

Transaction costs related to held for trading financial assets are expensed as incurred. Transaction costs related to available-for-sale financial assets, held-to-maturity financial assets, other liabilities and loans and receivables are netted against the carrying value of the asset or liability and are recognized over the expected life of the instrument using the effective interest method.

Inventories

Inventories are valued at the lower of average cost and net realizable value.

Capital Assets and Amortization

Capital assets are recorded at cost. Amortization is calculated on the basis of the straight-line method with reference to estimated useful lives of the assets in accordance with Ontario Energy Board policy at the following terms:

	Years
Land rights	25
Building	50
Transmission equipment	22 to 40
Distribution equipment	25 to 30
Office equipment	5 to 10
Rolling stock and equipment	4 to 10

Acquisitions made during the year are amortized at half the normal rate

Customer Deposits

Deposits are taken to guarantee the payment of power bills or contract performance and follow the Board approved guidelines.

Impairment of Long Lived Assets

Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable.
An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

Other Assets

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between forecast and actual purchased power costs in the rate year are held until the following year, when their final disposition is decided by the Board.

Hawkesbury Hydro Inc. recognizes purchased power cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, customers. In the absence of rate regulation, generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred.

The assets, other than variances, are recorded at cost in accordance with accounting principles as required by the Ontario Energy Board.

For some of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. Any disallowed costs will be expensed in the year that they are disallowed.

Recoveries for these assets are presented in a separate account until the Ontario Energy Board approves the recoveries. At that time, recoveries will be applied against the regulated assets.

Revenue Recognition

The Company recognizes revenue when persuasive evidence of an arrangement exists, delivery has occurred, the price to the buyer is fixed or determinable and collection is reasonably assured.

Additional Notes on Accounting Policies

Wages

Hours worked by line employees are recorded on a timesheet on a weekly basis using various codes for betterments to the distribution line, new developments or maintenance.

Payroll is recorded in a temporary account. On a monthly basis, an entry is made to distribute the salary expenses (including payroll burden) to the various G/L accounts (capital assets and expenses) based on the timesheets. Administrative payroll is recorded only to expense accounts

Regulation and Rate Setting

The corporation is required to follow regulations as set by the OEB. The OEB approves and sets rates for the transmission and distribution of electricity, ensures distribution companies fulfill their obligations to connect and service customers, and has the authority to provide rate protection for certain electricity customers. The OEB sets rates on an annual basis with rates becoming effective on May 1st through April 30th of the following year. The regulation and monitoring of Ontario's Energy Sector is completed by the OEB through application of codes, rules and guidelines, the licensing of market participants, assisting firms with the management of regulatory requirements, monitoring and enforcing compliance and adjudication.

Payment in Lieu (PIL) of Corporate Income Taxes and Capital Taxes

The corporation is a municipal electricity utility ("MEU") for purposes of the PIL's regime contained in the Electricity Act, 1998. As a municipally owned corporation HHI is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Each taxation year, the corporation is required to make payments in lieu of corporate income taxes and capital taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated based on the rules for computing taxable income and taxable capital outlined in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) taking into account any modifications made by the Electricity Act, 1998, and related regulations. The corporation provides for payments in lieu of corporate income taxes and capital taxes related to its regulated business using the taxes payable method as permitted by the CICA and the OEB. Under this method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable or receivable, it is expected that they will be reflected in the rates approved by the OEB at that point in time.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated amortization. Costs may include material, labour, contracted services, overhead, engineering costs. Also included in property, plant and equipment is the cost of capital assets constructed by developers or customers and contributed to the corporation. Upon disposal the cost and accumulated amortization related to the asset are removed and any gains or losses on disposal are credited or charged to other income on the statement of operations. Amortization is provided using the following method and annual rates:

- Land rights - 50 years straight-line basis
- Buildings - 20 years straight-line basis
- Distribution system - 25 years straight-line basis
- Supervisory equipment - 15 years straight-line basis
- Rolling stock - 5 and 8 years straight-line basis
- Shop, general office, and stores equipment - 10 years straight-line basis
- Computer hardware and computer software - 5 years straight-line basis
- Wireless equipment - 10 years straight-line basis

HISTORICAL FINANCIAL STATEMENTS

The Financial Statements presented in the following schedule depict HHI's formal records of its financial activities. These Financial Statements are for 2006, 2007, and 2008. These statements are prepared and audited by Deloitte & Touche. Please note that HHI does not prepare interim financial statements for the current year.

Financial Statements of
États financiers de

HAWKESBURY HYDRO INC.
HYDRO HAWKESBURY INC.

December 31, 2007
31 décembre 2007

Deloitte.

Deloitte and Touche LLP
300 McGill Street
Hawkesbury, Ontario
K6A 1P8

Tel: (613) 632-4178
Fax: (613) 632-7703
www.deloitte.ca

Auditors' Report

To the Directors of Hawkesbury Hydro Inc.

We have audited the balance sheet of Hawkesbury Hydro Inc. as at December 31, 2007 and the statements of earnings, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles

Rapport des vérificateurs

Aux administrateurs de Hydro Hawkesbury Inc.

Nous avons vérifié le bilan de Hydro Hawkesbury Inc. au 31 décembre 2007 et les états des résultats, des bénéfices non répartis et des flux de trésorerie de l'exercice terminé à cette date. La responsabilité de ces états financiers incombe à la direction de la Société. Notre responsabilité consiste à exprimer une opinion sur ces états financiers en nous fondant sur notre vérification.

Notre vérification a été effectuée conformément aux normes de vérification généralement reconnues du Canada. Ces normes exigent que la vérification soit planifiée et exécutée de manière à fournir l'assurance raisonnable que les états financiers sont exempts d'inexactitudes importantes. La vérification comprend le contrôle par sondages des éléments probants à l'appui des montants et des autres éléments d'information fournis dans les états financiers. Elle comprend également l'évaluation des principes comptables suivis et des estimations importantes faites par la direction, ainsi qu'une appréciation de la présentation d'ensemble des états financiers.

À notre avis, ces états financiers donnent, à tous les égards importants, une image fidèle de la situation financière de la Société au 31 décembre 2007 ainsi que des résultats de son exploitation et de ses flux de trésorerie pour l'exercice terminé à cette date selon les principes comptables généralement reconnus du Canada.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

Comptables agréés
Experts-comptables autorisés

Hawkesbury, Ontario
March 19, 2008

Hawkesbury, Ontario
Le 19 mars 2008

HAWKESBURY HYDRO INC.
Financial Statements
December 31, 2007

HYDRO HAWKESBURY INC.
États financiers
31 décembre 2007

HAWKESBURY HYDRO INC. / **HYDRO HAWKESBURY INC.**

Balance Sheet / **Bilan**

as at December 31, 2007 / **au 31 décembre 2007**

		2007		2006	
CURRENT ASSETS					ACTIF À COURT TERME
Cash and term deposits	**$**	**3 062 949**	$	2 371 211	Encaisse et dépôts à terme
Accounts receivable (note 4)		**1 404 973**		1 655 179	Débiteurs (note 4)
Inventories		**204 332**		225 743	Stocks
Unbilled revenue		**1 393 627**		1 258 322	Revenus non facturés
Prepaid charges		**31 543**		47 592	Frais payés d'avance
		6 097 424		5 558 047	
OTHER ASSETS (note 5)		**411 030**		479 549	AUTRES ACTIFS (note 5)
FUTURE INCOME TAXES		**427 998**		206 744	IMPÔTS FUTURS
CAPITAL ASSETS (note 6)		**1 923 495**		2 020 199	IMMOBILISATIONS CORPORELLES (note 6)
	$	**8 859 947**	$	8 264 539	
CURRENT LIABILITIES					PASSIF À COURT TERME
Accounts payable and accrued liabilities	**$**	**2 296 283**	$	2 251 055	Créditeurs et frais courus
Other current liabilities		**264 892**		216 940	Autres frais courus
Income taxes payable		**98 425**		116 364	Impôts sur le revenu à payer
Current portion of other long-term liabilities (note 7)		**192 427**		223 602	Tranche des autres passifs à long terme échéant à moins d'un an (note 7)
Current portion of note payable (note 8)		**190 525**		178 566	Tranche à court terme du billet à payer (note 8)
		3 042 552		2 986 527	
LONG-TERM LIABILITIES					DETTE À LONG TERME
Provision for sick leave benefits		**62 848**		58 529	Provision pour congés de maladie
Other long-term liabilities (note 7)		**2 043 087**		1 386 929	Autres passifs à long terme (note 7)
Note payable (note 8)		**1 151 897**		1 342 422	Billet à payer (note 8)
		3 257 832		2 787 880	
		6 300 384		5 774 407	
SHAREHOLDER'S EQUITY					CAPITAUX PROPRES
Share capital (note 9)		**1 689 346**		1 689 346	Capital-actions (note 9)
Retained earnings		**870 217**		800 786	Bénéfices non répartis
		2 559 563		2 490 132	
	$	**8 859 947**	$	8 264 539	

CONTINGENCIES (note 13) / ÉVENTUALITÉS (note 13)

ON BEHALF OF THE BOARD / AU NOM DU CONSEIL

Director ______________________ Administrateur

Director ______________________ Administrateur

The accompanying notes are an integral part of these financial statements.

Les notes complémentaires font partie intégrante de ces états financiers.

HAWKESBURY HYDRO INC.
Statement of Earnings
year ended December 31, 2007

HYDRO HAWKESBURY INC.
État des résultats
exercice terminé le 31 décembre 2007

	2007	2006	
REVENUE (note 10)			REVENUS (note 10)
Energy	**$ 14 304 462**	$ 13 996 585	Énergie
Distribution	**1 055 315**	1 102 774	Distribution
	15 359 777	15 099 359	
COST OF POWER	**14 304 462**	13 996 585	COÛT DE L'ÉNERGIE
	1 055 315	1 102 774	
OTHER OPERATING REVENUES	**318 280**	288 127	AUTRES PRODUITS
	1 373 595	1 390 901	
EXPENSES			DÉPENSES
Distribution	**229 814**	181 906	Distribution
Administration	**731 385**	771 562	Administration
Depreciation of capital assets	**164 127**	162 042	Amortissement des immobilisations corporelles
	1 125 326	1 115 510	
EARNINGS BEFORE INCOME TAXES	**248 269**	275 391	BÉNÉFICE AVANT IMPÔTS SUR LE REVENU
Income taxes			Impôts
Current	**315 625**	194 177	Courant
Future	**(221 254)**	(137 853)	Futurs
	94 371	56 324	
NET EARNINGS	**$ 153 898**	$ 219 067	BÉNÉFICE NET

The accompanying notes are an integral part of these financial statements.

Les notes complémentaires font partie intégrante de ces états financiers.

HAWKESBURY HYDRO INC.
Statement of Retained Earnings
year ended December 31, 2007

HYDRO HAWKESBURY INC.
État des bénéfices non répartis
exercice terminé le 31 décembre 2007

		2007		2006	
RETAINED EARNINGS, BEGINNING OF YEAR	**$**	**800 786**	$	666 186	BÉNÉFICES NON RÉPARTIS AU DÉBUT
NET EARNINGS		**153 898**		219 067	BÉNÉFICE NET
DIVIDEND ON COMMON SHARES		**(84 467)**		(84 467)	DIVIDENDE SUR LES ACTIONS ORDINAIRES
RETAINED EARNINGS, END OF YEAR	**$**	**870 217**	$	800 786	BÉNÉFICES NON RÉPARTIS À LA FIN

The accompanying notes are an integral part of these financial statements.

Les notes complémentaires font partie intégrante de ces états financiers.

HAWKESBURY HYDRO INC.
Statement of Cash Flows
year ended December 31, 2007

HYDRO HAWKESBURY INC.
État des flux de trésorerie
exercice terminé le 31 décembre 2007

	2007	2006	
OPERATING			EXPLOITATION
Net earnings	**$ 153 898**	$ 219 067	Bénéfice net
Adjustments for:			Ajustements pour:
Depreciation of capital assets	**164 127**	162 042	Amortissement des immobilisations corporelles
Future income taxes	**(221 254)**	(137 853)	Impôts futurs
Increase in sick leave benefits	**4 319**	846	Augmentation des congés de maladie
Changes in non-cash operating working capital items (note 11)	**227 602**	(418 116)	Variation des éléments hors caisse du fonds de roulement d'exploitation (note 11)
	328 692	(174 014)	
FINANCING			FINANCEMENT
Dividend on common shares	**(84 467)**	(84 467)	Dividende sur actions ordinaires
Increase in other long-term liabilities	**624 983**	384 656	Augmentation des autres passifs à long terme
Reimbursement of note payable	**(178 566)**	(167 357)	Remboursement du billet à payer
	361 950	132 832	
INVESTING			INVESTISSEMENT
Acquisition of capital assets	**(67 423)**	(150 887)	Acquisitions d'immobilisations corporelles
Decrease (increase) in other assets	**68 519**	(5 458)	Diminution (augmentation) des autres actifs
	1 096	(156 345)	
NET CASH INFLOW (OUTFLOW)	**691 738**	(197 527)	AUGMENTATION (DIMINUTION) NETTE DE L'ENCAISSE
CASH AND TERM DEPOSITS, BEGINNING OF YEAR	**2 371 211**	2 568 738	ENCAISSE ET DÉPÔTS À TERME AU DÉBUT
CASH AND TERM DEPOSITS, END OF YEAR	**$ 3 062 949**	$ 2 371 211	ENCAISSE ET DÉPÔTS À TERME À LA FIN

Additional information is presented in note 11.

Des renseignements supplémentaires sont présentés à la note 11.

The accompanying notes are an integral part of these financial statements.

Les notes complémentaires font partie intégrante de ces états financiers.

1. DESCRIPTION OF BUSINESS

The Company is incorporated under the Ontario Business Corporations Act and is engaged in the distribution of electricity.

2. CHANGES IN ACCOUNTING POLICIES

Financial Instruments

The Company adopted the following recommendations of CICA Handbook:

Section 3855, *Financial Instruments – Recognition and Measurement.* This Section describes the standards for recognizing and measuring financial instruments in the balance sheet and the standards for reporting gains and losses in the financial statements. Under the new standard, financial assets and liabilities are initially recorded at fair value. Subsequently, financial instruments classified as financial assets or liabilities held for trading, financial assets available-for-sale and derivative financial instruments, part of a hedging relationship or not, have to be measured at fair value on the balance sheet at each reporting date, whereas other financial instruments are measured at amortized cost using the effective interest method.

Section 3861, *Financial instruments – Disclosure and Presentation*. This Section establishes standards for presentation of financial instruments and non-financial derivatives, and identifies the information that should be disclosed about them.

Section 3251, *Equity*. This Section establishes standards for the presentation of equity and changes in equity during the reporting period.

The Company has made the following classification:

- Cash and term deposits are classified as financial asset held for trading and are measured at fair value.
- Accounts receivable and unbilled revenues are classified as loans and receivables and are recorded at amortized cost using the effective interest method.
- Accounts payable and accrued liabilities, other current liabilities, long-term liabilities and note payable are classified as other liabilities and measured at amortized cost using the effective interest method.

1. DESCRIPTION DE L'ENTREPRISE

La Société est constituée en vertu de la Loi sur les sociétés par actions de l'Ontario et se spécialise dans la distribution de l'électricité.

2. MODIFICATIONS DE CONVENTIONS COMPTABLES

Instruments financiers

La Société a adopté les recommandations suivantes du Manuel de l'ICCA :

Le chapitre 3855 intitulé « Instruments financiers – comptabilisation et évaluation ». Ce chapitre énonce les normes de comptabilisation et d'évaluation des instruments financiers figurant au bilan et les normes de présentation des gains et des pertes dans les états financiers. Conformément à la nouvelle norme, les actifs et les passifs financiers sont initialement comptabilisés à leur juste valeur. Par la suite, les instruments financiers classés comme des actifs ou des passifs financiers détenus à des fins de transaction, les actifs financiers disponibles à la vente et les instruments financiers dérivés, qu'ils fassent ou non partie d'une relation de couverture, doivent être évalués à la juste valeur dans le bilan à chaque date de clôture, tandis que les autres instruments financiers sont mesurés au coût après amortissement selon la méthode du taux d'intérêt effectif.

Le chapitre 3861 intitulé « Instruments financiers – Information à fournir et présentation ». Le chapitre établit des normes de présentation pour les instruments financiers et les dérivés non financiers, et précise quelles sont les informations à fournir à leur sujet.

Le chapitre 3251 intitulé « Capitaux propres ». Le chapitre définit des normes pour la présentation des capitaux propres et des variations des capitaux propres au cours de la période considérée.

La Société a effectué les classements suivants :

- L'encaisse et dépôts à terme sont classés comme des actifs financiers détenus à des fins de transaction et sont comptabilisés à la juste valeur.
- Les débiteurs et les revenus non facturés sont classés comme des prêts et créances, et sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif.
- Les créditeurs et frais courus, autres frais courus, passifs à long terme et billet à payer sont classés comme autres passifs et sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif.

2. CHANGES IN ACCOUNTING POLICIES (continued)

Financial Instruments (continued)

Transaction Costs

Transaction costs will be capitalized to the cost of financial assets and liabilities classified as other than held for trading.

These new standards were applied as of January 1st 2007 without restatement of prior years figures. The application of these new standards had no impact on the financial statements.

Future Accounting Changes

Inventories

In June 2007, the Canadian Institute of Chartered Accountants ("CICA") issued Section 3031, *Inventories*, replacing Section 3030, *Inventories*. The new Section will be applicable to financial statements relating to fiscal years beginning on or after January 1, 2008. Accordingly, the Company will adopt the new standards for its fiscal year beginning January 1, 2008. It provides more guidance on the measurement and disclosure requirements for inventories. (For example, it requires that fixed and variable production overheads be systematically allocated to the carrying amount of inventory.) The Company does not expect that the adoption of this new Section will have a material impact on its financial statements.

Financial Instruments

In December 2006, the CICA issued Section 3862, *Financial Instruments - Disclosures*; Section 3863, *Financial Instruments - Presentation*; and Section 1535, *Capital Disclosures*. All three Sections will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2007. Accordingly, the Company will adopt the new standards for its fiscal year beginning January 1, 2008. Section 3862 on financial instruments disclosures, requires the disclosure of information about: the significance of financial instruments for the entity's financial position and performance and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks. Section 3863 on the presentation of financial instruments is unchanged from the presentation requirements included in Section 3861. Section 1535 on capital disclosures requires the disclosure of information about an entity's objectives, policies and processes for managing capital.

The Company does not expect that the adoption of these new Sections will have a material impact on its financial statements.

2. MODIFICATIONS DE CONVENTIONS COMPTABLES (suite)

Instruments financiers (suite)

Coûts de transaction

Les coûts de transaction seront capitalisés au coût des actifs et passifs financiers qui ne sont pas classés comme détenus à des fins de transaction.

Ces nouvelles normes ont été appliquées à compter du 1er janvier 2007 sans retraitement des états financiers des exercices antérieurs. L'application de ces nouvelles normes n'a eu aucun impact sur les états financiers.

Modifications comptables futures

Stocks

En juin 2007, l'Institut Canadien des Comptables Agréés (" ICCA ") a publié le chapitre 3031 intitulé « Stocks » remplaçant le chapitre 3030 intitulé « Stocks ». Ce nouveau chapitre s'appliquera aux états financiers des exercices ouverts à partir du 1er janvier 2008. Par conséquent, la Société adoptera les nouvelles normes au cours de son exercice débutant le 1er janvier 2008. Le chapitre fournit davantage de directives concernant le traitement comptable et la présentation des stocks. (Il exige notamment que les frais généraux de production fixes et variables soient systématiquement affectés à la valeur comptable des stocks.) La Société ne prévoit pas que l'adoption de ce nouveau chapitre aura une incidence importante sur ses états financiers.

Instruments financiers

En décembre 2006, l'ICCA a publié le chapitre 3862 intitulé « Instruments financiers - informations à fournir »", le chapitre 3863 intitulé "Instruments financiers - présentation" et le chapitre 1535 intitulé « Informations à fournir concernant le capital ». Ces trois chapitres s'appliqueront aux états financiers des exercices ouverts à partir du 1er octobre 2007. Par conséquent, la Société adoptera les nouvelles normes au cours de son exercice débutant le 1er janvier 2008. Le chapitre 3862 qui traite des informations à fournir à l'égard des instruments financiers, impose aux entités de fournir des informations au sujet de : l'importance des instruments financiers au regard de la situation financière et de la performance financière de l'entité et la nature et l'ampleur des risques découlant des instruments financiers auxquels l'entité est exposée au cours de la période et à la date de clôture, ainsi que la façon dont l'entité gère ces risques. Le chapitre 3863 comporte les mêmes exigences en matière de présentation des instruments financiers que le chapitre 3861. Le chapitre 1535 sur les informations à fournir concernant le capital exige la présentation d'informations sur les objectifs, les politiques et les procédés de gestion de capital d'une entité.

La Société ne prévoit pas que l'adoption de ces nouveaux chapitres aura une incidence importante sur ses états financiers.

3. ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles with rate regulation specifications described under the other assets heading for electricity distributors as required by the Ontario Energy Board and set forth in the "Accounting Procedures Handbook":

Financial Instruments

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

Classification

Cash and term deposits/Held for trading
Accounts receivable/Loans and receivables
Unbilled revenue/Loans and receivables
Accounts payable and accrued liabilities/Other liabilities
Other current liabilities/Other liabilities
Long-term liabilities/Other liabilities
Note payable/Other liabilities

Held for Trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other income.

Loans and Receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other Liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Transaction Costs

Transaction costs related to held for trading financial assets are expensed as incurred. Transaction costs related to available-for-sale financial assets, held-to-maturity financial assets, other liabilities and loans and receivables are netted against the carrying value of the asset or liability and are then recognized over the expected life of the instrument using the effective interest method.

3. CONVENTIONS COMPTABLES

Les états financiers ont été préparés conformément aux principes comptables généralement reconnus du Canada et tiennent compte des particularités énumérées sous la rubrique des autres actifs pour les distributeurs d'électricité tel que requis par la Commission de l'énergie de l'Ontario et établis dans le ''Accounting Procedures Handbook'':

Instruments financiers

Les actifs financiers et les passifs financiers sont constatés initialement à la juste valeur et leur évaluation ultérieure dépend de leur classement, comme il est décrit ci-après. Leur classement dépend de l'objet visé lorsque les instruments financiers ont été acquis ou émis, de leurs caractéristiques et de leur désignation par la Société. La comptabilisation à la date de règlement est utilisée.

Classification

Encaisse et dépôts à terme/Détenus à des fins de transaction
Débiteurs/Prêts et créances
Revenus non facturés/Prêts et créances
Créditeurs et frais courus/Autres passifs
Autres frais courus/Autres passifs
Passifs à long terme/Autres passifs
Billet à payer/Autres passifs

Détenus à des fins de transaction

Les actifs financiers détenus à des fins de transaction sont des actifs financiers qui sont généralement acquis en vue d'être revendus avant leur échéance ou qui ont été désignés comme étant détenus à des fins de transaction. Ils sont mesurés à la juste valeur à la date de clôture. Les fluctuations de la juste valeur qui incluent les intérêts gagnés, les intérêts courus, les gains et pertes réalisés sur cession et les gains et pertes non réalisés sont inclus dans les autres produits.

Prêts et créances

Les prêts et créances sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif.

Autres passifs

Les autres passifs sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif et comprennent tous les passifs financiers autres que les instruments dérivés.

Coûts de transaction

Les coûts de transaction liés aux actifs financiers détenus à des fins de transaction sont passés en charge au moment où ils sont engagés. Les coûts de transaction liés aux actifs financiers disponibles à la vente, aux actifs financiers détenus jusqu'à leur échéance, aux autres passifs et aux prêts et créances sont comptabilisés en diminution de la valeur comptable de l'actif ou du passif et sont ensuite constatés sur la durée de vie prévue de l'instrument selon la méthode du taux d'intérêt effectif.

3. ACCOUNTING POLICIES (continued)

Financial Instruments (continued)

Effective Interest Method

The Company uses the effective interest method to recognize interest income or expense which includes transaction costs or fees, premiums or discounts earned or incurred for financial instruments.

Inventories

Inventories are valued at the lower of average cost and replacement cost.

Capital Assets and Depreciation

Capital assets are recorded at cost. Depreciation is calculated on the basis of the straight-line method with reference to estimated useful lives of the assets in accordance with Ontario Energy Board policy at the following terms:

	Years
Land rights	25
Building	50
Transmission equipment	22 to 40
Distribution equipment	25 to 30
Office equipment	5 to 10
Rolling stock and equipment	4 to 10

Acquisitions made during the year are depreciated at half the normal rate.

Customer Deposits

Deposits are taken to guarantee the payment of power bills or contract performance.

Impairment of Long-lived Assets

Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

3. CONVENTIONS COMPTABLES (suite)

Instruments financiers (suite)

Méthode du taux d’intérêt effectif

La Société utilise la méthode du taux d’intérêt effectif pour constater le produit ou la charge d’intérêt, ce qui inclut les coûts de transaction ainsi que les frais, les primes et les escomptes gagnés ou engagés relativement aux instruments financiers.

Stocks

Les stocks sont évalués au moins élevé du coût moyen et la valeur de remplacement.

Immobilisations corporelles et amortissement

Les immobilisations corporelles sont comptabilisées au coût. L'amortissement est calculé selon la méthode de l'amortissement linéaire réparti sur la durée estimative de vie utile de l'immobilisation selon les politiques de la Commission de l’énergie de l’Ontario aux termes suivants:

	Années
Droit de passage	25
Immeuble	50
Équipement de transmission	22 à 40
Équipement de distribution	25 à 30
Équipement de bureau	5 à 10
Matériel roulant et équipement	4 à 10

Les acquisitions de l’année sont amorties à la moitié du taux régulier.

Dépôts de clients

Des dépôts sont pris en garantie de paiement de la facturation ou de contrat.

Dépréciation d’actifs à long terme

Les actifs à long terme sont soumis à un test de recouvrabilité lorsque des événements ou des changements de situation indiquent que leur valeur comptable pourrait ne pas être recouvrable. Une perte de valeur est constatée lorsque leur valeur comptable excède les flux de trésorerie non actualisés découlant de leur utilisation et de leur sortie éventuelle. La perte de valeur constatée est mesurée comme étant l'excédent de la valeur comptable de l'actif sur sa juste valeur.

3. ACCOUNTING POLICIES (continued)

Other Assets

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between forecast and actual purchased power costs in the rate year are held until the following year, when their final disposition is decided. Hawkesbury Hydro Inc. recognizes purchased power cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, customers. In the absence of rate regulation, generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred.

The assets, other than variances, are recorded at cost in accordance with accounting principles as required by the Ontario Energy Board.

For some of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. Any disallowed costs will be expensed in the year that they are disallowed.

Recoveries for these assets are presented in a separate account until the Ontario Energy Board approves the recoveries. At that time, recoveries will be applied against the regulated assets.

The financial statements effects of rate regulation are presented in note 15.

Revenue Recognition

The Company recognizes revenue when persuasive evidence of an arrangement exists, delivery has occurred, the price to the buyer is fixed or determinable and collection is reasonably assured.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

3. CONVENTIONS COMPTABLES (suite)

Autres actifs

Les coûts associés à l'énergie achetée sont pris en compte dans les tarifs autorisés, sur une base prévisionnelle. Aux fins de l'établissement des tarifs, les écarts entre les coûts prévus et les coûts réels associés à l'énergie achetée au cours de l'année de tarification sont laissés en suspens jusqu'à l'année suivante, au cours de laquelle leur traitement définitif est déterminé. Hydro Hawkesbury Inc. comptabilise les écarts de coûts associés à l'énergie achetée à titre d'actif ou de passif réglementaire, parce que la Société s'attend à obtenir l'autorisation de recouvrer auprès des clients futurs les montants laissés en suspens d'une année à l'autre aux fins de l'établissement des tarifs, ou à devoir rembourser les montants à ces clients. Si les tarifs n'étaient pas réglementés, les coûts réels associés à l'énergie achetée devraient être passés en charges au moment où ils sont engagés, selon les principes comptables généralement reconnus.

Les actifs autres que les écarts de prix ont aussi été établis selon les règles de la Commission de l'Énergie. Ils ont été comptabilisés au coût.

Dans le cas de certains des éléments réglementaires mentionnés ci-dessus, les risques et incertitudes découlant du pouvoir ultime de l'autorité de réglementation de déterminer le traitement de l'élément aux fins de la tarification influent sur la période prévue de recouvrement ou de règlement, ou sur la probabilité de recouvrement ou de règlement. Les montants refusés seront imputés aux résultats dans l'année où ils seront refusés.

Les recouvrements pour tous ces frais sont identifiés dans un compte distinct et seront appliqués contre les actifs suite à l'approbation par la Commission de l'Énergie.

Les effets de la règlementation des tarifs sont décris à la note 15.

Constatation des produits

La Société constate ses produits lorsqu'il existe des preuves convaincantes de l'existence d'un accord, que les marchandises sont expédiées aux clients, que le prix est déterminé ou déterminable et que l'encaissement est raisonnablement assuré.

Utilisation d'estimations

Dans le cadre de la préparation des états financiers, la direction doit établir des estimations et des hypothèses qui ont une incidence sur les montants des actifs et des passifs présentés et sur la présentation des actifs et des passifs éventuels à la date des états financiers, ainsi que sur les montants des produits d'exploitation et des charges constatés au cours de la période visée par les états financiers. Les résultats réels pourraient varier par rapport à ces estimations.

4. ACCOUNTS RECEIVABLE / 4. DÉBITEURS

	2007	2006	
Electrical energy	**$ 1 410 196**	$ 1 663 706	Énergie électrique
Allowance for doubtful account	**(9 350)**	(11 274)	Provision pour mauvaises créances
	1 400 846	1 652 432	
Others	**4 127**	2 747	Autres
	$ 1 404 973	$ 1 655 179	

5. OTHER ASSETS / 5. AUTRES ACTIFS

	2007	2006	
Transition costs	**$ -**	$ 204 090	Frais de transition
Other regulatory assets	**339 323**	387 688	Autres actifs réglementaires
Amounts to recover (recoveries)	**71 707**	(112 229)	Montants à récupérer (recouvrements)
	$ 411 030	$ 479 549	

6. CAPITAL ASSETS / 6. IMMOBILISATIONS CORPORELLES

	2007			2006	
	Cost/coût	Accumulated depreciation/ Amortissement cumulé	Net book value/ Valeur nette	Net book value/ Valeur nette	
Land & land rights	**$ 56 888**	**$ 4 486**	**$ 52 402**	$ 53 028	Terrain & droit de passage
Building	**824 124**	**145 826**	**678 298**	697 246	Immeuble
Transmission equipment	**433 901**	**140 762**	**293 139**	315 685	Équipement de transmission
Distribution equipment	**1 471 950**	**640 331**	**831 619**	891 697	Équipement de distribution
Office equipment	**108 551**	**49 415**	**59 136**	30 562	Équipement de bureau
Rolling stock and equipment	**201 199**	**192 298**	**8 901**	31 981	Matériel roulant et équipement
	$ 3 096 613	**$ 1 173 118**	**$ 1 923 495**	$ 2 020 199	

7. OTHER LONG-TERM LIABILITIES / 7. AUTRES PASSIFS À LONG TERME

	2007	2006	
Pre-market opening energy variance	**$ -**	$ 103 456	Écarts de prix avant l'ouverture du marché
Retail settlement variance account	**1 561 205**	1 006 272	Écarts de prix avec les détaillants
Refunded	**-**	(213 297)	Remboursements
Customer deposits	**620 282**	587 967	Dépôts de clients
Hydro One	**54 027**	114 651	Hydro One
Other	**-**	11 482	Autre
	2 235 514	1 610 531	
Current portion	**192 427**	223 602	Portion à court terme
	$ 2 043 087	$ 1 386 929	

Amounts owed to Hydro One are to be repaid as follows: 2008, $ 27 427; 2009, $ 20 796 and 2010, $ 5 804.

Les sommes dues à Hydro One doivent être remboursées de la façon suivante : 2008, $ 27 427; 2009, $ 20 796 and 2010, $ 5 804.

8. NOTE PAYABLE / 8. BILLET À PAYER

	2007	2006	
Note payable to shareholder, 6.5%, payable in monthly instalments of $ 22 681, including interest	**$ 1 342 422**	$ 1 520 988	Billet à payer à l'actionnaire, 6.5%, remboursable par versements mensuels de $ 22 681, incluant les intérêts
Current portion	**190 525**	178 566	Tranche à court terme
	$ 1 151 897	$ 1 342 422	

Principal repayments to be made during the next five years are as follows: 2008, $ 190 525; 2009, $ 203 284; 2010, $ 216 899; 2011, $ 231 425 and 2012, $ 246 924.

Les versements en capital à effectuer au cours des cinq prochains exercices sont les suivants : 2008, $ 190 525; 2009, $ 203 284 ; 2010, $ 216 899 ; 2011, $ 231 425 and 2012, $ 246 924.

9. SHARE CAPITAL / 9. CAPITAL-ACTIONS

Authorized / *Autorisé*

Unlimited number of common shares / Nombre illimité d'actions ordinaires

Issued / *Émis*

	2007	2006	
1 000 common shares	**$ 1 689 346**	$ 1 689 346	1 000 actions ordinaires

10. REVENUE / 10. REVENUS

	2007	2006	
Energy			*Énergie*
Residential	**$ 2 799 874**	$ 2 817 016	Résidentiel
General < 50 KW	**1 128 659**	1 131 809	Général < 50 KW
General > 50 KW	**3 745 637**	4 008 407	Général > 50 KW
Large users	**1 604 641**	1 712 679	Consommation significative
Street light	**68 177**	68 857	Éclairage des rues
Sentinel	**6 602**	6 812	Sentinelle
Retailers	**1 605 910**	1 003 830	Détaillants
Regulatory charges	**3 344 962**	3 247 175	Frais réglementés
	$ 14 304 462	$ 13 996 585	
Distribution			*Distribution*
Residential	**$ 722 604**	$ 723 774	Résidentiel
General < 50 KW	**160 189**	164 180	Général < 50 KW
General > 50 KW	**(3 204)**	45 239	Général > 50 KW
Large users	**135 842**	130 130	Consommation significative
Street light	**13 987**	14 202	Éclairage des rues
Sentinel	**2 312**	2 425	Sentinelle
Administration fees	**23 585**	22 824	Frais d'administration
	$ 1 055 315	$ 1 102 774	

11. ADDITIONAL INFORMATION RELATING TO THE STATEMENT OF CASH FLOWS / 11. RENSEIGNEMENTS COMPLÉMENTAIRES À L'ÉTAT DES FLUX DE TRÉSORERIE

	2007	2006	
Changes in non-cash operating working capital items			*Variation des éléments hors caisse du fonds de roulement d'exploitation*
Accounts receivable	**$ 250 206**	$ (886 501)	Débiteurs
Inventories	**21 411**	(45 138)	Stocks
Unbilled revenue	**(135 305)**	396 390	Revenus non facturés
Prepaid expenses	**16 049**	(7 424)	Frais payés d'avance
Accounts payable and accrued charges	**45 228**	195 655	Créditeurs et frais courus
Other current liabilities	**47 952**	(106 017)	Autres frais courus
Income taxes	**(17 939)**	34 919	Impôts sur le revenu
	$ 227 602	$ (418 116)	
Other information			*Autres renseignements*
Interest paid	**$ 119 755**	$ 132 027	Intérêts payés
Income taxes paid	**$ 333 564**	$ 159 258	Impôts payés

12. PENSION PLAN

The Hydro makes contributions to the Ontario Municipal Employees Retirement Fund (OMERS), which is a multi-employer plan, on behalf of 7 members of its staff. The plan is a defined benefit plan, which specifies the amount or the retirement benefit to be received by the employees based on the length of service and rates of pay.

The amount contributed to OMERS for 2007 is $ 25 055 (2006 - $ 24 188) for current service and is included as an expenditure in the ''Statement of Earnings''.

12. RÉGIME DE RETRAITE

L'Hydro contribue au régime de retraite des employés municipaux de l'Ontario (RREMO), qui est un régime à employeurs multiples, pour 7 membres de son personnel. Il s'agit d'un régime à prestations déterminées qui prévoit le niveau de pension à être reçu par les employés en se basant sur les années de service et le niveau salarial.

Le montant contribué à RREMO en 2007 est de $ 25 055 (2006 - $ 24 188) pour services courants et est inclus dans les dépenses à l'''État des résultats''.

13. CONTINGENCIES

Letter of Guarantee

A letter of guarantee in the amount of $ 399 528 was issued in favour of the Independent Electricity System Operator. The Corporation of the Town of Hawkesbury endorsed this letter of guarantee.

13. ÉVENTUALITÉS

Lettre de garantie

Une lettre de garantie au montant de $ 399 528 a été émise en faveur de "Independent Electricity System Operator". La Corporation de la Ville de Hawkesbury a endossé cette lettre de garantie.

14. RELATED PARTY TRANSACTIONS

During the year, the Company purchased and sold services to the Corporation of the Town of Hawkesbury, its sole shareholder. These transactions were made in the normal course of business and have been recorded at the exchange amounts.

14. OPÉRATIONS ENTRE APPARENTÉS

Au cours de l'exercice, la Société a achetée et vendue des services à la Corporation de la Ville de Hawkesbury, son unique actionnaire. Les opérations ont été effectuées dans le cours normal des activités et ont été comptabilisées à la valeur d'échange.

	2007	2006	
Note payable to shareholder			Billet à payer à l'actionnaire
Interest paid	**$ 93 606**	$ 104 815	Intérêts versés
Principal paid	**178 566**	167 357	Capital versé
Dividend on common shares	**84 467**	84 467	Dividende sur actions ordinaires
Other operating revenues	**12 624**	30 135	Autres produits
Distribution	**4 200**	3 850	Distribution
Administration	**25 634**	25 171	Administration
	$ 399 097	$ 415 795	

15. RATE REGULATION'S EFFECTS ON FINANCIAL STATEMENTS / 15. EFFETS DE LA RÉGLEMENTATION DES TARIFS SUR LES ÉTATS FINANCIERS

	2007	2006	
Earnings before income taxes in accordance with accounting principles for electricity distributers as required by the Ontario Energy Board	**$ 248 269**	$ 275 391	Bénéfice avant impôts sur le revenu conformément aux principes comptables pour les distributeurs d'électricité tels que requis par la Commission de l'Énergie de l'Ontario
Variances/expenses included in other assets/other long-term liabilities	**642 699**	339 956	Variations/dépenses incluses dans les autres actifs/autre dette à long terme
Depreciation of capital assets included in other assets	**-**	(740)	Amortissement des immobilisations corporelles inclus dans les autres actifs
Recovered	**90 596**	38 261	Recouvrements
Adjusted earnings before income taxes and before the effect of the regulation on the financial statements	**$ 981 564**	$ 652 868	Bénéfice avant impôts sur le revenu et avant l'effet de la réglementation sur les états financiers

16. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

16. CHIFFRES DE L'EXERCICE PRÉCÉDENT

Certains chiffres de l'exercice précédent ont été reclassés afin que leur présentation soit conforme à celle adoptée pour l'exercice courant.

Financial Statements of
États financiers de

HAWKESBURY HYDRO INC.
HYDRO HAWKESBURY INC.

December 31, 2008
31 décembre 2008

Deloitte and Touche LLP
300 McGill Street
Hawkesbury, Ontario
K6A 1P8

Tel: (613) 632-4178
Fax: (613) 632-7703
www.deloitte.ca

Auditors' Report

To the Directors of Hawkesbury Hydro Inc.

We have audited the balance sheet of Hawkesbury Hydro Inc. as at December 31, 2008 and the statements of earnings, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles

Rapport des vérificateurs

Aux administrateurs de Hydro Hawkesbury Inc.

Nous avons vérifié le bilan de Hydro Hawkesbury Inc. au 31 décembre 2008 et les états des résultats, des bénéfices non répartis et des flux de trésorerie de l'exercice terminé à cette date. La responsabilité de ces états financiers incombe à la direction de la Société. Notre responsabilité consiste à exprimer une opinion sur ces états financiers en nous fondant sur notre vérification.

Notre vérification a été effectuée conformément aux normes de vérification généralement reconnues du Canada. Ces normes exigent que la vérification soit planifiée et exécutée de manière à fournir l'assurance raisonnable que les états financiers sont exempts d'inexactitudes importantes. La vérification comprend le contrôle par sondages des éléments probants à l'appui des montants et des autres éléments d'information fournis dans les états financiers. Elle comprend également l'évaluation des principes comptables suivis et des estimations importantes faites par la direction, ainsi qu'une appréciation de la présentation d'ensemble des états financiers.

À notre avis, ces états financiers donnent, à tous les égards importants, une image fidèle de la situation financière de la Société au 31 décembre 2008 ainsi que des résultats de son exploitation et de ses flux de trésorerie pour l'exercice terminé à cette date selon les principes comptables généralement reconnus du Canada.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

Hawkesbury, Ontario
March 19, 2009

Comptables agréés
Experts-comptables autorisés

Hawkesbury, Ontario
Le 19 mars 2009

HAWKESBURY HYDRO INC.
Financial statements
December 31, 2008

HYDRO HAWKESBURY INC.
États financiers
31 décembre 2008

HAWKESBURY HYDRO INC.
Balance sheet
as at December 31, 2008

HYDRO HAWKESBURY INC.
Bilan
au 31 décembre 2008

	2008	2007	
CURRENT ASSETS			ACTIF À COURT TERME
Cash and term deposits	**$ 3 027 690**	$ 3 062 949	Encaisse et dépôts à terme
Accounts receivable (note 4)	**1 505 355**	1 404 973	Débiteurs (note 4)
Inventories	**218 227**	204 332	Stocks
Unbilled revenue	**1 478 591**	1 393 627	Revenus non facturés
Prepaid charges	**52 632**	31 543	Frais payés d'avance
Income taxes	**18 532**	-	Impôts sur le revenu
	6 301 027	6 097 424	
OTHER ASSETS (note 5)	**473 905**	411 030	AUTRES ACTIFS (note 5)
FUTURE INCOME TAXES	**552 700**	427 998	IMPÔTS FUTURS
CAPITAL ASSETS (note 6)	**1 894 469**	1 923 495	IMMOBILISATIONS CORPORELLES (note 6)
	$ 9 222 101	$ 8 859 947	
CURRENT LIABILITIES			PASSIF À COURT TERME
Accounts payable and accrued liabilities	**$ 2 211 933**	$ 2 296 283	Créditeurs et frais courus
Other current liabilities	**156 660**	264 892	Autres frais courus
Income taxes	**-**	98 425	Impôts sur le revenu
Current portion of other long-term liabilities (note 7)	**252 329**	192 427	Tranche des autres passifs à long terme échéant à moins d'un an (note 7)
Current portion of note payable (note 8)	**203 284**	190 525	Tranche à court terme du billet à payer (note 8)
	2 824 206	3 042 552	
LONG-TERM LIABILITIES			DETTE À LONG TERME
Provision for sick leave benefits	**67 626**	62 848	Provision pour congés de maladie
Other long-term liabilities (note 7)	**2 843 071**	2 043 087	Autres passifs à long terme (note 7)
Note payable (note 8)	**948 614**	1 151 897	Billet à payer (note 8)
	3 859 311	3 257 832	
	6 683 517	6 300 384	
SHAREHOLDER'S EQUITY			CAPITAUX PROPRES
Share capital (note 9)	**1 689 346**	1 689 346	Capital-actions (note 9)
Retained earnings	**849 238**	870 217	Bénéfices non répartis
	2 538 584	2 559 563	
	$ 9 222 101	$ 8 859 947	

CONTINGENCIES (note 13) — ÉVENTUALITÉS (note 13)

ON BEHALF OF THE BOARD — AU NOM DU CONSEIL

Director ______________________ Administrateur

Director ______________________ Administrateur

HAWKESBURY HYDRO INC. / HYDRO HAWKESBURY INC.

Statement of earnings / **État des résultats**

year ended December 31, 2008 / **exercice terminé le 31 décembre 2008**

	2008	2007	
REVENUE (note 10)			REVENUS (note 10)
Energy	**$ 13 590 055**	$ 14 304 462	Énergie
Distribution	**1 057 466**	1 055 315	Distribution
	14 647 521	15 359 777	
COST OF POWER	**13 590 055**	14 304 462	COÛT DE L'ÉNERGIE
	1 057 466	1 055 315	
OTHER OPERATING REVENUES	**268 774**	318 280	AUTRES PRODUITS
	1 326 240	1 373 595	
EXPENSES			DÉPENSES
Distribution	**224 291**	229 814	Distribution
Administration	**816 094**	731 385	Administration
Amortization of capital assets	**149 158**	164 127	Amortissement des immobilisations corporelles
Amortization of contribution for capital assets	**(1 093)**	-	Amortissement des apports pour immobilisations corporelles
	1 188 450	1 125 326	
EARNINGS BEFORE INCOME TAXES	**137 790**	248 269	BÉNÉFICE AVANT IMPÔTS SUR LE REVENU
Income taxes			Impôts
Current	**199 004**	315 625	Courant
Future	**(124 702)**	(221 254)	Futurs
	74 302	94 371	
NET EARNINGS	**$ 63 488**	$ 153 898	BÉNÉFICE NET

HAWKESBURY HYDRO INC.
Statement of retained earnings
year ended December 31, 2008

HYDRO HAWKESBURY INC.
État des bénéfices non répartis
exercice terminé le 31 décembre 2008

		2008		2007	
RETAINED EARNINGS, BEGINNING OF YEAR	**$**	**870 217**	$	800 786	BÉNÉFICES NON RÉPARTIS AU DÉBUT
NET EARNINGS		**63 488**		153 898	BÉNÉFICE NET
DIVIDEND ON COMMON SHARES		**(84 467)**		(84 467)	DIVIDENDE SUR LES ACTIONS ORDINAIRES
RETAINED EARNINGS, END OF YEAR	**$**	**849 238**	$	870 217	BÉNÉFICES NON RÉPARTIS À LA FIN

HAWKESBURY HYDRO INC.
Statement of cash flows
year ended December 31, 2008

HYDRO HAWKESBURY INC.
État des flux de trésorerie
exercice terminé le 31 décembre 2007

	2008	2007	
OPERATING			EXPLOITATION
Net earnings	**$ 63 488**	$ 153 898	Bénéfice net
Adjustments for:			Ajustements pour:
Amortization of capital assets	**149 158**	164 127	Amortissement des immobilisations corporelles
Amortization of contribution for capital assets	**(1 093)**	-	Amortissement des apports pour immobilisations corporelles
Future income taxes	**(124 702)**	(221 254)	Impôts futurs
Increase in sick leave benefits	**4 778**	4 319	Augmentation des congés de maladie
Changes in non-cash operating working capital items (note 11)	**(529 869)**	227 602	Variation des éléments hors caisse du fonds de roulement d'exploitation (note 11)
	(438 240)	328 692	
FINANCING			FINANCEMENT
Dividend on common shares	**(84 467)**	(84 467)	Dividende sur actions ordinaires
Increase in other long-term liabilities	**859 886**	624 983	Augmentation des autres passifs à long terme
Reimbursement of note payable	**(190 524)**	(178 566)	Remboursement du billet à payer
Increase of contribution for capital assets	**55 867**	-	Augmentation des apports pour immobilisations corporelles
	640 762	361 950	
INVESTING			INVESTISSEMENT
Acquisition of capital assets	**(174 906)**	(67 423)	Acquisitions d'immobilisations corporelles
Decrease (increase) in other assets	**(62 875)**	68 519	Diminution (augmentation) des autres actifs
	(237 781)	1 096	
NET CASH INFLOW (OUTFLOW)	**(35 259)**	691 738	AUGMENTATION (DIMINUTION) NETTE DE L'ENCAISSE
CASH AND TERM DEPOSITS, BEGINNING OF YEAR	**3 062 949**	2 371 211	ENCAISSE ET DÉPÔTS À TERME AU DÉBUT
CASH AND TERM DEPOSITS, END OF YEAR	**$ 3 027 690**	$ 3 062 949	ENCAISSE ET DÉPÔTS À TERME À LA FIN

Additional information is presented in note 11.

Des renseignements supplémentaires sont présentés à la note 11.

1. Description of business

The Company is incorporated under the Ontario Business Corporations Act and is engaged in the distribution of electricity.

2. Changes in accounting policies

Inventories

The company adopted the recommendations of CICA Handbook Section 3031 on inventories which provides guidance on the determination of cost of inventories and its subsequent recognition as an expense, and includes additional disclosure requirements. The new Section also requires to account for the reversal of write-downs previously recognized when there is a subsequent increase in the value of inventories. This accounting policy, which was adopted as of January 1, 2008, was applied retroactively and the adoption of this section had no impact on the financial statements.

3. Accounting policies

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles with rate regulation specifications described under the other assets heading for electricity distributors as required by the Ontario Energy Board and set forth in the "Accounting Procedures Handbook":

Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

Classification

Cash and term deposits/Held for trading
Accounts receivable/Loans and receivables
Unbilled revenue/Loans and receivables
Accounts payable and accrued liabilities/Other liabilities
Other current liabilities/Other liabilities
Long-term liabilities/Other liabilities
Note payable/Other liabilities

1. Description de l'entreprise

La Société est constituée en vertu de la Loi sur les sociétés par actions de l'Ontario et se spécialise dans la distribution de l'électricité.

2. Modifications de conventions comptables

Stocks

La Société a adopté les recommandations du chapitre 3031 du Manuel de l'ICCA qui fournit davantage de directives concernant la détermination du coût des stocks et sa comptabilisation ultérieure en charges en plus d'exiger des informations connexes supplémentaires. La nouvelle norme exige également la reprise de toute perte de valeur comptabilisée antérieurement lorsque survient une augmentation subséquente de la valeur des stocks. Cette convention comptable, qui a été adoptée à compter du 1er janvier 2008, a été appliquée rétrospectivement et l'adoption de ce chapitre n'a eu aucune incidence sur les états financiers.

3. Conventions comptables

Les états financiers ont été préparés conformément aux principes comptables généralement reconnus du Canada et tiennent compte des particularités énumérées sous la rubrique des autres actifs pour les distributeurs d'électricité tel que requis par la Commission de l'énergie de l'Ontario et établis dans le ''Accounting Procedures Handbook'':

Instruments financiers

Les actifs financiers et les passifs financiers sont constatés initialement à la juste valeur et leur évaluation ultérieure dépend de leur classement, comme il est décrit ci-après. Leur classement dépend de l'objet visé lorsque les instruments financiers ont été acquis ou émis, de leurs caractéristiques et de leur désignation par la Société. La comptabilisation à la date de règlement est utilisée.

Classification

Encaisse et dépôts à terme/Détenus à des fins de transaction
Débiteurs/Prêts et créances
Revenus non facturés/Prêts et créances
Créditeurs et frais courus/Autres passifs
Autres frais courus/Autres passifs
Passifs à long terme/Autres passifs
Billet à payer/Autres passifs

3. Accounting policies (continued)

Held for trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other income.

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Transaction costs

Transaction costs related to held for trading financial assets are expensed as incurred. Transaction costs related to available-for-sale financial assets, held-to-maturity financial assets, other liabilities and loans and receivables are netted against the carrying value of the asset or liability and are then recognized over the expected life of the instrument using the effective interest method.

Inventories

Inventories are valued at the lower of average cost and net realizable value.

Capital assets and amortization

Capital assets are recorded at cost. Amortization is calculated on the basis of the straight-line method with reference to estimated useful lives of the assets in accordance with Ontario Energy Board policy at the following terms:

	Years
Land rights	25
Building	50
Transmission equipment	22 to 40
Distribution equipment	25 to 30
Office equipment	5 to 10
Rolling stock and equipment	4 to 10

Acquisitions made during the year are amortized at half the normal rate.

3. Conventions comptables (suite)

Détenus à des fins de transaction

Les actifs financiers détenus à des fins de transaction sont des actifs financiers qui sont généralement acquis en vue d'être revendus avant leur échéance ou qui ont été désignés comme étant détenus à des fins de transaction. Ils sont mesurés à la juste valeur à la date de clôture. Les fluctuations de la juste valeur qui incluent les intérêts gagnés, les intérêts courus, les gains et pertes réalisés sur cession et les gains et pertes non réalisés sont inclus dans les autres produits.

Prêts et créances

Les prêts et créances sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif.

Autres passifs

Les autres passifs sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif et comprennent tous les passifs financiers autres que les instruments dérivés.

Coûts de transaction

Les coûts de transaction liés aux actifs financiers détenus à des fins de transaction sont passés en charge au moment où ils sont engagés. Les coûts de transaction liés aux actifs financiers disponibles à la vente, aux actifs financiers détenus jusqu'à leur échéance, aux autres passifs et aux prêts et créances sont comptabilisés en diminution de la valeur comptable de l'actif ou du passif et sont ensuite constatés sur la durée de vie prévue de l'instrument selon la méthode du taux d'intérêt effectif.

Stocks

Les stocks sont évalués au moins élevé du coût moyen de la valeur nette de réalisation.

Immobilisations corporelles et amortissement

Les immobilisations corporelles sont comptabilisées au coût. L'amortissement est calculé selon la méthode de l'amortissement linéaire réparti sur la durée estimative de vie utile de l'immobilisation selon les politiques de la Commission de l'énergie de l'Ontario aux termes suivants:

	Années
Droit de passage	25
Immeuble	50
Équipement de transmission	22 à 40
Équipement de distribution	25 à 30
Équipement de bureau	5 à 10
Matériel roulant et équipement	4 à 10

Les acquisitions de l'année sont amorties à la moitié du taux régulier.

3. Accounting policies (continued)

Customer deposits

Deposits are taken to guarantee the payment of power bills or contract performance.

Impairment of long-lived assets

Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

Other assets

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between forecast and actual purchased power costs in the rate year are held until the following year, when their final disposition is decided. Hawkesbury Hydro Inc. recognizes purchased power cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, customers. In the absence of rate regulation, generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred.

The assets, other than variances, are recorded at cost in accordance with accounting principles as required by the Ontario Energy Board.

For some of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. Any disallowed costs will be expensed in the year that they are disallowed.

Recoveries for these assets are presented in a separate account until the Ontario Energy Board approves the recoveries. At that time, recoveries will be applied against the regulated assets.

The financial statements effects of rate regulation are presented in note 15.

3. Conventions comptables (suite)

Dépôts de clients

Des dépôts sont pris en garantie de paiement de la facturation ou de contrat.

Dépréciation d’actifs à long terme

Les actifs à long terme sont soumis à un test de recouvrabilité lorsque des événements ou des changements de situation indiquent que leur valeur comptable pourrait ne pas être recouvrable. Une perte de valeur est constatée lorsque leur valeur comptable excède les flux de trésorerie non actualisés découlant de leur utilisation et de leur sortie éventuelle. La perte de valeur constatée est mesurée comme étant l'excédent de la valeur comptable de l'actif sur sa juste valeur.

Autres actifs

Les coûts associés à l'énergie achetée sont pris en compte dans les tarifs autorisés, sur une base prévisionnelle. Aux fins de l'établissement des tarifs, les écarts entre les coûts prévus et les coûts réels associés à l'énergie achetée au cours de l'année de tarification sont laissés en suspens jusqu'à l'année suivante, au cours de laquelle leur traitement définitif est déterminé. Hydro Hawkesbury Inc. comptabilise les écarts de coûts associés à l'énergie achetée à titre d'actif ou de passif réglementaire, parce que la Société s'attend à obtenir l'autorisation de recouvrer auprès des clients futurs les montants laissés en suspens d'une année à l'autre aux fins de l'établissement des tarifs, ou à devoir rembourser les montants à ces clients. Si les tarifs n'étaient pas réglementés, les coûts réels associés à l'énergie achetée devraient être passés en charges au moment où ils sont engagés, selon les principes comptables généralement reconnus.

Les actifs autres que les écarts de prix ont aussi été établis selon les règles de la Commission de l’Énergie. Ils ont été comptabilisés au coût.

Dans le cas de certains des éléments réglementaires mentionnés ci-dessus, les risques et incertitudes découlant du pouvoir ultime de l'autorité de réglementation de déterminer le traitement de l'élément aux fins de la tarification influent sur la période prévue de recouvrement ou de règlement, ou sur la probabilité de recouvrement ou de règlement. Les montants refusés seront imputés aux résultats dans l’année où ils seront refusés.

Les recouvrements pour tous ces frais sont identifiés dans un compte distinct et seront appliqués contre les actifs suite à l’approbation par la Commission de l’Énergie.

Les effets de la règlementation des tarifs sont décris à la note 15.

3. Accounting policies (continued)

Revenue recognition

The Company recognizes revenue when persuasive evidence of an arrangement exists, delivery has occurred, the price to the buyer is fixed or determinable and collection is reasonably assured.

Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

3. Conventions comptables (suite)

Constatation des produits

La Société constate ses produits lorsqu'il existe des preuves convaincantes de l'existence d'un accord, que les marchandises sont expédiées aux clients, que le prix est déterminé ou déterminable et que l'encaissement est raisonnablement assuré.

Utilisation d'estimations

Dans le cadre de la préparation des états financiers, la direction doit établir des estimations et des hypothèses qui ont une incidence sur les montants des actifs et des passifs présentés et sur la présentation des actifs et des passifs éventuels à la date des états financiers, ainsi que sur les montants des produits d'exploitation et des charges constatés au cours de la période visée par les états financiers. Les résultats réels pourraient varier par rapport à ces estimations.

4. Accounts receivable / 4. Débiteurs

	2008	2007	
Electrical energy	**$ 1 511 586**	$ 1 410 196	Énergie électrique
Allowance for doubtful account	**(8 280**	(9 350	Provision pour mauvaises créances
	1 503 306	1 400 846	
Others	**2 049**	4 127	Autres
	$ 1 505 355	$ 1 404 973	

5. Other assets / 5. Autres actifs

	2008	2007	
Transition costs	**$ 22 611**	$ -	Frais de transition
Other regulatory assets	**388 291**	339 323	Autres actifs réglementaires
Amounts to recover	**63 003**	71 707	Montants à récupérer
	$ 473 905	$ 411 030	

6. Capital assets

6. Immobilisations corporelles

	2008			2007	
	Cost/coût	Accumulated amortization/ Amortissement cumulé	Net book value/ Valeur nette	Net book value/ Valeur nette	
Land & land rights	**$ 56 888**	**$ 5 112**	**$ 51 776**	$ 52 402	Terrain & droit de passage
Building	**824 124**	**166 237**	**657 887**	678 298	Immeuble
Transmission equipment	**454 565**	**161 818**	**292 747**	293 139	Équipement de transmission
Distribution equipment	**1 532 418**	**722 624**	**809 794**	831 619	Équipement de distribution
Office equipment	**181 167**	**71 534**	**109 633**	59 136	Équipement de bureau
Rolling stock and equipment	**222 357**	**194 951**	**27 406**	8 901	Matériel roulant et équipement
Capital contribution	**(55 867)**	**(1 093)**	**(54 774)**	-	Apports en immobilisations
	$ 3 215 652	**$ 1 321 183**	**$ 1 894 469**	$ 1 923 495	

7. Other long-term liabilities

7. Autres passifs à long terme

	2008	2007	
Pre-market opening energy variance	**$ 10 682**	$ -	Écarts de prix avant l'ouverture du marché
Retail settlement variance account	**2 371 303**	1 561 205	Écarts de prix avec les détaillants
Customer deposits	**686 815**	620 282	Dépôts de clients
Hydro One	**26 600**	54 027	Hydro One
	3 095 400	2 235 514	
Current portion	**252 329**	192 427	Portion à court terme
	$ 2 843 071	$ 2 043 087	

Amounts owed to Hydro One are to be repaid as follows: 2009, $ 20 796 and 2010, $ 5 804.

Les sommes dues à Hydro One doivent être remboursées de la façon suivante : 2009, $ 20 796 et 2010, $ 5 804.

8. Note payable

8. Billet à payer

	2008	2007	
Note payable to shareholder, 6.5%, payable in monthly instalments of $ 22 681, including interest	**$ 1 151 898**	$ 1 342 422	Billet à payer à l'actionnaire, 6.5%, remboursable par versements mensuels de $ 22 681, incluant les intérêts
Current portion	**203 284**	190 525	Tranche à court terme
	$ 948 614	$ 1 151 897	

Principal repayments to be made during the next five years are as follows: 2009, $ 203 284; 2010, $ 216 899; 2011, $ 231 425; 2012, $ 246 924 and 2013, $ 253 366.

Les versements en capital à effectuer au cours des cinq prochains exercices sont les suivants : 2009, $ 203 284 ; 2010, $ 216 899 ; 2011, $ 231 425 ; 2012, $ 246 924 and 2013 $ 253 366.

9. Share capital / 9. Capital-actions

Authorized / *Autorisé*

Unlimited number of common shares / Nombre illimité d'actions ordinaires

Issued	**2008**	2007	*Émis*
1 000 common shares	**$ 1 689 346**	$ 1 6	1 000 actions ordinaires

10. Revenue / 10. Revenus

	2008	2007	
Energy			*Énergie*
Residential	**$ 2 714 449**	$ 2 799 874	Résidentiel
General < 50 KW	**1 098 482**	1 128 659	Général < 50 KW
General > 50 KW	**3 737 678**	3 745 637	Général > 50 KW
Large users	**1 385 221**	1 604 641	Consommation significative
Street light	**72 216**	68 177	Éclairage des rues
Sentinel	**6 157**	6 602	Sentinelle
Retailers	**1 626 060**	1 605 910	Détaillants
Regulatory charges	**2 949 792**	3 344 962	Frais réglementés
	$ 13 590 055	$ 14 304 462	
Distribution			*Distribution*
Residential	**$ 726 549**	$ 722 604	Résidentiel
General < 50 KW	**159 523**	160 189	Général < 50 KW
General > 50 KW	**164**	(3 204)	Général > 50 KW
Large users	**133 053**	135 842	Consommation significative
Street light	**14 878**	13 987	Éclairage des rues
Sentinel	**2 272**	2 312	Sentinelle
Administration fees	**21 027**	23 585	Frais d'administration
	$ 1 057 466	$ 1 055 315	

11. Additional information relating to the statement of cash flows / 11. Renseignements complémentaires à l'état des flux de trésorerie

	2008	2007	
Changes in non-cash operating working capital items			*Variation des éléments hors caisse du fonds de roulement d'exploitation*
Accounts receivable	**$ (100 382)**	$ 250 206	Débiteurs
Inventories	**(13 895)**	21 411	Stocks
Unbilled revenue	**(84 964)**	(135 305)	Revenus non facturés
Prepaid expenses	**(21 089)**	16 049	Frais payés d'avance
Income taxes	**(116 957)**	(17 939)	Impôts sur le revenu
Accounts payable and accrued charges	**(84 350)**	45 228	Créditeurs et frais courus
Other current liabilities	**(108 232)**	47 952	Autres frais courus
	$ (529 869)	$ 227 602	
Other information			*Autres renseignements*
Interest paid	**$ 102 101**	$ 119 755	Intérêts payés
Income taxes paid	**$ 315 961**	$ 333 564	Impôts payés

12. Pension plan

The Hydro makes contributions to the Ontario Municipal Employees Retirement Fund (OMERS), which is a multi-employer plan, on behalf of 7 members of its staff. The plan is a defined benefit plan, which specifies the amount or the retirement benefit to be received by the employees based on the length of service and rates of pay.

The amount contributed to OMERS for 2008 is $ 28 494 (2007 - $ 25 055) for current service and is included as an expenditure in the ''Statement of Earnings''.

12. Régime de retraite

L'Hydro contribue au régime de retraite des employés municipaux de l'Ontario (RREMO), qui est un régime à employeurs multiples, pour 7 membres de son personnel. Il s'agit d'un régime à prestations déterminées qui prévoit le niveau de pension à être reçu par les employés en se basant sur les années de service et le niveau salarial.

Le montant contribué à RREMO en 2008 est de $ 28 494 (2007 - $ 25 055) pour services courants et est inclus dans les dépenses à l'''État des résultats''.

13. Contingencies

Letter of Guarantee

A letter of guarantee in the amount of $ 399 528 was issued in favour of the Independent Electricity System Operator. The Corporation of the Town of Hawkesbury endorsed this letter of guarantee.

13. Éventualités

Lettre de garantie

Une lettre de garantie au montant de $ 399 528 a été émise en faveur de "Independent Electricity System Operator". La Corporation de la Ville de Hawkesbury a endossé cette lettre de garantie.

14. Related party transactions

During the year, the Company purchased and sold services to the Corporation of the Town of Hawkesbury, its sole shareholder. These transactions were made in the normal course of business and have been recorded at the exchange amounts.

14. Opérations entre apparentés

Au cours de l'exercice, la Société a achetée et vendue des services à la Corporation de la Ville de Hawkesbury, son unique action-naire. Les opérations ont été effectuées dans le cours normal des activités et ont été comptabilisées à la valeur d'échange.

	2008	2007	
Note payable to shareholder			Billet à payer à l'actionnaire
Interest paid	**$ 81 648**	$ 93 606	Intérêts versés
Principal paid	**190 524**	178 566	Capital versé
Dividend on common shares	**84 467**	84 467	Dividende sur actions ordinaires
Other operating revenues	**10 531**	12 624	Autres produits
Distribution	**4 640**	4 200	Distribution
Administration	**26 205**	25 634	Administration
	$ 398 015	$ 399 097	

15. Rate regulation's effects on financial statements

15. Effets de la réglementation des tarifs sur les états financiers

	2008	2007	
Earnings before income taxes in accordance with accounting principles for electricity distributers as required by the Ontario Energy Board	**$ 137 790**	$ 248 269	Bénéfice avant impôts sur le revenu conformément aux principes comptables pour les distributeurs d'électricité tels que requis par la Commission de l'Énergie de l'Ontario
Variances/expenses included in other assets/other long-term liabilities	**618 656**	642 699	Variations/dépenses incluses dans les autres actifs/autre dette à long terme
Carrying charges on other assets/liabilities	**88 025**	-	Frais d'intérêts sur les autres actifs/passifs
Recovered	**51 224**	90 596	Recouvrements
Adjusted earnings before income taxes and before the effect of the regulation on the financial statements	**$ 895 695**	$ 981 564	Bénéfice avant impôts sur le revenu et avant l'effet de la réglementation sur les états financiers

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1050-Current Assets	1005-Cash	629,250.37	670,605.11	576,604.78	
	1010-Cash Advances and Working Funds	1,200.00	1,200.00	1,200.00	
	1060-Term Deposits	2,397,240.00	2,391,144.00	1,793,664.00	
	1100-Customer Accounts Receivable	1,486,576.61	1,391,076.50	1,603,314.29	
	1102-Accounts Receivable - Services	25,009.22	19,119.36	60,134.80	
	1120-Accrued Utility Revenues	1,478,591.26	1,393,627.16	1,258,321.76	
	1130-Accumulated Provision for Uncollectible Accounts--Credit	(8,280.38)	(9,350.38)	(11,274.21)	
	1140-Interest and Dividends Receivable	2,049.15	4,129.84	2,747.01	
	1180-Prepayments	31,370.56	31,166.16	47,591.70	
	1190-Miscellaneous Current and Accrued Assets	1,574.43			
1100-Inventory	1330-Plant Materials and Operating Supplies	218,227.48	204,331.93	225,743.27	
1150-Non-Current Assets	1460-Other Non-Current Assets	21,261.55	32,814.96	3,856.47	
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets	46,165.48	44,566.06	42,669.34	
	1518-RCVARetail	2,165.45	319.39	1,120.26	
	1525-Miscellaneous Deferred Debits	269,647.50	260,031.56	248,628.23	
	1548-RCVASTR	10,500.04	7,622.89	4,820.85	
	1550-LV Variance Account	144,669.50	80,976.37	54,536.55	
	1555-Smart Meters Capital Variance Account	(44,722.90)	(26,766.63)	(9,441.34)	
	1560-Deferred Development Costs	(40,133.58)			
	1562-Deferred Payments in Lieu of Taxes	(58,833.10)	(60,860.58)	(123,533.13)	
	1563-Account 1563 - Deferred PILs Contra Account	58,833.10	60,860.58	123,533.13	
	1565-Conservation and Demand Management Expenditures and Recoveries	(805.44)	(805.44)	(13,145.84)	373.00
	1566-CDM Contra Account	805.44	805.44	13,145.84	
	1570-Qualifying Transition Costs	22,611.10	22,611.10	22,611.10	
	1571-Pre-market Opening Energy Variance	(10,682.28)	(10,682.28)	(10,682.28)	
	1580-RSVAWMS	(315,210.21)	(240,407.59)	(91,273.65)	
	1582-RSVAONE-TIME	13,302.51	12,902.02	12,427.09	
	1584-RSVANW	(231,432.00)	(106,839.84)	(38,792.66)	
	1586-RSVACN	(1,446,759.67)	(1,230,148.38)	(901,922.16)	
	1588-RSVAPOWER	(391,203.66)	(92,473.78)	86,476.47	
	1590-Recovery of Regulatory Asset Balances	63,002.84	95,675.06	158,084.25	

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1450-Distribution Plant	1805-Land	20,000.00	20,000.00	20,000.00	10,000.00
	1806-Land Rights	8,588.00	8,588.00	8,588.00	8,588.00
	1815-Transformer Station Equipment - Normally Primary above 50 kV	302,188.32	281,524.36	281,524.36	56,416.00
	1820-Distribution Station Equipment - Normally Primary below 50 kV	152,376.45	152,376.45	152,376.45	151,715.00
	1830-Poles, Towers and Fixtures	298,256.75	297,192.19	284,040.23	255,254.00
	1835-Overhead Conductors and Devices	362,382.62	355,021.59	353,822.98	320,205.00
	1840-Underground Conduit	113,633.99	113,414.13	113,414.13	113,060.00
	1845-Underground Conductors and Devices	202,282.65	175,904.59	174,723.83	172,400.00
	1850-Line Transformers	310,027.53	288,119.37	283,501.39	279,164.00
	1855-Services	21,013.15	19,412.80	17,800.39	14,185.00
	1860-Meters	224,821.63	222,885.19	221,805.19	218,045.00
1500-General Plant	1905-Land	28,299.70	28,299.70	28,299.70	28,300.00
	1908-Buildings and Fixtures	824,123.77	824,123.77	822,675.49	820,347.00
	1915-Office Furniture and Equipment	25,510.99	18,426.73	14,168.38	8,097.00
	1920-Computer Equipment - Hardware	42,613.62	40,390.93	30,321.98	20,309.00
	1925-Computer Software	113,041.91	49,733.80	22,263.08	1,833.00
	1930-Transportation Equipment	205,345.80	184,896.00	184,896.00	184,896.00
	1940-Tools, Shop and Garage Equipment	12,648.19	11,939.35	10,605.63	5,912.00
	1950-Power Operated Equipment	4,363.29	4,363.29	4,363.29	
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(55,867.11)			
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(1,321,182.55)	(1,173,117.54)	(1,008,991.80)	(610,760.00)
1650-Current Liabilities	2205-Accounts Payable	(2,190,015.35)	(2,303,882.99)	(2,320,125.71)	
	2208-Customer Credit Balances	(156,659.69)	(264,891.72)	(216,939.92)	
	2210-Current Portion of Customer Deposits	(231,532.99)	(165,000.00)	(162,977.65)	
	2220-Miscellaneous Current and Accrued Liabilities	(48,581.34)	(43,683.60)	(52,862.62)	
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	18,532.41	(98,425.00)	(116,364.00)	
	2296-Future Income Taxes - Current	552,700.00	427,998.00	206,744.00	
1700-Non-Current Liabilities	2310-Vested Sick Leave Liability	(69,138.37)	(65,592.31)	(62,729.02)	
	2335-Long Term Customer Deposits	(455,282.10)	(455,282.10)	(424,989.77)	
1800-Long-Term Debt	2520-Other Long Term Debt	(1,151,897.67)	(1,342,422.22)	(1,520,987.88)	

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1850-Shareholders' Equity	3005-Common Shares Issued	(1,689,346.00)	(1,689,346.00)	(1,689,346.00)	
	3045-Unappropriated Retained Earnings	(870,217.35)	(800,786.05)	(666,186.41)	
	3046-Balance Transferred From Income	(63,487.91)	(153,898.60)	(219,066.94)	
	3049-Dividends Payable-Common Shares	84,467.30	84,467.30	84,467.30	
3000-Sales of Electricity	4006-Residential Energy Sales	(2,714,448.74)	(2,799,873.86)	(2,817,016.89)	(2,384,528)
	4020-Energy Sales to Large Users	(1,385,220.56)	(1,604,640.70)	(1,712,679.40)	(2,314,808)
	4025-Street Lighting Energy Sales	(72,215.63)	(68,176.76)	(68,857.01)	(53,026)
	4030-Sentinel Lighting Energy Sales	(6,157.40)	(6,601.58)	(6,812.33)	(5,608)
	4035-General Energy Sales	(4,836,159.78)	(4,874,296.83)	(5,140,215.48)	(4,720,398)
	4050-Revenue Adjustment				108,508
	4055-Energy Sales for Resale	(1,626,059.70)	(1,605,910.28)	(1,003,829.60)	(1,033,306)
	4062-Billed WMS	(1,212,610.23)	(1,256,431.39)	(1,248,083.69)	(1,300,225)
	4066-Billed NW	(952,489.12)	(1,090,133.05)	(1,068,248.57)	(1,099,936)
	4068-Billed CN	(679,241.54)	(884,089.60)	(887,093.87)	(960,882)
	4075-Billed-LV	(105,452.49)	(114,308.04)	(43,748.34)	
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(1,050,698.87)	(1,045,788.90)	(1,094,090.83)	(1,174,471)
3100-Other Operating Revenues	4210-Rent from Electric Property	(16,465.91)	(17,894.48)	(16,429.73)	(17,573)
	4225-Late Payment Charges	(29,867.86)	(10,521.22)	(10,444.15)	(9,483)
	4235-Miscellaneous Service Revenues	(75,323.93)	(79,001.38)	(68,903.09)	(30,617)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(50,833.34)	(88,846.59)	(113,193.68)	(62,399)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	19,864.73	37,287.31	41,849.94	40,731
	4390-Miscellaneous Non-Operating Income	(470.90)	(1,464.60)	(831.00)	(3,268)
3200-Investment Income	4405-Interest and Dividend Income	(95,812.13)	(120,552.04)	(78,325.15)	(35,517)
3350-Power Supply Expenses	4705-Power Purchased	10,640,261.81	10,959,500.04	10,749,410.71	10,511,673
	4708-Charges-WMS	1,212,610.23	1,256,431.39	1,248,083.69	1,300,225
	4710-Cost of Power Adjustments				378,498
	4714-Charges-NW	952,489.12	1,090,133.05	1,068,248.57	1,099,936
	4716-Charges-CN	679,241.54	884,089.60	887,093.87	960,882
	4750-Charges-LV	105,452.49	114,308.04	43,748.34	
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	10,812.87	11,156.89	12,576.50	21,775
	5015-Transformer Station Equipment - Operation Supplies and Expenses	11,967.16	(4,680.53)	5,986.08	4,750

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	5016-Distribution Station Equipment - Operation Labour	8,942.08	5,141.65	2,407.64	793
	5017-Distribution Station Equipment - Operation Supplies and Expenses	60.97	2,775.50		
	5020-Overhead Distribution Lines and Feeders - Operation Labour	9,387.80	10,098.71	7,524.05	6,466
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,035.63	1,567.77	1,802.41	2,736
	5035-Overhead Distribution Transformers- Operation	4,327.32	4,866.72	1,705.39	3,090
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,969.54	1,225.24	1,442.01	
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	23.52	45.71	174.21	341
	5055-Underground Distribution Transformers - Operation	2,278.74	2,306.24	2,414.22	2,979
	5065-Meter Expense	12,566.50	19,231.53	14,621.54	8,702
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,029.96	1,029.96	1,029.96	1,030
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,452.00	4,200.00	3,850.00	
	5120-Maintenance of Poles, Towers and Fixtures	10,560.59	6,121.78	5,507.15	1,256
	5125-Maintenance of Overhead Conductors and Devices	31,597.56	59,148.66	42,063.90	31,287
	5130-Maintenance of Overhead Services	31,172.56	25,162.84	21,370.16	47,020
	5135-Overhead Distribution Lines and Feeders - Right of Way	42,795.07	38,175.72	24,466.63	25,396
	5145-Maintenance of Underground Conduit	1,107.89	248.06	1,245.10	31
	5150-Maintenance of Underground Conductors and Devices	17,192.94	11,904.79	13,511.22	6,042
	5155-Maintenance of Underground Services	6,634.87	6,788.52	5,062.49	5,808
	5160-Maintenance of Line Transformers	2,183.58	11,912.16	5,399.35	9,275
	5175-Maintenance of Meters	12,191.83	11,387.54	7,745.62	(2,961)
3650-Billing and Collecting	5310-Meter Reading Expense	30,857.62	28,192.47	27,844.61	34,946

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	5315-Customer Billing	171,856.33	140,043.43	137,987.06	172,841
	5320-Collecting	93,857.70	58,499.80	55,788.08	51,296
	5325-Collecting- Cash Over and Short	(23.29)		10.90	
	5335-Bad Debt Expense	7,328.94	9,610.22	7,139.35	8,232
3700-Community Relations	5410-Community Relations - Sundry	100.00	327.74	100.00	100
	5415-Energy Conservation		12,340.40	60,710.46	
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	93,536.52	90,146.30	89,592.76	81,251
	5610-Management Salaries and Expenses	63,458.33	60,727.69	63,259.92	54,036
	5620-Office Supplies and Expenses	20,065.04	19,728.29	14,711.09	13,873
	5630-Outside Services Employed	16,898.25	30,829.54	23,680.26	35,430
	5635-Property Insurance	4,343.58	4,249.98	4,098.96	3,732
	5640-Injuries and Damages	11,489.04	11,941.56	13,053.96	16,545
	5645-Employee Pensions and Benefits	3,419.52	3,808.64	2,920.88	2,119
	5655-Regulatory Expenses	9,772.93	15,730.42	15,134.77	
	5665-Miscellaneous General Expenses	12,500.00	11,998.00	11,550.00	119,618
	5675-Maintenance of General Plant	28,562.71	35,970.10	31,011.74	22,443
	5680-Electrical Safety Authority Fees	5,108.91	5,037.90	5,235.22	1,142
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	148,065.01	164,125.74	162,042.62	156,577
	5715-Amortization of Intangibles and Other Electric Plant				2,301
3900-Interest Expense	6035-Other Interest Expense	190,125.29	119,754.54	132,027.00	
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	26,204.89	25,634.08	25,171.48	24,654
4000-Income Taxes	6110-Income Taxes	199,004.00	315,625.00	194,177.00	
	6115-Provision for Future Income Taxes	(124,702.00)	(221,254.00)	(137,853.00)	
Balance Sheet Total		**0.01**	**(0.00)**	**(0.00)**	
Net Income		**(63,487.91)**	**(153,898.60)**	**(219,066.94)**	

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND RESULTS FILED

Please find the reconciliation between Results Filed and the Financial Statements for 2006, 2007 and 2008 in the following attachment.

Appendix 2-B
Capital Projects Table - 2008 Historical

		1805	1806	1815	1820	1830	1835	1840	1845
	Project No.	Land	Land Rights	Transformer Station Equip, - Normally > 50 kV	Distribution Station Equip. – Normally < 50 kV	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices
Project 1 - Purchase of new truck	2008-01								
Project 2 - Purchase of office furniture	2008-02								
Project 3 - Purchase of office computers	2008-03								
Project 4 - Conversion to Harris- Nortstar billing software	2008-04								
Project 5 - Purchase of transformer	2008-05			20,664					
Project 6 - Purchase of small tools for line crew	2008-06								
Project 7 - Capital work (betterment)	2008-07					1,065			
Project 8 - Purchase of supplies & capital work	2008-08						7,361		
Project 9 - Purchase of conductors & devices for new subdivision	2008-09								26,378
Project 10 - Purchase of line transformers	2009-10								
Project 11 - Capital work	2009-11							220	
Project 12 - Capital work	2009-12								
Project 13 - Purchase of meters	2009-13								
Project 14 - Contributions and Grants - 2 Projects	2009-14								
Total				**20,664**		**1,065**	**7,361**	**220**	**26,378**

Appendix 2-B
Capital Projects Table - 2008 Historical

	1850	1855	1860	1905	1906	1908	1915	1920	1925	1930	1935
	Line Transformers	Services	Meters	Land	Land Rights	Buildings and Fixtures	Office Furniture and Equipment	Computer Equipment - Hardware	Computer Software	Transportation Equipment	Stores Equipment
Project 1 - Purchase of new truck										20,450	
Project 2 - Purchase of office furniture							7,084				
Project 3 - Purchase of office computers								2,223			
Project 4 - Conversion to Harris- Nortstar billing software									63,308		
Project 5 - Purchase of transformer											
Project 6 - Purchase of small tools for line crew											
Project 7 - Capital work (betterment)											
Project 8 - Purchase of supplies & capital work											
Project 9 - Purchase of conductors & devices for new subdivision											
Project 10 - Purchase of line transformers	21,908										
Project 11 - Capital work											
Project 12 - Capital work		1,600									
Project 13 - Purchase of meters			1,936								
Project 14 - Contributions and Grants - 2 Projects											
Total	**21,908**	**1,600**	**1,936**				**7,084**	**2,223**	**63,308**	**20,450**	

Appendix 2-B
Capital Projects Table - 2008 Historical

	1940	1945	1950	1955	1995	TOTAL
	Tools, Shop and Garage Equipment	Measurement and Testing Equipment	Power Operated Equipment	Communication Equipment	Contributions and Grants - Credit	
Project 1 - Purchase of new truck						20,450
Project 2 - Purchase of office furniture						7,084
Project 3 - Purchase of office computers						2,223
Project 4 - Conversion to Harris- Nortstar billing software						63,308
Project 5 - Purchase of transformer						20,664
Project 6 - Purchase of small tools for line crew	709					709
Project 7 - Capital work (betterment)						1,065
Project 8 - Purchase of supplies & capital work						7,361
Project 9 - Purchase of conductors & devices for new subdivision						26,378
Project 10 - Purchase of line transformers						21,908
Project 11 - Capital work						220
Project 12 - Capital work						1,600
Project 13 - Purchase of meters						1,936
Project 14 - Contributions and Grants - 2 Projects					54,774	54,774
Total	**709**				**54,774**	**229,680**

FINANCIAL PROJECTIONS

Projections for Bridge and Test years can be found in the following schedules. Note that revenues in the pro-forma statements assume that rate changes are in effect for the entire year, notwithstanding expected effective date of May 1.

BUDGET DIRECTIVES AND ASSUMPTIONS

HHI compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information is provided for both the Bridge and Test Years.

Revenue Forecast

The revenue budget is comprised of three components: energy revenue, distribution revenue and other revenue.

The energy revenue for 2010 was forecast using the weather normalized load forecast prepared by the Elenchus Research Associates ("ERA") as discussed in Exhibit 3, Tab 1, Schedule 2. A commodity price of $.0660 per kWh based on the OEB Regulated Price Plan Report dated April 15, 2009 has been assumed for the forecast.

Distribution revenue was forecast using the weather normalized volumes multiplied by both current approved distribution rates and by proposed rates in order to project distribution deficiency for the 2010 test year. Other revenues were reviewed on an item for item basis and other revenue was determined based on the most reliable historical indicator.

Operating and Maintenance Expense Forecast

The operating and maintenance expenses for fiscal 2009 Bridge Year and 2010 Test Year have been forecasted using a zero based methodology. Each item is reviewed by account for each of the forecast years. A review of historical costs is completed and where applicable costs are included in the budget for the following year. New expenditures are added once the Board of Directors and Management have approved the expenditure.

Capital Budget

The capital budget process begins with a review of the previous year's work. All capital expenditures are budgeted on a line by line and/or project basis based on need and forecasted customer growth. In addition, HHI completes ground inspections throughout the year while performing maintenance on the distribution system and other infrastructure. From these inspections capital projects are identified and prioritized for inclusion in an upcoming capital budget year. A detailed analysis of the Capital Budget is provided at Exhibit 2, Tab 4, Schedule 2.

Under favorable economic circumstances, HHI would continue to expand its distribution system in order to meet the demand of new and existing customers in its service territory. However, in times of economic downturn, capital spending is attributed mostly to the replacing of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers. This includes fulfilling its obligation to connect and provide service to the residents of the town of Hawkesbury.

RECONCILIATION OF HISTORICAL ACTUAL RESULTS TO FINANCIAL STATEMENTS

	2006			
	Actuals	**Fin. Stmt.**	**Variance**	
Total Assets	7,161,365	8,264,539	**-1,103,174**	
Difference due to:				
Other Non-Current Assets	3,856		3,856	*Offset to Carrying Charges included in Deferral Accounts*
Deferral accounts	-420,738	479,549	-900,287	*Credit balances reflected as Liabilities on Fin. Stmt.*
Future Income Taxes		206,744	-206,744	*Balance recorded as Liability in Actuals*
TOTAL DIFFERENCES			**-1,103,174**	
Total Liabilities	4,671,233	5,774,407	**-1,103,174**	
Difference due to:				
Deferral accounts		896,431	-896,431	*Balances recorded as Assets in Actuals*
Future Income Taxes	-206,744		-206,744	*Balance reflected as Asset on Fin. Stmt.*
TOTAL DIFFERENCES			**-1,103,175**	
Total Equity	2,490,132	2,490,132	**0**	
Net Income	219,067	219,067	**-0**	
Differences:				
Distribution Revenue	1,094,091	1,102,774	-8,683	*Fin. Stmt includes Retail Services Revenue*
Other Operating Revenue	95,777	288,127	-192,350	*Fin. Stmt includes Investment Income, late payment charges ($113,194) and misc. non-operating income ($831)*
Other Income & Deductions	72,175		72,175	*Actuals include net revenues from jobbing ($71,343) and misc. non-operating income*
Investment Income	78,325		78,325	*Reflected in Other Operating Revenue on Fin. Stmt.*
Administration Expense [1]	-589,002	-771,562	182,561	*Fin. Stmt includes Interest Expense and the costs of revenues for retail services ($8,684) and jobbing ($41,850)*
Interest Expense	-132,027		-132,027	*Reflected as Administration Expense on Fin. Stmt.*
TOTAL DIFFERENCES			**0**	

[1] *Actuals include: Billing & Collecting, Community Relations, Administrative and General, and Taxes Other Than Income Taxes*

Changes in Methodology

HHI does not propose any changes to its budget process unless otherwise instructed by the Board.

RECONCILIATION OF HISTORICAL ACTUAL RESULTS TO FINANCIAL STATEMENTS

	2007			
	Actuals	**Fin. Stmt.**	**Variance**	
Total Assets	6,870,745	8,859,947	**-1,989,202**	
Difference due to:				
Prepaid Charges	31,166	31,543	-377	*Fin. Stmt. includes unused OPA funding*
Other Non-Current Assets	32,815		32,815	*Offset to Carrying Charges included in Deferral Accounts*
Deferral accounts	-1,182,614	411,030	-1,593,644	*Credit balances reflected as Liabilities on Fin. Stmt.*
Future Income Taxes		427,998	-427,998	*Balance recorded as Liability in Actuals*
TOTAL DIFFERENCES			**-1,989,204**	
Total Liabilities	4,311,182	6,300,384	**-1,989,202**	
Difference due to:				
Deferral accounts		1,561,205	-1,561,205	*Credit balances recorded as Assets in Actuals*
Future Income Taxes	-427,998		-427,998	*Balance reflected as Asset on Fin. Stmt.*
TOTAL DIFFERENCES			**-1,989,203**	
Total Equity	2,559,563	2,559,563	**0**	
Net Income	153,899	153,898	**1**	
Differences:				
Distribution Revenue	1,045,789	1,055,315	-9,526	*Fin. Stmt includes Retail Services Revenue*
Other Operating Revenue	107,417	318,280	-210,863	*Fin. Stmt includes Investment Income, gross revenues from jobbing ($88,846) and misc. non-operating income ($1,465)*
Other Income & Deductions	53,024		53,024	*Actuals include net revenues from jobbing ($51,559) and misc. non-operating income*
Investment Income	120,552		120,552	*Reflected in Other Operating Revenue on Fin. Stmt.*
Administration Expense [1]	-564,817	-731,385	166,568	*Fin. Stmt includes Interest Expense and the costs of revenues for retail services ($9,526) and jobbing ($37,287)*
Interest Expense	-119,755		-119,755	*Reflected as Administration Expense on Fin. Stmt.*
TOTAL DIFFERENCES			**1**	

[1] Actuals include: Billing & Collecting, Community Relations, Administrative and General, and Taxes Other Than Income Taxes

RECONCILIATION OF HISTORICAL ACTUAL RESULTS TO FINANCIAL STATEMENTS

	2008			
	Actuals	**Fin. Stmt.**	**Variance**	
Total Assets	6,270,459	9,222,101	**-2,951,642**	
Difference due to:				
Deferral accounts	-1,908,080	473,905	-2,381,985	*Balances reflected as Liabilities on Fin. Stmt.*
Income Taxes (Current Asset)		18,532	-18,532	*Balance recorded as Liability in Actuals*
Future Income Taxes		552,700	-552,700	*Balance recorded as Liability in Actuals*
Misc. Accrued & Deferred Assets	1,574		1,574	*Balance included in Liabilities on Fin. Stmt.*
TOTAL DIFFERENCES			**-2,951,643**	
Total Liabilities	3,731,875	6,683,517	**-2,951,642**	
Difference due to:				
Deferral accounts		2,381,985	-2,381,985	*Credit balances recorded as Assets in Actuals*
Income Taxes (Current Asset)	-18,532		-18,532	*Balance reflected as Asset on Fin. Stmt.*
Future Income Taxes	-552,700		-552,700	*Balance reflected as Asset on Fin. Stmt.*
Misc. Accrued & Deferred Assets		-1,574	1,574	*Balance recorded as Asset in Actuals*
TOTAL DIFFERENCES			**-2,951,643**	
Total Equity	2,538,584	2,538,584	**-0**	
Net Income	63,488	63,488	**0**	
Differences:				
Distribution Revenue	1,050,699	1,057,466	-6,767	*Fin. Stmt includes Retail Services Revenue*
Other Operating Revenue	121,658	268,774	-147,116	*Fin. Stms. includes Investment Income, gross revenues from jobbing ($50,833) and misc. non-operating income ($471)*
Other Income & Deductions	31,440		31,440	*Actuals include net revenues from jobbing ($30,969) and misc. non-operating income*
Investment Income	95,812		95,812	*Reflected in Other Operating Revenue on Fin. Stmt.*
Administration Expense [1]	-599,337	-816,094	216,757	*Fin. Stmt includes Interest Expense and the costs of revenues for retail services ($6,767) and jobbing ($19,865)*
Interest Expense	-190,125		-190,125	*Reflected as Administration Expense on Fin. Stmt.*
TOTAL DIFFERENCES			**-0**	

[1] Actuals include: Billing & Collecting, Community Relations, Administrative and General, and Taxes Other Than Income Taxes

2009-2010 PRO-FORMA FINANCIAL STATEMENTS

Exhibit 1, Tab 4, Schedule 5, Attachment 1 and 2 present the pro-formas for the bridge and test year.

Hydro Hawkesbury Inc. (ED-2003-0027)

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G1 Finalize 2009 Pro-forma Projections

Enter final adjustments to projected account balances for 2009

Account Grouping	Account Description	2008 Actual	2009 Model Projection *	2009 Override Amount	2009 Final Projection	Comment
1050-Current Assets	1005-Cash	629,250		517,509	517,509	
	1010-Cash Advances and Working Funds	1,200		1,200	1,200	
	1060-Term Deposits	2,397,240		2,397,240	2,397,240	
	1100-Customer Accounts Receivable	1,486,577		1,486,570	1,486,570	
	1102-Accounts Receivable - Services	25,009		24,990	24,990	
	1120-Accrued Utility Revenues	1,478,591		1,478,591	1,478,591	
	1130-Accumulated Provision for Uncollectible Accounts--Credit	(8,280)		(8,280)	(8,280)	
	1140-Interest and Dividends Receivable	2,049		2,065	2,065	
	1180-Prepayments	31,371		31,400	31,400	
	1190-Miscellaneous Current and Accrued Assets	1,574		1,572	1,572	
1100-Inventory	1330-Plant Materials and Operating Supplies	218,227		218,200	218,200	
1150-Non-Current Assets	1460-Other Non-Current Assets	21,262		21,262	21,262	
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets	46,165	46,567		46,567	
	1518-RCVARetail	2,165	2,186		2,186	
	1525-Miscellaneous Deferred Debits	269,648	272,059		272,059	
	1548-RCVASTR	10,500	10,598		10,598	
	1550-LV Variance Account	144,670	146,036		146,036	
	1555-Smart Meters Capital Variance Account	(44,723)	(45,148)		(45,148)	
	1556-Smart Meters OM&A Variance Account		15,091		15,091	
	1560-Deferred Development Costs	(40,134)				
	1562-Deferred Payments in Lieu of Taxes	(58,833)	(53,670)		(53,670)	
	1563-Account 1563 - Deferred PILs Contra Account	58,833	53,670		53,670	
	1565-Conservation and Demand Management Expenditures and Recoveries	(805)	(805)		(805)	
	1566-CDM Contra Account	805	805		805	
	1570-Qualifying Transition Costs	22,611	22,611		22,611	
	1571-Pre-market Opening Energy Variance	(10,682)	(10,682)		(10,682)	
	1580-RSVAWMS	(315,210)	(318,403)		(318,403)	

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G1 Finalize 2009 Pro-forma Projections

Enter final adjustments to projected account balances for 2009

Account Grouping	Account Description	2008 Actual	2009 Model Projection *	2009 Override Amount	2009 Final Projection	Comment
	1582-RSVAONE-TIME	13,303	13,403		13,403	
	1584-RSVANW	(231,432)	(233,600)		(233,600)	
	1586-RSVACN	(1,446,760)	(1,459,204)		(1,459,204)	
	1588-RSVAPOWER	(391,204)	(395,542)		(395,542)	
	1590-Recovery of Regulatory Asset Balances	63,003	26,132		26,132	
1450-Distribution Plant	1805-Land	20,000	20,000		20,000	
	1806-Land Rights	8,588	8,588		8,588	
	1815-Transformer Station Equipment - Normally Primary above 50 kV	302,188	372,188		372,188	
	1820-Distribution Station Equipment - Normally Primary below 50 kV	152,376	229,376		229,376	
	1830-Poles, Towers and Fixtures	298,257	347,257		347,257	
	1835-Overhead Conductors and Devices	362,383	390,383		390,383	
	1840-Underground Conduit	113,634	113,634		113,634	
	1845-Underground Conductors and Devices	202,283	219,783		219,783	
	1850-Line Transformers	310,028	323,028		323,028	
	1855-Services	21,013	21,013		21,013	
	1860-Meters	224,822	224,822		224,822	
1500-General Plant	1905-Land	28,300	28,300		28,300	
	1908-Buildings and Fixtures	824,124	824,124		824,124	
	1915-Office Furniture and Equipment	25,511	38,511		38,511	
	1920-Computer Equipment - Hardware	42,614	48,614		48,614	
	1925-Computer Software	113,042	120,042		120,042	
	1930-Transportation Equipment	205,346	205,346		205,346	
	1940-Tools, Shop and Garage Equipment	12,648	24,648		24,648	
	1950-Power Operated Equipment	4,363	4,363		4,363	
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(55,867)	(55,867)		(55,867)	
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(1,321,183)	(1,483,814)		(1,483,814)	
1650-Current Liabilities	2205-Accounts Payable	(2,190,015)		(2,142,055)	(2,142,055)	
	2208-Customer Credit Balances	(156,660)		(157,500)	(157,500)	
	2210-Current Portion of Customer Deposits	(231,533)		(230,000)	(230,000)	
	2220-Miscellaneous Current and Accrued Liabilities	(48,581)		(47,000)	(47,000)	
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	18,532		18,625	18,625	
	2296-Future Income Taxes - Current	552,700		550,000	550,000	
1700-Non-Current Liabilities	2310-Vested Sick Leave Liability	(69,138)		(69,500)	(69,500)	
	2335-Long Term Customer Deposits	(455,282)		(445,185)	(445,185)	
1800-Long-Term Debt	2520-Other Long Term Debt	(1,151,898)		(1,175,000)	(1,175,000)	

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G1 Finalize 2009 Pro-forma Projections

Enter final adjustments to projected account balances for 2009

Account Grouping	Account Description	2008 Actual	2009 Model Projection *	2009 Override Amount	2009 Final Projection	Comment
1850-Shareholders' Equity	3005-Common Shares Issued	(1,689,346)		(1,689,346)	(1,689,346)	
	3045-Unappropriated Retained Earnings	(870,217)	(933,705)		(933,705)	
	3046-Balance Transferred From Income	(63,488)	(52,561)		(52,561)	
	3049-Dividends Payable-Common Shares	84,467		84,467	84,467	
3000-Sales of Electricity	4006-Residential Energy Sales	(2,714,449)	(3,400,060)		(3,400,060)	
	4020-Energy Sales to Large Users	(1,385,221)	(790,287)		(790,287)	
	4025-Street Lighting Energy Sales	(72,216)	(76,791)		(76,791)	
	4030-Sentinel Lighting Energy Sales	(6,157)	(6,893)		(6,893)	
	4035-General Energy Sales	(4,836,160)	(6,790,729)		(6,790,729)	
	4055-Energy Sales for Resale	(1,626,060)				
	4062-Billed WMS	(1,212,610)	(1,174,674)		(1,174,674)	
	4066-Billed NW	(952,489)	(848,257)		(848,257)	
	4068-Billed CN	(679,242)	(537,182)		(537,182)	
	4075-Billed-LV	(105,452)	(105,452)		(105,452)	
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(1,050,699)	(1,045,192)		(1,045,192)	
	4082-Retail Services Revenues		(7,885)		(7,885)	
	4084-Service Transaction Requests (STR) Revenues		(607)		(607)	
3100-Other Operating Revenues	4210-Rent from Electric Property	(16,466)	(16,000)		(16,000)	
	4225-Late Payment Charges	(29,868)	(31,875)		(31,875)	
	4235-Miscellaneous Service Revenues	(75,324)	(68,442)		(68,442)	
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(50,833)	(45,000)		(45,000)	
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	19,865	25,000		25,000	
	4390-Miscellaneous Non-Operating Income	(471)	(500)		(500)	
3200-Investment Income	4405-Interest and Dividend Income	(95,812)	(12,000)		(12,000)	
3350-Power Supply Expenses	4705-Power Purchased	10,640,262	11,064,760		11,064,760	
	4708-Charges-WMS	1,212,610	947,575		947,575	
	4714-Charges-NW	952,489	848,257		848,257	
	4716-Charges-CN	679,242	537,182		537,182	
	4730-Rural Rate Assistance Expense		227,099		227,099	
	4750-Charges-LV	105,452	105,452		105,452	
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	10,813	11,245		11,245	
	5015-Transformer Station Equipment - Operation Supplies and Expenses	11,967	12,446		12,446	
	5016-Distribution Station Equipment - Operation Labour	8,942	9,300		9,300	
	5017-Distribution Station Equipment - Operation Supplies and Expenses	61	63		63	

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G1 Finalize 2009 Pro-forma Projections

Enter final adjustments to projected account balances for 2009

Account Grouping	Account Description	2008 Actual	2009 Model Projection *	2009 Override Amount	2009 Final Projection	Comment
	5020-Overhead Distribution Lines and Feeders - Operation Labour	9,388	9,763		9,763	
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,036	1,077		1,077	
	5035-Overhead Distribution Transformers- Operation	4,327	11,813		11,813	
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,970	2,048		2,048	
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	24	24		24	
	5055-Underground Distribution Transformers - Operation	2,279	2,370		2,370	
	5065-Meter Expense	12,567	11,569		11,569	
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,030	1,071		1,071	
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,452	4,630		4,630	
	5120-Maintenance of Poles, Towers and Fixtures	10,561	16,160		16,160	
	5125-Maintenance of Overhead Conductors and Devices	31,598	32,545		32,545	
	5130-Maintenance of Overhead Services	31,173	32,108		32,108	
	5135-Overhead Distribution Lines and Feeders - Right of Way	42,795	50,795		50,795	
	5145-Maintenance of Underground Conduit	1,108	1,152		1,152	
	5150-Maintenance of Underground Conductors and Devices	17,193	17,881		17,881	
	5155-Maintenance of Underground Services	6,635	6,900		6,900	
	5160-Maintenance of Line Transformers	2,184	2,271		2,271	
	5175-Maintenance of Meters	12,192	8,700		8,700	
3650-Billing and Collecting	5310-Meter Reading Expense	30,858	32,092		32,092	
	5315-Customer Billing	171,856	178,731		178,731	
	5320-Collecting	93,858	96,460		96,460	
	5325-Collecting- Cash Over and Short	(23)				
	5335-Bad Debt Expense	7,329	7,622		7,622	
3700-Community Relations	5410-Community Relations - Sundry	100	104		104	

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G1 Finalize 2009 Pro-forma Projections

Enter final adjustments to projected account balances for 2009

Account Grouping	Account Description	2008 Actual	2009 Model Projection *	2009 Override Amount	2009 Final Projection	Comment
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	93,537	100,278		100,278	
	5610-Management Salaries and Expenses	63,458	68,997		68,997	
	5620-Office Supplies and Expenses	20,065	20,868		20,868	
	5630-Outside Services Employed	16,898	17,574		17,574	
	5635-Property Insurance	4,344	4,517		4,517	
	5640-Injuries and Damages	11,489	11,949		11,949	
	5645-Employee Pensions and Benefits	3,420	3,556		3,556	
	5655-Regulatory Expenses	9,773	10,164		10,164	
	5665-Miscellaneous General Expenses	12,500	13,000		13,000	
	5675-Maintenance of General Plant	28,563	29,420		29,420	
	5680-Electrical Safety Authority Fees	5,109	5,313		5,313	
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	148,065	162,631		162,631	
3900-Interest Expense	6035-Other Interest Expense	190,125	86,178		86,178	
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	26,205	26,916		26,916	
4000-Income Taxes	6110-Income Taxes	199,004	27,640		27,640	
	6115-Provision for Future Income Taxes	(124,702)				

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G2 Finalize 2010 Pro-forma Projections

Enter final adjustments to projected account balances for 2010 at Existing Rates

Account Grouping	Account Description	2009 Projection	2010 (existing rates) Model Projection *	Override Amount	Final Projection	Comment
1050-Current Assets	1005-Cash	517,509		575,000	575,000	
	1010-Cash Advances and Working Funds	1,200		1,200	1,200	
	1060-Term Deposits	2,397,240		1,270,692	1,270,692	
	1100-Customer Accounts Receivable	1,486,570		1,450,000	1,450,000	
	1102-Accounts Receivable - Services	24,990		24,000	24,000	
	1120-Accrued Utility Revenues	1,478,591		1,478,000	1,478,000	
	1130-Accumulated Provision for Uncollectible Accounts--Credit	(8,280)		(8,280)	(8,280)	
	1140-Interest and Dividends Receivable	2,065		2,000	2,000	
	1180-Prepayments	31,400		31,400	31,400	
	1190-Miscellaneous Current and Accrued Assets	1,572		1,550	1,550	
1100-Inventory	1330-Plant Materials and Operating Supplies	218,200		218,000	218,000	
1150-Non-Current Assets	1460-Other Non-Current Assets	21,262		21,200	21,200	
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets	46,567	46,968		46,968	
	1518-RCVARetail	2,186	2,206		2,206	
	1525-Miscellaneous Deferred Debits	272,059	274,471		274,471	
	1548-RCVASTR	10,598	10,695		10,695	
	1550-LV Variance Account	146,036	147,403		147,403	
	1555-Smart Meters Capital Variance Account	(45,148)	(45,573)		(45,573)	
	1556-Smart Meters OM&A Variance Account	15,091	82,223		82,223	
	1562-Deferred Payments in Lieu of Taxes	(53,670)	(54,202)		(54,202)	
	1563-Account 1563 - Deferred PILs Contra Account	53,670	54,202		54,202	
	1565-Conservation and Demand Management Expenditures and Recoveries	(805)	(805)		(805)	
	1566-CDM Contra Account	805	805		805	
	1570-Qualifying Transition Costs	22,611	22,611		22,611	
	1571-Pre-market Opening Energy Variance	(10,682)	(10,682)		(10,682)	
	1580-RSVAWMS	(318,403)	(321,595)		(321,595)	
	1582-RSVAONE-TIME	13,403	13,503		13,503	

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G2 Finalize 2010 Pro-forma Projections

Enter final adjustments to projected account balances for 2010 at Existing Rates

Account Grouping	Account Description	2009 Projection	2010 (existing rates) Model Projection *	Override Amount	Final Projection	Comment
	1584-RSVANW	(233,600)	(235,767)		(235,767)	
	1586-RSVACN	(1,459,204)	(1,471,649)		(1,471,649)	
	1588-RSVAPOWER	(395,542)	(399,880)		(399,880)	
	1590-Recovery of Regulatory Asset Balances	26,132	26,393		26,393	
1450-Distribution Plant	1805-Land	20,000	20,000		20,000	
	1806-Land Rights	8,588	8,588		8,588	
	1815-Transformer Station Equipment - Normally Primary above 50 kV	372,188	454,188		454,188	
	1820-Distribution Station Equipment - Normally Primary below 50 kV	229,376	279,376		279,376	
	1830-Poles, Towers and Fixtures	347,257	420,257		420,257	
	1835-Overhead Conductors and Devices	390,383	423,383		423,383	
	1840-Underground Conduit	113,634	113,634		113,634	
	1845-Underground Conductors and Devices	219,783	237,283		237,283	
	1850-Line Transformers	323,028	334,028		334,028	
	1855-Services	21,013	21,013		21,013	
	1860-Meters	224,822	224,822		224,822	
1500-General Plant	1905-Land	28,300	28,300		28,300	
	1908-Buildings and Fixtures	824,124	849,124		849,124	
	1915-Office Furniture and Equipment	38,511	58,011		58,011	
	1920-Computer Equipment - Hardware	48,614	59,614		59,614	
	1925-Computer Software	120,042	129,242		129,242	
	1930-Transportation Equipment	205,346	205,346		205,346	
	1940-Tools, Shop and Garage Equipment	24,648	29,648		29,648	
	1950-Power Operated Equipment	4,363	34,363		34,363	
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(55,867)	(55,867)		(55,867)	
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(1,483,814)	(1,659,294)		(1,659,294)	
1650-Current Liabilities	2205-Accounts Payable	(2,142,055)		(2,220,900)	(2,220,900)	
	2208-Customer Credit Balances	(157,500)		(158,200)	(158,200)	
	2210-Current Portion of Customer Deposits	(230,000)		(240,000)	(240,000)	
	2220-Miscellaneous Current and Accrued Liabilities	(47,000)		(46,000)	(46,000)	
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	18,625		18,718	18,718	
	2296-Future Income Taxes - Current	550,000		(545,000)	(545,000)	
1700-Non-Current Liabilities	2310-Vested Sick Leave Liability	(69,500)		(70,000)	(70,000)	
	2335-Long Term Customer Deposits	(445,185)		(447,411)	(447,411)	
1800-Long-Term Debt	2520-Other Long Term Debt	(1,175,000)	(850,364)		(850,364)	
1850-Shareholders' Equity	3005-Common Shares Issued	(1,689,346)				
	3045-Unappropriated Retained Earnings	(933,705)	(989,459)		(989,459)	
	3046-Balance Transferred From Income	(55,754)	130149.0219		130149.0219	

Hydro Hawkesbury Inc. (ED-2003-0027)

2010 EDR Application (EB-2009-0186) version: v0.1
November 4, 2009

G2 Finalize 2010 Pro-forma Projections

Enter final adjustments to projected account balances for 2010 at Existing Rates

Account Grouping	Account Description	2009 Projection	2010 (existing rates) Model Projection *	Override Amount	Final Projection	Comment
	3049-Dividends Payable-Common Shares	84,467		84,890	84,890	
3000-Sales of Electricity	4006-Residential Energy Sales	(3,400,060)	(3,403,658)		(3,403,658)	
	4020-Energy Sales to Large Users	(790,287)				
	4025-Street Lighting Energy Sales	(76,791)	(76,791)		(76,791)	
	4030-Sentinel Lighting Energy Sales	(6,893)	(6,893)		(6,893)	
	4035-General Energy Sales	(6,790,729)	(6,797,901)		(6,797,901)	
	4062-Billed WMS	(1,174,674)	(1,101,022)		(1,101,022)	
	4066-Billed NW	(848,257)	(708,152)		(708,152)	
	4068-Billed CN	(537,182)	(379,120)		(379,120)	
	4075-Billed-LV	(105,452)	(70,600)		(70,600)	
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(1,045,192)	(923,914)		(923,914)	
	4082-Retail Services Revenues	(7,885)	(7,785)		(7,785)	
	4084-Service Transaction Requests (STR) Revenues	(607)	(607)		(607)	
3100-Other Operating Revenues	4210-Rent from Electric Property	(16,000)	(16,000)		(16,000)	
	4225-Late Payment Charges	(31,875)	(31,875)		(31,875)	
	4235-Miscellaneous Service Revenues	(68,442)	(72,077)		(72,077)	
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(45,000)	(45,000)		(45,000)	
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	25,000	25,000		25,000	
	4390-Miscellaneous Non-Operating Income	(500)	(500)		(500)	
3200-Investment Income	4405-Interest and Dividend Income	(12,000)	(17,000)		(17,000)	
3350-Power Supply Expenses	4705-Power Purchased	11,064,760	10,285,243		10,285,243	
	4708-Charges-WMS	947,575	880,818		880,818	
	4714-Charges-NW	848,257	708,152		708,152	
	4716-Charges-CN	537,182	379,120		379,120	
	4730-Rural Rate Assistance Expense	227,099	220,204		220,204	
	4750-Charges-LV	105,452	70,600		70,600	
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	11,245	11,695		11,695	
	5015-Transformer Station Equipment - Operation Supplies and Expenses	12,446	12,944		12,944	
	5016-Distribution Station Equipment - Operation Labour	9,300	9,672		9,672	
	5017-Distribution Station Equipment - Operation Supplies and Expenses	63	66		66	
	5020-Overhead Distribution Lines and Feeders - Operation Labour	9,763	10,154		10,154	
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,077	1,120		1,120	
	5035-Overhead Distribution Transformers- Operation	11,813	12,046		12,046	

Hydro Hawkesbury Inc. (ED-2003-0027)

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G2 Finalize 2010 Pro-forma Projections

Enter final adjustments to projected account balances for 2010 at Existing Rates

Account Grouping	Account Description	2009 Projection	2010 (existing rates) Model Projection *	2010 (existing rates) Override Amount	2010 (existing rates) Final Projection	Comment
	5040-Underground Distribution Lines and Feeders - Operation Labour	2,048	2,130		2,130	
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	24	25		25	
	5055-Underground Distribution Transformers - Operation	2,370	2,465		2,465	
	5065-Meter Expense	11,569	12,032		12,032	
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,071	1,114		1,114	
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,630	4,815		4,815	
	5120-Maintenance of Poles, Towers and Fixtures	16,160	18,022		18,022	
	5125-Maintenance of Overhead Conductors and Devices	32,545	32,799		32,799	
	5130-Maintenance of Overhead Services	32,108	33,392		33,392	
	5135-Overhead Distribution Lines and Feeders - Right of Way	50,795	44,827		44,827	
	5145-Maintenance of Underground Conduit	1,152	1,198		1,198	
	5150-Maintenance of Underground Conductors and Devices	17,881	18,596		18,596	
	5155-Maintenance of Underground Services	6,900	7,176		7,176	
	5160-Maintenance of Line Transformers	2,271	2,362		2,362	
	5175-Maintenance of Meters	8,700	8,700		8,700	
3650-Billing and Collecting	5310-Meter Reading Expense	32,092	33,376		33,376	
	5315-Customer Billing	178,731	185,880		185,880	
	5320-Collecting	96,460	100,389		100,389	
	5335-Bad Debt Expense	7,622	7,927		7,927	
3700-Community Relations	5410-Community Relations - Sundry	104	2,108		2,108	
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	100,278	107,289		107,289	
	5610-Management Salaries and Expenses	68,997	74,757		74,757	
	5620-Office Supplies and Expenses	20,868	21,702		21,702	
	5630-Outside Services Employed	17,574	43,817		43,817	

Hydro Hawkesbury Inc. (ED-2003-0027)
2010 EDR Application (EB-2009-0186) version: v0.1
November 4, 2009

G2 Finalize 2010 Pro-forma Projections

Enter final adjustments to projected account balances for 2010 at Existing Rates

Account Grouping	Account Description	2009 Projection	2010 (existing rates) Model Projection *	Override Amount	Final Projection	Comment
	5635-Property Insurance	4,517	4,698		4,698	
	5640-Injuries and Damages	11,949	12,427		12,427	
	5645-Employee Pensions and Benefits	3,556	3,699		3,699	
	5655-Regulatory Expenses	10,164	41,820		41,820	
	5665-Miscellaneous General Expenses	13,000	13,520		13,520	
	5675-Maintenance of General Plant	29,420	30,596		30,596	
	5680-Electrical Safety Authority Fees	5,313	5,526		5,526	
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	162,631	175,480		175,480	
3900-Interest Expense	6035-Other Interest Expense	82,985	79,285		79,285	
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	26,916	28,262		28,262	
4000-Income Taxes	6110-Income Taxes	27,640				

PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

HHI does not issue shares nor does it produce a prospectus.

MATERIALITY THRESHOLD

Except where specifically identified, the materiality threshold used within this application is in compliance with Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated May 27, 2009 (the “Filing Requirements”). In HHI’s case, since the revenue requirement is less than $10 million. The materiality threshold used in this application is $50,000.

Appendix 7-1

Revenue Sufficiency / Deficiency

		2010 Projection	2009 Projection	Var #	Var %
Utility Income	*(see below)*	(50,864)	138,739	(189,603)	(136.7%)
Utility Rate Base		4,146,090	4,149,976	(3,886)	(0.1%)
Indicated Rate of Return		(1.23%)	3.34%	(4.57%)	(136.7%)
Requested / Approved Rate of Return		7.52%	7.44%	0.08%	1.1%
Sufficiency / (Deficiency) in Return		(8.75%)	(4.10%)	(4.65%)	(113.6%)
Net Revenue Sufficiency / (Deficiency)		**(362,833)**	**(170,051)**	**(192,782)**	**(113.4%)**
Provision for PILs/Taxes		(31,623)	(33,878)	2,256	6.7%
Gross Revenue Sufficiency / (Deficiency)		**(394,455)**	**(203,929)**	**(190,526)**	**(93.4%)**
Deemed Overall Debt Rate		*7.20%*	*6.25%*	*0.95%*	*15.2%*
Deemed Cost of Debt		*179,128*	*153,045*	*26,083*	*17.0%*
Utility Income less Deemed Cost of Debt		*(229,992)*	*(14,306)*	*(215,686)*	*(1507.6%)*
Return On Deemed Equity		*(13.87%)*	*(0.80%)*	*(13.07%)*	*(1641.9%)*

UTILITY INCOME

	2010 Projection	2009 Projection	Var #	Var %
Total Net Revenues	1,089,759	1,202,502	(112,743)	(9.4%)
OM&A Expenses	936,881	846,576	90,305	10.7%
Depreciation & Amortization	175,480	162,631	12,849	7.9%
Taxes other than PILs / Income Taxes	28,262	26,916	1,346	5.0%
Total Costs & Expenses	1,140,623	1,036,123	104,500	10.1%
Utility Income before Income Taxes / PILs	(50,864)	166,379	(217,243)	(130.6%)
PILs / Income Taxes		27,640	(27,640)	(100.0%)
Utility Income	**(50,864)**	**138,739**	**(189,603)**	**(136.7%)**

Ontario

REVENUE REQUIREMENT WORK FORM

Name of LDC: Hawkesbury Hydro Inc.
File Number: EB-2009-0186
Rate Year: 2010

Data Input (1)

		Application		Adjustments	Per Board Decision	
1	**Rate Base**					
	Gross Fixed Assets (average)	$3,691,251	**(4)**		$3,691,251	
	Accumulated Depreciation (average)	($1,571,554)	**(5)**		($1,571,554)	
	Allowance for Working Capital:					
	Controllable Expenses	$965,143	(6)		$965,143	
	Cost of Power	$12,544,138			$12,544,138	
	Working Capital Rate (%)	15.00%			15.00%	
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$909,761				
	Distribution Revenue at Proposed Rates	$1,304,216				
	Other Revenue:					
	Specific Service Charges	$88,077				
	Late Payment Charges	$31,875				
	Other Distribution Revenue	$22,545				
	Other Income and Deductions	$37,500				
	Operating Expenses:					
	OM+A Expenses	$936,881			$936,881	
	Depreciation/Amortization	$175,480			$175,480	
	Property taxes	$28,262			$28,262	
	Capital taxes	$0				
	Other expenses					
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	$27,188	**(3)**			
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$26,405				
	Income taxes (grossed up)	$31,623				
	Capital Taxes	$ -				
	Federal tax (%)	11.00%				
	Provincial tax (%)	5.50%				
	Income Tax Credits	$ -				
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	**(2)**			**(2)**
	Common Equity Capitalization Ratio (%)	40.0%				
	Prefered Shares Capitalization Ratio (%)					
					Capital Structure must total 100%	
	Cost of Capital					
	Long-term debt Cost Rate (%)	7.62%				
	Short-term debt Cost Rate (%)	1.33%				
	Common Equity Cost Rate (%)	8.01%				
	Prefered Shares Cost Rate (%)					

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

Ontario

REVENUE REQUIREMENT WORK FORM

Name of LDC: Hawkesbury Hydro Inc.
File Number: EB-2009-0186
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$3,691,251	$ -	$3,691,251
2	Accumulated Depreciation (average)	(3)	($1,571,554)	$ -	($1,571,554)
3	Net Fixed Assets (average)	(3)	$2,119,698	$ -	$2,119,698
4	Allowance for Working Capital	(1)	$2,026,392	$ -	$2,026,392
5	**Total Rate Base**		$4,146,090	$ -	$4,146,090

Line No.	(1) Allowance for Working Capital - Derivation		Application	Adjustments	Per Board Decision
6	Controllable Expenses		$965,143	$ -	$965,143
7	Cost of Power		$12,544,138	$ -	$12,544,138
8	Working Capital Base		$13,509,281	$ -	$13,509,281
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$2,026,392	$ -	$2,026,392

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Hawkesbury Hydro Inc.
File Number: EB-2009-0186
Rate Year: 2010

Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$1,304,216	$ -	$1,304,216
2	Other Revenue	(1)	$179,998	$ -	$179,998
3	Total Operating Revenues		$1,484,214	$ -	$1,484,214
	Operating Expenses:				
4	OM+A Expenses		$936,881	$ -	$936,881
5	Depreciation/Amortization		$175,480	$ -	$175,480
6	Property taxes		$28,262	$ -	$28,262
7	Capital taxes		$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -
9	Subtotal		$1,140,623	$ -	$1,140,623
10	Deemed Interest Expense		$179,128	$ -	$179,128
11	Total Expenses (lines 4 to 10)		$1,319,751	$ -	$1,319,751
12	**Utility income before income taxes**		$164,463	$ -	$164,463
13	Income taxes (grossed-up)		$31,623	$ -	$31,623
14	**Utility net income**		$132,841	$ -	$132,841

Notes

(1)

Other Revenues / Revenue Offsets	Application		Per Board Decision
Specific Service Charges	$88,077		$88,077
Late Payment Charges	$31,875		$31,875
Other Distribution Revenue	$22,545		$22,545
Other Income and Deductions	$37,500		$37,500
Total Revenue Offsets	$179,998		$179,998

REVENUE REQUIREMENT WORK FORM

Name of LDC: Hawkesbury Hydro Inc.
File Number: EB-2009-0186
Rate Year: 2010

Ontario

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$132,841	$132,841
2	Adjustments required to arrive at taxable utility income	$27,188	$27,188
3	Taxable income	$160,029	$160,029
	Calculation of Utility income Taxes		
4	Income taxes	$26,405	$26,405
5	Capital taxes	$ -	$ -
6	Total taxes	$26,405	$26,405
7	Gross-up of Income Taxes	$5,218	$5,218
8	Grossed-up Income Taxes	$31,623	$31,623
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$31,623	$31,623
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	11.00%	11.00%
12	Provincial tax (%)	5.50%	5.50%
13	Total tax rate (%)	16.50%	16.50%

Notes

REVENUE REQUIREMENT WORK FORM

Ontario

Name of LDC: Hawkesbury Hydro Inc.
File Number: EB-2009-0186
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Application				
	Debt				
1	Long-term Debt	56.00%	$2,321,810	7.62%	$176,922
2	Short-term Debt	4.00%	$165,844	1.33%	$2,206
3	**Total Debt**	60.00%	$2,487,654	7.20%	$179,128
	Equity				
4	Common Equity	40.00%	$1,658,436	8.01%	$132,841
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$1,658,436	8.01%	$132,841
7	**Total**	100%	$4,146,090	7.52%	$311,968
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$2,321,810	7.62%	$176,922
9	Short-term Debt	4.00%	$165,844	1.33%	$2,206
10	**Total Debt**	60.00%	$2,487,654	7.20%	$179,128
	Equity				
11	Common Equity	40.0%	$1,658,436	8.01%	$132,841
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$1,658,436	8.01%	$132,841
14	**Total**	100%	$4,146,090	7.52%	$311,968

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Hawkesbury Hydro Inc.
File Number: EB-2009-0186
Rate Year: 2010

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application: At Current Approved Rates	Per Application: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$394,455		$394,455
2	Distribution Revenue	$909,761	$909,761	$909,761	$909,761
3	Other Operating Revenue Offsets - net	$179,998	$179,998	$179,998	$179,998
4	**Total Revenue**	$1,089,759	$1,484,214	$1,089,759	$1,484,214
5	Operating Expenses	$1,140,623	$1,140,623	$1,140,623	$1,140,623
6	Deemed Interest Expense	$179,128	$179,128	$179,128	$179,128
	Total Cost and Expenses	$1,319,751	$1,319,751	$1,319,751	$1,319,751
7	**Utility Income Before Income Taxes**	($229,992)	$164,463	($229,992)	$164,463
8	Tax Adjustments to Accounting Income per 2009 PILs	$27,188	$27,188	$27,188	$27,188
9	**Taxable Income**	($202,804)	$191,652	($202,804)	$191,652
10	Income Tax Rate	16.50%	16.50%	16.50%	16.50%
11	**Income Tax on Taxable Income**	($33,463)	$31,623	($33,463)	$31,623
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	($196,529)	$132,841	($196,529)	$132,841
14	**Utility Rate Base**	$4,146,090	$4,146,090	$4,146,090	$4,146,090
	Deemed Equity Portion of Rate Base	$1,658,436	$1,658,436	$1,658,436	$1,658,436
15	Income/Equity Rate Base (%)	-11.85%	8.01%	-11.85%	8.01%
16	Target Return - Equity on Rate Base	8.01%	8.01%	8.01%	8.01%
	Sufficiency/Deficiency in Return on Equity	-19.86%	0.00%	-19.86%	0.00%
17	Indicated Rate of Return	-0.42%	7.52%	-0.42%	7.52%
18	Requested Rate of Return on Rate Base	7.52%	7.52%	7.52%	7.52%
19	Sufficiency/Deficiency in Rate of Return	-7.94%	0.00%	-7.94%	0.00%
20	Target Return on Equity	$132,841	$132,841	$132,841	$132,841
21	Revenue Sufficiency/Deficiency	$329,370	$ -	$329,370	$ -
22	**Gross Revenue Sufficiency/Deficiency**	$394,455 (1)		$394,455 (1)	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

REVENUE REQUIREMENT WORK FORM

Name of LDC: Hawkesbury Hydro Inc.
File Number: EB-2009-0186
Rate Year: 2010

Line No.	Particulars	Revenue Requirement: Application		Revenue Requirement: Per Board Decision	
1	OM&A Expenses	$936,881		$936,881	
2	Amortization/Depreciation	$175,480		$175,480	
3	Property Taxes	$28,262		$28,262	
4	Capital Taxes	$ -		$ -	
5	Income Taxes (Grossed up)	$31,623		$31,623	
6	Other Expenses	$ -		$ -	
7	Return				
	Deemed Interest Expense	$179,128		$179,128	
	Return on Deemed Equity	$132,841		$132,841	
8	Distribution Revenue Requirement before Revenues	$1,484,214		$1,484,214	
9	Distribution revenue	$1,304,216		$1,304,216	
10	Other revenue	$179,998		$179,998	
11	**Total revenue**	$1,484,214		$1,484,214	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)

Notes
(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Name of LDC: Hawkesbury Hydro Inc.
File Number: EB-2009-0186
Rate Year: 2010

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order							
		Monthly Delivery Charge				Total Bill			
		Current	Per Draft Rate Order	Change $	Change %	Current	Per Draft Rate Order	Change $	Change %
Residential	**800 kWh/month**	$ 29.80	$ 28.59	-$ 1.21	-4.1%	$ 91.65	$ 90.71	-$ 0.94	-1.0%
GS < 50kW	**2000** kWh/month	$ 63.49	$ 64.67	$ 1.18	1.9%	$ 224.84	$ 226.72	$ 1.88	0.8%

Notes:

Exhibit 2:

RATE BASE

Exhibit 2: Rate Base

Tab 1 (of 6): Overview

RATE BASE OVERVIEW

The Rate Base Summary table including variances is presented at Exhibit 2, Tab 1, Schedule 2. This table provides a projection of HHI's rate base for both the Bridge Year (2009) and the Test Year (2010). Comparisons are also provided for the 2006 EDR and 2006 actual data, 2007 and 2008 actual data. The rate base underlying HHI's revenue requirement includes a forecast of net fixed assets, plus a working capital allowance defined as 15% of the sum of the cost of power and controllable expenses. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

The following items are discussed in the following schedules:

- The Rate Base Trend Table presented at Exhibit 2, Tab 1, Schedule 1 details the year over year variations between the 2006 EDR and 2010 Test year.

- Exhibit 2, Tab 1, Schedule 2 contains the Annual Variance Analysis along with an explanation of the main drivers behind those variances;

Overall, the rate base has remained steady over the past six years, with a projected decline in the test year of $173K from the 2006 EDR Approved results (2004 actuals). The Rate Base for the Test Year is slightly lower than that of the Bridge Year Rate Base with the 2010 increase in average balances being offset by a decrease in working capital due in large to the reduction in power supply expenses. HHI has managed its capital and operating costs diligently since 2004. Marginal increases in OM&A (less than 2.8%) have been tempered with average balance reduction in 2006, 2007, 2008. HHI has reduced its capital expenditures related to growth and increased spending on system improvements, with the overall impact being an increase in rate base. Capital Costs and OM&A Costs are discussed in detail at Exhibit 4 and Exhibit 2 respectively.

Rate Base Trend Table

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Net Capital Assets in Service:						
Opening Balance		2,021,354	2,020,199	1,923,495	1,894,469	2,024,338
Ending Balance		2,020,199	1,923,495	1,894,469	2,024,338	2,215,058
Average Balance	2,058,337	2,020,776	1,971,847	1,908,982	1,959,403	2,119,698
Working Capital Allowance *(see below)*	2,260,393	2,215,124	2,264,864	2,162,052	2,190,573	2,026,392
Total Rate Base	**4,318,730**	**4,235,900**	**4,236,711**	**4,071,034**	**4,149,976**	**4,146,090**

Expenses for Working Capital

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	52,662	51,684	54,765	64,402	72,789	75,463
3550-Distribution Expenses - Maintenance	123,155	130,222	175,050	159,889	173,142	171,887
3650-Billing and Collecting	267,315	228,770	236,346	303,877	314,905	327,572
3700-Community Relations	100	60,810	12,668	100	104	2,108
3800-Administrative and General Expenses	350,188	274,250	290,168	269,155	285,636	359,851
3950-Taxes Other Than Income Taxes	24,654	25,171	25,634	26,205	26,916	28,262
Total Eligible Distribution Expenses	818,074	770,907	794,632	823,628	873,492	965,143
3350-Power Supply Expenses	14,251,214	13,996,585	14,304,462	13,590,055	13,730,325	12,544,138
Total Expenses for Working Capital	15,069,288	14,767,492	15,099,094	14,413,683	14,603,817	13,509,281
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**2,260,393**	**2,215,124**	**2,264,864**	**2,162,052**	**2,190,573**	**2,026,392**

RATE BASE VARIANCE ANALYSIS

Included on the next page is the Variance Analysis on Rate Base Table which provides a listing of the Net Capital Assets in Service and Working Capital for the 2006 EDR Approved, 2006, 2007, 2008 Actuals, 2009 Bridge and 2010 Test Years along with the year over year variances. Net Capital Assets in Service are calculated by taking an average of the opening and closing balances in each year. The Materiality Threshold for Net Capital Assets as well as Working Capital Allowance is consistent with "*Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*"". Since HHI's revenue requirement is less than $10Million, materiality has been set at $50,000. Working Capital Allowance is calculated at 15% of the Eligible Distribution Expenses plus Power Supply Expenses. Explanations for variances that exceed the materiality threshold as prescribed in the Filing Guidelines are set out in the following sections. As can be seen from the variance table at Exhibit 2, Tab 1, Schedule 2, Attachment 1, HHI's rate base has declined by roughly 4% since 2006 approved EDR.

2006 Actual compared to 2006 Approved EDR.

The 2006 Actual Year Rate Base is ($87,830) or 2.0% lower than the 2006 Approved Rate Base, representing an average annual reduction of $43,915. This amount falls below the materiality threshold. The decrease Rate Base is due in large to the reduction in power supply expenses and the depreciation of capital assets.

2007 Actual compared to 2006 Actual

The 2007 Actual Year Rate Base is $811 or 0.01% higher than the 2006 Actual Year Rate Base. This amount falls below the materiality threshold.

2008 Actual compared to 2007 Actual

The 2008 Actual Year Rate Base is ($160,667) or 3.8% lower than the 2007 Actual Year Rate Base. The decrease Rate Base is due in large to the reduction in power supply expenses and the depreciation of capital assets.

2009 Bridge compared to 2008 Actual

The 2009 Bridge Year Rate Base is $78,942 or 1.9% higher than the 2008 Actual Year Rate Base. This increase can be broken down as follows:

Average Capital Asset	$50,442
Working Capital Allowance	$28,520
Total	$78,942

This increase in HHI's working capital partly attributable to an increase in cost of power as detailed at Exhibit 2, Tab 5. The remainder of the rate base variance $50,442 can be attributed to an increase in capital projects during that period. For a list of HHI's capital projects in 2008 and 2009, please refer to Exhibit 2, Tab 4, Schedule 2.

2010 Test compared to 2009 Bridge

The 2010 Test Year Rate Base is $3,886 or 0.1% lower than the 2009 Bridge Year Rate Base. This amount falls below the materiality threshold.

Attachment 1

Rate Base Variance Analysis

Variances in excess of $50,000 are shown in bold

	2010 Projection	2009 Projection	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	2,024,338	1,894,469	**129,869**	**6.9%**
Ending Balance	2,215,058	2,024,338	**190,720**	**9.4%**
Average Balance	2,119,698	1,959,403	**160,295**	**8.2%**
Working Capital Allowance *(see below)*	2,026,392	2,190,573	**(164,180)**	**(7.5%)**
Total Rate Base	**4,146,090**	**4,149,976**	**(3,886)**	**(0.1%)**

Expenses for Working Capital — ***Variances in excess of $50,000 are shown in bold***

	2010 Projection	2009 Projection	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	75,463	72,789	2,674	3.7%
3550-Distribution Expenses - Maintenance	171,887	173,142	(1,255)	(0.7%)
3650-Billing and Collecting	327,572	314,905	12,667	4.0%
3700-Community Relations	2,108	104	2,004	1926.9%
3800-Administrative and General Expenses	359,851	285,636	**74,215**	**26.0%**
3950-Taxes Other Than Income Taxes	28,262	26,916	1,346	5.0%
Total Eligible Distribution Expenses	965,143	873,492	**91,651**	**10.5%**
3350-Power Supply Expenses	12,544,138	13,730,325	**(1,186,187)**	**(8.6%)**
Total Expenses for Working Capital	13,509,281	14,603,817	**(1,094,536)**	**(7.5%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,026,392**	**2,190,573**	**(164,180)**	**(7.5%)**

Attachment 1

Rate Base Variance Analysis

Variances in excess of $50,000 are shown in bold

	2009 Projection	2008 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	1,894,469	1,923,495	(29,026)	(1.5%)
Ending Balance	2,024,338	1,894,469	**129,869**	**6.9%**
Average Balance	1,959,403	1,908,982	**50,422**	**2.6%**
Working Capital Allowance *(see below)*	2,190,573	2,162,052	28,520	1.3%
Total Rate Base	**4,149,976**	**4,071,034**	**78,942**	**1.9%**

Variances in excess of $50,000 are shown in bold

Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	72,789	64,402	8,387	13.0%
3550-Distribution Expenses - Maintenance	173,142	159,889	13,253	8.3%
3650-Billing and Collecting	314,905	303,877	11,028	3.6%
3700-Community Relations	104	100	4	4.0%
3800-Administrative and General Expenses	285,636	269,155	16,481	6.1%
3950-Taxes Other Than Income Taxes	26,916	26,205	711	2.7%
Total Eligible Distribution Expenses	873,492	823,628	49,864	6.1%
3350-Power Supply Expenses	13,730,325	13,590,055	**140,270**	**1.0%**
Total Expenses for Working Capital	14,603,817	14,413,683	**190,134**	**1.3%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,190,573**	**2,162,052**	**28,520**	**1.3%**

Attachment 1

Rate Base Variance Analysis

Variances in excess of $50,000 are shown in bold

	2008 Actual	2007 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	1,923,495	2,020,199	**(96,704)**	**(4.8%)**
Ending Balance	1,894,469	1,923,495	(29,026)	(1.5%)
Average Balance	1,908,982	1,971,847	**(62,865)**	**(3.2%)**
Working Capital Allowance *(see below)*	2,162,052	2,264,864	**(102,812)**	**(4.5%)**
Total Rate Base	**4,071,034**	**4,236,711**	**(165,677)**	**(3.9%)**

Expenses for Working Capital ***Variances in excess of $50,000 are shown in bold***

	2008 Actual	2007 Actual	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	64,402	54,765	9,637	17.6%
3550-Distribution Expenses - Maintenance	159,889	175,050	(15,161)	(8.7%)
3650-Billing and Collecting	303,877	236,346	**67,531**	**28.6%**
3700-Community Relations	100	12,668	(12,568)	(99.2%)
3800-Administrative and General Expenses	269,155	290,168	(21,014)	(7.2%)
3950-Taxes Other Than Income Taxes	26,205	25,634	571	2.2%
Total Eligible Distribution Expenses	823,628	794,632	28,996	3.6%
3350-Power Supply Expenses	13,590,055	14,304,462	**(714,407)**	**(5.0%)**
Total Expenses for Working Capital	14,413,683	15,099,094	**(685,411)**	**(4.5%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	2,162,052	2,264,864	**(102,812)**	**(4.5%)**

Attachment 1

Rate Base Variance Analysis

Variances in excess of $50,000 are shown in bold

	2007 Actual	2006 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	2,020,199	2,021,354	(1,155)	(0.1%)
Ending Balance	1,923,495	2,020,199	**(96,704)**	**(4.8%)**
Average Balance	1,971,847	2,020,776	(48,930)	(2.4%)
Working Capital Allowance *(see below)*	2,264,864	2,215,124	49,740	2.2%
Total Rate Base	**4,236,711**	**4,235,900**	**811**	**0.0%**

Expenses for Working Capital

Variances in excess of $50,000 are shown in bold

	2007 Actual	2006 Actual	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	54,765	51,684	3,081	6.0%
3550-Distribution Expenses - Maintenance	175,050	130,222	44,828	34.4%
3650-Billing and Collecting	236,346	228,770	7,576	3.3%
3700-Community Relations	12,668	60,810	(48,142)	(79.2%)
3800-Administrative and General Expenses	290,168	274,250	15,919	5.8%
3950-Taxes Other Than Income Taxes	25,634	25,171	463	1.8%
Total Eligible Distribution Expenses	794,632	770,907	23,725	3.1%
3350-Power Supply Expenses	14,304,462	13,996,585	**307,877**	**2.2%**
Total Expenses for Working Capital	15,099,094	14,767,492	**331,602**	**2.2%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	2,264,864	2,215,124	49,740	2.2%

Attachment 1

Rate Base Variance Analysis

Variances in excess of $50,000 are shown in bold

	2006 Actual	2006 EDR Approved	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	2,021,354			
Ending Balance	2,020,199			
Average Balance	2,020,776	2,058,337	**(37,560)**	**(1.8%)**
Working Capital Allowance *(see below)*	2,215,124	2,260,393	**(45,269)**	**(2.0%)**
Total Rate Base	**4,235,900**	**4,318,730**	**(82,830)**	**(1.9%)**

Expenses for Working Capital ***Variances in excess of $50,000 are shown in bold***

	2006 Actual	2006 EDR Approved	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	51,684	52,662	(978)	(1.9%)
3550-Distribution Expenses - Maintenance	130,222	123,155	7,066	5.7%
3650-Billing and Collecting	228,770	267,315	(38,545)	(14.4%)
3700-Community Relations	60,810	100	**60,710**	**60710.5%**
3800-Administrative and General Expenses	274,250	350,188	**(75,939)**	**(21.7%)**
3950-Taxes Other Than Income Taxes	25,171	24,654	518	2.1%
Total Eligible Distribution Expenses	770,907	818,074	(47,167)	(5.8%)
3350-Power Supply Expenses	13,996,585	14,251,214	**(254,628)**	**(1.8%)**
Total Expenses for Working Capital	14,767,492	15,069,288	**(301,795)**	**(2.0%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,215,124**	**2,260,393**	(45,269)	(2.0%)

Exhibit 2: Rate Base

Tab 2 (of 6): Capital Asset Policies

CAPITALIZATION POLICY

HHI records capital assets at cost in accordance with Canadian Generally Accepted Accounting Principles as well as guidelines set out by the Ontario Energy Board, where applicable. All expenditures by the Corporation are classified as either capital or operating expenditures. The intention of these classifications is to allocate costs across accounting periods in a manner that appropriately matches those costs with the related current and future economic benefits. The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. HHI does not currently capitalize interest on funds for construction. HHI's adherence to the capitalization policy can be described as follows;

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.
- General Plant items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset (i.e. there is a significant increase in the physical output or service capacity; or the useful life of the capital asset is extended) will be capitalized.
- With respect to transportation equipment (e.g. vehicles), all costs associated with putting a vehicle into service are capitalized.

ASSET RETIREMENT POLICY

HHI does not have an asset retirement policy in place but the subject of asset retirement is discussed as part of the exhibit entitled “Asset management practices” at Exhibit 2, Tab 4, Schedule 5.

DEPRECIATION POLICY

HHI records assets at cost. Amortization is calculated on the basis of the straight-line method with reference to estimated useful lives of the assets in accordance with Ontario Energy Board policy at the following terms:

USoA Account	Account Description	Straight Line Life - Years	Straight Line Rate
1805	Distribution Plant - Land	N/A	N/A
1806	Distribution Plant - Land Rights/Easements	25	4.0%
1820	Distribution Plant - Distribution Stn. Equip. < 50KV	30	3.3%
1830	Distribution Plant - Poles, Towers and Fixtures	25	4.0%
1835	Distribution Plant - Overhead Conductors, Devices	25	4.0%
1840	Distribution Plant - Underground Conduit	25	4.0%
1845	Distribution Plant - Underground Conductors, Devices	25	4.0%
1850	Distribution Plant - Line Transformers	25	4.0%
1855	Distribution Plant - Services Underground	25	4.0%
1860	Distribution Plant - Meters	25	4.0%
1908	General Plant - Building/Fixtures	60	1.7%
1915	General Plant - Office Furniture/Equipment	10	10.0%
1920	Computer Equipment Hardware	5	20.0%
1925	Computer Software	5	20.0%
1930	General Plant - Transportation Equipment - heavy	8	12.5%
1930	General Plant - Transportation Equipment - light	5	20.0%
1935	General Plant - Stores Equipment	10	10.0%
1940	General Plant - Tools and Garage Equipment	10	10.0%
1945	General Plant - Measure and Testing Equipment	10	10.0%
1955	General Plant - Communication Equipment - FM	10	10.0%
1960	General Plant - Miscellaneous Equipment	5	20.0%
1970	General Plant - Load Mgt Customer Premises	10	10.0%
1980	General Plant - System Supervisory Equipment	25	4.0%

The amortization rates used by HHI are the same as the rates found in Appendix B of the 2006 Distribution Rate Handbook. These rates have not changed since the approval of the 2006 EDR application. They reflect a rational and systematic allocation of cost over future periods appropriate to the nature of the property, plant and equipment. Acquisitions made during the year are amortized at half the normal rate.

CAPITAL CONTRIBUTION POLICY

Capital contributions are calculated in accordance and compliance with the Distribution System Code. HHI continually expands its distribution system to accommodate customer-driven requests for service or additional power requirements. Each request for power is assessed individually and an economic evaluation is performed to determine whether the future incremental distribution revenue from a system expansion will pay for the capital costs and ongoing maintenance costs of the system expansion. The economic evaluation determines the customer’s capital contribution for the equipment, labour and ongoing maintenance costs of the expansion costs. A shortfall in revenue will result in a capital contribution being required from the customer.

Exhibit 2: Rate Base

Tab 3 (of 6): Fixed Assets

GROSS ASSETS

This section provides an analysis on HHI's Fixed Assets. The analysis starts with the 2006 EDR Balances and provides information on the 2006, 2007 and 2008 actual years, and factors in additions, retirements and other adjustments and finally presents projections for the 2009 Bridge Year and 2010 Test Year.

The following items will be discussed in the subsequent schedules:

- The Gross Asset Variance Table presented at Exhibit 2, Tab 3, Schedule 1, Attachment 1 shows the year over year change in Gross Assets. Variances are shown in term of dollars and percentages. Variances exceeding the materiality threshold are explained at Exhibit 2, Tab 4, Schedule 1.

- The Capital Asset Amortization Table presented Exhibit 2, Tab 3, Schedule 2 shows year over year change in Capital Amortization including a presentation of amortization expenses for 2006 EDR through to the 2010 Test Year.

- The Fixed Asset Continuity Statements displayed at Exhibit 2, Tab 3, Schedule 3 show the continuity for the year 2006 EDR through to the 2010 Test Year.

Additions to assets have been attributed to a small but steady system growth during 2006, 2007 and the beginning of 2008. Since the downturn in the economy, HHI's focus has been on improvements to existing systems. Since this the beginning of the downturn, HHI has reduced its capital expenditures related to growth and increased spending on system improvements, with the overall impact being an increase in rate base.

Hydro Hawkesbury Inc. (ED-2003-0027)

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G4 Variance Analysis: Balance Sheet

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
1450-Distribution Plant	1805-Land	20,000	20,000		
	1806-Land Rights	8,588	8,588		
	1815-Transformer Station Equipment - Normally Primary above 50 kV	454,188	372,188	**82,000**	**22.0%**
	1820-Distribution Station Equipment - Normally Primary below 50 kV	279,376	229,376	50,000	21.8%
	1830-Poles, Towers and Fixtures	420,257	347,257	**73,000**	**21.0%**
	1835-Overhead Conductors and Devices	423,383	390,383	33,000	8.5%
	1840-Underground Conduit	113,634	113,634		
	1845-Underground Conductors and Devices	237,283	219,783	17,500	8.0%
	1850-Line Transformers	334,028	323,028	11,000	3.4%
	1855-Services	21,013	21,013		
	1860-Meters	224,822	224,822		
1500-General Plant	1905-Land	28,300	28,300		
	1908-Buildings and Fixtures	849,124	824,124	25,000	3.0%
	1915-Office Furniture and Equipment	58,011	38,511	19,500	50.6%
	1920-Computer Equipment - Hardware	59,614	48,614	11,000	22.6%
	1925-Computer Software	129,242	120,042	9,200	7.7%
	1930-Transportation Equipment	205,346	205,346		
	1940-Tools, Shop and Garage Equipment	29,648	24,648	5,000	20.3%
	1950-Power Operated Equipment	34,363	4,363	30,000	687.6%
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(55,867)	(55,867)		

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November 4, 2009

G4 Variance Analysis: Balance Sheet

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
1450-Distribution Plant	1805-Land	20,000	20,000		
	1806-Land Rights	8,588	8,588		
	1815-Transformer Station Equipment - Normally Primary above 50 kV	372,188	302,188	**70,000**	**23.2%**
	1820-Distribution Station Equipment - Normally Primary below 50 kV	229,376	152,376	**77,000**	**50.5%**
	1830-Poles, Towers and Fixtures	347,257	298,257	49,000	16.4%
	1835-Overhead Conductors and Devices	390,383	362,383	28,000	7.7%
	1840-Underground Conduit	113,634	113,634		
	1845-Underground Conductors and Devices	219,783	202,283	17,500	8.7%
	1850-Line Transformers	323,028	310,028	13,000	4.2%
	1855-Services	21,013	21,013		
	1860-Meters	224,822	224,822		
1500-General Plant	1905-Land	28,300	28,300		
	1908-Buildings and Fixtures	824,124	824,124		
	1915-Office Furniture and Equipment	38,511	25,511	13,000	51.0%
	1920-Computer Equipment - Hardware	48,614	42,614	6,000	14.1%
	1925-Computer Software	120,042	113,042	7,000	6.2%
	1930-Transportation Equipment	205,346	205,346		
	1940-Tools, Shop and Garage Equipment	24,648	12,648	12,000	94.9%
	1950-Power Operated Equipment	4,363	4,363		
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(55,867)	(55,867)		

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G4 Variance Analysis: Balance Sheet

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
1450-Distribution Plant	1805-Land	20,000	20,000		
	1806-Land Rights	8,588	8,588		
	1815-Transformer Station Equipment - Normally Primary above 50 kV	302,188	281,524	20,664	7.3%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	152,376	152,376		
	1830-Poles, Towers and Fixtures	298,257	297,192	1,065	0.4%
	1835-Overhead Conductors and Devices	362,383	355,022	7,361	2.1%
	1840-Underground Conduit	113,634	113,414	220	0.2%
	1845-Underground Conductors and Devices	202,283	175,905	26,378	15.0%
	1850-Line Transformers	310,028	288,119	21,908	7.6%
	1855-Services	21,013	19,413	1,600	8.2%
	1860-Meters	224,822	222,885	1,936	0.9%
1500-General Plant	1905-Land	28,300	28,300		
	1908-Buildings and Fixtures	824,124	824,124		
	1915-Office Furniture and Equipment	25,511	18,427	7,084	38.4%
	1920-Computer Equipment - Hardware	42,614	40,391	2,223	5.5%
	1925-Computer Software	113,042	49,734	**63,308**	127.3%
	1930-Transportation Equipment	205,346	184,896	20,450	11.1%
	1940-Tools, Shop and Garage Equipment	12,648	11,939	709	5.9%
	1950-Power Operated Equipment	4,363	4,363		
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(55,867)		**(55,867)**	

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G4 Variance Analysis: Balance Sheet

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
1450-Distribution Plant	1805-Land	20,000	20,000		
	1806-Land Rights	8,588	8,588		
	1815-Transformer Station Equipment - Normally Primary above 50 kV	281,524	281,524		
	1820-Distribution Station Equipment - Normally Primary below 50 kV	152,376	152,376		
	1830-Poles, Towers and Fixtures	297,192	284,040	13,152	4.6%
	1835-Overhead Conductors and Devices	355,022	353,823	1,199	0.3%
	1840-Underground Conduit	113,414	113,414		
	1845-Underground Conductors and Devices	175,905	174,724	1,181	0.7%
	1850-Line Transformers	288,119	283,501	4,618	1.6%
	1855-Services	19,413	17,800	1,612	9.1%
	1860-Meters	222,885	221,805	1,080	0.5%
1500-General Plant	1905-Land	28,300	28,300		
	1908-Buildings and Fixtures	824,124	822,675	1,448	0.2%
	1915-Office Furniture and Equipment	18,427	14,168	4,258	30.1%
	1920-Computer Equipment - Hardware	40,391	30,322	10,069	33.2%
	1925-Computer Software	49,734	22,263	27,471	123.4%
	1930-Transportation Equipment	184,896	184,896		
	1940-Tools, Shop and Garage Equipment	11,939	10,606	1,334	12.6%
	1950-Power Operated Equipment	4,363	4,363		
1550-Other Capital Assets	1995-Contributions and Grants - Credit				

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G4 Variance Analysis: Balance Sheet

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
1450-Distribution Plant	1805-Land	20,000	10,000	10,000	100.0%
	1806-Land Rights	8,588	8,588		
	1815-Transformer Station Equipment - Normally Primary above 50 kV	281,524	56,416	**225,108**	399.0%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	152,376	151,715	661	0.4%
	1830-Poles, Towers and Fixtures	284,040	255,254	28,786	11.3%
	1835-Overhead Conductors and Devices	353,823	320,205	33,618	10.5%
	1840-Underground Conduit	113,414	113,060	354	0.3%
	1845-Underground Conductors and Devices	174,724	172,400	2,324	1.3%
	1850-Line Transformers	283,501	279,164	4,337	1.6%
	1855-Services	17,800	14,185	3,615	25.5%
	1860-Meters	221,805	218,045	3,760	1.7%
1500-General Plant	1905-Land	28,300	28,300	(0)	(0.0%)
	1908-Buildings and Fixtures	822,675	820,347	2,328	0.3%
	1915-Office Furniture and Equipment	14,168	8,097	6,071	75.0%
	1920-Computer Equipment - Hardware	30,322	20,309	10,013	49.3%
	1925-Computer Software	22,263	1,833	20,430	1114.6%
	1930-Transportation Equipment	184,896	184,896		
	1940-Tools, Shop and Garage Equipment	10,606	5,912	4,694	79.4%
	1950-Power Operated Equipment	4,363		4,363	
1550-Other Capital Assets	1995-Contributions and Grants - Credit				

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B2 Amortization of Capital Assets

Enter breakdown of actual/approved balances and projected amortization expenses

Capital Asset Account	2006 EDR Approved	Variance to 2006 Actual: Amortization Expense	Variance to 2006 Actual: Retirements / Other	Variance to 2006 Actual: Ending Balance
1806-Land Rights	(2,295)	(1,565)		-3860
1815-Transformer Station Equipment - Normally Primary above 50 kV	(30,983)	(27,745)		-58728.36
1820-Distribution Station Equipment - Normally Primary below 50 kV	(35,358)	(24,129)		-59487.45
1830-Poles, Towers and Fixtures	(69,624)	(47,560)		-117184.23
1835-Overhead Conductors and Devices	(72,396)	(50,641)		-123036.98
1840-Underground Conduit	(21,664)	(14,784)		-36448.13
1845-Underground Conductors and Devices	(32,755)	(22,613)		-55367.83
1850-Line Transformers	(92,082)	(35,325)		-127407.39
1855-Services	(1,113)	(1,395)		-2508.39
1860-Meters	(58,537)	(36,921)		-95458.19
1908-Buildings and Fixtures	(74,504)	(50,925)		-125429.49
1915-Office Furniture and Equipment	(5,097)	(2,242)		-7339.38
1920-Computer Equipment - Hardware	(12,464)	(9,541)		-22004.98
1925-Computer Software	(492)	(6,355)		-6847.08
1930-Transportation Equipment	(98,158)	(63,604)		-161762
1940-Tools, Shop and Garage Equipment	(3,238)	(2,012)		-5249.63
1950-Power Operated Equipment		(872)		-872.29
1995-Contributions and Grants - Credit				
TOTAL	**(610,760)**	**(398,232)**		**(1,008,992)**
Accumulated Amortization on Balance Sheet	(610,760)	1.1600-Accumulated Amortization		(1,008,992)
Amortization Expense				

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B2 Amortization of Capital Assets

Enter breakdown of actual/approved balances and project

Capital Asset Account	2006 Actual Ending Balance	2007 Actual Amortization Expense	2007 Actual Retirements / Other	2007 Actual Ending Balance
1806-Land Rights	-3860	(626)		(4,486)
1815-Transformer Station Equipment - Normally Primary above 50 kV	-58728.36	(12,881)		(71,609)
1820-Distribution Station Equipment - Normally Primary below 50 kV	-59487.45	(9,665)		(69,152)
1830-Poles, Towers and Fixtures	-117184.23	(18,498)		(135,682)
1835-Overhead Conductors and Devices	-123036.98	(20,072)		(143,109)
1840-Underground Conduit	-36448.13	(5,922)		(42,370)
1845-Underground Conductors and Devices	-55367.83	(9,095)		(64,463)
1850-Line Transformers	-127407.39	(13,898)		(141,305)
1855-Services	-2508.39	(621)		(3,130)
1860-Meters	-95458.19	(14,814)		(110,272)
1908-Buildings and Fixtures	-125429.49	(20,396)		(145,826)
1915-Office Furniture and Equipment	-7339.38	(1,149)		(8,489)
1920-Computer Equipment - Hardware	-22004.98	(4,875)		(26,880)
1925-Computer Software	-6847.08	(7,200)		(14,047)
1930-Transportation Equipment	-161762	(23,134)		(184,896)
1940-Tools, Shop and Garage Equipment	-5249.63	(844)		(6,093)
1950-Power Operated Equipment	-872.29	(436)		(1,308)
1995-Contributions and Grants - Credit				
TOTAL	**-1008991.8**	**-164125.74**		**(1,173,118)**
Accumulated Amortization on Balance Sheet	1.1600-Accumulated Amortization			
Amortization Expense		**164,126**		

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B2 Amortization of Capital Assets

Enter breakdown of actual/approved balances and project

Capital Asset Account	2007 Actual Ending Balance	2008 Actual Amortization Expense	2008 Actual Retirements / Other	2008 Actual Ending Balance
1806-Land Rights	(4,486)	(626)		(5,112)
1815-Transformer Station Equipment - Normally Primary above 50 kV	(71,609)	(11,391)		(83,000)
1820-Distribution Station Equipment - Normally Primary below 50 kV	(69,152)	(9,665)		(78,817)
1830-Poles, Towers and Fixtures	(135,682)	(17,713)		(153,395)
1835-Overhead Conductors and Devices	(143,109)	(19,506)		(162,615)
1840-Underground Conduit	(42,370)	(5,926)		(48,296)
1845-Underground Conductors and Devices	(64,463)	(9,646)		(74,109)
1850-Line Transformers	(141,305)	(13,954)		(155,260)
1855-Services	(3,130)	(674)		(3,804)
1860-Meters	(110,272)	(14,874)		(125,147)
1908-Buildings and Fixtures	(145,826)	(20,411)		(166,237)
1915-Office Furniture and Equipment	(8,489)	(1,671)		(10,160)
1920-Computer Equipment - Hardware	(26,880)	(4,419)		(31,299)
1925-Computer Software	(14,047)	(16,028)		(30,075)
1930-Transportation Equipment	(184,896)	(1,278)		(186,174)
1940-Tools, Shop and Garage Equipment	(6,093)	(940)		(7,033)
1950-Power Operated Equipment	(1,308)	(436)		(1,744)
1995-Contributions and Grants - Credit		1,093		1,093
TOTAL	**(1,173,118)**	**(148,065)**		**(1,321,183)**
Accumulated Amortization on Balance Sheet	(1,173,118)	1.1600-Accumulated Amortization		
Amortization Expense		**148,065**		

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B2 Amortization of Capital Assets

Enter breakdown of actual/approved balances and projecte

Capital Asset Account	2008 Actual Ending Balance	2009 Projection Amortization Expense	Retirements / Other	Ending Balance
1806-Land Rights	(5,112)	(626)		(5,738)
1815-Transformer Station Equipment - Normally Primary above 50 kV	(83,000)	(13,451)		(96,451)
1820-Distribution Station Equipment - Normally Primary below 50 kV	(78,817)	(10,948)		(89,765)
1830-Poles, Towers and Fixtures	(153,395)	(18,558)		(171,953)
1835-Overhead Conductors and Devices	(162,615)	(19,277)		(181,892)
1840-Underground Conduit	(48,296)	(5,931)		(54,227)
1845-Underground Conductors and Devices	(74,109)	(10,523)		(84,632)
1850-Line Transformers	(155,260)	(14,598)		(169,858)
1855-Services	(3,804)	(700)		(4,504)
1860-Meters	(125,147)	(14,912)		(140,059)
1908-Buildings and Fixtures	(166,237)	(20,411)		(186,648)
1915-Office Furniture and Equipment	(10,160)	(2,657)		(12,817)
1920-Computer Equipment - Hardware	(31,299)	(4,882)		(36,181)
1925-Computer Software	(30,075)	(22,828)		(52,903)
1930-Transportation Equipment	(186,174)	(2,556)		(188,730)
1940-Tools, Shop and Garage Equipment	(7,033)	(1,522)		(8,555)
1950-Power Operated Equipment	(1,744)	(436)		(2,180)
1995-Contributions and Grants - Credit	1,093	2,185		3,278
TOTAL	**(1,321,183)**	**(162,631)**		**(1,483,814)**
Accumulated Amortization on Balance Sheet	(1,321,183)	1.1600-Accumulated Amortization		
Amortization Expense		**162,631**		

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B2 Amortization of Capital Assets

Enter breakdown of actual/approved balances and projecte

Capital Asset Account	2009 Projection Ending Balance	2010 Projection Amortization Expense	2010 Projection Retirements / Other	2010 Projection Ending Balance
1806-Land Rights	(5,738)	(626)		(6,364)
1815-Transformer Station Equipment - Normally Primary above 50 kV	(96,451)	(16,906)		(113,357)
1820-Distribution Station Equipment - Normally Primary below 50 kV	(89,765)	(13,065)		(102,830)
1830-Poles, Towers and Fixtures	(171,953)	(20,192)		(192,145)
1835-Overhead Conductors and Devices	(181,892)	(19,576)		(201,468)
1840-Underground Conduit	(54,227)	(5,931)		(60,158)
1845-Underground Conductors and Devices	(84,632)	(11,223)		(95,855)
1850-Line Transformers	(169,858)	(14,396)		(184,254)
1855-Services	(4,504)	(700)		(5,204)
1860-Meters	(140,059)	(14,772)		(154,831)
1908-Buildings and Fixtures	(186,648)	(20,661)		(207,309)
1915-Office Furniture and Equipment	(12,817)	(4,282)		(17,099)
1920-Computer Equipment - Hardware	(36,181)	(5,203)		(41,384)
1925-Computer Software	(52,903)	(23,268)		(76,171)
1930-Transportation Equipment	(188,730)	(2,556)		(191,286)
1940-Tools, Shop and Garage Equipment	(8,555)	(2,372)		(10,927)
1950-Power Operated Equipment	(2,180)	(1,936)		(4,116)
1995-Contributions and Grants - Credit	3,278	2,185		5,463
TOTAL	**(1,483,814)**	**(175,480)**		**(1,659,294)**
Accumulated Amortization on Balance Sheet				
Amortization Expense		**175,480**		

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Capital Asset Continuity Statements

	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other	Amortization	Balance
1610-Miscellaneous Intangible Plant					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1805-Land					
Gross Assets	10,000		10,000		20,000
Accumulated Amortization					
Net Book Value	10,000		10,000		20,000
1806-Land Rights					
Gross Assets	8,588				8,588
Accumulated Amortization	(2,295)			(1,565)	(3,860)
Net Book Value	6,293			(1,565)	4,728
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets	56,416	225,108			281,524
Accumulated Amortization	(30,983)			(27,745)	(58,728)
Net Book Value	25,433	225,108		(27,745)	222,796
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	151,715	661	0		152,376
Accumulated Amortization	(35,358)			(24,129)	(59,487)

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Capital Asset Continuity Statements

	2006 EDR Approved	Variance to 2006 Actual Additions	Ret./Other	Amortization	2006 Balance
Net Book Value	116,357	661	0	(24,129)	92,889
1830-Poles, Towers and Fixtures					
Gross Assets	255,254	28,786			284,040
Accumulated Amortization	(69,624)			(47,560)	(117,184)
Net Book Value	185,630	28,786		(47,560)	166,856
1835-Overhead Conductors and Devices					
Gross Assets	320,205	33,618			353,823
Accumulated Amortization	(72,396)			(50,641)	(123,037)
Net Book Value	247,809	33,618		(50,641)	230,786
1840-Underground Conduit					
Gross Assets	113,060	354	0		113,414
Accumulated Amortization	(21,664)			(14,784)	(36,448)
Net Book Value	91,396	354	0	(14,784)	76,966
1845-Underground Conductors and Devices					
Gross Assets	172,400	2,324	(0)		174,724
Accumulated Amortization	(32,755)			(22,613)	(55,368)
Net Book Value	139,645	2,324	(0)	(22,613)	119,356
1850-Line Transformers					
Gross Assets	279,164	4,337	0		283,501
Accumulated Amortization	(92,082)			(35,325)	(127,407)
Net Book Value	187,082	4,337	0	(35,325)	156,094
1855-Services					
Gross Assets	14,185	3,615			17,800
Accumulated Amortization	(1,113)			(1,395)	(2,508)
Net Book Value	13,072	3,615		(1,395)	15,292
1860-Meters					
Gross Assets	218,045	3,760			221,805

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Capital Asset Continuity Statements

	2006 EDR Approved	Variance to 2006 Actual Additions	Ret./Other	Amortization	2006 Balance
Accumulated Amortization	(58,537)			(36,921)	(95,458)
Net Book Value	159,508	3,760		(36,921)	126,347
1905-Land					
Gross Assets	28,300	(0)	0		28,300
Accumulated Amortization					
Net Book Value	28,300	(0)	0		28,300
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	820,347	2,328	(0)		822,675
Accumulated Amortization	(74,504)			(50,925)	(125,429)
Net Book Value	745,843	2,328	(0)	(50,925)	697,246
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	8,097	6,071			14,168
Accumulated Amortization	(5,097)			(2,242)	(7,339)
Net Book Value	3,000	6,071		(2,242)	6,829
1920-Computer Equipment - Hardware					
Gross Assets	20,309	10,013			30,322
Accumulated Amortization	(12,464)			(9,541)	(22,005)
Net Book Value	7,845	10,013		(9,541)	8,317
1925-Computer Software					

Appendix 2-1
Capital Asset Continuity Statements

	2006 EDR	Variance to 2006 Actual			2006
	Approved	**Additions**	**Ret./Other**	**Amortization**	**Balance**
Gross Assets	1,833	20,430			22,263
Accumulated Amortization	(492)			(6,355)	(6,847)
Net Book Value	1,341	20,430		(6,355)	15,416
1930-Transportation Equipment					
Gross Assets	184,896				184,896
Accumulated Amortization	(98,158)			(63,604)	(161,762)
Net Book Value	86,738			(63,604)	23,134
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets	5,912	4,694			10,606
Accumulated Amortization	(3,238)			(2,012)	(5,250)
Net Book Value	2,674	4,694		(2,012)	5,356
1945-Measurement and Testing Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets		4,363			4,363
Accumulated Amortization				(872)	(872)
Net Book Value		4,363		(872)	3,491
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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Capital Asset Continuity Statements

	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other	Amortization	Balance
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					

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Capital Asset Continuity Statements

	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other	Amortization	Balance
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets					
Accumulated Amortization					
Net Book Value					
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					
TOTAL					
Gross Assets	**2,668,726**	**350,465**	**10,000**		**3,029,191**
Accumulated Amortization	**(610,760)**			**(398,232)**	**(1,008,992)**
Net Book Value	**2,057,966**	**350,465**	**10,000**	**(398,232)**	**2,020,199**

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Capital Asset Continuity Statements

	2006	2007 Changes			2007
	Balance	Additions	Ret./Other	Amortization	Balance
1610-Miscellaneous Intangible Plant					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1805-Land					
Gross Assets	20,000				20,000
Accumulated Amortization					
Net Book Value	20,000				20,000
1806-Land Rights					
Gross Assets	8,588				8,588
Accumulated Amortization	(3,860)			(626)	(4,486)
Net Book Value	4,728			(626)	4,102
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets	281,524				281,524
Accumulated Amortization	(58,728)			(12,881)	(71,609)
Net Book Value	222,796			(12,881)	209,915
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	152,376				152,376
Accumulated Amortization	(59,487)			(9,665)	(69,152)

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Capital Asset Continuity Statements

	2006 Balance	2007 Changes Additions	Ret./Other	Amortization	2007 Balance
Net Book Value	92,889			(9,665)	83,224
1830-Poles, Towers and Fixtures					
Gross Assets	284,040	13,152	0		297,192
Accumulated Amortization	(117,184)			(18,498)	(135,682)
Net Book Value	166,856	13,152	0	(18,498)	161,510
1835-Overhead Conductors and Devices					
Gross Assets	353,823	1,199	0		355,022
Accumulated Amortization	(123,037)			(20,072)	(143,109)
Net Book Value	230,786	1,199	0	(20,072)	211,913
1840-Underground Conduit					
Gross Assets	113,414				113,414
Accumulated Amortization	(36,448)			(5,922)	(42,370)
Net Book Value	76,966			(5,922)	71,044
1845-Underground Conductors and Devices					
Gross Assets	174,724	1,181	0		175,905
Accumulated Amortization	(55,368)			(9,095)	(64,463)
Net Book Value	119,356	1,181	0	(9,095)	111,442
1850-Line Transformers					
Gross Assets	283,501	4,618	(0)		288,119
Accumulated Amortization	(127,407)			(13,898)	(141,305)
Net Book Value	156,094	4,618	(0)	(13,898)	146,814
1855-Services					
Gross Assets	17,800	1,612			19,413
Accumulated Amortization	(2,508)			(621)	(3,130)
Net Book Value	15,292	1,612		(621)	16,283
1860-Meters					
Gross Assets	221,805	1,080			222,885

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Capital Asset Continuity Statements

	2006	2007 Changes			2007
	Balance	Additions	Ret./Other	Amortization	Balance
Accumulated Amortization	(95,458)			(14,814)	(110,272)
Net Book Value	126,347	1,080		(14,814)	112,613
1905-Land					
Gross Assets	28,300				28,300
Accumulated Amortization					
Net Book Value	28,300				28,300
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	822,675	1,448	0		824,124
Accumulated Amortization	(125,429)			(20,396)	(145,826)
Net Book Value	697,246	1,448	0	(20,396)	678,298
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	14,168	4,258			18,427
Accumulated Amortization	(7,339)			(1,149)	(8,489)
Net Book Value	6,829	4,258		(1,149)	9,938
1920-Computer Equipment - Hardware					
Gross Assets	30,322	10,069			40,391
Accumulated Amortization	(22,005)			(4,875)	(26,880)
Net Book Value	8,317	10,069		(4,875)	13,511
1925-Computer Software					

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Capital Asset Continuity Statements

	2006	2007 Changes			2007
	Balance	**Additions**	**Ret./Other**	**Amortization**	**Balance**
Gross Assets	22,263	27,471			49,734
Accumulated Amortization	(6,847)			(7,200)	(14,047)
Net Book Value	15,416	27,471		(7,200)	35,687
1930-Transportation Equipment					
Gross Assets	184,896				184,896
Accumulated Amortization	(161,762)			(23,134)	(184,896)
Net Book Value	23,134			(23,134)	
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets	10,606	1,334			11,939
Accumulated Amortization	(5,250)			(844)	(6,093)
Net Book Value	5,356	1,334		(844)	5,846
1945-Measurement and Testing Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets	4,363				4,363
Accumulated Amortization	(872)			(436)	(1,308)
Net Book Value	3,491			(436)	3,055
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Appendix 2-1
Capital Asset Continuity Statements

	2006 Balance	2007 Changes Additions	Ret./Other	Amortization	2007 Balance
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					

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Capital Asset Continuity Statements

	2006 Balance	2007 Changes Additions	Ret./Other	Amortization	2007 Balance
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets					
Accumulated Amortization					
Net Book Value					
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					
TOTAL					
Gross Assets	**3,029,191**	**67,422**	**0**		**3,096,612**
Accumulated Amortization	**(1,008,992)**			**(164,126)**	**(1,173,118)**
Net Book Value	**2,020,199**	**67,422**	**0**	**(164,126)**	**1,923,495**

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Capital Asset Continuity Statements

	2007	2008 Changes			2008
	Balance	Additions	Ret./Other	Amortization	Balance
1610-Miscellaneous Intangible Plant					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1805-Land					
Gross Assets	20,000				20,000
Accumulated Amortization					
Net Book Value	20,000				20,000
1806-Land Rights					
Gross Assets	8,588				8,588
Accumulated Amortization	(4,486)			(626)	(5,112)
Net Book Value	4,102			(626)	3,476
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets	281,524	20,664	(0)		302,188
Accumulated Amortization	(71,609)			(11,391)	(83,000)
Net Book Value	209,915	20,664	(0)	(11,391)	219,188
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	152,376				152,376
Accumulated Amortization	(69,152)			(9,665)	(78,817)

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Capital Asset Continuity Statements

	2007	2008 Changes			2008
	Balance	Additions	Ret./Other	Amortization	Balance
Net Book Value	83,224			(9,665)	73,559
1830-Poles, Towers and Fixtures					
Gross Assets	297,192	1,065	(0)		298,257
Accumulated Amortization	(135,682)			(17,713)	(153,395)
Net Book Value	161,510	1,065	(0)	(17,713)	144,862
1835-Overhead Conductors and Devices					
Gross Assets	355,022	7,361	0		362,383
Accumulated Amortization	(143,109)			(19,506)	(162,615)
Net Book Value	211,913	7,361	0	(19,506)	199,768
1840-Underground Conduit					
Gross Assets	113,414	220	(0)		113,634
Accumulated Amortization	(42,370)			(5,926)	(48,296)
Net Book Value	71,044	220	(0)	(5,926)	65,338
1845-Underground Conductors and Devices					
Gross Assets	175,905	26,378	0		202,283
Accumulated Amortization	(64,463)			(9,646)	(74,109)
Net Book Value	111,442	26,378	0	(9,646)	128,174
1850-Line Transformers					
Gross Assets	288,119	21,908	0		310,028
Accumulated Amortization	(141,305)			(13,954)	(155,260)
Net Book Value	146,814	21,908	0	(13,954)	154,768
1855-Services					
Gross Assets	19,413	1,600	0		21,013
Accumulated Amortization	(3,130)			(674)	(3,804)
Net Book Value	16,283	1,600	0	(674)	17,209
1860-Meters					
Gross Assets	222,885	1,936	0		224,822

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Capital Asset Continuity Statements

	2007	2008 Changes			2008
	Balance	Additions	Ret./Other	Amortization	Balance
Accumulated Amortization	(110,272)			(14,874)	(125,147)
Net Book Value	112,613	1,936	0	(14,874)	99,675
1905-Land					
Gross Assets	28,300				28,300
Accumulated Amortization					
Net Book Value	28,300				28,300
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	824,124				824,124
Accumulated Amortization	(145,826)			(20,411)	(166,237)
Net Book Value	678,298			(20,411)	657,887
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	18,427	7,084	0		25,511
Accumulated Amortization	(8,489)			(1,671)	(10,160)
Net Book Value	9,938	7,084	0	(1,671)	15,351
1920-Computer Equipment - Hardware					
Gross Assets	40,391	2,223	(0)		42,614
Accumulated Amortization	(26,880)			(4,419)	(31,299)
Net Book Value	13,511	2,223	(0)	(4,419)	11,315
1925-Computer Software					

Appendix 2-1
Capital Asset Continuity Statements

	2007	2008 Changes			2008
	Balance	Additions	Ret./Other	Amortization	Balance
Gross Assets	49,734	63,308	0		113,042
Accumulated Amortization	(14,047)			(16,028)	(30,075)
Net Book Value	35,687	63,308	0	(16,028)	82,967
1930-Transportation Equipment					
Gross Assets	184,896	20,450	(0)		205,346
Accumulated Amortization	(184,896)			(1,278)	(186,174)
Net Book Value		20,450	(0)	(1,278)	19,172
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets	11,939	709	(0)		12,648
Accumulated Amortization	(6,093)			(940)	(7,033)
Net Book Value	5,846	709	(0)	(940)	5,615
1945-Measurement and Testing Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets	4,363				4,363
Accumulated Amortization	(1,308)			(436)	(1,744)
Net Book Value	3,055			(436)	2,619
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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Capital Asset Continuity Statements

	2007 Balance	2008 Changes Additions	Ret./Other	Amortization	2008 Balance
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					

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Capital Asset Continuity Statements

	2007	2008 Changes			2008
	Balance	Additions	Ret./Other	Amortization	Balance
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets		(55,867)			(55,867)
Accumulated Amortization				1,093	1,093
Net Book Value		(55,867)		1,093	(54,774)
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					
TOTAL					
Gross Assets	**3,096,612**	**119,039**	**0**		**3,215,651**
Accumulated Amortization	**(1,173,118)**			**(148,065)**	**(1,321,183)**
Net Book Value	**1,923,495**	**119,039**	**0**	**(148,065)**	**1,894,469**

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Capital Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
1610-Miscellaneous Intangible Plant					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1805-Land					
Gross Assets	20,000				20,000
Accumulated Amortization					
Net Book Value	20,000				20,000
1806-Land Rights					
Gross Assets	8,588				8,588
Accumulated Amortization	(5,112)			(626)	(5,738)
Net Book Value	3,476			(626)	2,850
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets	302,188	70,000			372,188
Accumulated Amortization	(83,000)			(13,451)	(96,451)
Net Book Value	219,188	70,000		(13,451)	275,737
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	152,376	77,000			229,376
Accumulated Amortization	(78,817)			(10,948)	(89,765)

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Capital Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
Net Book Value	73,559	77,000		(10,948)	139,611
1830-Poles, Towers and Fixtures					
Gross Assets	298,257	49,000			347,257
Accumulated Amortization	(153,395)			(18,558)	(171,953)
Net Book Value	144,862	49,000		(18,558)	175,304
1835-Overhead Conductors and Devices					
Gross Assets	362,383	28,000			390,383
Accumulated Amortization	(162,615)			(19,277)	(181,892)
Net Book Value	199,768	28,000		(19,277)	208,491
1840-Underground Conduit					
Gross Assets	113,634				113,634
Accumulated Amortization	(48,296)			(5,931)	(54,227)
Net Book Value	65,338			(5,931)	59,407
1845-Underground Conductors and Devices					
Gross Assets	202,283	17,500			219,783
Accumulated Amortization	(74,109)			(10,523)	(84,632)
Net Book Value	128,174	17,500		(10,523)	135,151
1850-Line Transformers					
Gross Assets	310,028	13,000			323,028
Accumulated Amortization	(155,260)			(14,598)	(169,858)
Net Book Value	154,768	13,000		(14,598)	153,170
1855-Services					
Gross Assets	21,013				21,013
Accumulated Amortization	(3,804)			(700)	(4,504)
Net Book Value	17,209			(700)	16,509
1860-Meters					
Gross Assets	224,822				224,822

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Capital Asset Continuity Statements

	2008 Balance	2009 Changes Additions	Ret./Other	Amortization	2009 Balance
Accumulated Amortization	(125,147)			(14,912)	(140,059)
Net Book Value	99,675			(14,912)	84,763
1905-Land					
Gross Assets	28,300				28,300
Accumulated Amortization					
Net Book Value	28,300				28,300
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	824,124				824,124
Accumulated Amortization	(166,237)			(20,411)	(186,648)
Net Book Value	657,887			(20,411)	637,476
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	25,511	13,000			38,511
Accumulated Amortization	(10,160)			(2,657)	(12,817)
Net Book Value	15,351	13,000		(2,657)	25,694
1920-Computer Equipment - Hardware					
Gross Assets	42,614	6,000			48,614
Accumulated Amortization	(31,299)			(4,882)	(36,181)
Net Book Value	11,315	6,000		(4,882)	12,433
1925-Computer Software					

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Capital Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	**Additions**	**Ret./Other**	**Amortization**	**Balance**
Gross Assets	113,042	7,000			120,042
Accumulated Amortization	(30,075)			(22,828)	(52,903)
Net Book Value	82,967	7,000		(22,828)	67,139
1930-Transportation Equipment					
Gross Assets	205,346				205,346
Accumulated Amortization	(186,174)			(2,556)	(188,730)
Net Book Value	19,172			(2,556)	16,616
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets	12,648	12,000			24,648
Accumulated Amortization	(7,033)			(1,522)	(8,555)
Net Book Value	5,615	12,000		(1,522)	16,093
1945-Measurement and Testing Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets	4,363				4,363
Accumulated Amortization	(1,744)			(436)	(2,180)
Net Book Value	2,619			(436)	2,183
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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Capital Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					

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Capital Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(55,867)				(55,867)
Accumulated Amortization	1,093			2,185	3,278
Net Book Value	(54,774)			2,185	(52,589)
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					
TOTAL					
Gross Assets	**3,215,651**	**292,500**			**3,508,151**
Accumulated Amortization	**(1,321,183)**			**(162,631)**	**(1,483,814)**
Net Book Value	**1,894,469**	**292,500**		**(162,631)**	**2,024,338**

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Capital Asset Continuity Statements

	2009 Balance	2010 Changes Additions	Ret./Other	Amortization	2010 Balance
1610-Miscellaneous Intangible Plant					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1805-Land					
Gross Assets	20,000				20,000
Accumulated Amortization					
Net Book Value	20,000				20,000
1806-Land Rights					
Gross Assets	8,588				8,588
Accumulated Amortization	(5,738)			(626)	(6,364)
Net Book Value	2,850			(626)	2,224
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets	372,188	82,000			454,188
Accumulated Amortization	(96,451)			(16,906)	(113,357)
Net Book Value	275,737	82,000		(16,906)	340,831
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	229,376	50,000			279,376
Accumulated Amortization	(89,765)			(13,065)	(102,830)

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Capital Asset Continuity Statements

	2009 Balance	2010 Changes Additions	Ret./Other	Amortization	2010 Balance
Net Book Value	139,611	50,000		(13,065)	176,546
1830-Poles, Towers and Fixtures					
Gross Assets	347,257	73,000			420,257
Accumulated Amortization	(171,953)			(20,192)	(192,145)
Net Book Value	175,304	73,000		(20,192)	228,112
1835-Overhead Conductors and Devices					
Gross Assets	390,383	33,000			423,383
Accumulated Amortization	(181,892)			(19,576)	(201,468)
Net Book Value	208,491	33,000		(19,576)	221,915
1840-Underground Conduit					
Gross Assets	113,634				113,634
Accumulated Amortization	(54,227)			(5,931)	(60,158)
Net Book Value	59,407			(5,931)	53,476
1845-Underground Conductors and Devices					
Gross Assets	219,783	17,500			237,283
Accumulated Amortization	(84,632)			(11,223)	(95,855)
Net Book Value	135,151	17,500		(11,223)	141,428
1850-Line Transformers					
Gross Assets	323,028	11,000			334,028
Accumulated Amortization	(169,858)			(14,396)	(184,254)
Net Book Value	153,170	11,000		(14,396)	149,774
1855-Services					
Gross Assets	21,013				21,013
Accumulated Amortization	(4,504)			(700)	(5,204)
Net Book Value	16,509			(700)	15,809
1860-Meters					
Gross Assets	224,822				224,822

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Capital Asset Continuity Statements

	2009	2010 Changes			2010
	Balance	Additions	Ret./Other	Amortization	Balance
Accumulated Amortization	(140,059)			(14,772)	(154,831)
Net Book Value	84,763			(14,772)	69,991
1905-Land					
Gross Assets	28,300				28,300
Accumulated Amortization					
Net Book Value	28,300				28,300
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	824,124	25,000			849,124
Accumulated Amortization	(186,648)			(20,661)	(207,309)
Net Book Value	637,476	25,000		(20,661)	641,815
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	38,511	19,500			58,011
Accumulated Amortization	(12,817)			(4,282)	(17,099)
Net Book Value	25,694	19,500		(4,282)	40,912
1920-Computer Equipment - Hardware					
Gross Assets	48,614	11,000			59,614
Accumulated Amortization	(36,181)			(5,203)	(41,384)
Net Book Value	12,433	11,000		(5,203)	18,230
1925-Computer Software					

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Capital Asset Continuity Statements

	2009	2010 Changes			2010
	Balance	Additions	Ret./Other	Amortization	Balance
Gross Assets	120,042	9,200			129,242
Accumulated Amortization	(52,903)			(23,268)	(76,171)
Net Book Value	67,139	9,200		(23,268)	53,071
1930-Transportation Equipment					
Gross Assets	205,346				205,346
Accumulated Amortization	(188,730)			(2,556)	(191,286)
Net Book Value	16,616			(2,556)	14,060
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets	24,648	5,000			29,648
Accumulated Amortization	(8,555)			(2,372)	(10,927)
Net Book Value	16,093	5,000		(2,372)	18,721
1945-Measurement and Testing Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets	4,363	30,000			34,363
Accumulated Amortization	(2,180)			(1,936)	(4,116)
Net Book Value	2,183	30,000		(1,936)	30,247
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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Capital Asset Continuity Statements

	2009	2010 Changes			2010
	Balance	Additions	Ret./Other	Amortization	Balance
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					

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Capital Asset Continuity Statements

	2009	2010 Changes			2010
	Balance	Additions	Ret./Other	Amortization	Balance
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(55,867)				(55,867)
Accumulated Amortization	3,278			2,185	5,463
Net Book Value	(52,589)			2,185	(50,404)
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					
TOTAL					
Gross Assets	**3,508,151**	**366,200**			**3,874,351**
Accumulated Amortization	**(1,483,814)**			**(175,480)**	**(1,659,294)**
Net Book Value	**2,024,338**	**366,200**		**(175,480)**	**2,215,058**

Exhibit 2: Rate Base

Tab 4 (of 6): Capital Plan

SUMMARY OF CAPITAL EXPENDITURES

HISTORICAL CAPITAL EXPENDITURES

This section provides an analysis on HHI Capital Plan Projects. The analysis starts with the 2006 EDR Balances and provides information on the 2006, 2007, 2008 additions the 2009 Bridge Year and the 2010 Test Year.

HHI has been and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. HHI continuously completes inspections throughout the year while completing maintenance on the distribution system. In addition, HHI relies on study completed in 2006 that has provided a comprehensive analysis of our distribution system and infrastructure within HHI distribution area.

The reliability indices are recorded and monitored on an annual basis as demonstrated at Exhibit 2, Tab 6, Schedule 1. They are use to assess our asset condition which impacts the capital budgeting process. HHI has an obligation to serve new growth within our service area in a timely and cost effective way. In order to fulfill this obligation, HHI identifies all potential areas where new growth may occur, while recognizing that the actual timing of each possible new development is uncertain. Although growth has an impact on capital expenditures, reliability and safety are the main components taken into account.

Our capital budget reflects the level of growth that we anticipate based on the overall rate of development in our service area in recent years, anticipated economic conditions and management judgment.

The Development Contribution Projects are budgeted based on new customer connections for new subdivisions. These are developer installed projects.

Each year HHI looks at other plant, equipment and vehicles, along with the distribution system and determines the needs to ensure only those capital investments that are required to ensure a safe and reliable operation of HHI distribution system are made.

Analysis of Major Capital Expenditures:

The following section of the Application is a breakdown of major capital projects for 2005, 2006, 2007 and 2008, projected capital projects for 2009 BY and projected capital projects for 2010 TY Capital Costs over the materiality threshold of $50,000 are discussed in detail and a brief explanation of the remaining Capital Projects over the materiality threshold of $4000 are presented.

2006 EDR - 2006 ACTUAL

			Actual 2006	EDR 2006	Variance
1450- Distribution Plant	1815 - Transformer Station Equipment >50KV	Increase	$281,524.00	$56,416.00	$225,108.00

Breakdown

ESA fees for permits for work done on transformer stn	$300.00
Recloser & transformer leak	$13,323.00
MSP transfer fees from Hydro One to Hydro Ottawa	$51,520.00
Primary bushing transformer maintenance	$103,466.00
Maintenance done at transformer station	$56,499.33
	$225,108.33

Additions throughout 2005 and 2006 include upgrades to the 115KV insulators and structure. The recloser and transformer leak repairs were done in order to correct wear and tear and to prevent damage to the equipment. The equipment was installed in compliance with IESO's requirements on metering equipment at the delivery point.

Need 1: The 115 KV station structure had insulator installed several years ago, in fact when the station was built by Ontario Hydro. Following visual inspection we found out that some of these insulators were cracked. They had to be removed from service to avoid a major power interruption.

Scope 1: This structure needed immediate attention considering the reliability issue which was jeopardized if one of these insulators failed. HHI crew with the assistance of a contractor and Hydro One performed the required work in order to correct these anomalies.

Need 2: The metering apparatus on our 115 KV station had to be changed to meet IESO requirements. Hydro One who was our MSP provider chose to get away from this type of service. HHI had to perform the required changes to comply and get a new MSP provider.

Scope 2: Hydro Ottawa was retained by HHI to perform the required work to comply with IESO. HHI employees provided assistance with hardware installation.

Need 3: Visual inspection by HHI staff identified a low oil volume in a Primary Bushing on transformer 55T1. Under the circumstance an emergency shutdown of the unit was required.

Scope 3: HHI and an external contractor worked at replacing this leaking primary bushing. While in shutdown degasification of the transformer oil was also performed since high gases were found following oil testing. All work performed to prevent damages and a major power interruption.

Other Costs not exceeding the materiality threshold

			Actual 2006	EDR 2006	Variance
1450- Distribution Plant	1830 – Poles Towers and Fixtures	Increase	$284,040	$255,254	$28,786

Need 1: On an annual basis HHI perform regular visual inspection of all assets on the distribution system. Rotten pole and cross arms have to be replaced to obtain an adequate level of reliability and avoid outages. Ongoing pole replacement were performed in 2005 and 2006

Scope 1: Poles and cross arms were replaced on to prevent failure of existing assets and provide reliability.

Need 2: The old HHI office on McGill Street was sold several years ago to a local entrepreneur. Along this building was one of HHI distribution system main feeder. ESA and the ministry of Labor refused any alteration to this building since clearances were improper.

Scope 2: HHI found out that several years ago this line was also used to feed a transformer within the Hydro office at the time. Today under O.Reg 22/04 and other legislation, clearance was a major issue. HHI rerouted the feeder 55F3 to eliminate the hazardous situation. Furthermore poles and cross arms had to be replaced to prevent failure. Land survey and easement were properly identified in the favor of HHI

			Actual 2006	EDR 2006	Variance
	1835-Overhead Conductors and Devices		$353823	$320205	$33,618

Need: Par of the new 55F3 circuit we had to install new primary conductor. The capital expenditure was divided between poles and conductors.

Scope: While re-routing 55F3 HHI respected some of the comments from the Line loss analysis performed in 2006. The existing circuit built several years ago was built with 1/0ACSR conductor. 336 MCM Tulip was installed on the circuit to minimize line loss.

Need: Again in order to meet some of the line loss study recommendations, several areas within our service area were upgrade to 336MCM.

Scope: Some main feeders were upgraded with this 336MCM primary conductor. Also we also upgraded old copper primary conductors. This capital addition was to reduce line Loss and increase reliability.

			Actual 2006	EDR 2006	Variance
	1850-Line Transformers		$283501	$279164	$4,337

Need: Burnt underground transformer.

Scope: Following a power failure on Royal Street, we found the cause to be a burnt underground transformer. Labor and new transformer was accounted for this job.

			Actual 2006	EDR 2006	Variance
	1915-Office Furniture and Equipment		$14168	$8097	$6,071

Need: Several important documents were files in boxes and regular filing cabinet.
Scope: In order to protect these important documents and respect the retaining period, HHI purchased to large fire proofs cabinet. Also HHI purchased a new printer

			Actual 2006	EDR 2006	Variance
	1920-Computer Equipment - Hardware		$30322	$20309	$10,013

Need: Technology is continuously growing. HHI had to upgrade some PC and surge protection equipment.
Scope: old workstations are between 6 and 8 years old. Capacity and speed is a major issue. HHI decided to replace two workstations, surge protectors and acquired a laptop. IT costs and equipment was accounted for. Also a new laser printer was purchased.

			Actual 2006	EDR 2006	Variance
	1925-Computer Software		$22263	$1833	$20,430

Need: New hardware required new software.
Scope: With the upgrade of our workstations came some new acquisition for the software to be used. Furthermore new upgrades was also required to meet Ontario Deregulation from our provider AUSC

			Actual 2006	EDR 2006	Variance
	1940-Tools, Shop and Garage Equipment		$10606	$5912	$4,694

Need: Safety, reliability and customer service is part of HHI ongoing mandate. Proper tolls and equipment is also important to deliver these services.
Scope: Adequate testing amp meters were purchased. Two new chainsaws and a telescopic chainsaw were purchased to do our tree trimming.

			Actual 2006	EDR 2006	Variance
	1950-Power Operated Equipment		$4363	$0	$4,363

Need: In order to facilitate new installations proper powered equipment is required.

Scope: some of the equipment used by HHI was purchased 20-30 years ago. All manual equipment became obsolete. Time to repair underground cable was an ongoing issue. Wear and tear caused longer period of time to repair damages to underground facilities and longer restoration periods. New powered crimping tolls were purchased to facilitate work and minimize power interruptions

2007 ACTUAL- 2006 ACTUAL

There were no capital cost exceeding the materiality threshold of $50,000 in 2007 Actual.

Other Costs not exceeding the materiality threshold

			Actual 2007	Actual 2006	Variance
	1830-Poles, Towers and Fixtures		$297192	$284140	$13,152

Need: Identified in the previous years and in 2007, HHI in order to maintain safety and reliability had planned to change some poles.
Scope: Labor and poles and hardware were accounted for the replacement of 10 poles within our service area.

			Actual 2007	Actual 2006	Variance
	1850-Line Transformers		$288119	$283501	$4,618

Need: Transformation in existing residential subdivision.
Scope: On Rupper Street, 2 new lots were developed. In order to bring power to these new customers a new pad mount transformer was added to our distribution system. Labor and material was accounted for

			Actual 2007	Actual 2006	Variance
	1915-Office Furniture and Equipment		$18427	$14168	$4,258

Need: More efficiency in billing, document retention and personal information on our customers.

Scope: In order to be more efficient with our billing department we purchase a high capacity HP printer. A fire proof safe was added to protect important documents such as easement, contract and miscellaneous agreements. Finally a shredder was also acquired to destroy customer's documents and protect their privacy

			Actual 2007	Actual 2006	Variance
	1920-Computer Equipment - Hardware		$40391	$30322	$10,069

Need: In order to perform adequately the day to day task and meet different software requirements we to upgrade workstations on a regular basis

Scope: HHI as always neglected to upgrade their workstation. With the new software being utilized by HHI we did purchase 2 new workstations and upgraded 2 existing stations. We also purchase a new server following the lost of the hard drive on our existing server. Along came surge protectors and other equipment such a router.

			Actual 2006	EDR 2006	Variance
	1925-Computer Software		$47734	$22263	$27,471

Need: Several issues had to be look into in 2007. With the lost of our old server, new software was added in order to be able to utilize our new server and workstations.

Scope: SQL server software, Windows server software and MS office were purchased. Our existing Accounting system (VIMAX) was lost during the failure of our server. Also this in-house program had no more annual support available since the program now obsolete. Even without the lost of our server en February 2006, HHI had to look at accounting software. HHI opted for Accpac. In 2007 HHI also learned that Advanced Utility System was sold to Harris Computer. As of December 2008 Advanced would no longer provide any services on Ontario Deregulation. Like many LDC'S HHI had to look for a new CIS system. In order to be ready for the conversion from Advanced (AUSC) Utility system to Harris CIS we entered in an A.S.P. contract with Erie Thames now called E-Caliber. Software and data conversion was also accounted for in 2007.

2008 ACTUAL- 2007 ACTUAL

			Actual 2008	Actual 2007	Variance
1500- General Plant	1925-Computer Software	Increase	$113,042.00	$49,734.00	$63,308.00
			Actual 2008	**Actual 2007**	**Variance**
1550- Other Capital Assets	1995-Contributions & Grant - Credit	Decrease	-$54,774.00	$0.00	-$54,774.00

Acquisitions is composed of the purchase of an SQL server & license, an ACCPAC Payroll module, implementation of new domain and workstations for new billing system and conversion fees as we moved from Advanced to Harris billing system.

Need: HHI had to switch from Advanced Utility System to Harris computer VIA E-Caliber acting as our ASP provider.

Scope: In order to move totally to our new CIS system, new software, programming, conversion and services were acquired to perform the transition. We also entered into an agreement with our new settlement provider Utilismart. Some software expenses were also accounted in account 1925

Other Costs not exceeding the materiality threshold

			Actual 2008	Actual 2007	Variance
	1815-Transformer Station Equipment – Normally Primary above 50 kV		$302188	$281524	$20,664

Need: Reliability and safety is important to HHI. HHI following regular inspection of the substation recognized that a three phase recloser was defective.

Scope: Tests were performed to determine if this recloser could be repaired. Unfortunately this was an older model and repairs would be more that buying a refurbished unit. HHI did purchase a new unit. Labor and equipment was accounted for in 2008.

Year 2008/ Account 1835/Addition $7361

			Actual 2008	Actual 2007	Variance
	1835-Overhead Conductors and Devices		$362383	$355022	$7,361

Need: Following the line loss study in 2006, HHI executed some more primary conductor replacement.

Scope: One major section had to be changed in 2008. In fact while performing some Switching procedure in the past year we experience some issues with our primary conductor coming our of our 44KV sub station. 336MCM was installed to obtain reliability and facilitate switching in emergency situations. Copper primary in other smaller areas in town were also upgraded to 336MCM.

			Actual 2008	Actual 2007	Variance
	1845-Underground Conductors and Devices		$202283	$175905	$26,378

Need: Following a few years of slow growth, HHI had to expand its distribution system within its service area. A new residential underground subdivision.

Scope: Labor and material for the construction of this first phase of a new underground subdivision is accounted for the installation of this new underground system.

			Actual 2008	Actual 2007	Variance
	1850-Line Transformers		$310028	$288119	21,908

Need: As part of this new project transformation was also required

Scope: Labor, transformers and hardware relating to the installation of these transformers were accounted for.

			Actual 2008	Actual 2007	Variance
	1915-Office Furniture and Equipment		$25511	$18427	$7,084

Need: Upgrade of office furniture in order to facilitate work conditions.

Scope: Office furniture came from the old office on McGill Street. Desk, work table are old and inadequate. The accounting office was upgraded in 2008. Also a fireproof filing cabinet was added as well as a network printer.

			Actual 2008	Actual 2007	Variance
	1930-Transportation Equipment		$205346	$184896	$20,450

Need: Our fleet is composed of two pick up truck and two Boom truck. Our oldest pick up was outdated and needed several repairs.

Scope: In April following annual inspections of all our vehicles we were told that in order to keep our 1996 pick up on the road we needed at least a new floor. The expenses couldn't be justified. A new Ford F150 was purchased by HHI.

SUMMARY OF CAPITAL EXPENDITURES

PROJECTED CAPITAL EXPENDITURES

This section provides an analysis on HHI Projected Capital Plan. The analysis pertains to the 2009 bridge year and the 2010 Test Year.

USoA Account 1830

			Actual 2008	**Bridge 2009**	**Variance**
1450 - Distribution Plant	1830 - Poles Towers and Fixtures	Increase	$298,257	$347,257	$49,000
			Bridge 2009	**Test 2010**	**Variance**
	1830 - Poles Towers and Fixtures	Increase	$347,257	$420,257	$73,000

2009 – Pole Replacement

POLE REPLACEMENT FOLLOWING YEARLY INSPECTIONS.	
REPLACE 2 POLES: 479 & 501 STANLEY	$3,840.00
REPLACE ROTTEN X-ARM ON REGENT ST.	$1,346.00
REPLACE POLE AT542 LAFLECHE	$1,920.00
REPLACE ROTTEN X-ARM, RELOCATE PRIMARY CONDUCTORS ET FRAME POLE CORNER NELSON AND GENEVIEVE/ CORNER LANDSDOWNE AND BERTHA AND MCGILL AND NELSON EAST	$8,500.00
REPLACE DEAD END ON WEST ST. , REMOVE UNDER SWITCH	$3,500.00
REPLACE POLE 484 AND 434 CHAMPLAIN	$3,840.00
REPLACE POLE 835 CARTIER B/Y	$1,920.00
TESSIER /TUPPER ST. 44KV LINE TAKE OFF POLE AT OPTEST	$2,950.00
TOTAL EXPENDITURES	$27,816.00

2009 – Chance Cut-out

REPLACE OLD CHANCE CUTOUTS (DEFFECTIVE AND CAUSING POLE FIRES & INTERRUPTIONS)	$21,184.00
TOTAL EXPENDITURES	$21,184.00

2010 – Pole Replacement

POLE REPLACEMENT FOLLOWING YEARLY INSPECTIONS.	
REPLACE 3 POLES: 322,300,254 MAIN ST. WEST.	$5,760.00
REPLACE 3 POLES ON PORTELANCE ST. 675 2 DEAD END POLES & ON AT 677 PORTELANCE ST.	$5,760.00
REPLACE POLE AT 820 ABERDEEN ST. BACK YARD	$1,920.00

REPLACE POLES CAMERON TO WELLSLEY ST. TAKE OFF POLE AS WELL AS POLE EAST AND WEST OF TAKE OFF	$4,483.00
REPLACE POLES CAMERON TO WELLSLEY ST. 4 POLES AROUND 1400 CAMERON ST. (EAST, WEST AND AT OFFICE)	$7,680.00
LANDSDOWN ST HAMILTON TO TUPPER REPLACE POLES 856, 926 (EAST) TO 1333 ; 394 CAMERON EAST; LBS/34-1311; 1156 TO 1180; 1243 (EAST); OLYMPIA BOWL WEST AND FRONT; 1450	$13,440.00
TESSIER /TUPPER ST. 44KV LINE REP POLE (HYDRO OFFICE)	$1,920.00
TESSIER /TUPPER ST. 44KV LINE TAKE OFF POLE AT OPTEST	$1,920.00
TESSIER /TUPPER ST. 44KV LINE REP LACE RISER POLE	$4,483.00
SPENCE ST. TAKE OFF POLE DEAD END. (X ROAD STEVENS) ALSO 511 (2 POLES) AND 601 STEVENS (BACK YARD POLES)	$3,840.00
TAKE OFF HAWK CENTER REP POLES HC1 HC3, HC4(RISER), HC5(RISER h.c.), HC 6 (DEAD END)	$7,725.00
REGENT ST FROM WILLIAM TO JAMES REP POLES TAKE OFF POST OFFICE, CREVIER (33) 106,116,147,199	$9,600.00
KENTUCKY TAKE OFF ON MCGILL 2 X-ARMS	$1,346.00
TAKE OFF MARY ST Replace rotten X-arm with side pole bracket PLUS REV POLE	$1,577.00
545 CHAMBERLAIN REPLACE 2 ROTTEN X-ARMS	$873.00
GENEVIÈVE ST REPLACE X-ARMS ON DEAD END POLE	$673.00
TOTAL EXPENDITURES	$73,000.00

Pole Replacement;

Each year, HHI’s poles are tested and rated to determine when they should be replaced. As a general rule, notes and recommendations are taken during the visual inspection of the poles. HHI’s line crew checks each pole to make sure it can support structural loadings such as transformers. While performing the testing and visual check, a situation may occur where hardware needs replacement. In such cases HHI takes appropriate action to ensure that deffective equipment is replaced promptly ensuring that distribution system remains safe.

Failure to replace poles as required jeopardizes the health and safety of the public. System reliability and the ability to connect new customers are basic policies of the ESA.

Chance Cut-outs;

Switches are devices that allow or disallow the conductivity of high voltage conductors. Fused cut-outs accept different sizes of fuses. Cutouts stop the flow of electricity in case of a surge, protecting transformers and other electric equipment. HHI has experienced outages due to faulty cut-outs. Insulators that have proven to be problematic in the past are being switched to a new kind of cutout that uses a polymer material as the insulator. Failure to replace these faulty switches will decrease reliability, jeopardize the safety of the public and our personnel.

Switch Replacements are undertaken for the following different reasons:

- Mechanical or electrical failure
- Vehicle accidents, lightning strikes
- New customer requirements
- ESA compliance

USoA account 1835 & 1845

			Actual 2008	Bridge 2009	Variance
1450 - Distribution Plant	1835 – Overhead Conductors and Devices	Increase	$362,383	$390,383	$28,000
1450 - Distribution Plant	1845 – Underground Conductors and Devices	Increase	$202,283	$219,783	$17,500
			Bridge 2009	Test 2010	Variance
1450 - Distribution Plant	1835 – Overhead Conductors and Devices	Increase	$390,383	$423,383	$33,000
1450 - Distribution Plant	1845 – Underground Conductors and Devices	Increase	$219,783	$237,283	$17,500

2009 - Overhead and Underground Conductor & Devices betterment	
LAFLECHE ST.PRIMARY 3/0 ACSR AND SECONDARY 3/0 TRIPLEX	$2,163.00
GARNEAU ST. PRIMARY 2 ACSR AND SECONDARY POLY 3/0	$2,163.00
STANTEC REPORT REENT TO BON PASTEUR UPGRADE 336 MCM	$2,890.00
UPGRADE 3/0 TO 336 MCM TYUPPER AND SPENCE (MAIN FEEDERS)	$20,784.00
New underground subdivision (possible in 2009)	$17,500.00
TOTAL EXPENDITURES	$45,500.00

2010 - Overhead and Underground Conductor & Devices betterment	
LAFLECHE ST.PRIMARY 3/0 ACSR AND SECONDARY 3/0 TRIPLEX	$2,163.00
GARNEAU ST. PRIMARY 2 ACSR AND SECONDARY POLY 3/0	$2,163.00
PAUL CRES. LOOP SYSTEM	$4,242.00
STANTEC REPORT REGENT TO BON PASTERU UPGRADE 336 MCM	$3,648.00
STANTEC REPORT CHARTRAND TO WEST UPGRADE 336 MCM CIRCUIT 55F2	$10,392.00
STANTEC REPORT CHARTRAND TO WEST UPGRADE 336 MCM CIRCUIT 55F1	$10,392.00
NEW RESIDENTIAL SUBDIVISION (ANDRE DESJARDINS)	$17,500.00
TOTAL EXPENDITURES	$50,500.00

Conductor betterment

Following the optimization study done in 2006, some recommendations to improve reliability and line losses were to upgrade our primary and secondary conductors. Part of our yearly visuals checks also cover over head conductors.

USoA account 1815 & 1820

			Actual 2008	Bridge 2009	Variance
1450 - Distribution Plant	1815 - TS Equipment >50kV	Increase	$302,188	$372,188	$70,000
1450 - Distribution Plant	1820 – Distribution Station Equip.>50kV	Increase	$152,376	$229,376	$77,000
			Bridge 2009	Test 2010	Variance
1450 - Distribution Plant	1815 - TS Equipment >50kV	Increase	$372,188	$454,188	$82,000
1450 - Distribution Plant	1820 – Distribution Station Equip.>50kV	Increase	$229,376	$279,376	$50,000

2009

SUBSTATION 115KV MAINTENANCE NEW RECLOSER	$70,000.00
SUBSTATION 44KV	$77,000.00
TOTAL EXPENDITURES	$147,000.00

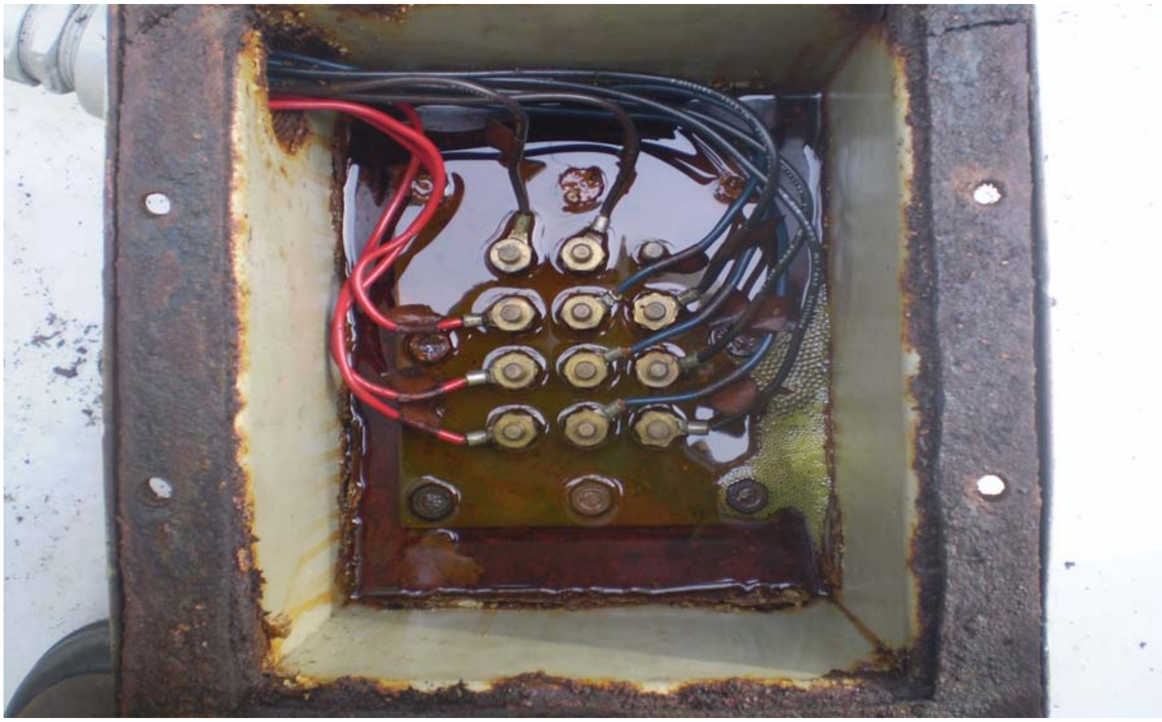
2010

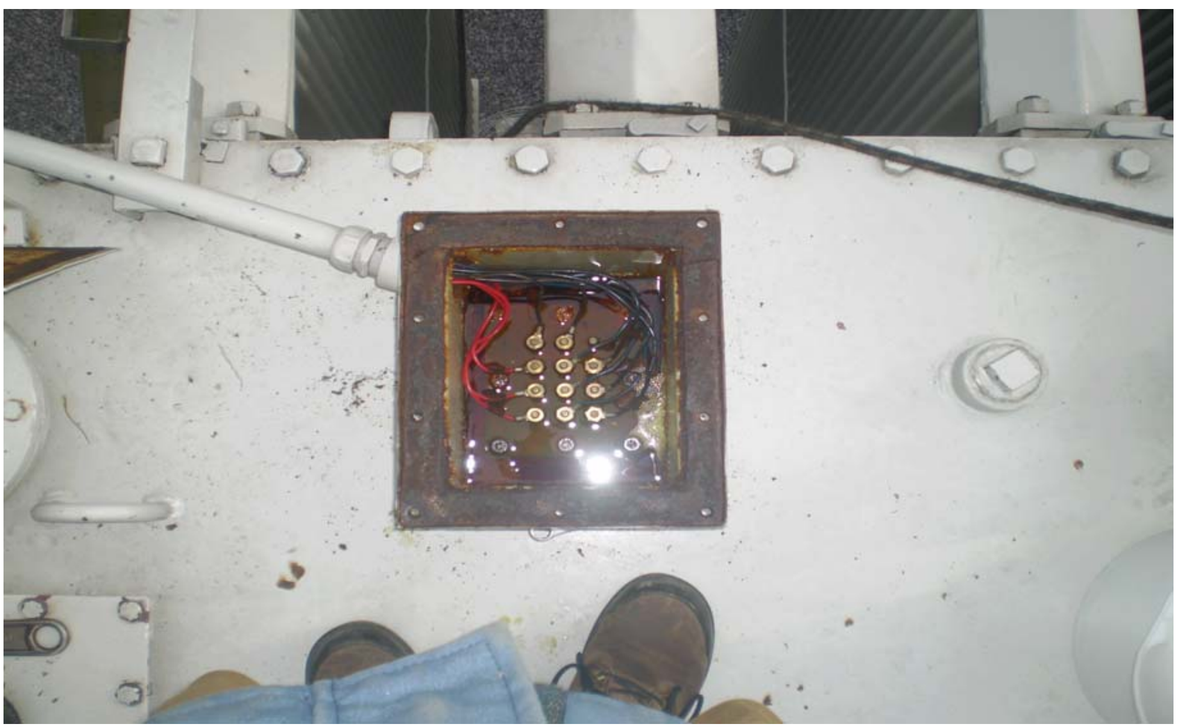
SUBSTATION 115KV MAINTENANCE NEW RECLOSER &	$82,000.00
SUBSTATION 44KV MAINTENANCE	$50,000.00
TOTAL EXPENDITURES	$132,000.00

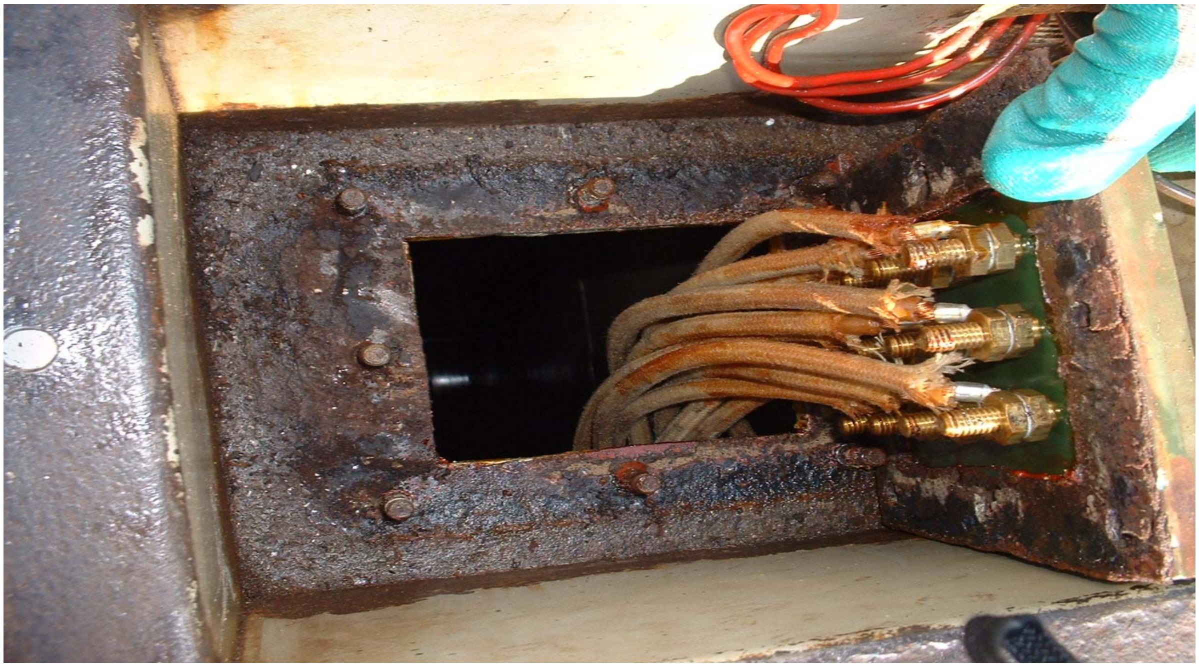
Distribution transformer stations;

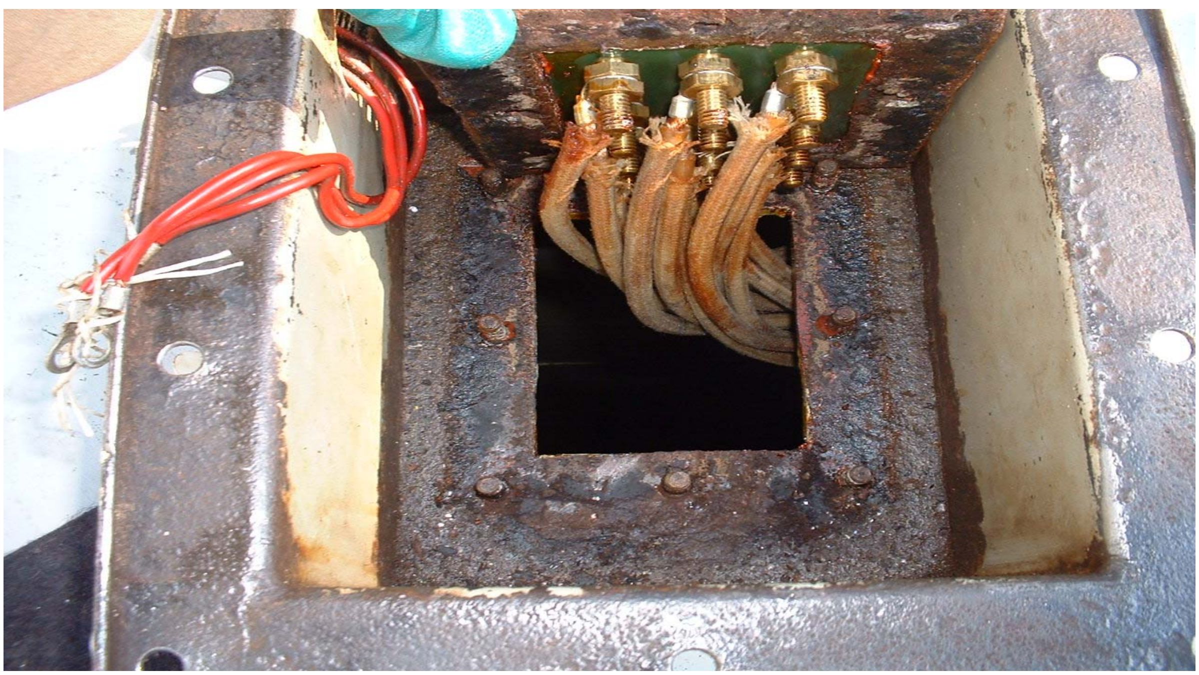
Distribution station inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice.

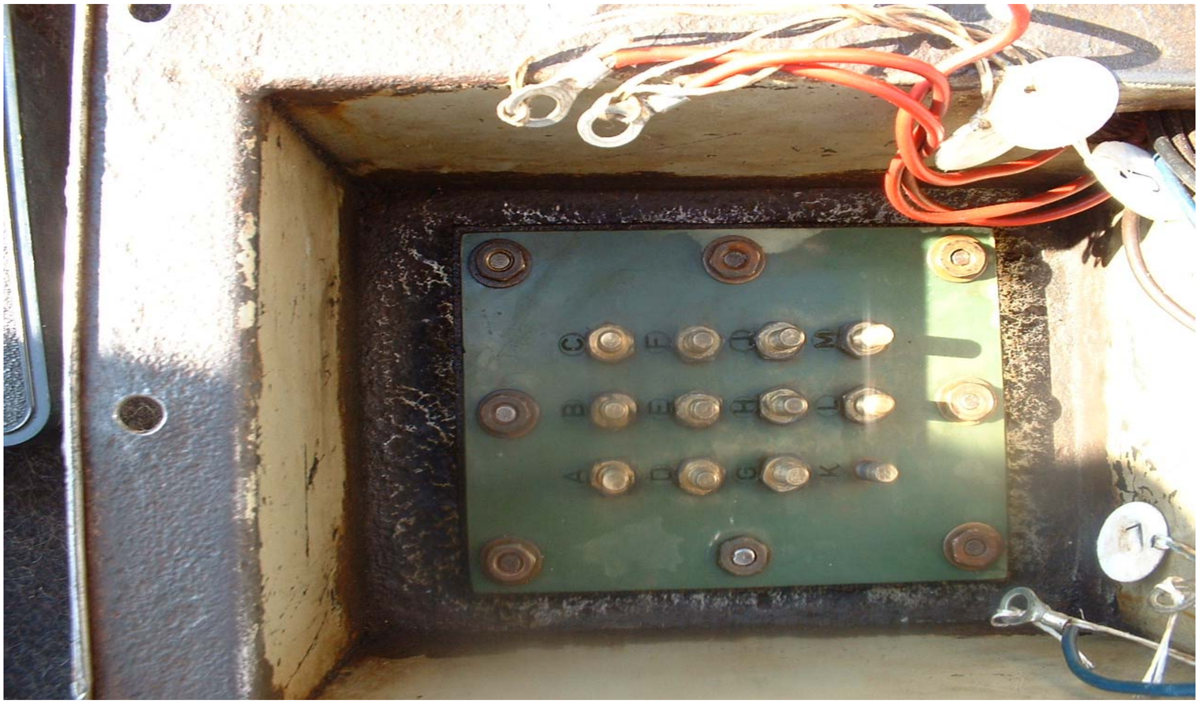
HHI receives its electricity supply from Hydro One at two delivery points. A substation at 115KV with two distribution transformers at the West end of town and a 44KV station at the East end of Hawkesbury. Both TS are over 45 years of age. In 2006 Stantec Engineering completed a study suggesting that the loss of 1 transformer could bring serious reliability issues and that HHI could not supply electricity to its entire service area with a single transformer. Due to these aging infrastructures, HHI has determined that it needs to assess and test components of theses substations often ensuring the safety of its customers and the reliability of its distribution system. Regular maintenance and monitoring is a major factor in the lifespan of a transformer and HHI has a yearly program to monitor the oil quality. Annual oil testing provides a good picture of the equipment and failure projection. Monthly inspections are also done both stations. A major interruption of the 115KV was required in early 2009. Following an oil test, a high level of gas which could cause deterioration and subsequently a major failure in the transformer was found. A 3-phase recloser was replaced to fix the problem. Reclosers act as circuit breakers and ultimately prevent damages from occurring to transformer. Documentation of the work describe above is presented in the following pages.

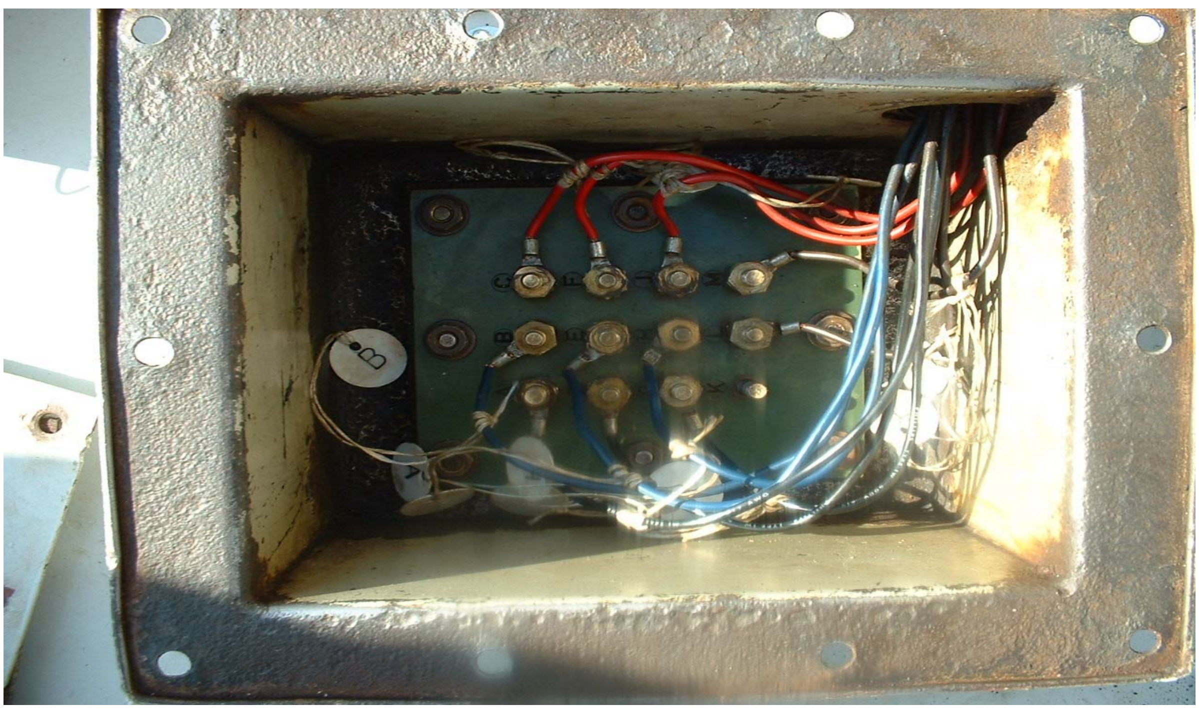


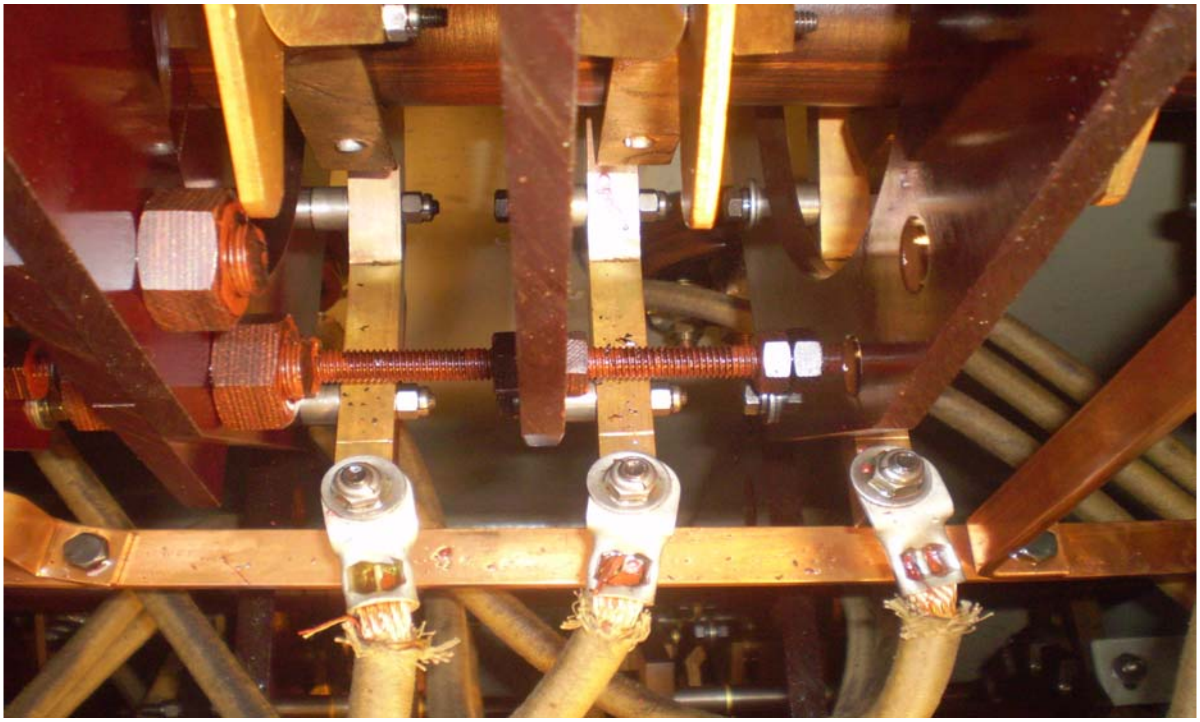


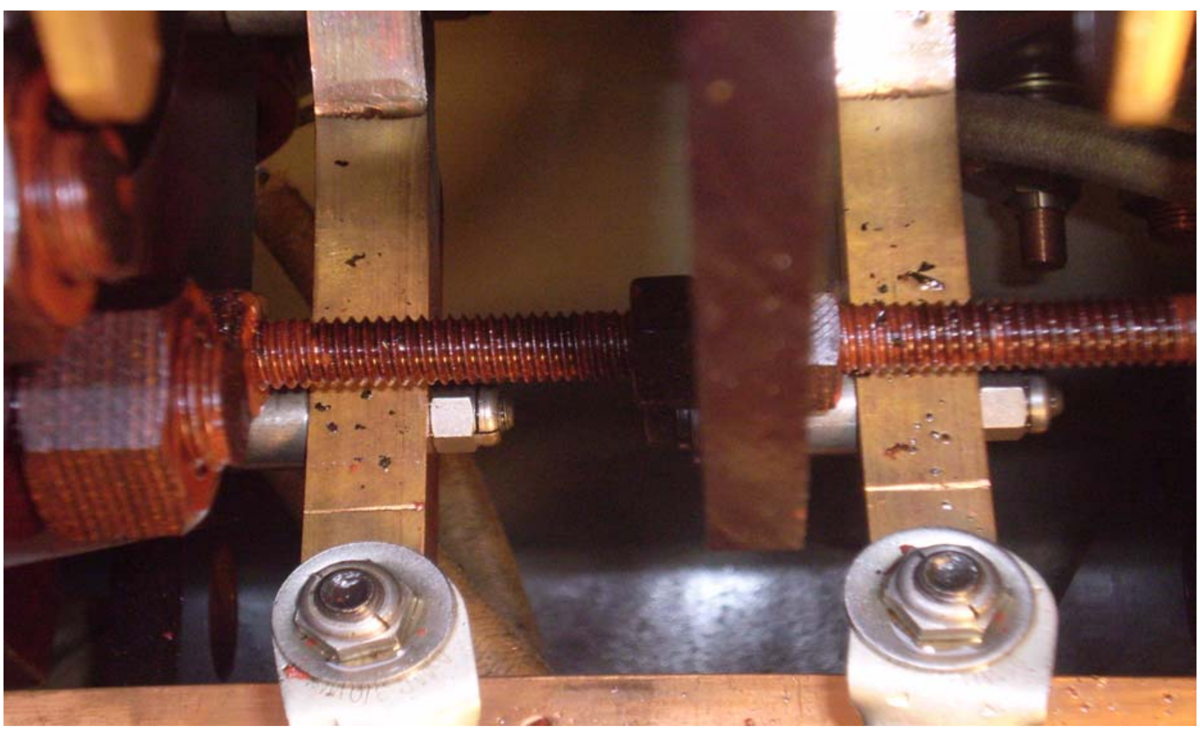


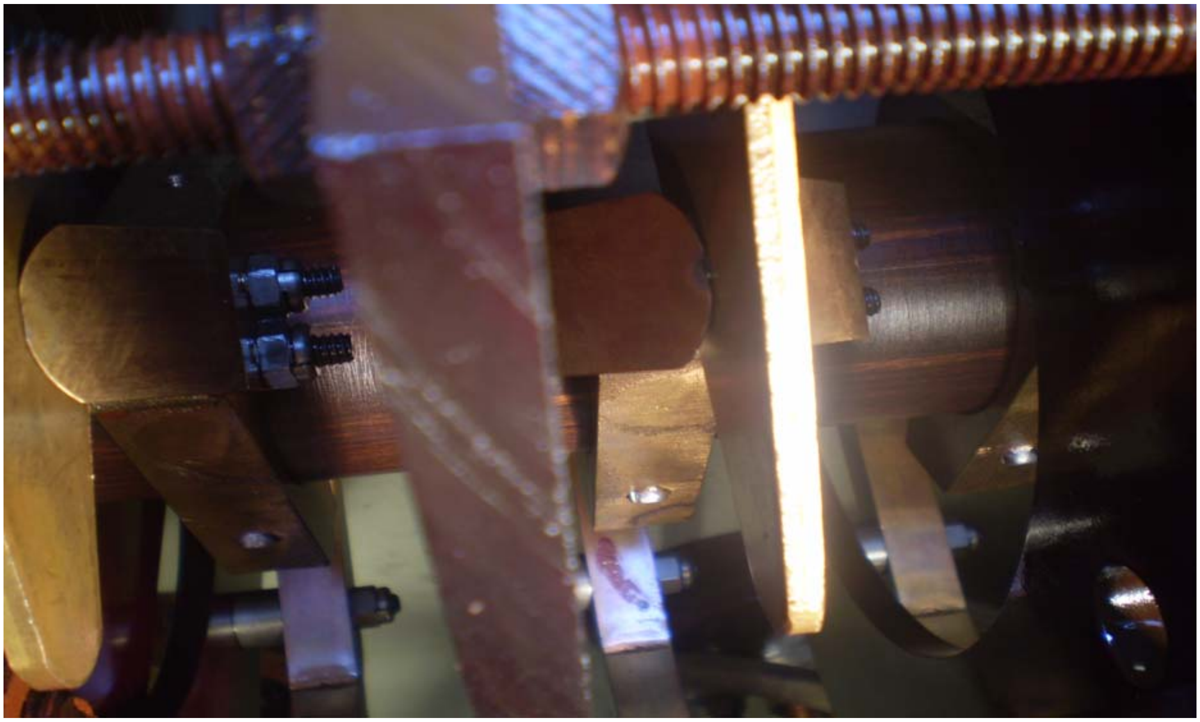


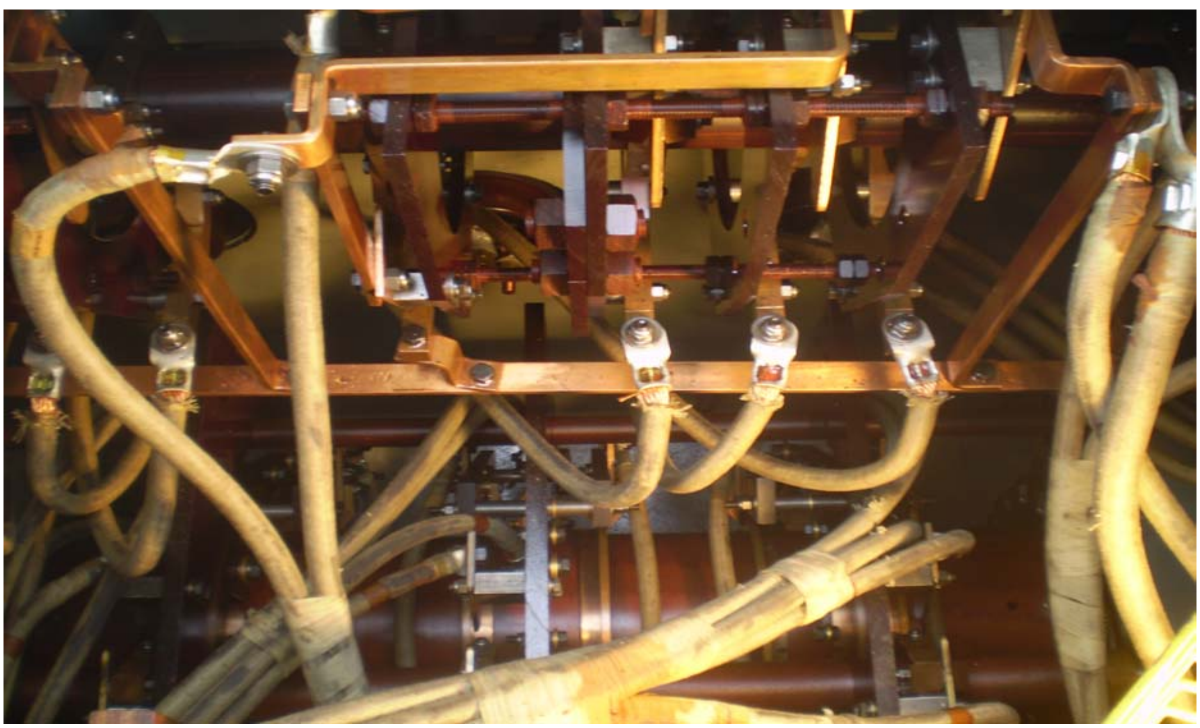












USoA Account 1850

			Actual 2008	**Bridge 2009**	**Variance**
1450 - Distribution Plant	1850 – Line Transformers	Increase	$310,028	$323,028	$13,000
			Bridge 2009	**Test 2010**	**Variance**
1450 - Distribution Plant	1850 – Line Transformers	Increase	$323,028	$334,028	$11,000

2009	
2 new pole mount and 1 new pad mount transformer	$13,000.00
2010	
1 new pole mount and 2 new pad mount transformer	$11,000.00

New residential Subdivision and transformation

New residential project are subject to a capital contribution from the developer. The need for new distribution transformers the amount of $13,000 is required for a new development in the eastern part of town. Distribution transformers in the amount of $11,000 will be required due to the possibility of an extension in the Eastern part of Hawkesbury.

Other General Plant Related Expenditures for Bridge Year 2009 and Test Year 2010

The following Table will provide full details of our 2009BY and 2010 TY capital budget requirements

USoA Account 1908

			Actual 2008	Bridge 2009	Variance
1550 - General Plant	1908 – Building and Fixtures	Increase	$824,124	$824,124	$0
			Bridge 2009	Test 2010	Variance
1550 - General Plant	1908 – Building and Fixtures	Increase	$824,124	$849,124	$25,000

2010	
Office carpet	$15,000
Office painting	$10,000
TOTAL	$25,000

Building and Fixtures; HHI office was built in 1991. New carpet and paint will be required in 2010 TY. Expenditures are expected to be $25,000

USoA Account 1915

			Actual 2008	Bridge 2009	Variance
1550 - General Plant	1915 – Office furniture and Equipment	Increase	$25,511	$38,511	$13,000
			Bridge 2009	Test 2010	Variance
1550 - General Plant	1915 – Office furniture and Equipment	Increase	$38,511	$58,011	$19,500

2009	
Chairs for office clerks	$3,150
Projector	$500
Projector stand	$300
Screen	$250
Radio system	$1,000

Calculators	$200
Filling cabinets	$3,500
Printers	$1,000
P-Touch	$100
Plantronics	$2,000
Microwave oven	$500
Heaters	$500
TOTAL	$13,000

2010	
Chairs for conference room	$5,000
Miscelleneous	10,000
Filling cabinets	$3,500
Printers	$1,000
TOTAL	$19,500

Office equipment and furniture; The safety and the well being of HHI's employees is an important factor. Proper equipment including chairs, desks, filing cabinets and other furniture is required for employees to perform their daily tasks well. When new furniture is purchased, displaced office equipment is re- used or re-cycled to other areas of the corporation where appropriate.

Expected costs are $13,000 in 2009 and $19500 in 2010

USoA Account 1920

			Actual 2008	Bridge 2009	Variance
1550 - General Plant	1920 – Computer Hardware	Increase	$42,614	$48,614	$6,000
			Bridge 2009	**Test 2010**	**Variance**
1550 - General Plant	1920 – Computer Hardware	Increase	$48,614	$59,614	11,000

2009	
Office computers	$5,000
Computer screens	$1,000
TOTAL	$6,000

2010	
Office computers	$10,000

Computer screens	$1,000
TOTAL	$11,000

Computer Hardware; In order to be able to perform adequately and to facilitate the use of different software, HHI has a 4 year turn-around plan to replace computer equipment. Costs are estimated at $6,000 for 2009 and $11,000 for 2010.Criteria for replacing computer hardware as follow;

- Improved space and speed requirements from new Software.
- New technologies not supported by existing equipment.
- Reliability problems from existing equipment.

USoA Account 1925

			Actual 2008	Bridge 2009	Variance
1550 - General Plant	1925 – Computer Software	Increase	$113,042	$120,042	$7,000
			Bridge 2009	**Test 2010**	**Variance**
1550 - General Plant	1925 – Computer Software	Increase	$120,242	$129,242	$9,200

2009	
Microsoft Office 2007	$2,000
ACCPAC upgrades	$5,000
TOTAL	$7,000

2010	
Microsoft Office 2007	$4,200
ACCPAC upgrades	$5,000
TOTAL	$9,200

Computer Software; Software is also an essential part of day to day operations and is often required in order to meet industry regulation. Software upgrades are estimated at $7,000 for 2009 and $9,200 for 2010.

USoA Account 1940

			Actual 2008	Bridge 2009	Variance
1550 - General Plant	1940 – Tools and Equipment	Increase	$12,648	$24,648	$12,000
			Bridge 2009	**Test 2010**	**Variance**
1550 - General Plant	1940 – Tools and Equipment	Increase	$24,648	$29,648	$5,000

2009	
Underground locator	$7,000
Live line	$5,000
TOTAL	$12,000

2010	
Live line	$5,000
TOTAL	$5,000

Tools and Equipment; HHI is concern with the safety of customers and well being of employees. In order to perform adequate work and comply with O. REG 22/04 from the Electrical Safety Authority and to ensure the safety of the line crew, the replacement of old or outdated tools and equipment for the line crews is required.

USoA Account 1950

			Actual 2008	Bridge 2009	Variance
1550 - General Plant	1950 – Power Operated Equipment	Increase	$4,363	$4,363	$0
			Bridge 2009	**Test 2010**	**Variance**
1550 - General Plant	1950 – Power Operated Equipment	Increase	$4,363	$34,363	$30,000

2010	
Wood Chipper	$30,000
TOTAL	$30,000

Power Operated Equipment; A new wood chipper estimated at $30,000 will be required for 2010.

PROJECT/PROGRAM CLASSIFICATIONS

Distribution Plant Capital Projects

The distribution plant capital projects are categorized into project pools. Each pool has a specific focus:

1) Future Demand

These are projects that HHI undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and HHI.'s Conditions of Service. Activities include all overhead and underground works to connect new customers or service upgrades, connection and inspection of new subdivisions and relocating system plant for roadway reconstruction work. Capital contributions toward the cost of these projects are collected by HHI in accordance with the DSC and the provisions of its Conditions of Service.

2) Capacity

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, transformers or transformer stations.

3) Replacement and Betterment

Projects are completed when assets reach their end of useful life and must be replaced. HHI completes visual inspections of its plant and replaces assets based on these inspections. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement.

4) Safety and Reliability

The Distribution System Code (DSC) requires an LDC to maintain its distribution system in good working condition, as follows:

> "4.4.1. A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."

The following components are regular activities undertaken by HHI to maintain reliability and promote safety.

2.1) Overhead Lines

1.1.1) Tree Trimming:

Vegetation and Right of Way control is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Where overhead hydro lines are in the proximity to trees, regular trimming is required to prevent vegetation form contacting energized lines and inflicting:

- Interruption of power due to short circuit to ground or between phases
- Damage to conductors, hardware and poles
- Danger to persons and property within the vicinity due to falling conductors, hardware, poles and trees
- Danger of electric shock potential from electricity energizing vegetation

In an effort of mitigating direct contact between trees and distribution assets, tree trimming is conducted on a one year cycle. HHI's contractor patrols the overhead lines and where tree trimming is needed the contractor will proceed with the necessary clearing.

During the patrol process, the following potential hazards are also examined.

1.1.2) Conductors and Cables

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Insulation fraying on secondary especially open-wire

1.1.3) Poles/Supports/ Cross arms

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Pole inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code as good utility practice. HHI conducts pole inspections annually to determine when poles need to be replaced.

Pole Replacements are undertaken for the following different reasons:

- Structural damage
- Taller or different class of pole required
- Health and safety hazard to the public and employees
- Pole damaged
- Line rebuilds

- ESA compliance

1.1.4) Hardware and Attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

1.1.5) Switches

HHI meets the switch inspection requirements under the Minimum Inspection Requirements of the Distribution System Code. Switches are devices that allow or disallow the conductivity of high voltage conductors. They are available in single phase solid or fused configurations and three phase applications involving load break and air break. Fused cut-outs accept different sizes of fuses, which are used for the protection of lines, equipment or transformers from main feeder amperages. Fused switches (cutouts) are inspected during yearly patrol process.

Switch Replacements are undertaken for the following reasons:

- Mechanical or electrical failure
- Vehicle accidents, lightning strikes
- New customer requirements
- Line rebuilds or circuit reconfigurations
- ESA compliance

1.1.6) Reclosures

As required under the Minimum Inspection Requirements of the Distribution System Code. HHI inspects and tests reclosures regularly and oil samples are taken on a yearly basis.

1.1.7) Transformers

Transformer inspection is performed as required under the Minimum Inspection Requirements of the Distribution System Code with visual inspections being conducted on an annual cycle basis to check for general appearance, loose wires, birds or animal nests.

2.2) Underground Lines

4.2.1.) Switching apparatus

Every 3 years, switching cubicles are visually inspected in accordance with the Minimum Inspection Requirements in the Distribution System Code.

4.2.2.) Primary Cables

Underground primary cable inspection is conducted annually by visually examining the riser poles with respect to cable, cable guards, terminators and arrestors

4.2.3.) Secondary Services

Similarly, with respect to underground secondary services, riser poles are examined yearly with a visual check of cable, cable guards and connections.

5) Substations

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations. Age and condition of the transformers are also a major factor in this decision.

6) Computer Hardware

Computer equipment is used in all departments of the utility and is a key initiative to maintain and improve reliability, improve customer service and reduce costs. New and replacement computer hardware consists of the following equipment:

- Computer Desktops;
- Servers;
- Printers;
- Disk space and memory

HHI utilizes a five year life cycle for its server hardware and for its workstation hardware. It is common industry practice to keep both the hardware and software environments up to date. Increased incidence of hardware failure reduced technical support, new technical standards and higher performance requirements of current operating systems and applications drive this lifecycle. The upgrade of aging servers and consolidation of multiple servers to a more manageable volume provide cost effective migration of workload with higher performance efficiencies and lower maintenance costs. Other benefits of replacing computer equipment and adding new equipment include:

- Reducing the dependence on IT resources to support older equipment;
- Taking advantage of new technologies and increasing server utilization;
- Empowering employees to be more productive with the right equipment to do their jobs;
- Improving access to data and other information;
- Adhering to best practices; and

- Allowing for employee growth, skills and training.

7) Computer Software

Computer software, whether operating system software or application software, are programs written in machine-readable languages, that control the operations of hardware or that enable users to perform certain tasks on computers.

The operating system software controls the hardware and manages its internal functions: controls input, output and storage and, handles its interaction with application programs. Application software enables users to accomplish particular tasks required to complete their distribution responsibilities.

Today, the functioning of computer software is tied closely into the hardware it resides on and it is important that the specification of any PC or Server is appropriate for the software being installed. Benefits of adding or replacing computer software include:

- Improvements in productivity from software enhancements;
- Empowering employees with the latest software technologies;
- Keeping up to date with industry standards;
- Ease of integration to other applications;
- Reduced costs using common operating system;
- Taking advantage of higher levels of security;
- Reduced dependence on IT resources; and
- Improved tools for web development/design

8) Transportation and Related Equipment

HHI owns its own vehicles and performs regular maintenance and replaces them when needed

9) Office Furniture and Equipment

General office furniture and equipment need to be purchase or upgraded periodically. Examples of Office furniture and equipment include desks, ergonomic equipment and phones. The benefits produced from these purchases include:

- Productivity increase
- Better employee communication and output,
- Fewer Complaints.
- Overall well-being of employees.

HISTORICAL INVESTMENTS BY PROJECT

The following attachment presents HHI's capital investment for the last actual year.

Appendix 2-B
Capital Projects Table - 2008 Historical

		1805	1806	1815	1820	1830	1835	1840	1845
	Project No.	Land	Land Rights	Transformer Station Equip, - Normally > 50 kV	Distribution Station Equip. – Normally < 50 kV	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices
Project 1 - Purchase of new truck	2008-01								
Project 2 - Purchase of office furniture	2008-02								
Project 3 - Purchase of office computers	2008-03								
Project 4 - Conversion to Harris- Nortstar billing software	2008-04								
Project 5 - Purchase of transformer	2008-05			20,664					
Project 6 - Purchase of small tools for line crew	2008-06								
Project 7 - Capital work (betterment)	2008-07					1,065			
Project 8 - Purchase of supplies & capital work	2008-08						7,361		
Project 9 - Purchase of conductors & devices for new subdivision	2008-09								26,378
Project 10 - Purchase of line transformers	2009-10								
Project 11 - Capital work	2009-11							220	
Project 12 - Capital work	2009-12								
Project 13 - Purchase of meters	2009-13								
Project 14 - Contributions and Grants - 2 Projects	2009-14								
Total				**20,664**		**1,065**	**7,361**	**220**	**26,378**

Appendix 2-B
Capital Projects Table - 2008 Historical

	1850	1855	1860	1905	1906	1908	1915	1920	1925	1930	1935
	Line Transformers	Services	Meters	Land	Land Rights	Buildings and Fixtures	Office Furniture and Equipment	Computer Equipment - Hardware	Computer Software	Transportation Equipment	Stores Equipment
Project 1 - Purchase of new truck										20,450	
Project 2 - Purchase of office furniture							7,084				
Project 3 - Purchase of office computers								2,223			
Project 4 - Conversion to Harris- Nortstar billing software									63,308		
Project 5 - Purchase of transformer											
Project 6 - Purchase of small tools for line crew											
Project 7 - Capital work (betterment)											
Project 8 - Purchase of supplies & capital work											
Project 9 - Purchase of conductors & devices for new subdivision											
Project 10 - Purchase of line transformers	21,908										
Project 11 - Capital work											
Project 12 - Capital work		1,600									
Project 13 - Purchase of meters			1,936								
Project 14 - Contributions and Grants - 2 Projects											
Total	**21,908**	**1,600**	**1,936**				**7,084**	**2,223**	**63,308**	**20,450**	

Appendix 2-B
Capital Projects Table - 2008 Historical

	1940	1945	1950	1955	1995	TOTAL
	Tools, Shop and Garage Equipment	Measurement and Testing Equipment	Power Operated Equipment	Communication Equipment	Contributions and Grants - Credit	
Project 1 - Purchase of new truck						20,450
Project 2 - Purchase of office furniture						7,084
Project 3 - Purchase of office computers						2,223
Project 4 - Conversion to Harris- Nortstar billing software						63,308
Project 5 - Purchase of transformer						20,664
Project 6 - Purchase of small tools for line crew	709					709
Project 7 - Capital work (betterment)						1,065
Project 8 - Purchase of supplies & capital work						7,361
Project 9 - Purchase of conductors & devices for new subdivision						26,378
Project 10 - Purchase of line transformers						21,908
Project 11 - Capital work						220
Project 12 - Capital work						1,600
Project 13 - Purchase of meters						1,936
Project 14 - Contributions and Grants - 2 Projects					54,774	54,774
Total	**709**				**54,774**	**229,680**

FORECAST INVESTMENTS BY PROJECT

The following two attachment presents HHI's capital investment for the 2009 bridge year and the 2010 test year.

Appendix 2-B
Capital Projects Table - 2009 Bridge

		1805	1806	1815	1820	1830	1835	1840
	Project No.	Land	Land Rights	Transformer Station Equip, - Normally > 50 kV	Distribution Station Equip. – Normally < 50 kV	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit
Project 1 - Purchase of lawn tractor	2009-01							
Project 2 - Purchase of office furniture & equipment	2009-02							
Project 3 - Purchase of office computers	2009-03							
Project 4 - Purchase of Microsoft Office 2007 and ACCPAC upgrades	2009-04							
Project 5 - Purchase of recloser & betterments to sub-station	2009-05			70,000				
Project 6 - Betterments - Degas & repairs	2009-06				77,000			
Project 7 - Purchase of underground locator & live line	2009-07							
Project 8 - Purchase of cutouts & poles	2009-08					49,000		
Project 9 - Purchase of wires	2009-09						28,000	
Project 10 - Purchase of underground cable	2009-10							
Project 11 - Purchase of pad mount for transformers	2009-11							
Project 12 - Contributions and Grants - Credit	2009-12							
Total		**-**	**-**	**70,000**	**77,000**	**49,000**	**28,000**	**-**

Appendix 2-B
Capital Projects Table - 2009 Bridge

		1845	1850	1855	1860	1905	1906	1908	1915	1920	1925
	Project No.	Underground Conductors and Devices	Line Transformers	Services	Meters	Land	Land Rights	Buildings and Fixtures	Office Furniture and Equipment	Computer Equipment - Hardware	Computer Software
Project 1 - Purchase of lawn tractor	2009-01										
Project 2 - Purchase of office furniture & equipment	2009-02								13,000		
Project 3 - Purchase of office computers	2009-03									6,000	
Project 4 - Purchase of Microsoft Office 2007 and ACCPAC upgrades	2009-04										7,000
Project 5 - Purchase of recloser & betterments to sub-station	2009-05										
Project 6 - Betterments - Degas & repairs	2009-06										
Project 7 - Purchase of underground locator & live line	2009-07										
Project 8 - Purchase of cutouts & poles	2009-08										
Project 9 - Purchase of wires	2009-09										
Project 10 - Purchase of underground cable	2009-10	17,500									
Project 11 - Purchase of pad mount for transformers	2009-11		13,000								
Project 12 - Contributions and Grants - Credit	2009-12										
Total		**17,500**	**13,000**	**-**	**-**	**-**	**-**	**-**	**13,000**	**6,000**	**7,000**

Appendix 2-B
Capital Projects Table - 2009 Bridge

		1930	1935	1940	1945	1950	1955	TOTAL
	Project No.	Transportation Equipment	Stores Equipment	Tools, Shop and Garage Equipment	Measurement and Testing Equipment	Power Operated Equipment	Communication Equipment	
Project 1 - Purchase of lawn tractor	2009-01							-
Project 2 - Purchase of office furniture & equipment	2009-02							13,000
Project 3 - Purchase of office computers	2009-03							6,000
Project 4 - Purchase of Microsoft Office 2007 and ACCPAC upgrades	2009-04							7,000
Project 5 - Purchase of recloser & betterments to sub-station	2009-05							70,000
Project 6 - Betterments - Degas & repairs	2009-06							77,000
Project 7 - Purchase of underground locator & live line	2009-07			12,000				12,000
Project 8 - Purchase of cutouts & poles	2009-08							49,000
Project 9 - Purchase of wires	2009-09							28,000
Project 10 - Purchase of underground cable	2009-10							17,500
Project 11 - Purchase of pad mount for transformers	2009-11							13,000
Project 12 - Contributions and Grants - Credit	2009-12							-
Total		**-**	**-**	**12,000**	**-**	**-**	**-**	**292,500**

Appendix 2-B
Capital Projects Table - 2010 Test

		1805	1806	1815	1820	1830	1835
	Project No.	Land	Land Rights	Transformer Station Equip, - Normally > 50 kV	Distribution Station Equip. – Normally < 50 kV	Poles, Towers and Fixtures	Overhead Conductors and Devices
Project 1 - Purchase of backhoe	2010-01						
Project 2 - Purchase of new carpet & office painting	2010-02						
Project 3 - Purchase of office furniture	2010-03						
Project 4 - Purchase of office computers	2010-04						
Project 5 - ACCPAC upgrades, setup of website & upgrades for EIS & File Nexus	2010-05						
Project 6 - Purchase of recloser & betterments to sub-station	2010-06			82,000			
Project 7 - Betterments - Degas & repairs	2010-07				50,000		
Project 8 - Purchase of live line	2010-08						
Project 9 - Purchase of wood chipper	2010-09						
Project 10 - Purchase of poles	2010-10					73,000	
Project 11 - Purchase of wires	2010-11						33,000
Project 12 - Purchase of underground cable	2010-12						
Project 13 - Purchase of pad mount for transformers	2010-13						
Project 14 - Contributions and Grants - Credit	2010-14						
Total		**-**	**-**	**82,000**	**50,000**	**73,000**	**33,000**

Appendix 2-B
Capital Projects Table - 2010 Test

		1840	1845	1850	1855	1860	1905	1906	1908
	Project No.	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters	Land	Land Rights	Buildings and Fixtures
Project 1 - Purchase of backhoe	2010-01								
Project 2 - Purchase of new carpet & office painting	2010-02								25,000
Project 3 - Purchase of office furniture	2010-03								
Project 4 - Purchase of office computers	2010-04								
Project 5 - ACCPAC upgrades, setup of website & upgrades for EIS & File Nexus	2010-05								
Project 6 - Purchase of recloser & betterments to sub-station	2010-06								
Project 7 - Betterments - Degas & repairs	2010-07								
Project 8 - Purchase of live line	2010-08								
Project 9 - Purchase of wood chipper	2010-09								
Project 10 - Purchase of poles	2010-10								
Project 11 - Purchase of wires	2010-11								
Project 12 - Purchase of underground cable	2010-12		17,500						
Project 13 - Purchase of pad mount for transformers	2010-13			11,000					
Project 14 - Contributions and Grants - Credit	2010-14								
Total		**-**	**17,500**	**11,000**	**-**	**-**	**-**	**-**	**25,000**

Appendix 2-B
Capital Projects Table - 2010 Test

		1915	1920	1925	1930	1935	1940	1945
	Project No.	Office Furniture and Equipment	Computer Equipment - Hardware	Computer Software	Transportation Equipment	Stores Equipment	Tools, Shop and Garage Equipment	Measurement and Testing Equipment
Project 1 - Purchase of backhoe	2010-01							
Project 2 - Purchase of new carpet & office painting	2010-02							
Project 3 - Purchase of office furniture	2010-03	19,500						
Project 4 - Purchase of office computers	2010-04		11,000					
Project 5 - ACCPAC upgrades, setup of website & upgrades for EIS & File Nexus	2010-05			9,200				
Project 6 - Purchase of recloser & betterments to sub-station	2010-06							
Project 7 - Betterments - Degas & repairs	2010-07							
Project 8 - Purchase of live line	2010-08						5,000	
Project 9 - Purchase of wood chipper	2010-09							
Project 10 - Purchase of poles	2010-10							
Project 11 - Purchase of wires	2010-11							
Project 12 - Purchase of underground cable	2010-12							
Project 13 - Purchase of pad mount for transformers	2010-13							
Project 14 - Contributions and Grants - Credit	2010-14							
Total		**19,500**	**11,000**	**9,200**	**-**	**-**	**5,000**	**-**

Appendix 2-B
Capital Projects Table - 2010 Test

		1950	1955	TOTAL
	Project No.	Power Operated Equipment	Communication Equipment	
Project 1 - Purchase of backhoe	2010-01			-
Project 2 - Purchase of new carpet & office painting	2010-02			25,000
Project 3 - Purchase of office furniture	2010-03			19,500
Project 4 - Purchase of office computers	2010-04			11,000
Project 5 - ACCPAC upgrades, setup of website & upgrades for EIS & File Nexus	2010-05			9,200
Project 6 - Purchase of recloser & betterments to sub-station	2010-06			82,000
Project 7 - Betterments - Degas & repairs	2010-07			50,000
Project 8 - Purchase of live line	2010-08			5,000
Project 9 - Purchase of wood chipper	2010-09	30,000		30,000
Project 10 - Purchase of poles	2010-10			73,000
Project 11 - Purchase of wires	2010-11			33,000
Project 12 - Purchase of underground cable	2010-12			17,500
Project 13 - Purchase of pad mount for transformers	2010-13			11,000
Project 14 - Contributions and Grants - Credit	2010-14			-
Total		**30,000**	**-**	**366,200**

ASSET MANAGEMENT PLAN

HHI does not currently have a formal asset management plan in place. Being a smaller utility with a fairly small service area allows HHI to be well informed on the condition of its assets and uses management's operating judgment and experienced contractors to replace plant cost effectively when it can no longer be maintained effectively or safely. Thus far, HHI has not felt that a detailed asset management plan was required nor that the cost required to implement an electronic data base and mapping was justified and in the best interest of HHI's customers.

That being said, HHI has taken a keen interest in the report conducted by KPMG on behalf of the OEB entitled *Review of Asset Management Practices in the Ontario Electricity Distribution Sector published March 10th, 2009.* As indicated on page 4 of the report, "*Smaller utilities should work toward the same objectives (e.g. optimized lifecycle costing, high reliability, and high standards of safety). They may simply require less formalized processes to do so*." HHI has taken the initiative to use the report's survey to establish its own performances and gage these processes against the key practices presented in the report. HHI will continue to work towards improving its asset management practices in a cost-efficient manner. HHI has included its results of the survey at Exhibit 2, Tab 4, Schedule 5, Attachment 1.

Ontario

Review of Asset Management Practices of Ontario Electricity Distributors

Questionnaire

June 2008

1. Implementation and Operation

	Questions	Yes	No
1.1	Has the company established performance targets (e.g. reliability factors, operational efficiency, health and safety, customer service) for the distribution network to measure the progress and effectiveness of its AM system?	☐	☒
1.2	Is responsibility assigned to each level for management for achieving the performance targets?	☐	☒
1.3	Are AM related accountabilities integrated with the performance measurement system at all levels?	☐	☒
1.4	Are meetings held regularly to discuss distribution network performance issues?	☒	☐
1.5	Are historical outage records and outage source considered in AM decisions (e.g. records of outages categorized by Board prescribed codes as to their sources)?	☒	☐
1.6	Does the company have documented AM procedures in place, and have they been communicated to the responsible staff.	☐	☒
1.7	Does the company ensure that asset condition information is accurately recorded and available to the responsible staff.	☒	☐
1.8	Are capital and maintenance plans updated on an ongoing basis as new developments occur?	☒	☐
1.9	Does the company conduct performance reviews of staff responsible for AM?	☐	☒
1.10	Does the company use external links for leading practices to new technologies, practices and network performance?	☒	☐
1.11	Does the company regularly evaluate leading edge inspection processes (e.g. infrared testing) and apply them if appropriate?	☒	☐
1.12	Does the company have a methodology for forecasting future capacity requirements, and is the effectiveness of forecasting reviewed on a regular basis?	☒	☐
1.13	Does the company have a Geographic Information System (GIS) to facilitate analysis of network performance and help in project planning?	☐	☒
1.14	Are the company's inspection and maintenance records integrated with its GIS system?	☐	☒
1.15	Does the company have a SCADA system to facilitate its network operations?	☐	☒
1.16	Are routine inspection and maintenance activities performed documented in a timely manner?	☒	☐
1.17	Are maintenance and inspection records available to staff electronically?	☐	☒
1.18	Does the company review the quality of maintenance activities?	☒	☐
1.19	Does the company link the maintenance activities to inspection results and plans for asset replacement?	☒	☐

Utility's comments on its AM implementation and operation process:

Review of Asset Management Practices of Ontario Electricity Distributors

Questionnaire
June 2008

2. Checking and Corrective Action

	Questions	Yes	No
2.1	Is the adequacy of inspection process reviewed periodically?	☒	☐
2.2	Do inspections provide adequate warning of asset deterioration?	☒	☐
2.3	Do inspections assist in identifying major problems?	☒	☐
2.4	Does the company use inspection results to inform decisions on maintenance levels and requirements and on the selection of projects?	☒	☐
2.5	Are OEB inspection guidelines adjusted based on past experience, industry data, and cost/benefit analysis?	☒	☐
2.6	Are key performance indicators for critical assets in place (e.g. service/supply standards, reliability, availability, maintainability, customer satisfaction, safety, legislative compliance etc.)?	☐	☒
2.7	Are service quality indicators reviewed regularly to ensure that service level is acceptable, and appropriate action is taken?	☒	☐
2.8	Are AM process audits conduced to ensure that the process in consistent with the strategy and policy?	☐	☒
2.9	Does the company use a specific industry standard for its AM process (e.g. PAS 55, ISO)?	☐	☒

Utility's comments on its AM checking and corrective action process:

Review of Asset Management Practices of Ontario Electricity Distributors

Questionnaire
June 2008

3. Asset Management Information, Risk Assessment and Planning

	Questions	Yes	No
3.1	Does the company have a complete inventory of its assets?	☐	☒
3.2	Has the company identified all asset categories?	☒	☐
3.3	Have assets been identified as critical or non-critical?	☐	☒
3.4	Has the company performed asset condition assessment on its assets?	☒	☐
3.5	Is the life expectancy of assets known?	☐	☒
3.6	Is the asset performance information available?	☐	☒
3.7	Is location of each asset known?	☒	☐
3.8	Do the company asset records maintained include incident and event information?	☐	☐
3.9	Are inspection results entered into the asset records on a timely basis?	☒	☐
3.10	Is there a linkage between the company's asset records and Geographical Information System including mapping for locations, fault monitoring etc.?	☐	☒
3.11	Does the company have a formalized process for risk assessment related to asset management?	☐	☒
3.12	Does the company consider all aspects of risks related to AM, including assets, skills, resources, and logistics?	☐	☒
3.13	Is risk assessment performed jointly with Engineering and Lines and Operations staff?	☒	☐
3.14	Is risk assessment performed at least annually?	☒	☐
3.15	Are immediate dangers addressed immediately?	☒	☐
3.16	Do the risk assessment results feed the company's: o Capital plan?	☒	☐
	o Maintenance plan?	☒	☐
3.17	Does the company have a "run-to-failure" policy that differentiates critical assets from non-critical assets?	☐	☒
3.18	Has the company performed a system wide risk assessment related to its: o Overhead lines assets?	☐	☒
	o Underground cables?	☒	☐
	o Substations?	☒	☐
3.19	Is detailed outage information analyzed?	☐	☒
3.20	Does the company's capital plan include all identified future projects?	☒	☐
3.21	Are all potential future projects listed in a central repository?	☐	☒
3.22	Does the capital plan reflect the overall strategy for replacing aging assets?	☒	☐
3.23	Does each project on the capital plan include business case documentation including problem statement, scope and cost of project, and justification and evaluation of project?	☐	☒
3.24	Do any of the following factors influence your company's capital budget decisions? o Past spending on capital projects	☒	☐

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	Questions	Yes	No
	o Level of depreciation expense	☐	☒
	o Target capital structure	☐	☒
	o External benchmarks	☐	☒
	o Ability to complete or deliver capital projects	☒	☐
	o Other (please list below under Utility's Comments section).	☐	☒
3.25	Are maintenance activities linked to inspection results and to plans for asset replacement (i.e. capital planning)?	☒	☐
3.26	Does the company consider applicability of new maintenance practices (e.g. dry-ice cleaning)?	☒	☐
3.27	Does the company keep track of historical outages sorted by codes by outage source?	☒	☐
3.28	Are actual maintenance activities documented in a timely manner into the asset records?	☐	☒
3.29	Are maintenance records integrated with the company's GIS system?	☐	☒

Utility's comments on its AM information, risk management, and planning process:

4. Asset Management Policy and Strategy

	Questions	Yes	No
4.1	Does the company have a documented AM strategy?	☐	☒
4.2	Does the company have clearly stated and documented AM objectives in place?	☐	☒
4.3	Does the company ensure that its AM strategy is consistent with its: o Strategic plan?	☐	☒
	o Priorities?	☐	☒
	o Asset condition requirements?	☐	☒
	o Health and Safety values?	☐	☒
	o Environmental position?	☐	☒
	o Continual improvement needs?	☐	☒
4.4	Is the company's capital planning process linked to its strategic plan?	☐	☒
4.5	Does the company's capital plan consider all assets?	☒	☐
4.6	Is the company's capital plan for less than 10 years?	☒	☐
4.7	Does the company have a documented AM policy in place?	☐	☒
4.8	Has the policy been communicated to managers, employees, stakeholders and understood and accepted by them?	☐	☒

Utility's comments on its AM policy and strategy:

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5. Management Review and Continual Improvement

	Questions	Yes	No
5.1	Does the company perform a regular review of its AM policy and objectives?	☐	☒
5.2	Does the company have a procedure to identify new assets/technology that may be beneficial?	☐	☒

Utility's comments on its management review and continual improvement processes:

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6. General

	Questions	Yes	No
6.1	Is the company's assessment of the current overall condition of its assets: o Poor	☒	☐
	o Fair	☒	☐
	o Good (Note: Poor condition assets will need remedial action within 5 years to correct significant deterioration; fair condition assets have noticeable deterioration but should survive another 5 years with regular maintenance; good condition assets are within the range expected for distribution assets that have been well maintained.)	☐	☐

Utility's comments on its current condition of assets:

Exhibit 2: Rate Base

Tab 5 (of 6): Allowance for Working Capital

DERIVATION OF WORKING CAPITAL ALLOWANCE

The Working Capital Allowance ("WCA") is designed to provide an adequate ongoing cash flow to distributors in advance of recovery through rate collection. Its most meaningful component is the cost of power, and cost items associated with the cost of power, which represent the distributor's primary business liability.

The methodology used by HHI in calculating the WCA is consistent with the 2006 Electricity Distribution Rate Handbook. HHI's WCA is presently calculated as 15% of the sum of the cost of power and the controllable distribution expenses. These accounts include the groups and accounts listed below.

HHI's projected WCA for 2010 is $2,026,392. Details of the derivation of this amount can be found at Exhibit 2, Tab 5, Schedule 1, Attachment 1.

Distribution Expenses – Operation

5005 Operation Supervision and Engineering

5010 Load Dispatching

5012 Station Buildings and Fixtures Expense

5014 Transformer Station Equipment - Operation Labour

5015 Transformer Station Equipment - Operation Supplies and Expenses

5016 Distribution Station Equipment - Operation Labour

5017 Distribution Station Equipment - Operation Supplies and Expenses

5020 Overhead Distribution Lines and Feeders - Operation Labour

5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses

5030 Overhead Sub-transmission Feeders - Operation

5035 Overhead Distribution Transformers- Operation

5040 Underground Distribution Lines and Feeders - Operation Labour

5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses

5050 Underground Sub-transmission Feeders - Operation

5055 Underground Distribution Transformers - Operation

5060 Street Lighting and Signal System Expense

5065 Meter Expense

5070 Customer Premises - Operation Labour

5075 Customer Premises - Materials and Expenses

5085 Miscellaneous Distribution Expense

5090 Underground Distribution Lines and Feeders - Rental Paid

5095 Overhead Distribution Lines and Feeders - Rental Paid

5096 Other Rent

Distribution Expenses – Maintenance

5105 Maintenance Supervision and Engineering

5110 Maintenance of Buildings and Fixtures - Distribution Stations

5112 Maintenance of Transformer Station Equipment

5114 Maintenance of Distribution Station Equipment

5120 Maintenance of Poles, Towers and Fixtures

5125 Maintenance of Overhead Conductors and Devices

5130 Maintenance of Overhead Services

5135 Overhead Distribution Lines and Feeders - Right of Way

5145 Maintenance of Underground Conduit

5150 Maintenance of Underground Conductors and Devices

5155 Maintenance of Underground Services

5160 Maintenance of Line Transformers

5165 Maintenance of Street Lighting and Signal Systems

5170 Sentinel Lights - Labour

5172 Sentinel Lights - Materials and Expenses

5175 Maintenance of Meters

5178 Customer Installations Expenses- Leased Property

5195 Maintenance of Other Installations on Customer Premises

Billing and Collecting

5305 Supervision

5310 Meter Reading Expense

5315 Customer Billing

5320 Collecting

5325 Collecting- Cash Over and Short

5330 Collection Charges

5335 Bad Debt Expense

5340 Miscellaneous Customer Accounts Expenses

Community Relations (including sales expenses)

5405 Supervision

5410 Community Relations - Sundry

5415 Energy Conservation

5420 Community Safety Program

5425 Miscellaneous Customer Service and Informational Expenses

5505 Supervision

5510 Demonstrating and Selling Expense

5515 Advertising Expense

5520 Miscellaneous Sales Expense

Administrative and General Expenses

5605 Executive Salaries and Expenses

5610 Management Salaries and Expenses

5615 General Administrative Salaries and Expenses

5620 Office Supplies and Expenses

5625 Administrative Expense Transferred–Credit

5630 Outside Services Employed

5635 Property Insurance

5640 Injuries and Damages

5645 Employee Pensions and Benefits

5650 Franchise Requirements

5655 Regulatory Expenses

5660 General Advertising Expenses

5665 Miscellaneous General Expenses

5670 Rent

5675 Maintenance of General Plant

5680 Electrical Safety Authority Fees

5685 Independent Electricity System Operator Fees and Penalties

5695 OM&A Contra Account

6205 Charitable Donations

Power Supply Expense

3350-Power Supply Expenses

Working Capital Allowance

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Working Capital Allowance *(see below)*	2,260,393	2,215,124	2,264,864	2,162,052	2,190,573	2,026,392
Expenses for Working Capital						
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	52,662	51,684	54,765	64,402	72,789	75,463
3550-Distribution Expenses - Maintenance	123,155	130,222	175,050	159,889	173,142	171,887
3650-Billing and Collecting	267,315	228,770	236,346	303,877	314,905	327,572
3700-Community Relations	100	60,810	12,668	100	104	2,108
3800-Administrative and General Expenses	350,188	274,250	290,168	269,155	285,636	359,851
3950-Taxes Other Than Income Taxes	24,654	25,171	25,634	26,205	26,916	28,262
Total Eligible Distribution Expenses	818,074	770,907	794,632	823,628	873,492	965,143
3350-Power Supply Expenses	14,251,214	13,996,585	14,304,462	13,590,055	13,730,325	12,544,138
Total Expenses for Working Capital	15,069,288	14,767,492	15,099,094	14,413,683	14,603,817	13,509,281
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**2,260,393**	**2,215,124**	**2,264,864**	**2,162,052**	**2,190,573**	**2,026,392**

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ new dist. rates	2010 @ existing rates	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	11,695	11,695		
	5015-Transformer Station Equipment - Operation Supplies and Expenses	12,944	12,944		
	5016-Distribution Station Equipment - Operation Labour	9,672	9,672		
	5017-Distribution Station Equipment - Operation Supplies and Expenses	66	66		
	5020-Overhead Distribution Lines and Feeders - Operation Labour	10,154	10,154		
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,120	1,120		
	5035-Overhead Distribution Transformers- Operation	12,046	12,046		
	5040-Underground Distribution Lines and Feeders - Operation Labour	2,130	2,130		
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	25	25		
	5055-Underground Distribution Transformers - Operation	2,465	2,465		
	5065-Meter Expense	12,032	12,032		
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,114	1,114		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,815	4,815		
	5120-Maintenance of Poles, Towers and Fixtures	18,022	18,022		
	5125-Maintenance of Overhead Conductors and Devices	32,799	32,799		
	5130-Maintenance of Overhead Services	33,392	33,392		
	5135-Overhead Distribution Lines and Feeders - Right of Way	44,827	44,827		
	5145-Maintenance of Underground Conduit	1,198	1,198		
	5150-Maintenance of Underground Conductors and Devices	18,596	18,596		
	5155-Maintenance of Underground Services	7,176	7,176		

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ new dist. rates	2010 @ existing rates	Var $	Var %
	5160-Maintenance of Line Transformers	2,362	2,362		
	5175-Maintenance of Meters	8,700	8,700		
3650-Billing and Collecting	5310-Meter Reading Expense	33,376	33,376		
	5315-Customer Billing	185,880	185,880		
	5320-Collecting	100,389	100,389		
	5325-Collecting- Cash Over and Short				
	5335-Bad Debt Expense	7,927	7,927		
3700-Community Relations	5410-Community Relations - Sundry	2,108	2,108		
	5415-Energy Conservation				
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	107,289	107,289		
	5610-Management Salaries and Expenses	74,757	74,757		
	5620-Office Supplies and Expenses	21,702	21,702		
	5630-Outside Services Employed	43,817	43,817		
	5635-Property Insurance	4,698	4,698		
	5640-Injuries and Damages	12,427	12,427		
	5645-Employee Pensions and Benefits	3,699	3,699		
	5655-Regulatory Expenses	41,820	41,820		
	5665-Miscellaneous General Expenses	13,520	13,520		
	5675-Maintenance of General Plant	30,596	30,596		
	5680-Electrical Safety Authority Fees	5,526	5,526		
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	28,262	28,262		
Net Income		**225,197**	**(137,636)**	**362,833**	**263.6%**

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	11,695	11,245	450	4.0%
	5015-Transformer Station Equipment - Operation Supplies and Expenses	12,944	12,446	498	4.0%
	5016-Distribution Station Equipment - Operation Labour	9,672	9,300	372	4.0%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	66	63	3	4.8%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	10,154	9,763	391	4.0%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,120	1,077	43	4.0%
	5035-Overhead Distribution Transformers-Operation	12,046	11,813	233	2.0%
	5040-Underground Distribution Lines and Feeders - Operation Labour	2,130	2,048	82	4.0%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	25	24	1	4.2%
	5055-Underground Distribution Transformers - Operation	2,465	2,370	95	4.0%
	5065-Meter Expense	12,032	11,569	463	4.0%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,114	1,071	43	4.0%
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,815	4,630	185	4.0%
	5120-Maintenance of Poles, Towers and Fixtures	18,022	16,160	1,862	11.5%
	5125-Maintenance of Overhead Conductors and Devices	32,799	32,545	254	0.8%
	5130-Maintenance of Overhead Services	33,392	32,108	1,284	4.0%
	5135-Overhead Distribution Lines and Feeders - Right of Way	44,827	50,795	(5,968)	(11.7%)
	5145-Maintenance of Underground Conduit	1,198	1,152	46	4.0%
	5150-Maintenance of Underground Conductors and Devices	18,596	17,881	715	4.0%
	5155-Maintenance of Underground Services	7,176	6,900	276	4.0%

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
	5160-Maintenance of Line Transformers	2,362	2,271	91	4.0%
	5175-Maintenance of Meters	8,700	8,700		
3650-Billing and Collecting	5310-Meter Reading Expense	33,376	32,092	1,284	4.0%
	5315-Customer Billing	185,880	178,731	7,149	4.0%
	5320-Collecting	100,389	96,460	3,929	4.1%
	5325-Collecting- Cash Over and Short				
	5335-Bad Debt Expense	7,927	7,622	305	4.0%
3700-Community Relations	5410-Community Relations - Sundry	2,108	104	2,004	1926.9%
	5415-Energy Conservation				
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	107,289	100,278	7,011	7.0%
	5610-Management Salaries and Expenses	74,757	68,997	5,760	8.3%
	5620-Office Supplies and Expenses	21,702	20,868	834	4.0%
	5630-Outside Services Employed	43,817	17,574	26,243	149.3%
	5635-Property Insurance	4,698	4,517	181	4.0%
	5640-Injuries and Damages	12,427	11,949	478	4.0%
	5645-Employee Pensions and Benefits	3,699	3,556	143	4.0%
	5655-Regulatory Expenses	41,820	10,164	31,656	311.5%
	5665-Miscellaneous General Expenses	13,520	13,000	520	4.0%
	5675-Maintenance of General Plant	30,596	29,420	1,176	4.0%
	5680-Electrical Safety Authority Fees	5,526	5,313	213	4.0%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	28,262	26,916	1,346	5.0%
Net Income		**(137,636)**	**52,561**	**(190,196)**	**(361.9%)**

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	11,245	10,813	432	4.0%
	5015-Transformer Station Equipment - Operation Supplies and Expenses	12,446	11,967	479	4.0%
	5016-Distribution Station Equipment - Operation Labour	9,300	8,942	358	4.0%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	63	61	2	3.3%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	9,763	9,388	375	4.0%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,077	1,036	41	4.0%
	5035-Overhead Distribution Transformers-Operation	11,813	4,327	7,486	173.0%
	5040-Underground Distribution Lines and Feeders - Operation Labour	2,048	1,970	78	4.0%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	24	24	0	2.0%
	5055-Underground Distribution Transformers - Operation	2,370	2,279	91	4.0%
	5065-Meter Expense	11,569	12,567	(998)	(7.9%)
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,071	1,030	41	4.0%
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,630	4,452	178	4.0%
	5120-Maintenance of Poles, Towers and Fixtures	16,160	10,561	5,599	53.0%
	5125-Maintenance of Overhead Conductors and Devices	32,545	31,598	947	3.0%
	5130-Maintenance of Overhead Services	32,108	31,173	935	3.0%
	5135-Overhead Distribution Lines and Feeders - Right of Way	50,795	42,795	8,000	18.7%
	5145-Maintenance of Underground Conduit	1,152	1,108	44	4.0%
	5150-Maintenance of Underground Conductors and Devices	17,881	17,193	688	4.0%
	5155-Maintenance of Underground Services	6,900	6,635	265	4.0%

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
	5160-Maintenance of Line Transformers	2,271	2,184	87	4.0%
	5175-Maintenance of Meters	8,700	12,192	(3,492)	(28.6%)
3650-Billing and Collecting	5310-Meter Reading Expense	32,092	30,858	1,234	4.0%
	5315-Customer Billing	178,731	171,856	6,875	4.0%
	5320-Collecting	96,460	93,858	2,602	2.8%
	5325-Collecting- Cash Over and Short		(23)	23	100.0%
	5335-Bad Debt Expense	7,622	7,329	293	4.0%
3700-Community Relations	5410-Community Relations - Sundry	104	100	4	4.0%
	5415-Energy Conservation				
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	100,278	93,537	6,741	7.2%
	5610-Management Salaries and Expenses	68,997	63,458	5,539	8.7%
	5620-Office Supplies and Expenses	20,868	20,065	803	4.0%
	5630-Outside Services Employed	17,574	16,898	676	4.0%
	5635-Property Insurance	4,517	4,344	173	4.0%
	5640-Injuries and Damages	11,949	11,489	460	4.0%
	5645-Employee Pensions and Benefits	3,556	3,420	136	4.0%
	5655-Regulatory Expenses	10,164	9,773	391	4.0%
	5665-Miscellaneous General Expenses	13,000	12,500	500	4.0%
	5675-Maintenance of General Plant	29,420	28,563	857	3.0%
	5680-Electrical Safety Authority Fees	5,313	5,109	204	4.0%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	26,916	26,205	711	2.7%
Net Income		52,561	63,488	(10,927)	(17.2%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	10,813	11,157	(344)	(3.1%)
	5015-Transformer Station Equipment - Operation Supplies and Expenses	11,967	(4,681)	16,648	355.7%
	5016-Distribution Station Equipment - Operation Labour	8,942	5,142	3,800	73.9%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	61	2,776	(2,715)	(97.8%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour	9,388	10,099	(711)	(7.0%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,036	1,568	(532)	(33.9%)
	5035-Overhead Distribution Transformers- Operation	4,327	4,867	(539)	(11.1%)
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,970	1,225	744	60.7%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	24	46	(22)	(48.5%)
	5055-Underground Distribution Transformers - Operation	2,279	2,306	(28)	(1.2%)
	5065-Meter Expense	12,567	19,232	(6,665)	(34.7%)
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,030	1,030		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,452	4,200	252	6.0%
	5120-Maintenance of Poles, Towers and Fixtures	10,561	6,122	4,439	72.5%
	5125-Maintenance of Overhead Conductors and Devices	31,598	59,149	(27,551)	(46.6%)
	5130-Maintenance of Overhead Services	31,173	25,163	6,010	23.9%
	5135-Overhead Distribution Lines and Feeders - Right of Way	42,795	38,176	4,619	12.1%
	5145-Maintenance of Underground Conduit	1,108	248	860	346.6%
	5150-Maintenance of Underground Conductors and Devices	17,193	11,905	5,288	44.4%
	5155-Maintenance of Underground Services	6,635	6,789	(154)	(2.3%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
	5160-Maintenance of Line Transformers	2,184	11,912	(9,729)	(81.7%)
	5175-Maintenance of Meters	12,192	11,388	804	7.1%
3650-Billing and Collecting	5310-Meter Reading Expense	30,858	28,192	2,665	9.5%
	5315-Customer Billing	171,856	140,043	31,813	22.7%
	5320-Collecting	93,858	58,500	35,358	60.4%
	5325-Collecting- Cash Over and Short	(23)		(23)	
	5335-Bad Debt Expense	7,329	9,610	(2,281)	(23.7%)
3700-Community Relations	5410-Community Relations - Sundry	100	328	(228)	(69.5%)
	5415-Energy Conservation		12,340	(12,340)	(100.0%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	93,537	90,146	3,390	3.8%
	5610-Management Salaries and Expenses	63,458	60,728	2,731	4.5%
	5620-Office Supplies and Expenses	20,065	19,728	337	1.7%
	5630-Outside Services Employed	16,898	30,830	(13,931)	(45.2%)
	5635-Property Insurance	4,344	4,250	94	2.2%
	5640-Injuries and Damages	11,489	11,942	(453)	(3.8%)
	5645-Employee Pensions and Benefits	3,420	3,809	(389)	(10.2%)
	5655-Regulatory Expenses	9,773	15,730	(5,957)	(37.9%)
	5665-Miscellaneous General Expenses	12,500	11,998	502	4.2%
	5675-Maintenance of General Plant	28,563	35,970	(7,407)	(20.6%)
	5680-Electrical Safety Authority Fees	5,109	5,038	71	1.4%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	26,205	25,634	571	2.2%
Net Income		63,488	153,899	**(90,411)**	(58.7%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	11,157	12,577	(1,420)	(11.3%)
	5015-Transformer Station Equipment - Operation Supplies and Expenses	(4,681)	5,986	(10,667)	(178.2%)
	5016-Distribution Station Equipment - Operation Labour	5,142	2,408	2,734	113.6%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	2,776		2,776	
	5020-Overhead Distribution Lines and Feeders - Operation Labour	10,099	7,524	2,575	34.2%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,568	1,802	(235)	(13.0%)
	5035-Overhead Distribution Transformers- Operation	4,867	1,705	3,161	185.4%
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,225	1,442	(217)	(15.0%)
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	46	174	(129)	(73.8%)
	5055-Underground Distribution Transformers - Operation	2,306	2,414	(108)	(4.5%)
	5065-Meter Expense	19,232	14,622	4,610	31.5%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,030	1,030		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,200	3,850	350	9.1%
	5120-Maintenance of Poles, Towers and Fixtures	6,122	5,507	615	11.2%
	5125-Maintenance of Overhead Conductors and Devices	59,149	42,064	17,085	40.6%
	5130-Maintenance of Overhead Services	25,163	21,370	3,793	17.7%
	5135-Overhead Distribution Lines and Feeders - Right of Way	38,176	24,467	13,709	56.0%
	5145-Maintenance of Underground Conduit	248	1,245	(997)	(80.1%)
	5150-Maintenance of Underground Conductors and Devices	11,905	13,511	(1,606)	(11.9%)
	5155-Maintenance of Underground Services	6,789	5,062	1,726	34.1%

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
	5160-Maintenance of Line Transformers	11,912	5,399	6,513	120.6%
	5175-Maintenance of Meters	11,388	7,746	3,642	47.0%
3650-Billing and Collecting	5310-Meter Reading Expense	28,192	27,845	348	1.2%
	5315-Customer Billing	140,043	137,987	2,056	1.5%
	5320-Collecting	58,500	55,788	2,712	4.9%
	5325-Collecting- Cash Over and Short		11	(11)	(100.0%)
	5335-Bad Debt Expense	9,610	7,139	2,471	34.6%
3700-Community Relations	5410-Community Relations - Sundry	328	100	228	227.7%
	5415-Energy Conservation	12,340	60,710	(48,370)	(79.7%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	90,146	89,593	554	0.6%
	5610-Management Salaries and Expenses	60,728	63,260	(2,532)	(4.0%)
	5620-Office Supplies and Expenses	19,728	14,711	5,017	34.1%
	5630-Outside Services Employed	30,830	23,680	7,149	30.2%
	5635-Property Insurance	4,250	4,099	151	3.7%
	5640-Injuries and Damages	11,942	13,054	(1,112)	(8.5%)
	5645-Employee Pensions and Benefits	3,809	2,921	888	30.4%
	5655-Regulatory Expenses	15,730	15,135	596	3.9%
	5665-Miscellaneous General Expenses	11,998	11,550	448	3.9%
	5675-Maintenance of General Plant	35,970	31,012	4,958	16.0%
	5680-Electrical Safety Authority Fees	5,038	5,235	(197)	(3.8%)
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	25,634	25,171	463	1.8%
Net Income		153,899	219,067	**(65,168)**	(29.7%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	12,577	21,775	(9,199)	(42.2%)
	5015-Transformer Station Equipment - Operation Supplies and Expenses	5,986	4,750	1,236	26.0%
	5016-Distribution Station Equipment - Operation Labour	2,408	793	1,615	203.6%
	5017-Distribution Station Equipment - Operation Supplies and Expenses				
	5020-Overhead Distribution Lines and Feeders - Operation Labour	7,524	6,466	1,058	16.4%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,802	2,736	(934)	(34.1%)
	5035-Overhead Distribution Transformers- Operation	1,705	3,090	(1,384)	(44.8%)
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,442		1,442	
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	174	341	(167)	(48.9%)
	5055-Underground Distribution Transformers - Operation	2,414	2,979	(565)	(19.0%)
	5065-Meter Expense	14,622	8,702	5,920	68.0%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,030	1,030		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	3,850		3,850	
	5120-Maintenance of Poles, Towers and Fixtures	5,507	1,256	4,251	338.3%
	5125-Maintenance of Overhead Conductors and Devices	42,064	31,287	10,777	34.4%
	5130-Maintenance of Overhead Services	21,370	47,020	(25,650)	(54.6%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	24,467	25,396	(929)	(3.7%)
	5145-Maintenance of Underground Conduit	1,245	31	1,214	3930.8%
	5150-Maintenance of Underground Conductors and Devices	13,511	6,042	7,469	123.6%
	5155-Maintenance of Underground Services	5,062	5,808	(746)	(12.8%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
	5160-Maintenance of Line Transformers	5,399	9,275	(3,876)	(41.8%)
	5175-Maintenance of Meters	7,746	(2,961)	10,707	361.6%
3650-Billing and Collecting	5310-Meter Reading Expense	27,845	34,946	(7,101)	(20.3%)
	5315-Customer Billing	137,987	172,841	(34,854)	(20.2%)
	5320-Collecting	55,788	51,296	4,493	8.8%
	5325-Collecting- Cash Over and Short	11		11	
	5335-Bad Debt Expense	7,139	8,232	(1,093)	(13.3%)
3700-Community Relations	5410-Community Relations - Sundry	100	100		
	5415-Energy Conservation	60,710		**60,710**	
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	89,593	81,251	8,341	10.3%
	5610-Management Salaries and Expenses	63,260	54,036	9,224	17.1%
	5620-Office Supplies and Expenses	14,711	13,873	838	6.0%
	5630-Outside Services Employed	23,680	35,430	(11,750)	(33.2%)
	5635-Property Insurance	4,099	3,732	367	9.8%
	5640-Injuries and Damages	13,054	16,545	(3,491)	(21.1%)
	5645-Employee Pensions and Benefits	2,921	2,119	802	37.9%
	5655-Regulatory Expenses	15,135		15,135	
	5665-Miscellaneous General Expenses	11,550	119,618	**(108,068)**	(90.3%)
	5675-Maintenance of General Plant	31,012	22,443	8,569	38.2%
	5680-Electrical Safety Authority Fees	5,235	1,142	4,093	358.5%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	25,171	24,654	518	2.1%
Net Income		219,067	(171,361)	**390,428**	227.8%

Exhibit 2: Rate Base

Tab 6 (of 6): Service Quality and Reliability Performance

SERVICE QUALITY AND RELIABILITY PERFORMANCE

HHI continues to expand and build up its distribution system in order to meet the demand of new and existing customers in its service territory. This increase in demand comes both from expansion of the distribution system into currently non serviced areas and distribution system upgrades needed in existing areas.

Service quality has always been a priority for the company. HHI has consistently exceeded the OEB's Service Quality Indicators, as set out in this schedule.

HHI monitors and reports service quality indicators as required in Chapter 15 of the Ontario Energy Board 2006 Electricity Distribution Rate Handbook. A list of the service quality metrics that a distributor is required to measure and report back to the OEB is provided below.

Customer Service	**Customer Service**
• Connection of new services • Underground cable locates • Appointments • Telephone accessibility • Written response to enquiries • Emergency response	• System average interruption duration index • System average interruption frequency index • Customer average interruption duration index

Definitions of the above quality metrics can be found in Chapter 15 of the Ontario Energy Board 2006 Electricity Distribution Rate Handbook.

HHI strives to establish its operating performance at levels no less than the minimum standards, taking into consideration the needs and expectations of its customers. Having the benefits of being a small HHI, the results are reported internally as they occur and are reported to the OEB quarterly in accordance with the RRR filing requirements. HHI Customer Service and Service Reliability results and targets from 2006 to 2011 are shown at Schedule 1. The OEB imposed standards and reason codes are presented at Table 2.6.1.1 and Table 2.6.1.2.

Service Reliability Performance

Table 2.6.1.1

Cause of Service Interruption

Code	Cause
0	Unknown/Other Customer interruptions with no apparent cause that contributed to the outage
1	Scheduled Outage Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance
2	Loss of Supply Customer interruptions due to problems in the bulk electricity supply system
3	Tree Contacts Customer interruptions caused by faults resulting from tree contact with energized circuits
4	Lightning Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs
5	Defective Equipment Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance
6	Adverse Weather Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events)
7	Adverse Environment Customer interruptions due to equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing (previously Code 9)
8	Human Element Customer interruptions due to the interface of distributor staff with the system (previously Code 7)
9	Foreign Interference Customer interruptions beyond the control of the distributor, such as animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects (previously Code 8)

Summary of the annual performance for the years 2006 to 2008 is provided below showing the reported service reliability indicators and the cause of service interruptions.

2006 Cause of Service Interruption

Month	# Interruptions	Code	Cause Of Service Interruption
January	1	5	Defective Equipment
February	2	9	Foreign Interference
		9	Foreign Interference
March	2	3	Tree Contact
		3	Tree Contact
April	3	5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
May	3	4	Lightning
		5	Defective Equipment
		0	Unknown
June	4	9	Foreign Interference
		0	Unknown
		5	Defective Equipment
		5	Defective Equipment
July	3	5	Defective Equipment
		4	Lightning
		9	Foreign Interference
August	3	0	Unknown
		0	Unknown
		9	Foreign Interference
September	4	3	Tree Contact
		9	Foreign Interference

		9	Foreign Interference
		2	Loss Supply
October	2	6	Adverse Weather
		3	Tree Contact
November	3	5	Defective Equipment
		5	Defective Equipment
		9	Foreign Interference
December	3	9	Foreign Interference
		9	Foreign Interference
		9	Foreign Interference

2007 Cause of Service Interruption

Month	# Interruptions	Code	Cause Of Service Interruption
January	2	5	Defective Equipment
		5	Defective Equipment
February	2	1	Scheduled Outage
		5	Defective Equipment
March	5	1	Scheduled Outage
		2	Loss Supply
		5	Defective Equipment
		5	Defective Equipment
		9	Foreign Interference
April	3	2	Loss Supply
		5	Defective Equipment
		2	Loss Supply
May	1	5	Defective Equipment
June	5	6	Adverse Weather
		5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
July	6	9	Foreign Interference
		9	Foreign Interference
		5	Defective Equipment
		5	Defective Equipment
		3	Tree Contact
		5	Defective Equipment

August	3	3	Tree Contact
		5	Defective Equipment
		5	Defective Equipment
September	5	5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
October	8	2	Loss Supply
		4	Lightning
		5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
November	2	1	Scheduled Outage
		5	Defective Equipment
December	1	5	Defective Equipment

2008 Cause of Service Interruption

Month	# Interruptions	Code	Cause Of Service Interruption
January	2	5	Defective Equipment
		1	Scheduled Outage
February	1	2	Loss Supply
March	2	4	Lightning
		1	Scheduled Outage
April	4	9	Foreign Interference
		5	Defective Equipment
		5	Defective Equipment
		5	Defective Equipment
May	7	5	Defective Equipment
		9	Foreign Interference
		1	Scheduled Outage
		1	Scheduled Outage
		9	Foreign Interference
		9	Foreign Interference
		9	Foreign Interference
June	2	9	Foreign Interference
		5	Defective Equipment
July	3	1	Scheduled Outage

		9	Foreign Interference
		3	Tree Contact
August	1	5	Defective Equipment
September	2	5	Defective Equipment
		5	Defective Equipment
October	0		
November	3	4	Lightning
		5	Defective Equipment
		5	Defective Equipment
December	1	2	Loss Supply

Service Quality Performance

Table 2.6.1.1

Cause of Service Interruption

Standard for Service Quality Indicators	
Connection of New Services – Low Voltage	Standard: 90% or better
Connection of New Services – High Voltage	Standard: 90% or better
Underground Cable Locates	Standard: 90% or better
Appointments Met	Standard: 90% or better
Telephone Accessibility (Telephone Service Factor)	Standard: 65% or better
Written Responses to Enquiries	Standard: 80% or better
Emergency Response – Rural	Standard: 80% or better

A summary of their result is presented in the tables below.

2006

2006 New connection – LV Annual Total (LV = Low Voltage)

Total # of new LV Services connected within 5 days	Total # of new LV Services connected	NC LV Annual Percentages
91	91	100%

2006 UCL Annual Total (UCL = Underground Cable Locates)

Total # of UCL completed within 5 days	Total # of UCL Requested	UCL Annual Total Percentage
182	182	100%

2006 Telephone Accessibility

Total # General Inquiries, Telephone calls answered within 30 sec.	Total # General Inquiries, Telephone calls	Total # General Inquiries, Telephone calls percentages
10,006	10,013	99.93%

2006 Appointments Met – Annual Total

Total # of visits to customer sites where App date and time met	Total # of appointments requiring visits to cust. sites	Total # of visits to customer sites where App date and time met
28	28	100%

2006 WRI Annual Total (WRI= Written Responses to Inquiries)

Total WRI Request in 10 days	Total WRI Request	WRI Annual Total Percentages
10	10	100%

2006 ERU Annual Total (ERU = Emergency Response – Urban)

Total # of ER Urban onsite within 60 min.	Total # of ER Urban Calls	ER Urban Annual Total Percentage
33	33	100%

2007

2007 New connection – LV Annual Total *(LV = Low Voltage)*

Total # of new LV Services connected within 5 days	Total # of new LV Services connected	NC LV Annual Percentages
130	130	100%

2007 UCL Annual Total (UCL = Underground Cable Locates)

Total # of UCL completed within 5 days	Total # of UCL Requested	UCL Annual Total Percentage
185	185	100%

2007 Telephone Accessibility

Total # General Inquiries, Telephone calls answered within 30 sec.	Total # General Inquiries, Telephone calls	Total # General Inquiries, Telephone calls percentages
10,266	10,270	99.96%

2007 Appointments Met – Annual Total

Total # of visits to customer sites where App date and time met	Total # of appointments requiring visits to cust. sites	Total # of visits to customer sites where App date and time met
98	99	99%

2007 WRI Annual Total (WRI= Written Responses to Inquiries)

Total WRI Request in 10 days	Total WRI Request	WRI Annual Total Percentages
321	321	100%

2007 ERU Annual Total (ERU = Emergency Response – Urban)

Total # of ER Urban onsite within 60 min.	Total # of ER Urban Calls	ER Urban Annual Total Percentage
34	34	100%

2008

2008 New connection – LV Annual Total *(LV = Low Voltage)*

Total # of new LV Services connected within 5 days	Total # of new LV Services connected	NC LV Annual Percentages
99	99	100%

2008 UCL Annual Total (UCL = Underground Cable Locates)

Total # of UCL completed within 5 days	Total # of UCL Requested	UCL Annual Total Percentage
184	184	100%

2008 Telephone Accessibility

Total # General Inquiries, Telephone calls answered within 30 sec.	Total # General Inquiries, Telephone calls	Total # General Inquiries, Telephone calls percentages
9,309	9,318	99.90%

2008 Appointments Met – Annual Total

Total # of visits to customer sites where App date and time met	Total # of appointments requiring visits to cust. sites	Total # of visits to customer sites where App date and time met
38	38	100%

2008 WRI Annual Total (WRI= Written Responses to Inquiries)

Total WRI Request in 10 days	Total WRI Request	WRI Annual Total Percentages
357	357	100%

2008 ERU Annual Total (ERU = Emergency Response – Urban)

Total # of ER Urban onsite within 60 min.	Total # of ER Urban Calls	ER Urban Annual Total Percentage
43	43	100%

<u>Exhibit 3</u>:

REVENUE

Exhibit 3: Revenue

Tab 1 (of 3): Throughput Revenue

FORECAST METHODOLOGY

A weather normal load forecast has been used for HHI's rate application. Weather normalization involves removing the year-to-year variations in consumption due to weather. This is achieved by estimating a statistical relationship between observed monthly weather and observed monthly consumption. In addition to weather, monthly consumption can also be affected by the number of weekdays and holidays in the month and economic factors (such as growth or decline). These factors are also accounted for in the statistical relationship.

Once the statistical relationship between monthly weather and consumption is obtained, year-to-year variance in weather conditions is controlled for by defining a "weather normal" month. For the purpose of this application, HHI adopted the most recent 10-year average weather data from 1999 to 2008 of observed weather in each month as the definition of "weather normal". With respect to HHI's specific load forecast, monthly weather observations describing the extent of heating degree days (HDD – the number of Celsius degrees that the mean temperature is below 18°C) or cooling degree days (CDD – the number of Celsius degrees that the mean temperature is above 18°C) as reported at Ottawa International Airport have been used. The historical consumption are weather normalized by replacing actual observed weather with normal weather in the statistical relationship to obtain what consumption would have been if weather had been "normal". Future consumption is forecast based on normal weather and forecast economic and timing variables. Monthly full–time employment levels for the Ottawa economic regions, along with non-holiday weekdays were used in the regression equations for the load forecast.

As can been seen from ERA's report, HHI yields a small yet steady Residential customer growth, but shows a sign of slowing down compared to the past 5 years. The report forecasts minor peaks and valleys for the residential class and GS classes between the bridge and test years. For all other customer classes (Streetlights and USL), no changes from 2008 are expected. With respect to the energy forecast, HHI's residential and

GS<50 classes showed strong correlations with weather, and regression equations were used to weather normalize and forecast kWh consumption for these classes.

This weather-normalized throughput was generated by Elenchus Research Associates (ERA) using regression equations. Attached at Exhibit 3, Tab 1, Schedule 1, Attachment 2 is a copy of HHI's Weather Normalized Load Forecast for 2010 Test Year prepared by Elenchus Research Associates. The volumetric trend table can be found in the following page or at Exhibit 3, Tab 1, Schedule 1, Attachment 1.

Hydro Hawkesbury Inc. (ED-2003-0027)

2010 EDR Application (EB-2009-0186) version: v0.1
November 4, 2009

C1 Load Data and Forecast

Enter historical volume data and projections for 2009-2010

CUSTOMERS (CONNECTIONS)

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Estimated	2010 Normalized
Residential	4,580	4,642	4,775	4,724	4,724	4,672	4,672	4,705
General Service Less Than 50 kW	566	564	571	569	569	567	567	566
General Service 50 to 4,999 kW	78	77	79	79	79	79	79	79
Large Use	1	1	1	1	1	1	1	
Sentinel Lighting	23	22	21	21	21	21	21	21
Street Lighting	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
Unmetered Scattered Load	4	4	4	4	4	4	4	4
TOTAL	**6,410**	**6,468**	**6,609**	**6,556**	**6,556**	**6,502**	**6,502**	**6,533**

METERED KILOWATT-HOURS (kWh)

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Estimated	2010 Normalized
Residential	54,159,435	**51,530,722**	**53,035,556**	**56,866,845**	**53,947,877**	**53,502,498**	**53,502,498**	**53,559,119**
General Service Less Than 50 kW	22,341,766	**20,666,608**	**20,483,521**	**20,528,976**	**20,711,904**	**20,748,524**	**20,540,911**	**20,562,650**
General Service 50 to 4,999 kW	87,075,751	**81,391,278**	**85,703,128**	**86,045,628**	**86,812,352**	**86,095,652**	**86,095,652**	**86,186,766**
Large Use	49,538,379	**34,899,217**	**31,642,779**	**26,758,904**	**26,758,704**	**13,015,266**	**13,015,266**	
Sentinel Lighting	106,690	**108,681**	**108,700**	**108,470**	**108,470**	**108,470**	**108,470**	**108,470**
Street Lighting	975,914	**1,025,217**	**972,416**	**1,208,363**	**1,208,363**	**1,208,363**	**1,208,363**	**1,208,363**
Unmetered Scattered Load	**21,626**	**211,626**	**211,626**	**220,667**	**220,667**	**220,667**	**220,667**	**220,667**
TOTAL	**214,219,561**	**189,833,349**	**192,157,726**	**191,737,853**	**189,768,337**	**174,899,440**	**174,691,827**	**161,846,035**

KILOWATTS (kW)

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Estimated	2010 Normalized
Residential								
General Service Less Than 50 kW								
General Service 50 to 4,999 kW	191,625	198,735	214,682	229,438	231,483	229,572	229,572	229,814
Large Use	89,145	75,465	75,608	74,710	74,710	42,872	42,872	
Sentinel Lighting	301	300	300	325	325	325	325	325
Street Lighting	2,734	2,870	2,874	3,096	3,096	3,096	3,096	3,096
Unmetered Scattered Load								
TOTAL	**283,805**	**277,370**	**293,464**	**307,569**	**309,614**	**275,865**	**275,865**	**233,235**

Customer Class Name	Loss Factor
Residential	1.0466
General Service Less Than 50 kW	1.0466
General Service 50 to 4,999 kW	1.0466
Large Use	
Sentinel Lighting	1.0466
Street Lighting	1.0466
Unmetered Scattered Load	1.0466

WHOLESALE kWh's [1]

2009 Normalized	2009 Estimated	2010 Normalized
55,995,714	55,995,714	56,054,974
21,715,405	21,498,117	21,520,869
90,107,709	90,107,709	90,203,069
13,015,266	13,015,266	
113,525	113,525	113,525
1,264,673	1,264,673	1,264,673
230,950	230,950	230,950

[1] Metered kWh's multiplied by Loss Factor

Weather Normalized Distribution System Load Forecast – 2010 Test Year

Prepared for

Hydro Hawkesbury Inc.

May 14, 2009

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Hydro Hawkesbury Inc.'s rebasing rate application for 2010 rates. A weather normal load forecast is developed for the bridge year (2009) and test year (2010) and weather normalized historical consumption is also derived.

Short-term variation in monthly electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the most dominant effect for most systems; economic factors (increases or decreases in economic activity leads to changes in employment, industrial and commercial activity, building and population change); and timing factors, such as holidays, weekdays, and number of days in the month. We have incorporated variables, as appropriate, to account for these factors in considering Hawkesbury's load and correcting for weather anomalies.

The forecast for Hydro Hawkesbury is based on monthly deliveries to the Distribution System from January 2004 to December 2008. From January 2004 to September 2006, this is measured as wholesale metered amounts delivered from the IESO controlled grid. After October 2006, one delivery point was de-registered and this supply is now metered and billed by Hydro One.

Class specific consumption for Hawkesbury is available on an annual basis only, except for one large user which is interval metered. While ERA believes it is desirable to isolate demand determinants related to individual rate classes, such as residential, commercial, and industrial, since demand determinants and weather sensitivity may be different for each of these classes, it is not always possible to do this due to the data limitations imposed by using class-level billing data. Since the majority of class retail data for Hawkesbury is only available on an annual basis, this precludes the ability to derive class specific demand determinants. Additionally, the large user constitutes a significant portion of monthly load. This user does not have a weather sensitive load profile but monthly consumption from 2004 is available. Therefore, a "weather sensitive" net system load for Hawkesbury is derived by subtracting the monthly consumption of the large user from monthly deliveries. We are unable to remove consumption related to street lighting and sentinel lighting from the weather sensitive monthly load due to the fact that class consumption is available on an annual basis only. However, this consumption is a very small proportion of the total (less than one per cent, combined).

In May of 2009, the single large use customer in Hawkesbury, announced that it would be permanently cease operations at the end of November, 2009. In late 2008 and early 2009, consumption in this class has declined significantly. This will be discussed further in the section on non-weather sensitive load below.

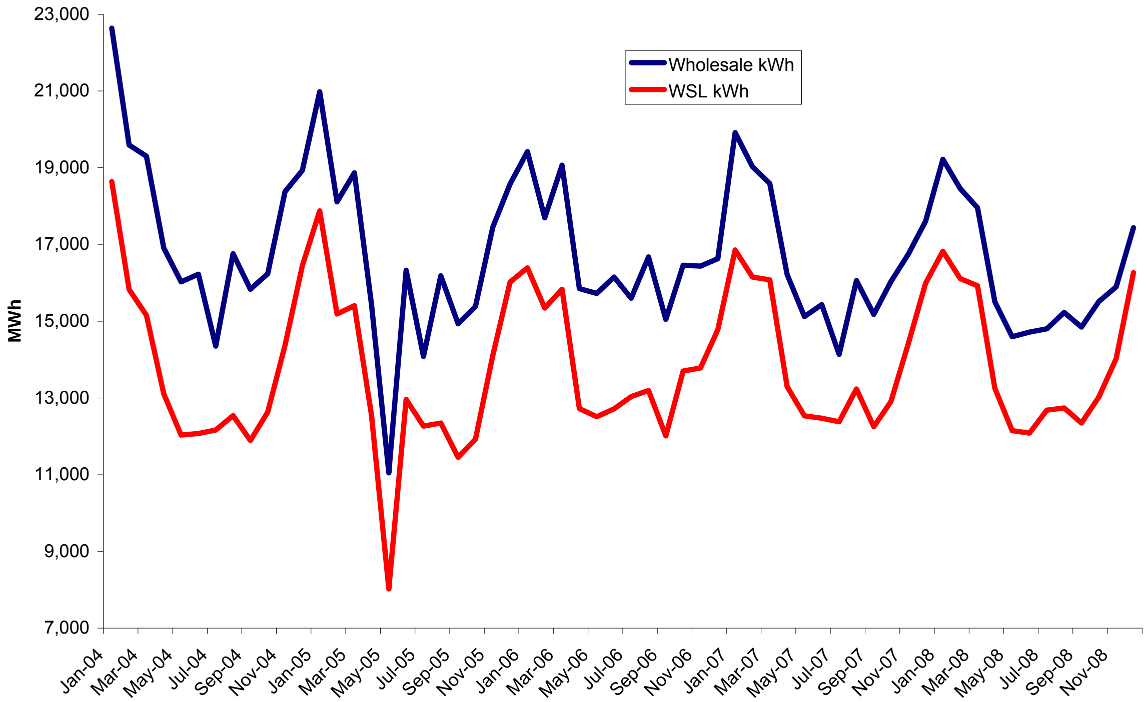
2 Energy Forecast Using Wholesale kWh Deliveries

The following table (Table 1) outlines monthly "weather sensitive" net system load from January 2004 to December 2008. The accompanying chart (Chart 1) illustrates the "weather sensitive" net system load or "WSL" and monthly wholesale deliveries.

Table 1: Monthly Net System Load (kWh), Hydro Hawkesbury

	2004	2005	2006	2007	2008
January	18,637,678	17,870,916	16,388,891	16,852,233	16,819,638
February	15,824,597	15,185,261	15,340,991	16,146,860	16,106,414
March	15,151,388	15,401,451	15,831,060	16,075,177	15,917,303
April	13,105,910	12,546,018	12,717,270	13,292,923	13,249,917
May	12,030,458	8,016,770	12,509,932	12,531,854	12,145,403
June	12,072,109	12,955,942	12,713,980	12,467,928	12,078,793
July	12,162,321	12,262,516	13,030,943	12,374,953	12,676,710
August	12,534,002	12,339,980	13,193,056	13,234,020	12,733,825
September	11,886,209	11,447,564	12,006,692	12,246,087	12,344,575
October	12,630,027	11,922,695	13,698,125	12,901,675	13,017,951
November	14,372,743	14,103,083	13,777,519	14,405,846	14,022,435
December	16,443,722	16,017,182	14,773,857	15,984,980	16,262,824
Annual	**166,851,163**	**160,069,380**	**165,982,315**	**168,514,536**	**167,375,788**
% change		***-4.1%***	***3.7%***	***1.5%***	***-0.7%***

Chart 1
Hydro Hawkesbury - Monthly Wholesale and WSL kWh



In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For Hawkesbury, we have used monthly HDD and CDD as reported at Dorval Airport near Montreal.

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. We have used the monthly full-time employment levels for the Ottawa economic region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054772).

The forecast equation for Hydro Hawkesbury's monthly WSL also contains the number of peak days (non-holiday week days) in the month and a "dummy variable" to account for the unexplained[1] decline in monthly consumption in May 2005. For holidays, we have included New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, August Civic Holiday (Simcoe Day), Labour Day, Thanksgiving Day, Christmas and Boxing Day. From 2008, we have included the Ontario Family Day holiday in February, but we have not included Remembrance Day in November.

The historical data for monthly peak days and full-time employment are displayed in *Table 2* below.

Table 2
Monthly Peak Days

	2004	2005	2006	2007	2008
January	21	20	21	22	22
February	20	20	20	20	20
March	23	21	23	22	21
April	20	21	18	19	20
May	20	21	22	22	21
June	22	22	22	21	21
July	21	20	20	22	22
August	21	22	22	22	20
September	21	21	20	19	21
October	20	20	21	22	22
November	22	22	22	22	20
December	21	20	19	19	21
	Ottawa Full-Time Employment ('000s) – CANSIM v2054772				
January	490.6	499.2	509.1	497	543.1
February	486	496.7	510.1	497.9	535.2
March	482.2	487.5	509.5	501.8	530.5
April	479.1	490.8	517.2	507.7	532.7
May	488.1	497.4	528.1	523.3	539.1
June	501.3	509.3	536.6	536.9	548.4
July	514.2	519	545.4	555.3	563.3
August	518.4	522.8	547.2	561.7	573
September	515	516.7	537.5	560.5	565.8
October	512.8	511.8	521.4	556.5	554
November	506.5	506.3	504.1	551.6	541.6
December	506.5	512.8	499.6	551.5	540.9

Using these data, a multiple regression analysis was used to develop an equation describing the relationship between monthly actual WSL kWh and the explanatory variables.

[1] We have been unable to reconcile this one-time occurrence with a specific event, but it is confirmed with monthly consumption data from the IESO.

The resulting equation, estimated using the 60 observations from 2004:01-2008:12 is displayed below:

Table 3

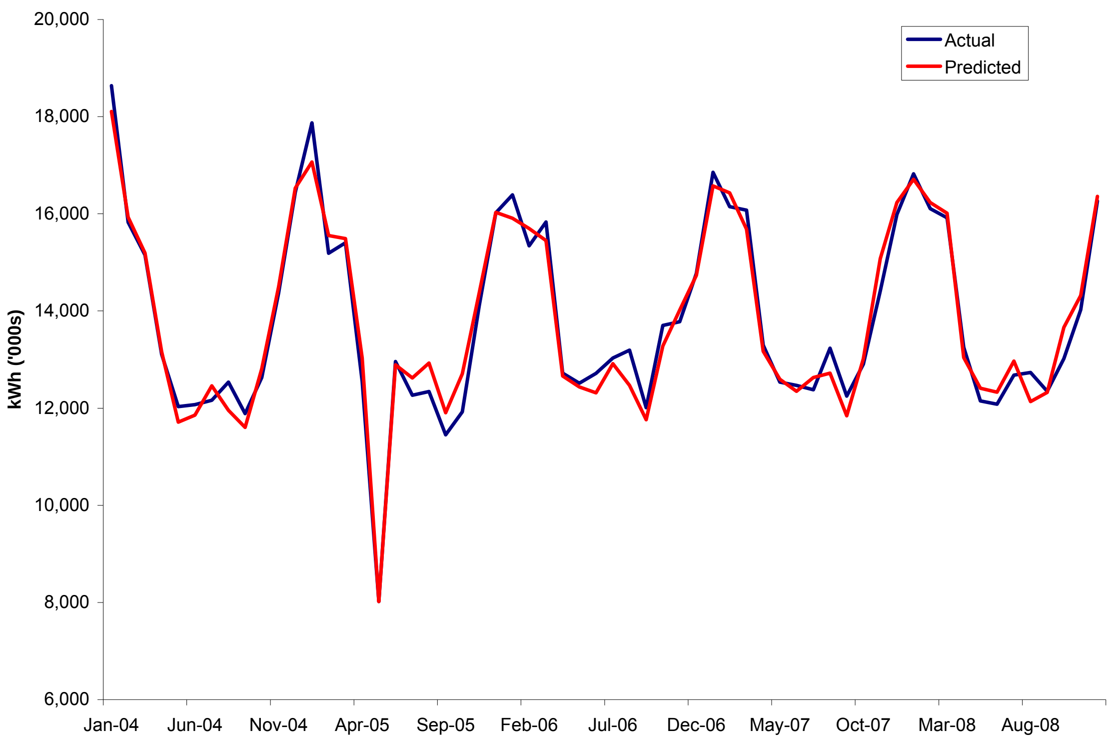
OLS estimates using the 60 observations 2004:01-2008:12
Dependent variable: WSLkWh

Unadjusted R^2 = 0.966331
Adjusted R^2 = 0.963214
F-statistic (5, 54) = 309.9718 (p-value < 0.00001)
Durbin-Watson statistic = 1.723520

Variable	*Coefficient*	*t-statistic*	*p-value*
Const	3,287,155.0	2.1249	0.03819
HDD	7,071.3	30.7066	<0.00001
CDD	13,205.9	7.9823	<0.00001
D_May05	-4,235,561.1	-10.9678	<0.00001
Peak Days	195,683.1	4.307	0.00007
FTE_OttReg	7,033.1	3.0989	0.00308

Fitted vs. actual observations are plotted in the chart below:

Chart 2
Hydro Hawkesbury - Monthly Actual vs Predicted WSL kWh (2004-2008)



Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 0.9% with the largest absolute error on an annual estimate at 1.6%.

Table 4 – Actual vs. Predicted WSL kWh, Hydro Hawkesbury

Year	*Actual WSL kWh*	*Predicted WSL kWh*	*Absolute % Error*
2004	166,851,163	165,790,146	0.6%
2005	160,069,380	162,589,465	1.6%
2006	165,982,315	163,627,030	1.4%
2007	168,514,536	168,297,644	0.1%
2008	167,375,788	168,487,853	0.7%
		Mean Absolute Percentage Error	***0.9%***

2.1 WEATHER NORMALIZATION AND FORECASTED KWH

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells “average” out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. The OEB has considered and approved several different approaches to what constitutes “weather normal” over the past several years. For gas utilities, the Board has approved a five-year moving average for NRG (RP-2004-0167), a weighted average of 20 year and 30 year for Union Gas (RP-2003-0063), and a combination of methods including a 20 year trend, weighted average 20 year and 30 year, and variations of the so-called “de Bever” method depending upon location for Enbridge Gas Distribution (EB-2006-0034). For electric LDCs, Hydro One Networks Inc. (HONI) has used a 31 year average for their definition of weather normal (EB-2005-0378 and EB-2007-0681). On the other hand, Toronto Hydro Electric System Limited (THESL) has used the most recent 10 year average as a definition of weather normal (EB-2005-0421 and EB-2007-0680) as have many of the LDCs that filed for cost-of-service rebasing for 2009 rates. Hawkesbury has adopted the 10 year average from 1999 to 2008 as the definition of weather normal. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing.

Presented below is a table outlining the 10-year monthly HDD and CDD for Trudeau International Airport (Dorval), the weather station selected for Hydro Hawkesbury.

Table 5 –10-yr average (1999-2008) HDD and CDD, P.E. Trudeau (Dorval) Airport

Heating Degree Days

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	10- yr avg
Jan	843.9	870.4	835.3	695.7	948.3	1026.4	898.4	697.4	775.6	749.3	**834.1**
Feb	647.1	725.4	745.6	643.3	805.6	750.8	686.7	694	809.7	744.7	**725.3**
Mar	597.4	508.3	661.1	616.2	674.9	567.6	659.4	576.5	644.9	690.8	**619.7**
Apr	332.3	372.1	346.4	336.6	413.1	361.5	308.4	313	366.4	296	**344.6**
May	77.9	137.1	103.3	214.4	144.8	144.9	190.3	126.6	152.9	172.3	**146.5**
Jun	13.1	61.6	20.7	53.3	39.9	45.5	16.2	23.8	26	16.8	**31.7**
Jul	2	9.5	13.1	2.9	0.8	0.7	2.7	0	6.5	0	**3.8**
Aug	11.8	12.4	4.4	4.3	10.2	18.4	6.2	23.9	15.5	10.8	**11.8**
Sep	55.4	119.2	68.9	51	43.2	60.9	54.3	96.1	69.9	72.1	**69.1**
Oct	318.9	276.7	231.9	343.7	310.2	281.8	253.2	312.9	207.9	307.1	**284.4**
Nov	390.7	466.7	402.6	517.1	453.7	472.6	454.5	407.2	509.7	467.9	**454.3**
Dec	662.2	843.4	570.7	699.9	710.8	787.5	738.3	595.9	756.4	729.5	**709.5**
Total	3952.7	4402.8	4004	4178.4	4555.5	4518.6	4268.6	3867.3	4341.4	4257.3	**4234.66**

Cooling Degree Days

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	10- yr avg
Jan	0	0	0	0	0	0	0	0	0	0	**0.0**
Feb	0	0	0	0	0	0	0	0	0	0	**0.0**
Mar	0	0	0	0	0	0	0	0	0	0	**0.0**
Apr	0	0	0	3.2	0	2.4	0	0	0	0	**0.6**
May	32.6	1.4	21.6	6.6	3.4	3.8	0.9	17.8	18	0	**10.6**
Jun	101.6	37.4	79.9	38.1	64.1	31.4	121.3	59	74.9	72.4	**68.0**
Jul	145.8	73.8	80.8	130.2	112.6	108.9	132.6	141.9	82.1	106.8	**111.6**
Aug	72.5	68.3	144.9	123.1	121.5	59.2	122.1	65	80.8	62.7	**92.0**
Sep	58	11.3	32.9	60.1	33	11.6	37.1	7.5	30.1	33	**31.5**
Oct	0	0	0	3.3	0	0.5	8.6	0	3.1	0	**1.6**
Nov	0	0	0	0	0	0	0	0	0	0	**0.0**
Dec	0	0	0	0	0	0	0	0	0	0	**0.0**
Total	410.5	192.2	360.1	364.6	334.6	217.8	422.6	291.2	289	274.9	**315.75**

Forecasts for Ontario's employment outlook for 2008 and 2009 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 6 - Employment Forecast – Ontario
(figures in annual percentage change)

	BMO *(March 20,2009)*	RBC *(Mar 2009)*	Scotia *(Mar. 17, 2009)*	TD *(Mar 17,2009)*	Avg
2009	-3.1	-1.9	-2.6	-2.6	-2.6
2010	0.6	1.3	0.2	-0.6	0.4

Incorporating the forecast economic variables, monthly peak days, and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

Table 7 - Weather Corrected WSL kWh, Hydro Hawkesbury				
			10-yr (1999-2008)	
Year	Actual WSL kWh	%chg	Weather Normal	%chg
2004	166,851,163		165,075,839	
2005	160,069,380	-4.1%	160,938,415	-2.5%
2006	165,982,315	3.7%	166,548,947	3.5%
2007	168,514,536	1.5%	167,896,112	0.8%
2008	167,375,788	-0.7%	168,867,220	0.6%
2009F			167,473,096	-0.8%
2010F			167,650,331	0.1%

3 Class Specific Weather Normalization and Consumption Forecasts

The following table (Table 8) presents class specific weather normal historic and forecast values for those classes that have weather sensitive load. Historic class specific kWh consumption is allocated based on each class' share in WSL kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2008.

Table 8 Weather Corrected Class Specific Consumption, Hawkesbury			
			10-yr (1999-2008)
Year	Actual residential kWh	*Share%*	Weather Normal
2004	50,437,571	30.2%	49,900,907
2005	52,898,956	33.0%	53,186,151
2006	51,530,722	31.0%	51,706,638
2007	53,035,556	31.5%	52,840,923
2008	53,471,411	31.9%	53,947,877
2009F			53,502,498
2010F			53,559,119

Year	Actual GS<50 kWh	*Share%*	Weather Normal
2004	21,290,810	12.8%	21,064,272
2005	21,840,735	13.6%	21,959,311
2006	20,878,234	12.6%	20,949,508
2007	20,695,147	12.3%	20,619,199
2008	20,736,468	12.4%	20,921,244
2009F			20,748,524
2010F			20,770,482
Year	Actual GS>50 kWh	*Share%*	Weather Normal
2004	85,081,206	51.0%	84,175,927
2005	80,172,094	50.1%	80,607,358
2006	81,391,278	49.0%	81,669,132
2007	85,703,128	50.9%	85,388,610
2008	86,045,628	51.4%	86,812,352
2009F			86,095,652
2010F			86,186,766

Actual, normalized and forecast kW for the weather sensitive GS>50 class are summarized in Table 9 below. Historical normalized values are calculated based on the annual ratio of class kW to class kWh. Forecast kW is based on the class kW to class kWh ratio in 2008.

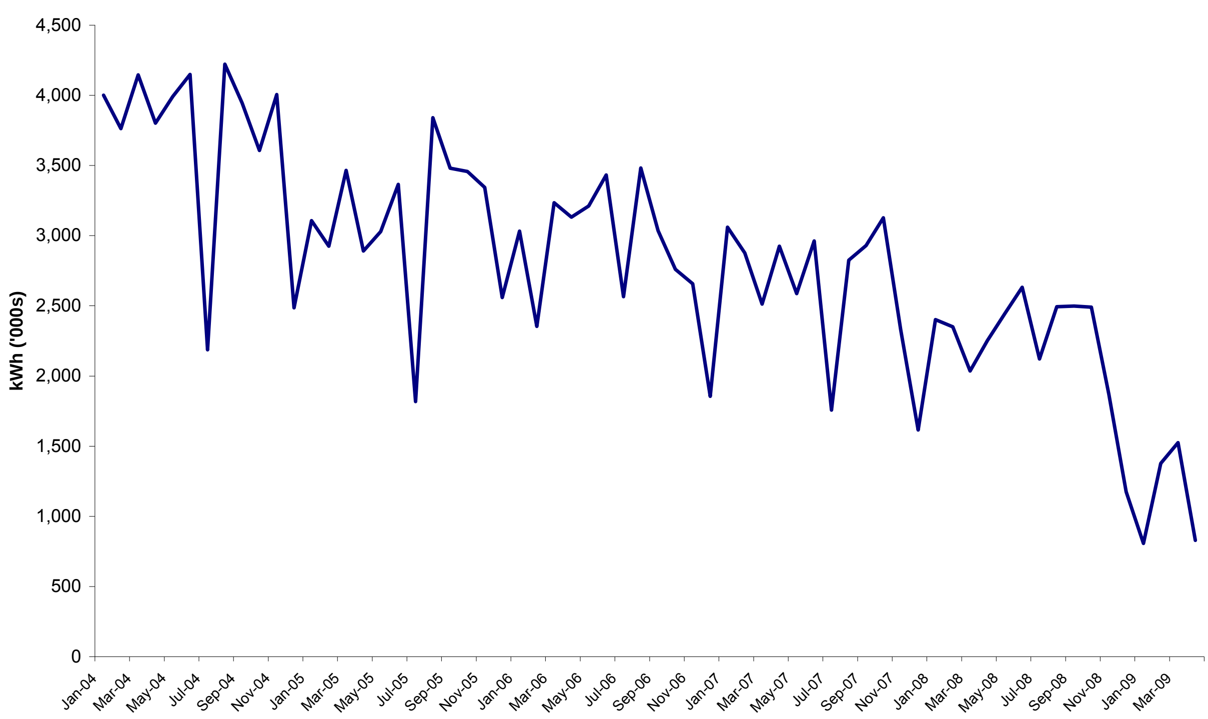
Table 9 – GS>50 Class kW (Actual, Normalized, and Forecast)

Year	**Actual kW**	**Class kW/kWh ratio**	**Normalized kW**	**% change**
2004	197,611	0.00232	195,508	
2005	198,609	0.00248	199,687	*2.1%*
2006	198,735	0.00244	199,413	*-0.1%*
2007	214,682	0.0025	213,894	*7.3%*
2008	229,438	0.00267	231,483	*8.2%*
2009F			229,572	*-0.8%*
2010F			229,814	*0.1%*

4 Large User and Lighting – Non-Weather Sensitive Clases

The large user, street lighting and sentinel lighting classes are not weather sensitive. Hydro Hawkesbury has one large user that is a manufacturer involved in the automotive sector. This one large user has comprised anywhere from 15 to over 20 per cent of total retail kWh sales in the LDC over the past 5 years. However, this customer has had steadily declining use every year since 2004 and has had a dramatic decline in use in the fourth quarter of 2008 and the first four months of 2009. The company shut down completely in the month of January (2009) and has resumed production in February with only one out of three production lines. The company informed the LDC in January 2009 that this is likely for the foreseeable future until automotive demand recovers, and will also likely involve several weeks of complete, lights out shutdown from time-to-time. Subsequently, the company has announced it will cease operations in Hawkesbury permanently at the end of November 2009. The following chart (Chart 3) illustrates monthly kWh consumption for the large user.

Chart 3
Monthly Large User kWh (billed), Jan 2004 to Apr 2009



The table below (Table 10) illustrates the recent decline in large user consumption and a projection to the end of 2009 based on January to April actual consumption (and assuming no consumption in December 2009).

Table 10 – Large User Consumption

	kW	% chg	kWh	% chg
Jan – Apr 2009	15,151	-32.8%	4,534,965	-49.8%
Jan – Apr 2008	22,558		9,037,549	
Dec 2008	3,841		1,174,558	
Prorated Dec'09 (to remove)	2,581		589,628	
Annual 2009 (est)	42,872		13,015,266	

Based on consumption in recent months and indications from the customer, we are projecting a 51.4 per cent decline in kWh throughput for this class in 2009 and a 42.6% decline in kW in 2009. In 2010, this class will have no customer. The 2009 consumption is based on the first four months consumption (kWh and kW), multiplied by 3 and subtracting a prorated December consumption (as in December the customer will be shut down). The prorated December consumption is based on December 2008 reduced by the kW and kWh declines indicated in Table 10.

Table 11 presents actual and forecast kWh and kW for the non-weather sensitive classes: Large User, Street Lighting, and Sentinel Lighting. The forecast throughput for the lighting classes is not expected to change as no changes to customer connections is anticipated in 2009 or 2010.

Table 11

Large User Street Lighting & Sentinel Lighting Historic and Forecast Consumption

	Street lighting				*Sentinel Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2004	887,585		2,776		97,906		305	
2005	912,953	2.9%	2,843	2.4%	109,473	11.8%	300	-1.6%
2006	1,025,217	12.3%	2,870	0.9%	108,681	-0.7%	300	0.0%
2007	972,416	-5.2%	2,874	0.1%	108,700	0.0%	300	0.0%
2008	1,208,363	24.3%	3,096	7.7%	108,470	-0.2%	325	8.3%
2009F	1,208,363	0.0%	3,096	0.0%	108,470	0.0%	325	0.0%
2010F	1,208,363	0.0%	3,096	0.0%	108,470	0.0%	325	0.0%

Large User

Year	kWh	%	kW	%
2004	44,293,181		83,420	
2005	37,273,246	-15.8%	76,540	-8.2%
2006	34,742,875	-6.8%	75,465	-1.4%
2007	31,501,025	-9.3%	75,608	0.2%
2008	26,758,704	-15.1%	74,710	-1.2%
2009F	13,015,266	-51.4%	42,872	-42.6%
2010F	0	-100.0%	0	-100.0%

Table 12 below presents the results for class specific historic actual and historic normalized (2008) kWh and kW (where applicable), and normalized forecast values for bridge year (2009) and test year (2010).

Table 12 – Load Forecast (Historical, Bridge and Test Years).

	2008 Actual	2008 Normalized	2009f Normalized	2010f Normalized
Residential (kWh)	53,471,411	53,947,877	53,502,498	53,559,119
GS<50 (kWh)	20,736,468	20,921,244	20,748,524	20,770,482
GS>50 (kWh)	86,045,628	86,812,352	86,095,652	86,186,766
(kW)	229,438	231,483	229,572	229,814
Street Lights (kWh)	1,208,363	1,208,363	1,208,363	1,208,363
(kW)	3,096	3,096	3,096	3,096
Sentinel Lights (kWh)	108,470	108,470	108,470	108,470
(kW)	325	325	325	325
Large User (kWh)	26,758,704	26,758,704	13,015,266	-
(kW)	74,710	74,710	42,872	-
Total Retail kWh	188,329,043	189,757,011	174,678,773	161,833,200

5 CUSTOMER FORECAST

Historic customer figures on an annual basis are presented in Table 13 below. Table 13 also presents the projected values for the number of customers in each rate class for 2009 and 2010.

Residential connections in 2009 are assumed to drop by 1.1%, equivalent to 2008, with growth in 2010 equivalent to the 2004 to 2008 average. This is consistent for housing start forecasts for Ottawa and Kingston, the two markets in eastern Ontario CMHC does analysis for. Ottawa 2009 starts forecast to decline by -12.4% (CMHC) and Kingston by -3.9% (CMHC). GS<50 class is projected to decline in 2009 and 2010 equivalent to decline in 2008. No other changes are expected other than the loss of the large use customer in 2010.

Table 13 – Average Annual Customer Connections – Hydro Hawkesbury

	Residential	%chg	GS<50	%chg	GS>50	%chg	Street Light	%chg	Sent Light	%chg	LU
2004	4,580		568		78		1,158		23		1
2005	4,611	0.7%	564	-0.7%	72	-7.7%	1,158	0.0%	24	4.3%	1
2006	4,642	0.7%	566	0.4%	77	6.9%	1,158	0.0%	22	-8.3%	1
2007	4,775	2.9%	573	1.2%	79	2.6%	1,158	0.0%	21	-4.5%	1
2008	4,724	-1.1%	571	-0.3%	79	0.0%	1,158	0.0%	21	0.0%	1
2009f	4,672	-1.1%	569	-0.3%	79	0.0%	1,158	0.0%	21	0.0%	1
2010f	4,705	0.7%	568	-0.3%	79	0.0%	1,158	0.0%	21	0.0%	0

6 AVERAGE USE

Displayed below (Table 14) are the observed actual average use per customer, by customer class, as well as historical weather normalized and weather normal forecast average use per customer generated using our load forecast.

Table 14

Weather Actual Use Per Customer – Hydro Hawkesbury

Year	Residential	GS<50	GS>50	Street	Sentinel
2004	11,013	37,484	272,959	766	4,257
2005	11,472	38,725	303,344	788	4,561
2006	11,101	36,887	271,146	885	4,940
2007	11,107	36,117	261,964	840	5,176
2008	11,319	36,316	262,487	1,043	5,165

Weather Normal Use Per Customer – Historic & Forecast

Year	Residential	GS<50	GS>50
2004	10,895	37,085	1,079,179
2005	11,535	38,935	1,119,547
2006	11,139	37,013	1,060,638
2007	11,066	35,985	1,080,868
2008	11,420	36,640	1,098,891
2009	11,452	36,447	1,089,818
2010	11,384	36,595	1,090,972

Hydro Hawkesbury Inc. (ED-2003-0027)

2010 EDR Application (EB-2009-0186) version: v0.1
November 4, 2009

C2 Pass-through Charges

Enter rates for pass-through charges and estimated Low Voltage revenues

Electricity (Commodity)	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	*rate ($/kWh):*	**$0.06072 Amount**
kWh	Residential	4006	4705	55,995,714		3,400,060
kWh	General Service Less Than 50 kW	4035	4705	21,498,117		1,305,366
kWh	General Service 50 to 4,999 kW	4035	4705	90,107,709		5,471,340
kWh	Large Use	4020	4705	13,015,266		790,287
kWh	Sentinel Lighting	4030	4705	113,525		6,893
kWh	Street Lighting	4025	4705	1,264,673		76,791
kWh	Unmetered Scattered Load	4035	4705	230,950		14,023
	TOTAL			**182,225,955**		**11,064,760**

Transmission - Network	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	**Rate**	**Amount**
kWh	Residential	4066	4714	55,995,714	$0.0047	263,180
kWh	General Service Less Than 50 kW	4066	4714	21,498,117	$0.0043	92,442
kW	General Service 50 to 4,999 kW	4066	4714	229,572	$1.7399	399,432
kW	Large Use	4066	4714	42,872	$2.0461	87,720
kW	Sentinel Lighting	4066	4714	325	$1.3127	427
kW	Street Lighting	4066	4714	3,096	$1.3122	4,063
kWh	Unmetered Scattered Load	4066	4714	230,950	$0.0043	993
	TOTAL			**78,000,647**		**848,257**

Transmission - Connection	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	**Rate**	**Amount**
kWh	Residential	4068	4716	55,995,714	$0.0030	167,987
kWh	General Service Less Than 50 kW	4068	4716	21,498,117	$0.0027	58,045
kW	General Service 50 to 4,999 kW	4068	4716	229,572	$1.0849	249,063
kW	Large Use	4068	4716	42,872	$1.3601	58,310
kW	Sentinel Lighting	4068	4716	325	$1.7125	557
kW	Street Lighting	4068	4716	3,096	$0.8387	2,597
kWh	Unmetered Scattered Load	4068	4716	230,950	$0.0027	624
	TOTAL			**78,000,647**		**537,182**

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C2 Pass-through Charges

Enter rates for pass-through charges and estimatec

Volumes from sheet C1, Account #s from sheet Y4

Electricity (Commodity)		Customer Class Name	2010 Volume	rate ($/kWh):	$0.06072 Amount
	kWh	Residential	56,054,974		3,403,658
	kWh	General Service Less Than 50 kW	21,520,869		1,306,747
	kWh	General Service 50 to 4,999 kW	90,203,069		5,477,130
	kWh	Large Use			
	kWh	Sentinel Lighting	113,525		6,893
	kWh	Street Lighting	1,264,673		76,791
	kWh	Unmetered Scattered Load	230,950		14,023
		TOTAL	**169,388,060**		**10,285,243**

Transmission - Network		Customer Class Name	2010 Volume	Rate	Amount
	kWh	Residential	56,054,974	$0.0044	246,642
	kWh	General Service Less Than 50 kW	21,520,869	$0.0040	86,083
	kW	General Service 50 to 4,999 kW	229,814	$1.6115	370,345
	kW	Large Use			
	kW	Sentinel Lighting	325	$1.2159	395
	kW	Street Lighting	3,096	$1.2154	3,763
	kWh	Unmetered Scattered Load	230,950	$0.0040	924
		TOTAL	**78,040,029**		**708,152**

Transmission - Connection		Customer Class Name	2010 Volume	Rate	Amount
	kWh	Residential	56,054,974	$0.0024	134,532
	kWh	General Service Less Than 50 kW	21,520,869	$0.0021	45,194
	kW	General Service 50 to 4,999 kW	229,814	$0.8547	196,422
	kW	Large Use			
	kW	Sentinel Lighting	325	$1.3492	438
	kW	Street Lighting	3,096	$0.6618	2,049
	kWh	Unmetered Scattered Load	230,950	$0.0021	485
		TOTAL	**78,040,029**		**379,120**

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C2 Pass-through Charges

Enter rates for pass-through charges and estimated Low Voltage revenues

	Customer Class Name	Revenue USA #	Expense USA #	2009 Volume	rate ($/kWh):	Amount
Wholesale Market Service						$0.00520
kWh	Residential	4062	4708	55,995,714		291,178
kWh	General Service Less Than 50 kW	4062	4708	21,498,117		111,790
kWh	General Service 50 to 4,999 kW	4062	4708	90,107,709		468,560
kWh	Large Use	4062	4708	13,015,266		67,679
kWh	Sentinel Lighting	4062	4708	113,525		590
kWh	Street Lighting	4062	4708	1,264,673		6,576
kWh	Unmetered Scattered Load	4062	4708	230,950		1,201
	TOTAL			**182,225,955**		**947,575**
Rural Rate Protection						$0.00130
kWh	Residential	4062	4730	53,502,498		69,553
kWh	General Service Less Than 50 kW	4062	4730	20,540,911		26,703
kWh	General Service 50 to 4,999 kW	4062	4730	86,095,652		111,924
kWh	Large Use	4062	4730	13,015,266		16,920
kWh	Sentinel Lighting	4062	4730	108,470		141
kWh	Street Lighting	4062	4730	1,208,363		1,571
kWh	Unmetered Scattered Load	4062	4730	220,667		287
	TOTAL			**174,691,827**		**227,099**
Debt Retirement Charge						$0.00700
	TOTAL					
Low Voltage Charges						
	TOTAL (Input amount)	4075	4750		105,452.49	**105,452**
GRAND TOTAL						**13,730,325**

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C2 Pass-through Charges

Enter rates for pass-through charges and estimatec

Volumes from sheet C1, Account #s from sheet Y4

		Customer	2010	rate ($/kWh):	$0.00520
Wholesale Market Service		**Class Name**	**Volume**		**Amount**
	kWh	Residential	56,054,974		291,486
	kWh	General Service Less Than 50 kW	21,520,869		111,909
	kWh	General Service 50 to 4,999 kW	90,203,069		469,056
	kWh	Large Use			
	kWh	Sentinel Lighting	113,525		590
	kWh	Street Lighting	1,264,673		6,576
	kWh	Unmetered Scattered Load	230,950		1,201
		TOTAL	**169,388,060**		**880,818**
Rural Rate Protection		**Customer**	**2010**	rate ($/kWh):	**$0.00130**
		Class Name	**Volume**		**Amount**
	kWh	Residential	56,054,974		72,871
	kWh	General Service Less Than 50 kW	21,520,869		27,977
	kWh	General Service 50 to 4,999 kW	90,203,069		117,264
	kWh	Large Use			
	kWh	Sentinel Lighting	113,525		148
	kWh	Street Lighting	1,264,673		1,644
	kWh	Unmetered Scattered Load	230,950		300
		TOTAL	**169,388,060**		**220,204**
Debt Retirement Charge		**Customer**	**2010**	rate ($/kWh):	**$0.00700**
		Class Name	**Volume**		**Amount**
		TOTAL			
Low Voltage Charges		**Customer**		**2010**	
		Class Name	**Volume**		**Amount**
		TOTAL (Input amount)		70,600.00	**70,600**
GRAND TOTAL					**12,544,138**

Power Supply Expenses

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	10,285,243	11,064,760	**(779,517)**	**(7.0%)**
	4708-Charges-WMS	880,818	947,575	**(66,757)**	**(7.0%)**
	4710-Cost of Power Adjustments				
	4714-Charges-NW	708,152	848,257	**(140,104)**	**(16.5%)**
	4716-Charges-CN	379,120	537,182	**(158,061)**	**(29.4%)**
	4730-Rural Rate Assistance Expense	220,204	227,099	(6,895)	(3.0%)
	4750-Charges-LV	70,600	105,452	(34,852)	(33.1%)

Power Supply Expenses

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	11,064,760	10,640,262	**424,498**	**4.0%**
	4708-Charges-WMS	947,575	1,212,610	**(265,035)**	**(21.9%)**
	4710-Cost of Power Adjustments				
	4714-Charges-NW	848,257	952,489	**(104,232)**	**(10.9%)**
	4716-Charges-CN	537,182	679,242	**(142,060)**	**(20.9%)**
	4730-Rural Rate Assistance Expense	227,099		**227,099**	
	4750-Charges-LV	105,452	105,452		

Power Supply Expenses

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	10,640,262	10,959,500	**(319,238)**	(2.9%)
	4708-Charges-WMS	1,212,610	1,256,431	(43,821)	(3.5%)
	4710-Cost of Power Adjustments				
	4714-Charges-NW	952,489	1,090,133	**(137,644)**	(12.6%)
	4716-Charges-CN	679,242	884,090	**(204,848)**	(23.2%)
	4730-Rural Rate Assistance Expense				
	4750-Charges-LV	105,452	114,308	(8,856)	(7.7%)

Power Supply Expenses

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	10,959,500	10,749,411	**210,089**	2.0%
	4708-Charges-WMS	1,256,431	1,248,084	8,348	0.7%
	4710-Cost of Power Adjustments				
	4714-Charges-NW	1,090,133	1,068,249	21,884	2.0%
	4716-Charges-CN	884,090	887,094	(3,004)	(0.3%)
	4730-Rural Rate Assistance Expense				
	4750-Charges-LV	114,308	43,748	**70,560**	161.3%

Power Supply Expenses

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	10,749,411	10,511,673	**237,737**	2.3%
	4708-Charges-WMS	1,248,084	1,300,225	**(52,141)**	(4.0%)
	4710-Cost of Power Adjustments		378,498	**(378,498)**	(100.0%)
	4714-Charges-NW	1,068,249	1,099,936	(31,687)	(2.9%)
	4716-Charges-CN	887,094	960,882	**(73,788)**	(7.7%)
	4730-Rural Rate Assistance Expense				
	4750-Charges-LV	43,748		43,748	

Exhibit 3: Revenue

Tab 2 (of 3): Distribution Revenue

OVERVIEW OF DISTRIBUTION REVENUE

This exhibit provides a detailed calculations and variance analysis by rate class of the Distribution Revenue components on HHI's Distribution Revenues for 2006 EDR, 2006, 2007 and 2008 Actuals, 2009 Bridge year and Test years. The Historical, Actual and Bridge years have been calculated based on the Board Approved Rates. HHI's Distribution Revenue for the 2010 Bridge Year has been calculated using the 2010 proposed rates. Distribution Revenues do not include commodity revenues.

Details are presented in Exhibit 3, Tab 2, Schedule 1, Attachment 1. Please note that this schedule assumes rates are effective January 1st in each year. Consequently, actual Distribution Revenues will differ as rates become effective in May of each year.

C4 Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

Customer Class Name	2009 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$4.9600	4,672	278,077	$0.0092	kWh	53,502,498	490,297	768,374
General Service Less Than 50 kW	$9.7300	567	66,203	$0.0051	kWh	20,540,911	105,498	171,701
General Service 50 to 4,999 kW	$46.5000	79	44,082	$0.5422	kW	229,572	124,474	168,556
Large Use	$6,464.0100	1	77,568	$1.6804	kW	42,872	72,042	149,610
Sentinel Lighting	$1.0000	21	252	$5.1688	kW	325	1,680	1,932
Street Lighting	$0.0360	1,158	500	$3.3563	kW	3,096	10,391	10,891
Unmetered Scattered Load	$9.7300	4	467	$0.0051	kWh	220,667	1,125	1,592
Gross Revenue (before Transformer Allowances)			467,150				805,507	1,272,657
Transformer Allowances				($0.6000)	kW	226,943	(136,166)	(136,166)
Total Revenue			**467,150**				**669,342**	**1,136,491**
Less: Pass-through amount embedded in distribution rates *							(105,452)	(105,452)
DISTRIBUTION REVENUE			**467,150**				**563,889**	**1,031,039**

Customer Class Name	2010 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$4.9600	4,705	280,042	$0.0092	kWh	53,559,119	490,816	770,857
General Service Less Than 50 kW	$9.7300	566	66,086	$0.0051	kWh	20,562,650	105,610	171,696
General Service 50 to 4,999 kW	$46.5000	79	44,082	$0.5422	kW	229,814	124,605	168,687
Large Use	$6,464.0100			$1.6804	kW			
Sentinel Lighting	$1.0000	21	252	$5.1688	kW	325	1,680	1,932
Street Lighting	$0.0360	1,158	500	$3.3563	kW	3,096	10,391	10,891
Unmetered Scattered Load	$9.7300	4	467	$0.0051	kWh	220,667	1,125	1,592
Gross Revenue (before Transformer Allowances)			391,429				734,227	1,125,656
Transformer Allowances				($0.6000)	kW	184,071	(110,443)	(110,443)
Total Revenue			**391,429**				**623,784**	**1,015,214**
Less: Pass-through amount embedded in distribution rates *							(105,452)	(105,452)
DISTRIBUTION REVENUE			**391,429**				**518,332**	**909,761**

** per revenue amounts on sheet C2 e.g. Low Voltage*

C4 Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

Customer Class Name	PROJECTED REVENUE FROM DISTRIBUTION CHARGES AT EXISTING RATES					
	2009 Fixed %	2009 Variable %	2009 Total %	2010 Fixed %	2010 Variable %	2010 Total %
Residential	36.19%	63.81%	60.38%	36.33%	63.67%	68.48%
General Service Less Than 50 kW	38.56%	61.44%	13.49%	38.49%	61.51%	15.25%
General Service 50 to 4,999 kW	26.15%	73.85%	13.24%	26.13%	73.87%	14.99%
Large Use	51.85%	48.15%	11.76%			
Sentinel Lighting	13.04%	86.96%	0.15%	13.04%	86.96%	0.17%
Street Lighting	4.59%	95.41%	0.86%	4.59%	95.41%	0.97%
Unmetered Scattered Load	29.33%	70.67%	0.13%	29.33%	70.67%	0.14%
TOTAL	**41.10%**	**58.90%**	**100.00%**	**38.56%**	**61.44%**	**100.00%**

	2010 PROCEEDS FROM CURRENT MONTHLY SERVICE (FIXED) RATES					
Customer Class Name	Distribution	Smart Meters				TOTAL
Residential	280,042	56,460				336,502
General Service Less Than 50 kW	66,086	6,792				72,878
General Service 50 to 4,999 kW	44,082	948				45,030
Large Use						
Sentinel Lighting	252					252
Street Lighting	500					500
Unmetered Scattered Load	467					467
TOTAL	**391,429**	**64,200**				**455,629**

	2010 PROCEEDS FROM CURRENT VARIABLE RATES					
Customer Class Name	Distribution					TOTAL
Residential	490,816					490,816
General Service Less Than 50 kW	105,610					105,610
General Service 50 to 4,999 kW	124,605					124,605
Large Use						
Sentinel Lighting	1,680					1,680
Street Lighting	10,391					10,391
Unmetered Scattered Load	1,125					1,125
TOTAL	**734,227**					**734,227**

2010 PROJECTED DISTRIBUTION REVENUE AT NEW RATES								
Customer Class Name	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Rate**	**per**	**Volume**	**Variable Charge Revenue**	**TOTAL**
Residential	$5.9600	4,705	336,502	$0.0080	kWh	53,559,119	427,265	763,767
General Service Less Than 50 kW	$13.8000	566	93,730	$0.0056	kWh	20,562,650	114,427	208,157
General Service 50 to 4,999 kW	$94.4100	79	89,501	$1.7049	kW	229,814	391,820	481,320
Large Use		0			kW	0	0	0
Sentinel Lighting	$1.7100	21	431	$3.2418	kW	325	1,054	1,484
Street Lighting	$0.6000	1,158	8,338	$6.8897	kW	3,096	21,330	29,668
Unmetered Scattered Load	$7.1900	4	345	$0.0023	kWh	220,667	517	862
Gross Revenue (before Transformer Allowances)			528,846				956,414	1,485,259
Transformer Allowances				($0.6000)	kW	184,071	(110,443)	(110,443)
Total Revenue			528,846				845,971	1,374,817
Less: Pass-through amount embedded in distribution rates *							(105,452)	(105,452)
DISTRIBUTION REVENUE			**528,846**				**740,519**	**1,269,364**

* per revenue amounts on sheet C2 e.g. Low Voltage

Exhibit 3: Revenue

Tab 3 (of 3): Other Revenue

OTHER DISTRIBUTION REVENUE FROM SERVICE CHARGE

Other Distribution Revenue is any revenue that is distribution in nature but that is sourced from means other than distribution rates. It includes items such as

- Specific Service Charges
- Late Payment Charges
- Other Distribution Revenues
- Other Income and Expenses

A Specific Service Charge is an approved fixed rate charged to a customer for a specific activity or service, or as a penalty. Activities include services that are only available from, or under the control of, the distributor. There are also special or extra services that a distributor chooses to provide. Such services may be those that are of benefit to the distributor or to other customers, and that are provided at a customer's request or as the result of a customer's action or inaction. Specific Service Charges are established for activities that are over and above the distributor's standard level of service. The Board has outlined what it considers to be a standard level of service for a distributor in the Distribution System Code. The costs of providing the standard level of service are recovered in the regular distribution rates.

HHI's Trend Table of Revenue from Service Charges can be found at Exhibit 3, Tab 3, Schedule 1, Attachment 1 and details of the Other Operating Revenues are provided at Exhibit 3, Tab 3, Schedule 2, Attachment 1. A Variance analysis of the Other Operating Revenues is provided at Exhibit 3, Tab 3, Schedule 2.

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C8 Other Service Revenues

Enter volumes and rates for other distributor services

Service	USA #	2006 EDR Approved			2006 Actual		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	58,228	$0.25	14,557	56,566	$0.25	14,142
Arrears Certificate	4235	161	$15.00	2,415	119	$15.00	1,792
Statement of Account	4235		$15.00		63	$15.00	938
Duplicate invoices for previous billing	4235		$15.00		31	$15.00	469
New Services	4235				36	$250.00	9,000
Credit reference/credit check (plus credit agency costs)	4235		$15.00		31	$15.00	469
Returned Cheque charge (plus bank charges)	4235	219	$25.50	5,585	142	$25.50	3,619
Account set up charge / change of occupancy charge	4235	1,043	$30.00	31,290	785	$30.00	23,550
Meter dispute charge plus Measurement Canada fees (if meter found corr	4235		$30.00			$30.00	
Late Payment - per month	4225		1.50%		696,277	1.50%	10,444
Collection of account charge – no disconnection	4235	1,422	$15.00	21,330	1,479	$15.00	22,181
Disconnect/Reconnect at meter – during regular hours	4235	34	$30.00	1,020	212	$30.00	6,366
Disconnect/Reconnect at meter – after regular hours	4235	5	$130.00	650	4	$130.00	520
Retailer Service Agreement -- standard charge	4082		$100.00			$100.00	
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082		$20.00		91	$20.00	1,820
Retailer Service Agreement -- monthly variable charge (per customer)	4082		$0.50		7,759	$0.50	3,880
Distributor-Consolidated Billing -- monthly charge (per customer)	4082		$0.30		6,716	$0.30	2,015
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)		10	($0.30)	(3)
Service Transaction Request -- request fee (per request)	4084		$0.25		1,548	$0.25	387
Service Transaction Request -- processing fee (per processed request)	4084		$0.50		1,171	$0.50	586
TOTAL				**76,847**			**102,173**

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C8 Other Service Revenues

Enter volumes and rates for other distributor services

Service	USA #	2007 Actual			2008 Actual		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	56,234	$0.25	14,059	57,040	$0.25	14,260
Arrears Certificate	4235	162	$15.00	2,435	160	$15.00	2,400
Statement of Account	4235	148	$15.00	2,215	70	$15.00	1,051
Duplicate invoices for previous billing	4235	74	$15.00	1,107	45	$15.00	671
New Services	4235	25	$250.00	6,300	26	$250.00	6,500
Credit reference/credit check (plus credit agency costs)	4235	74	$15.00	1,107	97	$15.00	1,455
Returned Cheque charge (plus bank charges)	4235	141	$25.50	3,596	115	$25.50	2,933
Account set up charge / change of occupancy charge	4235	1,131	$30.00	33,930	936	$30.00	28,080
Meter dispute charge plus Measurement Canada fees (if meter found corr	4235		$30.00			$30.00	
Late Payment - per month	4225	701,415	1.50%	10,521	1,991,200	1.50%	29,868
Collection of account charge – no disconnection	4235	1,562	$15.00	23,432	1,922	$15.00	28,826
Disconnect/Reconnect at meter – during regular hours	4235	141	$30.00	4,230	105	$30.00	3,150
Disconnect/Reconnect at meter – after regular hours	4235	5	$130.00	650	2	$130.00	260
Retailer Service Agreement -- standard charge	4082	1	$100.00	100		$100.00	
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	64	$20.00	1,280	96	$20.00	1,920
Retailer Service Agreement -- monthly variable charge (per customer)	4082	10,157	$0.50	5,079	6,220	$0.50	3,110
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	8,261	$0.30	2,478	4,926	$0.30	1,478
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)			($0.30)	
Service Transaction Request -- request fee (per request)	4084	1,208	$0.25	302	426	$0.25	107
Service Transaction Request -- processing fee (per processed request)	4084	575	$0.50	288	302	$0.50	151
TOTAL				**113,109**			**126,218**

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C8 Other Service Revenues

Enter volumes and rates for other distributor services

		2009 Projection			2010 Projection (existing rates)		
Service	**USA #**	**Volume**	**Rate**	**Revenue**	**Volume**	**Rate**	**Revenue**
Standard Supply Service -- Administrative Charge	4080	56,613	$0.25	14,153	56,613	$0.25	14,153
Arrears Certificate	4235	78	$15.00	1,170	95	$15.00	1,425
Statement of Account	4235	61	$15.00	915	75	$15.00	1,125
Duplicate invoices for previous billing	4235	30	$15.00	450	40	$15.00	600
New Services	4235	20	$250.00	5,000	25	$250.00	6,250
Credit reference/credit check (plus credit agency costs)	4235	32	$15.00	480	40	$15.00	600
Returned Cheque charge (plus bank charges)	4235	133	$25.50	3,382	133	$25.50	3,382
Account set up charge / change of occupancy charge	4235	805	$30.00	24,150	850	$30.00	25,500
Meter dispute charge plus Measurement Canada fees (if meter found corr	4235	1	$30.00	30	1	$30.00	30
Late Payment - per month	4225	2,125,000	1.50%	31,875	2,125,000	1.50%	31,875
Collection of account charge – no disconnection	4235	1,895	$15.00	28,425	1,895	$15.00	28,425
Disconnect/Reconnect at meter – during regular hours	4235	135	$30.00	4,050	145	$30.00	4,350
Disconnect/Reconnect at meter – after regular hours	4235	3	$130.00	390	3	$130.00	390
Retailer Service Agreement -- standard charge	4082	2	$100.00	200	1	$100.00	100
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	84	$20.00	1,673	84	$20.00	1,673
Retailer Service Agreement -- monthly variable charge (per customer)	4082	8,045	$0.50	4,023	8,045	$0.50	4,023
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	6,634	$0.30	1,990	6,634	$0.30	1,990
Retailer-Consolidated Billing -- monthly credit (per customer)	4082	3	($0.30)	(1)	3	($0.30)	(1)
Service Transaction Request -- request fee (per request)	4084	1,061	$0.25	265	1,061	$0.25	265
Service Transaction Request -- processing fee (per processed request)	4084	683	$0.50	341	683	$0.50	341
TOTAL				**122,963**			**126,498**

OTHER REVENUE VARIANCE ANALYSIS

Specific Service Charges, Late Payment Charges, Other Distribution Revenues, Other Income and Expenses

The forecast of revenue to be received from the specific service charges for 2009 and 2010 is determined by the trend presented in the load forecast. The projections provide for existing trends to continue, but incorporating any known factors that would affect the revenue projections. HHI proposes to continue to charge all of the previously authorized specific service charges at the same rates, and does not propose to add any new charges at this time.

As can be seen from the details presented at Exhibit 3, Tab 3, Schedule 2, Attachment 1, the revenues from specific service charges vary each year.

2006 Actual compared to 2006 Approved EDR.

The 2006 Actual total Other Revenue ($136,420) or 102.82.0% higher than the 2006 Approved total Other Revenue. This increase is due primarily to the customer growth during that period. Two subdivisions were built in HHI' service area during that period.

2007 Actual compared to 2006 Actual

The 2007 Actual total Other Revenue ($35,476) or 13.18% higher than the 2006 Actual total Other Revenue. This amount falls below the materiality threshold.

2008 Actual compared to 2007 Actual

The 2008 Actual total Other Revenue ($34,634) or 11.37% lower than the 2007 Actual total Other Revenue. This amount falls below the materiality threshold.

2009 Bridge compared to 2008 Actual

The 2009 Bridge Year Other Revenue is $98,472 or -36.48% lower than the 2008 Actual total Other Revenue. This decrease during 2009 is partly attributable to a decrease in interest in dividend income. This is due to the low interest rates during that period.

2010 Test compared to 2009 Bridge

The 2010 Actual total Other Revenue ($8,534) or 4.98% lower than the 2009 Bridge total Other Revenue. This amount falls below the materiality threshold.

Other Revenue Variances Table

	2010 @ new dist. rates	2010 @ existing rates	Var $	Var %	2010 @ existing rates	2009 Projection	Var $	Var %
Other Distribution Revenues								
4080-Distribution Services Revenue	(14,153.34)	(14,153.34)		0.00%	(14,153.34)	(14,153.34)	-	0.00%
4082-Retail Services Revenues	(7,785.30)	(7,785.30)	-	0.00%	(7,785.30)	(7,885.30)	100.00	-1.27%
4084-Service Transaction Requests (STR) Revenues	(606.50)	(606.50)	-	0.00%	(606.50)	(606.50)	-	0.00%
4210-Rent from Electric Property	(16,000.00)	(16,000.00)	-	0.00%	(16,000.00)	(16,000.00)	-	0.00%
	(38,545.14)	(38,545.14)	-	0.00%	(38,545.14)	(38,645.14)	100.00	-0.26%
Late Payment Charges								
4225-Late Payment Charges	(31,875.00)	(31,874.00)	-	0.00%	(31,874.00)	(31,875.00)	1.00	0.00%
	(31,875.00)	(31,874.00)	-	0.00%	(31,874.00)	(31,875.00)	1.00	0.00%
Specific Service Charges								
4235-Miscellaneous Service Revenues	(72,077.49)	(72,077.49)	-	0.00%	(72,077.49)	(68,442.49)	(3,635.00)	5.31%
	(72,077.49)	(72,077.49)	-	0.00%	(72,077.49)	(68,442.49)	(3,635.00)	5.31%
Other Income and Expenses								
4325-Revenues from Merchandise, Jobbing, Etc.	(45,000.00)	(45,000.00)	-	0.00%	(45,000.00)	(45,000.00)	-	0.00%
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	25,000.00	25,000.00	-	0.00%	25,000.00	25,000.00	-	0.00%
4390-Miscellaneous Non-Operating Income	(500.00)	(500.00)	-	0.00%	(500.00)	(500.00)	-	0.00%
4405-Interest and Dividend Income	(17,000.00)	(17,000.00)	-	0.00%	(17,000.00)	(12,000.00)	(5,000.00)	41.67%
	(37,500.00)	(37,500.00)	-	0.00%	(37,500.00)	(32,500.00)	(5,000.00)	15.38%
TOTAL	(179,997.63)	(179,996.63)	-	0.00%	(179,996.63)	(171,462.63)	(8,534.00)	4.98%

	2009 Projection	2008 Actual	Var $	Var %	2008 Actual	2007 Actual	Var $	Var %
Other Distribution Revenues								
4080-Distribution Services Revenue	(14,153.34)	(14,260.00)	106.66	-0.75%	(14,260.00)	(14,059.00)	(201.00)	1.43%
4082-Retail Services Revenues	(7,885.30)	(6,508.00)	(1,377.30)	21.16%	(6,508.00)	(8,937.00)	2,429.00	-27.18%
4084-Service Transaction Requests (STR) Revenues	(606.50)	(258.00)	(348.50)	135.08%	(258.00)	(590.00)	332.00	-56.27%
4210-Rent from Electric Property	(16,000.00)	(16,465.91)	465.91	-2.83%	(16,465.91)	(17,894.48)	1,428.57	-7.98%
	(38,645.14)	(37,491.91)	(1,153.23)	3.08%	(37,491.91)	(41,480.48)	3,988.57	-9.62%
Late Payment Charges								
4225-Late Payment Charges	(31,875.00)	(29,867.86)	(2,007.14)	6.72%	(29,867.86)	(10,521.22)	(19,346.64)	183.88%
	(31,875.00)	(29,867.86)	(2,007.14)	6.72%	(29,867.86)	(10,521.22)	(19,346.64)	183.88%
Specific Service Charges								
4235-Miscellaneous Service Revenues	(68,442.49)	(75,323.93)	6,881.44	-9.14%	(75,323.93)	(79,001.38)	3,677.45	-4.65%
	(68,442.49)	(75,323.93)	6,881.44	-9.14%	(75,323.93)	(79,001.38)	3,677.45	-4.65%
Other Income and Expenses								
4325-Revenues from Merchandise, Jobbing, Etc.	(45,000.00)	(50,833.34)	5,833.34	-11.48%	(50,833.34)	(88,846.59)	38,013.25	-42.79%
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	25,000.00	19,864.73	5,135.27	25.85%	19,864.73	37,287.31	(17,422.58)	-46.73%
4390-Miscellaneous Non-Operating Income	(500.00)	(470.90)	(29.10)	6.18%	(470.90)	(1,464.60)	993.70	-67.85%
4405-Interest and Dividend Income	(12,000.00)	(95,812.13)	83,812.13	-87.48%	(95,812.13)	(120,552.04)	24,739.91	-20.52%
	(32,500.00)	(127,251.64)	94,751.64	-74.46%	(127,251.64)	(173,575.92)	46,324.28	-26.69%
TOTAL	(171,462.63)	(269,935.34)	98,472.71	-36.48%	(269,935.34)	(304,579.00)	34,643.66	-11.37%

	2007 Actual	2006 Actual	Var $	Var %	2006 Actual	2006 EDR Approved	Var $	Var %
Other Distribution Revenues								
4080-Distribution Services Revenue	(14,059.00)	(14,142.00)	83.00	-0.59%	(14,142.00)	(14,557.00)	415.00	-2.85%
4082-Retail Services Revenues	(8,937.00)	(7,711.00)	(1,226.00)	15.90%	(7,711.00)	-	(7,711.00)	0.00%
4084-Service Transaction Requests (STR) Revenues	(590.00)	(973.00)	383.00	-39.36%	(973.00)	-	(973.00)	0.00%
4210-Rent from Electric Property	(17,894.48)	(16,429.73)	(1,464.75)	8.92%	(16,429.73)	(17,573.49)	1,143.76	-6.51%
	(41,480.48)	(39,255.73)	(2,224.75)	5.67%	(39,255.73)	(32,130.49)	(7,125.24)	22.18%
Late Payment Charges								
4225-Late Payment Charges	(10,521.22)	(10,444.15)	(77.07)	0.74%	(10,444.15)	(9,483.09)	(961.06)	10.13%
	(10,521.22)	(10,444.15)	(77.07)	0.74%	(10,444.15)	(9,483.09)	(961.06)	10.13%
Specific Service Charges								
4235-Miscellaneous Service Revenues	(79,001.38)	(68,903.09)	(10,098.29)	14.66%	(68,903.09)	(30,617.49)	(38,285.60)	125.04%
	(79,001.38)	(68,903.09)	(10,098.29)	14.66%	(68,903.09)	(30,617.49)	(38,285.60)	125.04%
Other Income and Expenses								
4325-Revenues from Merchandise, Jobbing, Etc.	(88,846.59)	(113,193.68)	24,347.09	-21.51%	(113,193.68)	(62,398.77)	(50,794.91)	81.40%
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	37,287.31	41,849.94	(4,562.63)	-10.90%	41,849.94	40,731.13	1,118.81	2.75%
4390-Miscellaneous Non-Operating Income	(1,464.60)	(831.00)	(633.60)	76.25%	(831.00)	(3,267.50)	2,436.50	-74.57%
4405-Interest and Dividend Income	(120,552.04)	(78,325.15)	(42,226.89)	53.91%	(78,325.15)	(35,516.56)	(42,808.59)	120.53%
	(173,575.92)	(150,499.89)	(23,076.03)	15.33%	(150,499.89)	(60,451.70)	(90,048.19)	148.96%
TOTAL	(304,579.00)	(269,102.86)	(35,476.14)	13.18%	(269,102.86)	(132,682.77)	(136,420.09)	102.82%

REVENUE OFFSETS

The following attachment presents HHI's revenue offsets for the bridge and test year. The total of revenue offsets are deducted from the Service Revenue Requirement to generate the base revenue amount to be realized from distribution rates. In the case of HHI, revenue offsets include a small portion of Distribution Services Revenue attributed to SSS administration charge, Retail Service Revenue which include items such retail service agreement, and Miscellaneous Service Revenues that include items such as late payment charges, return cheques, set up fee and collection charges. Details of Revenue Offsets are presented at Exhibit 3, Tab 3, Schedule 3, Attachment 1.

C9 Revenue Offset Projections

Account Grouping	Account Description	2009 Service Projection	2009 Other (+ / -)	2009 Total	2010 (existing rates) Service Projection	2010 (existing rates) Other (+ / -)	2010 (existing rates) Total	201 Service Projection
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	14,153		14,153	14,153		14,153	14,153
	4082-Retail Services Revenues	7,885		7,885	7,785		7,785	7,785
	4084-Service Transaction Requests (STR) Revenues	607		607	607		607	607
	4090-Electric Services Incidental to Energy Sales							
3100-Other Operating Revenues	4205-Interdepartmental Rents							
	4210-Rent from Electric Property		16,000	16,000		16,000	16,000	
	4215-Other Utility Operating Income							
	4220-Other Electric Revenues							
	4225-Late Payment Charges	31,875		31,875	31,875		31,875	31,875
	4230-Sales of Water and Water Power							
	4235-Miscellaneous Service Revenues	68,442		68,442	72,077		72,077	72,077
	4240-Provision for Rate Refunds							
	4245-Government Assistance Directly Credited to Income							
3150-Other Income & Deductions	4305-Regulatory Debits							
	4310-Regulatory Credits							
	4315-Revenues from Electric Plant Leased to Others							
	4320-Expenses of Electric Plant Leased to Others							
	4325-Revenues from Merchandise, Jobbing, Etc.		45,000	45,000		45,000	45,000	
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.		(25,000)	(25,000)		(25,000)	(25,000)	
	4335-Profits and Losses from Financial Instrument Hedges							
	4340-Profits and Losses from Financial Instrument Investments							
	4345-Gains from Disposition of Future Use Utility Plant							
	4350-Losses from Disposition of Future Use Utility Plant							
	4355-Gain on Disposition of Utility and Other Property							
	4360-Loss on Disposition of Utility and Other Property							
	4365-Gains from Disposition of Allowances for Emission							
	4370-Losses from Disposition of Allowances for Emission							
	4390-Miscellaneous Non-Operating Income		500	500		500	500	
	4395-Rate-Payer Benefit Including Interest							
	4398-Foreign Exchange Gains and Losses, Including Amortization							
3200-Investment Income	4405-Interest and Dividend Income		12,000	12,000		17,000	17,000	
TOTAL		**122,963**	**48,500**	**171,463**	**126,498**	**53,500**	**179,998**	**126,498**

C9 Revenue Offset Projections

Service Projections from Sheet C8

Account Grouping	Account Description	0 (proposed rates) Other (+ / -)	Total	Offset Input %	or	$	2010 Offset Amount
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue		14,153	100%			14,153
	4082-Retail Services Revenues		7,785	100%			7,785
	4084-Service Transaction Requests (STR) Revenues		607	100%			607
	4090-Electric Services Incidental to Energy Sales						
3100-Other Operating Revenues	4205-Interdepartmental Rents						
	4210-Rent from Electric Property	16,000	16,000	100%			16,000
	4215-Other Utility Operating Income						
	4220-Other Electric Revenues						
	4225-Late Payment Charges		31,875	100%			31,875
	4230-Sales of Water and Water Power						
	4235-Miscellaneous Service Revenues		72,077	100%			72,077
	4240-Provision for Rate Refunds						
	4245-Government Assistance Directly Credited to Income						
3150-Other Income & Deductions	4305-Regulatory Debits						
	4310-Regulatory Credits						
	4315-Revenues from Electric Plant Leased to Others						
	4320-Expenses of Electric Plant Leased to Others						
	4325-Revenues from Merchandise, Jobbing, Etc.	45,000	45,000	100%			45,000
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	(25,000)	(25,000)	100%			(25,000)
	4335-Profits and Losses from Financial Instrument Hedges						
	4340-Profits and Losses from Financial Instrument Investments						
	4345-Gains from Disposition of Future Use Utility Plant						
	4350-Losses from Disposition of Future Use Utility Plant						
	4355-Gain on Disposition of Utility and Other Property						
	4360-Loss on Disposition of Utility and Other Property						
	4365-Gains from Disposition of Allowances for Emission						
	4370-Losses from Disposition of Allowances for Emission						
	4390-Miscellaneous Non-Operating Income	500	500	100%			500
	4395-Rate-Payer Benefit Including Interest						
	4398-Foreign Exchange Gains and Losses, Including Amortization						
3200-Investment Income	4405-Interest and Dividend Income	17,000	17,000	100%			17,000
TOTAL		**53,500**	**179,998**				**179,998**

Exhibit 4:

OPERATING COSTS

Exhibit 4: Operating Costs

Tab 1 (of 8): Manager's Summary

OVERALL COST TRENDS

For its test year, HHI is proposing OM&A costs totaling $965,143. These expenses are necessary to fund an integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements, regulatory requirements and Government direction; and to maintain distribution business service quality and reliability at targeted performance levels. These costs also include providing services to customers connected to HHI's distribution system, and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

The proposed OM&A spending for the 2010 test year results from a detailed review of 2007 and 2008 actual expenditures, business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place.

As can be seen in the Operating Cost Trend Table at Exhibit 4, Tab 1, Schedule 1, Attachment 1, HHI has diligently managed its controllable costs over the last six years at an average increase of less than 2.8% per annum or $24.5K over the six year period.

The comparable increases for Operations, Billing, Maintenance and Administration are 6.2%, 3.4%, 5.7% and 0.5% respectively.

HHI make every effort to prudently manage its internal costs while ensuring that the quality and reliability of its network meets the expectations of its customers and the Board's service quality benchmarks.

The cost drivers behind this marginal increase are discussed in detail at Exhibit 4, Tab 2, Schedule 1.

Appendix 1-2

Operating Trend Table

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
3500-Distribution Expenses - Operation	52,662	51,684	54,765	64,402	72,789	75,463	75,463
3550-Distribution Expenses - Maintenance	123,155	130,222	175,050	159,889	173,142	171,887	171,887
3650-Billing and Collecting	267,315	228,770	236,346	303,877	314,905	327,572	327,572
3700-Community Relations	100	60,810	12,668	100	104	2,108	2,108
3950-Taxes Other Than Income Taxes	24,654	25,171	25,634	26,205	26,916	28,262	28,262
OM&A Expenses	818,074	770,907	794,632	823,628	873,492	965,143	965,143

Exhibit 4: Operating Costs

Tab 2 (of 8): Summary and Cost Driver Tables

OM&A COSTS

This section provides various tables presenting HHI's OM&A Cost Drivers. Cost Drivers are the components of an activity that cause the cost of the activity to change. In the case of HHI, OM&A costs are expected to increase by $147,069 or 18% in the 2010 Test Year over 2006 EDR, representing an average annual increase of $24,512 or 2.79% per annum. These cost increases are necessary in order to maintain distribution business service quality and reliability at targeted performance levels.

The following items will be discussed in the subsequent schedules:

- Exhibit 4, Tab 2, Schedule 1, Attachment 1 contains the Summary of OM&A Expenses;
- Exhibit 4, Tab 2, Schedule 1, Attachment 2 contains the Detailed Account by Account of OM&A Expenses;
- Exhibit 4,Tab 2, Schedule 1, Attachment 3 contains the OM&A Cost Driver Table;
- Exhibit 4, Tab 2, Schedule 1, Attachment 4 contains the Regulatory Costs Table;
- Exhibit 4, Tab 2, Schedule 1, Attachment 5 contains the OM&A per Customer and per Full Time Equivalent;

One-time costs and regulatory costs are discussed in detail at Exhibit 4, Tab 2, Schedule 2 and Exhibit 4, Tab 2, Schedule 3, respectively.

Summary of OM&A Variances Table

Account Grouping	2010 @ existing rates	2009 Projection	Var $	Var %	2009 Projection	2008 Actual	Var $	Var $
3500-Distribution Expenses - Operation	$ 75,463.00	$ 72,788.00	$ 2,675.00	4%	$ 72,788.00	$ 64,402.00	$ 8,386.00	13%
3550-Distribution Expenses - Maintenance	$ 171,887.00	$ 173,142.00	$ (1,255.00)	-1%	$ 173,142.00	$ 159,889.00	$ 13,253.00	8%
3650-Billing and Collecting	$ 327,572.00	$ 314,905.00	$ 12,667.00	4%	$ 314,905.00	$ 303,877.00	$ 11,028.00	4%
3700-Community Relations	$ 2,108.00	$ 104.00	$ 2,004.00	1927%	$ 104.00	$ 100.00	$ 4.00	4%
3800-Administrative and General Expenses	$ 359,851.00	$ 285,636.00	$ 74,215.00	26%	$ 285,636.00	$ 269,155.00	$ 16,481.00	6%
3950-Taxes Other Than Income Taxes	$ 28,262.00	$ 26,916.00	$ 1,346.00	5%	$ 26,916.00	$ 26,205.00	$ 711.00	3%
TOTAL	**$ 965,143.00**	**$ 873,491.00**	**$ 90,306.00**	10%	**$ 873,491.00**	**$ 823,628.00**	**$ 49,152.00**	6%

Account Grouping	2008 Actual	2007 Actual	Var $	Var %	2007 Actual	2006 Actual	Var $	Var $
3500-Distribution Expenses - Operation	$ 64,402.00	$ 54,765.00	$ 9,637.00	18%	$ 54,765.00	$ 51,684.00	$ 3,081.00	6%
3550-Distribution Expenses - Maintenance	$ 159,889.00	$ 175,050.00	$ (15,161.00)	-9%	$ 175,050.00	$ 130,222.00	$ 44,828.00	34%
3650-Billing and Collecting	$ 303,877.00	$ 236,346.00	$ 67,531.00	29%	$ 236,346.00	$ 228,770.00	$ 7,576.00	3%
3700-Community Relations	$ 100.00	$ 12,668.00	$ (12,568.00)	-99%	$ 12,668.00	$ 60,810.00	$ (48,142.00)	-79%
3800-Administrative and General Expenses	$ 269,155.00	$ 290,168.00	$ (21,013.00)	-7%	$ 290,168.00	$ 274,250.00	$ 15,918.00	6%
3950-Taxes Other Than Income Taxes	$ 26,205.00	$ 25,634.00	$ 571.00	2%	$ 25,634.00	$ 25,171.00	$ 463.00	2%
TOTAL	**$ 823,628.00**	**$ 794,631.00**	**$ 28,426.00**	4%	**$ 794,631.00**	**$ 770,907.00**	**$ 23,261.00**	3%

Account Grouping	2006 Actual	2006 EDR Approved	Var $	Var %
3500-Distribution Expenses - Operation	$ 51,684.00	$ 52,662.00	$ (978.00)	-2%
3550-Distribution Expenses - Maintenance	$ 130,222.00	$ 123,155.00	$ 7,067.00	6%
3650-Billing and Collecting	$ 228,770.00	$ 267,315.00	$ (38,545.00)	-14%
3700-Community Relations	$ 60,810.00	$ 100.00	$ 60,710.00	60710%
3800-Administrative and General Expenses	$ 274,250.00	$ 350,188.00	$ (75,938.00)	-22%
3950-Taxes Other Than Income Taxes	$ 25,171.00	$ 24,654.00	$ 517.00	2%
TOTAL	**$ 770,907.00**	**$ 818,074.00**	**$ (47,684.00)**	-6%

Percent Change Test year vs. Most Current Actuals	**17%**
Percent Change Test year vs. Last Board Approved Rebasing Year	**18%**
Average for Y1, Y2, Y3	**$ 796,388.67**

Over the course of 6 periods the OM&A Costs grew from $818,074 to $965,143.00, its compound annual growth rate, or overall return, is **2.79%.**

Hydro Hawkesbury Inc. (ED-2003-0027)

2010 EDR Application (EB-2009-0186) version: v0.1
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Bridge and Test OM&A Expenses

Enter projected expenses for Operations, Maintenance and Administration

Account Grouping	Account Description	2008 Actual	2009 Projection	2010 Projection
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	10,813	11,245	11,695
	5015-Transformer Station Equipment - Operation Supplies and Expenses	11,967	12,446	12,944
	5016-Distribution Station Equipment - Operation Labour	8,942	9,300	9,672
	5017-Distribution Station Equipment - Operation Supplies and Expenses	61	63	66
	5020-Overhead Distribution Lines and Feeders - Operation Labour	9,388	9,763	10,154
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,036	1,077	1,120
	5035-Overhead Distribution Transformers- Operation	4,327	11,813	12,046
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,970	2,048	2,130
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	24	24	25
	5055-Underground Distribution Transformers - Operation	2,279	2,370	2,465
	5065-Meter Expense	12,567	11,569	12,032
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,030	1,071	1,114
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,452	4,630	4,815
	5120-Maintenance of Poles, Towers and Fixtures	10,561	16,160	18,022
	5125-Maintenance of Overhead Conductors and Devices	31,598	32,545	32,799
	5130-Maintenance of Overhead Services	31,173	32,108	33,392
	5135-Overhead Distribution Lines and Feeders - Right of Way	42,795	50,795	44,827
	5145-Maintenance of Underground Conduit	1,108	1,152	1,198
	5150-Maintenance of Underground Conductors and Devices	17,193	17,881	18,596
	5155-Maintenance of Underground Services	6,635	6,900	7,176
	5160-Maintenance of Line Transformers	2,184	2,271	2,362
	5175-Maintenance of Meters	12,192	8,700	8,700

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Bridge and Test OM&A Expenses

Enter projected expenses for Operations, Maintenance and Administration

Account Grouping	Account Description	2008 Actual	2009 Projection	2010 Projection
3650-Billing and Collecting	5310-Meter Reading Expense	30,858	32,092	33,376
	5315-Customer Billing	171,856	178,731	185,880
	5320-Collecting	93,858	96,460	100,389
	5325-Collecting- Cash Over and Short	(23)		
	5335-Bad Debt Expense	7,329	7,622	7,927
3700-Community Relations	5410-Community Relations - Sundry	100	104	2,108
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	93,537	100,278	107,289
	5610-Management Salaries and Expenses	63,458	68,997	74,757
	5620-Office Supplies and Expenses	20,065	20,868	21,702
	5630-Outside Services Employed	16,898	17,574	43,817
	5635-Property Insurance	4,344	4,517	4,698
	5640-Injuries and Damages	11,489	11,949	12,427
	5645-Employee Pensions and Benefits	3,420	3,556	3,699
	5655-Regulatory Expenses	9,773	10,164	41,820
	5665-Miscellaneous General Expenses	12,500	13,000	13,520
	5675-Maintenance of General Plant	28,563	29,420	30,596
	5680-Electrical Safety Authority Fees	5,109	5,313	5,526
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	26,205	26,916	28,262
TOTAL		**823,628**	**873,492**	**965,143**

OM&A Cost Drivers Table

Increases

OM&A	2006 Actual	Change	2007 Actual	Change	2008 Actual	Change	2009 Test	2009 Bridge	2010 Test	Change
Cost Driver #1	5415-Energy Conservation	$ 60,710.00	5125-Maintenance of Overhead Conductors and Devices	$ 17,085.00	5320-Collecting	$ 35,358.00			5630-Outside Services Employed	$ 26,243.00
Cost Driver #2			5135-Overhead Distribution Lines and Feeders - Right of Way		5320-Customer Billing	$ 31,813.00			5655-Regulatory Expenses	$ 32,656.00
Cost Driver #3					5015-Transformer Station Equipment - Operation Supplies and Expenses	$ 16,648.00				

Decrease

Cost Driver #4	5665-Miscellaneous General Expenses	$ (108,068.00)	5415-Energy Conservation	$ (48,370.00)	5125-Maintenance of Overhead Conductors and Devices	$ (27,551.00)				
Cost Driver #6	5320-Customer Billing	$ (34,854.00)	5015-Transformer Station Equipment - Operation Supplies and Expenses	$ (10,667.00)	5630-Outside Services Employed	$ (13,931.00)				
	5130-Maintenance of Overhead Services	$ (25,650.00)			5415-Energy Conservation	$ (12,340.00)				
	5630-Outside Services Employed	$ (11,750.00)								
NET CHANGE		**$ (119,612.00)**		**$ (41,952.00)**		**$ 29,997.00**				**$ 58,899.00**

Regulatory Costs Table

Regulatory Cost Category		USoA Account	USoA Account Balance at Dec 31/08	Ongoing or One-time Cost?	Last Rebasing Year	Last Year of Actuals	Test Year Forecast	IRM 1st Gen	IRM 2nd Gen	IRM 3rd Gen
1. OEB Annual Assessment		5655	$ 5,364.00	Ongoing		$ 4,200.00	$ 4,200.00	$ 4,200.00	$ 4,200.00	$ 4,200.00
2. OEB Hearing Assessments (applicant initiated)		5655								
3. OEB Section 30 Costs (OEB initiated)		5655								
4. Expert Witness cost for regulatory matters		5655					$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00
5. Legal costs for regulatory matters		5655								
6. Consultants costs for regulatory matters	ERA	5655		Every rabasing period			$ 23,750.00	$ 23,750.00	$ 23,750.00	$ 23,750.00
7. Operating expenses associated with staff resources allocated to regulatory matters		5655								
8. Operating expenses associated with other resources allocated to regulatory matters (please identify the)		5655		Every rabasing period			$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00
9. Other regulatory agency fees or assessments		5655								
10. Any other costs for regulatory matters (notice of application in the newspaper, notice of new rates)		5655		Ongoing		$ 1,163.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00
11. Intervenor Costs		5655		Every rabasing period			$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00

Total cost of rebasing

4. Expert Witness cost for regulatory matters		**$ 5,000.00**
6.Consultants costs for regulatory matters		**$ 95,000.00**
Evidence Drafting		$ 65,000.00
Strategic Review		$ 5,000.00
Load Forecast		$ 5,000.00
Revisions to Cost Allocation		$ 5,000.00
accounting costs		$ 15,000.00
11.Interrogatories and Interveener cost		**$ 10,000.00**
10.rate order		**$ 5,000.00**

2010 EDR Model		**$ 10,000.00**
2012 EDR Total		**$ 125,000.00**

Note: The Minimum Filing Requirement state the following:
The amortization period would normally be the duration of the expected cost of service plus IRM term. If the applicant is proposing a different amortization period, it should explain why it believes this is

HHI proposes to amortize cost related to the rebasing application over a period of 4 years. The summary shown here is the total cost of rebasing

OM&A per Customer and per Full Time Equivalent

	2006 EDR	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test	2010 Test	Avg
							without rebasing and IFRS	
Number of Customers	6410	6468	6609	6556	6502	6533	6533	6513
Total OMA	$818,074.00	$770,907.00	$794,631.00	$823,628.00	$873,491.00	$965,143.00	$780,133.00	$840,977.33
OMA cost per Customer	$127.62	$119.19	$120.23	$125.63	$134.34	$147.73	$119.41	$129.12
Number of FTEEs	7	7	7	8	8	8	8	8
FTEEs/Customer	$915.71	$924.00	$944.14	$819.50	$812.75	$816.63	$816.63	$872.12
OMA cost per FTEE	$116,867.71	$110,129.57	$113,518.71	$102,953.50	$109,186.38	$120,641.63	$97,516.63	$112,216.25

As shown in the table above, the OMA costs per customer in the Test Year have risen by only $20 (15.7%) over six years, representing an annual increase of $3.33 (2.47%) or roughly $0.28 per month per customer. When the regulatory and IFRS costs are removed from the test year expenditures to make the 2004 and 2010 cost components more comparable, the cost per customer shows a marginal increase of less than $2.00 per customer, over the period.

ONE-TIME COSTS

ASSESSMENT OF TWO (2) 7.5/10/12.5 MVA

HHI is seeking the outside services to provide the engineering and technical services to perform testing and inspection of two (2) 7.5/10/12.5 MVA power transformers and provide a condition assessment of each transformer. This study is part of HHI effort to asses it own assets. The two transformers are approximately 45 year of age and are showing signs of deterioration. Their operating condition is a growing concern for the utility and its customers. The study will provide a detailed report outlining the overall condition of each transformer, its components and accessories. The study will involve the following inspections;

<u>Mechanical Inspections</u>

The following devices will be visually inspected:

- Main tank and conservator tank
- Oil levels in the main tank and conservator tank
- Radiators and cooling fans
- Gas detector and sudden pressure relays
- Pressure relief device
- Oil and winding temperature gauges
- High and low voltage bushings
- Valves and piping
- Control, VT and CT wiring

- Control Devices

Oil Sample Analysis

The following analysis will be performed on the insulating fluid in the main tank and on-load tapchanger:

- Standard (including dielectric breakdown, neutralization number, interfacial tension, specific gravity, colour and visual condition)
- Water content
- Power Factor 25C
- PCB ppm

The dielectric breakdown analysis will be performed to the ASTM-1816 standard which is the current method recommend by the IEEE.

The following analysis will be performed on the insulating fluid in the main tank only:

- Dissolved gas-in-oil
- Furan analysis
- Inhibitor

Electrical Inspections

The following electrical testing will be performed:

- Turns ratio test
- Insulation resistance (Megger) tests will be conducted on the primary and secondary windings

- Dielectric absorption test on the primary and secondary windings
- Winding resistance test on the primary and secondary windings
- Core ground test, if applicable
- Capacitance and Power factor (Doble) tests on the primary and secondary windings
- Capacitance and Power factor (Doble) tests on each HV bushing utilizing the cap tap connection.

Mechanical Inspection

Inspect the physical condition of the following internal components:

- Stationary Current Carrying Contacts
- Moving Current Carrying Contacts
- Arcing Switch Contacts
- Drive mechanism (gears & springs)
- Tap Position Indicators
- Total Number of Operations
- Gaskets and Seals
- Bushings

****Electrical and Oil Testing included with Transformer Testing**

The cost of this study is estimated at $42,160. This amount is to be amortized over a period of 4 years. HHI recorded the amount of $10,540 to account 5630 – Outside services employed.

IFRS

The Canadian Accounting Standards Board ("AcSB") is requiring all publicly accountable companies to transition from Canadian Generally Accepted Accounting Principles ("GAAP") to International Financial Reporting Standards ("IFRS") in 2011. This includes HHI and most Local Distribution Companies ("LDCs") in the province.

The transition to IFRS will have a major impact on certain aspects of HHI's operations and require significant incremental financial resources. Since HHI does not have the internal resources to comply with this requirement, HHI will employ external resources to effectively transition to IFRS. In addition to an increase in outside services, HHI anticipates that it will require and upgrade in its accounting system. A cost of $60,000 has therefore been projected in 2010 rates. This amount is to be amortized over a period of 4 years. HHI recorded the amount of $15,000 to account 5630 – Outside services employed.

Listed below is a high level project plan of how HHI anticipates using these funds.

<u>Pre-implementation</u>

- Appoint a project team (opt to outsource resources)
- Learning about IFRS
- Assess the impact of IFRS on the utility
- Drafting of a project plan

IFRS Implementation: Phase 1

IFRS Analysis

- Preliminary analysis of the potential impact
- Analysis of existing accounting structure
- Identification of gaps between both systems
- Establishing new accounting rules
- Establishing regulatory filing requirement

IFRS Implementation: Phase 2

Analysis

- Detailed revision of information processes and application
- Identification of software upgrade
- Definition of organizational responsibility
- Decision to opt for coexistence or migration (based on regulatory requirements).

Design and Development

- Definition of technical and functional specifications
- System and process implementation
- Presentation to Board Members

<u>Implementation</u>

- Compliance test
- Process test
- Accounting manuals
- Board of Director approval

With respect to regulatory costs, HHI does consider it to be an on-going cost. In HHI' expects that it will incur similar levels of cost in the four years. A detailed description of the required regulatory costs is provided in Exhibit 4, Tab 2, Schedule 3.

REGULATORY COSTS

HHI estimated the consulting fees of rebasing to be $125,000. For the purpose of putting together the 2010 Rate Application, HHI engaged the services of Elenchus Research Associates ("ERA"). The need to hire external consultants was driven first and foremost by the lack of internal resources to put together such a detailed and time-consuming submission. In addition, HHI's staff and management are primarily French speaking and while the Board will accept a submission written in French, HHI felt that doing so could result in delays in the processing of the application and increased costs for the Board and intervention. ERA estimated 325 hours of drafting and preparation for the submission resulting in a cost of $65,000. Other consulting costs included the Load Forecast, Revision to the Cost Allocation and the purchase of a 2010 EDR Model. HHI also set aside $20,000 to be used for the purpose of Interrogatory support and/or expert witness or support for an oral component and similarly, another $15,000 for accounting costs. HHI used Deloitte & Touche to establish its regulatory and accounting budgets and calculations of PILS. The table below presents a breakdown of the cost of the rebasing.

Total Cost of Rebasing

Expert Witness cost for regulatory matters		$5,000
Consultants costs for regulatory matters		$95,000
Evidence Drafting	$65,000	
Strategic Review	$5,000	
Load Forecast	$5,000	
Revisions to Cost Allocation	$5,000	
Accounting costs	$15,000	
Interrogatories and Intervener cost		$10,000
Rate order		$5,000
2010 EDR Model		$10,000
TOTAL		**$125,000**

In addition to the cost of rebasing, HHI has projected an amount of $10,570 to cover the cost of OEB assessment, unexpected cost award and miscellaneous fees.

LOW-INCOME ENERGY ASSISTANCE PROGRAM (LEAP)

On March 10, 2009, the Board issued the Report of the Board: Low-Income Energy Assistance Program (EB-2008-0150). In this Report, the Board stated that it had determined that the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000, is a reasonable commitment of distributors to LEAP. The Board stated that it would allow distributors to incorporate such amounts in their OM&A expenses at the time of rebasing. HHI has incorporated the amount of $2,000 in its forecasted OM&A. With being a small utility with limited internal resources, HHI proposed to use the funds to;

- work with outside consultants to develop an understanding of new and existing programs as they become available; and,
- link with local social interest groups to identify low income customers and build a process to deal with their needs.

HHI acknowledges the Board's final report on deferring the treatment of low-income energy assistance program, HHI feels that the seed amount of $2,000 can be put to good use by raising awareness within the company as well as with HHI's customers.

CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT

The Green Energy Act amends the *Ontario Energy Board Act, 1998* to allow for the assessment of special purpose charges related to expenses incurred and expenditures made by the Ministry of Energy and Infrastructure in respect of its energy conservation programs or renewable energy programs.

HHI is not requesting funds related to the *Green Energy and Green Economy Act* in this proceeding and understands that a deferral account or alternate recovery mechanism will be developed by the Board to record necessary costs for future disposition.

CHARITABLE DONATIONS

HHI attests that as a policy, it does not issue donations to charity groups or any other groups.

Exhibit 4: Operating Costs

Tab 3 (of 8): OM&A Variance Analysis

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OM&A Table

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	11,695	11,245	450	4.0%
	5015-Transformer Station Equipment - Operation Supplies and Expenses	12,944	12,446	498	4.0%
	5016-Distribution Station Equipment - Operation Labour	9,672	9,300	372	4.0%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	66	63	3	4.8%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	10,154	9,763	391	4.0%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,120	1,077	43	4.0%
	5035-Overhead Distribution Transformers-Operation	12,046	11,813	233	2.0%
	5040-Underground Distribution Lines and Feeders - Operation Labour	2,130	2,048	82	4.0%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	25	24	1	4.2%
	5055-Underground Distribution Transformers - Operation	2,465	2,370	95	4.0%
	5065-Meter Expense	12,032	11,569	463	4.0%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,114	1,071	43	4.0%
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,815	4,630	185	4.0%
	5120-Maintenance of Poles, Towers and Fixtures	18,022	16,160	1,862	11.5%
	5125-Maintenance of Overhead Conductors and Devices	32,799	32,545	254	0.8%
	5130-Maintenance of Overhead Services	33,392	32,108	1,284	4.0%
	5135-Overhead Distribution Lines and Feeders - Right of Way	44,827	50,795	(5,968)	(11.7%)
	5145-Maintenance of Underground Conduit	1,198	1,152	46	4.0%
	5150-Maintenance of Underground Conductors and Devices	18,596	17,881	715	4.0%

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OM&A Table

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
	5155-Maintenance of Underground Services	7,176	6,900	276	4.0%
	5160-Maintenance of Line Transformers	2,362	2,271	91	4.0%
	5175-Maintenance of Meters	8,700	8,700		
3650-Billing and Collecting	5310-Meter Reading Expense	33,376	32,092	1,284	4.0%
	5315-Customer Billing	185,880	178,731	7,149	4.0%
	5320-Collecting	100,389	96,460	3,929	4.1%
	5325-Collecting- Cash Over and Short				
	5335-Bad Debt Expense	7,927	7,622	305	4.0%
3700-Community Relations	5410-Community Relations - Sundry	2,108	104	2,004	1926.9%
	5415-Energy Conservation				
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	107,289	100,278	7,011	7.0%
	5610-Management Salaries and Expenses	74,757	68,997	5,760	8.3%
	5620-Office Supplies and Expenses	21,702	20,868	834	4.0%
	5630-Outside Services Employed	43,817	17,574	26,243	149.3%
	5635-Property Insurance	4,698	4,517	181	4.0%
	5640-Injuries and Damages	12,427	11,949	478	4.0%
	5645-Employee Pensions and Benefits	3,699	3,556	143	4.0%
	5655-Regulatory Expenses	41,820	10,164	31,656	311.5%
	5665-Miscellaneous General Expenses	13,520	13,000	520	4.0%
	5675-Maintenance of General Plant	30,596	29,420	1,176	4.0%
	5680-Electrical Safety Authority Fees	5,526	5,313	213	4.0%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	28,262	26,916	1,346	5.0%

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OM&A Table

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	11,245	10,813	432	4.0%
	5015-Transformer Station Equipment - Operation Supplies and Expenses	12,446	11,967	479	4.0%
	5016-Distribution Station Equipment - Operation Labour	9,300	8,942	358	4.0%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	63	61	2	3.3%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	9,763	9,388	375	4.0%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,077	1,036	41	4.0%
	5035-Overhead Distribution Transformers-Operation	11,813	4,327	7,486	173.0%
	5040-Underground Distribution Lines and Feeders - Operation Labour	2,048	1,970	78	4.0%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	24	24	0	2.0%
	5055-Underground Distribution Transformers - Operation	2,370	2,279	91	4.0%
	5065-Meter Expense	11,569	12,567	(998)	(7.9%)
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,071	1,030	41	4.0%
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,630	4,452	178	4.0%
	5120-Maintenance of Poles, Towers and Fixtures	16,160	10,561	5,599	53.0%
	5125-Maintenance of Overhead Conductors and Devices	32,545	31,598	947	3.0%
	5130-Maintenance of Overhead Services	32,108	31,173	935	3.0%
	5135-Overhead Distribution Lines and Feeders - Right of Way	50,795	42,795	8,000	18.7%
	5145-Maintenance of Underground Conduit	1,152	1,108	44	4.0%
	5150-Maintenance of Underground Conductors and Devices	17,881	17,193	688	4.0%

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OM&A Table

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Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
	5155-Maintenance of Underground Services	6,900	6,635	265	4.0%
	5160-Maintenance of Line Transformers	2,271	2,184	87	4.0%
	5175-Maintenance of Meters	8,700	12,192	(3,492)	(28.6%)
3650-Billing and Collecting	5310-Meter Reading Expense	32,092	30,858	1,234	4.0%
	5315-Customer Billing	178,731	171,856	6,875	4.0%
	5320-Collecting	96,460	93,858	2,602	2.8%
	5325-Collecting- Cash Over and Short		(23)	23	100.0%
	5335-Bad Debt Expense	7,622	7,329	293	4.0%
3700-Community Relations	5410-Community Relations - Sundry	104	100	4	4.0%
	5415-Energy Conservation				
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	100,278	93,537	6,741	7.2%
	5610-Management Salaries and Expenses	68,997	63,458	5,539	8.7%
	5620-Office Supplies and Expenses	20,868	20,065	803	4.0%
	5630-Outside Services Employed	17,574	16,898	676	4.0%
	5635-Property Insurance	4,517	4,344	173	4.0%
	5640-Injuries and Damages	11,949	11,489	460	4.0%
	5645-Employee Pensions and Benefits	3,556	3,420	136	4.0%
	5655-Regulatory Expenses	10,164	9,773	391	4.0%
	5665-Miscellaneous General Expenses	13,000	12,500	500	4.0%
	5675-Maintenance of General Plant	29,420	28,563	857	3.0%
	5680-Electrical Safety Authority Fees	5,313	5,109	204	4.0%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	26,916	26,205	711	2.7%

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OM&A Table

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Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	10,813	11,157	(344)	(3.1%)
	5015-Transformer Station Equipment - Operation Supplies and Expenses	11,967	(4,681)	16,648	355.7%
	5016-Distribution Station Equipment - Operation Labour	8,942	5,142	3,800	73.9%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	61	2,776	(2,715)	(97.8%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour	9,388	10,099	(711)	(7.0%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,036	1,568	(532)	(33.9%)
	5035-Overhead Distribution Transformers- Operation	4,327	4,867	(539)	(11.1%)
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,970	1,225	744	60.7%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	24	46	(22)	(48.5%)
	5055-Underground Distribution Transformers - Operation	2,279	2,306	(28)	(1.2%)
	5065-Meter Expense	12,567	19,232	(6,665)	(34.7%)
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,030	1,030		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,452	4,200	252	6.0%
	5120-Maintenance of Poles, Towers and Fixtures	10,561	6,122	4,439	72.5%
	5125-Maintenance of Overhead Conductors and Devices	31,598	59,149	(27,551)	(46.6%)
	5130-Maintenance of Overhead Services	31,173	25,163	6,010	23.9%
	5135-Overhead Distribution Lines and Feeders - Right of Way	42,795	38,176	4,619	12.1%
	5145-Maintenance of Underground Conduit	1,108	248	860	346.6%
	5150-Maintenance of Underground Conductors and Devices	17,193	11,905	5,288	44.4%

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Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
	5155-Maintenance of Underground Services	6,635	6,789	(154)	(2.3%)
	5160-Maintenance of Line Transformers	2,184	11,912	(9,729)	(81.7%)
	5175-Maintenance of Meters	12,192	11,388	804	7.1%
3650-Billing and Collecting	5310-Meter Reading Expense	30,858	28,192	2,665	9.5%
	5315-Customer Billing	171,856	140,043	31,813	22.7%
	5320-Collecting	93,858	58,500	35,358	60.4%
	5325-Collecting- Cash Over and Short	(23)		(23)	
	5335-Bad Debt Expense	7,329	9,610	(2,281)	(23.7%)
3700-Community Relations	5410-Community Relations - Sundry	100	328	(228)	(69.5%)
	5415-Energy Conservation		12,340	(12,340)	(100.0%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	93,537	90,146	3,390	3.8%
	5610-Management Salaries and Expenses	63,458	60,728	2,731	4.5%
	5620-Office Supplies and Expenses	20,065	19,728	337	1.7%
	5630-Outside Services Employed	16,898	30,830	(13,931)	(45.2%)
	5635-Property Insurance	4,344	4,250	94	2.2%
	5640-Injuries and Damages	11,489	11,942	(453)	(3.8%)
	5645-Employee Pensions and Benefits	3,420	3,809	(389)	(10.2%)
	5655-Regulatory Expenses	9,773	15,730	(5,957)	(37.9%)
	5665-Miscellaneous General Expenses	12,500	11,998	502	4.2%
	5675-Maintenance of General Plant	28,563	35,970	(7,407)	(20.6%)
	5680-Electrical Safety Authority Fees	5,109	5,038	71	1.4%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	26,205	25,634	571	2.2%

Hydro Hawkesbury Inc. (ED-2003-0027)

2010 EDR Application (EB-2009-0186) version: v0.1
November 4, 2009

OM&A Table

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	11,157	12,577	(1,420)	(11.3%)
	5015-Transformer Station Equipment - Operation Supplies and Expenses	(4,681)	5,986	(10,667)	(178.2%)
	5016-Distribution Station Equipment - Operation Labour	5,142	2,408	2,734	113.6%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	2,776		2,776	
	5020-Overhead Distribution Lines and Feeders - Operation Labour	10,099	7,524	2,575	34.2%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,568	1,802	(235)	(13.0%)
	5035-Overhead Distribution Transformers-Operation	4,867	1,705	3,161	185.4%
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,225	1,442	(217)	(15.0%)
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	46	174	(129)	(73.8%)
	5055-Underground Distribution Transformers - Operation	2,306	2,414	(108)	(4.5%)
	5065-Meter Expense	19,232	14,622	4,610	31.5%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,030	1,030		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	4,200	3,850	350	9.1%
	5120-Maintenance of Poles, Towers and Fixtures	6,122	5,507	615	11.2%
	5125-Maintenance of Overhead Conductors and Devices	59,149	42,064	17,085	40.6%
	5130-Maintenance of Overhead Services	25,163	21,370	3,793	17.7%
	5135-Overhead Distribution Lines and Feeders - Right of Way	38,176	24,467	13,709	56.0%
	5145-Maintenance of Underground Conduit	248	1,245	(997)	(80.1%)
	5150-Maintenance of Underground Conductors and Devices	11,905	13,511	(1,606)	(11.9%)

Hydro Hawkesbury Inc. (ED-2003-0027)

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November 4, 2009

OM&A Table

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Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
	5155-Maintenance of Underground Services	6,789	5,062	1,726	34.1%
	5160-Maintenance of Line Transformers	11,912	5,399	6,513	120.6%
	5175-Maintenance of Meters	11,388	7,746	3,642	47.0%
3650-Billing and Collecting	5310-Meter Reading Expense	28,192	27,845	348	1.2%
	5315-Customer Billing	140,043	137,987	2,056	1.5%
	5320-Collecting	58,500	55,788	2,712	4.9%
	5325-Collecting- Cash Over and Short		11	(11)	(100.0%)
	5335-Bad Debt Expense	9,610	7,139	2,471	34.6%
3700-Community Relations	5410-Community Relations - Sundry	328	100	228	227.7%
	5415-Energy Conservation	12,340	60,710	(48,370)	(79.7%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	90,146	89,593	554	0.6%
	5610-Management Salaries and Expenses	60,728	63,260	(2,532)	(4.0%)
	5620-Office Supplies and Expenses	19,728	14,711	5,017	34.1%
	5630-Outside Services Employed	30,830	23,680	7,149	30.2%
	5635-Property Insurance	4,250	4,099	151	3.7%
	5640-Injuries and Damages	11,942	13,054	(1,112)	(8.5%)
	5645-Employee Pensions and Benefits	3,809	2,921	888	30.4%
	5655-Regulatory Expenses	15,730	15,135	596	3.9%
	5665-Miscellaneous General Expenses	11,998	11,550	448	3.9%
	5675-Maintenance of General Plant	35,970	31,012	4,958	16.0%
	5680-Electrical Safety Authority Fees	5,038	5,235	(197)	(3.8%)
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	25,634	25,171	463	1.8%

Hydro Hawkesbury Inc. (ED-2003-0027)

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OM&A Table

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	12,577	21,775	(9,199)	(42.2%)
	5015-Transformer Station Equipment - Operation Supplies and Expenses	5,986	4,750	1,236	26.0%
	5016-Distribution Station Equipment - Operation Labour	2,408	793	1,615	203.6%
	5017-Distribution Station Equipment - Operation Supplies and Expenses				
	5020-Overhead Distribution Lines and Feeders - Operation Labour	7,524	6,466	1,058	16.4%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,802	2,736	(934)	(34.1%)
	5035-Overhead Distribution Transformers- Operation	1,705	3,090	(1,384)	(44.8%)
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,442		1,442	
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	174	341	(167)	(48.9%)
	5055-Underground Distribution Transformers - Operation	2,414	2,979	(565)	(19.0%)
	5065-Meter Expense	14,622	8,702	5,920	68.0%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	1,030	1,030		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	3,850		3,850	
	5120-Maintenance of Poles, Towers and Fixtures	5,507	1,256	4,251	338.3%
	5125-Maintenance of Overhead Conductors and Devices	42,064	31,287	10,777	34.4%
	5130-Maintenance of Overhead Services	21,370	47,020	(25,650)	(54.6%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	24,467	25,396	(929)	(3.7%)
	5145-Maintenance of Underground Conduit	1,245	31	1,214	3930.8%
	5150-Maintenance of Underground Conductors and Devices	13,511	6,042	7,469	123.6%

Hydro Hawkesbury Inc. (ED-2003-0027)

2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

OM&A Table

Review highlighted variances (no input on this sheet)

Variances in excess of $50,000 are shown in bold

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
	5155-Maintenance of Underground Services	5,062	5,808	(746)	(12.8%)
	5160-Maintenance of Line Transformers	5,399	9,275	(3,876)	(41.8%)
	5175-Maintenance of Meters	7,746	(2,961)	10,707	361.6%
3650-Billing and Collecting	5310-Meter Reading Expense	27,845	34,946	(7,101)	(20.3%)
	5315-Customer Billing	137,987	172,841	(34,854)	(20.2%)
	5320-Collecting	55,788	51,296	4,493	8.8%
	5325-Collecting- Cash Over and Short	11		11	
	5335-Bad Debt Expense	7,139	8,232	(1,093)	(13.3%)
3700-Community Relations	5410-Community Relations - Sundry	100	100		
	5415-Energy Conservation	60,710		**60,710**	
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	89,593	81,251	8,341	10.3%
	5610-Management Salaries and Expenses	63,260	54,036	9,224	17.1%
	5620-Office Supplies and Expenses	14,711	13,873	838	6.0%
	5630-Outside Services Employed	23,680	35,430	(11,750)	(33.2%)
	5635-Property Insurance	4,099	3,732	367	9.8%
	5640-Injuries and Damages	13,054	16,545	(3,491)	(21.1%)
	5645-Employee Pensions and Benefits	2,921	2,119	802	37.9%
	5655-Regulatory Expenses	15,135		15,135	
	5665-Miscellaneous General Expenses	11,550	119,618	**(108,068)**	(90.3%)
	5675-Maintenance of General Plant	31,012	22,443	8,569	38.2%
	5680-Electrical Safety Authority Fees	5,235	1,142	4,093	358.5%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	25,171	24,654	518	2.1%

OM&A VARIANCES TABLE

The OM&A Variance Table shown at Exhibit 4, Tab 3. Schedule 1, Attachment 1 shows the expenses for the 2006 EDR, the 2006 and 2007, 2008 actuals and the 2009 and 2010 projections. As directed in Appendix 2-E, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications published May 27, 2009 the following Account Groupings are included in OM&A analysis.

- 3500- Distribution Expenses – Operation
- 3550- Distribution Expenses – Maintenance
- 3650- Billing & Collecting
- 3700- Community Relations
- 3800- Administrative and General Expenses

Although the materiality threshold is calculated as per the minimum filing requirements and is set at $50,000, HHI has identified and explained the main cost drivers in the summary and detail tables presented below.

SUMMARY - 2006 EDR - 2006 ACTUAL			
Acct No.	Name		
5125	Maintenance of Overhead Conductors & Devices	Increase	$ 10,777.00
5130	Maintenance of Overhead Services	Decrease	$ (25,650.00)
5175	Maintenance of Meters	Increase	$ 10,707.00
5315	Customer Billing	Decrease	$ (34,854.00)
5415	Energy Conservation	Increase	$ 60,710.00
5630	Outside Services Employed	Decrease	$ (11,750.00)
5655	Regulatory Expenses	Increase	$ 15,135.00
5665	Miscelleneous General Expenses	Decrease	$ (108,068.00)
		TOTAL OM&A DECREASE	$ (82,993.00)

1 Details of the variances are presented in the table below.

DETAIL - ACCT VARIANCE EXPLANATION

Acct No.	Name	Actual 2006	EDR 2006	Variance
5125	Maintenance of Overhead Conductors & Devices	$ 42,064.00	$ 31,287.00	$ 10,777.00
COST DRIVERS:				
	Labour - Increase	$ 13,080.52	$ 11,085.03	$ 1,995.49
	Yr end inventory adjustment - Increase	$ 10,094.34	$ 3,666.92	$ 6,427.42
	Yr end reclassification of rolling stock equip - Increase	$ 16,356.42	$ 16,338.38	$ 18.04
	Supplies - Increase	$ 2,532.04	$ 195.99	$ 2,336.05
				$ 10,777.00
Acct No.	Name	Actual 2006	EDR 2006	Variance
5130	Maintenance of Overhead Services	$ 21,370.00	$ 47,020.00	$ (25,650.00)
COST DRIVERS:				
	Labour/Burden - Decrease	$ 9,338.38	$ 33,493.04	$ (24,154.66)
	EHT Expense - Increase	$ 2,480.73	$ 2,212.22	$ 268.51
	Yr end reclassification of payroll burden - Decrease	$ 9,551.05	$ 11,251.40	$ (1,700.35)
	Supplies - Decrease	$ -	$ 63.05	$ (63.05)
				$ (25,649.55)
Acct No.	Name	Actual 2006	EDR 2006	Variance
5175	Maintenance of Meters	$ 7,746.00	$ (2,961.00)	$ 10,707.00
COST DRIVERS:				
	Maintenance/Testing done by Hydro Ottawa - Decrease	$ 4,450.15	$ 4,657.26	$ (207.11)
	Supplies - Increase	$ 16.19	$ -	$ 16.19
	Yr end inventory adjustment - Increase	$ 3,279.28	$ (7,618.26)	$ 10,897.54
				$ 10,706.62
Acct No.	Name	Actual 2006	EDR 2006	Variance
5315	Customer Billing	$ 137,987.00	$ 172,841.00	$ (34,854.00)
COST DRIVERS:				
	Labour - Increase	$ 38,633.57	$ 36,179.91	$ 2,453.66
	Settlement (Hydro Ottawa)	$ 29,196.00	$ 29,196.00	$ -
	Harris/AUSC costs - Decrease	$ 37,818.12	$ 54,383.99	$ (16,565.87)
	Canada post - Increase	$ 16,354.06	$ 14,765.17	$ 1,588.89
	Billing supplies (Hydro bills, reminders…) - Decrease	$ 7,276.11	$ 27,871.53	$ (20,595.42)

	Supplies - Decrease	$ 2,693.31	$ 3,712.58	$ (1,019.27)
	EHT Expense - Increase	$ 1,240.37	$ 1,106.11	$ 134.26
	Yr end reclassification of payroll burden - Decrease	$ 4,775.52	$ 5,625.71	$ (850.19)
				$ (34,853.94)
Acct No.	**Name**	**Actual 2006**	**EDR 2006**	**Variance**
5415	Energy Conservation	$ 60,710.00	$ -	$ 60,710.00
COST DRIVERS:				
	OEB approved CDM expenses recorded monthly	$ 60,710.00	$ -	$ 60,710.00
				$ 60,710.00
Acct No.	**Name**	**Actual 2006**	**EDR 2006**	**Variance**
5630	Outside Services Employed	$ 23,680.00	$ 35,430.00	$ (11,750.00)
COST DRIVERS:				
	ACCPAC Support (ESM) - Increase	$ 7,496.30	$ -	$ 7,496.30
	Deloitte (Audit costs) - Decrease	$ 9,700.00	$ 9,975.00	$ (275.00)
	Consultant costs - Decrease	$ -	$ 25,455.00	$ (25,455.00)
	Summer student costs - Increase	$ 6,483.96	$ -	$ 6,483.96
				$ (11,749.74)
Acct No.	**Name**	**Actual 2006**	**EDR 2006**	**Variance**
5655	Regulatory Expenses	$ 15,135.00	$ -	$ 15,135.00
COST DRIVERS:				
	Cost allocation study - Increase	$ 6,240.00	$ -	$ 6,240.00
	Rate publication - Increase	$ 744.00	$ -	$ 744.00
	OEB cost awards & assessment costs - Increase	$ 8,150.77	$ -	$ 8,150.77
				$ 15,134.77
Acct No.	**Name**	**Actual 2006**	**EDR 2006**	**Variance**
5665	Miscelleneous General Expenses	$ 11,550.00	$ 119,618.00	$ (108,068.00)
COST DRIVERS:				
	EDA annual dues - Increase	$ 11,550.00	$ 5,000.00	$ 6,550.00
NOTE	Low voltage wheeling adjustment - Decrease	$ -	$ 114,618.00	$ (114,618.00)
				$ (108,068.00)

NOTE: Details of the adjustment in low voltage wheeling charge are presented in the next page.

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416-481-1967
Facsimile: 416-440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416-481-1967
Télécopieur: 416-440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY E-MAIL

June 23, 2006

Mr. Michel Poulin
Manager
Hydro Hawkesbury Inc.
850 Tupper Street
Hawkesbury ON K6A 3S7

Dear Mr. Poulin:

Re: Hydro Hawkesbury Inc. – 2006 Electricity Distribution Rates Application
Board File Number RP-2005-0020 / EB-2005-0379
Amended Decision and Order

On April 12, 2006 the Board issued a Decision and Order with respect to the Hydro Hawkesbury Inc. 2006 Distribution Rate Application, under file number RP-2005-0020/ EB-2005-0379. It has come to the Board's attention that an error resulted in an incorrect statement of Hydro Hawkesbury's approved revenue requirement appearing in the Decision. Specifically, the Decision approved an increase to Hydro Hawkesbury's revenue requirement of $114,618 for the recovery of low voltage costs charged by Hydro One Networks, the host distributor. The determination of the resulting rates, however, did not incorporate this additional amount.

Pursuant to section 43.02 of the Ontario Energy Board's Rules of Practice and Procedure, the Board has revised the level of Hydro Hawkesbury's resulting revenue requirement from $1,430,234 to $1,544,852 as shown in its Amended Decision and Order. The Board has revised the Tariff of Rates and Charges to reflect this revised amount. The effective date of the resulting revised rates remains as May 1, 2006, unchanged from the original Order.

The Amended Decision and Order, together with the revised Tariff of Rates and Charges, are attached.

The Board will leave the decision as to whether to implement retroactive billing to the discretion of Hydro Hawkesbury, noting that variances between costs and revenues related to LV services are captured in a variance account for future disposition.

Yours truly,

Peter H. O'Dell
Assistant Board Secretary

c. School Energy Coalition

1

SUMMARY - 2006 ACTUAL - 2007 ACTUAL

Acct No.	Name		
5015	Transformer Stn Equipment - Operations Supplies & Expenses	Decrease	**$ (10,667.00)**
5125	Maintenance of O/H Conductors & Devices	Increase	**$ 17,085.00**
5135	O/H Distribution lines & feeders - Right of way	Increase	**$ 13,709.00**
5415	Energy Conservation	Decrease	**$ (48,370.00)**
		TOTAL OM&A DECREASE	**$ (28,243.00)**

2

DETAIL - ACCT VARIANCE EXPLANATION

Acct No.	Name	Actual 2007	Actual 2006	Variance
5015	Transformer Stn Equipment - Operations Supplies & Expenses	**$ (4,681.00)**	**$ 5,986.00**	**$ (10,667.00)**
COST DRIVERS:				
	Phone line fees	$ 673.40	$ 644.54	$ 28.86
	MSP Billing fees	$ 2,400.00	$ 1,600.00	$ 800.00
	Publicity to advise customers of maintenance to be done	$ -	$ 279.00	$ (279.00)
	Supplies purchased to perform maintenance work	$ 2,898.90	$ 1,678.84	$ 1,220.06
	Generator rental to perform maintenance work	$ -	$ 1,783.70	$ (1,783.70)
	Hydro One MSB billing adjustment	$ (10,652.83)	$ -	$ (10,652.83)
				$ (10,666.61)
Acct No.	**Name**	**Actual 2007**	**Actual 2006**	**Variance**
5125	Maintenance of O/H Conductors & Devices	**$ 59,149.00**	**$ 42,064.00**	**$ 17,085.00**
COST DRIVERS:				
	Labour/Burden	$ 14,393.44	$ 13,080.52	$ 1,312.92
	Yr end inventory adjustment	$ 26,032.19	$ 10,094.34	$ 15,937.85
	Yr end reclassification of rolling stock equip	$ 15,332.96	$ 16,356.42	$ (1,023.46)
	Supplies	$ 2,970.12	$ 2,532.04	$ 438.08
	Line crew cellular phone	$ 419.95	$ -	$ 419.95
				$ 17,085.34
Acct No.	**Name**	**Actual 2007**	**Actual 2006**	**Variance**
5135	O/H Distribution lines & feeders - Right of way	**$ 38,176.00**	**$ 24,467.00**	**$ 13,709.00**
COST DRIVERS:				

	Labour	$ 20,738.14	$ 11,719.50	$ 9,018.64
	Supplies	$ 328.28	$ 55.18	$ 273.10
	EHT Expense	$ 1,266.30	$ 1,240.34	$ 25.96
	Yr end reclassification of rolling stock expense	$ 6,258.35	$ 6,676.09	$ (417.74)
	Yr end reclassification of payroll burden	$ 7,499.65	$ 4,775.52	$ 2,724.13
	Legal advise for LDC responsibility regarding tree trimming	$ 2,085.00	$ -	$ 2,085.00
				$ 13,709.09
Acct No.	**Name**	**Actual 2007**	**Actual 2006**	**Variance**
5415	Energy Conservation	**$ 12,340.00**	**$ 60,710.00**	**$ (48,370.00)**
COST DRIVERS:				
	OEB approved CDM expenses recorded monthly	**$ 12,340.00**	**$ 60,710.00**	**$ (48,370.00)**
				$ (48,370.00)

SUMMARY- 2007 ACTUAL - 2008 ACTUAL

Acct No.	Name		
5015	Transformer Stn Equipment - Operations Supplies & Expenses	Increase	**$ 16,648.00**
5125	Maintenance of O/H Conductors & Devices	Decrease	**$ (27,551.00)**
5160	Maintenance of Line Transformers	Decrease	**$ (9,729.00)**
5315	Customer Billing	Increase	**$ 31,813.00**
5320	Collecting	Increase	**$ 35,358.00**
5415	Energy Conservation	Decrease	**$ (12,340.00)**
5630	Outside Services Employed	Decrease	**$ (13,931.00)**
		TOTAL OM&A INCREASE	**$ 20,268.00**

DETAIL- ACCT VARIANCE EXPLANATION

Acct No.	Name	Actual 2008	Actual 2007	Variance
5015	Transformer Stn Equipment - Operations Supplies & Expenses	**$ 11,967.00**	**$ (4,681.00)**	**$ 16,648.00**
COST DRIVERS:				
	Phone line fees	**$ 689.24**	**$ 673.40**	**$ 15.84**
	MSP Billing fees	**$ 2,400.00**	**$ 2,400.00**	**$ -**
	Study done by Stantec for recloser	**$ 556.00**	**$ -**	**$ 556.00**
	Supplies purchased to perform maintenance work	**$ 137.13**	**$ 2,898.90**	**$ (2,761.77)**
	Maintenance done by Sure Voltage on Sub 115KV	**$ 4,940.94**	**$ -**	**$ 4,940.94**
	Hydro One MSB billing adjustment	**$ -**	**$ (10,652.83)**	**$ 10,652.83**
	115KV Training given by PTI Transformers	**$ 3,243.85**	**$ -**	**$ 3,243.85**
				$ 16,647.69

Acct No.	Name	Actual 2008	Actual 2007	Variance
5125	Maintenance of O/H Conductors & Devices	**$ 31,598.00**	**$ 59,149.00**	**$ (27,551.00)**
COST DRIVERS:				
	Labour/Burden	**$ 15,064.89**	**$ 14,393.44**	**$ 671.45**
	Yr end inventory adjustment	**$ (5,376.68)**	**$ 26,032.19**	**$ (31,408.87)**
	Yr end reclassification of rolling stock equip	**$ 18,408.63**	**$ 15,332.96**	**$ 3,075.67**
	Supplies	**$ 1,527.86**	**$ 2,970.12**	**$ (1,442.26)**
	Line crew cellular phone	**$ 637.50**	**$ 419.95**	**$ 217.55**

	Yr end contributed capital adjustment	$ (664.64)	$ -	$ (664.64)
	EUSA Training fees	$ 2,000.00	$ -	$ 2,000.00
				$ (27,551.10)
Acct No.	**Name**	**Actual 2008**	**Actual 2007**	**Variance**
5160	Maintenance of Line Transformers	**$ 2,183.00**	**$ 11,912.00**	**$ (9,729.00)**
COST DRIVERS:				
	Labour	**$ 5,423.04**	**$ 2,720.66**	**$ 2,702.38**
	Supplies	**$ 122.16**	**$ 270.41**	**$ (148.25)**
	Yr end inventory adjustment	**$ (7,118.49)**	**$ 5,791.91**	**$ (12,910.40)**
	Yr end reclassification of rolling stock equip	**$ 3,756.87**	**$ 3,129.18**	**$ 627.69**
				$ (9,728.58)
Acct No.	**Name**	**Actual 2008**	**Actual 2007**	**Variance**
5315	Customer Billing	**$ 171,856.00**	**$ 140,043.00**	**$ 31,813.00**
COST DRIVERS:				
	Labour - Increase	**$ 54,749.58**	**$ 40,950.75**	**$ 13,798.83**
	Settlement (Hydro Ottawa)	**$ 14,598.00**	**$ 34,062.00**	**$ (19,464.00)**
	Harris/AUSC costs	**$ 55,573.21**	**$ 28,494.74**	**$ 27,078.47**
	Canada post - Increase	**$ 17,640.93**	**$ 17,040.56**	**$ 600.37**
	Billing supplies (Hydro bills, reminders…)	**$ 5,377.18**	**$ 3,906.81**	**$ 1,470.37**
	Supplies	**$ 4,278.82**	**$ 3,184.09**	**$ 1,094.73**
	EHT Expense	**$ 1,647.40**	**$ 1,266.32**	**$ 381.08**
	Yr end reclassification of payroll burden	**$ 9,170.81**	**$ 7,499.65**	**$ 1,671.16**
	Pitney Bowes expenses	**$ 3,490.12**	**$ 1,453.39**	**$ 2,036.73**
	Training expenses	**$ 4,523.30**	**$ 2,185.12**	**$ 2,338.18**
	Cogeco - Internet connection	**$ 806.65**	**$ -**	**$ 806.65**
				$ 31,812.57
Acct No.	**Name**	**Actual 2008**	**Actual 2007**	**Variance**
5320	Collecting	**$ 93,858.00**	**$ 58,500.00**	**$ 35,358.00**
COST DRIVERS:				
	Comprehensive crime insurance	**$ 1,341.72**	**$ 1,300.32**	**$ 41.40**
	Labour	**$ 81,007.06**	**$ 45,563.57**	**$ 35,443.49**
	Supplies	**$ 64.08**	**$ 375.50**	**$ (311.42)**
	Training	**$ -**	**$ 625.00**	**$ (625.00)**
	EHT expense	**$ 1,647.40**	**$ 1,266.32**	**$ 381.08**

	Yr end reclassification of payroll burden	$ 9,170.81	$ 7,499.65	$ 1,671.16
	Collection agency fees	$ 626.93	$ 1,869.44	$ (1,242.51)
				$ 35,358.20
Acct No.	**Name**	**Actual 2008**	**Actual 2007**	**Variance**
5415	Energy Conservation	$ -	$ 12,340.00	$ (12,340.00)
COST DRIVERS:				
	OEB approved CDM expenses recorded monthly	$ -	$ 12,340.00	$ (12,340.00)
				$ (12,340.00)
Acct No.	**Name**	**Actual 2008**	**Actual 2007**	**Variance**
5630	Outside Services Employed	$ 16,899.00	$ 30,830.00	$ (13,931.00)
COST DRIVERS:				
	ACCPAC Support	$ 1,463.75	$ 2,375.00	$ (911.25)
	Audit fees (Deloitte)	$ 12,000.00	$ 12,500.00	$ (500.00)
	Extra staff hired through an employment center	$ 664.30	$ 15,954.40	$ (15,290.10)
	PC Maintenance (Programmer/IT fees)	$ 2,770.20	$ -	$ 2,770.20
				$ (13,931.15)

SUMMARY - 2008 ACTUAL - 2009 PROJECTED

Acct No.	Name		
5120	Maintenance of poles, towers & fixtures	Increase	$ 5,599.00
		TOTAL OM&A INCREASE	**$ 5,599.00**

DETAIL - ACCT VARIANCE EXPLANATION

Acct No.	Name	Projected 2009	Actual 2008	Variance
5120	Maintenance of poles, towers & fixtures	$ 16,160.00	$ 10,561.00	$ 5,599.00
COST DRIVERS:				
	Labour	$ 13,160.00	$ 9,120.62	$ 4,539.38
	Supplies	$ 2,500.00	$ 1,439.97	$ 1,060.03
				$ 5,599.41

SUMMARY - 2009 PROJECTED - 2010 PROJECTED

Acct No.	Name		
5630	Outside Services Employed	Increase	$ 26,243.00
5655	Regulatory Expenses	Increase	$ 31,656.00
		TOTAL OM&A INCREASE	**$ 57,359.00**

DETAIL - ACCT VARIANCE EXPLANATION

Acct No.	Name	Projected 2010	Projected 2009	Variance
5630	Outside Services Employed	$ 43,817.00	$ 17,574.00	$ 26,243.00
COST DRIVERS:				
	ACCPAC Support	$ 777.00	$ 700.00	$ 77.00
	Audit fees (Deloitte)	$ 16,500.00	$ 15,700.00	$ 800.00
	PC Maintenance (Programmer/IT fees)	$ 1,000.00	$ 1,174.00	$ (174.00)
	25% of estimated cost for transition to IFRS ($60,000)	$ 15,000.00	$ -	$ 15,000.00
	25% of estimated cost for substation study ($42,160)	$ 10,540.00	$ -	$ 10,540.00
				$ 26,243.00
Acct No.	**Name**	**Projected 2010**	**Projected 2009**	**Variance**
5655	Regulatory Expenses	$ 41,820.00	$ 10,164.00	$ 31,656.00
COST DRIVERS:				
	Miscelleneous fees	$ 570.00	$ 664.00	$ (94.00)
	Rate publication	$ 1,000.00	$ -	$ 1,000.00
	OEB cost awards & assessment costs	$ 9,000.00	$ 9,500.00	$ (500.00)
	25% of estimated cost for rate rebasing ($125,000)	$ 31,250.00	$ -	$ 31,250.00
				$ 31,656.00

Specifics about Regulatory Expenses and Outside Services Employed are presented in an earlier schedule namely Exhibit 4, Schedule 2, Tab 2.

Exhibit 4: Operating Costs

Tab 4 (of 8): Employee Compensation

STAFFING AND COMPENSATION LEVELS

Details of HHI's employee compensation and benefits and a breakdown of those costs are set out in Exhibit 4, Tab 4, Schedule 1, Attachment 1.

Please note that the 2006 Rate Handbook states the following: "Where there are three, or fewer, full-time equivalents (FTEs) in any category, HHI may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three, or fewer, FTEs" In compliance with the above and since HHI only has aggregated information relating to its 3 full time employees in the FTE class.

The increase in total compensation paid to employees in non-union and management position are attributable to cost of living increase HHI hired an additional customer service representative to support the increase in the number of customers that occurred during that period. The number of customer service representative increased from one to two. The overall number of full time employees increased from 7 to 8.

Management Staff	2
Inside Staff	3
Outside Staff	3
Board Members	5

- Union employee salaries are determined according to the collective agreement that is reviewed every three years.

- Management salaries are negotiated with and approved by the Board of Directors.

- The normal work week of employees covered by the agreement is thirty-seven and one-half (37.5) hours per week for outside staff and is thirty-five (35) hours per week for inside staff.

- HHI pays 100% of the cost of the premiums of the Employer Health Tax, 100% of the MEARIE Extended Health Care Plan and 100% of the cost for Life Insurance Plan.

- HHI pays 90% of the cost of the MEARIE Dental Plan and the Vision Plan.

- Long Term Disability costs are shared 50%/50% by the employer and employee.

- All LDCs are required to participate in the OMERS retirement plan. Therefore, the pension benefits provided to the employees of HHI are consistent with other utilities. The plan is a contributory plan with employees contributing 50 percent of the premiums and HHI contributing the remaining 50%.

EMPLOYEE COSTS TABLE

Number of Employees:

Description	2006 EDR	2006 Actual	2007 Actual	2008 Actual	2009 Projected	2010 Projected
Management	2	2	2	2	2	2
Union	5	5	5	6	6	6
FTE TOTAL	7	7	7	8	8	8

Compensation - Salary & Wages:

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Projected	Average	2010 Projected	Average
Management	114,196	57,098	123,622	61,811	127,711	63,856	133,996	66,998	138,016	69,008	142,156	71,078
Union	232,275	46,455	235,100	47,020	239,181	47,836	275,247	45,874	283,504	47,251	292,009	48,668
FTE TOTAL	346,471		358,722		366,892		409,243		421,520		434,166	

Compensation - Benefits:

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Projected	Average	2010 Projected	Average
Management	22,638	11,319	23,339	11,670	24,131	12,065	24,224	12,112	24,856	12,428	25,630	12,815
Union	58,211	11,642	60,015	12,003	62,051	12,410	72,673	12,112	74,567	12,428	76,890	12,815
FTE TOTAL	80,849		83,354		86,182		96,897		99,422		102,520	

Compensation - Incentives:

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Projected	Average	2010 Projected	Average
Management	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Union	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
FTE TOTAL	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil

TOTAL - Salary, Wages & Benefits:

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Projected	Average	2010 Projected	Average
Management	136,834	68,417	146,961	73,481	151,842	75,921	158,220	79,110	162,872	81,436	167,786	83,893
Union	290,486	58,097	295,115	59,023	301,232	60,246	347,920	57,987	358,071	59,678	368,899	61,483
FTE TOTAL	427,320		442,076		453,074		506,140		520,942		536,686	

Costs Charged to OM&A:

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Projected	Average	2010 Projected	Average
Management	136,834	68,417	146,961	73,481	151,842	75,921	158,220	79,110	162,872	81,436	167,786	83,893
Union	280,589	56,118	273,261	54,652	290,226	58,045	337,276	56,213	345,000	57,500	355,399	59,233
FTE TOTAL												

BREAKDOWN OF EMPLOYEE COSTS

EMPLOYEE COSTS	YEAR 2005	YEAR 2006	YEAR 2007	YEAR 2008	ESTIMATED YEAR 2009	ESTIMATED YEAR 2010
Employee wages	346,471	358,722	366,892	409,243	421,520	434,166
Employee benefits - MEARIE (Employer portion only)	30,662	30,063	31,648	33,783	35,472	37,245
Employee benefits - OMERS (Employer portion only)	21,648	24,188	25,055	28,494	29,000	30,000
Employee benefits - EHT	5,495	6,202	6,332	8,237	8,300	8,400
CPP (Employer portion only)	12,393	12,595	12,979	14,937	15,100	15,200
EI (Employer portion only)	7,231	6,899	6,759	7,530	7,600	7,700
WSIB	3,420	3,408	3,409	3,916	3,950	3,975
SUBTOTAL	**427,320**	**442,076**	**453,073**	**506,140**	**520,942**	**536,686**
Board of Directors - Wages	10,000	9,833	10,000	10,000	10,000	10,000
TOTAL	**437,320**	**451,909**	**463,073**	**516,140**	**530,942**	**546,686**

Exhibit 4: Operating Costs

Tab 5 (of 8): Corporate Cost Allocations

SHARED SERVICES & CORPORATE COST ALLOCATIONS

As defined by the Board, Shared Services is the concentration of a company's resources performing like activities (typically spread across the organization) in order to service affiliates (and/or a parent company), with the intention of achieving lower costs and higher service levels.

HHI does not have any affiliates and having only 8 employees, does not have shared services or allocate corporate costs. HHI's workforce strives on managing and operating a highly efficient, cost effective, distribution utility serving more customers per FTEE than larger distributors including those with shared services. HHI's economies are gained through the prudent purchases of utility services from non-affiliated vendors.

Exhibit 4: Operating Costs

Tab 6 (of 8): Purchase of Non-Affiliate Services

PURCHASES FROM SUPPLIERS

HHI's purchases equipment, materials, and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of service. Vendors are screened to ensure knowledge, reputation, and the capability to meet HHI's needs. The procurement of goods and/or services for HHI is carried out with highest of ethical standards and consideration to the public nature of the expenditures.

PURCHASE AUTHORIZATION

The General Manager, along with Board of Director input, approves all purchases of goods and/or services.

TENDERING

If there are multiple vendors servicing Hawkesbury's service area, a minimum of 3 quotes will be requested. Once again, the General Manager, along with the Board of Director input, shall authorize the acceptance of the proposals.

The tables presented at Exhibit 4, Tab 6, Schedule 1, Attachment 1 disclose expenditures for suppliers.

2008 Purchases by Supplier

Name Of Supplier	Amount Spent In Historical Year	Type Of Expense	Cost Or Contract Approach
Hydro Ottawa	$ 26,018.94	Metering Points Settlement Services Till End Of June 2008 & Meter Verification	Contract
Partner Technologies Incorporated	$ 24,471.80	Recloser For 115 Kv Substation	Cost
Lakeport Power	$ 22,443.16	Inventory Purchases: Pole Top Extensions, Rubber Gloves, Padmount Transformers, Conductor Covers And Gripall	Cost
Sylvain Goulet	$ 20,375.86	Meter Reading Services	Contract
Harris Computer Systems	$ 18,823.73	Annual Maintenance Support Till May 31St 2008, Dereg Support & Users Conference	Contract
Canada Post Corporation	$ 17,986.63	Stamps And Postage For Billing And Other Correspondence	Cost
Deloitte Touche	$ 17,640.00	Annual Audit Fees And Rate Rebasing Costs.	Cost
Bell Canada	$ 15,825.23	Monthly Service Charge & Equipement Rental	Contract
Elenchus Research Associates Inc.	$ 15,290.63	Rate Rebasing Costs	Contract
Electricity Distributors Association	$ 13,440.00	Eda Annual Membership Fees	Cost
Summitt Energy Management Inc.	$ 12,992.18	Retail Settlement Charges	Contract
Master Card (Bnc)	$ 11,810.00	Miscelleneous	Cost
Mearie-Liability Insurance	$ 11,603.52	Liability Insurance	Contract
Carkner Office Supply Ltd.	$ 9,485.47	Office Supplies & Equipment	Cost
Ontario Energy Board	$ 8,609.93	Regulatory Expenses	Cost
Econo Gas Bar	$ 8,250.38	Fuel & Gas	Cost
Sure Voltage	$ 8,043.99	Substation Equipement And Maintenance	Contract
Stantec Consulting Ltd. (Scl)	$ 6,467.86	Co-Generation Document & Requirements	Contract
Minister Of Finance	$ 6,331.57	Employer Health Tax	Cost
Theoret & Martel Insurance	$ 6,043.68	Board, Comprehensive Crime & Property Insurance	Contract
General Electric Canada Inc.	$ 5,559.56	Oil Tests And Maintenance	Contract
Sage Accpac Canada Inc.	$ 5,480.50	Accpac Support & Updates	Cost
Cupe -Local 1026H	$ 4,487.45	Union Fees	Pass Through
Workplace Safety & Ins Board	$ 3,820.75	Wsib Fees	Cost
Mearie-Vehicle Insurance Program	$ 3,664.00	Fleet Insurance	Contract
Pitney Bowes Global Credit Services	$ 3,652.50	Rental Fees	Contract
Pc Maintenance	$ 3,542.55	It Services & Maintenance	Cost
Shell Energy North America	$ 3,503.44	Retail Settlement Charges	Contract
Lucette Denis	$ 3,468.28	Janitorial Service	Cost
Universal Energy Corporation	$ 3,411.21	Retail Settlement Charges	Contract
Burlington Business Forms	$ 3,306.81	Billing Stationnary	Cost
Electrical Safety Authority	$ 3,281.28	Regulatory Oversight Cost & Licence Fee	Cost
I.G.S. Hawkesbury	$ 3,275.21	Internet Service And Upgrade To High Speed	Contract
The Spi Group	$ 2,959.33	Ebt Spokes	Contract
Peterborough Utilities Services Inc.	$ 2,520.00	Msp Services	Contract
Excavation Claude Lacombe Inc.	$ 2,509.29	Snow Removal Services	Contract
Thibert Printing Inc.	$ 2,451.53	Business Forms & Printing Services	Cost
Bell Mobility	$ 2,316.94	Cellular Phones	Contract
Electrical Utilities Safety	$ 2,100.00	Course Fees	Cost
Quasar	$ 2,083.07	Esa Annual Audit Fees	Contract
Esm Services Informatiques Inc.	$ 2,074.64	Accounting Software Maintenance & Services	Cost
Centre De Services À L'Emploi	$ 2,047.10	Outside Service Employed	Cost
Woods Parisien	$ 1,574.55	Easements Fees	Cost
Arpentages Schultz Barrette	$ 1,484.00	Easements Fees	Cost
Kinectrics Inc.	$ 1,335.60	Dielectric Testing	Cost
Sproule Powerline Construction	$ 1,286.25	Trouble Call Assistance	Cost
Winworld	$ 1,275.77	Computer Equipement	Cost
Pageau Morel & Associés Inc.	$ 1,102.50	Plans To Meet O.Reg 22/04	Cost
Le Carillon	$ 924.00	Public Notification For New Rates	Cost

Benson 1953	$ 848.43	Tires For Trucks	Cost
Cogeco Cable Canada Inc.	$ 847.00	High Speed Internet Service	Contract
Terry'S Restoration Shop	$ 840.00	Repair Bucket On Boom Truck & Safety Check	Cost
Macewen Mcgill	$ 803.60	Fuel & Gas	Cost
King Garage	$ 788.24	Tires For Boom Truck	Cost
Securité Heb Security Inc.	$ 732.90	Office Security System	Contract
Shepherds Utility Equipment	$ 729.93	Small Tools	Cost
Ministre Des Finances / Mto	$ 611.00	Fleet Annual Registration Renewal	Cost
Bell Mobility Paging	$ 604.77	Pagers & Maintenance Costs	Contract
Canadian Tire Commercial Mc	$ 537.17	Small Tools	Cost
Ecng Limited Partnership	$ 494.44	Retail Settlement Charges	Contract
Larocque Engine Rebuilders Inc.	$ 490.22	Truck Maintenance & Air Tests	Cost
Commercial Equipment Corp - Woodstock	$ 483.11	Rubber Gloves Testing	Cost
Jg Barrette Electric Ltd	$ 444.63	Electric Supplies	Cost
The Review	$ 378.00	Public Notification For New Rates	Cost
Gauthier Auto Glass Ltd.	$ 318.55	Bed Liner For Pick Up	Cost
Receiver General For Canada	$ 311.00	Radio Licence Fees	Cost
Garage Chartrand & Pineau Inc.	$ 307.33	Truck Maintenance	Cost
Trophy Hill	$ 288.15	Lineman Clothing	Cost
Main Industrial Sales Ltd.	$ 260.12	Electric Supplies	Cost
Jiffy Muffler	$ 252.85	Truck Maintenance	Cost
Bertrand Body Shop & Welding	$ 210.52	Safety Gloves And Glasses	Cost
General Bearing Service	$ 182.43	Slings	Cost
Pageau Fire Protection	$ 133.34	Fire Extinguishers & Inspection	Cost
Normand Excavation	$ 109.40	Sand For U/G Service Repairs	Cost
Comtés Unis De Prescott & Russell	$ 100.00	Community Relations	Cost
F.L.C. Sanitation Centre	$ 84.64	Cleaning Supplies	Cost
Agence De Collection Unik	$ 82.14	Collection Agency Fees	Cost
Hawkesbury Motor Sports	$ 81.18	Maintenance Of Lawn Mower	Cost
Purolator Courrier Ltd.	$ 77.41	Courrier Services	Cost
Dell Canada Inc.	$ 67.78	Computer Equipement	Cost
Hawkesbury Lumber - Home Hardware	$ 58.61	Small Tools	Cost
Château Décor	$ 42.36	Rust Paint For Transformers	Cost
Hotte Automobile Inc.	$ 41.30	Oil Change On Pick Up	Cost

Exhibit 4: Operating Costs

Tab 7 (of 8): Depreciation and Amortization

DEPRECIATION RATES AND METHODOLOGY

Details of Depreciation Rates and Methodology can be found at Exhibit 2, Tab 2, Schedule 3 entitled “Depreciation Policy”. HHI’s depreciation rates are consistent with the rates found in Appendix B of the 2006 EDR Handbook.

Depreciation Expense

Account Description	USA # Accumulated Amortisation	USA # Amortisation Expense	Opening Balance (a)	Less Fully Depreciated (b)	Net Of Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e)/(f)	RateMaker
1805-Land	2105	5705	20,000.00		20,000.00		20,000.00	0	-	
1806-Land Rights	2105	5705	8,588.00	(7,050.00)	15,638.00		15,638.00	25	626.00	-626
1815-Transformer Station Equipment - Normally Primary above 50 kV	2105	5705	372,188.32	41,256.32	330,932.00	82,000.00	371,932.00	22	16,906.00	-31912
1820-Distribution Station Equipment - Normally Primary below 50 kV	2105	5705	229,376.45	(137,580.00)	366,956.45	50,000.00	391,956.45	30	13,065.00	-12165
1830-Poles, Towers and Fixtures	2105	5705	347,256.75	(121,050.00)	468,306.75	73,000.00	504,806.75	25	20,192.00	-21143
1835-Overhead Conductors and Devices	2105	5705	390,382.62	(180,390.00)	570,772.62	33,000.00	587,272.62	30	19,576.00	-19898
1840-Underground Conduit	2105	5705	113,633.99	(34,650.00)	148,283.99		148,283.99	25	5,931.00	-5931
1845-Underground Conductors and Devices	2105	5705	219,782.65	(52,050.00)	271,832.65	17,500.00	280,582.65	25	11,223.00	-11317
1850-Line Transformers	2105	5705	323,027.53	(31,375.00)	354,402.53	11,000.00	359,902.53	25	14,396.00	-13915
1855-Service	2105	5705	21,013.15		21,013.15		21,013.15	30	700.00	-700
1860-Meters	2105	5705	224,821.63	(144,475.00)	369,296.63		369,296.63	25	14,772.00	-20031
1865-Other Installations on Customer's Premises	2105	5705			-		-	0	-	
1870-Leased Property on Customer Premises	2105	5705			-		-	0	-	
1875-Street Lighting and Signal Systems	2105	5705			-		-	0	-	
1905-Land	2105	5705	28,299.70		28,299.70		28,299.70	0	-	
1906-Land Rights	2105	5705			-		-	0	-	
1908-Buildings and Fixtures	2105	5705	824,123.77	(196,450.00)	1,020,573.77	25,000.00	1,033,073.77	50	20,661.00	-20661
1910-Leasehold Improvements	2105	5705			-		-	0	-	
1915-Office Furniture and Equipment	2105	5705	38,510.99	5,440.00	33,070.99	19,500.00	42,820.99	10	4,282.00	-4572
1920-Computer Equipment - Hardware	2105	5705	48,613.62	28,100.00	20,513.62	11,000.00	26,013.62	5	5,203.00	-6203
1925-Computer Software	2105	5705	120,041.91	8,300.00	111,741.91	9,200.00	116,341.91	5	23,268.00	-26563
1930-Transportation Equipment	2105	5705	205,345.80	184,896.00	20,449.80		20,449.80	8	2,556.00	-4256
1935-Stores Equipment	2105	5705			-		-	0	-	
1940-Tools, Shop and Garage Equipment	2105	5705	24,648.19	3,430.00	21,218.19	5,000.00	23,718.19	10	2,372.00	-2272
1945-Measurement and Testing Equipment	2105	5705			-		-	0	-	
1950-Power Operated Equipment	2105	5705	4,363.29		4,363.29	30,000.00	19,363.29	10	1,936.00	-1936
1955-Communication Equipment	2105	5705			-		-	0	-	
1960-Miscellaneous Equipment	2105	5705			-		-	0	-	
1965-Water Heater Rental Units	2105	5705			-		-	0	-	
1970-Load Management Controls - Customer Premises	2105	5705			-		-	0	-	
1975-Load Management Controls - Utility Premises	2105	5705			-		-	0	-	
1980-System Supervisory Equipment	2105	5705			-		-	0	-	
1985-Sentinel Lighting Rental Units	2105	5705			-		-	0	-	
1990-Other Tangible Property	2105	5705			-		-	0	-	
1995-Contributions and Grants - Credit	2105	5705	(55,867.11)	(1,250.00)	(54,617.11)		(54,617.11)	25	(2,185.00)	2185
2005-Property Under Capital Leases	2105	5710			-		-	0	-	
			3,508,151.25	(634,897.68)	4,143,048.93	366,200.00	4,326,148.93		175,480.00	

Exhibit 4: Operating Costs

Tab 8 (of 8): Income & Capital Taxes

OVERVIEW OF PROVISION IN LIEU OF TAXES (PILS)

This section of Exhibit 4 presents details on the Provision in Lieu of Taxes (PILS)

At Exhibit 4, Tab 8, Schedule 3, Attachment 1 presents the following tables:

- Undepreciated Capital Costs; proposed to be $2,486,839 for the 2010 Test Year
- Cumulative Eligible Capital; proposed to be $12,115 for the 2010 Test Year
- Interest Expense; projected to be $86,771 for the 2010 Test Year
- Loss Carryforward; projected to be $0 for the 2010 Test Year
- Reserve Balances; proposed to be $0 for the 2010 Test Year
- Taxable Income; proposed to be $160,029 at the new rates, for the 2010 Test year
- Total PILS Expense; proposed to be $31,623 for the 2010 Test year

The Proposed PILs model presented at Exhibit 4, Tab 8, Schedule 3, Attachment 1 was developed by Elenchus Research Associates (“ERA”) and provide a detailed calculations of PILS for the 2009 Bridge Year and 2010 Test years. The PILs model was populated, reviewed and approved by Deloitte & Touche.

Historical PILs

Ontario Energy Board
Commission de l'énergie de l'Ontario
2nd Generation Incentive Regulation Mechanism

Email the Board

Previous | Forward | Table of Contents | Current Tariff Sheet | Proposed Tariff Sheet | Current & Proposed Tariff Sheets | Bill Impacts Generator

Instructions

This worksheet derives the 2009 Federal Tax Rate Adjustment Factor.

No input required.

	2006		2008	2008 Adjustment	2009	2009 Adjustment	
From 2006 PIL's Model							
2006 Regulatory Taxable Income *(K-Factor Cell H87)*	181,942	A	181,942		181,942		
2006 Corporate Income Tax Rate *(K-Factor Cell E79)*	18.62%	B	16.50%		16.00%		
Corporate PILs/Income Tax Provision for Test Year	33,878	C = A * B	30,020		29,111		
Income Tax (grossed-up)	41,629	D = C / (1 -B)	35,953	-5,676	34,656	-1,297	← 2009 Amount to be adjusted
From 2006 EDR Model							
2006 EDR Base Revenue Requirement From Distribution Rates *(K-Factor Cell E105)*	1,313,201	E	1,313,201		1,313,201		
Grossed up taxes as a % of Revenue Requirement	3.200%	F = D / E	2.700%	-0.500%	2.600%	-0.100%	

2009 Federal Tax Rate Adjustment Factor

Sheet Index:

Ontario Energy Board

PILS / CORPORA

Name of Utility:	**Hydro Hawkesbury Inc. / Hawke**
License Number:	**ED-1999-0233**
File Number:	**RP-2005-0020**
	EB-2005-0379
Name of Contact:	**Michel Poulin**
Phone Number:	**613-632-6689** **Ext:**
E-Mail Address:	poulinmi@hawk.igs.net
Date:	**16/01/2006**
Version Number:	**PILS2006.V2.1**

SUMMARY SHEET

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin
Phone Number: 613-632-6689

Ratebase	4,301,537	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	193,569	4-1 DATA for PILS MODEL	F 23

Calculation of Deemed Interest

Debt Ratio	50.00%	4-1 DATA for PILS MODEL	E 20
Debt Rate % (as calculated)	6.50%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	139,800		

<u>Questions that must be answered</u>	Yes or No
1. Did the applicant elect to apply the FMV Bump-up of assets of October 1, 2001 in their annual tax filings? *If No, please explain your reasons in the manager's summary.*	No
Has the applicant included in their reported UCC/ECE the FMV Bump-up of assets in this application ? *If No, please explain your reasons in the manager's summary.*	No
2. Does the applicant have any Investment Tax Credits (ITC)?	No
3. Does the applicant have any Scientific Research and Experimental Development Expenditures?	No
4. Does the applicant have any Capital Gains or Losses for tax purposes?	No
5. Does the applicant have any Capital Leases?	No
6. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No
7. Has the applicant deducted regulatory assets for tax purposes in 2004 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	Yes
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2004 and/or prior years? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes
10 Did the applicant elect to capitalize interest incurred on CWIP for tax purposes for 2004 and/or prior years?	No

Tax Rates & Exemptions

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

Applicant	Rate Base	OCT Exemption	LCT Exemption
		10,000,000	50,000,000
Hydro Hawkesbury Inc. / Hawkesbury Hydr	4,301,537	10,000,000	50,000,000
Regulated Affiliates (if applicable)			
1		0	0
2		0	0
3		0	0
4		0	0
5		0	0
Total	4,301,537	10,000,000	50,000,000

Corporate Tax Rates for Test Year

Income Range	0 to 300,000	300,000 to 400,000	400,000 to 1,128,519	>1,128,519
Federal	13.12%	22.12%	22.12%	22.12%
Ontario	5.50%	5.50%	5.50%	14.00%
Income Tax Rates used to gross up the true up variance	18.62%	27.62%	27.62%	36.12%
Ontario SBD Clawback			4.67%	

Capital Tax Rate	0.300%
LCT rate	0.125%
Surtax	1.12%

2004 Adjusted Taxable Income

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin
Phone Number: 613-632-6689

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2004 Wires Only
Income before PILs/Taxes	A	247,386	0	247,386
Additions:				
Interest and penalties on taxes	103	186	0	186
Amortization of tangible assets	104	156,576	0	156,576
Amortization of intangible assets	106	2,301	0	2,301
Recapture of capital cost allowance from Schedule 8	107	0	0	0
Gain on sale of eligible capital property from Schedule 10	108	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	109	0	0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112	0	0	0
Taxable Capital Gains	113	0	0	0
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	0	0	0
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120	0	0	0
Non-deductible meals and entertainment expense	121	0	0	0
Non-deductible automobile expenses	122	0	0	0
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves deducted in prior year	125	0	0	0
Reserves from financial statements- balance at end of year	126	0	0	0
Soft costs on construction and renovation of buildings	127	0	0	0
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0
Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Other Additions				
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
Amounts collected for regulatory assets	294	38,302	0	38,302
	295	0	0	0
Total Additions		**197,365**	**0**	**197,365**

2004 Adjusted Taxable Income

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin
Phone Number: 613-632-6689

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2004 Wires Only
Deductions:				
Gain on disposal of assets per financial statements	401	0	0	0
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	129,804	0	129,804
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	1,409	0	1,409
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	0	0	0
Tax reserves claimed in current year	413	0	0	0
Reserves from financial statements - balance at beginning of year	414	0	0	0
Contributions to deferred income plans	416	0	0	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	0	0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390	0	0	0
Capital Lease Payments	391	0	0	0
Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
Capitalized regulatory assets	393	277,252	0	277,252
Refund of RSVA amounts	394	124,290	0	124,290
Total Deductions		**532,755**	**0**	**532,755**
Net Income for Tax Purposes		**-88,004**	**0**	**-88,004**
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 4	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
TAXABLE INCOME		**-88,004**	**0**	**-88,004**

2004 Schedule 8 and 10 UCC and CEC

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Michel Poulin Phone Number: 613-632-6689

Methodology: This schedule starts with 2004 Schedules 8 and 10, as filed in the actual 2004 corporate tax returns; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the Test Year Schedules

Class	Class Description	UCC End of Year Dec 31/04 per tax returns	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Test Year Opening Balance
1	Distribution System - post 1987	1,603,712	0	0	1,603,712
2	Distribution System - pre 1988	502,628	0	0	502,628
8	General Office/Stores Equip	10,517	0	0	10,517
10	Computer Hardware/ Vehicles	67,151	0	0	67,151
10.1	Certain Automobiles	0	0	0	0
12	Computer Software	582	0	0	582
13_1	Lease # 1	0	0	0	0
13_2	Lease #2	0	0	0	0
13_3	Lease # 3	0	0	0	0
13_4	Lease # 4	0	0	0	0
14	Franchise	0	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	1,403	0	0	1,403
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0
		0	0	0	0
		0	0	0	0
	SUB-TOTAL - UCC	**2,185,993**	**0**	**0**	**2,185,993**
CEC	Goodwill	0	0	0	0
CEC	Land Rights	0	0	0	0
CEC	FMV Bump-up	0	0	0	0
	Incorporation fees	18,725	0	0	18,725
		0	0	0	0
	SUB-TOTAL - CEC	**18,725**	**0**	**0**	**18,725**

UCC Additions and CEC Additions

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin
Phone Number: 613-632-6689

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total Additions	Test Year - Tier 1, Tier 2 Total Disposals
			Additions	Disposals	Additions	Disposals		
1620	Buildings and Fixtures	1	0	0	0	0	0	0
1635	Boiler Plant Equipment	1	0	0	0	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0	0	0	0
1708	Buildings and Fixtures	1	0	0	0	0	0	0
1715	Station Equipment	1	0	0	0	0	0	0
1720	Towers and Fixtures	1	0	0	0	0	0	0
1725	Poles and Fixtures	1	0	0	0	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0	0	0	0
1735	Underground Conduit	1	0	0	0	0	0	0
1740	Underground Conductors and Devices	1	0	0	0	0	0	0
1745	Roads and Trails	1	0	0	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0	0	0	0
1825	Storage Battery Equipment	1	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0	0	0	0
1840	Underground Conduit	1	0	0	0	0	0	0
1845	Underground Conductors and Devices	1	0	0	0	0	0	0
1850	Line Transformers	1	0	0	0	0	0	0
1855	Services	1	0	0	0	0	0	0
1860	Meters	1	0	0	0	0	0	0
1865	Other Installations on Customer's Premises	1	0	0	0	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0	0	0	0
1908	Buildings and Fixtures	1	0	0	0	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0	0	0	0
2070	Other Utility Plant	1	0	0	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0	0	0	0
xxx2	Smart Meters	1	0	0	0	0	0	0
	SUBTOTAL - CLASS 1		**0**	**0**	**0**	**0**	**0**	**0**

UCC Additions and CEC Additions

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total Additions	Test Year - Tier 1, Tier 2 Total Disposals
			Additions	Disposals	Additions	Disposals		
1620	Buildings and Fixtures	2	0	0	0	0	0	0
1635	Boiler Plant Equipment	2	0	0	0	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0	0	0	0
1708	Buildings and Fixtures	2	0	0	0	0	0	0
1715	Station Equipment	2	0	0	0	0	0	0
1720	Towers and Fixtures	2	0	0	0	0	0	0
1725	Poles and Fixtures	2	0	0	0	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0	0	0	0
1735	Underground Conduit	2	0	0	0	0	0	0
1740	Underground Conductors and Devices	2	0	0	0	0	0	0
1745	Roads and Trails	2	0	0	0	0	0	0
1808	Buildings and Fixtures	2	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0	0	0	0
1825	Storage Battery Equipment	2	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0	0	0	0
1840	Underground Conduit	2	0	0	0	0	0	0
1845	Underground Conductors and Devices	2	0	0	0	0	0	0
1850	Line Transformers	2	0	0	0	0	0	0
1855	Services	2	0	0	0	0	0	0
1860	Meters	2	0	0	0	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0	0	0	0
1908	Buildings and Fixtures	2	0	0	0	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0	0	0	0
2070	Other Utility Plant	2	0	0	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0	0	0	0
xxx2	Smart Meters	2	0	0	0	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**	**0**	**0**	**0**

UCC Additions and CEC Additions

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total Additions	Test Year - Tier 1, Tier 2 Total Disposals
			Additions	Disposals	Additions	Disposals		
1875	Street Lighting and Signal Systems	8	0	0	0	0	0	0
1915	Office Furniture and Equipment	8	0	0	0	0	0	0
1935	Stores Equipment	8	0	0	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0	0	0
1955	Communication Equipment	8	0	0	0	0	0	0
1960	Miscellaneous Equipment	8	0	0	0	0	0	0
1965	Water Heater Rental Units	8	0	0	0	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0	0	0	0
1980	System Supervisory Equipment	8	0	0	0	0	0	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0	0	0
	SUBTOTAL - CLASS 8		**0**	**0**	**0**	**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	0	0	0	0	0	0
	SUBTOTAL - CLASS 45		**0**	**0**	**0**	**0**	**0**	**0**
1930	Transportation Equipment	10	0	0	0	0	0	0
	SUBTOTAL - CLASS 10		**0**	**0**	**0**	**0**	**0**	**0**
1925	Computer Software - CL12	12	0	0	0	0	0	0
	SUBTOTAL - CLASS 12		**0**	**0**	**0**	**0**	**0**	**0**
1630	Leasehold Improvements	13_1	0	0	0	0	0	0
1710	Leasehold Improvements	13_2	0	0	0	0	0	0
1810	Leasehold Improvements	13_3	0	0	0	0	0	0
1910	Leasehold Improvements	13_4	0	0	0	0	0	0
	SUBTOTAL - CLASS 13		**0**	**0**	**0**	**0**	**0**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0	0	0	0
1645	Turbogenerator Units	43.1	0	0	0	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0	0	0	0
1670	Prime Movers	43.1	0	0	0	0	0	0
1675	Generators	43.1	0	0	0	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0	0	0	0
	SUBTOTAL - Generating Equipment		**0**	**0**	**0**	**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0	0	0	0
	SUBTOTAL - Capital Leases		**0**	**0**	**0**	**0**	**0**	**0**
1606	Organization	ECP	0	0	0	0	0	0
1610	Miscellaneous Intangible Plant	ECP	0	0	0	0	0	0
1616	Land Rights	ECP	0	0	0	0	0	0
1706	Land Rights	ECP	0	0	0	0	0	0
1806	Land Rights	ECP	0	0	0	0	0	0
1906	Land Rights	ECP	0	0	0	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0	0	0	0
1608	Franchises and Consents	14	0	0	0	0	0	0
	SUBTOTAL - Eligible Capital Property		**0**	**0**	**0**	**0**	**0**	**0**
1615	Land	LAND	0	0	0	0	0	0
1705	Land	LAND	0	0	0	0	0	0
1805	Land	LAND	0	0	0	0	0	0
1905	Land	LAND	0	0	0	0	0	0
	SUBTOTAL - Land		**0**	**0**	**0**	**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0	0	0	0
			0	0	0	0	0	0
	Total Tier 1 and Tier 2 Adjustments		**0**	**0**	**0**	**0**	**0**	**0**

Schedule 8 CCA Test Year

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin   Phone Number: 613-632-6689

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC Test Year Opening Balance	Test Year - Tier 1, Tier 2 Additions	Test Year - Tier 1, Tier 2 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	1,603,712	0	0	1,603,712	0	1,603,712	4%	64,148	1,539,564
2	Distribution System - pre 1988	502,628	0	0	502,628	0	502,628	6%	30,158	472,470
8	General Office/Stores Equip	10,517	0	0	10,517	0	10,517	20%	2,103	8,414
10	Computer Hardware/ Vehicles	67,151	0	0	67,151	0	67,151	30%	20,145	47,006
10.1	Certain Automobiles	0	0	0	0	0	0	30%	0	0
12	Computer Software	582	0	0	582	0	582	100%	582	0
13 1	Leasehold Improvement # 1	0	0	0	0	0	0	5	0	0
13 2	Leasehold Improvement # 2	0	0	0	0	0	0	4	0	0
13 3	Leasehold Improvement # 3	0	0	0	0	0	0	3	0	0
13 4	Leasehold Improvement # 4	0	0	0	0	0	0	4	0	0
14	Franchise	0	0	0	0	N/A	0	7	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Software acq'd post Mar 22/04	1,403	0	0	1,403	0	1,403	45%	631	772
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
			0	0	0	0	0		0	0
			0	0	0	0	0		0	0
		0			0	0	0		0	0
		0			0	0	0		0	0
	TOTAL	2,185,993	0	0	2,185,993	0	2,185,993		117,768	2,068,225

Cumulative Eligible Capital Deduction - Schedul

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Michel Poulin Phone Number: 613-632-6689

Cumulative Eligible Capital				**18,725**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**18,725**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	**0**
Cumulative Eligible Capital Balance				**18,725**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**18,725**	**x 7% =**	**1,311**
Cumulative Eligible Capital - Closing Balance				**17,414**

Schedule 13 - Tax Reserves

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Michel Poulin
Phone Number: 613-632-6689

CONTINUITY OF RESERVES

Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)			0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)			0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Michel Poulin   Phone Number: 613-632-6689

CONTINUITY OF RESERVES

Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)			0		0			0	0	
General reserve for bad debts			0		0			0	0	
Accrued Employee Future Benefits:			0		0			0	0	
- Medical and Life Insurance			0		0			0	0	
-Short & Long-term Disability			0		0			0	0	
-Accmulated Sick Leave			0		0			0	0	
- Termination Cost			0		0			0	0	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs			0		0			0	0	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs			0		0			0	0	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 13 - Tax Reserves

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Michel Poulin Phone Number: 613-632-6689

CONTINUITY OF RESERVES

						Test Year Adjustments				
Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Additions	Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses

Schedule 7-1 Loss Carry-Forwards

Name of Utility:	Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number:	ED-1999-0233
File Numbers:	RP-2005-0020, EB-2005-0379
Name of Contact:	Michel Poulin

Phone Number: 613-632-6689

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion [1]**	**Utility Balance**
Actual/Estimated December 31, 2004	0		0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion [1]**	**Utility Balance**
Actual/Estimated December 31, 2004	0		0
Application of Loss Carry Forward to reduce taxable capital gains in 2005			0
Other Adjustments +ADD -(DEDUCT)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year (see Note 2)			0
Balance available for use post Test Year	0	0	0

Note

[1] **Please describe your methodology and rationale in the Manager's Summary**

[2] **Please provide calculation of the net-capital loss utilization and the inclusion rates that you proposes to use in your actual tax returns**

Excess Interest Expense

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin
Phone Number: 613-632-6689

Calculated Deemed 2004 Interest Expense in 2006 EDR model	139,800	
2004 Actual Interest Expense	115,839	2-2 UNADJUSTED ACCOUNTING DATA L 491
2004 Capitalized Interest (USoA 6040)	0	2-2 UNADJUSTED ACCOUNTING DATA L 431
2004 Capitalized Interest (USoA 6042)	0	2-2 UNADJUSTED ACCOUNTING DATA L 432
2004 Actual Interest	115,839	
Interest Forecast for Tier 1 or 2 Adjustments		
Total Interest	115,839	
Excess Interest Expense for 2006 PILs	0	

Note: The applicant must indicate whether it made an election to capitalize interest incurred on CWIP for tax purposes for 2004 and prior years.

Test Year Taxable Income

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Net Income Before Taxes		193,569	247,386	-53,817	*Note this value will be significantly larger due to PILs collected in 2004 Adjusted Taxable Income.*
Additions:					
Interest and penalties on taxes	103	0	186	-186	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	156,576	156,576	0	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	2,301	2,301	0	
Recapture of capital cost allowance from Schedule 8	107		0	0	
Gain on sale of eligible capital property from Schedule 10	108		0	0	
Income or loss for tax purposes- joint ventures or partnerships	109		0	0	
Loss in equity of subsidiaries and affiliates	110		0	0	
Loss on disposal of assets	111		0	0	
Charitable donations	112		0	0	
Taxable Capital Gains	113		0	0	
Political Donations	114		0	0	
Deferred and prepaid expenses	116		0	0	
Scientific research expenditures deducted on financial statements	118		0	0	
Capitalized interest	119		0	0	
Non-deductible club dues and fees	120		0	0	
Non-deductible meals and entertainment expense	121		0	0	
Non-deductible automobile expenses	122		0	0	
Non-deductible life insurance premiums	123		0	0	
Non-deductible company pension plans	124		0	0	
Tax reserves beginning of year	125	0	0	0	
Reserves from financial statements- balance at end of year	126	0	0	0	
Soft costs on construction and renovation of buildings	127		0	0	
Book loss on joint ventures or partnerships	205		0	0	
Capital items expensed	206		0	0	
Debt issue expense	208		0	0	
Development expenses claimed in current year	212		0	0	
Financing fees deducted in books	216		0	0	
Gain on settlement of debt	220		0	0	
Non-deductible advertising	226		0	0	
Non-deductible interest	227		0	0	
Non-deductible legal and accounting fees	228		0	0	
Recapture of SR&ED expenditures	231		0	0	
Share issue expense	235		0	0	
Write down of capital property	236		0	0	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		0	0	
Other Additions: (please explain in detail the nature of the item)					
Interest Expensed on Capital Leases	290		0	0	
Realized Income from Deferred Credit Accounts	291		0	0	
Pensions	292		0	0	
Non-deductible penalties	293		0	0	
Amounts collected for regulatory assets	294	0	38,302	-38,302	See line 394 below
	295		0	0	
	296		0	0	
	297		0	0	
Total Additions		**158,877**	**197,365**	**-38,488**	

Test Year Taxable Income

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin   Phone Number: 613-632-6689

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Deductions:					
Gain on disposal of assets per financial statements	401		0	0	
Dividends not taxable under section 83	402		0	0	
Capital cost allowance from Schedule 8	403	117,768	129,804	-12,036	
Terminal loss from Schedule 8	404		0	0	
Cumulative eligible capital deduction from Schedule 10 CEC	405	1,311	1,409	-98	
Allowable business investment loss	406		0	0	
Deferred and prepaid expenses	409		0	0	
Scientific research expenses claimed in year	411		0	0	
Tax reserves end of year	413	0	0	0	
Reserves from financial statements - balance at beginning of year	414	0	0	0	
Contributions to deferred income plans	416		0	0	
Book income of joint venture or partnership	305		0	0	
Equity in income from subsidiary or affiliates	306		0	0	
Other deductions: (Please explain in detail the nature of the item)					
Interest capitalized for accounting deducted for tax	390		0	0	
Capital Lease Payments	391		0	0	
Non-taxable imputed interest income on deferral and variance accounts	392		0	0	
Capitalized regulatory assets	393	15,020	277,252	-262,232	ar is 0 because estimate included in 2004 is greate
Refund of RSVA amounts	394	36,405	124,290	-87,885	Based on actual and estimated sales
Excess Interest (from Tab "Schedule 7-3")	395	0	0	0	Applicable to Test Year only
	396		0	0	
	397		0	0	
Total Deductions		**170,504**	**532,755**	**-362,251**	
NET INCOME FOR TAX PURPOSES		**181,942**	**-88,004**	**269,946**	
Charitable donations	311		0	0	
Taxable dividends received under section 112 or 113	320		0	0	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0	
Net-capital losses of preceding taxation years (Please show calculation)	332		0	0	
Limited partnership losses of preceding taxation years from Schedule 4	335		0	0	
TAXABLE INCOME (C/F to tab "Tax Provision)		**181,942**	**-88,004**	**269,946**	

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

If Rate Base is proxy for paid-up capital, use Section A
If using actual paid-up capital, use Section B
Enter the LCT amount from either Section A or B in tab "Tax Provision" cell D28

Section A

	Wires Only
ONTARIO CAPITAL TAX	
Rate Base	4,301,537
Less: Exemption	10,000,000
Deemed Taxable Capital	-5,698,463
Rate in 2006	0.300%
Net Amount (Taxable Capital x Rate)	-17,095
FEDERAL LCT	
Rate Base from	4,301,537
Less: Exemption	50,000,000
Deemed Taxable Capital	0
Rate in 2006	0.125%
Gross Amount (Taxable Capital x Rate)	0
Less: Federal Surtax	2,038
Net LCT	0
Grossed-up LCT	0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

Section B

Detailed Calculation of the Ontario Capital Tax

ONTARIO CAPITAL TAX
(From Ontario CT23)
PAID-UP CAPITAL

	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Paid-up capital stock	1,689,346		1,689,346
Retained earnings (if deficit, use negative sign)	625,383		625,383
Capital and other surplus excluding			0
appraisal surplus			0
Loans and advances	1,845,198		1,845,198
Bank loans			0
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable			0
Deferred credits	-19,885		-19,885
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions			0
Share of partnership(s), joint venture(s) paid-up capital			0
Sub-total	4,140,042	0	4,140,042
Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked	-48,753		-48,753
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	4,188,795	0	4,188,795

ELIGIBLE INVESTMENTS

Bonds, lien notes, interest coupons			0
Mortgages due from other corporations			0
Shares in other corporations			0
Loans and advances to unrelated corporations			0
Eligible loans and advances to related corporations			0
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	0	0	0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

TOTAL ASSETS	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	7,309,253		7,309,253
Mortgages or other liabilities deducted from assets			0
Share of partnership(s)/ joint venture(s) total assets			0
Deduct			
Investment in partnership(s)/joint venture(s)			0
Total assets as adjusted	7,309,253	0	7,309,253
Add: (if deducted from assets)			
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions			0
Deduct			
Amounts deducted for income tax purposes in excess of amounts booked	-48,753		-48,753
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Deduct			
Appraisal surplus if booked			0
Other adjustments (if deducting, use negative sign)			0
Total Assets	7,358,006	0	7,358,006
Investment Allowance	0	0	0
Taxable Capital			
Net paid-up capital	4,188,795	0	4,188,795
Investment Allowance	0	0	0
Taxable Capital	4,188,795	0	4,188,795
Capital Tax Calculation			
Deduction from taxable capital up to $10,000,000	10,000,000		10,000,000
Net Taxable Capital			0
Rate			0.3000%
Ontario Capital Tax (Deductible, not grossed-up)			0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

LARGE CORPORATION TAX
(From Federal Schedule 33)

CAPITAL

	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
ADD:			
Reserves that have not been deducted in computing income for the year under Part I			0
Capital stock	1,689,346		1,689,346
Retained earnings	625,383		625,383
Contributed surplus			0
Any other surpluses			0
Deferred unrealized foreign exchange gains			0
All loans and advances to the corporation	1,845,198		1,845,198
All indebtedness- bonds, debentures, notes, mortgages, bankers acceptances, or similar obligations			0
Any dividends declared but not paid			0
All other indebtedness outstanding for more than 365 days			0
Subtotal	4,159,927	0	4,159,927
DEDUCT:			
Deferred tax debit balance	19,885		19,885
Any deficit deducted in computing shareholders' equity			0
Any patronage dividends 135(1) deducted in computing income under Part I included in amounts above			0
Deferred unrealized foreign exchange losses			0
			0
Subtotal	19,885	0	19,885
Capital for the year	4,140,042	0	4,140,042

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin Phone Number: 613-632-6689

INVESTMENT ALLOWANCE	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Shares in another corporation			0
Loan or advance to another corporation			0
Bond, debenture, note, mortgage, or			0
similar obligation of another corporation			0
Long term debt of financial institution			0
Dividend receivable from another corporation			0
Debts of corporate partnerships that were not exempt from tax under Part I.3			0
Interest in a partnership			0
Investment Allowance	0	0	0

TAXABLE CAPITAL	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Capital for the year	4,140,042	0	4,140,042
Deduct: Investment allowance	0	0	0
Taxable Capital for taxation year	4,140,042	0	4,140,042
Deduct: Capital Deduction upto $50,000,000	50,000,000		50,000,000
Taxable Capital	0	0	0
Rate			0.12500%
Gross Part I.3 Tax LCT			0.00
Federal Surtax Rate			1.1200%
Less: Federal Surtax = Taxable Income x Surtax Rate			2,038
Net Part I.3 Tax - LCT Payable ***(If surtax is greater than Gross LCT, then zero)***			0
Net Part I.3 Tax - LCT Payable grossed-up (1 - 0.1862)			0

Test Year PILs/ Tax Provision

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin
Phone Number: 613-632-6689

	Wires Only			
Regulatory Taxable Income - From 'Test Year Taxable Income'	181,942			
Corporate Income Tax Rate	18.62%			
Total Income Taxes	33,878	2004 Actual	Variance	Explanation of Variance
Investment Tax Credits			0	
Miscellaneous Tax Credits			0	
Total Tax Credits	0	0	0	
Corporate PILs/Income Tax Provision for Test Year	33,878			
Ontario Capital Tax	0			
LCT	0			
INCLUSION IN RATES				
Income Tax (grossed-up)	41,629			
Ontario Capital Tax (not grossed-up)	0			
LCT (grossed-up)	0			
Tax Provision for 2006 EDR Model Rate Recovery (EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)	41,629			

PILs VARIANCE

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin   Phone Number: 613-632-6689

		Income Taxes	OCT	LCT	TOTAL
Actual PILs/Taxes Paid by the Utility [1]	**2002**	0	0	0	0
	2003	31,746	0	0	31,746
	2004	-16,386	0	0	-16,386
Test Year PILs/Taxes [2]	**2006**	41,629	0	0	41,629
Variance (2006 vs. 2004)		58,015	-	-	58,015

Percentage Variance between Actual 2004 and 2006 Proxy 139%

If Cell K18 exceeds 25%, a narrative description of this variance shall be included in the Manager's Summary

Comments:

In 2004, there was a loss. We recovered PILs paid in 2003. In 2004, there should be a profit. Therefore, there is a significant difference betwe

[1] Actual Wires-Only PILs/ Taxes paid includes income taxes, Ontario Capital Tax and Large Corporation Tax.
These values are available from your annual filings - SIMPIL model TaxRec

[2] Test Year PILs/Taxes include the grossed-up amounts for income taxes and Large Corporation Tax, plus Ontario Capital Tax.

2001 Fair Market Value (FMV) Bump

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	1	0	0	0
1635	Boiler Plant Equipment	1	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0
1708	Buildings and Fixtures	1	0	0	0
1715	Station Equipment	1	0	0	0
1720	Towers and Fixtures	1	0	0	0
1725	Poles and Fixtures	1	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0
1735	Underground Conduit	1	0	0	0
1740	Underground Conductors and Devices	1	0	0	0
1745	Roads and Trails	1	0	0	0
1808	Buildings and Fixtures	1	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0
1840	Underground Conduit	1	0	0	0
1845	Underground Conductors and Devices	1	0	0	0
1850	Line Transformers	1	0	0	0
1855	Services	1	0	0	0
1860	Meters	1	0	0	0
1865	Other Installations on Customer's Premises	1	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0
2070	Other Utility Plant	1	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0
xxx2	Smart Meters	1	0	0	0
SUBTOTAL - CLASS 1			**0**	**0**	**0**

2001 Fair Market Value (FMV) Bump

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	2	0	0	0
1635	Boiler Plant Equipment	2	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0
1708	Buildings and Fixtures	2	0	0	0
1715	Station Equipment	2	0	0	0
1720	Towers and Fixtures	2	0	0	0
1725	Poles and Fixtures	2	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0
1735	Underground Conduit	2	0	0	0
1740	Underground Conductors and Devices	2	0	0	0
1745	Roads and Trails	2	0	0	0
1808	Buildings and Fixtures	2	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0
1825	Storage Battery Equipment	2	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0
1840	Underground Conduit	2	0	0	0
1845	Underground Conductors and Devices	2	0	0	0
1850	Line Transformers	2	0	0	0
1855	Services	2	0	0	0
1860	Meters	2	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0
1908	Buildings and Fixtures	2	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0
2070	Other Utility Plant	2	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0
xxx2	Smart Meters	2	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**

2001 Fair Market Value (FMV) Bump

Name of Utility: Hydro Hawkesbury Inc. / Hawkesbury Hydro Inc.
License Number: ED-1999-0233
File Numbers: RP-2005-0020, EB-2005-0379
Name of Contact: Michel Poulin
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1875	Street Lighting and Signal Systems	8	0	0	0
1915	Office Furniture and Equipment	8	0	0	0
1935	Stores Equipment	8	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0
1950	Power Operated Equipment	8	0	0	0
1955	Communication Equipment	8	0	0	0
1960	Miscellaneous Equipment	8	0	0	0
1965	Water Heater Rental Units	8	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0
1980	System Supervisory Equipment	8	0	0	0
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
SUBTOTAL - CLASS 8			**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	0	0	0
SUBTOTAL - CLASS 45			**0**	**0**	**0**
1930	Transportation Equipment	10	0	0	0
SUBTOTAL - CLASS 10			**0**	**0**	**0**
1925	Computer Software - CL12	12	0	0	0
SUBTOTAL - CLASS 12			**0**	**0**	**0**
1630	Leasehold Improvements	13_1	0	0	0
1710	Leasehold Improvements	13_2	0	0	0
1810	Leasehold Improvements	13_3	0	0	0
1910	Leasehold Improvements	13_4	0	0	0
SUBTOTAL - CLASS 13			**0**	**0**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0
1645	Turbogenerator Units	43.1	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0
1670	Prime Movers	43.1	0	0	0
1675	Generators	43.1	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**
1606	Organization	ECP	0	0	0
1610	Miscellaneous Intangible Plant	ECP	0	0	0
1616	Land Rights	ECP	0	0	0
1706	Land Rights	ECP	0	0	0
1806	Land Rights	ECP	0	0	0
1906	Land Rights	ECP	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0
1608	Franchises and Consents	14	0	0	0
SUBTOTAL - Eligible Capital Property			**0**	**0**	**0**
1615	Land	LAND	0	0	0
1705	Land	LAND	0	0	0
1805	Land	LAND	0	0	0
1905	Land	LAND	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0
			0	0	0
	Total FMV Bump-up		**0**	**0**	**0**

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Business Consent form

Complete this form to consent to the release of confidential information about your program account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre (see Instructions).** Make sure you complete this form correctly, since we cannot change the information that you provided. You can also give **or** cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount.**

Note: Read all the instructions before completing this form.

Part 1 – Business information

Complete this part to identify your business (all fields have to be completed)

Business name: HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.

BN: 890592611 Telephone Number: (613) 632-6689

Part 2 – Authorize a representative

Complete either part a) or b)

a) Authorize access by telephone, fax, mail or in person by appointment

If you are giving consent for an individual, enter that person's full name. If you are giving consent to a firm, enter the name and BN of the firm. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the firm's name and BN. If you do not identify an individual of the firm, then you are giving us consent to deal with anyone from that firm.

Note: If you are authorizing a representative (individual or firm) who is not registered with the Represent a client service, the phone number is required.

Name of Individual:

Name of Firm: DELOITTE.

Telephone number: (613) 632-4178 Extension: **BN:** 133245290

Or

b) Authorize online access (includes access by telephone, fax, mail or by appointment)

You can authorize your representative to deal with us through our online service for representatives. **The name of the firm must be the same name that is registered with the Represent a client service at www.cra.gc.ca/representatives**. Our online service does not have a year-specific option, so your representative will have access to **all years**. Please enter the name and RepId of the individual or name and BN of the firm.

Name of Individual:

Name of Firm: DELOITTE.

RepID: **BN:** 133245290
The Business Number must be registered with the Represent a client service to be an online representative.

Part 3 – Select the program accounts, years and authorization level

a) Program Accounts – Select the program accounts the above individual or firm is authorized to access (tick only box A **or** B).

A. [X] This authorization applies to all program accounts and all years.
Online access is available for all years only.

Expiry date:

And

Authorization Level (tick level 1 or 2)

[ ] Level 1 lets CRA disclose information only on your program account(s) **Or**

[X] Level 2 lets CRA disclose information **and** accept changes to your program account(s).

Or

B. [ ] This authorization applies only to program accounts and periods listed in Part 3b). If you ticked this option, you must complete 3b).

RC59 E (08) Canada

Business Consent form (RC59 continued)

Part 3 – Select the program accounts, years and authorization level (continued)

b) Details of program accounts and fiscal periods – Complete this area only if you ticked box B in Part 3a) on page 1.

If you ticked box B in part 3a), you have to provide at least one program identifier (see Instructions on page 1). You can then tick the "All program accounts" box for that program identifier **or** enter a reference number. Provide the authorization level (tick **either** box 1 to disclose information or box 2 to disclose information **and** accept changes to your program account).

You can also tick the "All years" box to allow unlimited tax year access or enter a specific fiscal period (specific period authorization **is not available** for online access). You can also enter an expiry date to automatically cancel authorization. If more authorizations or more than four program identifiers are needed, complete another Form RC59.

Program identifier	All program accounts		Reference number	Authorization level 1	Authorization level 2	All years	or	Specific fiscal period (not available for online access) Year-end	Expiry date
		or					or		
		or					or		
		or					or		
		or					or		

Part 4 – Cancel one or more authorizations

Complete this part **only** to cancel authorization(s)

☐ **A.** Cancel **all** authorizations.

☐ **B.** Cancel authorization for the individual or firm identified below.

Name of Individual: ______________________

Name of Firm: ______________________

Part 5 – Certification

This form has to be signed by an authorized person of the business such as an owner, a partner of a partnership, a director of a corporation, an officer of a non-profit organization or a trustee of an estate. By signing and dating this form, you authorize the CRA to deal with the individual or firm listed in Part 2 of this form or cancel the authorizations listed in Part 4.

First name: MICHEL Last name: POULIN

Sign here ► ______________________ Date 2009-10-27

We wil not process this form unless it is **signed** and **dated** by an authorized person of the business.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2009-12-31

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2009-01-31	17,852			17,852
2009-02-28	17,852			17,852
2009-03-31	17,852			17,852
2009-04-30	17,852			17,852
2009-05-31	17,852			17,852
2009-06-30	17,852			17,852
2009-07-31	17,852			17,852
2009-08-31	17,852			17,852
2009-09-30	17,852			17,852
2009-10-31	17,852			17,852
2009-11-30	17,852			17,852
2009-12-31	17,848			17,848
Total	214,220			214,220

Quarterly instalment workchart

Date	Quarterly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2009-03-31				
2009-06-30				
2009-09-30				
2009-12-31				
Total				

Instalment method

Indicate instalment method chosen [1-3] 1

1st Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.). 1

Select this box if you want the instalments to be calculated without taking the applicable thresholds into account ☐

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

1 – Is the corporation a Canadian-controlled private corporation (CCPC)?	X Yes	No
2 – Did the corporation claim any deduction under the section 125, during either the current or previous year?	X Yes	No
3 – Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to $500,000?*	Yes	No
4 – Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to $10,000,000?	Yes	No
5 – Does the corporation have a perfect compliance history in the last 12 months?	Yes	No

If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments. ☐

*Consult the Help (F1) for information on the changes relating to years subsequent to 2008.

1 – 1st Instalment base method

1st Instalment base amount (amount N below)	214,220	÷ 12	=	17,852
Monthly instalments required				17,852
Quarterly tax instalments required	214,220	÷ 4	=	

2 – Combined 1st and 2nd instalment base method

Select this box if you want the first 2 payments* to be calculated without taking the applicable thresholds into account? ☐

2nd Monthly instalment base amount

Indicate: Part I tax		183,260				
Part VI, VI.1 and XIII.1 tax	+					
Federal adjustment for amalgamation, winding up or transfer	+					
Provincial tax, other than Alberta, Québec and Ontario	+					
Ontario tax**	+	132,365				
Provincial adjustment for amalgamation, winding up or transfer	+					
Total	=	315,625	÷ 12	=	26,303	A
1/12 of estimated current year credits (M below /12)				–		
Each of the first two instalment payments				=	26,303	B
Total tax from N below		214,220				
Amount B above x 2	–	52,606				
	=	161,614	÷ 10	=	16,162	
Each of the remaining ten instalment payments				=	16,162	

2nd Quarterly instalment base amount

Indicate: Part I tax		183,260				
Part VI, VI.1 and XIII.1 tax	+					
Federal adjustment for amalgamation, winding up or transfer	+					
Provincial tax, other than Alberta, Québec and Ontario	+					
Ontario tax**	+	132,365				
Provincial adjustment for amalgamation, winding up or transfer	+					
Total	=	315,625	÷ 4	=	78,907	A
1/4 of estimated current year credits (M below /4)				–		
The first instalment payment				=		B
Total tax from N below		214,220				
Amount B above	–					
	=	214,220	÷ 3	=	71,407	
Each of the remaining three instalment payments				=		

* It is the first payment if the quarterly instalments are applicable.

** Use this line only to calculate instalments payable with regard to taxation years ending in 2009 and after.

3 – Estimated tax method

Instalment base amount (amount N below)		÷ 12	=	
Monthly instalments required				
Quarterly tax instalments required		÷ 4	=	

Instalment base calculation

Federal tax

		1st instalment base method		Estimated tax method	
Taxable income		826,411			
Calculation of tax payable					
Federal part I tax		314,036			
Federal surtax	+		+		
Recapture of investment tax credit	+		+		
Refundable tax on a CCPC's investment income	+		+		
Subtotal	=	314,036	=		A
Deduction					
Small business deduction		68,000			
Investment corporation deduction	+		+		
Federal tax abatement	+	82,641	+		
Manufacturing and processing profits deduction	+		+		
Non-business foreign tax credit	+		+		
Business foreign tax credit	+		+		
Tax reduction, general and accelerated	+	36,245	+		
Logging tax credit	+		+		
Federal political contribution tax credit	+		+		
Investment tax credit per Schedule 31 and resource deduction	+		+		
Qualifying environmental trust tax credit	+		+		
Subtotal	=	186,886	=		B
Federal tax summary					
Total part I tax payable (A minus B)		127,150			C
Part VI tax	+		+		D
Part VI.1 tax	+		+		E1
Part XIII.1 tax	+		+		E2
Parts I, VI, VI.1 and XIII.1 **Total**	=	127,150	=		F
Federal adjustments					
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 365	x	365 / 365	
Subtotal	=	127,150	=		
Federal adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total federal tax after adjustments	=	127,150	=		G

Provincial tax

Provincial/territorial tax, other than Alberta, Québec and Ontario			+		+	H

Ontario tax

Use this section only to calculate instalments payable with regard to taxation years ending in 2009 and after (for other tax years, see the *Ontario Tax Instalments* schedule (Jump Code: **ION**)):

				1st instalment base method		Estimated tax method	
Income tax		87,070					
Capital tax	+						
Corporate minimum tax paid (credited)	+						
Special additional tax on life insurance corporations	+						
Total Ontario tax*	=	87,070	+ ▶	87,070	+		I
Harmonized provincial tax (H + I) **Total harmonized provincial tax**			=	87,070	=		J
Provincial adjustments							
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365			x	365 / 365	x	365 / 365	
Subtotal			=	87,070	=		
Provincial adjustment for amalgamation, winding up or transfer			+		+	N/A	
Total provincial tax after adjustments			=	87,070	=		K
Total of tax before refundable credits** (G + K)			=	214,220	=		L

Instalment base calculation (continued)

Estimated current year credits

Investment tax credit refund					
Dividend refund	+		+		
Federal capital gains refund	+		+		
Provincial and territorial capital gains refund	+		+		
NRO allowable refund per Schedule 26	+		+		
Tax withheld at source	+		+		
Other estimated credits	+		+		
Total estimated current year credits	=		=		**M**
Instalment base amount (L minus M)		214,220			**N**

* Ontario tax corresponds to the amount before the application of specified Ontario tax credits.

** For instalments payable for tax years beginning before 2008, the amount on line G is not added to line L unless it exceeds $1,000. The same rule applies to line K. For instalments payable for tax years beginning after 2007, the amount on line G is not added to line L unless it exceeds $3,000. The same rule applies to line K.

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T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 89059 2611 RC0001

Corporation's name
002 HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.

Address of head office
Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018)
011 850 TUPPER STREET
012
015 City: HAWKESBURY
016 Province, territory, or state: ON
017 Country (other than Canada):
018 Postal code/Zip code: K6A 3S7

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028)
021 c/o
022
023
025 City:
026 Province, territory, or state:
027 Country (other than Canada):
028 Postal code/Zip code:

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038)
031 850 TUPPER STREET
032
035 City: HAWKESBURY
036 Province,territory, or state: ON
037 Country (other than Canada):
038 Postal code/Zip code: K6A 3S7

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ______ YYYY MM DD

To which tax year does this return apply?
060 Tax year start: 2008-01-01 (YYYY MM DD)
061 Tax year-end: 2008-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 ______ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

T2 E (08)

Canada

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150		9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234		
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? **282**
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail **283** 1 Wholesale [ ] 2 Retail [X]

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	ELECTRICITY DISTRIBU	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible **294** YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? **295** 1 Yes [ ] 2 No [ ]

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		826,411	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction *	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal			►	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			826,411	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		826,411	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			826,411	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	826,411	A
Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax	405	826,411	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year after 2006 and before 2009 / Number of days in the tax year	366 / 366	=	400,000	1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	/ 366	=		2
		Add amounts at lines 1 and 2			400,000	4

Business limit (see notes 1 and 2 below)	410	400,000	C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C	400,000	x	415 *** ________ D / 11,250	=	E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425	400,000	F

Small business deduction

Amount A, B, C, or F whichever is the least	400,000	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x	16 %	=		5
Amount A, B, C, or F whichever is the least	400,000	x	Number of days in the tax year after December 31, 2007 / Number of days in the tax year	366 / 366	x	17 %	=	68,000	6
			Total of amounts 5 and 6 – enter on line 9				430	68,000	G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)]	435		H

Amount H		x	Number of days in the tax year in 2006 / Number of days in the tax year	/ 366	x	5 %	=	I
Amount H		x	Number of days in the tax year in 2007 / Number of days in the tax year	/ 366	x	7 %	=	J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – Total of amounts I and J Enter amount K on line 10.	438		K

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		826,411	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	B		
Amount QQ from Part 13 of Schedule 27	C		
Taxable resource income from line 435	D		
Amount used to calculate the credit union deduction from Schedule 17	E		
Amount from line 400, 405, 410, or 425, whichever is the least	400,000 F		
Aggregate investment income from line 440	G		
Total of amounts B, C, D, E, F, and G	400,000 ►	400,000	H
Amount A **minus** amount H (if negative, enter "0")		426,411	I

Amount I	426,411	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366	x	7 %	=	J
Amount I	426,411	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 366 / Number of days in the tax year 366	x	8.5 %	= 36,245	K
Amount I	426,411	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 366	x	9 %	=	L
Amount I	426,411	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 366	x	10 %	=	L1

General tax reduction for Canadian-controlled private corporations – Total of amounts J, K, L, and L1 . . . 36,245 M
Enter amount M on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	O		
Amount QQ from Part 13 of Schedule 27	P		
Taxable resource income from line 435	Q		
Amount used to calculate the credit union deduction from Schedule 17	R		
Total of amounts O, P, Q, and R	►		S
Amount N **minus** amount S (if negative, enter "0")			T

Amount T		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366	x	7 %	=	U
Amount T		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 366 / Number of days in the tax year 366	x	8.5 %	=	V
Amount T		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 366	x	9 %	=	W
Amount T		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 366	x	10 %	=	W1

General tax reduction – Total of amounts U, V, W, and W1 . . . X
Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	**440**		x 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632					
Deduct: Foreign investment income from Schedule 7	**445**		x 9 1 / 3 % =		
			(if negative, enter "0")	▶	B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360			826,411		
Deduct:					
Amount from line 400, 405, 410, or 425, whichever is the least		400,000			
Foreign non-business income tax credit from line 632		x 25 / 9 =			
Foreign business income tax credit from line 636		x 3 =			
		400,000 ▶	400,000		
			426,411		
			x 26 2 / 3 % =	113,710	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)			127,150		
Deduct: Corporate surtax from line 600					
Net amount			127,150 ▶	127,150	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least			**450**		F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	**460**			
Deduct: Dividend refund for the previous tax year	**465**			
		▶		G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	**480**			
		▶		H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	**485**			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3	84,467	x 1 / 3	28,156	I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)				

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . **550** 314,036 A

Corporate surtax calculation

Base amount from line A above	314,036	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	82,641	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360		a		
28.00 % of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		
Total of lines 2 to 6			82,641	7
Net amount (line 1 **minus** line 7)			231,395	8

Corporate surtax*

Line 8 231,395 x Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366 x 4 % = **600** B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . . **602** C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360	826,411		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least	400,000		
Net amount	426,411 ▶	426,411	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . **604** D

Subtotal (**add** lines A, B, C, and D) 314,036 E

Deduct:

Small business deduction from line 430		68,000	9	
Federal tax abatement	**608**	82,641		
Manufacturing and processing profits deduction from Schedule 27	**616**			
Investment corporation deduction	**620**			
Taxed capital gains **624**				
Additional deduction – credit unions from Schedule 17	**628**			
Federal foreign non-business income tax credit from Schedule 21	**632**			
Federal foreign business income tax credit from Schedule 21	**636**			
Resource deduction from line 438			10	
General tax reduction for CCPCs from amount M	**638**	36,245		
General tax reduction from amount X	**639**			
Federal logging tax credit from Schedule 21	**640**			
Federal political contribution tax credit	**644**			
Federal political contributions **646**				
Federal qualifying environmental trust tax credit	**648**			
Investment tax credit from Schedule 31	**652**			
Subtotal		186,886 ▶		186,886 F

Part I tax payable – Line E **minus** line F . . . . . 127,150 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	127,150
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		127,150

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
Total tax payable	770		127,150 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 1 Overpayment

Balance (line A **minus** line B) 127,150

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid 127,150

Enclosed payment 898 127,150

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

Certification

I, 950 POULIN (Last name in block letters) 951 MICHEL (First name in block letters) 954 DIRECTEUR GÉNÉRAL (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2009-10-27 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (613) 632-6689 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☒ 2 No ☐

958 ______ Name in block letters 959 ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 2

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	6,301,027	6,097,424
	Total tangible capital assets	2008	+	3,271,519	3,096,613
	Total accumulated amortization of tangible capital assets	2009	–	1,322,276	1,173,118
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	971,831	839,028
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	9,222,101	8,859,947
	Liabilities				
	Total current liabilities	3139	+	2,824,206	3,042,552
	Total long-term liabilities	3450	+	3,859,311	3,257,832
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	6,683,517	6,300,384
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	2,538,584	2,559,563
	Total liabilities and shareholder equity	3640	=	9,222,101	8,859,947
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	849,238	870,217

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	14,647,521	15,359,777
	Cost of sales	8518	–	13,590,055	14,304,462
	Gross profit/loss	8519	=	1,057,466	1,055,315
	Cost of sales	8518	+	13,590,055	14,304,462
	Total operating expenses	9367	+	1,188,450	1,125,326
	Total expenses (mandatory field)	9368	=	14,778,505	15,429,788
	Total revenue (mandatory field)	8299	+	14,916,295	15,678,057
	Total expenses (mandatory field)	9368	–	14,778,505	15,429,788
	Net non-farming income	9369	=	137,790	248,269
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	137,790	248,269
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	199,004	315,625
	Deferred income tax provision	9995	–	-124,702	-221,254
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	63,488	153,898

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SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the “accountant”) who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation?	095	1 Yes X	2 No
Is the accountant connected* with the corporation?	097	1 Yes	2 No X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant:

	198	
Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation?	099	1 Yes	2 No X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options:

	110	
Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

Were notes to the financial statements prepared?	101	1 Yes X	2 No
If **yes**, complete lines 102 to 107 below:			
Are any values presented at other than cost?	102	1 Yes	2 No X
Has there been a change in accounting policies since the last return?	103	1 Yes	2 No X
Are subsequent events mentioned in the notes?	104	1 Yes	2 No X
Is re-evaluation of asset information mentioned in the notes?	105	1 Yes	2 No X
Is contingent liability information mentioned in the notes?	106	1 Yes	2 No X
Is information regarding commitments mentioned in the notes?	107	1 Yes	2 No X
Does the corporation have investments in joint venture(s) or partnership(s)?	108	1 Yes	2 No X
If **yes**, complete line 109 below:			
Are you filing financial statements of the joint venture(s) or partnership(s)?	109	1 Yes	2 No

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements			63,488 A
Add:			
Provision for income taxes – current	101	199,004	
Provision for income taxes – deferred	102	-124,702	
Interest and penalties on taxes	103	51	
Amortization of tangible assets	104	148,065	
Tax reserves deducted in prior year from Schedule 13	125	27,061	
Subtotal of additions		249,479 ►	249,479
Other additions:			
Miscellaneous other additions:			
600 Montants collecté pour actifs règlementés	290	51,224	
601 Actifs règlementés capitalisés (créditeurs)	291	618,656	
602 Carrying charges	292	88,025	
604			
Subtotal of other additions	199	757,905 ►	757,905
Total additions	500	1,007,384 ►	1,007,384
Deduct:			
Capital cost allowance from Schedule 8	403	159,941	
Cumulative eligible capital deduction from Schedule 10	405	1,054	
Tax reserves claimed in current year from Schedule 13	413	83,466	
Subtotal of deductions		244,461 ►	244,461
Other deductions:			
Miscellaneous other deductions:			
704			
Total	394		
Subtotal of other deductions	499	0 ►	0
Total deductions	510	244,461 ►	244,461
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			826,411

* For reference purposes only

T2 SCH 1 E (08)

Canada

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide.*
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "1" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	B 205	C Business Number 210	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
		Complete if payer corporation is connected			
1		2			
				Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1 Eligible dividends	F2	G Total taxable dividends paid by connected payer corporation 250	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 270
			If payer corporation is not connected, leave these columns blank.		
1					
Total (enter amount of column F on line 320 of the T2 return)					J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . ______

Deduct:
Part IV.I tax payable on dividends subject to Part IV tax . . . . **320** ______
Subtotal ______

Deduct:
Current-year non-capital loss claimed to reduce Part IV tax . . . . **330** ______
Non-capital losses from previous years claimed to reduce Part IV tax . . . . **335** ______
Current-year farm loss claimed to reduce Part IV tax . . . . **340** ______
Farm losses from previous years claimed to reduce Part IV tax . . . . **345** ______
Total losses applied against Part IV tax ______ x 1 / 3 = ______

Part IV tax payable (enter amount on line 712 of the T2 return) . . . . **360** ______

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A	B	C	D
	Name of connected recipient corporation	Business Number	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD	Taxable dividends paid to connected corporations
	400	410	420	430
1	Corporation Ville de Hawkesbury	10698 4644 RC0001	2008-12-31	84,467
2				

Note
If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total 84,467

Total taxable dividends paid in the taxation year to other than connected corporations . . . . **450** ______

Total taxable dividends paid in the taxation year for the purposes of a dividend refund
(total of column D above plus line 450) **460** 84,467

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above) 84,467
Other dividends paid in the taxation year (total of 510 to 540) . . . . ______
Total dividends paid in the taxation year **500** 84,467

Deduct:

Dividends paid out of capital dividend account . . . . **510** ______
Capital gains dividends . . . . **520** ______
Dividends paid on shares described in subsection 129(1.2) . . . . **530** ______
Taxable dividends paid to a controlling corporation that was
bankrupt at any time in the year . . . . **540** ______
Subtotal ______ ► ______

Total taxable dividends paid in the taxation year for purposes of a dividend refund 84,467

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1	1	Transm + Distr 1988 and later	1,029,945			0		1,029,945	4	0	0	41,198	988,747
2	2	Transm + Distr before 1988	417,475			0		417,475	6	0	0	25,049	392,426
3	8	Office equipment	10,856	7,084		0	3,542	14,398	20	0	0	2,880	15,060
4	10	Computer	2,925			0		2,925	30	0	0	878	2,047
5	12	Software	13,736	63,308		0	31,654	45,390	100	0	0	45,390	31,654
6	1	Building	639,271			0		639,271	4	0	0	25,571	613,700
7	8	Equipment (Tools)	7,532	709		0	355	7,886	20	0	0	1,577	6,664
8	10	Rolling stock	20,108	20,450		0	10,225	30,333	30	0	0	9,100	31,458
9	45	Computer 22-03-04 to 18-03-07	8,220			0		8,220	45	0	0	3,699	4,521
10	47	Transm + Distr Feb 22, 2005 an	21,928	25,265		0	12,633	34,560	8	0	0	2,765	44,428
11	50	Computer > 18-03-07	2,224	2,223		0	1,112	3,335	55	0	0	1,834	2,613
		Total	2,174,220	119,039			59,521	2,233,738				159,941	2,133,318

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		119,039		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Depreciation land rights	+	626		
Total additions per books	=	119,665	►	119,665
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
	+			
Total proceeds per books	=		– ►	
Depreciation and amortization per accounts – Schedule 1			–	148,065
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	-28,400

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		1,897,467
Opening net book value	–	1,871,093
Net change per financial statements	=	26,374

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 15,061 A

Add: Cost of eligible capital property acquired during the taxation year . . . . **222** ______

Other adjustments . . . . **226** ______

Subtotal (line 222 plus line 226) ______ x 3 / 4 = ______ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** ______ x 1 / 2 = ______ C

amount B minus amount C (if negative, enter "0") ______ ▶ ______ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** ______ E

Subtotal (add amounts A, D, and E) **230** 15,061 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** ______ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** ______ H

Other adjustments . . . . **246** ______ I

(add amounts G,H, and I) ______ x 3 / 4 = **248** ______ J

Cumulative eligible capital balance (amount F minus amount J) . . . . 15,061 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . . **249** ______

amount K 15,061

less amount from line 249 ______

Current year deduction . . . . 15,061 x 7.00 % = **250** 1,054 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 1,054 ▶ 1,054 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 14,007 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4			
Line 3 minus line 4 (if negative, enter "0")			►		5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8			
Subtotal (line 7 plus line 8)	409		►		9	
Line 6 minus line 9 (if negative, enter "0")					►	O
Line N minus line O (if negative, enter "0")						P
Line 5				x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")						R
Amount R				x 2 / 3 =		S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)					410	

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SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- References to parts, sections, subsections, paragraphs, and subparagraphs are from the federal *Income Tax Act*.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on amalgamation or wind-up of subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The total capital gains reserve at the beginning of the taxation year plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary should be entered on line 880, and the total capital gains reserve at the end of the taxation year, should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description		Balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add $	Deduct $	Balance at the end of the year $
Reserve for doubtful debts		110	115			120
Reserve for undelivered goods and services not rendered		130	135			140
Reserve for prepaid rent		150	155			160
Reserve for December 31, 1995 income		170	175			180
Reserve for refundable containers		190	195			200
Reserve for unpaid amounts		210	215			220
Other tax reserves		230 27,061	235	83,466	27,061	240 83,466
Totals		270 27,061	275	83,466	27,061	280 83,466

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 plus the amount from line 275 should be entered on line 125 of Schedule 1 as an addition.
The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business Number **200**	Social insurance number **300**	Trust number **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	THE CORPORATION OF THE TOWN OF HAWKESBURY	10698 4644 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

On: 2008-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year				100	737,196	A
Taxable income for the year (DICs enter "0")*	110	826,411	B			
Income for the credit union deduction* (amount E in Part 3 of Schedule 17) — 120						
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less* — 130: 400,000						
Subtotal (**add** lines 120 and 130): 400,000 ►		400,000	C			
For a CCPC, aggregate investment income (line 440 of the T2 return)* — D						
Line B **minus** line C (if negative enter "0"): 426,411 E						
Amount from line D or E, whichever is less	140		F			
Income taxable at the general corporate rate (line B **minus** lines C and F)	150	426,411				
After-tax income (line 150 **multiplied by** 68 %)				190	289,959	G
Eligible dividends received in the tax year	200					
Dividends deductible under section 113 received in the tax year	210					
Subtotal (**add** lines 200 and 210) ►						H
GRIP addition:						
Becoming a CCPC (line PP from Part 4)	220					
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230					
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240					
Subtotal (**add** lines 220, 230, and 240) ►				290		I
Subtotal (**add** lines A, G, H, and I)					1,027,155	J
Eligible dividends paid in the previous tax year	300					
Excessive eligible dividend designations made in the previous tax year	310					
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.						
Subtotal (line 300 **minus** line 310) ►						K
GRIP before adjustment for specified future tax consequences (line J **minus** line K) (amount can be negative)				490	1,027,155	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)				560		
GRIP at the end of the tax year (line 490 **minus** line 560) Enter this amount on line 160 on Schedule 55.				590	1,027,155	

*** Note:** For lines 110, 120, 130 and D, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 or leave it blank.

First previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year			991,230	J1		
Enter the following amounts before specified future tax consequences from the current tax year:						
Income for the credit union deduction (amount E in Part 3 of Schedule 17)		K1				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	400,000	L1				
Aggregate investment income (line 440 of the T2 return)		M1				
Subtotal (**add** lines K1, L1, and M1)	400,000 ►		400,000	N1		
Subtotal (line J1 **minus** line N1) (if negative, enter "0")			591,230 ►		591,230	O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to first previous tax year (line V1 **multiplied by** 68 %) . . . **500** ______

Second previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year 723,846 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less 300,000 L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . . ______

Subtotal (**add** lines K2, L2, and M2) 300,000 ▶ 300,000 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 423,846 ▶ 423,846 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . . ______

Subtotal (**add** lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to second previous tax year (line V2 **multiplied by** 68 %) **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year . . . . ______ J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . ______ M3

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . . ______

Subtotal (**add** lines K3, L3, and M3) ______ ► ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") ______ ► ______ O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . . ______

Subtotal (**add** lines Q3, R3, and S3) ______ ► ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ► ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to third previous tax year (line V3 **multiplied by** 68 %) . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ► ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)
(line AA **minus** line DD) . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year			FF
The corporation's money on hand immediately before the end of its previous/last tax year			GG
Unused and unexpired losses at the end of the corporation's previous/last tax year:			
Non-capital losses			
Net capital losses			
Farm losses			
Restricted farm losses			
Limited partnership losses			
Subtotal		►	HH
Subtotal (**add** lines FF, GG, and HH)			II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		JJ	
Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		KK	
All the corporation's reserves deducted in its previous/last tax year		LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year		MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year		NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)		►	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")			PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2008-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation,* or Schedule 54, *Low Rate Income Pool Calculation (LRIP)*; whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		84,467			
Total taxable dividends paid in the tax year	100	84,467			
Total eligible dividends paid in the tax year			150		
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")			160	1,027,155	
Excessive eligible dividend designation (line 150 **minus** line 160)					A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (line A **multiplied** by 20%)		x 20 %	190		

Enter the amount from line 190 at line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (line A of Schedule 54)					B
Part III.1 tax on excessive eligible dividend designations – Other corporations (line B **multiplied** by 20%)		x 20 %	290		

Enter the amount from line 290 at line 710 of the T2 return.

Ontario

Ministry of Revenue
Corporations Tax
33 King St. West
PO Box 622
Oshawa ON L1H 8H6

Authorizing or Cancelling a Representative

Complete this form to:

- **authorize** the release of confidential information about the Corporations Tax, Mining Tax or Electricity Act account(s) to the representative named below.
- **cancel** an existing authorization.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	1800111	2008-12-31

Part 1 Client Information

Legal Name: HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.
Phone number: (613) 632-6689

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR
850 TUPPER STREET

City: HAWKESBURY
Province/Territory: ON
Postal code: K6A 3S7

This authorization applies to the following statute(s) and account number(s).

- X **Corporations Tax Act** 1800111
- ☐ **Mining Tax Act**
- ☐ **Electricity Act**

Part 2 Authorize the release of information to a representative

Name of representative (If a firm, name of firm.)
Last First
DELOITTE.

Phone number: (613) 632-4178
Fax number:

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR
300 MCGILL

City: HAWKESBURY
Province/Territory: ON
Postal code: K6A 1P8

If your representative is a firm, and you want a specific person in the firm to represent you, state their name and title.
If you do not identify a specific individual in the firm, you are authorizing the Ministry of Finance to deal with anyone from that firm.

Name of person in firm
Last First

Title

Part 3 Authorization scope and applicable years

X Representative to **deal fully** on your behalf with the Ministry of Finance.
or
☐ Representative to **deal in a limited manner** on your behalf, for matters specified here. (e.g., account inquiry, applications, annual returns, payments, etc.)▼

X Representative to act for **all years**, including all previous and future years.
or
☐ Representative to act for **specific year or years** (describe). ▼

Part 4 Cancel the release of information to a representative

Name of representative (If a firm, name of firm.)
Last First

If your representative is an individual within a firm, state their name and title.

Name of person in firm
Last First

Title

Part 5 Signature *This form will not be accepted unless it is completed fully, signed and dated.*

I authorize the Ministry of Finance to:

- release confidential information about the tax accounts specified in Part 1 and to deal with the representative named in Part 2 in the manner described in Part 3; and/or
- cancel an existing authorization as described in Part 4.

Name
Last First
POULIN MICHEL

Title / Relationship to Corporation: DIRECTEUR GÉNÉRAL

Phone number: (613) 632-6689

Signature

Date 2009-10-27

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No

Corporation's Legal Name *(including punctuation)*
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.

Ontario Corporations Tax Account No. (MOF)
1800111

Mailing Address
850 TUPPER STREET
HAWKESBURY
ON CA K6A 3S7

This Return covers the Taxation Year
Start (year month day): 2008-01-01
End (year month day): 2008-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes
Date of Change (year month day):

Date of Incorporation or Amalgamation (year month day): 2000-10-25

Registered/Head Office Address
850 TUPPER STREET
HAWKESBURY
ON CA K6A 3S7

Ontario Corporation No. (MGS): 1436779

Location of Books and Records
850 TUPPER STREET
HAWKESBURY
ON CA K6A 3S7

Canada Revenue Agency Business No.
If applicable, enter
89059 2611 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
MICHEL POULIN	(613) 632-6689	

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced (year month day):
Ceased (year month day):
[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). No. of Schedule(s):

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). [X] **No Change**

Preferred Language / *Langue de préférence*
[ ] English *anglais* [X] French *français*

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*
MICHEL POULIN

Title D [X] Director O [ ] Officer P [ ] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) **box(es) and complete required information.**

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired — year / month / day

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
[ ]	[X]	the Carry-back of a Loss?
[X]	[ ]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	826,411
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax ____ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses	–	From 704	
Net capital losses From 715 (page 16) ____ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	826,411

Addition to taxable income for unused foreign tax deduction for federal purposes	+	11	
Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11)	=	20	826,411

Taxable Income

Number of Days in Taxation Year

From	Amount		Ontario Allocation		Rate		Days		Total Days			
10 (or 20 if applicable)	826,411	x 30	100.0000 %	x	12.5 %	x	33 (Days after Dec. 31, 2002 and before Jan. 1, 2004)	÷ 73	366	= +	29	
10 (or 20 if applicable)	826,411	x 30	100.0000 %	x	14 %	x	34 366 (Days after Dec. 31, 2003)	÷ 73	366	= +	32	115,698

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 115,698

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X)

X Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))				50	826,411
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+	51	826,411		
Add: Losses of other years deducted for federal purposes (fed.s.111)	+	52			
Subtract: Losses of other years deducted for Ontario purposes (s.34)	–	53			
	=		826,411	54	826,411
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	400,000		

Ontario Business Limit Calculation

320,000 x 31 ____ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ ** 366 = + 46 ____

400,000 x 34 366 (Days after Dec. 31, 2003) ÷ ** 366 = + 47 ____

Business Limit for Ontario purposes 46 + 47 = 44 500,000 x 48 100.0000 % (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) = 45 500,000

Income eligible for the IDSBC From 30 100.0000 % (***Ontario Allocation) x 56 500,000 (Least of 50, 54 or 45) = 60 500,000

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

Calculation of IDSBC Rate - - - 7 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 31 ______ ÷ 73 (Total Days) 366 = + 89 .

8.5 % x (Days after Dec. 31, 2003) 34 366 ÷ 73 (Total Days) 366 = + 90 8.5000

IDSBC Rate for Taxation Year 89 + 90 - - - = 78 8.5000

Claim - - - From 60 500,000 x From 78 8.5000 % - - - = 70 42,500

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 500,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** - - - From 10 (or 20 if applicable) + 80 826,411

If you are a member of an associated group (X) 81 ☐ (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
			+ 82	
			+ 83	
			+ 84	

Aggregate Taxable Income 80 + 82 + 83 + 84 , etc. - - - = 85 826,411

Number of Days in Taxation Year

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 31 ______ ÷ 73 (Total Days) 366 = + 115 ______

400,000 x (Days after Dec. 31, 2003) 34 366 ÷ 73 (Total Days) 366 = + 116 ______

115 + 116 = 500,000 ▶ - - - – 114 500,000

(If negative, enter nil) - - - = 86 326,411

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax - - - 4.6670 % x (Days after Dec. 31, 2002) 38 ______ ÷ 73 (Total Days) 366 = + 97 4.2500

From 86 326,411 x From 97 4.2500 % - - - = 87 13,872

From 87 13,872 x From 60 500,000 ÷ From 114 500,000 = 88 13,872

Surtax Lesser of 70 or 88 - - - = 100 13,872

**** Note: Short Taxation Years –*** Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

DOLLARS ONLY

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)*

Additional Deduction for Credit Unions	110	.

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits	+	120	.
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	– From	56	500,000 .

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 13,872 . ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 163,200 .

*Ontario Allocation

Lesser of 56 or 121	+	122	163,200 .
120 – 56 + 122	=	130	.
Taxable Income	+ From	10	826,411 .
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	– From	56	500,000 .
Add: Adjustments for Surtax on Canadian-controlled private corporations	+ From	122	163,200 .
Subtract: Taxable Income 10 826,411 X Allocation % to jurisdictions outside Canada	–	140	.
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses	–	141	.
10 – 56 + 122 – 140 – 141	=	142	489,611 .

Claim

				Number of Days in Taxation Year		
143 . (Lesser of 130 or 142)	x From 30 100.0000 % (Ontario Allocation)	x 1.5 %	x	Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ÷ 73 Total Days: 366	= +	154 .
143 . (Lesser of 130 or 142)	x From 30 100.0000 % (Ontario Allocation)	x 2 %	x	Days after Dec. 31, 2003: 34 366 ÷ 73 Total Days: 366	= +	156 .

M&P claim for taxation year 154 + 156	=	160	.

*** Note:** *Ontario Allocation for M&P Credit purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations	=	161	.
Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity	=	162	.

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* 170 .

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 . Credit Claimed 180 .

Subtotal of Income Tax 40 – 70 + 100 – 110 – 160 – 161 – 162 – 170 – 180	=	190	87,070 .

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.

Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.

Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)

Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production 204

Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 193

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From 6596

Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194

Eligible Credit From 6598 CT23 Schedule 115 (*Attach Schedule 115*) + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)

Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.

Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)

Applies to labour relating to computer animation and special effects on an eligible production.

Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)

Applies to qualifying R&D expenditures under an eligible research institute contract.

Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10)

Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.

Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)

Applies to qualifying labour expenditures of eligible products for the taxation year.

Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)

Applies to qualifying expenditures in respect of eligible Canadian sound recordings.

Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From 5896

Applies to employment of eligible apprentices. 202

Eligible Credit From 5898 CT23 Schedule 114 (*Attach Schedule 114*) + 203

Other (specify) + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220

Specified Tax Credits ***Applied to reduce Income Tax*** = 225

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 87,070

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

DOLLARS ONLY

Total Assets of the corporation	+ 240	9,222,101	
Total Revenue of the corporation	+ 241		14,916,295

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 ☐ (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Total Assets		Total Revenue
			+ 243		+ 244	
			+ 245		+ 246	
			+ 247		+ 248	

Aggregate Total Assets 240 + 243 + 245 + 247 , etc. = 249 9,222,101

Aggregate Total Revenue 241 + 244 + 246 + 248 , etc. = 250 14,916,295

Determination of Applicability

Applies if ***either*** Total Assets 249 exceeds $5,000,000 ***or*** Total Revenue 250 exceeds $10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101**.

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - - CMT Base From Schedule 101 2136 137,790 (If negative, enter zero) x From 30 100.0000 % (Ontario Allocation) X 4 % = 276 5,512

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	–	277	
Subtract: Income Tax	–	From 190	87,070
Net CMT Payable (If negative, enter Nil on Page 17.)	=	280	-81,558

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From 2333

Application of CMT Credit Carryovers

A.

Income Tax (before deduction of specified credits)			+	From 190	87,070
Gross CMT Payable	+ From 276	5,512			
Subtract: Foreign Tax Credit for CMT purposes	– From 277				
If 276 – 277 is negative, enter NIL in 290	=	5,512	–	290	5,512
Income Tax eligible for CMT Credit			=	300	81,558

B.

Income Tax (after deduction of specified credits)	+	From 230	87,070
Subtract: CMT credit used to reduce income taxes	–	310	
Income Tax	=	320	87,070

Transfer to page 17

If A & B apply, 310 ***cannot exceed the lesser of*** 230 ***,*** 300 ***and your CMT credit carryover available*** 2333 **.**

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333 **.**

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	1,689,346
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	849,238
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	2,538,584
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	2,538,584
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	–	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	–	382	
Net Paid-up Capital	=	390	2,538,584

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	

continued on Page 10

ALLOWANCE FOR PILS

The calculations of the allowance for 2010 PILs in the amount of $31,623 are provided in the “Proposed PILs model” at Exhibit 4, Tab 8, Schedule 3, Attachment 1.

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

Model Overview

Select a worksheet link

Tab	ShortName	Title	Instruction	Link
P		**PILS Calculationa**		P0 Administration
P0	Admin	Administration	Enter administrative information about the Application	P0 Administration
P1	UCC	Undepreciated Capital Costs (UCC)	Enter actual balances and projected asset additions & retirements	P1 Undepreciated Capital Costs (UCC)
P2	CEC	Cumulative Eligible Capital (CEC)	Enter actual balance, projected changes and deduction rates	P2 Cumulative Eligible Capital (CEC)
P3	Interest	Interest Expense	Enter deemed and projected actual interest amounts	P3 Interest Expense
P4	LCF	Loss Carry-Forward (LCF)	Enter details of historical losses available to offset projected taxable income	P4 Loss Carry-Forward (LCF)
P5	Reserves	Reserve Balances	Enter balance amounts and projected changes in tax and accounting reserves	P5 Reserve Balances
P6	TxblIncome	Taxable Income	Enter amounts required to calculate taxable income	P6 Taxable Income
P7	CapitalTax	Capital Taxes	Enter rate base amounts	P7 Capital Taxes
P8	TotalPILs	Total PILs Expense	Enter tax credit amounts	P8 Total PILs Expense
Y		**Reference Information**		Y1 Tax Rates and Exemptions
Y1	TaxRates	Tax Rates and Exemptions	Enter applicable rates and exemption amounts	Y1 Tax Rates and Exemptions
Y2	CCA	Capital Cost Allowances (CCA)	Enter asset classes and applicable rates for CCA deductions	Y2 Capital Cost Allowances (CCA)
Z		**Model Parameters**		Z1 Model Variables
Z1	ModelVariables	Model Variables		Z1 Model Variables
Z0	Disclaimer	Software Terms of Use		Z0 Software Terms of Use

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1
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P0 Administration

Enter administrative information about the Application

Application Version	v0.1
Name of Applicant	Hydro Hawkesbury Inc.
License Number	ED-2003-0027
Test Year	2010
File Number(s)	EB-2009-0186
Date of Application	4-Nov-2009
Contact:	
Name	Linda Parisien
email	lindapar@hawk.igs.net
phone	613-632-6689
Date of previous Test Year approval	12-Apr-2006

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions & retirements

Class	Description	UCC Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Less: Disallowed FMV Increment
1	Distribution System - post 1987	988,747		
2	Distribution System - pre 1988	392,426		
8	General Office/Stores Equip	21,724		
10	Computer Hardware/ Vehicles	33,505		
10.1	Certain Automobiles			
12	Computer Software	31,654		
13.1	Leasehold Improvement # 1			
13.2	Leasehold Improvement # 2			
13.3	Leasehold Improvement # 3			
13.4	Leasehold Improvement # 4			
14	Franchise			
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			
43.1	Certain Energy-Efficient Electrical Generating Equipment			
45	Computers & Systems Software acq'd post Mar 22/04	4,521		
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			
47	Distribution System post Feb 22/05	44,428		
50	Computer Equipment Post March 18, 2007	2,613		
1	Building	613,700		
	TOTAL	**2,133,318**		

[1] per Schedule 8 of 2008 corporate tax return

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-018(

November 4, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	2009 Projected Additions	2009 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2009 CCA	UCC 31 Dec/09
1	Distribution System - post 1987			988,747		988,747	4.0%	39,550	949,197
2	Distribution System - pre 1988			392,426		392,426	6.0%	23,546	368,880
8	General Office/Stores Equip	25,000		46,724	12,500	34,224	20.0%	6,845	39,879
10	Computer Hardware/ Vehicles	6,000		39,505	3,000	36,505	30.0%	10,952	28,554
10.1	Certain Automobiles						30.0%		
12	Computer Software	7,000		38,654	3,500	35,154	100.0%	35,154	3,500
13.1	Leasehold Improvement # 1						25 years		
13.2	Leasehold Improvement # 2						4 years		
13.3	Leasehold Improvement # 3								
13.4	Leasehold Improvement # 4								
14	Franchise						6 years		
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%		
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%		
45	Computers & Systems Software acq'd post Mar 22/04			4,521		4,521	45.0%	2,034	2,487
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%		
47	Distribution System post Feb 22/05	254,500		298,928	127,250	171,678	8.0%	13,734	285,194
50	Computer Equipment Post March 18, 2007			2,613		2,613	55.0%	1,437	1,176
1	Building			613,700		613,700	4.0%	24,548	589,152
	TOTAL	**292,500**		**2,425,818**	**146,250**	**2,279,568**		**157,800**	**2,268,018**

[1] per Schedule 8 of 2008 corporate tax return

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-018(

November 4, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	2010 Projected Additions	2010 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2010 CCA	UCC 31 Dec/10
1	Distribution System - post 1987			949,197		949,197	4.0%	37,968	911,229
2	Distribution System - pre 1988			368,880		368,880	6.0%	22,133	346,748
8	General Office/Stores Equip	65,500		105,379	32,750	72,629	20.0%	14,526	90,853
10	Computer Hardware/ Vehicles	9,200		37,754	4,600	33,154	30.0%	9,946	27,807
10.1	Certain Automobiles						30.0%		
12	Computer Software			3,500		3,500	100.0%	3,500	
13.1	Leasehold Improvement # 1								
13.2	Leasehold Improvement # 2								
13.3	Leasehold Improvement # 3								
13.4	Leasehold Improvement # 4								
14	Franchise								
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%		
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%		
45	Computers & Systems Software acq'd post Mar 22/04			2,487		2,487	45.0%	1,119	1,368
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%		
47	Distribution System post Feb 22/05	266,500		551,694	133,250	418,444	8.0%	33,476	518,218
50	Computer Equipment Post March 18, 2007			1,176		1,176	55.0%	647	529
1	Building	25,000		614,152	12,500	601,652	4.0%	24,066	590,086
	TOTAL	**366,200**		**2,634,218**	**183,100**	**2,451,118**		**147,380**	**2,486,839**

[1] per Schedule 8 of 2008 corporate tax return

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

P2 Cumulative Eligible Capital (CEC)

Enter actual balance, projected changes and deduction rates

	2009			2010		
CEC Opening Balance [1]			**14,007**			**13,027**
Eligible Capital Property (ECP) Acquisitions						
Other Adjustments						
Subtotal		**x 3/4 =**			**x 3/4 =**	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after December 20, 2002		**x 1/2 =**			**x 1/2 =**	
Amount transferred on amalgamation or wind-up of subsidiary						
Subtotal before deductions			**14,007**			**13,027**
ECP Dispositions (net)						
Other Adjustments						
Subtotal		**x 3/4 =**			**x 3/4 =**	
Balance before tax deduction			**14,007**			**13,027**
Tax Deduction	*Rate:*	***7.0%***	**980**	*Rate:*	***7.0%***	**912**
CEC Ending Balance			**13,027**			**12,115**

[1] 2009 amount per ending balance on Schedule 10 of 2008 corporate rax return

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

P3 Interest Expense

Enter deemed and projected actual interest amounts

	2009	2010	
Deemed Interest Expense (A)	153,045	179,128	
3900-Interest Expense	86,178	86,771	
Add: Capitalized Interest (USA #6040)			*Enter credit to P&L as positive number*
Add: Capitalized Interest (USA #6042)			*Enter credit to P&L as positive number*
Less: non-debt interest expense (USA #6035)			
			Enter other adjustments for tax purposes
Total Interest Projected (B)	**86,178**	**86,771**	
Excess Interest Expense			*(B) less (A); if negative: zero*

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

P4 Loss Carry-Forward (LCF)

Enter details of historical losses available to offset projected taxable income

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	2009	2010
Non-Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable income					
Ending Balance					
Net Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable capital gains					
Ending Balance					

[1] per Schedule 7-1 of 2008 corporate tax return

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

P5 Reserve Balances

Enter balance amounts and projected changes in tax and accounting reserves

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	Changes (+ / -) in 2009	Balance 31 Dec/09	Changes (+ / -) in 2010	Balance 31 Dec/10
Capital Gains Reserves ss.40(1)							
Tax Reserves not deducted for book purposes:							
Reserve for doubtful accounts ss. 20(1)(l)							
Reserve for goods and services not delivered ss. 20(1)(m)	83,466		83,466	(83,466)			
Reserve for unpaid amounts ss. 20(1)(n)							
Debt & Share Issue Expenses ss. 20(1)(e)							
TOTAL	**83,466**		**83,466**	**(83,466)**			
Accounting Reserves not deducted for tax purposes:							
General Reserve for Inventory Obsolescence (non-specific)							
General reserve for bad debts							
Accrued Employee Future Benefits:							
- Medical and Life Insurance							
- Short & Long-term Disability							
- Accumulated Sick Leave							
- Termination Cost							
- Other Post-Employment Benefits							
Provision for Environmental Costs							
Restructuring Costs							
Accrued Contingent Litigation Costs							
Accrued Self-Insurance Costs							
Other Contingent Liabilities							
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)							
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)							
TOTAL							

[1] per Schedule 13 of 2008 corporate tax return

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved			2009 Projection	2010 @ existing rates	2010 @ new dist. rates
		Total Entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		193,569		193,569	80,201	(137,636)	132,841
Additions:							
Interest and penalties on taxes	103						
Amortization of tangible assets	104	156,576		156,576	162,631	175,480	175,480
Amortization of intangible assets	106	2,301		2,301			
Recapture of capital cost allowance from Schedule 8	107						
Gain on sale of eligible capital property from Schedule 10	108						
Income or loss for tax purposes- joint ventures or partnerships	109						
Loss in equity of subsidiaries and affiliates	110						
Loss on disposal of assets	111						
Charitable donations	112						
Taxable Capital Gains	113						
Political Donations	114						
Deferred and prepaid expenses	116						
Scientific research expenditures deducted on financial statements	118						
Capitalized interest	119						
Non-deductible club dues and fees	120						
Non-deductible meals and entertainment expense	121						
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125				83,466		
Reserves from financial statements- balance at end of year	126						

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved			2009 Projection	2010 @ existing rates	2010 @ new dist. rates
		Total Entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		193,569		193,569	80,201	(137,636)	132,841
Soft costs on construction and renovation of buildings	127						
Book loss on joint ventures or partnerships	205						
Capital items expensed	206						
Debt issue expense	208						
Development expenses claimed in current year	212						
Financing fees deducted in books	216						
Gain on settlement of debt	220						
Non-deductible advertising	226						
Non-deductible interest	227						
Non-deductible legal and accounting fees	228						
Recapture of SR&ED expenditures	231						
Share issue expense	235						
Write down of capital property	236						
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237						
Total Additions		**158,877**		**158,877**	**246,097**	**175,480**	**175,480**

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		193,569		193,569	80,201	(137,636)	132,841
Deductions:							
Gain on disposal of assets per financial statements	401						
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403	117,768		117,768	157,800	147,380	147,380
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405	1,311		1,311	980	912	912
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413						
Reserves from financial statements - balance at beginning of year	414						
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Capitalized regulatory assets		15,020		15,020			
Refund of RSVA amounts		36,405		36,405			
Total Deductions		**170,504**		**170,504**	**158,780**	**148,292**	**148,292**

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		193,569		193,569	80,201	(137,636)	132,841
NET INCOME (LOSS) FOR TAX PURPOSES		**181,942**		**181,942**	**167,518**	**(110,448)**	**160,029**
Charitable donations from Schedule 2							
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME (LOSS)		**181,942**		**181,942**	**167,518**	**(110,448)**	**160,029**

[1] *2009 Projection = "Earnings before Tax' (sheet E1); 2010 @ existing rates = "Earnings before Tax' (sheet E2); 2010 @ new dist. rates = "Deemed Return On Equity' (sheet E3)*

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

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P7 Capital Taxes

Enter rate base amounts

Rates and exemptions from sheet Y1

	2009	2010	
OCT (Ontario Capital Tax):			
Rate Base	4,149,976	4,146,090	*'Calculated Value' from sheet E3*
Less: Exemption	12,500,000	12,500,000	
Deemed Taxable Capital			
Tax Rate	0.225%	0.225%	
OCT payable			
Federal LCT (Large Corporations Tax):			
Rate Base	4,149,976	4,146,090	
Less: Exemption	50,000,000	50,000,000	
Deemed Taxable Capital			
Tax Rate			
LCT payable			

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

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P8 Total PILs Expense

Enter tax credit amounts

	2009 Projection	2010 Projection [1]	2010 Test [1]	
Regulatory Taxable Income/(Loss)	167,518	(110,448)	160,029	*from sheet P6*
Combined Income Tax Rate	16.50%		16.50%	*"t" (from sheet Y1)*
Total Income Taxes	27,640		26,405	
Investment & Miscellaneous Tax Credits				*Input amounts*
Income Tax Payable	**27,640**		**26,405**	*"i"*
Large Corporations Tax (LCT)				*from sheet P7*
Ontario Capital Tax (OCT)				*from sheet P7*
Grossed-up Income Tax			31,623	*= i / (1 - t)*
Grossed-up LCT				*= LCT / (1 - t)*
Total PILs Expense	**27,640**		**31,623**	***Enter these results on sheet E4***

[1] 'Projection' per existing rates; 'Test' based on proposed revenue requirement

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

Y1 Tax Rates and Exemptions

Enter applicable rates and exemption amounts

2009 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$400,000	11.00%	5.50%	16.50%	
$400,000	$500,000	19.00%	5.50%	24.50%	
$500,000	$1,500,000	19.00%	14.00%	33.00%	4.25%
$1,500,000		19.00%	14.00%	33.00%	

2009 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$12,500,000
Capital Tax Rate		0.225%
Surtax Rate		

2010 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$400,000	11.00%	5.50%	16.50%	
$400,000	$500,000	19.00%	5.50%	24.50%	
$500,000	$1,500,000	19.00%	14.00%	33.00%	4.25%
$1,500,000		19.00%	14.00%	33.00%	

2010 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$12,500,000
Capital Tax Rate		0.225%
Surtax Rate		

Hydro Hawkesbury Inc. (ED-2003-0027)

PILs Calculations for 2010 EDR Application (EB-2009-0186) version: v0.1

November 4, 2009

Y2 Capital Cost Allowances (CCA)

Enter asset classes and applicable rates for CCA deductions

Class	Description	Rate	Years	½ Year Rule
1	Distribution System - post 1987	4.0%		YES
2	Distribution System - pre 1988	6.0%		YES
8	General Office/Stores Equip	20.0%		YES
10	Computer Hardware/ Vehicles	30.0%		YES
10.1	Certain Automobiles	30.0%		YES
12	Computer Software	100.0%		YES
13.1	Leasehold Improvement # 1		25	YES
13.2	Leasehold Improvement # 2		4	YES
13.3	Leasehold Improvement # 3			YES
13.4	Leasehold Improvement # 4			YES
14	Franchise		6	NO
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	8.0%		YES
43.1	Certain Energy-Efficient Electrical Generating Equipment	30.0%		YES
45	Computers & Systems Software acq'd post Mar 22/04	45.0%		YES
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	30.0%		YES
47	Distribution System post Feb 22/05	8.0%		YES
50	Computer Equipment Post March 18, 2007	55.0%		YES
1	Building	4.0%		YES

Exhibit 5:

COST OF CAPITAL AND RATE OF RETURN

Exhibit 5: Cost Of Capital And Rate Of Return

Tab 1 (of 1): Cost of Capital and Rate of Return

CAPITAL STRUCTURE AND COST OF CAPITAL

The purpose of this evidence is to summarize the method and cost of financing HHI's capital requirements for the 2010 test year.

HHI has a current deemed capital structure of 56.7% debt with a return of 7.25% and 43.3% equity with a return of 9% as approved in its 2009 IRM.

In this application, HHI is requesting a regulated rate of return of 7.52% based on a deemed capital structure of 56% long term debt, 4% short term debt and 40% equity as shown in Exhibit 5, Tab 1, Schedule 1, Appendix 1. This structure complies with the report of the board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006.

The following section outlines HHI's cost of capital assumptions with respect to long term debt, short term debt and return on equity.

COST OF DEBT: LONG TERM

HHI has a promissory note with the City of Hawkesbury, its municipal shareholder. The amount outstanding in 2010 will be $850,364. (average amount of principal outstanding in 2010. This amount was recalculated based on the actual interest payable in 2010, divided by the actual interest rate: $55,273.71 / 0.065 = $850,364.77). HHI has no other long term debt as of the time of filing. The promissory note was issued January 1, 2001 and has a term date of December 31, 2013. A copy of the promissory note is included at Attachment 3, Schedule of 1 this Exhibit.

It is HHI's understanding that because the promissory note does not qualify as embedded debt, the OEB's long term debt rate would be applied to the deemed long term debt component of its capital structure. For the purposes of calculating its cost of capital in the 2010 rate application, HHI has used the current Board approved rate of 7.62%.

COST OF DEBT: SHORT TERM.

For the purposes of calculating its cost of capital in the 2010 rate application, HHI has used the current Board approved rate of 1.33% for its short term debt component. HHI acknowledges that both debt rates may be updated by the Board early in 2010 to reflect market conditions and the outcome of the Cost of Capital Consultation (EB-2009-0084).

RETURN ON EQUITY:

HHI is requesting a return on equity ("ROE") for the 2010 Test year of 8.01% in accordance with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications. HHI understands that the OEB will be finalizing the ROE for 2010 rates based on January 2010 market interest rate information, and in conjunction with the Cost of Capital Consultation (EB-2009-0084). HHI's use of an ROE of 8.01% is without prejudice to any revised ROE that may be adopted by the OEB in early 2010.

Hydro Hawkesbury Inc. (ED-2003-0027)

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D3 Deemed Capital Structure and Return On Capital

Enter deemed portions of debt and equity capitalization

	Current Application			2006 EDR Approved		
	Deemed Portion	*Effective Rate* [1]	*Return Amount*	*Deemed Portion*	*Effective Rate*	*Return Amount*
Short-Term Debt	4.00%	1.33%				
Long-Term Debt	56.00%	7.62%		50.00%	6.25%	
Total Equity	40.00%	8.01%		50.00%	9.00%	
Regulated Rate of Return	**100.00%**	**7.52%**		**100.00%**	**7.63%**	
Rate Base [2]			4,146,090			4,318,730
Regulated Return on Capital			**311,968**			**329,303**
Deemed Interest Expense			*179,128*			*134,960*
Deemed Return on Equity			*132,841*			*194,343*

[1] *Long-Term Debt rate from sheet D2; Short-Term Debt and Equity rates from sheet Y1*

[2] *Amount for Current Application from sheet D1*

Hydro Hawkesbury Inc. (ED-2003-0027)

2010 EDR Application (EB-2009-0186) version: v0.1
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D2 2010 Debt Balances

Enter details of debt balances outstanding in 2010 (excluding short-term debt e.g. line of credit)

Description	Amount	Issue Date (dd-mmm-yyyy)	Term Date (dd-mmm-yyyy)	Interest Rate (a)	Other Costs (b)	Apply Deemed Rate?	Annual Cost (c)
Note payable to shareholder	850,364	1-Jan-2001	31-Dec-2013	6.50%		YES	64,798

Description	Effective Rate	Days o/s in 2010	Average Balance	2010 Cost	2010 Ending Balance	Debt o/s USA #	Int. Expense USA #
Note payable to shareholder	7.62%	365	850,364	64,798	850,364	2520	6035
TOTAL	**7.62%**		**850,364**	**64,798**	**850,364**		

(a) For debt held issued prior to 12-Apr-2006 (prior Test Year approval, per sheet A1), represents the previously approved rate.

(b) Annual charges other than interest (e.g. commitment fees, amortization of issuance costs, etc.)

(c) For debt issued to an affiliate since 12-Apr-2006, represents the lower of (i) actual cost and (ii) cost based on the deemed debt rate (7.62%, per sheet Y1)

HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC.

Convertible promissory note

March 2, 2009

For value received, subject to the terms and conditions of this promissory note (the "Note"), HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC., a corporation incorporated under the laws of the Province of Ontario (the "Company"), hereby promises to pay on demand to the order of the Corporation of the Town of Hawkesbury (the "Holder") the principal sum of two million one hundred and nine thousand one hundred and forty-seven dollars ($2,109,147.00) in lawful money of Canada with the terms of payment stated below:

1. __Interest Rate__ The principal amount shall bear interest at a rate of six and one half percent (6.5%) per annum calculated semi-annually not in advance and calculated from the first of January 2009.

2. __Terms of Payment__ The principal sum due under this note shall be due and payable on the first of February 2009. Until payment in full of the principal sum, this note shall bear interest at the rate stipulated above which interest shall be paid by means of monthly payments commencing on the first of February 2009 until the principal amount is fully paid.

3. __Conversion__ The principal amount of this Note together with the Interest is convertible in whole or in part at the option of the Holder by surrender of this Note at the registered office of the Company at any time prior to repayment into fully paid non-assessable common shares of the Company as presently constituted ("Shares") at a price of $1,691.94 (Canadian Dollars) per Share (the "Conversion Price") of principal amount and Interest then outstanding for each Share to be issued upon the conversion of this Note. The Conversion Price shall be adjusted to give effect to adjustments in the number of shares of the Company resulting from subdivisions, consolidations or reclassifications of the shares of the Company, the payment of stock dividends by the Company or other relevant changes in the capital stock of the Company.

4. __Issuance of Conversion Stock__ As soon as practicable after conversion of this Note into Shares as provided herein, and the surrender of this Note to the Company at its principal office, the Company at its expense, will cause to be issued in the name and delivered to the Holder, a share certificate or certificates for the number of Shares to which the holder of this Note shall be entitled upon the conversion.

5. __Fully Paid Shares__ All Shares issued upon the conversion of this Note shall be validly issued, fully paid and non-assessable.

.../2

6. **No Impairment** The Company will not wilfully avoid or seek to avoid the observance or performance of any of the terms of this Note, but will act at all times in good faith to assist in the carrying out of all such terms and in the taking of all such action as may be necessary or appropriate in order to protect the rights of the Holder against impairment. Without limiting the generality of the foregoing, the Company will take all such action as may be necessary or appropriate in order that the Company may validly and legally issue fully paid and non-assessable Shares upon any conversion of this Note.

7. **Prepayment** The Company may at any time upon giving the Holder seven (7) days prior written notice (and during which notice period the Holder may exercise its right of conversion), without penalty, repay in whole or in part the principal amount and Interest outstanding under this Note. Any prepayment shall be applied first to the Interest until it has been paid and then to unpaid principal.

8. **Event of Default** The principal amount due hereunder together with the Interest will accelerate and become due if an Event of Default (as hereinafter defined) occurs. An "Event of Default" shall exist under this Note if the Company: (i) petitions or applies to any tribunal for or consents to the appointment of a receiver, trustee or liquidator of the Company or of all or any substantial part of its properties or assets, (ii) admits in writing its inability to pay its debts as they mature, (iii) makes a general assignment for the benefit of its creditors, (iv) is adjudicated bankrupt or insolvent; (v) files voluntarily or has filed against it a petition in bankruptcy or a petition seeking reorganization or an arrangement with creditors to take advantage of any bankruptcy, reorganization insolvency, readjustment of debts, dissolution or liquidation law or statute, or, (vi) breaches any of its obligations under this Note or the General Security Agreement made in favour of the Holder executed the date hereof by the Company.

9. **Amendment: Waiver** This Note may only be amended and the observance of any term of this Note may only be waived (either generally or in a particular instance and either retroactively or prospectively) by the written consent of the Company and the Holder of this Note. Any amendment or waiver effected in accordance with the previous sentence shall be binding upon each future holder or transferee of the Note and the Company.

10. **Assignment** This Note may be assigned by the Holder.

11. **Headings: References** The headings in this Note are for the purposes of convenience or reference only, and shall not be deemed to constitute a part of this Note. Unless otherwise expressly noted, all references herein to Sections refer to Sections of this Note.

12. **Notices** All notices given by the Company or Holder pursuant to this Note shall be in writing and shall be served by either personal service, facsimile transmission, nationally recognized overnight courier service or mail at the notice of address of the receiving party set forth below. All notices served by personal service shall be deemed to have been given upon actual delivery to the receiving party, all notices served by

.../3

facsimile transmission or nationally recognized overnight courier shall be deemed to have been given on the next business day following their dispatch, and all notices given by mail shall be by certified or registered mail, return receipt requested, and shall be deemed to have been given (5) days after deposit into the Canadian mail, postage paid. The Company's notice of address shall be its principal office and the Noteholder's notice of address shall be the last address for notice furnished to the Company by Noteholder in writing.

13. **Law Governing** This Note shall be construed and enforced in accordance with, and governed by, the laws of Ontario.

14. **Lawyers' Fees; Waiver of Presentment** The Company promises to pay the Holder hereof, without demand, all reasonable lawyers' fees, costs and other expenses incurred by such holder in enforcing any provisions of this Note and hereby waives presentment, notice of nonpayment, notice of dishonour, protest, demand and diligence.

IN WITNESS WHEREOF, the Company has caused this Note to be signed in its name the date first written above.

THE CORPORATION OF THE TOWN OF

HAWKESBURY

Jeanne Charlebois, Mayor

Christine Groulx, Clerk

HYDRO HAWKESBURY INC./
HAWKESBURY HYDRO INC.

THE CORPORATION OF THE TOWN OF HAWKESBURY

By-law N° 8-2009

**A by-law to authorize
the Mayor and the Clerk
to execute a promissory note between
the Corporation of the Town of Hawkesbury
and
Hawkesbury Hydro Inc.**

WHEREAS on October 24, 2000, the Municipal Council of the Town of Hawkesbury adopted By-law N° 74-2000 which transfers the assets of the Hawkesbury Hydro-Electric Commission associated with the distribution of electricity to Hydro Hawkesbury Inc./Hawkesbury Hydro Inc. ("Hawkesbury Hydro");

AND WHEREAS pursuant to paragraph 4.02 of By-law N° 74-2000, the balance of the purchase price, after deduction of the value of the debts transferred by Hawkesbury Hydro, should be shared by a promissory note and common shares of the Hawkesbury Hydro according to proportions to be determined by the Council;

AND WHEREAS that, after an audit conducted by the auditors of the Corporation of the Town of Hawkesbury, it has been determined that the balance of the purchase price in the amount of $3,798,493.00 was shared by the issuance and delivery of a promissory note and capital stock as follows:

Promissory Note:	$2,109,147.
Capital stock (999 common shares):	$1,689,346.

AND WHEREAS that the amount of the promissory note from Hawkesbury Hydro Inc. to the Corporation of the Town of Hawkesbury as of December 31, 2008 is $1,151,897.50.

NOW THEREFORE the Municipal Council of the Corporation of the Town of Hawkesbury enacts as follows:

1. That the Council confirms the allocation of a promissory note.

2. That the Mayor and Clerk of the Corporation of the Town of Hawkesbury be authorized to sign the said promissory note.

3. That By-law N° 14-2008 is hereby repealed.

**READ A FIRST, SECOND AND ADOPTED UPON THIRD READING
THIS 2nd DAY OF March 2009.**

Mayor Clerk

CERTIFIED A TRUE COPY
CERTIFIÉ COPIE CONFORME
This/Ce 12 day of / jour de March 2009

Christine Groulx, Greffière/Clerk

BILLET À ORDRE HAWKESBURY HYDRO

Analyse	
Solde au 31 décembre 2008	$1,151,897.50
Taux d'intérêt	6.50
Durée en année	5
date de début	1/1/2009
Paiement mensuel	$22,681.03
Montant total de paiement	60
Principal et intérêt annuel	272,172.36
Montant en principal	$1,151,897.50
Frais d'intérêt	$208,964.30
Coût total	$1,360,861.80

# Pmt	Date de paiement	Solde au début	Intérêt	Principal	Balance	Intérêt accumulé	Principal accumulé
1	1/1/2009	1,151,897.50	6,239.44	16,441.59	1,135,455.91	6,239.44	16,441.59
2	2/1/2009	1,135,455.91	6,150.39	16,530.64	1,118,925.27	12,389.83	32,972.23
3	3/1/2009	1,118,925.27	6,060.85	16,620.18	1,102,305.09	18,450.68	49,592.41
4	4/1/2009	1,102,305.09	5,970.82	16,710.21	1,085,594.88	24,421.50	66,302.62
5	5/1/2009	1,085,594.88	5,880.31	16,800.72	1,068,794.15	30,301.80	83,103.35
6	6/1/2009	1,068,794.15	5,789.30	16,891.73	1,051,902.42	36,091.10	99,995.08
7	7/1/2009	1,051,902.42	5,697.80	16,983.23	1,034,919.20	41,788.91	116,978.30
8	8/1/2009	1,034,919.20	5,605.81	17,075.22	1,017,843.98	47,394.72	134,053.52
9	9/1/2009	1,017,843.98	5,513.32	17,167.71	1,000,676.27	52,908.04	151,221.23
10	10/1/2009	1,000,676.27	5,420.33	17,260.70	983,415.57	58,328.37	168,481.93
11	11/1/2009	983,415.57	5,326.83	17,354.20	966,061.38	63,655.21	185,836.12
12	12/1/2009	966,061.38	5,232.83	17,448.20	948,613.17	68,888.04	203,284.32
TOTAL 2008			**68,888.04**	**203,284.32**			
13	1/1/2010	948,613.17	5,138.32	17,542.71	931,070.46	74,026.36	220,827.03
14	2/1/2010	931,070.46	5,043.30	17,637.73	913,432.73	79,069.66	238,464.76
15	3/1/2010	913,432.73	4,947.76	17,733.27	895,699.46	84,017.42	256,198.03
16	4/1/2010	895,699.46	4,851.71	17,829.32	877,870.13	88,869.12	274,027.36
17	5/1/2010	877,870.13	4,755.13	17,925.90	859,944.23	93,624.25	291,953.26
18	6/1/2010	859,944.23	4,658.03	18,023.00	841,921.23	98,282.28	309,976.26
19	7/1/2010	841,921.23	4,560.41	18,120.62	823,800.61	102,842.69	328,096.88
20	8/1/2010	823,800.61	4,462.25	18,218.78	805,581.83	107,304.94	346,315.66
21	9/1/2010	805,581.83	4,363.57	18,317.46	787,264.37	111,668.51	364,633.12
22	10/1/2010	787,264.37	4,264.35	18,416.68	768,847.69	115,932.86	383,049.80
23	11/1/2010	768,847.69	4,164.59	18,516.44	750,331.25	120,097.45	401,566.24
24	12/1/2010	750,331.25	4,064.29	18,616.74	731,714.52	124,161.75	420,182.97
TOTAL 2009			**55,273.71**	**216,898.65**			
25	1/1/2011	731,714.52	3,963.45	18,717.58	712,996.94	128,125.20	438,900.55
26	2/1/2011	712,996.94	3,862.07	18,818.96	694,177.98	131,987.27	457,719.51
27	3/1/2011	694,177.98	3,760.13	18,920.90	675,257.08	135,747.40	476,640.41
28	4/1/2011	675,257.08	3,657.64	19,023.39	656,233.69	139,405.04	495,663.80
29	5/1/2011	656,233.69	3,554.60	19,126.43	637,107.26	142,959.64	514,790.23
30	6/1/2011	637,107.26	3,451.00	19,230.03	617,877.23	146,410.64	534,020.26
31	7/1/2011	617,877.23	3,346.83	19,334.20	598,543.03	149,757.47	553,354.46
32	8/1/2011	598,543.03	3,242.11	19,438.92	579,104.11	152,999.58	572,793.38
33	9/1/2011	579,104.11	3,136.81	19,544.22	559,559.90	156,136.40	592,337.59
34	10/1/2011	559,559.90	3,030.95	19,650.08	539,909.81	159,167.34	611,987.68
35	11/1/2011	539,909.81	2,924.51	19,756.52	520,153.30	162,091.86	631,744.19
36	12/1/2011	520,153.30	2,817.50	19,863.53	500,289.76	164,909.35	651,607.73
TOTAL 2010			**40,747.61**	**231,424.76**			
37	1/1/2012	500,289.76	2,709.90	19,971.13	480,318.64	167,619.26	671,578.85
38	2/1/2012	480,318.64	2,601.73	20,079.30	460,239.33	170,220.98	691,658.16
39	3/1/2012	460,239.33	2,492.96	20,188.07	440,051.26	172,713.94	711,846.23
40	4/1/2012	440,051.26	2,383.61	20,297.42	419,753.85	175,097.56	732,143.64
41	5/1/2012	419,753.85	2,273.67	20,407.36	399,346.48	177,371.22	752,551.01
42	6/1/2012	399,346.48	2,163.13	20,517.90	378,828.58	179,534.35	773,068.91
43	7/1/2012	378,828.58	2,051.99	20,629.04	358,199.54	181,586.34	793,697.95
44	8/1/2012	358,199.54	1,940.25	20,740.78	337,458.76	183,526.59	814,438.73
45	9/1/2012	337,458.76	1,827.90	20,853.13	316,605.63	185,354.49	835,291.86
46	10/1/2012	316,605.63	1,714.95	20,966.08	295,639.54	187,069.43	856,257.95
47	11/1/2012	295,639.54	1,601.38	21,079.65	274,559.89	188,670.81	877,337.60
48	12/1/2012	274,559.89	1,487.20	21,193.83	253,366.06	190,158.01	898,531.43
TOTAL 2011			**25,248.66**	**246,923.70**			
49	1/1/2013	253,366.06	1,372.40	21,308.63	232,057.43	191,530.41	919,840.06
50	2/1/2013	232,057.43	1,256.98	21,424.05	210,633.38	192,787.39	941,264.11
51	3/1/2013	210,633.38	1,140.93	21,540.10	189,093.28	193,928.32	962,804.21
52	4/1/2013	189,093.28	1,024.26	21,656.77	167,436.51	194,952.58	984,460.98
53	5/1/2013	167,436.51	906.95	21,774.08	145,662.43	195,859.53	1,006,235.06

# Pmt	Date de paiement	Solde au début	Intérêt	Principal	Balance	Intérêt accumulé	Principal accumulé
54	6/1/2013	145,662.43	789.00	21,892.03	123,770.40	196,648.53	1,028,127.09
55	7/1/2013	123,770.40	670.42	22,010.61	101,759.79	197,318.95	1,050,137.70
56	8/1/2013	101,759.79	551.20	22,129.83	79,629.96	197,870.15	1,072,267.53
57	9/1/2013	79,629.96	431.33	22,249.70	57,380.26	198,301.48	1,094,517.23
58	10/1/2013	57,380.26	310.81	22,370.22	35,010.04	198,612.29	1,116,887.45
59	11/1/2013	35,010.04	189.64	22,491.39	12,518.65	198,801.93	1,139,378.84
60	12/1/2013	12,518.65	67.81	22,613.22	-10,094.57	198,869.74	1,161,992.06
TOTAL 2012			**8,711.72**	**263,460.64**			
61	1/1/2014	-10,094.57	-54.68	0.00		198,815.06	

Exhibit 6:

REVENUE DEFICIENCY OR SUFFICIENCY

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 1 (of 2): Utility Revenue

OVERVIEW OF REVENUE REQUIREMENT

HHI's $1.3 million revenue requirement for 2010 contemplates the recovery of its costs of providing distribution service, a fair return on the invested capital as determined by the Board, and its Payments in Lieu of Taxes ("PILS").

When its forecasted customers and volumes for 2010 are taken into account, HHI estimates that its present rates will produce a Revenue Deficiency of $362,833 for the 2010 Test Year. The estimated deficiency does not include and consideration for the impact of energy costs, variance/deferral accounts, smart metering and low voltage charges.

Through this Application, HHI seeks to recover a Base Revenue Requirement of $1,304,216 which leads to a Gross Revenue Deficiency in the amount of $394,455 arising from changes in OM&A, Amortization, Rate of Return and PILS.

Details of HHI's Distribution Revenue Requirement can be found in the next page at Exhibit 6, Tab 2, Schedule 1, Attachment 1.

The Test Year service revenue requirement is derived from the following components:

- Distribution Expenses:
- OM&A $965,143 (Exhibit 4, Tab 2, Schedule 1, Attachment 1)
- Amortization expense $175,480 (Exhibit 4, Tab 7, Schedule 1, Attachment 1)
- Return On Capital $311,968 (Exhibit 5, Tab 1 Schedule 1, Attachment 1)
- Allowance for PILs $31,623 (Exhibit 4, Tab 8 Schedule 3, Attachment 1)

The Test Year base revenue requirement, is net of revenue offsets (Exhibit 3, Tab 3, Schedule 4), and includes any adjustments for non-recurring items.

Hydro Hawkesbury Inc. (ED-2003-0027)

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November 4, 2009

F1 Distribution Revenue Requirement

Enter adjustments for non-recurring items in 2010 to be addressed via rate adder

		2010 Projection	Non-recurring items (Total)	2010 Normalized	Comment
OM&A Expenses	*from sheet D1*	965,143		965,143	
3850-Amortization Expense	*from sheet E2*	175,480		175,480	
Total Distribution Expenses		1,140,623		1,140,623	
Regulated Return On Capital	*from sheet D3*	311,968		311,968	
PILs (with gross-up)	*from sheet E4*	31,623		31,623	
Service Revenue Requirement		**1,484,214**		**1,484,214**	
Less: Revenue Offsets	*from sheet C9*	179,998		179,998	
Base Revenue Requirement		**1,304,216**		**1,304,216**	

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 2 (of 2): Deficiency or Surplus

CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

This exhibit describes the main components used in the calculation of the forecasted revenue deficiency for HHI during the 2010 test year. If existing rates are continued, HHI expects to realize a net revenue shortfall of $362,833. The calculation is based on the following:

- Utility income loss of $50,864 from total net revenues of $1,089,759 for 2010 using current rates, along with projected OM&A of $936,881, depreciation of $175,480, and other taxes totalling $28,262.
- A utility rate base of 4,146,090 projected for the 2010 test year.
- An indicated rate of return of (1.23%) as compared to the proposed rate of return of 7.52% which leads to a gross revenue deficiency after PILs of $394,455.

Details of the calculation of revenue deficiency are presented at Exhibit 6, Tab 2, Schedule 1, Attachment 1.

Hydro Hawkesbury Inc. (ED-2003-0027)

2010 EDR Application (EB-2009-0186) version: v0.1
November 4, 2009

G7 Variance Analysis: Revenue Sufficiency / Deficiency

Review highlighted variances (no input on this sheet)

		2010 Projection	2009 Projection	Var #	Var %
Utility Income	*(see below)*	(50,864)	138,739	(189,603)	(136.7%)
Utility Rate Base	*from sheet G6*	4,146,090	4,149,976	(3,886)	(0.1%)
Indicated Rate of Return		(1.23%)	3.34%	(4.57%)	(136.7%)
Requested / Approved Rate of Return	*from sheet E3*	7.52%	7.44%	0.08%	1.1%
Sufficiency / (Deficiency) in Return		(8.75%)	(4.10%)	(4.65%)	(113.6%)
Net Revenue Sufficiency / (Deficiency)		**(362,833)**	**(170,051)**	**(192,782)**	**(113.4%)**
Provision for PILs/Taxes *		(31,623)	(33,878)	2,256	6.7%
Gross Revenue Sufficiency / (Deficiency)		**(394,455)**	**(203,929)**	**(190,526)**	**(93.4%)**
Deemed Overall Debt Rate	*from sheet E3*	*7.20%*	*6.25%*	*0.95%*	*15.2%*
Deemed Cost of Debt	*from sheet E3*	*179,128*	*153,045*	*26,083*	*17.0%*
Utility Income less Deemed Cost of Debt		*(229,992)*	*(14,306)*	*(215,686)*	*(1507.6%)*
Return On Deemed Equity		*(13.87%)*	*(0.80%)*	*(13.07%)*	*(1641.9%)*

UTILITY INCOME	*from sheets E1 & E2 (except PILS / Income Taxes)*				
Total Net Revenues		1,089,759	1,202,502	(112,743)	(9.4%)
OM&A Expenses		936,881	846,576	90,305	10.7%
Depreciation & Amortization		175,480	162,631	12,849	7.9%
Taxes other than PILs / Income Taxes		28,262	26,916	1,346	5.0%
Total Costs & Expenses		1,140,623	1,036,123	104,500	10.1%
Utility Income before Income Taxes / PILs		(50,864)	166,379	(217,243)	(130.6%)
PILs / Income Taxes	*from sheet E4*		27,640	(27,640)	(100.0%)
Utility Income		**(50,864)**	**138,739**	**(189,603)**	**(136.7%)**

** In 2010: difference between amounts on sheet E4 for 2010 at existing rates vs. 2010 at new revenue requirement;*
in 2009: Net Sufficiency / (Deficiency) multiplied by grossed-up effective tax rate on Utility Income.

<u>Exhibit 7</u>:

COST ALLOCATION

Exhibit 7: Cost Allocation

Tab 1 (of 1): Cost Allocation Model

OVERVIEW OF COST ALLOCATION

Introduction

On September 29, 2006 the Ontario Energy Board (the "OEB") issued the Board Directions on Cost Allocation Methodology for Electricity Distributors (“the Directions”). On November 15, 2006 the OEB also issued the Cost Allocation Information Filing Guidelines for Electricity Distributors (“the Guidelines”), the Cost Allocation Model (“the Model”) and User Instruction (the Instructions”) for the Model. HHI prepared its information filing consistent with HHI’s understanding of the Directions, the Guidelines, the Model and the Instructions and submitted it to the Board on March 31, 2006.

The main purpose of this cost allocation filing was to provide evidence to show HHI’s rate classifications that are being subsidized by other classes and those rate classifications that are over contributing based on the assumptions of the Model.

The 2006 Cost Allocation Study

The 2006 cost allocation filings aimed at determining whether or not the distribution rates charged each customer class were recovering the distribution costs that are allocated to each class.

For purposes of the 2006 Cost Allocation filing:

- HHI used the Board approved 2006 EDR, RP-2005-0020/EB-2005-0379, as the sole basis for costs and revenue components.
- HHI was a historical test year filer in the 2006 EDR.
- HHI is a Wholesale Market Participant.
- HHI has utilized the weather normalization data provided by, Hydro One Networks.
- HHI utilized the generic minimum system approach incorporated into the Board’s

- Allocation Model.
- HHI utilized the Peak Load Carrying Capability Adjustment incorporated into the Board's Allocation Model.
- HHI did not supplement or adjust the Board approved methodology or the Board's Cost Allocation Model.

2010 Filing Requirements

In the report entitled "Chapter 2 of the Filing Requirements for Transmission and Distribution Applications" issued May 27, 2009, the board presented filing requirements for a 2010 Cost Allocation Study. This study must;

- Reflect future loads and costs and be supported by appropriate explanations;
- Be corrected for transformer ownership allowance (see below); and
- Be presented in the form of Excel spreadsheets.

HHI adapted the 2006 cost allocation informational filing (model) to reflect future load and cost responsibility, to be consistent with the load forecast and costs in the test year, and supported this claim by an appropriate explanations as presented in the 2010 Cost Allocation Study report.

HHI's model was re-run to reflect the changes in load forecast and the change and customer classes. In HHI's case, the large user class was removed from the equation. The 2010 Cost allocation Study presented at Exhibit 7, Tab 1, Schedule 2 was conducted by ERA.

In addition, HHI revised its cost allocation by removing the "cost" associated with transformer ownership allowance from the revenue requirement and subtracting the "revenue" associated with the transformer ownership allowance from the approved revenue of the affected rates classes

HHI's revenue to cost ratios for each customer class are presented at page 13 of the 2010 Cost Allocation Study. HHI is filing 3 versions of the CA models

1. HHI-2006 HAWKESBURY_DETAILED_CA_Model_Run 2.xls

2. HHI-2006C HAWKESBURY_DETAILED_CA_Model_Run 2.xls

3. HHI-2010 HAWKESBURY_DETAILED_CA_Model_Run 2

The steps undertaken to modify the CA models and produce the above models are described below:

1 Start with existing 2006 CAIF as filled with the Board (model #1 - HHI-2006 HAWKESBURY_DETAILED_CA_Model_Run 2.xls)

2 2006 CAIF, with transformer ownership allowance corrected (HHI-2006C HAWKESBURY_DETAILED_CA_Model_Run 2.xls)

3 2006 CAIF (TOA correction), with corrections for new / lost customers, or customers changing classes, or customers significantly changing demand, changes in billing practices, or anything of that nature.

4 2006 CAIF (TOA correction), with 2010 loads by rate class (assuming hourly load profiles are unchanged)

5 2006 CAIF (TOA correction), with 2010 loads by rate class (updated hourly load profiles based on available customer data

6 Updated CA model with 2010 costs and loads (HHI-2010 HAWKESBURY_DETAILED_CA_Model_Run 2)

Hawkesbury Hydro Inc.
2010 Cost Allocation Study

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Hawkesbury Hydro Inc.

October 2009

elenchus
Research Associates

Table of Contents

1 INTRODUCTION

Hawkesbury Hydro Inc. (“Hawkesbury”) has prepared its 2010 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the May 27, 2009 update to the document entitled *Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications* (“Filing Requirements”).

Section 2.8 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements state:

> *A completed cost allocation study using the Board approved methodology must be filed whether the applicant proposes to use it or not. This filing must*
>
> - *reflect future loads and cost and be supported by appropriate explanations;*
> - *be corrected for transformer ownership allowance ..., and*
> - *be presented in the form of an Excel spreadsheet.*[1]

The Filing Requirements also state that:

> *The Board expects the filings made by the applicant will follow the cost allocation policies reflected in the Board’s report of November 28, 2007, Application of Cost Allocation for Electricity Distributors (EB-2007-0667).*

Hawkesbury asked Elenchus Research Associated (ERA)[2] to assist it by preparing an appropriate cost allocation study for its 2010 cost of service rate application. In addressing this issue, ERA was guided by the Filing Requirements and the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) (“CA Application Report”) which “sets out the Board’s policies in relation to specific cost allocation matters for electricity distributors”.[3]

---

[1] *Ontario Energy Board, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, May 27, 2009,* p. 19.

[2] John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Hawkesbury and documented in this report. John Todd’s curriculum vitae is available at www.era-inc.ca.

[3] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

The CA Application Report observes at page 2 that:

> *The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report.*

The "influencing factors" discussed in section 2.3 of the report are:

- **Quality of the data:** The Board notes "that accounting and load data can be improved." (p. 5)
- **Limited modelling experience:** The Board observed that "the cost allocation model is complex, and the data required for the model was not always readily available for modelling." (p. 6)
- **Status of current rate classes:** The Board points out that "Any changes in customer classification or load data could have a significant impact on future cost allocation studies" (p. 6).
- **Managing the movement of rates closer to allocated costs:** The Board notes:

  > *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. (p. 6)*

In utilizing the Board's cost allocation model for Hawkesbury's 2010 cost allocation study, ERA has been cognizant of these "influencing factors" as they apply to Hawkesbury.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on a 2010 forward test year, the primary purpose of the cost allocation study ("CA Study") is to determine the proportions of a distributor's total revenue requirement that are the "responsibility" of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, the desired results can be achieved in either of two ways.

- **Prospective Year CA Study:** A cost allocation study for the 2010 test year can be based on an allocation of the 2010 test year costs (i.e., the 2010 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Assuming there is a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.

- **Historic Year CA Study:** As an alternative, an historic year cost allocation study can be prepared that determines the proportion of costs allocated to each class for the most recent historic year. In the case, the CA Study will rely on actual costs, weather adjusted loads, customer counts, etc. that are not affected by forecast errors. Assuming the costs and loads are relatively stable so that the proportionate cost responsibility of each rate class in the historic year is a reasonable proxy for the 2010 test year cost responsibility, the resulting proportionate cost responsibilities can be used to allocate the 2010 revenue requirement to the various classes.

The Hawkesbury CA Study uses the first of these methods in order to ensure compliance with the Board's direction in the Filing Requirements that the CA Study should "reflect future loads and cost". Relying on a Prospective Year CA Study is also appropriate at this time since the Ontario economy has suffered over the past two years and, as a result, many distributors have experienced significant changes in the load profiles of their customer classes. These changes could have a significant impact on the allocation of costs to the classes and the resulting revenue to cost ratios. This approach implicitly assumes that the economic recovery will be slow and, as a result, the relative loads of customer classes are more likely to reflect 2010 loads than 2008 loads during the next IRM cycle.

1.2 HAWKESBURY'S 2006 COST ALLOCATION INFORMATION FILING

Hawkesbury filed its 2006 Cost Allocation Information Filing ("CAIF") on March 31, 2007, using 2004 financial information. Hawkesbury's 2006 CAIF relied on the Board's 2006 Cost Allocation Model ("CA Model") and was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* ("the Instructions").

1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into three additional sections. Section 2 provides an overview of the Hawkesbury CA Study, explaining each of the model runs (or version of the CA model) included in the study, as well as the load and cost information used for each run. Section 3 explains the methodology used to develop the 2010 Hawkesbury model by documenting each step taken in completing the model. Section 4 summarizes the results of the Hawkesbury CA Study, showing the class revenue requirements and revenue to cost ratios generated by each version of the CA models.

2 OVERVIEW OF THE HAWKESBURY 2010 CA STUDY

There are two factors affecting the Hawkesbury cost allocation results in 2010 as compared to the 2006 CAIF:

- Hawkesbury's only client in the Large Use class has closed. As a result, the entire Large Use Class has been removed
- The NCP values for the GS > 50 class which represents GS 50 – 4,999 kW were incorrectly computed in the 2006 CAIF. Separate NCP values for GS 50-999 kW and GS 1,000 - 4,999 were added, and the total was presented as the combined GS > 50 NCP. This had the effect of overstating the NCP values for this class.

2.1 MODELS RUNS INCLUDED IN THE HAWKESBURY COST ALLOCATION STUDY

Section 2.8.3 of the updated Filing Requirements specifies that "three sets of revenue to cost ratios for each customer class" must be provided based on:

- "the initial cost allocation model" which is the 2006 cost allocation information filing ("CAIF");
- "the initial cost allocation model revised with the adjusted transformer ownership allowance" which is the 2006 cost allocation information filings, adjusted in accordance with section 2.8.2 of the updated Filing Requirements; and
- "the updated cost allocation model" which is the appropriate 2010 model.

Hence, the cost allocation studies prepared for purposes of all 2010 cost of service filings must include these three separate CA models. As a result, the Hawkesbury Cost Allocation Study ("CA Study") consists of three versions of the OEB's cost allocation model. For clarity, the following designations are used.

- **HHI-2006: Hawkesbury 2006 Model**: The Hawkesbury CAIF as filed in 2006.
- **HHI-2006C1: Hawkesbury 2006 Model with Corrected Transformer Ownership Allowance (TFOA) treatment**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements.

- **HHI-2006C2: Hawkesbury 2006 Model Corrected for TFOA and NCP calculation**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements was further corrected by locating the one hour in each month when the GS > 50 class as a whole was peaking, and using those peak hours to determine the class's NCP values.

- **HHI-2010: Hawkesbury 2010 Model**: The 2006 CAIF with the corrected treatment of the Transformer Ownership Allowance and 2010 loads, costs, and revenues.

2.2 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "the updated model must be consistent with the load forecast and costs in the test year ... If updated load profiles are not available, the load profiles of the classes may be the same as those used in the information filing scaled to match the load forecast." (Section 2.8.1, pp. 19-20)

The Hawkesbury 2010 model has been prepared using the following load and load profile information:

- **Annual Loads (kW and kWh, as appropriate) and customer counts:** The 2010 load forecast and customer counts by class being used by Hawkesbury in its application were also used for the 2010 CA models. Hawkesbury's load forecast was prepared by ERA.

- **Hourly load profile:** The hourly load profiles prepared by Hydro One for the 2006 CAIF were used for all classes. The hourly load profile for the Large Use class was removed, and not used due to the loss of the only customer in that class.

The hourly load profiles provided by Hydro One for all of the remaining classes for the 2006 model were considered to be appropriate for use in the 2010 models for the following reasons.

1. ERA explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the

Hawkesbury for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of Hawkesbury-specific hourly load profiles. As far as ERA is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario Hawkesbury. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.

2. There would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.

3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information will be available in the next few years at minimal incremental cost.

4. Both time-of-use commodity pricing and changes to the design of distribution rates can be expected to alter the hourly load profiles of the affected classes.

5. The 2006 hourly load profiles were based on 2004 actual loads and updated hourly load profiles would be based on 2008 actual loads. An update of the hourly load profiles after only 4 years (2004 to 2008) can be expected to produce changes in cost responsibility that are small relative to the tolerances that are necessary given the imprecision of the allocated costs based on the 2006 CA Model methodology. (The revenue-to-cost ratio bands set out in the CA Application Report appear to recognize the lack of precision in cost allocation studies at this time.)

6. There is no longer Intermediate or Large User customers in the Hawkesbury service area.

2.3 COST INFORMATION

As noted earlier, ERA's preferred methodology for preparing 2010 cost allocation models is to use the prospective 2010 test year as the basis for the CA Study, assuming appropriate expense and asset information is available for the 2010 test year. In the case of Hawkesbury, the financial information for the forecast year has been prepared at the USoA level consistent with the level of detail embedded in the OEB's cost allocation model. [4]

[4] Some information (i.e., meter counts and some amortization detail) that is used in the Board's CA Model is not explicitly forecasted for the test year. These values were estimated using scaling factors based on prior year ratios. For example, the ratio of meters to customers was assumed to be constant. The portion of the total costs accounted for in this manner was too small for any plausible estimation errors to have a significant impact on the test year revenue to cost ratios.

3 HAWKESBURY COST ALLOCATION STUDY METHODOLOGY

This section documents ERA's methodology for the Hawkesbury Cost Allocation Study which includes the 2006 models and the 2010 CA Model.

The uncorrected 2006 CAIF model (HHI-2006) is an unaltered version of the model that was filed with the Board in 2007

3.1 CORRECTED 2006 HAWKESBURY CA MODEL

As described in section 2.1, two additional versions of the 2006 Model were completed to apply certain corrections:

- HHI-2006C1: This version of the Hawkesbury CA Model was corrected only for the treatment of the transformer ownership allowance in accordance with the Filing Requirements, section 2.8.2.
- HHI-2006C2: This version of the Hawkesbury CA Model was corrected not only for the treatment of the transformer ownership allowance, but also for the error that was identified in the original 2006 Hawkesbury CAIF. This version is the appropriate basis for examining the impact of the rates proposed for Hawkesbury on the revenue to cost ratios by class, as compared to the 2006 revenue to cost ratios.

Since the appropriate version of the Hawkesbury 2006 CAIF to be used for reference proposes in the Hawkesbury application is HHI-2006C2, ERA has modified the Revenue to Cost Ratio table set out in Appendix 2-P of the Filing Requirements by adding a column labelled "HHI-2006C2". This format for the table is used in the Summary of Revenue to Cost Ratios in section 4 below. The HHI-2006C2 revenue to cost ratios should be used in assessing the direction and magnitude of changes in the revenue to cost ratios from 2006 to 2010.

3.2 2010 HAWKESBURY CA MODEL

3.2.1 HOURLY LOAD PROFILE (HONI FILE)

For the Hawkesbury CAIF, HONI provided data files with three worksheets that were used as input to the 2006 CAIF:

- **Data Summary:** actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- **Hourly Load Shape by Class:** GWh by class for each hour in 2004.
- **Input to Cost Allocation Model**: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

The Hawkesbury hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2010. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HOPNI file to levels consistent with the 2010 load forecast while maintaining the hourly load shapes.

3.2.2 DEMAND ALLOCATORS (HONI FILE)

The demand allocators used in the HHI-2010 CA model were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2010 hourly load profiles resulting from the preceding step. Using the 2010 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.

- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.2.3 2010 Demand Data (HHI-2010 Model)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2010 Hawkesbury CA Model. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values (rows 57-58, 63-64, 69-70) are not equal to the full class NCP values since not all customers use these facilities, and due to transformation losses. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

Further, scaling factors have been added at I8 Demand Data, rows 75 and 79 to provide the appropriate adjustment to the kWh that was input from the 2006 EDR in the original 2006 CAIF. The scaling factor is the ratio of the 2010 to the 2006 EDR kWhs by class.

3.2.4 2010 Customer Data (HHI-2010 Model)

The 30 year weather normalized kWh by rate class which was an input from the Hydro One file at Sheet I6 Customer Data row 27 in the 2006 CA model was replaced with the 2010 load forecast in the 2010 CA Model.

In addition, the demand data (kW and kWh) in rows 21, 22, 25, and 56 of Sheet I6 Customer Data were replaced with the forecasted values. Row 23 was scaled by the percentage change in row 22.

The 2010 Distribution Revenue in row 29 was derived using the forecast demand (kW and kWh) and customer counts by rate class and the existing 2009 rates.

3.2.5 2010 REVENUE TO COST RATIOS

Since Hawkesbury is proposing to set rates that recover its full revenue requirement, the total revenue to cost ratio at proposed rates will be 100% in 2010. The 2010 total revenue to cost ratio at current rates is less than 100% by the amount of the required rate increase. The revenue to cost ratios of the classes reflect the costs allocated to the classes based on the OEB CA Model methodology and the revenues that would be generated at current rates given the forecast demand (kW and kWh) and customer counts by rate class for 2010.

4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the Hawkesbury cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	HHI-2006	HHI-2006C1	HHI-2006C2	HHI-2010	Board Target Range
Residential	120.74	128.10	127.84	103.72	85-115
GS < 50 kW	105.06	111.48	111.08	87.31	80-120
GS > 50 kW	42.19	26.54	26.72	21.53	80-180
Large Use	160.39	142.12	140.87	-	85-115
Street Lighting	22.16	26.26	26.26	26.66	70-120
Sentinel Lighting	126.77	148.06	147.77	144.93	70-120
USL	6.32	7.53	7.53	145.72	80-120
Total	100.00	100.00	100.00	73.42	

Note that the total revenue to cost ratio for HHI-2010 is less than 100% because it represents the revenue to cost ratios for 2010 at current rates. At proposed rate the total revenue to cost ratio would be 100%. In addition, Hawkesbury's proposed rates for 2010 will alter the relative revenue to cost ratios of the classes.

The HHI-2010 ratios (at current rates) reflect the impact of changes in throughput by class as well as changes in costs from 2006 through the 2010 forecast test year.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

Table 8: Revenue Responsibility by Rate Class

Customer Class	HHI-2006		HHI-2006C1		HHI-2006C2		HHI-2010	
	$	$	%	%	$	%	$	%
Residential	663,523	49.25	625,385	50.49	626,772	50.60	765433	51.57
GS < 50 kW	178,365	13.24	168,091	13.57	168,761	13.62	206783	13.93
GS > 50 kW	317,672	23.58	284,640	22.98	281,491	22.73	466079	31.40
Large Use	131,496	9.76	113,183	9.14	114,272	9.23		
Street Lighting	53,609	3.98	45,236	3.65	45,236	3.65	43656	2.94
Sentinel Lighting	1,415	0.11	1,212	0.10	1,214	0.10	1251	0.08
USL	1,087	0.08	913	0.07	913	0.07	1013	0.07
Total	1,347,167	100.00	1,238,660	100.00	1,238,659	100.00	1484215	100.00

Exhibit 8:

RATE DESIGN

Exhibit 8: Rate Design

Tab 1 (of 4): Existing Rates

OVERVIEW OF EXISTING RATES

The existing rate schedule is presented at Exhibit 8, Tab 1, Schedule 1, Attachment 1.

The current rates were approved as part of the proceeding EB-2008-0185. HHI applied for distribution rate adjustments pursuant to the IRM process. Notice of HHI's rate application was given through newspaper publication in HHI's service area, and advising how interested parties may intervene in the proceeding or comment on the application. No intervention requests or comments were received.

The Board found that HHI's rate application was filed on the basis of the new guidelines.

- Rates were adjusted by a price escalator less a productivity factor. Based on the final 2008 data published by Statistics Canada, the Board established the price escalator to be 2.3%.

- Hydro Hawkesbury reported that it is authorized to conduct smart meter activities because it has procured smart meters pursuant to and in compliance with the August 14, 2007 Request for Proposal issued by London Hydro Inc. The Board therefore allowed a smart meter funding adder of $1.00 per metered customer per month for the purpose of providing funding for HHI's smart metering activities in the 2009 rate year.

- HHI proposed no adjustment to their RTSR.

HHI's rates were approved by the Board and rendered effective May 1, 2009

Hydro Hawkesbury Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0185

Street Lighting
This classification refers to municipal lighting, Ministry of Transportation operation controlled by photo cells. Consumption is as per OEB street lighting load shape.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	5.96
Distribution Volumetric Rate	$/kWh	0.0092
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0030
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	10.73
Distribution Volumetric Rate	$/kWh	0.0051
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0027
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	47.50
Distribution Volumetric Rate	$/kW	0.5422
Retail Transmission Rate – Network Service Rate	$/kW	1.7399
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0849
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.8479
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.2938
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	6,465.01
Distribution Volumetric Rate	$/kW	1.6804
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.0461
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.3601
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	9.73
Distribution Volumetric Rate	$/kWh	0.0051
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0027
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

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Sentinel Lighting

Service Charge (per connection)	$	1.00
Distribution Volumetric Rate	$/kW	5.1688
Retail Transmission Rate – Network Service Rate	$/kW	1.3127
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7125
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.36
Distribution Volumetric Rate	$/kW	3.3563
Retail Transmission Rate – Network Service Rate	$/kW	1.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8387
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Duplicate invoices for previous billing	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	20.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	15.00
Disconnect/Reconnect at meter – during regular hours	$	30.00
Disconnect/Reconnect at meter – after regular hours	$	130.00
Disconnect/Reconnect at pole - during regular hours	$	100.00
Disconnect/Reconnect at pole – after regular hours	$	300.00
Install/Remove load control device – during regular hours	$	30.00
Install/Remove load control device – after regular hours	$	130.00
Service call – after regular hours	$	130.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – overhead – with transformer	$	1,000.00
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

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Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0635
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0528
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Exhibit 8: Rate Design

Tab 2 (of 4): Proposed Changes to Distribution Rates

OVERVIEW OF FIXED AND VARIABLE CHARGES

The delivery line charges on the electricity bill include a fixed component and a variable component

The fixed charge covers the utility's administrative costs, such as meter reading, billing, customer service and maintenance of accounts. The fixed component does not change with the amount of electricity used.

The variable charge involves the delivery of electricity from the utility to the end user. It includes the cost to design, build and maintain overhead and underground distribution lines, poles, stations and local transformers, and operate local systems. The variable charge varies with the amount of electricity used.

HHI is proposing to change the existing "fixed to variable split" (F/V Split) by increasing the fixed component percentage, bringing it closer to the F/V Split used by its cohorts and neighbouring utilities.

Current rates and fixed/variable split ("F/V Split")

		Existing Rates (1)	
Customer Class Name	**Rate**	**Fixed %**	**Variable %**
Residential	$4.96	36.33%	63.67%
General Service Less Than 50 kW	$9.73	38.49%	61.51%
General Service 50 to 4,999 kW	$46.50	26.13%	73.87%
Sentinel Lighting	$1.00	13.04%	86.96%
Street Lighting	$0.04	4.59%	95.41%
Unmetered Scattered Load	$9.73	29.33%	70.67%

At the current F/V split, HHI's monthly fixed charge is amongst the lowest in Ontario which puts the utility at greater risk than the average utility in Ontario. This is a cause of concern for HHI since company's revenue and earnings can become unpredictable as a result of large abnormal weather swings. Also, increasing the fixed charge provides a better match of revenue with the associated distribution costs, and is therefore a more efficient pricing methodology. In general, HHI provides each residential customer the same standard service regardless of their expected usage. Under current practices, high-usage customers effectively subsidize low-usage customers, especially in the residential class.

HHI conducted an analysis of its cohorts F/V split percentages using the list of comparators published by the OEB. The table below shows the cohorts' F/V splits.

Comparator’s F/V Split

CNP - Eastern Ontario				Lakefront Utilities		
	Fixed %	Variable %			Fixed %	Variable %
Residential	44.50%	55.50%		Residential	47.16%	52.84%
GS < 50kW	58.70%	41.30%		GS < 50kW	45.01%	54.99%
GS > 50kW	54.50%	45.50%		GS > 50kW	24.55%	75.45%
Street Lights	30.50%	69.50%		Street Lights	44.45%	55.55%
Sentinel Lights	21.00%	79.00%		Sentinel Lights	73.44%	26.56%
USL	35.00%	65.00%		USL	39.14%	60.86%
CNP - Port Colborne				Hydro 2000		
	Fixed %	Variable %			Fixed %	Variable %
Residential	48.50%	51.50%		Residential	38.87%	61.13%
GS < 50kW	52.00%	48.00%		GS < 50kW	36.30%	63.70%
GS > 50kW	62.75%	37.25%		GS > 50kW	27.24%	72.76%
Street Lights	39.44%	60.56%		Street Lights	24.62%	75.38%
Sentinel Lights	12.30%	87.70%		USL	39.33%	60.67%
USL	56.50%	43.50%				
Wellington North Power				Rideau St.Lawrence		
	Fixed %	Variable %			Fixed %	Variable %
Residential	49.92%	50.08%		Residential	51.90%	48.12%
GS < 50kW	44.32%	55.68%		GS < 50kW	50.37%	49.63%
GS > 50kW	46.37%	53.64%		GS > 50kW	48.81%	51.19%
Street Lights	25.93%	74.07%		Street Lights	55.89%	44.11%
Sentinel Lights	44.01%	55.99%		Sentinel Lights	15.91%	84.09%
USL	58.29%	41.71%		USL	29.29%	70.71%

.COMPARATOR AVERAGE		
	Fixed %	**Variable %**
Residential	46.81%	53.19%
GS < 50kW	47.78%	52.22%
GS > 50kW	44.04%	55.96%
Street Lights	36.80%	63.20%
Sentinel Lights	33.33%	66.67%
USL	42.93%	57.07%

HHI used the comparator average as a basis to shift its current F/V Split. With the exception of the GS>50 class, HHI proposes to change its F/V split by moving the F/V split percentages 75% of the way toward the comparator average. For the GS>50 class which fell outside the boundaries, the maximum "Cost Allocation" rate was used.

Hawkesbury Hydro (2010 @ existing rates)		
	Fixed %	**Variable %**
Residential	36.33%	63.67%
GS < 50kW	38.49%	61.51%
GS > 50kW	26.13%	73.87%
Street Lights	4.59%	95.41%
Sentinel Lights	13.04%	86.96%
USL	29.33%	70.67%

Comparator Average		
	Fixed %	Variable %
Residential	46.81%	53.19%
GS < 50kW	47.78%	52.22%
GS > 50kW	44.04%	55.96%
Street Lights	36.80%	63.20%
Sentinel Lights	33.33%	66.67%
USL	42.93%	57.07%
Hawkesbury vs Comparator Average		
	Fixed %	Variable %
Residential	-10.48%	10.48%
GS < 50kW	-9.29%	9.29%
GS > 50kW	-17.90%	17.90%
Street Lights	-32.21%	32.21%
Sentinel Lights	-20.29%	20.29%
USL	-13.60%	13.60%
Hawkesbury 2010 proposed		
	Fixed %	Variable %
Residential	44.00%	56.00%
GS < 50kW	45.00%	55.00%
GS > 50kW	39.00%	61.00%
Street Lights	29.00%	71.00%
Sentinel Lights	28.00%	72.00%
USL	39.00%	61.00%

The proposed F/V split remains below the comparator average and produces rates that are within the allowable boundaries. Details of these boundaries are found at Exhibit 8, Tab 2, Schedule 1, Attachment 2.

The Revenue Requirement allocation and revenue to cost ratios can be found at Exhibit 8, Tab 2, Schedule 1, Attachment 1. Details of the proposed variable/fixed split are found at Exhibit 8, Tab 2, Schedule 1, Attachment 2.

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F4 Revenue Requirement Allocation

Enter the outstanding Base Revenue Requirement and Transformer Allowance recoveries by customer class

Customer Class Name	Status	Outstanding Base Revenue Requirement % Cost Allocation [1]	Existing Rates [2]	Rate Application	Outstanding Base Revenue Requirement $ [3] Cost Allocation	Existing Rates	Rate Application	Directly Assigned Revenues [3]	Total Base Revenue Requirement
Residential	Continued	50.79%	68.48%	56.64%	662,351	893,137	738,714		738,714
General Service Less Than 50 kW	Continued	13.81%	15.25%	15.32%	180,080	198,932	199,741		199,741
General Service 50 to 4,999 kW	Continued	32.04%	14.99%	25.63%	417,874	195,446	334,300		334,300
Sentinel Lighting	Continued	0.09%	0.17%	0.11%	1,169	2,238	1,403		1,403
Street Lighting	Continued	3.20%	0.97%	2.25%	41,778	12,619	29,286		29,286
Unmetered Scattered Load	Continued	0.07%	0.14%	0.06%	964	1,845	772		772
TOTAL		**100.00%**	**100.00%**	**100.00%**	**1,304,216**	**1,304,216**	**1,304,216**		**1,304,216**
				OK			**OK**		

[1] from sheet F3
[2] from sheet C4
[3] from sheet F2

Customer Class Name	Status	Total Base Revenue Requirement	Transformer Allowance Recovery [4]	Low Voltage Revenue Required [5]	Gross Base Revenue Requirement
Residential	Continued	738,714		25,053	763,767
General Service Less Than 50 kW	Continued	199,741		8,416	208,157
General Service 50 to 4,999 kW	Continued	334,300	110,443	36,578	481,320
Sentinel Lighting	Continued	1,403		82	1,484
Street Lighting	Continued	29,286		382	29,668
Unmetered Scattered Load	Continued	772		90	862
TOTAL		**1,304,216**	**110,443**	**70,600**	**1,485,259**
			OK		

2010 Transformer Allowances

	Volume [4]	Rate	Amount
kW:	184,071	($0.6000)	(110,443)

[4] Volume per sheet C4; total allocations m
[5] allocated per table below:

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F4 Revenue Requirement Allocation

Enter the outstanding Base Revenue Requirement and Transformer Allowance recoveries by customer class

Customer Class Name	Status	Test Year Revenues [6] Transmission - Connection	Class Share	Low Voltage Charges [7]
Residential	Continued	134,532	35.5%	25,053
General Service Less Than 50 kW	Continued	45,194	11.9%	8,416
General Service 50 to 4,999 kW	Continued	196,422	51.8%	36,578
Sentinel Lighting	Continued	438	0.1%	82
Street Lighting	Continued	2,049	0.5%	382
Unmetered Scattered Load	Continued	485	0.1%	90
TOTAL		**379,120**	**100.0%**	**70,600**
			OK	

[6] charge type per sheet Y4; amounts per s
[7] Total per sheet C2; allocated to custome

Customer Class Name	Status	Rate Application			Cost Allocation	Variance	Target Range	
		Allocated Revenue [8]	Allocated Cost [8]	Revenue to Cost Ratio	Revenue to Cost Ratio [9]		Floor	Celiling
Residential	Continued	738,714	662,351	1.12	1.28	(0.16)	0.85	1.15
General Service Less Than 50 kW	Continued	199,741	180,080	1.11	1.11	(0.00)	0.80	1.20
General Service 50 to 4,999 kW	Continued	334,300	417,874	0.80	0.27	0.53	0.80	1.80
Sentinel Lighting	Continued	1,403	1,169	1.20	1.48	(0.28)	0.70	1.20
Street Lighting	Continued	29,286	41,778	0.70	0.26	0.44	0.70	1.20
Unmetered Scattered Load	Continued	772	964	0.80	0.08	0.73	0.80	1.20
TOTAL		1,304,216	1,304,216	1.00	1.00			

[8] see first table above (Outstanding Rever
[9] from sheet F3

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F5 Fixed/Variable Rate Design

Enter the proposed fixed monthly rate for each customer class

	Existing Rates (1)			Cost Allocation - Minimum Fixed Rate (2)			Cost Allocation - Maximun Fixed Rate (2)		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$4.96	36.33%	63.67%	$4.04	29.85%	70.15%	$8.58	63.45%	36.55%
General Service Less Than 50 kW	$9.73	38.49%	61.51%	$7.77	25.36%	74.64%	$15.09	49.25%	50.75%
General Service 50 to 4,999 kW	$46.50	26.13%	73.87%	$50.35	9.92%	90.08%	$94.41	18.59%	81.41%
Sentinel Lighting	$1.00	13.04%	86.96%	$0.32	5.37%	94.63%	$3.03	51.49%	48.51%
Street Lighting	$0.04	4.59%	95.41%	$0.03	1.48%	98.52%	$3.06	143.32%	-43.32%
Unmetered Scattered Load	$9.73	29.33%	70.67%			100.00%	$9.73	54.16%	45.84%

(1) per sheet C4
(2) Rates per sheet F3; %s based on # customers per sheet C1 and revenue requirement allocated to customer class per sheet F4

	Existing Fixed/Variable Split (3)			Rate Application			Resulting Usage		(4) Existing
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**per**	**Usage Rate**
Residential	$4.91	36.33%	63.67%	$5.96	44.06%	55.94%	$0.0080	kWh	$0.0092
General Service Less Than 50 kW	$11.80	38.49%	61.51%	$13.80	45.03%	54.97%	$0.0056	kWh	$0.0051
General Service 50 to 4,999 kW	$132.68	26.13%	73.87%	$94.41	18.59%	81.41%	$1.7049	kW	$0.5422
Sentinel Lighting	$0.77	13.04%	86.96%	$1.71	29.03%	70.97%	$3.2418	kW	$5.1688
Street Lighting	$0.10	4.59%	95.41%	$0.60	28.10%	71.90%	$6.8897	kW	$3.3563
Unmetered Scattered Load	$5.27	29.33%	70.67%	$7.19	40.02%	59.98%	$0.0023	kWh	$0.0051

(3) %s per Existing Rates, Rate based on Revenue Requirement allocated to Customer Class per sheet F4 and # customers per sheet C1
(4) per sheet C4

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F6 Reconciliation of Rates with Revenue / Recovery Requirements

Review reconciliations (no input on this sheet)

DISTRIBUTION CHARGES

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
Customer Class Name	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	$5.96	56,460	336,502	$0.0080	53,559,119	428,473	764,975	763,767	1,207
General Service Less Than 50 kW	$13.80	6,792	93,730	$0.0056	20,562,650	115,151	208,880	208,157	723
General Service 50 to 4,999 kW	$94.41	948	89,501	$1.7049	229,814	391,810	481,311	481,320	(10)
Sentinel Lighting	$1.71	252	431	$3.2418	325	1,054	1,485	1,484	0
Street Lighting	$0.60	13,896	8,338	$6.8897	3,096	21,331	29,668	29,668	0
Unmetered Scattered Load	$7.19	48	345	$0.0023	220,667	508	853	862	(10)
TOTAL			**528,846**			**958,325**	**1,487,171**	**1,485,259**	**1,912**

[1] From sheet F5, rounded off to decimals displayed
[2] Fixed Charge = # Customers (Connections) multiplied by 12 (months); Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
[3] Rate x Volume

** Sum of 'Revenue' columns*
*** From sheet F4 (Gross Base Revenue Requirement)*

DEFERRAL/VARIANCE ACCOUNT RECOVERY CHARGES (CREDITS)

	Variable Charge (Credit)			Proceeds from Recovery Charges (Credits)		
Customer Class Name	**Rate [1]**	**Volume [2]**	**Proceeds [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	($0.0054)	53,559,119	(289,219)	(289,219)	(290,112)	893
General Service Less Than 50 kW	($0.0059)	20,562,650	(121,320)	(121,320)	(121,608)	288
General Service 50 to 4,999 kW	($2.2926)	229,814	(526,872)	(526,872)	(526,871)	(1)
Sentinel Lighting	($1.5489)	325	(503)	(503)	(503)	0
Street Lighting	($2.3842)	3,096	(7,381)	(7,381)	(7,381)	(0)
Unmetered Scattered Load	($0.0060)	220,667	(1,324)	(1,324)	(1,324)	(0)
TOTAL			**(946,619)**	**(946,619)**	**(947,799)**	**1,180**

[1] From sheet C7 ('Proposed Rate Rider'), rounded off to decimals displayed
[2] Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
[3] Rate x Volume

** = 'Proceds' column*
*** From sheet C7 ('Annual Recovery Amounts')*

DISTRIBUTION RATE ADJUSTMENTS

Exhibit 8, Tab 2, Schedule 2, Attachment 1 presents the final rates including HHI's requested utility specific smart meter adder, requested loss factor and rate rider to dispose of the deferral and variance accounts. The evidence related to the smart meter rate adder can be found at Exhibit 9 Tab 3 Schedule 2. The evidence relating to the loss adjustment factor is presented at Exhibit 8, Tab 3, Schedule 3 and the evidence supporting the disposal of variance accounts can be found at Exhibit 9, Tab 2.

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F7 Final Proposed Distribution Rates

Enter rate adjustments and factors where applicable

Rate components per sheet Y5

Customer Class Name	PROPOSED FIXED RATES per Sheet F6	Smart Meters				TOTAL	* Default Loss Factor
Residential	$5.96	$1.51				$7.47	1.0466
General Service Less Than 50 kW	$13.80	$1.51				$15.31	1.0466
General Service 50 to 4,999 kW	$94.41	$1.51				$95.92	1.0466
Sentinel Lighting	$1.71					$1.71	1.0466
Street Lighting	$0.60					$0.60	1.0466
Unmetered Scattered Load	$7.19					$7.19	1.0466

** For Bill Impact Analysis: based on default Line Loss Category specified for the customer class in sheet C3 and associated Loss Factor specified below on this sheet*

Customer Class Name	PROPOSED VARIABLE RATES per Sheet F6					TOTAL	per
Residential	$0.0080					$0.0080	kWh
General Service Less Than 50 kW	$0.0056					$0.0056	kWh
General Service 50 to 4,999 kW	$1.7049					$1.7049	kW
Sentinel Lighting	$3.2418					$3.2418	kW
Street Lighting	$6.8897					$6.8897	kW
Unmetered Scattered Load	$0.0023					$0.0023	kWh

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F7 Final Proposed Distribution Rates

Enter rate adjustments and factors where applicable

Rate components per sheet Y5

Line Loss Category (per sheet C3)	Loss Factor
Secondary Metered Customer < 5,000 kW	1.0466
Secondary Metered Customer > 5,000 kW	
Primary Metered Customer < 5,000 kW	1.0466
Primary Metered Customer > 5,000 kW	

Allowances	Rate
Transformer Ownership ($/kW) *	($0.6000)
Primary Metering Allowance (%)	(1.00%)

** per sheet F4*

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F7 Final Proposed Distribution Rates

Enter rate adjustments and factors where applicable

Rate components per sheet Y5

Customer Class Name	2010 PROCEEDS FROM PROPOSED FIXED RATES					
	per Sheet F6	Smart Meters				TOTAL
Residential	336,502	85,255				421,756
General Service Less Than 50 kW	93,730	10,256				103,986
General Service 50 to 4,999 kW	89,501	1,431				90,932
Sentinel Lighting	431					431
Street Lighting	8,338					8,338
Unmetered Scattered Load	345					345
TOTAL	**528,846**	**96,942**				**625,788**

Customer Class Name	2010 PROCEEDS FROM PROPOSED VARIABLE RATES					
	per Sheet F6					TOTAL
Residential	428,473					428,473
General Service Less Than 50 kW	115,151					115,151
General Service 50 to 4,999 kW	391,810					391,810
Sentinel Lighting	1,054					1,054
Street Lighting	21,331					21,331
Unmetered Scattered Load	508					508
TOTAL	**958,325**					**958,325**

SPECIAL CIRCUMSTANCES - LOSS OF LARGE USER

HHI's sole large user announced that it will cease operation in its Hawkesbury plant in November of 2009. This large user manufactures parts for the automotive industry. Back in May of 2009, with the continued decline of North American automotive manufacturing and the unprecedented and radical restructuring of the automotive industry, this large user responded to the change in the markets it served by announcing the closure of its Hawkesbury Plant

The large user will be putting its assets up for auction upon closure of its business indicating that the chances of the plant reviving its daily operations are very unlikely. Given the economic downturn and the steady decline in HHI's customer base as shown in the demographic trends in the load forecast, it is unreasonable to presume that the lost load can be replaced by growth or a new large user within the expected four year term of the incentive period. Even in a normal economy, large use customers are difficult to replace (especially in smaller communities) due to the customer's unique location, load and system requirements. In recognition of these conditions, HHI has removed the departing customer's demand from the test year forecast and expects that this load will not be replaced over the next five years.

The dedicated lines that feeds into this particular customer's premises, are owned by the customer. The only element that is owned by the utility is a fully depreciated interval meter therefore no stranded assets are expected. The line to the plant will continue to be used and useful in providing electricity to the building until its fate is determined.

Under these conditions, the costs of maintaining the distribution system will need to be spread across a smaller demand and the rates for the customers remaining on the system and in the larger user class will increase. There will however be no need to increase the bad debt allowance as the result of this customer loss as this was a planned departure.

Exhibit 8: Rate Design

Tab 3 (of 4): Transmission, Low Voltage and Line Losses

RETAIL TRANSMISSION SERVICE RATES (RTSR)

On July 3, 2009 the Ontario Energy Board issued its Decision and Rate Order in proceeding EB-2008-0272, setting new Uniform Transmission Rates for Ontario transmitters, effective July 1, 2009. With the change in the UTRs, there is a need to review the rates charged by distributors for the corresponding retail transmission service.

HHI followed the guidelines proposed in the Board's report entitled "Electricity Distribution Retail Transmission Service Rates, G-2008-0001 published October 22, 2008, revised July 22, 2009.

As per the Board's report, Electricity transmitters in Ontario charge Uniform Transmission Rates to their transmission connected customers. These UTRs are charged for network, line connection and transformation connection services. Based on the Decision and Rate Order of the Board in the EB-2008-0272 proceeding, the new UTRs are effective July 1, 2009 and have been approved as shown in the following excerpts from G-2008-0001:

- Network Service Rate has increased from $2.57 to $2.66 per kW per month, a 3.5% increase.

- Line Connection Service Rate remains unchanged at $0.70 per kW per month, and

- Transformation Connection Service Rate has decreased from $1.62 to $1.57 per kW per month, for a combined Line and Transformation Connection Service Rates reduction of 2.2%.

In accordance with the minimum filing requirements, historical transmission costs and revenues as well as calculation of proposed retail transmission service rates are presented in the following pages.

Historical Transmission Costs and Revenues and Proposed Calculation

MONTH	IESO Network Service Charge	IESO Line Connection Service Charge	IESO Transformation Connection Service Charge	Network Billings	Connection Billings
Jan-08	$86,838	$49,991		$65,514	$53,011
Feb-08	$86,418	$49,175		$140,378	$113,482
Mar-08	$72,778	$43,179		$65,655	$53,148
Apr-08	$69,628	$42,750		$129,290	$104,400
May-08	$58,150	$39,327		$61,269	$49,187
Jun-08	$65,314	$42,661		$91,988	$64,292
Jul-08	$65,155	$42,455		$52,664	$34,491
Aug-08	$63,487	$41,173		$86,498	$56,031
Sep-08	$65,191	$40,516		$52,228	$34,113
Oct-08	$64,395	$40,436		$83,474	$53,946
Nov-08	$64,143	$38,018		$50,347	$33,000
Dec-08	$73,211	$85,671		$85,671	$55,255
Jan-09	$78,214	$40,872		$49,550	$32,070
Feb-09	$75,560	$42,126		$116,383	$74,735
Mar-09	$74,781	$43,448		$48,218	$31,321
Apr-09	$58,482	$38,529		$104,350	$67,121
May-09	$54,135	$34,518		$45,994	$29,863
Jun-09	$64,345	$38,347		$81,327	$52,476
Jul-09	$63,262	$37,543		$45,794	$29,971
Subtotal	$1,303,487	$830,736	$0	$1,456,591	$1,021,913
	(a)	**(b)**	**(c)**	**(d)**	**(e)**
Total	$1,303,487	$830,736	$830,736	$1,456,591	$1,021,913
	(f)	**(g)**	**(h)**		
Old Rate	2.57	0.7	1.62		
	(i)	**(j)**	**(k)**		
New Rate	2.66	0.7	1.57		
			$805,096		
	(l)	**(m)**	**(n)**		
Est Revised IESO Cost	$1,349,134	$830,736	$805,096		
	(a) / (f) *(i)	(b) / (g) *(j)	(c) / (h) *(k)		

Adjustements	Network		Connection	
Old				
IESO Costs	$1,303,487	(a)	$830,736	(c)
Billing Revenues	$1,456,591	(d)	$1,021,913	(e)
Ratio	**0.895**		**0.813**	
Estimated New				
IESO Costs	$1,349,134	(l)	$805,096	(n)
Billing Revenues	$1,456,591	(d)	$1,021,913	(e)
Ratio	**0.926**		**0.788**	

Current Rates	Network	Connection
Residential	$0.0047	$0.0030
GS < 50kW	$0.0043	$0.0027
GS 50 to 4999 kW		
non-interval meter	$1.7399	$1.0849
Inteval meter	$1.8479	$1.2938
USL	$0.0043	$0.0027
Sentinel Lights	$1.3127	$1.7125
Street Lights	$1.3122	$0.8387

Proposed Rates (current rates with ratio applied)

Residential	$0.0044	$0.0024
GS < 50kW	$0.0040	$0.0021
GS 50 to 4999 kW		
non-interval meter	$1.6115	$0.8547
Inteval meter	$1.7116	$1.0193
USL	$0.0040	$0.0021
Sentinel Lights	$1.2159	$1.3492
Street Lights	$1.2154	$0.6608

LOW VOLTAGE CHARGES

Consistent with the approach in the Board's 2006 EDR model, LV costs are projected to be $70,600 and have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. This calculation is outlined in the following table:

		Test Year Revenues [6]	Class	Low Voltage
Customer Class Name	**Status**	**Transmission - Connection**	**Share**	**Charges [7]**
Residential	Continued	134,532	35.5%	25,053
General Service Less Than 50 kW	Continued	45,194	11.9%	8,416
General Service 50 to 4,999 kW	Continued	196,422	51.8%	36,578
Sentinel Lighting	Continued	438	0.1%	82
Street Lighting	Continued	2,049	0.5%	382
Unmetered Scattered Load	Continued	485	0.1%	90
TOTAL		379,120	100.0%	70,600

These proposed LV costs by rate class are then divided by the projected volumes as seen in the table below (excerpt from Exhibit 3, Tab 1, Schedule 1, Attachment 1)

	KWh
Customer Class Name	**2010 Normalized**
Residential	53,559,119
General Service Less Than 50 kW	20,562,650
General Service 50 to 4,999 kW	86,186,766
Large Use	
Sentinel Lighting	108,470
Street Lighting	1,208,363
Unmetered Scattered Load	220,667
TOTAL	**161,846,035**

	KW
Customer Class Name	**2010 Normalized**
Residential	
General Service Less Than 50 kW	
General Service 50 to 4,999 kW	229,814
Large Use	
Sentinel Lighting	325
Street Lighting	3,096
Unmetered Scattered Load	
TOTAL	**233,235**

and this produces the proposed adjustments to the distribution volumetric charges set out in the table below:

Customer Class Name		LV adjustment ($ per KWh)	LV adjustment ($ per KW)
Residential		0.00046	
General Service Less Than 50 kW		0.00040	
General Service 50 to 4,999 kW		0.00042	0.1592
Large User			
Sentinel Lighting		0.00076	0.2523
Street Lighting		0.00032	0.1234
Unmetered Scattered Load		0.00041	

LOSS ADJUSTMENT FACTORS

This section addresses updates to the loss adjustment factor. HHI relied on direction from the minimum filing requirements and its appendix 2-Q to adjust its Loss Factor. Based on the calculations shown in the attached schedule, the proposed loss factor will decrease to 4.66% from 6.35%. Exhibit 8, Tab3, Schedule 3, Attachment 1 explains the calculation of loss factors.

BACKGROUND

In its 2006 EDR application, HHI applied for an increase in the distribution loss adjustment factor from 1.0392 to 1.0635 consistent with the methodology presented in the 2006 Handbook. Based on the evidence provided by HHI, the Board approved a 1.0587 total loss factor. The Board noted that the RP-2004-0188 Report of the Board dated May 11, 2005 stated that any distributor whose losses are higher than 5% will be required to report on those losses and provide an action plan as to how the distributor intends to reduce the level of losses. At the time, HHI proposed a line loss study to determine the reasons for the loss. The Board accepted this plan and also its commitment that the plan will be acted upon to reduce the losses.

Consequently, a line loss study had been completed and the report was filed within 90 days of the date of the 2006 EDR Decision and Order. The line loss study can be found at Exhibit 8, Tab3, Schedule 3, Attachment 2.

The proposed loss factor falls below the threshold of 5%, therefore, an explanation and a plan of action is not required for the purpose of this application.

Calculation of Proposed Total Loss Factors

	Losses in Distributor's System	2006	2007	2008	2009	2010	5 Year Average
A1	"Wholesale" kWh delivered to distributor (higher value)	-	-	-	-	-	
A2	"Wholesale" kWh delivered to distributor (lower value)	199,559,709.00	199,784,966.00	194,402,877.00	180,488,362.00	167,650,331.00	188,377,249.00
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	-	-	-	-	-	
C	Net "Wholesale" kWh delivered to distributor (A2)-(B)	199,559,709.00	199,784,966.00	194,402,877.00	180,488,362.00	167,650,331.00	188,377,249.00
D	"Retail" kWh delivered by distributor	189,833,349.00	192,427,726.00	185,032,775.00	174,678,773.00	161,833,200.00	180,761,164.60
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	-	-	-	-	-	
F	Net "Retail" kWh delivered by distributor (D)-(E)	189,833,349.00	192,427,726.00	185,032,775.00	174,678,773.00	161,833,200.00	180,761,164.60
G	Loss Factor in distributor's system [(C)/(F)]	1.0512	1.0382	1.0506	1.0333	1.0359	1.0419
	Losses Upstream of Distributor's System						
H	Supply Facility Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor [(G)x(H)]	1.0560	1.0429	1.0554	1.0379	1.0406	1.0466

Hawkesbury Hydro

Utility Load Flow and Evaluation Study

PREPARED FOR:

Hawkesbury Hydro
850 Tupper
Hawkesbury, ON, K6A 3S7

PREPARED BY:

Stantec Consulting Ltd.
1505 Laperriere Avenue
Ottawa ON   K1Z 7T1

February 16, 2007

File: 163300801

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INTRODUCTION

UTILITY LOAD FLOW STUDY

Stantec Consulting Ltd. is pleased to submit this Utility Load Flow Study of the electrical distribution systems of Hawkesbury. This study has been prepared in accordance with relevant standards, including the Ontario Electrical Safety Authority (ESA), National Electrical Manufacturer's Association (NEMA), Institute of Electrical and Electronic Engineers (IEEE), Municipal Electrical Association (MEA), Canadian Standards Authority (CSA), and the American National Standards Institute (ANSI).

OBJECTIVES

There were a number of objectives for this study, including:

- Determining the acceptability of the system with current and future load growth and to identify any voltage support problems, overloaded equipment, etc.
- Finding whether the system would operate acceptably during Emergency situations.
- Optimizing the system arrangement (cable sizes, load balancing, open points, etc.) to minimize losses, maximize voltage support, and to distribute loading evenly.
- Determine optimal switching strategies to prepare for emergency operations.

SCOPE OF STUDY

The Load Flow Study includes all feeders from and including both the 44kV and 115kV Utility Substations down to each major tap at the 12,480(7,200)V level; no secondary lines were included. All loads were represented as distributed loads over the segment that they were modelled on, and are shown on the system model layout under Appendix 1.

ASSUMPTIONS AND GENERALIZATIONS

A number of assumptions and generalizations are made when modelling a complex system. Some of the ones made in this study are as follows:

- In most cases, loads were modelled as spot loads, sized using current measurements made at strategic points within the system. For longer sections with multiple transformers, loads were distributed evenly across the section of line.
- Each feeder's loads were modelled at a Power Factor (PF) of 0.9. Please note, all figures are typically given either in Amps or kVA, which are more directly attributable to capacity reviews. Any figures given in kVA are typically assumed at 0.9 PF unless otherwise noted.
- There were some discrepancies in the phasing observed between the drawing and the measurements taken. Where the actual phasing of taps or transformers could not be verified, other measurements taken within the system were examined to determine the likely phasing arrangement actually implemented. The areas of discrepancy are listed in the table below. Hydro personnel should check the devices to confirm their phasing and update the drawings if necessary.

Feeder	***Section***	***Phase shown in drawing***	***Phase indicated by measurements***
43F2	North on Tupper, East on Lansdowne	R,B	R,W,B
43F2	Abbott and Dufferin	Most W, some B	Even Split W and B

- There were some general questions about open points and conductor sizes so it is recommended that the information in the following table be confirmed with Hydro personnel.

Feeder	***Section***	***Item to be confirmed***
55F1	Section along Main St. West	Confirm whether 3/0 or 336
43F1	Main Feeder (loop?)	Confirm open point at Spence and Cameron
55F3	Main Feeder (loop?)	Confirm open point at Garneau and Cartier

- The new final record drawing 'Primary Electrical Distribution System Map' completed on February 17, 2007 is the basis of the system model, along with photos and other information gathered during site inspections to determine line loading and feeder sizes.

LOAD FLOW STUDY FINDINGS AND RESULTS

SYSTEM EQUIPMENT RATINGS

The equipment within the Hawkesbury Hydro substations is listed below, along with the ratings that are used to evaluate each component for various loading scenarios. Ratings and information that could not be verified were estimated and are marked with an asterisk (*).

110kV Substation West # 55		
System Component	***Rating***	***Amps @ 12.48kV (110kV)***
110kV Primary Fuses S&C Electric SMD-2B, 80E Standard Speed, TCC 153-1	Continuous Amps Daily 4 hour peak Emergency 4 hour peak	1163A (132A) 1181A (134A) 1181A (134A)
110,000/12,480V Transformer Delta/Wye (Grnd.), 7.5/10/12.5 MVA (ONS/ONP/ONPP) Z = 8.9%	Continuous Amps ONS Continuous Amps ONP Continuous Amps ONPP	347A (39.4A) 462A (52.4A) 578A (65.6A)
12,480V Secondary Switchgear	Continuous Amps	1200A*
12,480V Hydraulic Oil Circuit Reclosers McGraw Edison Type 'L' with 560A Trips	Continuous Amps	560A
12,480V Recloser Bypass Fuses S&C Electric SM-5, 300E* Slow or Standard Speed, TCC 119-1 or 153-1	Continuous Amps Daily 4 hour peak Emergency 4 hour peak	300A 310A 330A
Recloser Load Side Isolation Cutouts	Continuous Amps	800A*
F1/F2/F3 Lines, 336 MCM ACSR	Continuous Amps (min)	647A
F1/F2/F3 Lines, 3/0 AWG ACSR	Continuous Amps (min)	370A
44kV Substation East # 43		
System Component	***Rating***	***Amps @ 12.48kV (44kV)***
44kV Primary Fuses S&C Electric SMD-2C*, 250E Standard Speed*, TCC 153-1*	Continuous Amps Daily 4 hour peak Emergency 4 hour peak	970A (275A) 1005A (285A) 1152A (327A)
44,000/12,480V Transformer Delta/Wye(Grnd), 10/13.3/16.7MVA (ONAN/ONAF/ONAF') Z = 7.0%	Continuous Amps ONAN Continuous Amps ONAF Continuous Amps ONAF'	463A (131A) 615A (174A) 773A (219A)
12,480V Secondary Switchgear	Continuous Amps	800A*
12,480V Hydraulic Oil Circuit Reclosers Kyle type 'WE' with 560A Trips	Continuous Amps	560A (280A Ground Trip)
12,480V Recloser Bypass Fuses S&C Electric SM-5, 300E* Slow or Standard Speed, TCC 119-1 or 153-1	Continuous Amps Daily 4 hour peak Emergency 4 hour peak	300A 310A 330A
F1/F2/F3 Lines, 336 MCM ACSR	Continuous Amps (min)	647A
F1/F2/F3 Lines, 3/0 AWG ACSR	Continuous Amps (min)	370A

Please note, the ONPP rating of the 115kV Substation West transformers is an old (pre 1968) transformer cooling designation, and is not an official CSA designation. ONP indicates fan cooling and ONPP usually indicates fan cooling with a second group of fans coming on to give this added rating. During the next testing cycle, it should be verified that both (or full) fans are triggered at the full rating.

The size of each switch in the system, and their associated fuse sizes (where applicable), could not be individually confirmed. However, the basic classes of switches are as follows:

Main Trunk Lines

- Pole mounted gang operated switches are S&C Omni-Rupter switches rated at 600 Amp.
- Pole mounted load buster switches are S&C Loadbuster switches rated for 600 Amps.
- Line mounted load buster switches are S&C Loadbuster disconnects rated for 800 Amps.

Distribution Tap Lines

- Fused cutouts are S&C SMD20, rated for 200 Amps, with fuse size as indicated on the 'Primary Electrical Distribution System Map'.

Typically winter ratings of these switches are at least 25% higher than summer ratings due to the lower ambient temperature, so the switches are evaluated accordingly within this study. Most fuse sizes for the distribution tap lines range from about 40 amps to 100 amps. Exact sizing, as indicated in the 'Primary Electrical Distribution System Map', will be used to evaluate the fuses in the loading summary.

The ratings used in this study to assess the loading of various conductors are listed in the table below. Please note, while insulated cables have a fairly limited set of current ratings (typically free air, raceway, or direct buried ratings), ACSR cables have a wide range of ratings, based on ambient temperatures, peak conductor temperatures, cross winds, emissivity of the conductor, and sun heating. The following conductor ratings are standard ratings, based on maximum absolute conductor temperatures of 105˚C, ambient temperatures of 30˚C (Summer) and 10˚C (Winter), 0.6m/sec (2feet/sec) of cross wind, 0.7 coefficient of emissivity, and full sun.

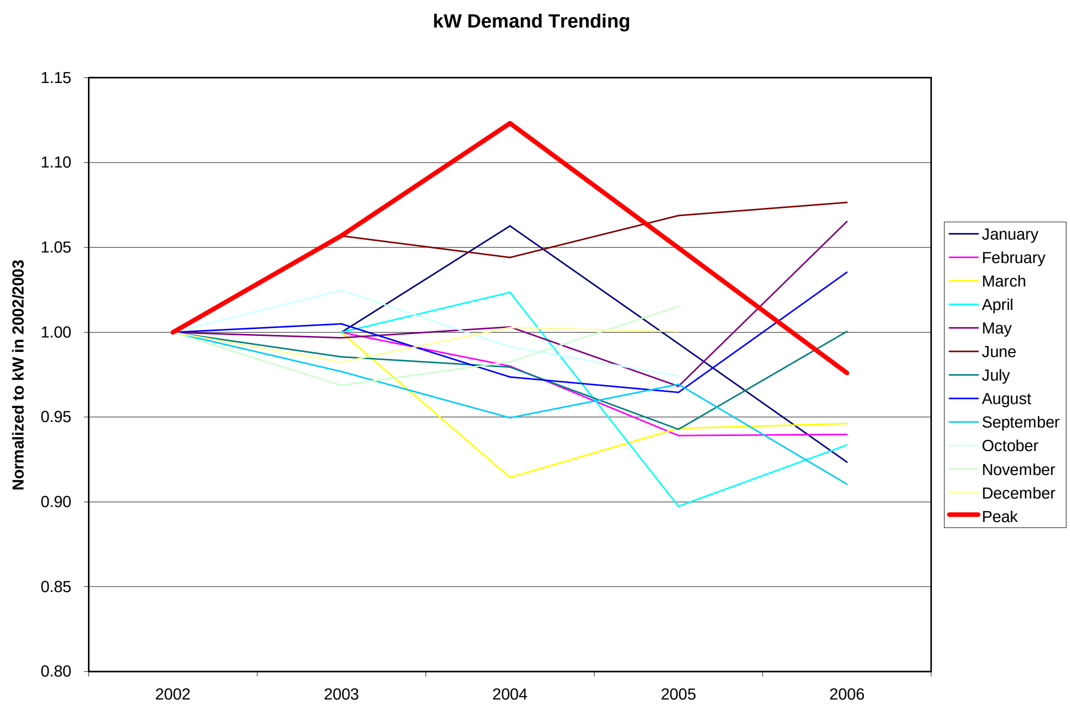
Cable Type	***Rating***	***Ampacity @ 30˚C Ambient***	***Ampacity @ 10˚C Ambient***
Cable - 2/0 AWG 1/C Alum TR-XLP 100%	Continuous Amps	245	245
ACSR - 336 kcmil 26/7	Continuous Amps	647	733
ACSR - 3/0 AWG	Continuous Amps	370	419
ACSR - 1/0 AWG	Continuous Amps	288	326
ACSR - #2 AWG	Continuous Amps	228	285
ACSR - #4 AWG	Continuous Amps	172	215

SYSTEM LOADING UNDER NORMAL OPERATION

The historical loading from 2002 till 2006 was supplied as is shown in the following table. As can be seen, the peak loading of 40 MW occurred in 2004. The peak loading dropped to 37.4 MW in 2005 and to 34.8 MW in 2006.

kW Peak Loading - Total System					
Month	***2002***	***2003***	***2004***	***2005***	***2006***
January	-	37,643	40,003	37,386	34,761
February	-	36,754	36,019	34,517	34,539
March	-	36,064	32,978	34,024	34,126
April	-	31,337	32,076	28,121	29,256
May	28,058	27,967	28,146	27,164	29,888
June	28,827	30,465	30,098	30,809	31,031
July	30,546	30,105	29,920	28,798	30,563
August	30,798	30,948	29,984	29,708	31,886
September	30,052	29,358	28,538	29,131	27,362
October	28,784	29,496	28,536	28,039	-
November	32,357	31,347	31,793	32,851	-
December	35,615	34,987	35,716	35,631	-
Peak	35,615	37,643	40,003	37,386	34,761

The individual demand trending for each month is also shown on the following graph, normalized to the year 2002 or 2003.



As can be seen, the kW peak for the system is significantly higher in winter, indicative of substantial electrical heating loads (probably electrical baseboard heating) in older residential neighbourhoods. The maximum total winter peak demand is shown in the table to be 34,761 kW (or 38,623 kVA) in 2006. This total is falling slowly from its 2004 peak, possibly due to more efficient heating methods, or conversion from electric baseboards to forced air. The summer peak loading has increased to 31,886 kW (or 35,429 kVA) in 2006, probably due to additional air conditioning loads and other discretionary items such as pools.

To determine the distribution of this loading over the system, the total load has to be divided among the three transformers within the two substations. Using data from August 2006 (for maximum summer period) and January 2006 (for maximum winter period), we see that the split between the transformers is as follows:

Peak Loading - Individual Substation Transformers						
Transformer	***Summer Demand***			***Winter Demand***		
	kW (4 hour)	***% of Total***	***kW (15 min)***	***kW (4 hour)***	***% of Total***	***kW (15 min)***
43T1	17,100	56%	17,952	18,546	51%	19,392
55T1	7,170	24%	7,396	9,814	27%	10,262
55T2	6,200	20%	6,404	8,267	23%	8,459
Total	30,470	100%	31,751	36,627	100%	38,113

We can also allocate the winter and summer loading between the five feeders based on ampere measurements taken at the source of all the five feeders early May 2006. Using these measurements, as well as the data in the above table, we can extrapolate maximum feeder currents for all cases using 4-hour average peaks.

110kV Substation West # 55							
Feeder	***Phase***	***Measured Data***		***Peak Summer***		***Peak Winter***	
		Amps	***kVA***	***Amps***	***kVA***	***Amps***	***kVA***
55F1	R	144	1,037	194	1,393	265	1,907
	W	140	1,008	188	1,355	258	1,854
	B	137	986	184	1,326	252	1,814
55F2	R	117	842	157	1,132	215	1,550
	W	82	590	110	793	151	1,086
	B	121	871	163	1,171	223	1,603
kVA Total - T1			5,335		7,170		9,814
55F3	R	219	1,577	309	2,226	412	2,968
	W	193	1,390	272	1,962	363	2,616
	B	198	1,426	280	2,012	373	2,683
kVA Total - T2			4,392		6,200		8,267
kVA Total - Sub			9,727		14,856		21,886

44kV Substation East # 43							
Feeder	Phase	Measured Data		Peak Summer		Peak Winter	
		Amps	kVA	Amps	kVA	Amps	kVA
43F1	R	106	763	417	3,001	452	3,255
	W	115	828	452	3,256	490	3,532
	B	102	734	401	2,888	435	3,132
43F2	R	112	803	439	3,157	476	3,424
	W	117	842	460	3,310	499	3,590
	B	120	861	470	3,387	510	3,673
kVA Total - Sub			4,831		19,000		20,606

System Capacity Evaluation Under Current Loading Conditions

To evaluate each of the substations and their feeders under current winter/summer peak loading conditions, we evaluated each system component's ampacity against the peak loading ampacity for both seasons. As can be seen, all the components are sized acceptably for normal conditions and are marginally acceptable given the loss of one side of the substation (for the 110kV Sub # 55). The recloser's bypass fuses should be upsized to 400E links for both the West and East Substations, as evidenced in the tables.

110kV Substation West # 55							
System Component	Rating	Summer			Winter		
		Rated Amps	Peak Amps	Pass/ Fail	Rated Amps	Peak Amps	Pass/ Fail
110kV Primary Fuses	Daily 4 hour peak	1181	332	28%	1181	454	38%
110kV Transformer	12.5 MVA ONPP	578	332	57%	665	454	68%
110kV Transformer	12.5 MVA @ 130%	751	332	44%	863	454	53%
12,480V Secondary Switchgear	Continuous Amps	1200	332	28%	1200	454	38%
12,480V Hydraulic Oil Reclosers	Continuous Amps	560	317	57%	560	423	76%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	317	102%	310	423	136%
Recloser Load Side Cutouts	Continuous Amps	800	317	40%	800	423	53%
3/0 AWG ACSR	Continuous Amps	370	317	86%	419	423	101%
F1, 336 MCM ACSR	Continuous Amps	647	194	30%	733	265	36%
F2, 336 MCM ACSR	Continuous Amps	647	163	25%	733	223	30%
F3, 336 MCM ACSR	Continuous Amps	647	317	49%	733	423	58%
110kV Substation West # 55 - Loss of Redundancy							
110kV Primary Fuses	Daily 4 hour peak	1181	619	52%	1181	836	71%
110kV Transformer	12.5 MVA ONPP	578	619	107%	665	836	126%
110kV Transformer	12.5 MVA @ 130%	751	619	82%	863	836	97%
12,480V Secondary Switchgear	Continuous Amps	1200	619	52%	1200	836	70%

44kV Substation East # 43								
System Component	Rating	Summer			Winter			
		Rated Amps	Peak Amps	Pass/ Fail	Rated Amps	Peak Amps	Pass/ Fail
44kV Primary Fuses	Daily 4 hour peak	1005	879	87%	1181	953	81%
44kV Transformer	16.7 MVA ONAF	773	879	114%	889	953	107%
44kV Transformer	16.7 MVA @ 130%	1005	879	87%	1156	953	82%
12,480V Secondary Switchgear	Continuous Amps	1200	879	73%	1200	953	79%
12,480V Hydraulic Oil Reclosers	Continuous Amps	560	450	80%	560	489	87%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	450	145%	310	489	158%
Recloser Load Side Cutouts	Continuous Amps	800	450	56%	800	489	61%
3/0 AWG ACSR	Continuous Amps	370	450	122%	419	489	117%
F1, 336 MCM ACSR	Continuous Amps	647	429	66%	733	465	63%
F2, 336 MCM ACSR	Continuous Amps	647	450	70%	733	489	67%

FEEDER REBALANCING, OPEN SWITCH OPTIMIZATIONS, AND FEEDER CONDUCTOR UPGRADING

To determine a system optimization strategy, we use an average loading figure, assumed to be approximately 50% of peak winter loading, or about 20,343 kVA in total across the system. The following table shows initial feeder losses, methods of reducing losses, and approximate budget figures for each change, along with estimated payback period.

Feeder Optimizations					
Feeder	Optimization	Losses/Loss Reduction (kW)	Capital Costs	Annual Savings	Payback (years)
43F1	Initial Feeder Losses	29.22	$ 25,012.32		
	Open Tessier/Cam, Close Spence/Cam	9.46	$ 50.00	$ 8,097.76	0.01
	Open Albert/Edmond, Close Benj/Cam	0.08	$ 50.00	$ 68.48	0.73
	Change Sub to Tessier 3/0 with 336	0.92	$ 2,400.00	$ 787.52	3.05
	Change Sub to Spence/Cam 3/0 with 336	5.32	$ 25,920.00	$ 4,553.92	5.69
	Final Feeder Losses	13.44	$ 11,504.64		
43F2	Total Feeder Losses	71.79	$ 61,452.24		
	Change Sub to Spence/Tupper 3/0 with 336	30.88	$ 22,560.00	$ 26,433.28	0.85
	Final Feeder Losses	40.91	$ 35,018.96		
55F1	Total Feeder Losses	21.82	$ 18,677.92		
	Upgrade Main from Chart to West 3/0 with 336	3.92	$ 10,392.00	$ 3,355.52	3.10
	Final Feeder Losses	17.9	$ 15,322.40		
55F2	Total Feeder Losses	12.11	$ 10,366.16		
	Change Main St from Chart to West 3/0 with 336	2.26	$ 10,392.00	$ 1,934.56	5.37
	Change B Tap on Main north of Sinclar to W	0.06	$ 50.00	$ 51.36	0.97
	Change R Tap on Main to Salisbury to W	0.06	$ 50.00	$ 51.36	0.97
	Final Feeder Losses	9.73	$ 8,328.88		
55F3	Total Feeder Losses	41.18	$ 35,250.08		
	Change McGill from Regent to Pasteur 3/0 to 336	0.14	$ 3,648.00	$ 119.84	30.44
	Final Feeder Losses	41.04	$ 35,130.24		

There were some unbalanced currents within the system, as shown in the previous chart. Transferring load to balance the currents will reduce energy losses, since return currents travel through undersized neutrals and the overall inductance of the line is higher. Optimizing the balance between the phases of a distribution network typically improves the voltage support within the system as well. The system will be able to sustain heavier loading before one of the phases is burdened to the extent that its voltages begin to drop below the low limits of the nominal voltage levels. When rebalancing changes are implemented, the system main feeders should be measured before the changes are implemented to re-verify the imbalance, and then the rebalancing changes should be done.

During peak winter loading of approximately 41 MVA, total losses are 490.6 kW, which is about 1.4% of the total load (34,900 kW). These losses are fairly reasonable for this voltage level.

FEEDER VOLTAGES UNDER NORMAL OPERATION

As per CAN3-C235-83 'Preferred Voltage Levels for AC Systems, 0 to 50 000V' all service entrance voltages should be no less than 91.7% of nominal (110V) and no higher than 104.2% of nominal (125V) during normal operating conditions. During extreme operating conditions the voltages may fall to 88.3% (106V) or rise to 105.8% (127V) of nominal. All feeders in both substations were simulated under nominal and winter peak loading conditions to identify any present voltage support issues within the network. The results are summarized below and the corresponding voltage profile maps can be seen on the relevant graphs under Appendix 2.

During System Average loadings of 20.343 MVA, Feeder 55F3 experienced a minimum feeder voltage of 97.06% of nominal. The 2nd worse feeder, 43F2 saw a minimum feeder voltage of 97.81% of nominal. This is well within acceptable ranges.

During peak winter loading of approximately 41 MVA, Feeder 55F3 experienced a minimum feeder voltage of 94.09% of nominal. The 2nd worse feeder, 43F2 saw a minimum feeder voltage of 95.53% of nominal. Voltages are well within acceptable ranges.

FEEDER CONFIGURATIONS UNDER EXISTING LOADING AND EMERGENCY CONDITIONS

There are a number of scenarios evaluated in this section. They are as follows:

- Loss of any one feeder
- Loss of any one transformer
- Loss of any one substation

Each scenario is run using an average loading of 66% of peak winter loading.

Loss of either 43F1 or 43F2

Using the switching scenario under Appendix 6 (which switches 43F1 or 43F2 to the other feeder) results in the capacity evaluation in the following table.

44kV Substation East # 43 - Loss of 43F1 or 43F2							
System Component	**Rating**	**Summer**			**Winter**		
		Rated Amps	**Peak Amps**	**Pass/ Fail**	**Rated Amps**	**Peak Amps**	**Pass/ Fail**
44kV Primary Fuses	Daily 4 hour peak	1005	628	62%	1181	628	53%
44kV Transformer	16.7 MVA ONAF	773	628	81%	889	628	71%
44kV Transformer	16.7 MVA @ 130%	1005	628	62%	1156	628	54%
12,480V Secondary Switchgear	Continuous Amps	1200	628	52%	1200	628	52%
12,480V Hydraulic Reclosers	Continuous Amps	560	628	112%	560	628	112%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	628	203%	310	628	203%
Recloser Load Side Cutouts	Continuous Amps	800	628	79%	800	628	79%
3/0 AWG ACSR	Continuous Amps	370	628	170%	419	628	150%
F2, 336 MCM ACSR	Continuous Amps	647	628	97%	733	628	86%

The minimum voltage within the 43 F1/F2 system is 97.01% of nominal, well within acceptable values. A future beneficial reconfiguration may be to install a switch on 43F2 on Tupper south of Aberdeen, to allow a quick split of the 43F2 feeder between 43F1 and either 55F1 or 55F2. If the feeder ampacity is above 560 amps continuous, a portion of 43F1 or 43F2 should be switched over to sub 55.

Loss of 55F1 or 55F2

Using the switching scenario under Appendix 6 (which switches either 55F1 to 55F2 to feeder 55F3) results in the capacity evaluation in the following table.

110kV Substation West # 55 - Loss of 55F1 or 55F2							
System Component	**Rating**	**Summer**			**Winter**		
		Rated Amps	**Peak Amps**	**Pass/ Fail**	**Rated Amps**	**Peak Amps**	**Pass/ Fail**
110kV Primary Fuses	Daily 4 hour peak	1181	337	29%	1181	337	29%
110kV Transformer	12.5 MVA ONPP	578	337	58%	665	337	51%
110kV Transformer	12.5 MVA @ 130%	751	337	45%	863	337	39%
12,480V Secondary Switchgear	Continuous Amps	1200	337	28%	1200	337	28%
12,480V Hydraulic Oil Reclosers	Continuous Amps	560	337	60%	560	337	60%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	337	109%	310	337	109%
Recloser Load Side Cutouts	Continuous Amps	800	337	42%	800	337	42%
3/0 AWG ACSR	Continuous Amps	370	337	91%	419	337	80%
336 kcmil ACSR	Continuous Amps	647	337	52%	733	337	46%

The minimum voltage within the 55F1/F2 system is 97.46% of nominal, well within acceptable values.

Loss of 55F3

Using the switching scenario under Appendix 6 (which switches 55F3 to 55F2) results in the capacity evaluation in the following table.

110kV Substation West # 55 - Loss of 55F3							
System Component	Rating	Summer			Winter		
		Rated Amps	Peak Amps	Pass/ Fail	Rated Amps	Peak Amps	Pass/ Fail
110kV Primary Fuses	Daily 4 hour peak	1181	337	29%	1181	337	29%
110kV Transformer	12.5 MVA ONPP	578	337	58%	665	337	51%
110kV Transformer	12.5 MVA @ 130%	751	337	45%	863	337	39%
12,480V Secondary Switchgear	Continuous Amps	1200	337	28%	1200	337	28%
12,480V Hydraulic Oil Reclosers	Continuous Amps	560	337	60%	560	337	60%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	337	109%	310	337	109%
Recloser Load Side Cutouts	Continuous Amps	800	337	42%	800	337	42%
3/0 AWG ACSR	Continuous Amps	370	337	91%	419	337	80%
336 MCM ACSR	Continuous Amps	647	337	52%	733	337	46%

The minimum voltage within the 55F2/F3 system is 96.06% of nominal, well within acceptable values.

Loss of 55T1 or 55T2

Using the switching scenario under Appendix 6 (which switches for loss of 55T1 or 55T2) results in the capacity evaluation in the following table.

110kV Substation West # 55 - Loss of T1 or T2							
System Component	Rating	Summer			Winter		
		Rated Amps	Peak Amps	Pass/ Fail	Rated Amps	Peak Amps	Pass/ Fail
110kV Primary Fuses	Daily 4 hour peak	1181	559	47%	1181	559	47%
110kV Transformer	12.5 MVA ONPP	578	559	97%	665	559	84%
110kV Transformer	12.5 MVA @ 130%	751	559	74%	863	559	65%
12,480V Secondary Switchgear	Continuous Amps	1200	559	47%	1200	559	47%
12,480V Hydraulic Oil Reclosers	Continuous Amps	560	382	68%	560	382	68%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	382	123%	310	382	123%
Recloser Load Side Cutouts	Continuous Amps	800	382	48%	800	382	48%
3/0 AWG ACSR	Continuous Amps	370	382	103%	419	382	91%
336 MCM ACSR	Continuous Amps	647	382	59%	733	382	52%

The minimum voltage within the 55F2/F3 system is 96.06% of nominal, well within acceptable values.

Loss of 43 Substation

Using the switching scenario under Appendix 6 (which switches 43F1 to 55F1 and 43F2 to 55F2) results in the capacity evaluation in the following table.

110kV Substation West # 55 - Loss of Sub 43, onto 55F1 and 55F2							
System Component	**Rating**	**Summer**			**Winter**		
		Rated Amps	**Peak Amps**	**Pass/ Fail**	**Rated Amps**	**Peak Amps**	**Pass/ Fail**
110kV Primary Fuses	Daily 4 hour peak	1181	928	79%	928	800	86%
110kV Transformer	12.5 MVA ONPP	578	928	161%	928	800	86%
110kV Transformer	12.5 MVA @ 130%	751	928	124%	928	800	86%
12,480V Secondary Switchgear	Continuous Amps	1200	928	77%	928	800	86%
12,480V Hydraulic Oil Reclosers	Continuous Amps	560	474	85%	560	474	85%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	474	153%	310	474	153%
Recloser Load Side Cutouts	Continuous Amps	800	474	59%	800	474	59%
3/0 AWG ACSR	Continuous Amps	370	474	128%	419	474	113%
336 MCM ACSR	Continuous Amps	647	474	73%	733	474	65%

The minimum voltage within the 55F1/43F1 system is 88.08% of nominal, within the 55F2/43F2 system is 87.26% of nominal, and within the 55F3 system is 96.08% of nominal. Changing the interconnect wires from 3/0 to 336 at 55F2/43F2 at Chamberlain improves the voltage within the 55F2/43F2 system to 87.73% of nominal.

As can be seen, the heavy loading on F1 and F2 will overload the transformer T1. Redistributing the load i.e. putting the 43F1 feeder on 55F3, and the 43F2 feeder on 55F2, gives the following results.

110kV Substation West # 55 - Loss of Sub 43, onto 55F2 and 55F3							
System Component	**Rating**	**Summer**			**Winter**		
		Rated Amps	**Peak Amps**	**Pass/ Fail**	**Rated Amps**	**Peak Amps**	**Pass/ Fail**
110kV Primary Fuses	Daily 4 hour peak	1181	623	53%	928	623	67%
110kV Transformer	12.5 MVA ONPP	578	623	108%	928	623	67%
110kV Transformer	12.5 MVA @ 130%	751	623	83%	928	623	67%
12,480V Secondary Switchgear	Continuous Amps	1200	623	52%	928	623	67%
12,480V Hydraulic Oil Reclosers	Continuous Amps	560	554	99%	560	554	99%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	554	179%	310	554	179%
Recloser Load Side Cutouts	Continuous Amps	800	554	69%	800	554	69%
3/0 AWG ACSR	Continuous Amps	370	554	150%	419	554	132%
336 MCM ACSR	Continuous Amps	647	554	86%	733	554	76%

The minimum voltage within the 55F1 system is 97.48% of nominal, within the 55F2/43F2 system is 87.26% of nominal, and within the 55F3/43F1 system is 85.03% of nominal. The 43F1 voltage is thus slightly below the recommended extreme voltage limit of 88.03%, however, some form of load shedding should allow acceptable minimum voltages.

Loss of 55 Substation

Using the switching scenario under Appendix 6 (which switches 55F2 and a portion of 55F3 onto 43F2, and 55F1 and a portion of 55F3 onto 43F1) results in the capacity evaluation in the following table.

44kV Substation East # 43 - Loss of Sub 55								
System Component	***Rating***	***Summer***			***Winter***			
		Rated Amps	***Peak Amps***	***Pass/ Fail***	***Rated Amps***	***Peak Amps***	***Pass/ Fail***
44kV Primary Fuses	Daily 4 hour peak	1005	1177	117%	1181	1177	100%
44kV Transformer	16.7 MVA ONAF	773	1177	152%	889	1177	132%
44kV Transformer	16.7 MVA @ 130%	1005	1177	117%	1156	1177	102%
12,480V Secondary Switchgear	Continuous Amps	1200	1177	98%	1200	1177	98%
12,480V Hydraulic Oil Reclosers	Continuous Amps	560	614	110%	560	614	110%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	614	198%	310	614	198%
Recloser Load Side Cutouts	Continuous Amps	800	614	77%	800	614	77%
3/0 AWG ACSR	Continuous Amps	370	614	166%	419	614	147%
F2, 336 MCM ACSR	Continuous Amps	647	614	95%	733	614	84%

As can be seen, the substation is heavily overloaded trying to support the complete system load. This indicates that either a second transformer must be installed or a new substation built to support the complete load acceptably.

The minimum voltage within the 43F1 system is 94.87% of nominal, within the 43F2 system is 90.03% of nominal.

LOAD GROWTH

There are a number of methods by which a utility's load will grow over time; the typical ones are listed below, with the trending graphs following:

- New in-fill customers are added within the Utility boundary.
- Existing customers add load (pool pumps, new air conditioners, etc.).
- Expansion of the Utility boundaries.

As there are no known plans for expansion of the Utility boundary, the main changes in loading expected in the coming years will be as a result of the first two factors listed above. To predict the growth for the system, we first evaluate and incorporate the load anticipated as a result of new developments within the boundary.

There are a few possible areas for new subdivisions, the most likely candidates would be south-west of Rupert and Roxanne (55F1) and/or to the east of Tupper (43F2). To approximate the additional loading that will result, we have estimated that each subdivision would have about 25 houses. Assuming a nominal load of 5 kW per house at 0.9 power factor, this will result in 125 kW, or 138 kVA for each subdivision. For forecasting purposes, we have assumed the subdivisions will be added within 5 years (in 2008). We assume another two subdivisions will be added east of Tupper in the 10 years period after that (in 2016). This loading is added to the nominal, summer, and winter peak loading. The forecast can be adjusted as required to account for differences between the projected development and that which will actually take place using the approximation of 5 kW per house used herein.

The second factor, or annual load growth, is typically assumed at around 1% per year. This is due to the natural addition of new electrical loads such as air conditioning systems, pools, electronic devices, and other energy consuming products. This is often balanced by a decline in loading for the majority of the winter months, probably due to increased energy efficiency and transitioning from baseboard heating to forced air. The natural load growth may also be substantially affected by the proposal to bring in smart metering. This should offset the peak loading to non peak-load times and thus reduce the overall peak demand, and is estimated by the government to bring about a 5% reduction when implemented. Therefore, our load growth estimates should be conservative.

Load Growth (kVA)																
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Feeder 43F1																
Nominal	2326	2349	2373	2396	2420	2445	2469	2494	2519	2544	2569	2595	2621	2647	2674	2700
Summer Peak	9146	9237	9330	9423	9517	9613	9709	9806	9904	10003	10103	10204	10306	10409	10513	10618
Winter Peak	9919	10018	10118	10220	10322	10425	10529	10635	10741	10848	10957	11066	11177	11289	11402	11516
Feeder 43F2																
Nominal	2506	2531	2695	2722	2750	2777	2805	2833	2861	2890	3197	3229	3261	3294	3326	3360
Summer Peak	9854	9953	10191	10293	10396	10500	10605	10711	10818	10926	11313	11427	11541	11656	11773	11891
Winter Peak	10687	10794	11041	11151	11263	11375	11489	11604	11720	11837	12234	12356	12480	12604	12730	12858
Feeder 55F1																
Nominal	3031	3061	3231	3263	3296	3329	3362	3396	3430	3464	3499	3534	3569	3605	3641	3677
Summer Peak	4074	4115	4295	4338	4381	4425	4469	4514	4559	4605	4651	4697	4744	4792	4840	4888
Winter Peak	5576	5632	5827	5885	5944	6004	6064	6124	6186	6247	6310	6373	6437	6501	6566	6632
Feeder 55F2																
Nominal	2304	2327	2350	2374	2398	2422	2446	2470	2495	2520	2545	2570	2596	2622	2648	2675
Summer Peak	3096	3127	3158	3190	3222	3254	3286	3319	3353	3386	3420	3454	3489	3524	3559	3594
Winter Peak	4238	4280	4323	4366	4410	4454	4499	4544	4589	4635	4681	4728	4775	4823	4871	4920
Feeder 55F3																
Nominal	4392	4436	4480	4525	4570	4616	4662	4709	4756	4803	4852	4900	4949	4999	5048	5099
Summer Peak	6200	6262	6325	6388	6452	6516	6581	6647	6714	6781	6849	6917	6986	7056	7127	7198
Winter Peak	8267	8350	8433	8517	8603	8689	8776	8863	8952	9041	9132	9223	9315	9409	9503	9598

The following table combines the nominal, summer peak and winter peak loading predicted for feeders 43F1 and 43F2 in 2021 in the table above, for comparison with the capacities of various Substation 43 equipment.

44kV Substation East # 43 - Load Growth to 2021							
System Component	**Rating**	**Summer**			**Winter**		
		Rated Amps	**Peak Amps**	**Pass/ Fail**	**Rated Amps**	**Peak Amps**	**Pass/ Fail**
44kV Primary Fuses	Daily 4 hour peak	1005	1041	104%	1181	1127	95%
44kV Transformer	16.7 MVA ONAF	773	1041	135%	889	1127	127%
44kV Transformer	16.7 MVA @ 130%	1005	1041	104%	1156	1127	97%
12,480V Secondary Switchgear	Continuous Amps	1200	1041	87%	1200	1127	94%
12,480V Hydraulic Oil Reclosers	Continuous Amps	560	550	98%	560	594	106%
12,480V Recloser Bypass Fuses	Daily 4 hour peak	310	550	177%	310	594	192%
Recloser Load Side Cutouts	Continuous Amps	800	550	69%	800	594	74%
3/0 AWG ACSR	Continuous Amps	370	550	149%	419	594	142%
F2, 336 MCM ACSR	Continuous Amps	647	550	85%	733	594	81%

The table above shows that, in 2021, this substation is expected to experience loading well beyond its capacity. Therefore, we would recommend that within 5-10 years a second transformer be added along with a 3rd feeder, or a 3rd substation be built to the east of the town. The existing transformer is expected to be adequate to support the future load growth for the next five years. However, the loading should be reviewed within 2 years to ensure that the capacity is acceptable with measured load growth, especially if further developments and/or significant changes to the distribution network are undertaken that have not been considered in this forecast.

The current system equipment looks like it is in good condition, no problematic issues were seen. The most critical items in any distribution system are the transformers, since the lead time to replace units is very length, and the probably of sourcing a quick replacement is fairly low. However, a review of recent test data for the transformers shows no anomalies. Regular maintenance with trended data is important to ensure problems are recognized before any units will advance to failure, allowing planned outages and maintenance to occur to minimize service disruption.

FUTURE SYSTEM CHANGES

Based on the preceding information, there are a few general recommendations that we can make to improve the distribution within the system. They are listed below:

New Matched Transformer at Sub 43 and Feeders 43F3 and 43F4

Within the next five years, a new matched transformer should be added to the 44kV substation 43. This transformer would be added with further switchgear to allow secondary redundancy (through a tie switch) and have at least 2 reclosers on its secondary. There are a number of options that could be done with the two feeders (depending on future load growth projections) as listed below:

1. Feeder 43F3 pick up portions of south-east 43F1 and 43F2 (which would allow 43F1 and 43F2 to pick up portions of 55F1, F2, and F3 as required) and/or south-east new development
2. Feeder 43F4 pick up portions of north eastern 43F2 and 43F3 and/or north-east new development

These feeders should be 336 ACSR, with minimum 800A interconnections to 55F1 and 55F3. This will allow the following improvements:

1. Reduce loading levels of 43F1 and 43F2 (and possibly 55F1, 55F2, and 55F3)
2. Reduce overall system losses by shortening normal feeder lengths
3. Allow complete redundancy within the substation # 43 in the event of a transformer or secondary switchgear failure
4. Provide additional emergency feeding options in the event of a failure, allowing for better voltage support and reduced current loadings

Please note, it is unsure at this point whether Hydro-One has sufficient capacity on the 44kV feeder to allow extensive load growth on this feeder (i.e. megawatts worth of future growth). However, the installation of a 2nd transformer for redundancy and emergency supply purposes should be acceptable along with minor load growth.

New Permanent 55F4 Recloser and Feeder

Within the next five years, a new 3-phase recloser should be added to Sub 55 in place of the existing emergency single phase set of reclosers. The new recloser should feed the 3 phase line along the West 115kV line, and pick up the west end of circuits 55F3, 55F1, and any new development south west of Rupert and Lafrance. The main line should be 336 ACSR, with minimum 800A interconnections to 55F1 and 55F3. This will allow the following improvements:

1. Reduce loading levels of 55F1 and 55F3
2. Provide additional emergency feeding options in the event of a failure, allowing for better voltage support and reduced current loadings
3. Increase redundancy in the event of a sub 55 secondary switchgear failure (since there will always be at least 2 reclosers available to carry sub 55 loading)
4. Reduce system losses (rather than add new loading to existing 55F1 or 55F3)

RECOMMENDATIONS

1. Within both the 110kV West and 44kV East Substation, there are a number of areas of vegetation growth. These areas should either be sprayed, or if the depth of clear crush ¾" stone is less than 150mm, a new layer of stone should be laid to attain a 150mm depth. This is required to meet resistivity levels for step and touch potential restrictions as per Ontario Electrical Safety Code (OESC) rule 36-304 (5). (Budget $3,000)

110kV West Sub

44kV East Sub

2. By OESC rule 36-304 (5), this layer should also extend 1m past the fence line. As can be seen by the pictures, currently there is no stone past the fence line, and vegetation is currently encroaching on the fence. All vegetation should be removed and the stone surface extended. (Budget $3,000)

110kV West Sub

44kV East Sub

3. Within or around the 44kV East Substation, there are a number of grounding conductors that are mechanically damaged. These conductors and/or joints should be repaired, and continuity checks completed to ensure that the grounding system is still connected with low impedance connections. All exposed connections should be covered by a protective covering layer of stone, at least 150mm thick. (Budget $4,000)

44kV East Sub


4. A comprehensive index of all switches should be completed. Each switch must be uniquely identified, and should be field identified with the same ID. This index should be cross-referenced against all switching orders and the distribution map. This is important to minimize operational errors and personnel hazards. (Completed – January, 2007)

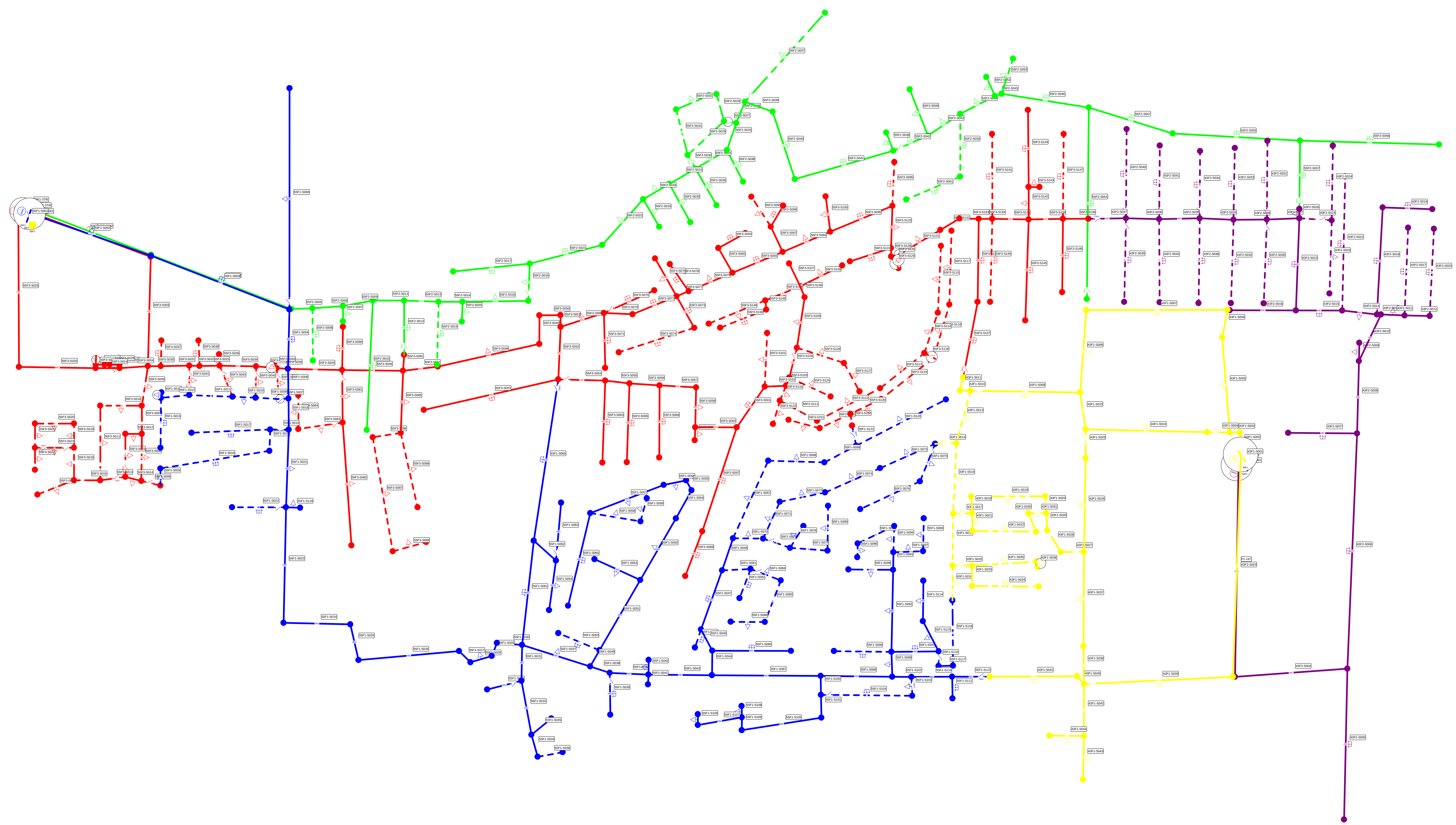
5. All main trunk conductors should be upgraded to 336 kcmil ACSR. This will help reduce losses, improve voltage support, and provide capacity in the event of emergency switching. The specific items are listed within the optimization section of the report.

6. Various capacity constraints during both normal and emergency situations will be approached in 2021 within the Substation 43 system. It is recommended that regular reviews of load growth be undertaken in the future, and with forecast load growth confirmed, construction begin within 5-10 years on twinning the existing 44kV transformer in the East substation # 43, adding 2 more feeders out of substation # 43, and adding a 4th normal feeder to the 115kV West Substation # 55.

7. To allow for better system data, it would be recommended to add modern digital metering for all five existing feeders. This metering should provide all basic electrical parameters (voltage, current, PF, power, energy, and demand), plus power quality parameters (sags and swells, harmonics, transients, flicker), data and waveform logs (triggering, min/max, trending, timestamps), communications, set points, and alarming. (Budget $6,000 per meter if existing metering current transformers and potential transformers can be used by Hawkesbury Hydro, more if special communications are required).

Appendix 1 – System Base Models

Peter Dyck
Stantec Consulting Ltd.
Base System Distribution Model - By Feeder



Legend

Default Layer:
Feeder color

Colors :
- 43F1
- 55F3
- 43F2
- 55F1
- 55F2

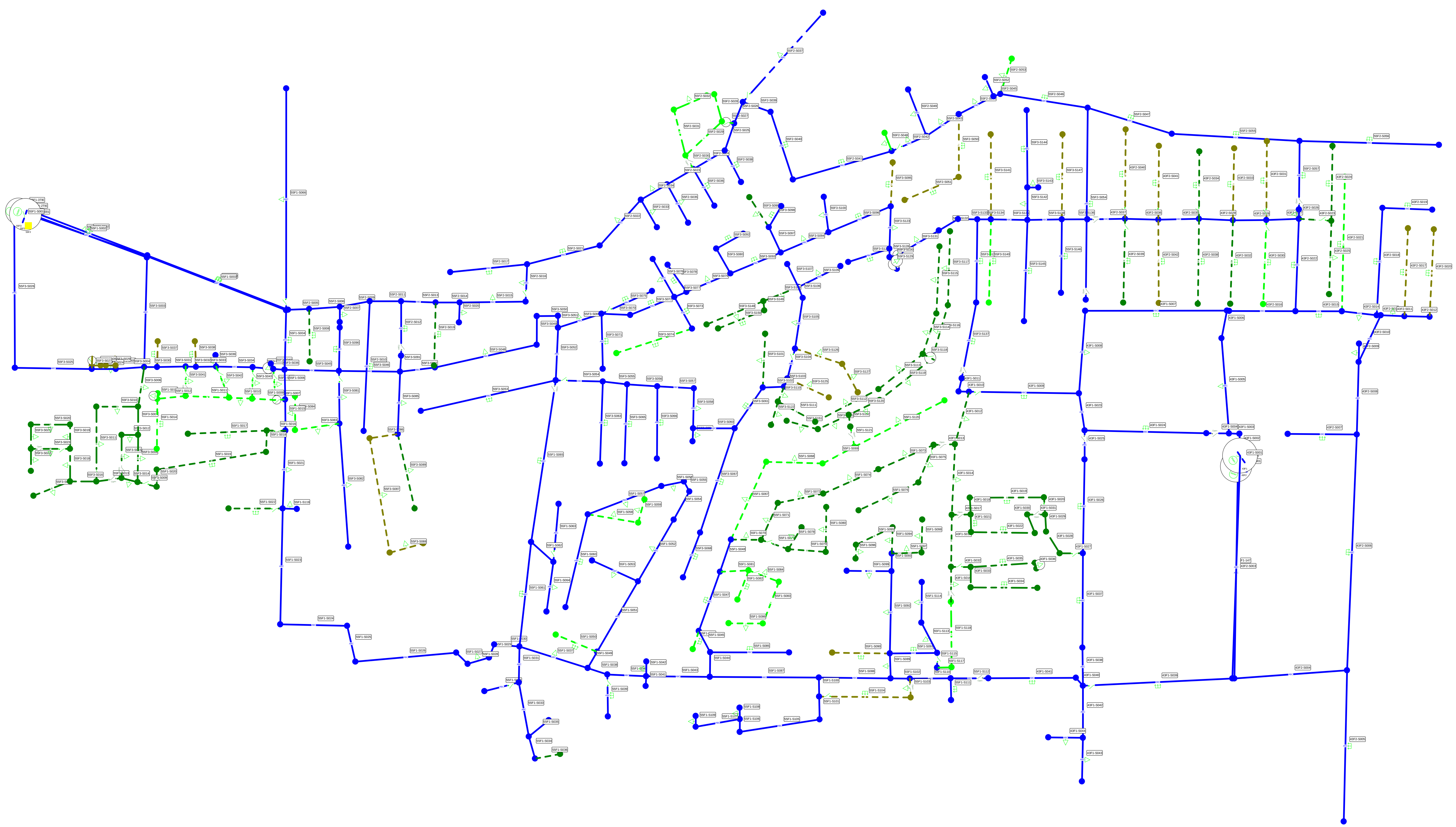
Analysis Layer :

Colors :
- 90.00 91.66
- 91.66 93.00
- 85.00 90.00
- 0.00 85.00
- 91.66 100.00

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (O)
- Switch, (C)
- Load

Peter Dyck
Stantec Consulting Ltd.
Base System Distribution Model - By Circuit Type



Legend
Default Layer:
Phase

Colors :
Three-phase OH
Three-phase UG
Two-phase OH
Two-phase UG
A OH
B OH
C OH
A UG
B UG
C UG

Analysis Layer :

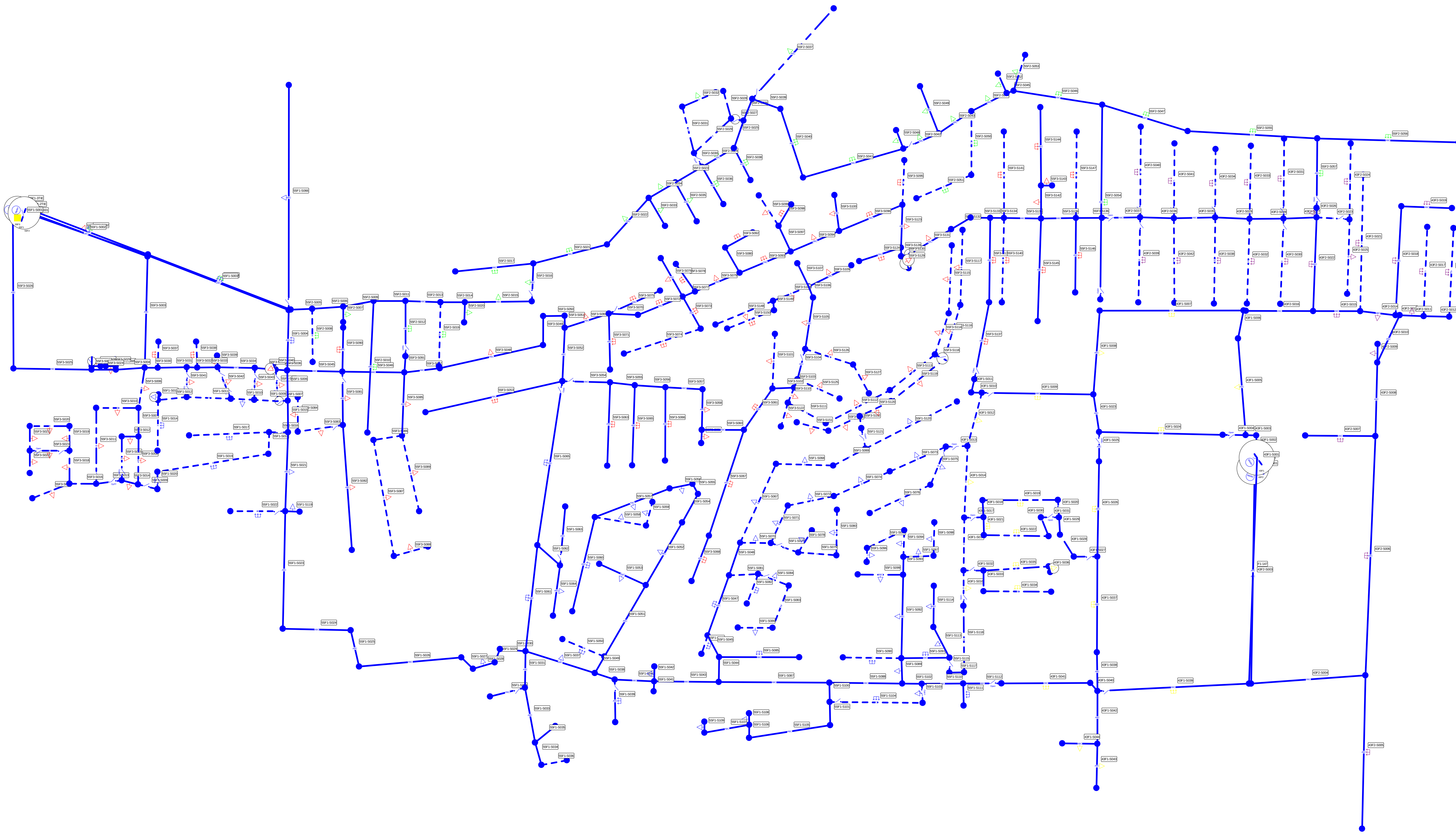
Colors :
90.00 91.66
91.66 93.00
85.00 90.00
0.00 85.00
91.66 100.00

Line Types:
3-OH
3-UG
2-OH
2-UG
A-OH
B-OH
C-OH
A-UG
B-UG
C-UG

Symbols :
Switch, (O)
Switch, (C)
Load

Appendix 2 – Voltage Support Results

Peter Dyck
Stantec Consulting Ltd.
Optimized System - Peak Winter Loading



Legend

Default Layer:
Feeder color

Colors :
- 43F1
- 55F3
- 43F2
- 55F1
- 55F2

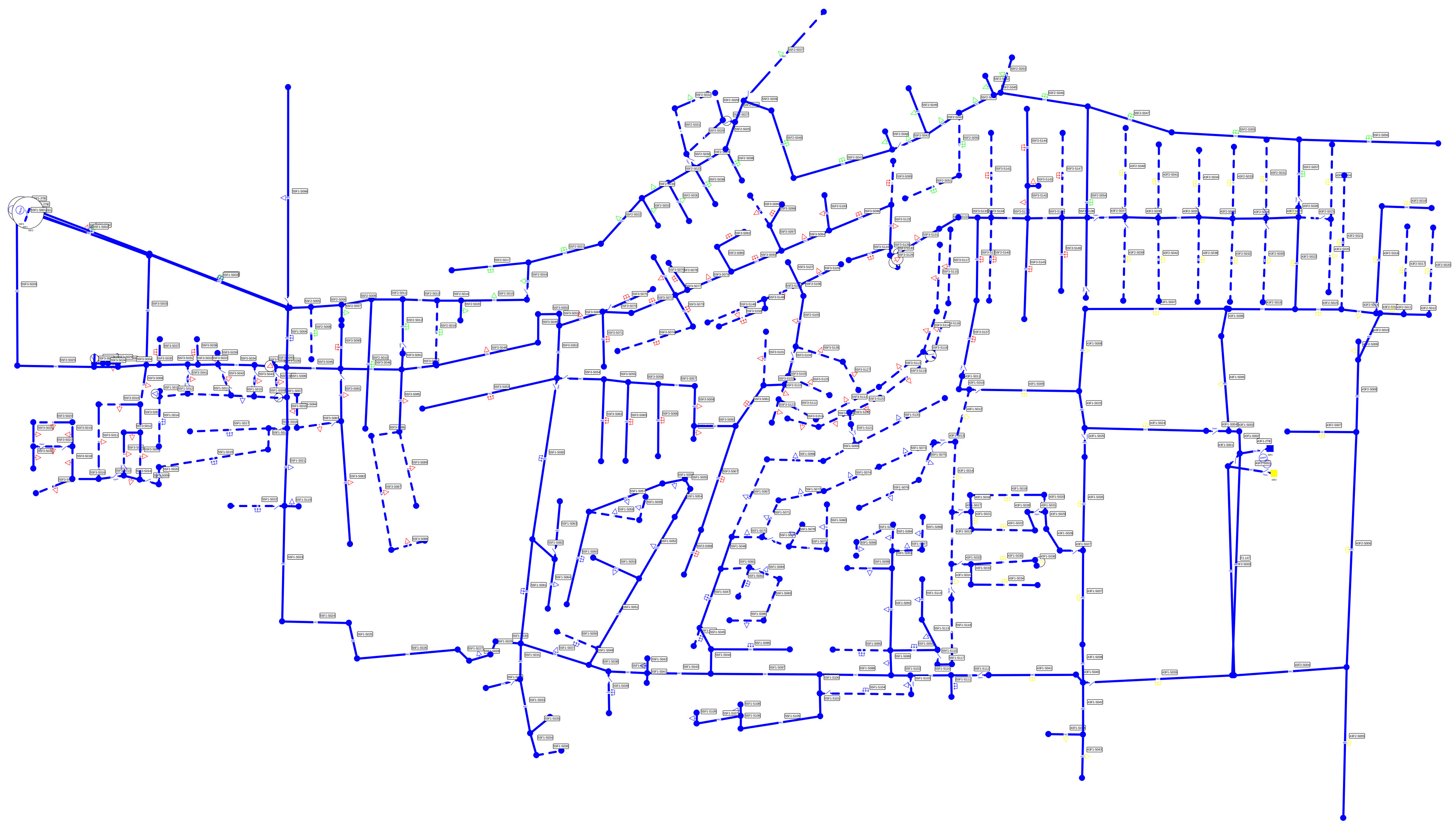
Analysis Layer :
Voltage level (%)

Colors :
- 90.00 91.66
- 91.66 93.00
- 85.00 90.00
- 0.00 85.00
- 91.66 100.00

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (O)
- Switch, (C)
- Load

Peter Dyck
Stantec Consulting Ltd
66% Winter Loading, Optimized Distribution - Failure of either 43F1 or F2



Legend
Default Layer:
Feeder color

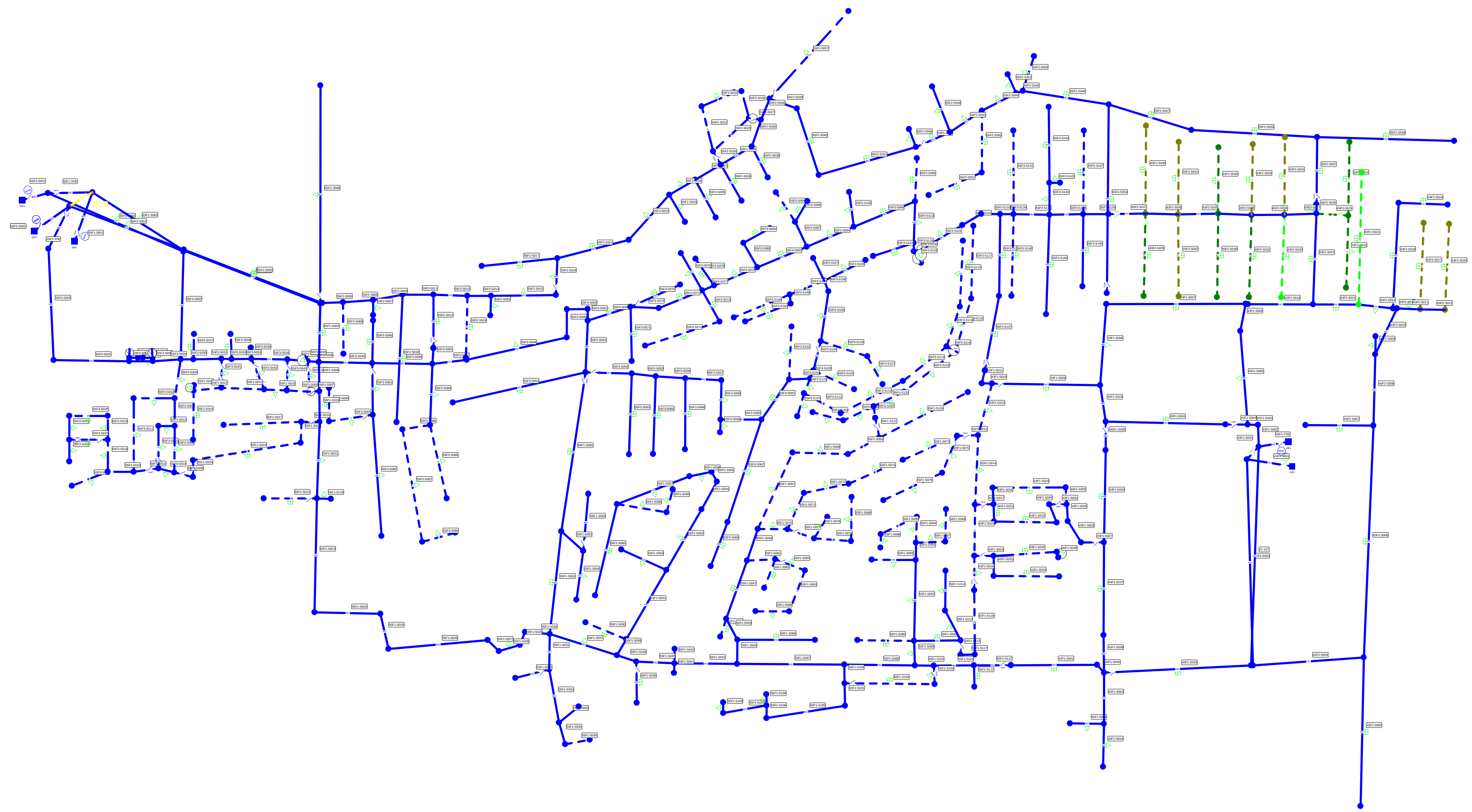
Colors :
- 43F1
- 55F3
- 43F2
- 55F1
- 55F2

Analysis Layer :
Voltage level (%)

Colors :
- 90.00 91.66
- 91.66 93.00
- 85.00 90.00
- 0.00 85.00
- 91.66 100.00

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (C)
- Load
- Switch, (O)



Legend
Default Layer:
Phase

Colors :
- Three-phase OH
- Three-phase UG
- Two-phase OH
- Two-phase UG
- A OH
- B OH
- C OH
- A UG
- B UG
- C UG

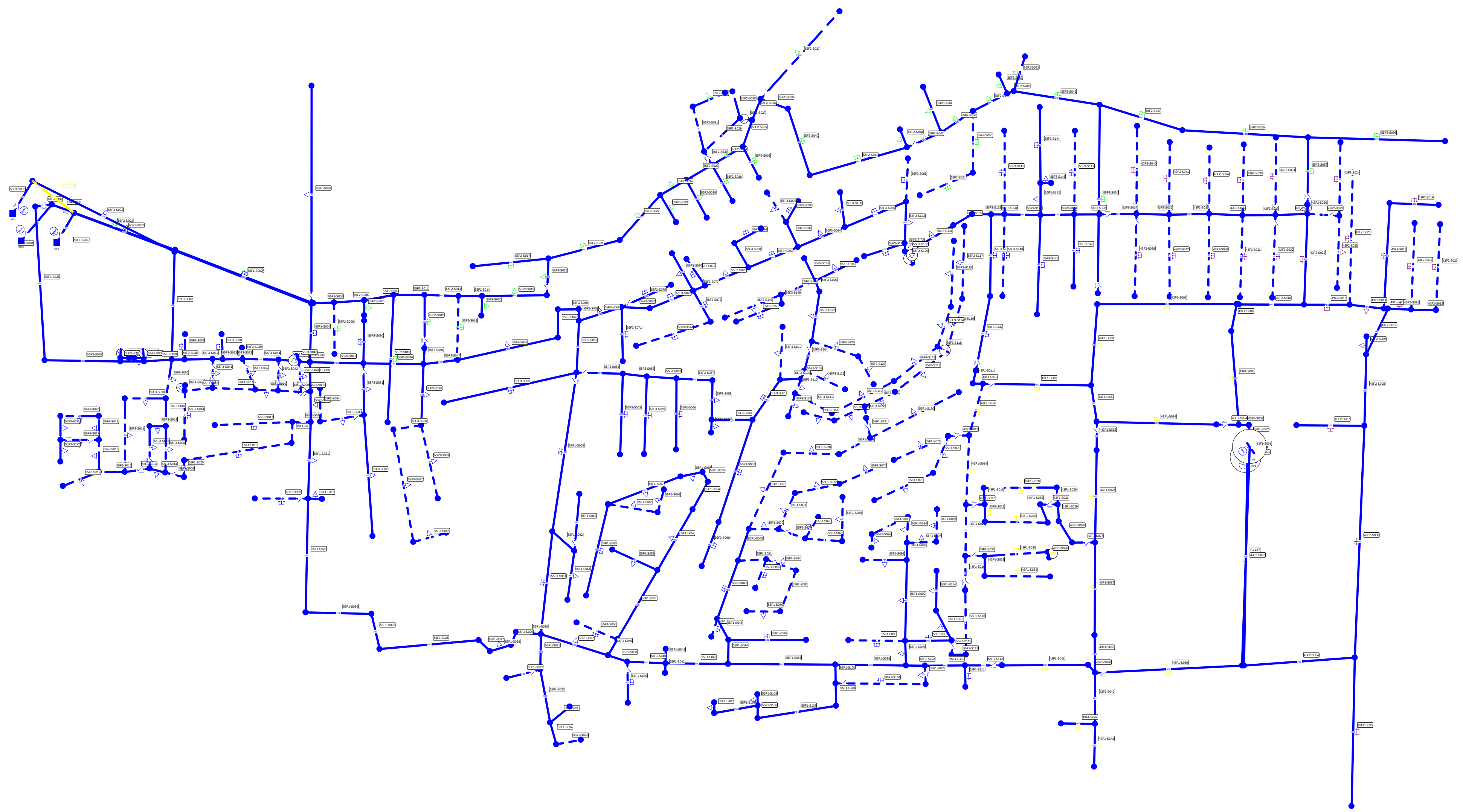
Analysis Layer :
Voltage level (%)

Colors :
- 90.00 91.66
- 91.66 93.00
- 85.00 90.00
- 0.00 85.00
- 91.66 100.00

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (O)
- Switch, (C)
- Load

Peter Dyck
Stantec Consulting Ltd.
66% Winter Loading, Optimized Distribution, Failure of 55F3, Transfer to 55F1



Legend
Default Layer:
Feeder color

Colors :
- 43F1
- 55F3
- 43F2
- 55F1
- 55F2

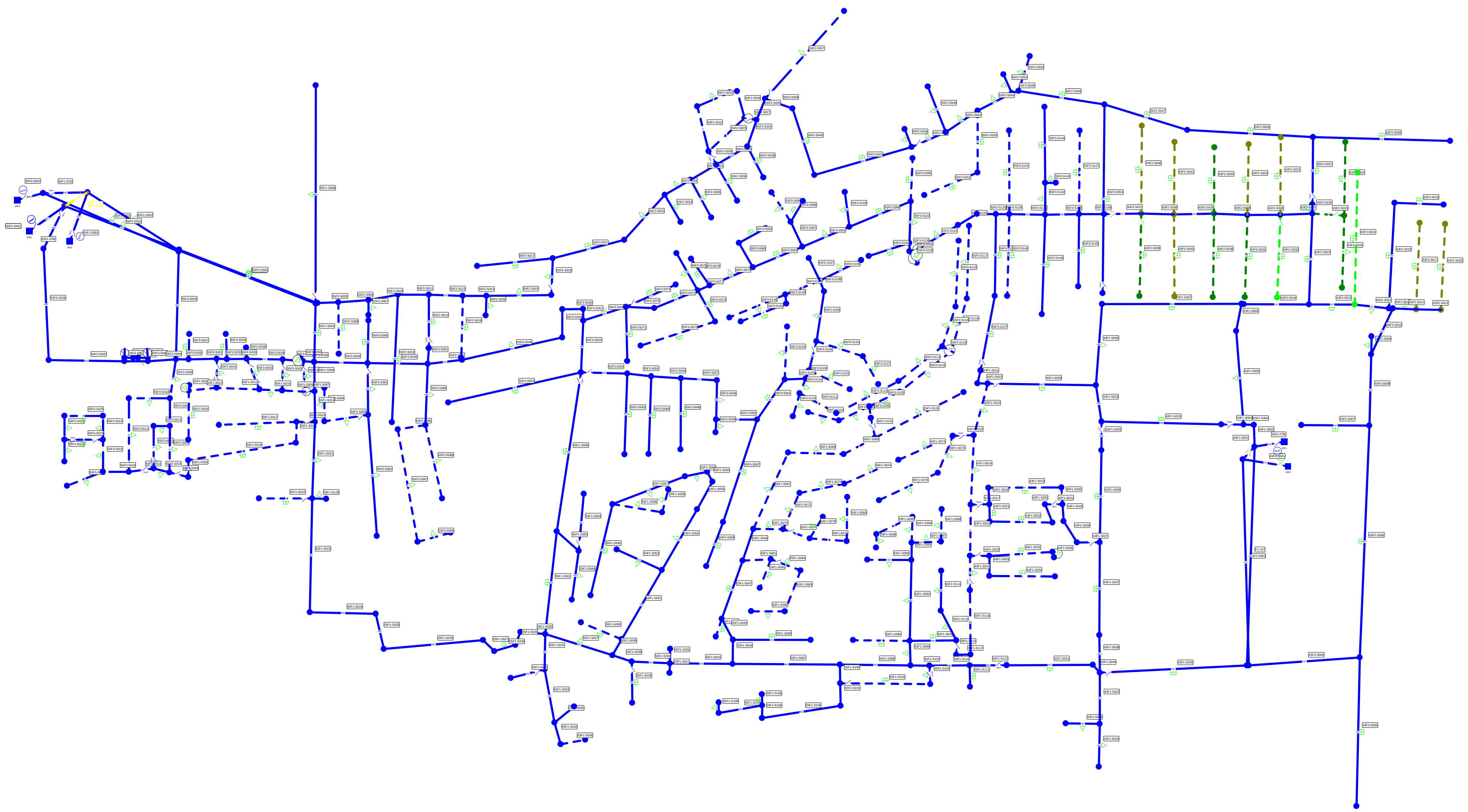
Analysis Layer :
Voltage level (%)

Colors :
- 90.00 91.66
- 91.66 93.00
- 85.00 90.00
- 0.00 85.00
- 91.66 100.00

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (O)
- Switch, (C)
- Load

Peter Dyck
Stantec Consulting Ltd
66% Winter Loading, Optimized Distribution - Failure of 55T1, transfer to 55T2



Legend
Default Layer:
Phase

Colors :
- Three-phase OH
- Three-phase UG
- Two-phase OH
- Two-phase UG
- A OH
- B OH
- C OH
- A UG
- B UG
- C UG

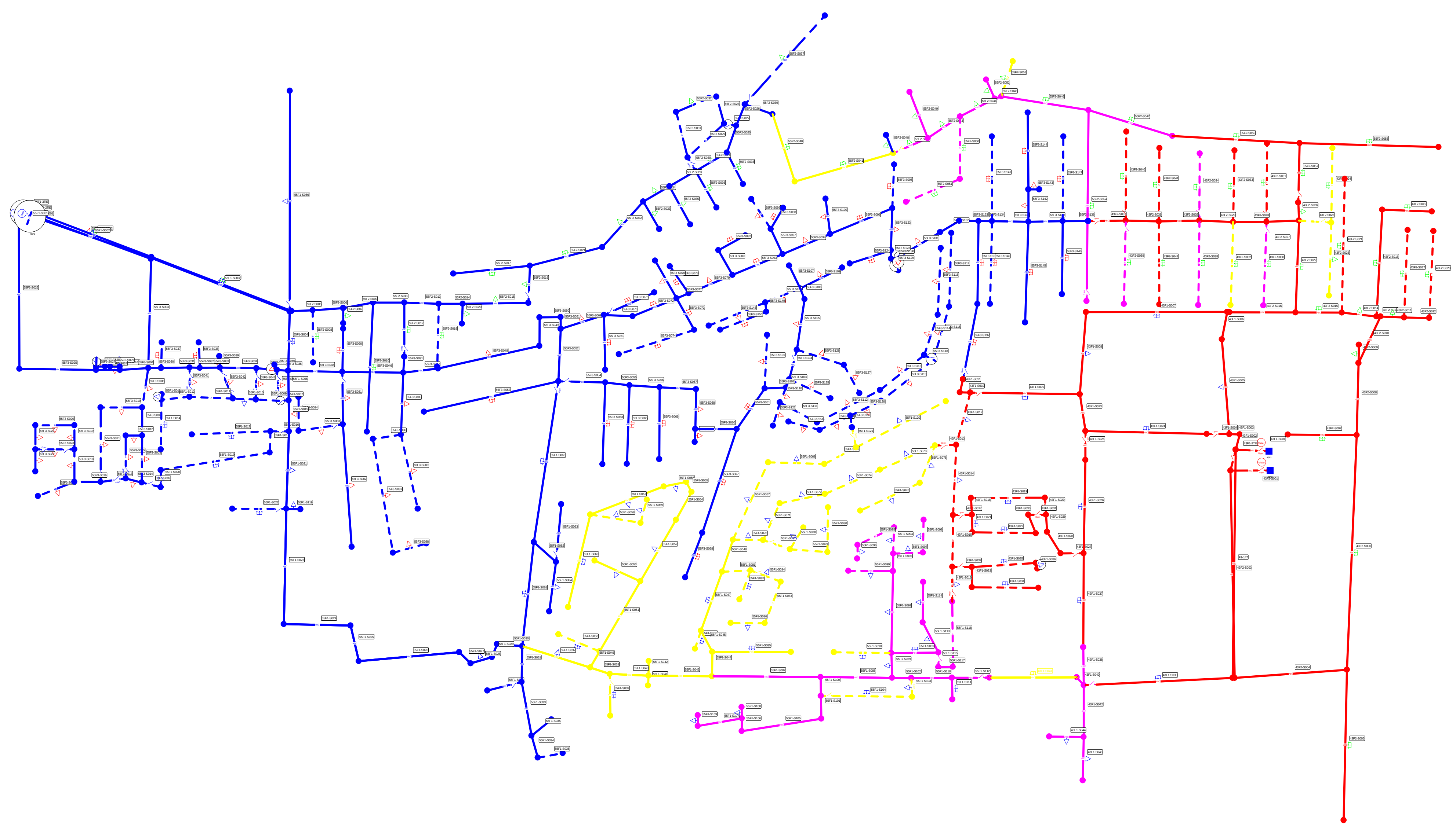
Analysis Layer :
Voltage level (%)

Colors :
- 90.00 91.66
- 91.66 93.00
- 85.00 90.00
- 0.00 85.00
- 91.66 100.00

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (O)
- Switch, (C)
- Load

Peter Dyck
Stantec Consulting Ltd.
66% Winter Loading, Optimized Distribution - Failure of Sub 43 East



Legend
Default Layer:
Feeder color

Colors :
43F1
55F3
43F2
55F1
55F2

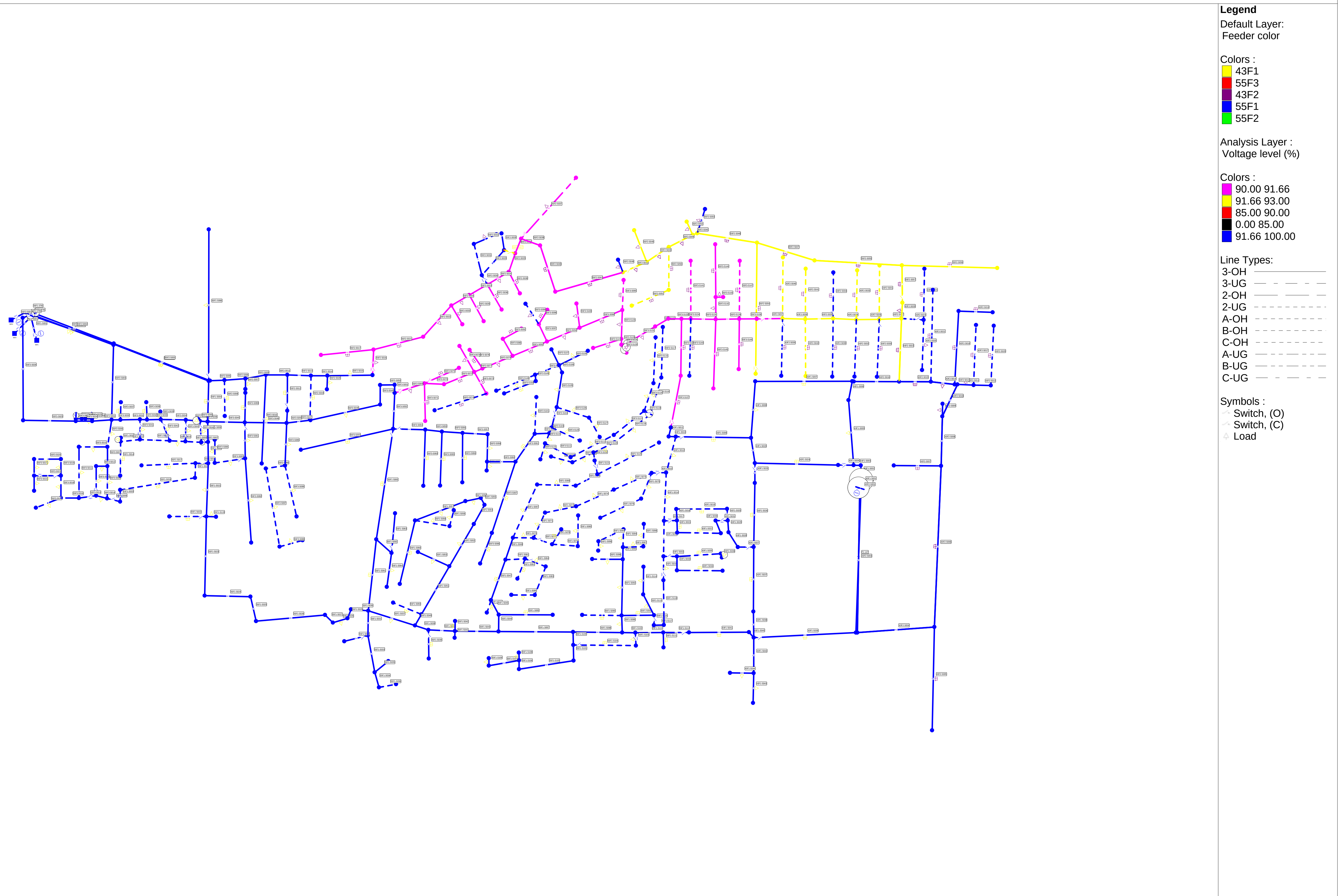
Analysis Layer :
Voltage level (%)

Colors :
90.00 91.66
91.66 93.00
85.00 90.00
0.00 85.00
91.66 100.00

Line Types:
3-OH
3-UG
2-OH
2-UG
A-OH
B-OH
C-OH
A-UG
B-UG
C-UG

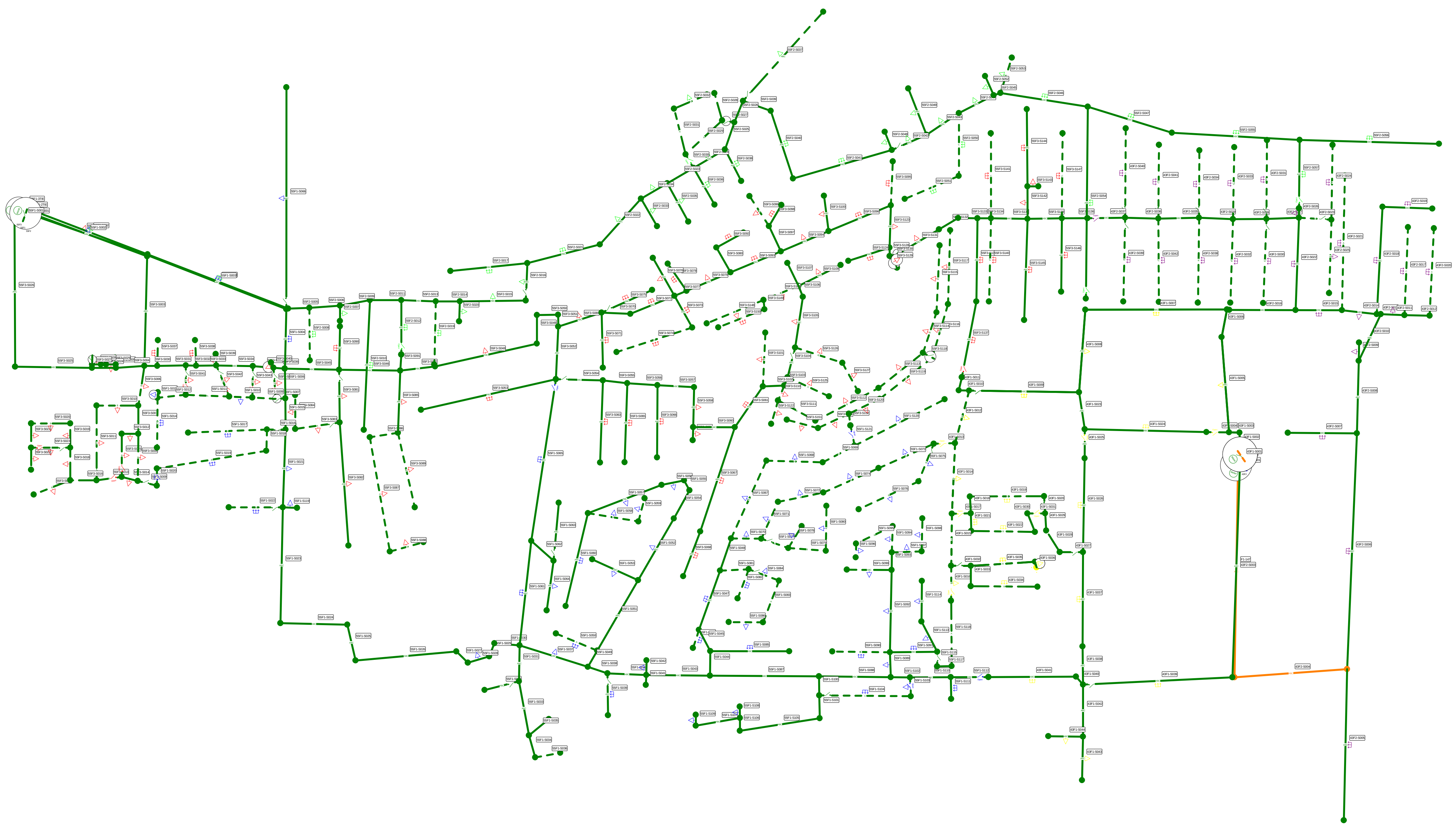
Symbols :
Switch, (O)
Load
Switch, (C)

Peter Dyck
Stantec Consulting
66% Winter Loading, Optimized Distribution - Failure of Sub 55 West



Appendix 3 – Loading Results

Peter Dyck
Stantec Consulting Ltd.
Optimized System - Peak Winter Loading Level



Legend
Default Layer:
Feeder color

Colors :
43F1
55F3
43F2
55F1
55F2

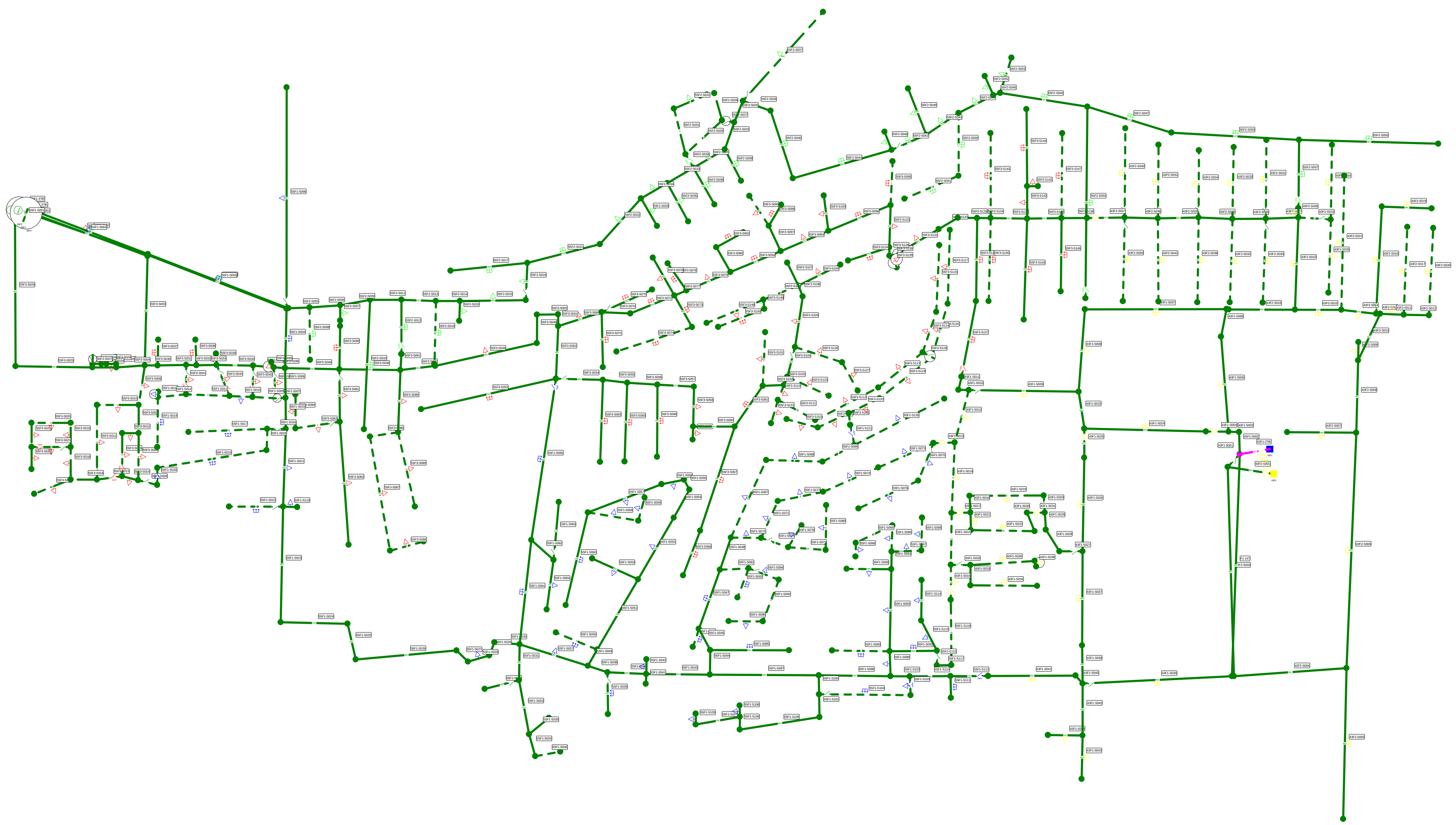
Analysis Layer :
Loading level (%)

Colors :
0.00 66.00
66.00 75.00
75.00 90.00
90.00 100.00
100.00 1000.00

Line Types:
3-OH
3-UG
2-OH
2-UG
A-OH
B-OH
C-OH
A-UG
B-UG
C-UG

Symbols :
Switch, (O)
Switch, (C)
Load

Peter Dyck
Stantec Consulting Ltd
66% Winter Loading, Optimized Distribution - Failure of either 43F1 or F2



Legend
Default Layer:
Feeder color

Colors :
43F1
55F3
43F2
55F1
55F2

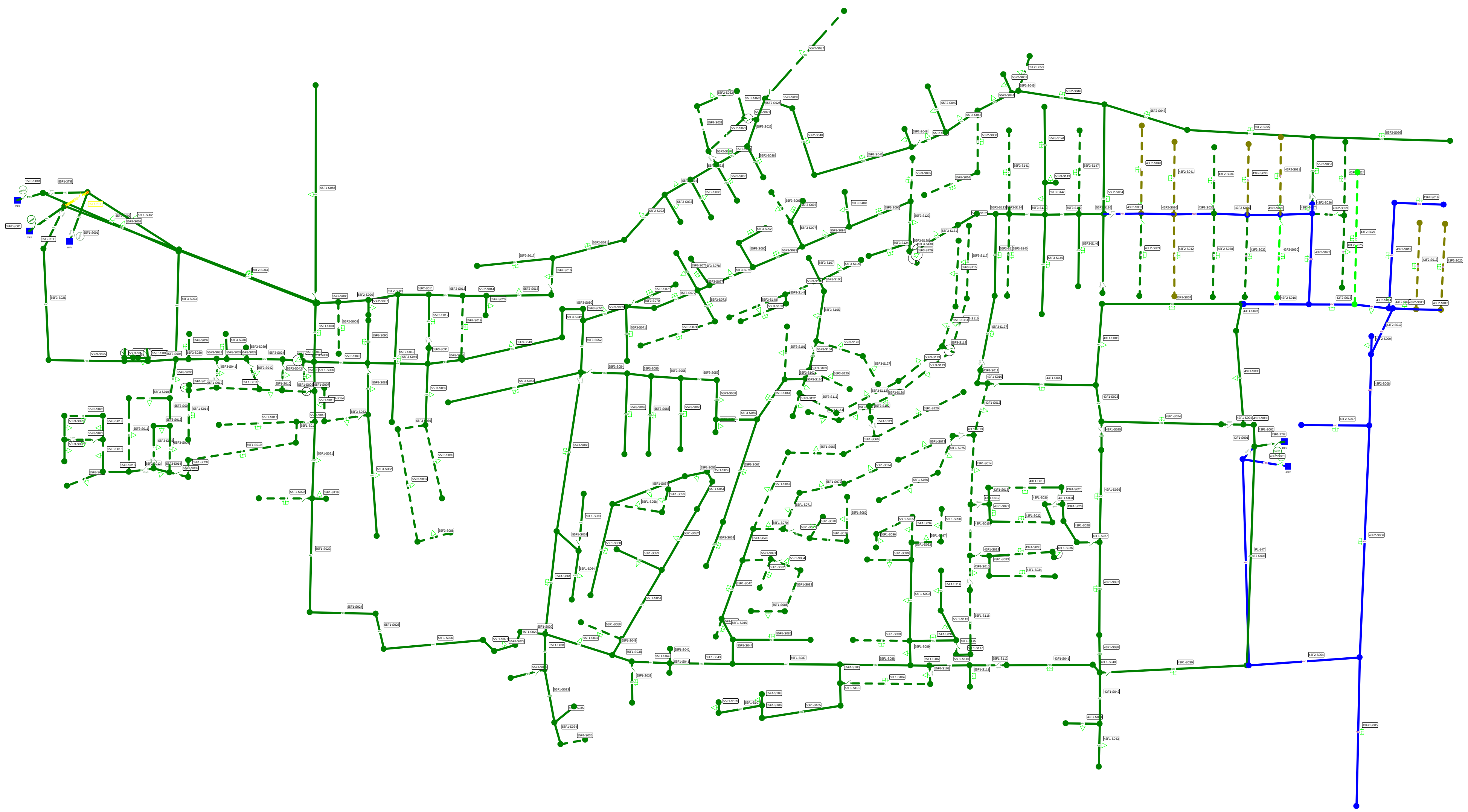
Analysis Layer :
Loading level (%)

Colors :
0.00 66.00
66.00 75.00
75.00 90.00
90.00 100.00
100.00 1000.00

Line Types:
3-OH
3-UG
2-OH
2-UG
A-OH
B-OH
C-OH
A-UG
B-UG
C-UG

Symbols :
Switch, (C)
Load
Switch, (O)

Peter Dyck
Stantec Consulting Ltd
66% Winter Loading, Optimized Distribution - Failure of either 55F1 or F2



Legend
Default Layer:
Phase

Colors :
Three-phase OH
Three-phase UG
Two-phase OH
Two-phase UG
A OH
B OH
C OH
A UG
B UG
C UG

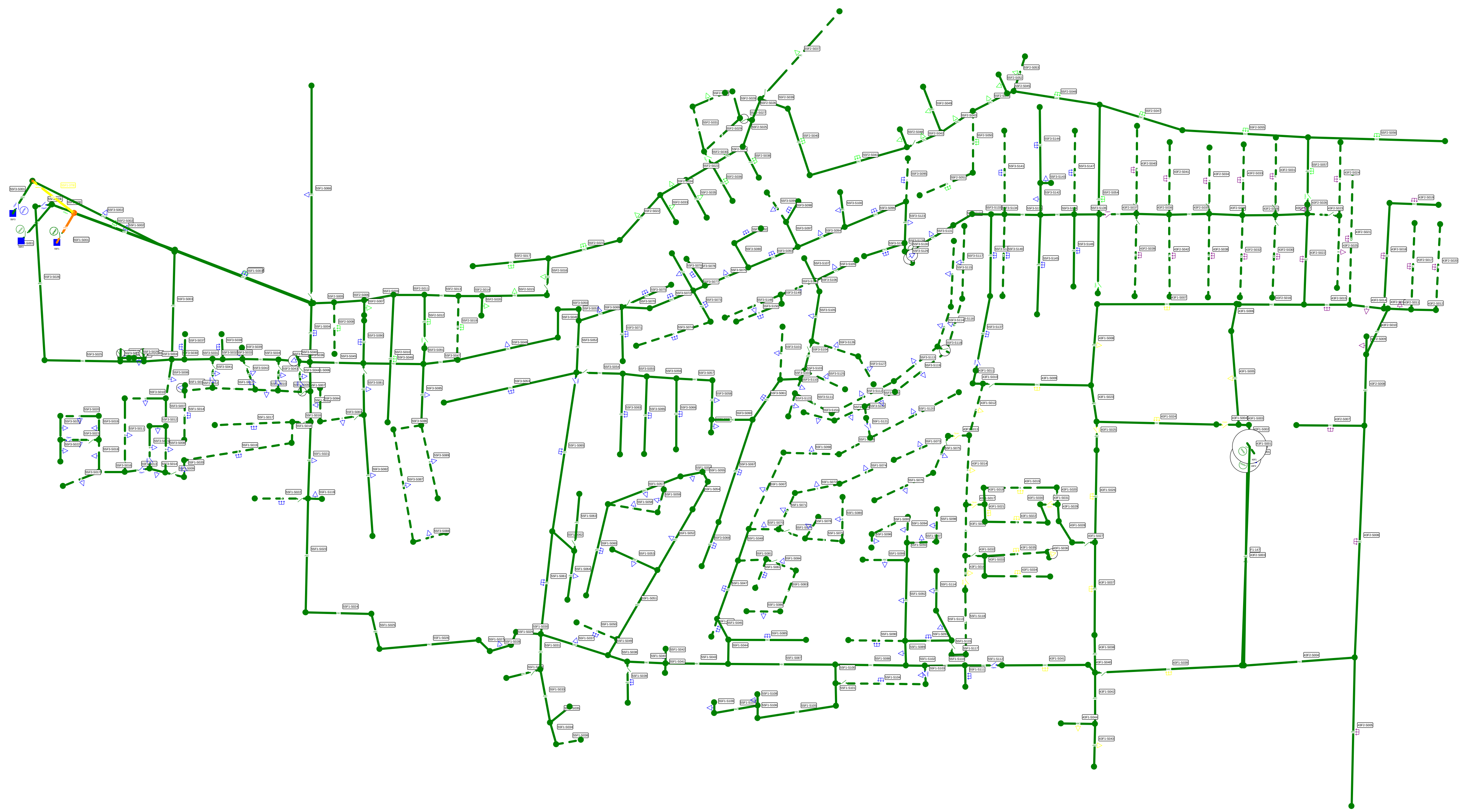
Analysis Layer :
Loading level (%)

Colors :
0.00 66.00
66.00 75.00
75.00 90.00
90.00 100.00
100.00 1000.00

Line Types:
3-OH
3-UG
2-OH
2-UG
A-OH
B-OH
C-OH
A-UG
B-UG
C-UG

Symbols :
Switch, (O)
Switch, (C)
Load

Peter Dyck
Stantec Consulting Ltd.
66% Winter Loading, Optimized Distribution, Failure of 55F3, Transfer to 55F1



Legend

Default Layer:
Feeder color

Colors :
- 43F1
- 55F3
- 43F2
- 55F1
- 55F2

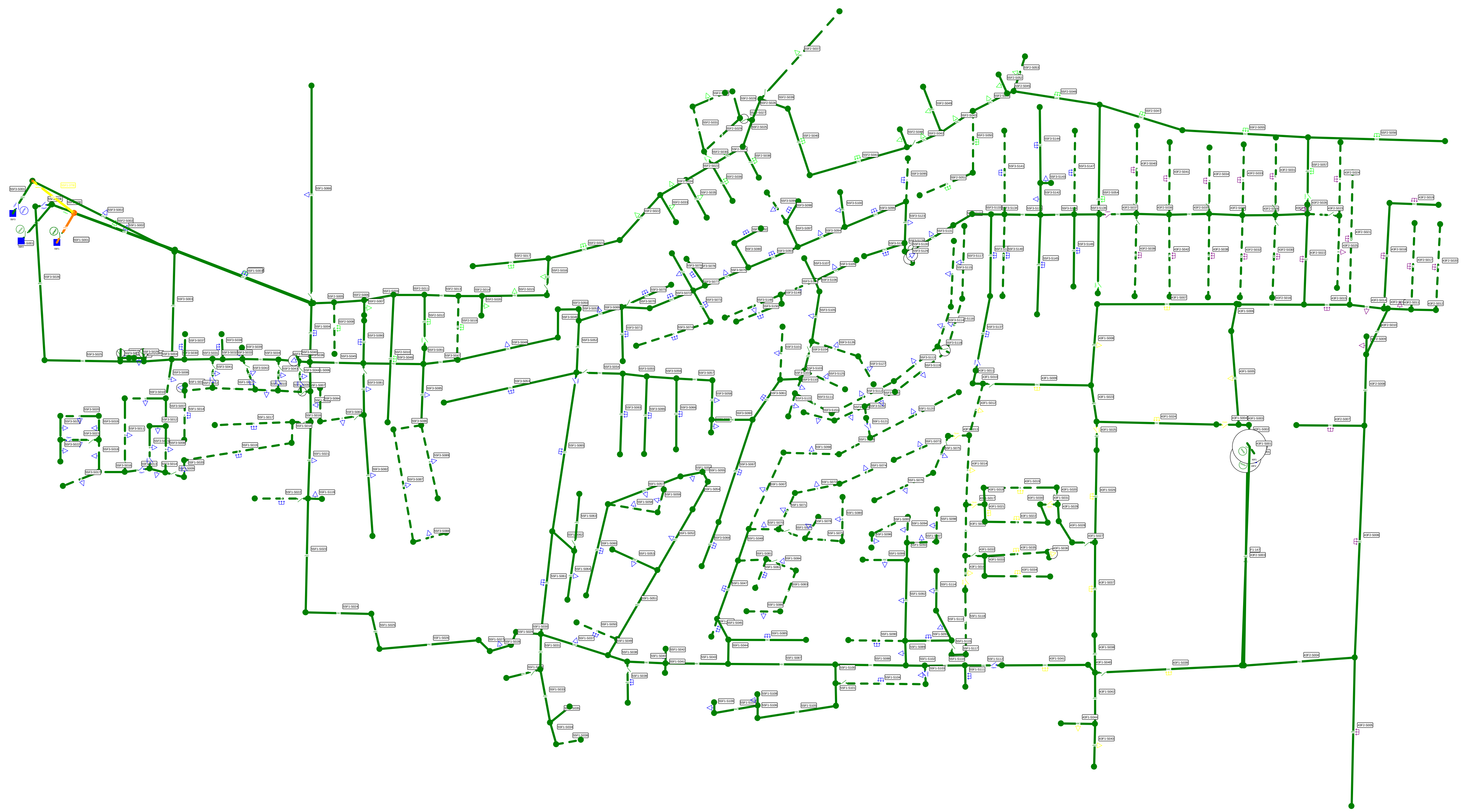
Analysis Layer :
Loading level (%)

Colors :
- 0.00 66.00
- 66.00 75.00
- 75.00 90.00
- 90.00 100.00
- 100.00 1000.00

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (O)
- Switch, (C)
- Load

Peter Dyck
Stantec Consulting Ltd.
66% Winter Loading, Optimized Distribution, Failure of 55T2, Transfer all loads to 55T1



Legend

Default Layer:
Feeder color

Colors :
- 43F1
- 55F3
- 43F2
- 55F1
- 55F2

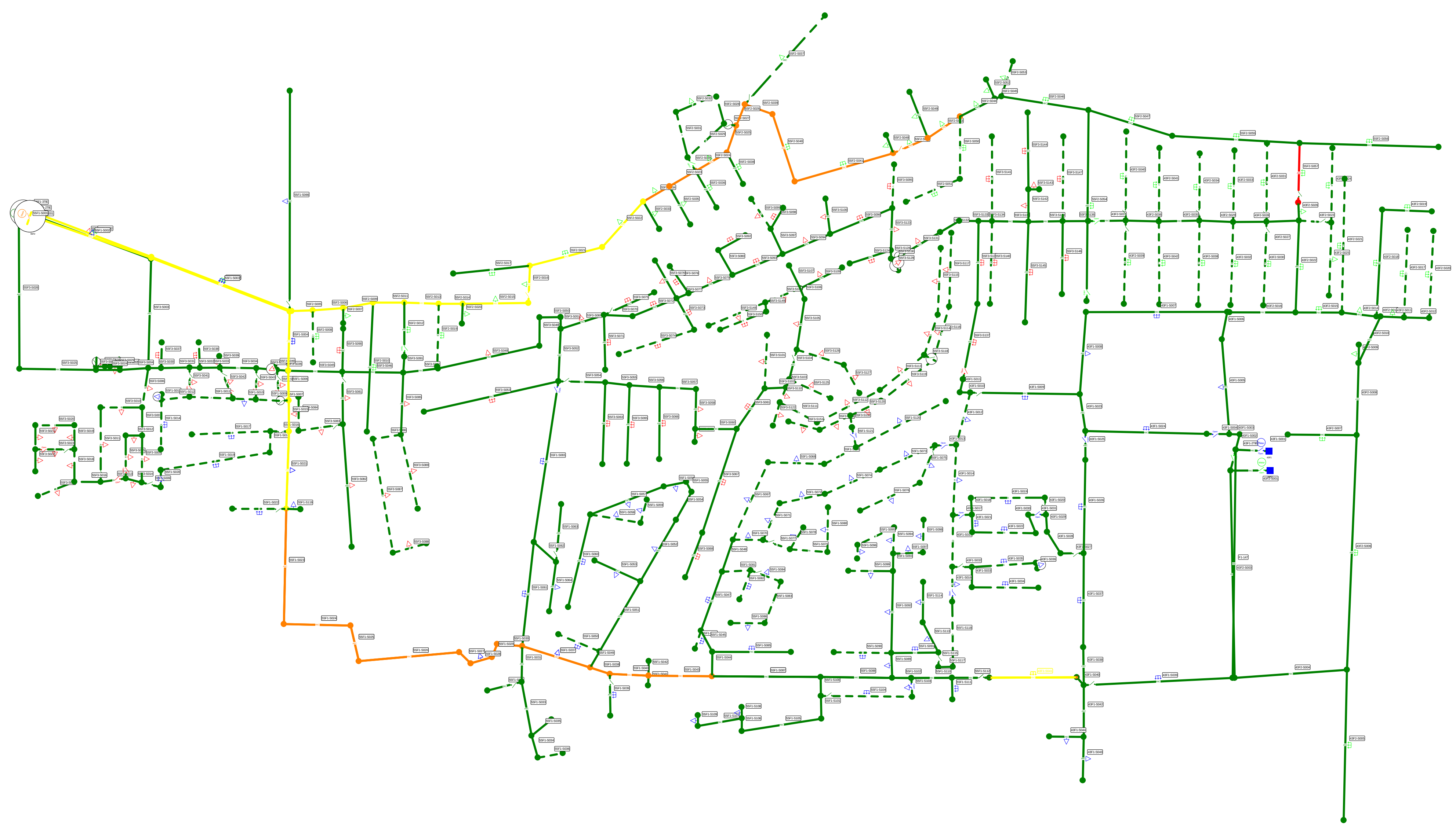
Analysis Layer :
Loading level (%)

Colors :
- 0.00 66.00
- 66.00 75.00
- 75.00 90.00
- 90.00 100.00
- 100.00 1000.00

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (O)
- Switch, (C)
- Load

Peter Dyck
Stantec Consulting Ltd.
66% Winter Loading, Optimized Distribution - Failure of Sub 43 East



Legend

Default Layer:
Feeder color

Colors :
- 43F1
- 55F3
- 43F2
- 55F1
- 55F2

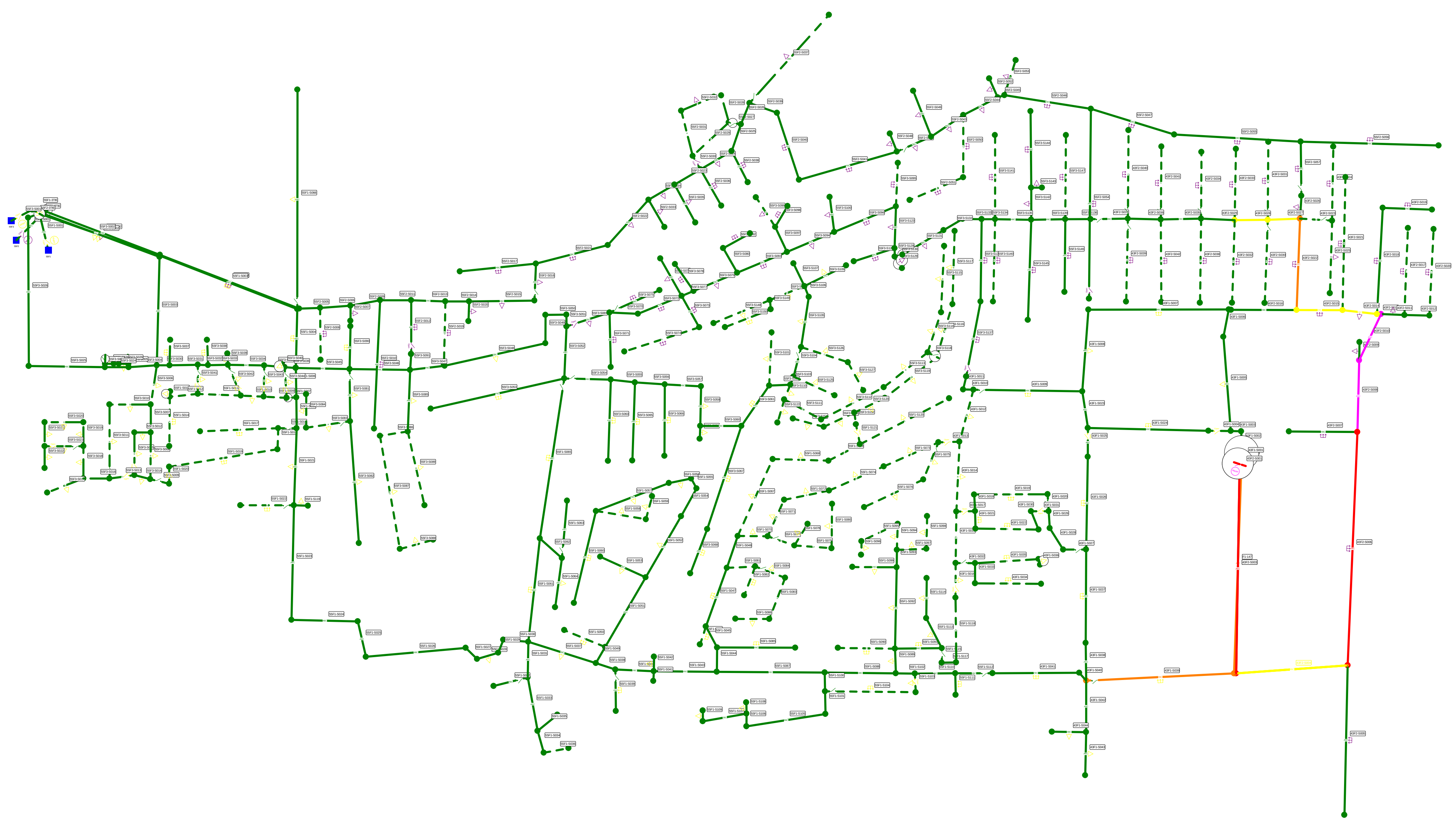
Analysis Layer :
Loading level (%)

Colors :
- 0.00 66.00
- 66.00 75.00
- 75.00 90.00
- 90.00 100.00
- 100.00 1000.00

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (O)
- Load
- Switch, (C)

Peter Dyck
Stantec Consulting
66% Winter Loading, Optimized Distribution - Failure of Sub 55 West



Legend
Default Layer:
Feeder color

Colors :
43F1
55F3
43F2
55F1
55F2

Analysis Layer :
Loading level (%)

Colors :
0.00 66.00
66.00 75.00
75.00 90.00
90.00 100.00
100.00 1000.00

Line Types:
3-OH
3-UG
2-OH
2-UG
A-OH
B-OH
C-OH
A-UG
B-UG
C-UG

Symbols :
Switch, (O)
Switch, (C)
Load

Appendix 4 –Load Flow Output

Page 1 Peak Winter Case Load Flow Output

Load Flow Output

Hawkesbury Hydro
Utility Load Flow and Evaluation Study
February 16, 2007

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
																				0	0	0
43F1	43F1	HH-EAST-SUB	SUB	ABC	1	1	1	448	487	443.8	122.9	126.6	122.5	2904	3155	2876	1408	1536	1399	0	0	0
43F1	43F1-S001	HH_800	Switch	ABC	1	1	1	448	487	443.8	44.8	48.7	44.4	2904	3155	2876	1408	1536	1399	0	0	0
43F1	43F1-S001	HH_3P_336ACSR_2	COND	ABC	1	1	1	448	487	443.8	61.1	66.4	60.5	2904	3155	2876	1408	1536	1399	0	0	0
43F1	F1-147	HH_3P_336ACSR_2	COND	ABC	0.999	0.999	0.999	203	189.7	179.5	27.7	25.9	24.5	1316	1232	1165	637	592	562	0	0	0
43F1	43F1-S039	HH_3P_336ACSR_2	COND	ABC	0.994	0.995	0.995	203	189.7	179.5	27.7	25.9	24.5	1315	1231	1164	635.1	590.4	560.7	120.8	90.6	96.7
43F1	43F1-S039	HH_800	Switch	ABC	0.994	0.995	0.995	186.1	177.1	166.1	18.6	17.7	16.6	1203	1147	1075	575.5	544.9	513.9	0	0	0
43F1	43F1-S042	HH_3P_3/0ACSR_#	COND	ABC	0.994	0.995	0.995	63.7	62	64.5	15.2	14.8	15.4	412	401	417.4	196.9	191.7	199.6	0	0	0
43F1	43F1-S044	HH_3P_#2ACSR_#4	COND	ABC	0.993	0.994	0.994	31.9	31	32.3	14	13.6	14.1	205.9	200.4	208.6	98.3	95.7	99.6	228.1	222	231.1
43F1	43F1-S043	HH_3P_3/0ACSR_#	COND	ABC	0.993	0.994	0.994	31.9	31	32.2	7.6	7.4	7.7	205.8	200.4	208.6	98.3	95.7	99.6	228.1	222	231.1
43F1	43F1-S040	HH_3P_336ACSR_2	COND	ABC	0.994	0.995	0.995	22.3	11.8	13.9	3	1.6	1.9	144.5	76.3	90	69	36.4	42.9	0	0	0
43F1	43F1-S041	HH_3P_336ACSR_2	COND	ABC	0.994	0.995	0.995	22.3	11.8	13.9	3	1.6	1.9	144.5	76.3	90	69	36.4	42.9	160.1	84.6	99.7
43F1	43F1-S038	HH_3P_336ACSR_2	COND	ABC	0.994	0.995	0.995	100.1	103.3	87.7	13.7	14.1	12	646.7	669.8	567.3	309.6	316.8	271.5	0	0	0
43F1	43F1-S037	HH_3P_336ACSR_2	COND	ABC	0.993	0.994	0.994	100.1	103.3	87.7	13.7	14.1	12	646.5	669.7	567.2	309.2	316.3	271.2	358	276.4	314.2
43F1	43F1-S027	HH_200	Switch	B		0.994			26.1			10.5			170.5			77.2		0	0	0
43F1	43F1-S027	15KV_3/0CU_XLPE	CAB	B		0.994			26.1			8.4			170.5			77.2		0	0	0
43F1	43F1-S028	15KV_3/0CU_XLPE	CAB	B		0.994			26.2			8.4			170.5			77.4		0	0	0
43F1	43F1-S029	15KV_3/0CU_XLPE	CAB	B		0.994			26.2			8.4			170.5			77.7		0	0	0
43F1	43F1-S020	HH_800	Switch	B		0.994			26.2			2.6			170.5			77.9		0	0	0
43F1	43F1-S020	15KV_3/0CU_XLPE	CAB	B		0.993			26.2			8.4			170.5			77.9		0	0	0
43F1	43F1-S019	15KV_3/0CU_XLPE	CAB	B		0.993			26.2			8.4			170.4			78.4		0	62.9	0
43F1	43F1-S018	15KV_3/0CU_XLPE	CAB	B		0.993			17.5			5.6			113.6			51.9		0	0	0
43F1	43F1-S021	15KV_3/0CU_XLPE	CAB	B		0.993			17.5			5.6			113.6			52.9		0	62.9	0
43F1	43F1-S022	15KV_3/0CU_XLPE	CAB	B		0.993			8.7			2.8			56.8			26		0	62.9	0
43F1	43F1-S030	15KV_3/0CU_XLPE	CAB	B		0.993			0			0			0			-0.3		0	0	0
43F1	43F1-S031	15KV_3/0CU_XLPE	CAB	B		0.993			0			0			0			-0.1		0	0	0
43F1	43F1-S031	DEFAULT	Switch	B		0.993			0			0			0			0		0	0	0
43F1	43F1-S017	15KV_3/0CU_XLPE	CAB	B		0.993			-0.1			0			0			-0.6		0	0	0
43F1	43F1-S017	HH_200	Switch	B		0.993			0			0			0			0		0	0	0
43F1	43F1-S026	HH_3P_336ACSR_2	COND	ABC	0.992	0.994	0.994	50.1	38.6	43.9	6.8	5.3	6	323.1	249.4	283.5	154.3	119.1	135.4	358	276.4	314.2
43F1	43F1-S025	HH_3P_336ACSR_2	COND	ABC	0.992	0.994	0.994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F1	43F1-S025	HH_800	Switch	ABC	0.992	0.994	0.994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F1	43F1-S002	HH_3P_336ACSR_2	COND	ABC	0.999	0.998	0.999	245	297.3	264.3	33.4	40.6	36.1	1588	1923	1710	770.3	942.7	836	0	0	0
43F1	43F1-S003	HH_3P_336ACSR_2	COND	ABC	0.998	0.998	0.998	245	297.3	264.3	33.4	40.6	36.1	1587	1921	1710	768.2	938.9	833.2	0	0	0
43F1	43F1-S005	HH_3P_336ACSR_2	COND	ABC	0.996	0.994	0.996	245	297.3	264.3	33.4	40.6	36.1	1586	1921	1709	767.5	937.6	832.3	214	241.7	244.2
43F1	43F1-S006	HH_3P_336ACSR_2	COND	ABC	0.995	0.993	0.995	215.2	263.7	230.3	29.4	36	31.4	1391	1699	1487	670.6	824.4	720.7	0	0	0
43F1	43F1-S007	HH_3P_336ACSR_2	COND	ABC	0.991	0.988	0.992	215.2	263.7	230.3	29.4	36	31.4	1390	1698	1487	669.2	821.8	718.9	499.3	563.9	569.7
43F1	43F1-S008	HH_3P_336ACSR_2	COND	ABC	0.99	0.985	0.991	145.4	184.6	150.7	19.8	25.2	20.6	936.5	1185	971.1	448.9	568.4	466.6	123.8	33.2	42
43F1	43F1-S023	HH_3P_336ACSR_2	COND	ABC	0.989	0.985	0.99	103.1	105.2	108.9	14.1	14.4	14.9	662.9	673.9	701.2	317.3	322.5	335.7	0	0	0
43F1	43F1-S024	HH_3P_3/0ACSR_#	COND	ABC	0.988	0.984	0.989	103.1	105.2	108.9	24.6	25.1	26	662.7	673.7	700.9	316.8	322	335.1	734	746.1	776.3
43F1	43F1-S009	HH_3P_3/0ACSR_#	COND	ABC	0.989	0.983	0.991	25	74.7	36	6	17.8	8.6	160.9	479.2	231.6	76.7	227.7	110.6	178.2	215.4	256.8
43F1	43F1-S009	HH_800	Switch	ABC	0.989	0.983	0.991	0	44.4	0	0	4.4	0	0	284.3	0	0	134	0	0	0	0
43F1	43F1-S012	HH_3P_3/0ACSR_#	COND	B		0.983			44.4			10.6			284.3			134		0	62.9	0
43F1	43F1-S014	HH_3P_3/0ACSR_#	COND	B		0.982			35.5			8.5			227.4			106.7		0	31.5	0
43F1	43F1-S015	HH_3P_3/0ACSR_#	COND	B		0.981			31			7.4			198.9			93		0	0	0
43F1	43F1-S032	HH_200	Switch	B		0.981			26.6			10.6			170.4			79.3		0	0	0
43F1	43F1-S032	15KV_3/0CU_XLPE	CAB	B		0.981			26.6			8.5			170.4			79.3		0	0	0
43F1	43F1-S035	15KV_3/0CU_XLPE	CAB	B		0.981			13.3			4.3			85.2			39.9		0	62.9	0
43F1	43F1-S036	15KV_3/0CU_XLPE	CAB	B		0.981			4.4			1.4			28.4			13.5		0	31.5	0

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
43F1	43F1-S033	15KV_3/0CU_XLPE	CAB	B		0.981			13.3			4.3			85.2			39.6		0	0	0
43F1	43F1-S034	15KV_3/0CU_XLPE	CAB	B		0.981			13.3			4.3			85.2			39.9		0	94.4	0
43F1	43F1-S016	HH_3P_3/0ACSR_#	COND	B		0.981			4.4			1.1			28.4			13.5		0	31.5	0
43F1	43F1-S016	HH_600	Switch	B		0.981			0			0			0			0		0	0	0
43F1	43F1-S013	HH_3P_3/0ACSR_#	COND	B		0.983			0			0			0			0		0	0	0
43F1	43F1-S013	HH_800	Switch	B		0.983			0			0			0			0		0	0	0
43F1	43F1-S010	HH_3P_336ACSR_2	COND	ABC	0.989	0.983	0.991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F1	43F1-S011	HH_3P_3/0ACSR_#	COND	ABC	0.989	0.983	0.991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F1	43F1-S004	HH_3P_336ACSR_2	COND	ABC	0.998	0.998	0.998	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F1	43F1-S004	DEFAULT	Switch	ABC	0.998	0.998	0.998	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F2	43F2	HH-EAST-SUB	SUB	ABC	1	1	1	499.9	489.5	500.8	122.9	126.6	122.5	3239	3167	3237	1576	1552	1594	0	0	0
43F2	43F2-S001	HH_800	Switch	ABC	1	1	1	499.9	489.5	500.8	50	48.9	50.1	3239	3167	3237	1576	1552	1594	0	0	0
43F2	43F2-S001	HH_3P_336ACSR_2	COND	ABC	1	1	1	499.9	489.5	500.8	68.2	66.8	68.3	3239	3167	3237	1576	1552	1594	0	0	0
43F2	43F2-S003	HH_3P_336ACSR_2	COND	ABC	0.986	0.986	0.985	499.9	489.5	500.8	68.2	66.8	68.3	3239	3167	3237	1575	1551	1593	0	0	0
43F2	43F2-S004	HH_3P_336ACSR_2	COND	ABC	0.978	0.978	0.977	500	489.5	500.8	68.2	66.8	68.3	3214	3142	3210	1508	1489	1526	0	0	0
43F2	43F2-S006	HH_3P_336ACSR_2	COND	ABC	0.974	0.974	0.972	389.4	376.5	391.4	53.1	51.4	53.4	2491	2404	2494	1150	1126	1172	600.2	219.4	233.9
43F2	43F2-S008	HH_3P_336ACSR_2	COND	ABC	0.972	0.97	0.969	256.3	330.9	343.7	35	45.1	46.9	1635	2105	2183	749.8	979.4	1017	0	0	0
43F2	43F2-S010	HH_3P_336ACSR_2	COND	ABC	0.971	0.967	0.967	256.3	330.9	321.5	35	45.1	43.9	1633	2099	2039	745.2	969.4	941.1	0	0	0
43F2	43F2-S013	HH_3P_336ACSR_2	COND	ABC	0.97	0.967	0.967	256.3	330.9	279.7	35	45.1	38.2	1631	2096	1772	741.8	962	813.3	0	0	0
43F2	43F2-S018	HH_200	Switch	ABC	0.97	0.967	0.967	14.2	9.6	13	5.7	3.8	5.2	90.2	61	82.3	40.9	27.6	37.3	0	0	0
43F2	43F2-S018	HH_3P_3/0ACSR_#	COND	ABC	0.97	0.967	0.967	14.2	9.6	13	3.4	2.3	3.1	90.2	61	82.3	40.9	27.6	37.3	40.5	34.6	90.3
43F2	43F2-S019	HH_3P_3/0ACSR_#	COND	ABC	0.97	0.967	0.967	8.4	4.6	0	2	1.1	0	53.4	29.5	0	24.2	13.4	0	58.6	32.4	0
43F2	43F2-S014	HH_3P_336ACSR_2	COND	ABC	0.969	0.965	0.966	242.1	321.3	266.8	33	43.8	36.4	1541	2034	1689	700.7	933.7	775.7	62.6	0	0
43F2	43F2-S021	HH_1P_3/0ACSR_#	COND	A	0.969			34.8			8.3			221.2			100.4			242.8	0	0
43F2	43F2-S015	HH_3P_336ACSR_2	COND	ABC	0.969	0.963	0.965	198.4	321.3	266.8	27.1	43.8	36.4	1262	2032	1689	572.4	928.6	772.5	1032	1133	1043
43F2	43F2-S022	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.959	0.964	50.5	158.1	116.8	12.1	37.7	27.9	321.3	997.6	738.6	145.6	455.9	338.8	0	161.9	0
43F2	43F2-S027	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.958	0.963	41.3	95.7	115	9.9	22.8	27.5	262.2	601.8	726.8	119	273.9	331.3	0	0	0
43F2	43F2-S031	HH_200	Switch	C			0.963			22.6			9			142.5			64.7	0	0	0
43F2	43F2-S031	HH_1P_3/0ACSR_#	COND	C			0.963			22.6			5.4			142.5			64.7	0	0	156.5
43F2	43F2-S030	HH_200	Switch	A	0.968			41.3			16.5			262.2			119.1			0	0	0
43F2	43F2-S030	HH_1P_3/0ACSR_#	COND	A	0.968			41.3			9.9			262.2			119.1			287.9	0	0
43F2	43F2-S028	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.957	0.962	0	95.7	92.5	0	22.8	22.1	0	601.3	583.9	-0.1	273.5	265.8	0	0	0
43F2	43F2-S033	HH_1P_3/0ACSR_#	COND	C			0.961			71.5			17.1			451.2			205	0	0	495.3
43F2	43F2-S032	HH_1P_3/0ACSR_#	COND	B		0.957			11.7			2.8			73.7			33.4		0	80.9	0
43F2	43F2-S029	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.956	0.962	0	83.9	21	0	20	5	0	527	132.6	-0.1	239.6	60.1	0	0	0
43F2	43F2-S038	HH_1P_3/0ACSR_#	COND	B		0.955			46.7			11.2			293			133.1		0	321.7	0
43F2	43F2-S035	HH_3P_3/0ACSR_#	COND	ABC	0.969	0.956	0.962	0	17.8	21	0	4.2	5	0	111.5	132.7	-0.1	50.6	60.1	0	0	0
43F2	43F2-S042	HH_1P_3/0ACSR_#	COND	C			0.962			7			1.7			44.2			20	0	0	48.6
43F2	43F2-S041	HH_200	Switch	C			0.962			7			2.8			44.2			20	0	0	0
43F2	43F2-S041	HH_1P_3/0ACSR_#	COND	C			0.962			7			1.7			44.2			20	0	0	48.6
43F2	43F2-S036	HH_3P_3/0ACSR_#	COND	ABC	0.969	0.956	0.962	0	17.8	7	0	4.2	1.7	0	111.5	44.2	0	50.6	20	0	0	0
43F2	43F2-S040	HH_200	Switch	C			0.962			7			2.8			44.2			20	0	0	0
43F2	43F2-S040	HH_1P_3/0ACSR_#	COND	C			0.962			7			1.7			44.2			20	0	0	48.6
43F2	43F2-S039	HH_200	Switch	B		0.956			17.8			7.1			111.5			50.6		0	0	0
43F2	43F2-S039	HH_1P_3/0ACSR_#	COND	B		0.955			17.8			4.2			111.5			50.6		0	122.4	0
43F2	43F2-S037	HH_3P_3/0ACSR_#	COND	ABC	0.969	0.956	0.962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F2	43F2-S037	HH_600	Switch	ABC	0.969	0.956	0.962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F2	43F2-S034	HH_200	Switch	B		0.956			19.5			7.8			122.1			55.4		0	0	0
43F2	43F2-S034	HH_1P_3/0ACSR_#	COND	B		0.956			19.5			4.6			122.1			55.4		0	134	0

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
43F2	43F2-S026	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.959	0.964	9.3	1.5	1.8	2.2	0.3	0.4	58.9	9.2	11.4	26.7	4.2	5.2	64.7	10.1	12.5
43F2	43F2-S023	HH_1P_3/0ACSR_#	COND	B		0.959			37.5			9			236.1			107.3		0	0	0
43F2	43F2-S023	HH_200	Switch	B		0.959			37.5			15			236.1			107.1		0	0	0
43F2	43F2-S025	HH_1P_3/0ACSR_#	COND	B		0.958			15.6			3.7			98.2			44.6		0	107.8	0
43F2	43F2-S024	HH_1P_3/0ACSR_#	COND	B		0.958			21.9			5.2			137.8			62.6		0	151.4	0
43F2	43F2-S016	HH_3P_336ACSR_2	COND	ABC	0.969	0.963	0.965	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F2	43F2-S011	HH_3P_336ACSR_2	COND	ABC	0.971	0.967	0.967	0	0	41.8	0	0	5.7	0	0	265.4	0	0	120.5	0	0	20.2
43F2	43F2-S017	HH_1P_3/0ACSR_#	COND	C			0.967			23.2			5.5			147.4			66.9	0	0	161.9
43F2	43F2-S012	HH_3P_336ACSR_2	COND	ABC	0.971	0.967	0.967	0	0	15.7	0	0	2.1	0	0	99.5	0	0	45.1	0	0	0
43F2	43F2-S020	HH_1P_3/0ACSR_#	COND	C			0.967			15.7			3.7			99.5			45.1	0	0	109.3
43F2	43F2-S009	HH_3P_336ACSR_2	COND	ABC	0.972	0.97	0.969	0	0	22.1	0	0	3	0	0	140.6	0	0	63.8	0	0	154.4
43F2	43F2-S007	HH_3P_3/0ACSR_#	COND	ABC	0.974	0.974	0.972	47.8	14.4	14.4	11.4	3.4	3.4	305.2	92.1	92.1	138.5	41.8	41.8	335.1	101.2	101.2
43F2	43F2-S005	HH_3P_3/0ACSR_#	COND	ABC	0.976	0.977	0.975	110.5	113	109.4	26.4	27	26.1	709.1	725	701.1	322.3	329.6	318.7	778	795.5	769.2
43F2	43F1-2TIE	HH_3P_336ACSR_2	COND	ABC	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43F2	43F1-2TIE	HH_800	Switch	ABC	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1	HH-WEST-SUB	SUB	ABC	1	1	1	293.6	245.6	237.6	87.7	68.9	79.8	1897	1591	1541	936.7	776.3	745.7	0	0	0
55F1	55F1-S001	HH_800	Switch	ABC	1	1	1	293.6	245.6	237.6	29.4	24.6	23.8	1897	1591	1541	936.7	776.3	745.7	0	0	0
55F1	55F1-S001	HH_3P_336ACSR_2	COND	ABC	1	1	1	293.6	245.6	237.6	40.1	33.5	32.4	1897	1591	1541	936.7	776.3	745.7	0	0	0
55F1	55F1-S002	HH_3P_336ACSR_2	COND	ABC	0.994	0.996	0.996	293.6	245.6	237.6	40.1	33.5	32.4	1897	1591	1541	936.4	776.1	745.6	0	12	0
55F1	55F1-S003	HH_3P_336ACSR_2	COND	ABC	0.987	0.992	0.991	293.6	244	237.6	40.1	33.3	32.4	1891	1577	1537	920.9	761.7	737.7	45.1	22.6	22.6
55F1	55F1-S066	HH_800	Switch	ABC	0.987	0.992	0.991	40.7	41.4	40.1	4.1	4.1	4	262.8	268.7	259.8	121.5	124.2	120.1	0	0	0
55F1	55F1-S066	HH_3P_336ACSR_2	COND	ABC	0.986	0.991	0.989	40.7	41.4	40.1	5.6	5.6	5.5	262.8	268.7	259.8	121.5	124.2	120.1	289.2	295.7	285.9
55F1	55F1-S004	HH_3P_336ACSR_2	COND	ABC	0.985	0.991	0.989	246.6	199.4	194.4	33.6	27.2	26.5	1580	1286	1251	763	617.3	599.2	52.6	0	0
55F1	55F1-S006	HH_3P_336ACSR_2	COND	ABC	0.984	0.99	0.988	239.2	199.4	194.4	32.6	27.2	26.5	1530	1285	1250	736	614.5	596.8	0	0	0
55F1	55F1-S015	HH_3P_336ACSR_2	COND	ABC	0.983	0.99	0.987	223.7	199.4	194.4	30.5	27.2	26.5	1430	1285	1249	687.7	613	595.6	0	0	0
55F1	55F1-S021	HH_3P_336ACSR_2	COND	ABC	0.98	0.988	0.985	223.7	190.5	194.4	30.5	26	26.5	1429	1226	1248	685.5	584.7	594.3	33.1	0	0
55F1	55F1-S119	HH_3P_3/0ACSR_#	COND	ABC	0.98	0.988	0.985	7.4	6.2	7.2	1.8	1.5	1.7	47.2	40.3	46.2	21.8	18.6	21.3	52	44.4	50.9
55F1	55F1-S023	HH_3P_336ACSR_2	COND	ABC	0.977	0.986	0.982	211.7	179.5	187.2	28.9	24.5	25.5	1349	1154	1201	644.7	548.5	569.6	0	0	0
55F1	55F1-S024	HH_3P_336ACSR_2	COND	ABC	0.975	0.984	0.98	211.7	179.5	187.2	28.9	24.5	25.5	1347	1152	1198	637.7	544.2	564.9	0	0	0
55F1	55F1-S025	HH_3P_336ACSR_2	COND	ABC	0.974	0.983	0.979	211.7	179.5	187.2	28.9	24.5	25.5	1345	1152	1197	633.6	541.7	562.2	0	0	0
55F1	55F1-S026	HH_3P_336ACSR_2	COND	ABC	0.971	0.981	0.976	211.7	179.5	187.2	28.9	24.5	25.5	1345	1151	1196	631.4	540.3	560.7	0	0	0
55F1	55F1-S027	HH_3P_336ACSR_2	COND	ABC	0.97	0.981	0.976	211.7	179.5	187.2	28.9	24.5	25.5	1342	1150	1194	625.2	536.5	556.6	0	0	0
55F1	55F1-S028	HH_3P_336ACSR_2	COND	ABC	0.969	0.98	0.975	211.7	179.5	187.2	28.9	24.5	25.5	1342	1150	1193	624.2	535.9	556	107.2	32.5	10.8
55F1	55F1-S029	HH_3P_336ACSR_2	COND	ABC	0.969	0.98	0.975	196.4	174.9	185.7	26.8	23.9	25.3	1244	1120	1183	577.8	521.3	550.4	0	0	0
55F1	55F1-S030	HH_3P_336ACSR_2	COND	ABC	0.968	0.979	0.974	196.4	174.9	185.7	26.8	23.9	25.3	1243	1120	1183	576.6	520.5	549.4	0	0	0
55F1	55F1-S061	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.973	8.6	11.7	31.1	2.1	2.8	7.4	54.6	75.2	198.1	25	34.5	91.3	22.6	22.6	90.3
55F1	55F1-S065	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.973	0	3.2	12.9	0	0.8	3.1	0	20.5	82	-0.1	9.4	37.7	0	22.6	90.3
55F1	55F1-S065	HH_600	Switch	ABC	0.968	0.979	0.973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-S062	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.973	5.4	5.3	5.4	1.3	1.3	1.3	34.1	34.1	34.1	15.7	15.7	15.7	0	0	0
55F1	55F1-S064	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.973	5.4	5.3	5.4	1.3	1.3	1.3	34.1	34.1	34.1	15.7	15.7	15.7	37.6	37.6	37.6
55F1	55F1-S063	HH_200	Switch	ABC	0.968	0.979	0.973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-S063	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-S037	HH_3P_336ACSR_2	COND	ABC	0.966	0.978	0.972	187.8	163.2	154.6	25.6	22.3	21.1	1188	1044	983.9	550.4	485.2	457.1	300.9	22.6	22.6
55F1	55F1-S049	HH_3P_336ACSR_2	COND	ABC	0.966	0.978	0.972	30.3	36.3	21.5	4.1	5	2.9	191.4	232.3	136.6	88.1	107.2	62.9	0	0	0
55F1	55F1-S051	HH_3P_336ACSR_2	COND	ABC	0.966	0.977	0.972	25.9	36.3	21.5	3.5	5	2.9	164	232.3	136.6	75.5	107.2	62.9	0	0	0
55F1	55F1-S053	HH_3P_3/0ACSR_#	COND	ABC	0.966	0.977	0.972	4.3	15	4.3	1	3.6	1	27.3	95.6	27.3	12.6	44.1	12.6	30.1	105.3	30.1
55F1	55F1-S052	HH_3P_336ACSR_2	COND	ABC	0.966	0.977	0.972	21.6	21.4	17.2	2.9	2.9	2.3	136.6	136.6	109.3	62.9	62.9	50.3	0	30.1	0
55F1	55F1-S054	HH_3P_336ACSR_2	COND	ABC	0.966	0.977	0.972	21.6	17.1	17.2	2.9	2.3	2.3	136.6	109.3	109.3	62.9	50.3	50.3	0	0	0
55F1	55F1-S055	HH_3P_336ACSR_2	COND	ABC	0.965	0.977	0.972	21.6	17.1	17.2	2.9	2.3	2.3	136.6	109.3	109.3	62.9	50.3	50.3	0	0	0

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
55F1	55F1-S056	HH_3P_336ACSR_2	COND	ABC	0.965	0.977	0.972	21.6	17.1	17.2	2.9	2.3	2.3	136.6	109.3	109.3	62.9	50.3	50.3	45.1	45.1	45.1
55F1	55F1-S057	HH_3P_336ACSR_2	COND	ABC	0.965	0.977	0.972	15.1	10.7	10.7	2.1	1.5	1.5	95.6	68.3	68.3	44	31.4	31.4	52.6	0	0
55F1	55F1-S060	HH_3P_336ACSR_2	COND	ABC	0.965	0.977	0.972	0	10.7	10.7	0	1.5	1.5	0	68.3	68.3	-0.1	31.5	31.5	0	75.2	75.2
55F1	55F1-S058	HH_1P_3/0ACSR_#	COND	A	0.965			7.6			1.8			47.8			22			22.6	0	0
55F1	55F1-S059	HH_1P_3/0ACSR_#	COND	A	0.965			4.3			1			27.3			12.6			30.1	0	0
55F1	55F1-S050	HH_1P_3/0ACSR_#	COND	A	0.966			4.3			1			27.3			12.6			30.1	0	0
55F1	55F1-S038	HH_3P_336ACSR_2	COND	ABC	0.966	0.977	0.972	114.3	123.7	129.9	15.6	16.9	17.7	722.8	790.5	825.9	333.7	366.2	382.9	0	0	0
55F1	55F1-S040	HH_3P_336ACSR_2	COND	ABC	0.966	0.977	0.972	109.5	115.8	121	14.9	15.8	16.5	692.2	740.2	768.7	319.3	342.7	356.1	0	0	0
55F1	55F1-S043	HH_3P_336ACSR_2	COND	ABC	0.965	0.976	0.97	98.7	112.2	119.9	13.5	15.3	16.4	623.7	716.6	761.6	287.5	331.6	352.5	0	0	0
55F1	55F1-S087	HH_3P_336ACSR_2	COND	ABC	0.964	0.975	0.969	76	67.2	79	10.4	9.2	10.8	479.9	428.8	501.7	221	197.7	231.5	0	0	0
55F1	55F1-S100	HH_3P_3/0ACSR_#	COND	ABC	0.964	0.975	0.969	21	21.6	37	5	5.2	8.8	132.6	138.1	234.6	61	63.6	108.1	0	0	0
55F1	55F1-S104	HH_200	Switch	C			0.969			17.4			7			110.2			50.8	0	0	0
55F1	55F1-S104	HH_1P_3/0ACSR_#	COND	C			0.969			17.4			4.1			110.2			50.8	0	0	91.2
55F1	55F1-S103	HH_1P_3/0ACSR_#	COND	C			0.969			4.3			1			27.3			12.6	0	0	30.1
55F1	55F1-S103	HH_200	Switch	C			0.969			0			0			0			0	0	0	0
55F1	55F1-S101	HH_3P_3/0ACSR_#	COND	ABC	0.964	0.975	0.969	21	21.6	19.6	5	5.2	4.7	132.6	138	124.4	61	63.6	57.2	0	0	0
55F1	55F1-S105	HH_3P_3/0ACSR_#	COND	ABC	0.963	0.974	0.968	21	21.6	19.6	5	5.2	4.7	132.6	138	124.4	61	63.6	57.2	0	0	0
55F1	55F1-S106	HH_3P_#2ACSR_#4	COND	ABC	0.963	0.974	0.968	21	21.6	19.6	9.2	9.5	8.6	132.5	138	124.3	61	63.5	57.2	0	0	0
55F1	55F1-S108	HH_3P_#2ACSR_#4	COND	ABC	0.963	0.974	0.968	10.5	10.8	9.8	4.6	4.7	4.3	66.3	69	62.2	30.6	31.8	28.7	73	76	68.4
55F1	55F1-S107	HH_3P_#2ACSR_#4	COND	ABC	0.963	0.974	0.968	10.5	10.8	9.8	4.6	4.7	4.3	66.3	69	62.2	30.5	31.7	28.6	0	0	0
55F1	55F1-S109	15KV_#2CU_XLPE	CAB	ABC	0.963	0.974	0.968	10.5	10.8	9.8	6.6	6.8	6.1	66.2	69	62.2	30.5	31.7	28.6	73	76	68.4
55F1	55F1-S088	HH_3P_336ACSR_2	COND	ABC	0.963	0.974	0.969	55	45.5	42	7.5	6.2	5.7	347.1	290.5	266.7	159.2	133.7	122.6	0	0	0
55F1	55F1-S102	HH_3P_336ACSR_2	COND	ABC	0.963	0.974	0.969	4.8	1.5	2	0.7	0.2	0.3	30.5	9.8	12.8	14	4.5	5.8	0	0	0
55F1	55F1-S110	HH_3P_336ACSR_2	COND	ABC	0.963	0.974	0.969	4.8	1.5	2	0.7	0.2	0.3	30.5	9.8	12.8	14	4.5	5.8	0	0	0
55F1	55F1-S111	HH_3P_3/0ACSR_#	COND	ABC	0.963	0.974	0.969	4.8	1.5	2	1.2	0.4	0.5	30.5	9.8	12.8	14.1	4.5	5.9	33.6	10.8	14.1
55F1	55F1-S112	HH_3P_336ACSR_2	COND	ABC	0.963	0.974	0.969	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-S112	HH_600	Switch	ABC	0.963	0.974	0.969	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-S089	HH_3P_3/0ACSR_#	COND	ABC	0.963	0.974	0.969	50.2	44	40	12	10.5	9.6	316.5	280.6	253.9	145	129.1	116.7	7.5	0	0
55F1	55F1-S092	HH_3P_3/0ACSR_#	COND	ABC	0.963	0.974	0.968	30.6	44	30.3	7.3	10.5	7.2	192.9	280.6	191.9	88.6	129.1	88.1	0	18.7	0
55F1	55F1-S099	15KV_#2CU_XLPE	CAB	ABC	0.962	0.973	0.968	30.6	30.7	30.3	19.1	19.2	18.9	192.8	195.8	191.9	88.6	89.9	88.1	212.3	215.5	211.2
55F1	55F1-S093	HH_3P_3/0ACSR_#	COND	ABC	0.963	0.974	0.969	0	10.6	0	0	2.5	0	0	67.8	0	0	31.2	0	0	0	0
55F1	55F1-S097	HH_1P_#2ACSR_#4	COND	B		0.974			5.3			2.3			33.9			15.6		0	18.7	0
55F1	55F1-S098	HH_1P_#2ACSR_#4	COND	B		0.973			2.7			1.2			16.9			7.8		0	18.7	0
55F1	55F1-S094	HH_1P_#2ACSR_#4	COND	B		0.974			5.3			2.3			33.9			15.6		0	18.7	0
55F1	55F1-S095	HH_1P_#2ACSR_#4	COND	B		0.973			2.7			1.2			16.9			7.8		0	0	0
55F1	55F1-S096	HH_1P_#2ACSR_#4	COND	B		0.973			2.7			1.2			16.9			7.8		0	18.7	0
55F1	55F1-S091	HH_3P_3/0ACSR_#	COND	ABC	0.963	0.974	0.969	18.5	0	0	4.4	0	0	116.7	0	0	53.2	-0.1	-0.1	60.8	0	0
55F1	55F1-S115	HH_3P_3/0ACSR_#	COND	ABC	0.963	0.974	0.969	0.1	0	0	0	0	0	0	0	0	-0.7	0	0	0	0	0
55F1	55F1-S115	HH_800	Switch	ABC	0.963	0.974	0.969	0.1	0	0	0	0	0	0	0	0	-0.6	0	0	0	0	0
55F1	55F1-S117	15KV_#2CU_XLPE	CAB	A	0.963			0.1			0.1			0			-0.6			0	0	0
55F1	55F1-S118	15KV_#2CU_XLPE	CAB	A	0.963			0.1			0			0			-0.5			0	0	0
55F1	55F1-S113	HH_3P_3/0ACSR_#	COND	ABC	0.963	0.974	0.969	9.8	0	0	2.3	0	0	61.5	0	0	28.3	0	0	33.8	0	0
55F1	55F1-S114	HH_3P_3/0ACSR_#	COND	ABC	0.963	0.974	0.969	4.9	0	0	1.2	0	0	30.7	0	0	14.2	0	0	33.8	0	0
55F1	55F1-S090	HH_1P_#2ACSR_#4	COND	C			0.968			9.8			4.3			62			28.6	0	0	68.2
55F1	55F1-S044	HH_3P_336ACSR_2	COND	ABC	0.965	0.976	0.97	22.7	45	40.9	3.1	6.1	5.6	143.5	287.3	259.5	65.9	132.9	119.7	0	0	0
55F1	55F1-S085	HH_3P_3/0ACSR_#	COND	ABC	0.965	0.975	0.97	4.5	4.5	16.4	1.1	1.1	3.9	28.7	28.7	103.8	13.2	13.2	47.9	31.6	31.6	114.3
55F1	55F1-S045	HH_3P_336ACSR_2	COND	ABC	0.965	0.975	0.97	18.2	40.5	24.5	2.5	5.5	3.3	114.8	258.6	155.7	52.7	119.7	71.8	0	0	0
55F1	55F1-S047	HH_3P_336ACSR_2	COND	ABC	0.965	0.975	0.97	13.6	40.5	24.5	1.9	5.5	3.3	86.1	258.6	155.7	39.5	119.6	71.8	10.5	0	171.5
55F1	55F1-S081	HH_1P_#2ACSR_#4	COND	A	0.965			6.1			2.7			38.3			17.6			0	0	0

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
55F1	55F1-S084	HH_200	Switch	A	0.965			3			1.2			19.1			8.8			0	0	0
55F1	55F1-S084	HH_1P_#2ACSR_#4	COND	A	0.964			3			1.3			19.1			8.8			10.5	0	0
55F1	55F1-S083	HH_1P_#2ACSR_#4	COND	A	0.964			1.5			0.7			9.6			4.4			0	0	0
55F1	55F1-S086	HH_1P_#2ACSR_#4	COND	A	0.964			1.5			0.7			9.6			4.4			10.5	0	0
55F1	55F1-S082	HH_1P_#2ACSR_#4	COND	A	0.964			3			1.3			19.1			8.8			21.1	0	0
55F1	55F1-S048	HH_3P_3/0ACSR_#	COND	ABC	0.964	0.974	0.971	6.1	40.5	0	1.4	9.7	0	38.3	258.5	0	17.5	119.5	0	0	0	0
55F1	55F1-S070	HH_1P_#2ACSR_#4	COND	B		0.974			40.5			17.8			258.4			119.3		0	31.6	0
55F1	55F1-S077	HH_200	Switch	B		0.974			9			3.6			57.4			26.4		0	0	0
55F1	55F1-S077	HH_1P_3/0ACSR_#	COND	B		0.974			9			2.1			57.4			26.4		0	0	0
55F1	55F1-S079	HH_1P_3/0ACSR_#	COND	B		0.974			4.5			1.1			28.7			13.2		0	0	0
55F1	55F1-S080	HH_1P_3/0ACSR_#	COND	B		0.973			4.5			1.1			28.7			13.2		0	31.6	0
55F1	55F1-S078	HH_1P_3/0ACSR_#	COND	B		0.974			4.5			1.1			28.7			13.2		0	31.6	0
55F1	55F1-S071	HH_1P_3/0ACSR_#	COND	B		0.973			27			6.5			172.2			79.5		0	31.6	0
55F1	55F1-S072	HH_1P_3/0ACSR_#	COND	B		0.973			22.5			5.4			143.5			66.2		0	31.6	0
55F1	55F1-S074	HH_1P_3/0ACSR_#	COND	B		0.973			18			4.3			114.8			52.9		0	31.6	0
55F1	55F1-S073	HH_3P_336ACSR_2	COND	B		0.972			13.5			1.8			86.1			39.6		0	31.6	0
55F1	55F1-S075	HH_200	Switch	B		0.972			9			3.6			57.4			26.4		0	0	0
55F1	55F1-S075	HH_3P_336ACSR_2	COND	B		0.972			9			1.2			57.4			26.4		0	31.6	0
55F1	55F1-S076	HH_1P_3/0ACSR_#	COND	B		0.972			4.5			1.1			28.7			13.2		0	31.6	0
55F1	55F1-S067	HH_1P_3/0ACSR_#	COND	A	0.964			6.1			1.4			38.3			17.5			10.5	0	0
55F1	55F1-S068	HH_1P_3/0ACSR_#	COND	A	0.964			4.5			1.1			28.7			13.1			10.5	0	0
55F1	55F1-S069	HH_1P_3/0ACSR_#	COND	A	0.964			3			0.7			19.1			8.7			0	0	0
55F1	55F1-S121	HH_1P_3/0ACSR_#	COND	A	0.964			0			0			0			0			0	0	0
55F1	55F1-S121	HH_600	Switch	A	0.964			0			0			0			0			0	0	0
55F1	55F1-S120	HH_1P_3/0ACSR_#	COND	A	0.964			3			0.7			19.1			8.8			21.1	0	0
55F1	55F1-S046	HH_1P_3/0ACSR_#	COND	A	0.965			4.5			1.1			28.7			13.2			31.6	0	0
55F1	55F1-S042	1/0_XLPE	CAB	ABC	0.965	0.977	0.972	10.8	3.6	1.1	5	1.7	0.5	68.3	23.2	6.8	31.4	10.6	3	75.2	25.6	7.5
55F1	55F1-S041	1/0_XLPE	CAB	ABC	0.966	0.977	0.972	0	0	0	0	0	0	0	0	0	-0.1	-0.1	-0.1	0	0	0
55F1	55F1-S039	HH_200	Switch	ABC	0.966	0.977	0.972	4.8	7.8	9	1.9	3.1	3.6	30.5	50.2	57	14	23.1	26.3	0	0	0
55F1	55F1-S039	HH_3P_1/0ACSR_#	COND	ABC	0.966	0.977	0.972	4.8	7.8	9	1.5	2.4	2.8	30.5	50.2	57	14	23.1	26.3	33.6	55.2	62.8
55F1	55F1-S031	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.974	0	0	0	0	0	0	0	0	0	-0.1	-0.1	-0.1	0	0	0
55F1	55F1-S033	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.974	0	0	0	0	0	0	0	0	0	-0.1	-0.1	-0.1	0	0	0
55F1	55F1-S035	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.974	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-S034	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.974	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-S036	HH_1P_3/0ACSR_#	COND	B		0.979			0			0			0			0		0	0	0
55F1	55F1-S032	HH_200	Switch	ABC	0.968	0.979	0.974	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-S032	HH_3P_3/0ACSR_#	COND	ABC	0.968	0.979	0.974	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-S022	HH_200	Switch	B		0.988			4.8			1.9			30.9			14.2		0	0	0
55F1	55F1-S022	HH_1P_3/0ACSR_#	COND	B		0.988			4.8			1.1			30.9			14.2		0	34	0
55F1	55F1-S016	HH_200	Switch	B		0.99			9			3.6			58.2			26.8		0	0	0
55F1	55F1-S016	HH_1P_3/0ACSR_#	COND	B		0.99			9			2.1			58.2			26.8		0	0	0
55F1	55F1-S018	HH_1P_3/0ACSR_#	COND	B		0.99			4.8			1.1			30.9			14.2		0	0	0
55F1	55F1-S019	HH_1P_3/0ACSR_#	COND	B		0.989			4.8			1.1			30.9			14.2		0	34	0
55F1	55F1-S020	HH_1P_3/0ACSR_#	COND	B		0.989			0			0			0			0		0	0	0
55F1	55F1-S020	HH_600	Switch	B		0.989			0			0			0			0		0	0	0
55F1	55F1-S017	HH_1P_3/0ACSR_#	COND	B		0.99			4.2			1			27.3			12.6		0	30.1	0
55F1	55F1-S007	HH_200	Switch	A	0.984			15.5			6.2			99.7			45.9			0	0	0
55F1	55F1-S007	HH_1P_3/0ACSR_#	COND	A	0.984			15.5			3.7			99.7			45.9			0	0	0
55F1	55F1-S009	HH_1P_3/0ACSR_#	COND	A	0.984			15.5			3.7			99.7			45.9			0	0	0

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
55F1	55F1-S010	HH_1P_3/0ACSR_#	COND	A	0.984			15.5			3.7			99.7			45.9			42.1	0	0
55F1	55F1-S011	HH_1P_3/0ACSR_#	COND	A	0.984			9.5			2.3			61.5			28.3			0	0	0
55F1	55F1-S012	HH_1P_3/0ACSR_#	COND	A	0.984			9.5			2.3			61.5			28.3			0	0	0
55F1	55F1-S014	HH_1P_3/0ACSR_#	COND	A	0.983			8.5			2			54.6			25.2			60.2	0	0
55F1	55F1-S013	#2_XLPE	CAB	A	0.984			1.1			0.7			6.8			3.1			7.5	0	0
55F1	55F1-3TIE	HH_3P_336ACSR_2	COND	ABC	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F1	55F1-3TIE	HH_800	Switch	ABC	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F2	55F2	HH-WEST-SUB	SUB	ABC	1	1	1	213.7	152.9	223.6	87.7	68.9	79.8	1380	996.4	1446	683.1	470.3	711.5	0	0	0
55F2	55F2-S001	HH_800	Switch	ABC	1	1	1	213.7	152.9	223.6	21.4	15.3	22.4	1380	996.4	1446	683.1	470.3	711.5	0	0	0
55F2	55F2-S001	HH_3P_336ACSR_2	COND	ABC	1	1	1	213.7	152.9	223.6	29.2	20.9	30.5	1380	996.4	1446	683.1	470.3	711.5	0	0	0
55F2	55F2-S002	HH_3P_336ACSR_2	COND	ABC	0.997	0.998	0.995	213.7	152.9	223.6	29.2	20.9	30.5	1380	996.3	1446	683	470.3	711.4	0	17	0
55F2	55F2-S003	HH_3P_336ACSR_2	COND	ABC	0.993	0.996	0.989	213.7	150.6	223.6	29.2	20.5	30.5	1378	979.7	1441	674.9	460.7	703.1	114.1	125	159.3
55F2	55F2-S005	HH_3P_336ACSR_2	COND	ABC	0.993	0.996	0.989	197.8	133.1	201.3	27	18.2	27.5	1273	865.3	1291	617.2	405.1	626.3	0	0	0
55F2	55F2-S008	HH_1P_3/0ACSR_#	COND	B		0.996			0			0			0			0		0	0	0
55F2	55F2-S006	HH_3P_336ACSR_2	COND	ABC	0.992	0.995	0.988	197.8	133.1	201.3	27	18.2	27.5	1273	865.2	1291	616.4	404.9	625.5	0	0	0
55F2	55F2-S009	HH_3P_336ACSR_2	COND	ABC	0.991	0.995	0.987	195.4	130.8	198.9	26.7	17.8	27.1	1257	849.6	1274	607.3	397.2	616.6	0	0	0
55F2	55F2-S011	HH_3P_336ACSR_2	COND	ABC	0.99	0.995	0.985	195.4	115.4	195	26.7	15.7	26.6	1257	749.5	1248	605.6	350	603	0	0	0
55F2	55F2-S013	HH_3P_336ACSR_2	COND	ABC	0.989	0.994	0.984	195.4	108.2	192.7	26.7	14.8	26.3	1257	702.8	1233	603.9	327.9	594.7	0	0	0
55F2	55F2-S019	HH_1P_3/0ACSR_#	COND	B		0.994			11.5			2.7			74.4			34.9		0	82.1	0
55F2	55F2-S014	HH_3P_336ACSR_2	COND	ABC	0.989	0.994	0.983	195.4	96.7	192.7	26.7	13.2	26.3	1256	628.3	1231	601.8	292.9	593	0	0	0
55F2	55F2-S020	HH_3P_3/0ACSR_#	COND	ABC	0.989	0.994	0.983	5.6	1.2	9.7	1.3	0.3	2.3	36.1	7.7	62.3	16.9	3.6	29.2	39.8	8.5	68.8
55F2	55F2-S015	HH_3P_336ACSR_2	COND	ABC	0.987	0.994	0.981	189.8	95.6	183	25.9	13	25	1220	620.6	1168	583.5	289.2	562.6	34	8.5	17
55F2	55F2-S016	HH_600	Switch	ABC	0.987	0.994	0.981	185	94.4	180.6	24.7	12.6	24.1	1189	612.8	1151	565.3	285.3	552.5	0	0	0
55F2	55F2-S016	HH_3P_336ACSR_2	COND	ABC	0.987	0.994	0.979	185	94.4	180.6	25.2	12.9	24.6	1189	612.8	1151	565.3	285.3	552.5	27.1	0	0
55F2	55F2-S021	HH_3P_336ACSR_2	COND	ABC	0.985	0.993	0.977	175.2	88.9	172.3	23.9	12.1	23.5	1125	577.2	1096	533.8	268.6	525.9	127.7	0	0
55F2	55F2-S022	HH_3P_336ACSR_2	COND	ABC	0.984	0.993	0.975	157.2	88.9	172.3	21.5	12.1	23.5	1009	577	1094	476.3	268.4	522.9	34	17	17
55F2	55F2-S034	HH_3P_336ACSR_2	COND	ABC	0.984	0.993	0.974	141.6	71.1	166.2	19.3	9.7	22.7	909.1	461.2	1054	427.1	214	502.3	8.5	8.5	8.5
55F2	55F2-S035	HH_3P_3/0ACSR_#	COND	ABC	0.984	0.993	0.974	9.6	9.5	9.7	2.3	2.3	2.3	61.7	61.7	61.7	28.9	28.9	28.9	68.1	68.1	68.1
55F2	55F2-S023	HH_3P_336ACSR_2	COND	ABC	0.983	0.993	0.973	130.8	60.4	155.3	17.8	8.2	21.2	839.7	391.8	984.1	393.6	181.4	468.6	0	0	0
55F2	55F2-S036	HH_3P_3/0ACSR_#	COND	ABC	0.983	0.993	0.973	2.4	2.4	6.8	0.6	0.6	1.6	15.4	15.4	43.1	7.2	7.2	20.2	17	17	47.6
55F2	55F2-S024	HH_3P_336ACSR_2	COND	ABC	0.983	0.993	0.972	128.4	58	148.5	17.5	7.9	20.3	824.3	376.3	940.4	385.7	174.3	447.4	0	0	51.1
55F2	55F2-S038	HH_3P_3/0ACSR_#	COND	ABC	0.983	0.993	0.972	35.6	0	0	8.5	0	0	228.1	0	0	107	0	0	252	0	0
55F2	55F2-S025	HH_3P_336ACSR_2	COND	ABC	0.983	0.993	0.971	92.9	58	141.2	12.7	7.9	19.3	596.2	376.3	893.4	277.8	174.3	424.6	0	0	0
55F2	55F2-S027	HH_200	Switch	A	0.983			16.9			6.8			109.2			48.9			0	0	0
55F2	55F2-S027	15KV_1/0CU_XLPE	CAB	A	0.983			16.9			7.8			109.2			48.9			0	0	0
55F2	55F2-S029	15KV_1/0CU_XLPE	CAB	A	0.982			16.9			7.8			109.2			49.3			0	0	0
55F2	55F2-S031	15KV_1/0CU_XLPE	CAB	A	0.982			17			7.8			109.1			50.4			0	0	0
55F2	55F2-S032	15KV_1/0CU_XLPE	CAB	A	0.982			17			7.8			109.1			50.8			120.5	0	0
55F2	55F2-S030	15KV_1/0CU_XLPE	CAB	A	0.982			0			0			0			-0.3			0	0	0
55F2	55F2-S030	HH_200	Switch	A	0.982			0			0			0			0			0	0	0
55F2	55F2-S028	15KV_1/0CU_XLPE	CAB	A	0.983			0			0			0			-0.3			0	0	0
55F2	55F2-S026	HH_3P_336ACSR_2	COND	ABC	0.983	0.992	0.971	76	58	141.2	10.4	7.9	19.3	487	376.2	892.9	228.6	174.3	423.7	0	0	0
55F2	55F2-S039	HH_3P_336ACSR_2	COND	ABC	0.983	0.992	0.97	76.1	58.1	137.3	10.4	7.9	18.7	487.1	376.1	867.1	229.7	175.6	412.2	0	0	0
55F2	55F2-S040	HH_3P_336ACSR_2	COND	ABC	0.983	0.991	0.968	76.1	58.1	137.3	10.4	7.9	18.7	487.1	376	866.7	229.6	175.6	411.3	25.5	51.1	51.1
55F2	55F2-S041	HH_3P_336ACSR_2	COND	ABC	0.982	0.991	0.966	72.4	50.9	130	9.9	6.9	17.7	464.2	329.6	819.5	218.3	153.9	387.5	27.2	5.1	143
55F2	55F2-S048	#2_XLPE	CAB	A	0.982			2.4			1.5			15.4			7.1			17	0	0
55F2	55F2-S042	HH_600	Switch	ABC	0.982	0.991	0.966	66.2	50.2	109.4	8.8	6.7	14.6	424.3	324.7	688.9	199	151.7	324.4	0	0	0
55F2	55F2-S042	HH_3P_336ACSR_2	COND	ABC	0.982	0.99	0.965	66.2	50.2	109.4	9	6.8	14.9	424.3	324.7	688.9	199	151.7	324.4	8.5	8.5	8.5
55F2	55F2-S049	HH_3P_3/0ACSR_#	COND	ABC	0.982	0.99	0.965	1.7	1.2	1.2	0.4	0.3	0.3	10.8	7.7	7.7	5	3.6	3.6	11.9	8.5	8.5

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
55F2	55F2-S043	HH_3P_336ACSR_2	COND	ABC	0.982	0.99	0.964	63.3	47.8	107	8.6	6.5	14.6	405.8	309.2	673.2	190.2	144.5	316.5	34	25.5	25.5
55F2	55F2-S050	HH_1P_#2ACSR_#4	COND	C			0.964			20.1			8.8			126.4			59.3	0	0	69.8
55F2	55F2-S051	HH_1P_#2ACSR_#4	COND	C			0.963			10.1			4.4			63.2			29.6	0	0	69.8
55F2	55F2-S044	HH_3P_336ACSR_2	COND	ABC	0.982	0.99	0.963	58.5	44.2	83.2	8	6	11.4	375	286	523.3	175.6	133.7	245.6	17	0	25.5
55F2	55F2-S052	15KV_1/0CU_XLPE	CAB	ABC	0.982	0.99	0.963	16.8	16.7	17.2	7.8	7.7	7.9	107.9	107.9	107.9	50.4	50.4	50.4	119.2	119.2	119.2
55F2	55F2-S045	HH_3P_336ACSR_2	COND	ABC	0.982	0.99	0.963	39.3	27.5	62.4	5.4	3.8	8.5	251.7	178	392.1	117.8	83.2	184	0	0	0
55F2	55F2-S053	#2_XLPE	CAB	A	0.982			0			0			0			-0.2			0	0	0
55F2	55F2-S046	HH_3P_336ACSR_2	COND	ABC	0.982	0.99	0.963	39.3	27.5	62.4	5.4	3.8	8.5	251.7	178	392.1	117.9	83.2	183.9	56.2	0	187.3
55F2	55F2-S054	HH_3P_336ACSR_2	COND	ABC	0.982	0.99	0.962	3.6	3.9	12.4	0.5	0.5	1.7	23.3	25.5	77.7	10.8	11.9	36.4	25.7	28.2	85.8
55F2	55F2-S054	DEFAULT	Switch	ABC	0.982	0.99	0.962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F2	55F2-S047	HH_3P_336ACSR_2	COND	ABC	0.981	0.989	0.962	27.7	23.6	23	3.8	3.2	3.1	177.5	152.4	144.7	83.2	71.4	67.7	52.8	25.5	34
55F2	55F2-S055	HH_3P_336ACSR_2	COND	ABC	0.981	0.989	0.962	20.3	20	18.1	2.8	2.7	2.5	129.7	129.3	113.9	60.7	60.5	53.3	52.8	25.5	34
55F2	55F2-S056	HH_3P_336ACSR_2	COND	ABC	0.981	0.989	0.962	9.2	9.3	9.5	1.3	1.3	1.3	58.8	59.9	59.9	27.5	28	28	65	66.2	66.2
55F2	55F2-S057	HH_3P_3/0ACSR_#	COND	ABC	0.981	0.989	0.962	3.6	7.2	3.7	0.9	1.7	0.9	23.1	46.2	23.1	10.8	21.7	10.8	25.5	51.1	25.5
55F2	55F2-S057	HH_600	Switch	ABC	0.981	0.989	0.962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F2	55F2-S037	HH_200	Switch	ABC	0.983	0.992	0.971	0.2	0.2	4	0.1	0.1	1.6	0	0	25.5	-1.3	-1.3	10.7	0	0	0
55F2	55F2-S037	15KV_2/0CU_XLPE	CAB	ABC	0.983	0.992	0.97	0.2	0.2	4	0.1	0.1	1.4	0	0	25.5	-1.3	-1.3	10.7	0	0	28.2
55F2	55F2-S033	HH_3P_3/0ACSR_#	COND	ABC	0.984	0.993	0.975	10.8	15.5	3.6	2.6	3.7	0.9	69.4	100.2	23.1	32.5	47	10.8	76.6	110.7	25.5
55F2	55F2-S017	HH_3P_3/0ACSR_#	COND	ABC	0.987	0.994	0.979	6	5.5	8.3	1.4	1.3	2	38.5	35.5	53.3	18	16.6	24.9	42.6	39.2	58.8
55F2	55F2-S012	HH_3P_3/0ACSR_#	COND	ABC	0.99	0.995	0.985	0	7.2	2.2	0	1.7	0.5	0	46.6	14.4	0	21.8	6.7	0	51.5	15.9
55F2	55F2-S012	HH_600	Switch	ABC	0.99	0.995	0.985	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F2	55F2-S010	HH_3P_3/0ACSR_#	COND	ABC	0.991	0.995	0.987	0	15.4	4	0	3.7	0.9	0	99.9	25.5	-0.1	46.8	11.9	0	110.3	28.2
55F2	55F2-S007	HH_3P_3/0ACSR_#	COND	ABC	0.992	0.995	0.988	2.4	2.4	2.4	0.6	0.6	0.6	15.4	15.4	15.4	7.2	7.2	7.2	17	17	17
55F2	55F1-2TIE	HH_3P_336ACSR_2	COND	ABC	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F2	55F1-2TIE	HH_800	Switch	ABC	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F3	55F3	HH-WEST-SUB-2	SUB	ABC	1	1	1	322	420.8	410.8	55.7	72.8	71	2091	2733	2638	1005	1313	1342	0	0	0
55F3	55F3-S001	HH_800	Switch	ABC	1	1	1	322	420.8	410.8	32.2	42.1	41.1	2091	2733	2638	1005	1313	1342	0	0	0
55F3	55F3-S001	HH_3P_336ACSR_2	COND	ABC	1	1	1	322	420.8	410.8	43.9	57.4	56	2091	2733	2638	1005	1313	1342	0	0	0
55F3	55F3-S002	HH_3P_336ACSR_2	COND	ABC	0.995	0.991	0.993	322	420.8	410.8	43.9	57.4	56	2091	2733	2638	1005	1313	1341	0	41	0
55F3	55F3-S003	HH_3P_336ACSR_2	COND	ABC	0.991	0.983	0.987	322	415.1	410.8	43.9	56.6	56	2085	2679	2630	990.3	1265	1310	0	0	0
55F3	55F3-S030	HH_3P_336ACSR_2	COND	ABC	0.99	0.983	0.986	322	358.9	402.6	43.9	49	54.9	2080	2301	2570	979	1083	1261	0	0	0
55F3	55F3-S037	1/0_XLPE	CAB	C			0.986			3.9			1.8			25.2			11	0	0	27.6
55F3	55F3-S031	HH_3P_336ACSR_2	COND	ABC	0.989	0.981	0.984	322	358.9	398.7	43.9	49	54.4	2080	2299	2544	977.5	1081	1247	0	0	0
55F3	55F3-S032	HH_3P_336ACSR_2	COND	ABC	0.989	0.98	0.984	320.4	358.9	398.7	43.7	49	54.4	2068	2297	2541	969.5	1077	1240	0	0	0
55F3	55F3-S038	1/0_XLPE	CAB	C			0.984			3.9			1.8			25.2			11	0	0	27.6
55F3	55F3-S033	HH_3P_336ACSR_2	COND	ABC	0.988	0.979	0.983	320.4	358.9	394.9	43.7	49	53.9	2067	2296	2515	968.3	1075	1227	0	0	0
55F3	55F3-S039	1/0_XLPE	CAB	ABC	0.988	0.979	0.983	2.4	2.4	2.4	1.1	1.1	1.1	15.8	15.8	15.8	6.9	6.9	6.9	17.3	17.3	17.3
55F3	55F3-S034	HH_3P_336ACSR_2	COND	ABC	0.987	0.977	0.981	315.1	356.5	392.4	43	48.6	53.5	2032	2279	2498	950.8	1065	1216	0	0	0
55F3	55F3-S035	HH_3P_336ACSR_2	COND	ABC	0.986	0.976	0.979	313.4	356.5	392.4	42.8	48.6	53.5	2020	2276	2496	942.2	1060	1208	0	0	0
55F3	55F3-S040	1/0_XLPE	CAB	ABC	0.986	0.976	0.979	0	0	2	0	0	0.9	0	0	12.6	-0.1	-0.1	5.6	0	0	13.8
55F3	55F3-S036	HH_3P_336ACSR_2	COND	ABC	0.986	0.976	0.979	311.7	356.5	390.5	42.5	48.6	53.3	2008	2274	2481	935.3	1056	1198	0	0	0
55F3	55F3-S045	HH_3P_336ACSR_2	COND	ABC	0.984	0.973	0.976	311.7	356.5	390.5	42.5	48.6	53.3	2007	2273	2481	934.1	1055	1196	0	0	0
55F3	55F3-S090	HH_3P_3/0ACSR_#	COND	ABC	0.984	0.973	0.976	0	8.5	0	0	2	0	0	54.5	0	0	24.3	0	0	59.7	0
55F3	55F3-S081	HH_600	Switch	ABC	0.984	0.973	0.976	22.1	13.2	15	2.9	1.8	2	143.1	84.4	96.5	63.9	37.6	43.1	0	0	0
55F3	55F3-S081	HH_3P_3/0ACSR_#	COND	ABC	0.984	0.973	0.976	22.1	13.2	15	5.3	3.1	3.6	143.1	84.4	96.5	63.9	37.6	43.1	26.5	0	23.6
55F3	55F3-S083	HH_200	Switch	A	0.984			6.1			2.4			39.4			17.6			0	0	0
55F3	55F3-S083	HH_1P_3/0ACSR_#	COND	A	0.984			6.1			1.5			39.4			17.6			17.3	0	0
55F3	55F3-S084	HH_1P_3/0ACSR_#	COND	A	0.984			3.7			0.9			23.6			10.6			25.9	0	0
55F3	55F3-S082	HH_3P_3/0ACSR_#	COND	ABC	0.983	0.972	0.975	12.3	13.2	11.7	2.9	3.1	2.8	79.5	84.4	74.9	35.5	37.7	33.4	87	92.4	82.1

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
55F3	55F3-S046	HH_3P_336ACSR_2	COND	ABC	0.982	0.97	0.973	289.6	334.8	375.4	39.5	45.7	51.2	1863	2130	2380	864.4	984.5	1141	0	0	0
55F3	55F3-S085	HH_3P_3/0ACSR_#	COND	ABC	0.982	0.969	0.972	0	8.7	9.8	0	2.1	2.3	0	55.7	62.5	0	24.8	27.8	0	17.3	0
55F3	55F3-S089	HH_1P_3/0ACSR_#	COND	B		0.969			6.2			1.5			39.9			17.8		0	43.7	0
55F3	55F3-S086	HH_1P_3/0ACSR_#	COND	C			0.972			9.8			2.3			62.4			27.9	0	0	0
55F3	55F3-S087	HH_1P_3/0ACSR_#	COND	C			0.972			9.8			2.3			62.4			27.9	0	0	51.8
55F3	55F3-S088	HH_1P_3/0ACSR_#	COND	C			0.972			2.4			0.6			15.1			6.7	0	0	16.6
55F3	55F3-S047	HH_3P_336ACSR_2	COND	ABC	0.981	0.968	0.971	289.6	326.1	365.7	39.5	44.5	49.9	1861	2069	2314	858.8	951.6	1101	0	0	0
55F3	55F3-S048	HH_3P_336ACSR_2	COND	ABC	0.978	0.963	0.965	289.6	326.1	365.7	39.5	44.5	49.9	1860	2067	2312	855.6	947.3	1095	21.1	21.1	21.1
55F3	55F3-S049	HH_3P_336ACSR_2	COND	ABC	0.977	0.961	0.964	286.6	323	362.7	39.1	44.1	49.5	1838	2040	2286	837.1	925.6	1066	0	0	0
55F3	55F3-S050	HH_3P_336ACSR_2	COND	ABC	0.976	0.96	0.963	286.6	323	362.7	39.1	44.1	49.5	1837	2038	2284	834.4	922.1	1061	0	0	0
55F3	55F3-S051	HH_3P_336ACSR_2	COND	ABC	0.976	0.959	0.962	286.6	323	362.7	39.1	44.1	49.5	1836	2037	2283	832.2	919.1	1056	0	0	0
55F3	55F3-S069	HH_3P_336ACSR_2	COND	ABC	0.975	0.958	0.96	219.7	212.6	317.8	30	29	43.4	1406	1341	1998	639.4	602.7	927.3	34.5	34.5	60.4
55F3	55F3-S075	HH_800	Switch	ABC	0.975	0.958	0.96	32.2	15.5	16.2	3.2	1.6	1.6	206.6	97.7	102.5	92.3	43.6	45.8	0	0	0
55F3	55F3-S075	HH_3P_3/0ACSR_#	COND	ABC	0.975	0.958	0.959	32.2	15.5	16.2	7.7	3.7	3.9	206.6	97.7	102.5	92.3	43.6	45.8	226.2	107.1	112.2
55F3	55F3-S071	HH_3P_3/0ACSR_#	COND	ABC	0.975	0.958	0.959	0	0	9.2	0	0	2.2	0	0	58	0	0	25.9	0	0	63.5
55F3	55F3-S070	HH_3P_336ACSR_2	COND	ABC	0.975	0.957	0.958	182.6	192.1	283.7	24.9	26.2	38.7	1168	1210	1780	530.5	543.2	824	0	0	0
55F3	55F3-S072	HH_3P_336ACSR_2	COND	ABC	0.974	0.956	0.956	182.6	192.1	283.7	24.9	26.2	38.7	1168	1209	1778	529.4	542.2	820.4	0	69.1	0
55F3	55F3-S077	HH_3P_336ACSR_2	COND	ABC	0.974	0.955	0.955	168.9	179.6	268.8	23	24.5	36.7	1080	1129	1683	488.5	505.6	772.9	0	0	0
55F3	55F3-S079	HH_3P_336ACSR_2	COND	ABC	0.973	0.954	0.954	162.8	173.3	250	22.2	23.6	34.1	1041	1089	1564	470.5	487.6	718.7	0	0	17.3
55F3	55F3-S093	HH_3P_336ACSR_2	COND	ABC	0.973	0.953	0.952	135.7	145.7	219.9	18.5	19.9	30	867.5	914.3	1373	391.7	408.8	629.5	129.5	155.4	138.1
55F3	55F3-S097	HH_3P_3/0ACSR_#	COND	ABC	0.973	0.953	0.952	3.9	19.6	9.6	0.9	4.7	2.3	25	122.6	60.2	11.1	54.8	26.9	0	0	0
55F3	55F3-S099	HH_3P_1/0ACSR_#	COND	B		0.953			9.5			2.9			59.5			26.6		0	65.2	0
55F3	55F3-S098	HH_3P_3/0ACSR_#	COND	ABC	0.973	0.953	0.952	3.9	10.1	9.6	0.9	2.4	2.3	25	63.1	60.2	11.1	28.2	26.9	27.4	69.1	65.9
55F3	55F3-S094	HH_3P_336ACSR_2	COND	ABC	0.972	0.951	0.948	113.3	103.5	190.1	15.5	14.1	25.9	724.3	648.9	1186	326.8	289.8	542.5	25.9	0	0
55F3	55F3-S100	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.951	0.948	7.4	7.6	7.6	1.8	1.8	1.8	47.3	47.3	47.3	21.1	21.1	21.1	51.8	51.8	51.8
55F3	55F3-S096	HH_3P_336ACSR_2	COND	ABC	0.972	0.95	0.946	102.3	95.9	182.6	14	13.1	24.9	653.7	600.5	1135	293.3	267.9	514.5	64	17.3	0
55F3	55F3-S123	HH_3P_336ACSR_2	COND	ABC	0.972	0.95	0.945	93.1	93.4	166.1	12.7	12.7	22.7	595.4	584.2	1032	266.7	260.6	465.8	0	10.5	0
55F3	55F3-S128	HH_3P_336ACSR_2	COND	ABC	0.972	0.95	0.945	71.3	64.8	144	9.7	8.8	19.6	455.8	405.1	893.8	204	180.5	402.5	0	0	0
55F3	55F3-S130	HH_800	Switch	ABC	0.972	0.95	0.945	67	60.7	139.3	6.7	6.1	13.9	428.6	379	864.2	191.9	169	389.2	0	0	0
55F3	55F3-S130	HH_3P_336ACSR_2	COND	ABC	0.972	0.949	0.944	67	60.7	139.3	9.1	8.3	19	428.6	379	864.2	191.9	169	389.2	0	0	0
55F3	55F3-S131	HH_3P_336ACSR_2	COND	ABC	0.972	0.949	0.943	67	60.7	139.3	9.1	8.3	19	428.6	379	864.1	191.8	169	388.9	3.5	0	0
55F3	55F3-S132	HH_3P_336ACSR_2	COND	ABC	0.972	0.949	0.943	66.5	60.7	139.3	9.1	8.3	19	425.6	378.7	863.4	190.2	168.9	387.3	0	0	0
55F3	55F3-S133	HH_3P_336ACSR_2	COND	ABC	0.972	0.948	0.942	66.6	60.7	139.3	9.1	8.3	19	425.7	378.6	863.2	190.1	168.9	386.6	0	0	0
55F3	55F3-S138	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.948	0.942	27.1	31.6	30.5	6.5	7.5	7.3	173.5	197.2	189.3	77.5	88.1	84.6	0	25.9	17.3
55F3	55F3-S137	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.948	0.941	27.1	27.8	28	6.5	6.6	6.7	173.4	173.4	173.4	77.5	77.5	77.5	189.9	189.9	189.9
55F3	55F3-S137	HH_600	Switch	ABC	0.972	0.948	0.941	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F3	55F3-S134	HH_3P_336ACSR_2	COND	ABC	0.972	0.948	0.942	39.4	29.1	108.7	5.4	4	14.8	252.2	181.4	673.6	112.5	80.8	301.4	0	0	0
55F3	55F3-S141	HH_1P_#2ACSR_#4	COND	C			0.941			35.6			15.6			220.8			98.7	0	0	241.7
55F3	55F3-S140	HH_1P_#2ACSR_#4	COND	A	0.972			6.2			2.7			39.4			17.6			43.2	0	0
55F3	55F3-S135	HH_3P_336ACSR_2	COND	ABC	0.972	0.948	0.941	33.3	29.1	73.1	4.5	4	10	212.8	181.4	452.7	94.9	80.8	202.4	0	0	0
55F3	55F3-S145	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.948	0.941	8.6	8.8	16.5	2.1	2.1	3.9	55.2	55.2	102.5	24.6	24.6	45.8	60.4	60.4	112.2
55F3	55F3-S142	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.948	0.941	17.3	17.7	36.9	4.1	4.2	8.8	110.4	110.4	228.7	49.3	49.3	102.2	0	0	25.9
55F3	55F3-S144	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.948	0.941	0	0	6.4	0	0	1.5	0	0	39.4	0	0	17.6	0	0	43.2
55F3	55F3-S143	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.948	0.941	17.3	17.7	26.7	4.1	4.2	6.4	110.4	110.4	165.5	49.3	49.3	74	120.9	120.9	181.3
55F3	55F3-S139	HH_3P_336ACSR_2	COND	ABC	0.972	0.948	0.941	7.4	2.5	19.6	1	0.3	2.7	47.3	15.8	121.4	21	7	54.2	0	0	0
55F3	55F3-S147	HH_1P_3/0ACSR_#	COND	C			0.941			17.1			4.1			105.6			47.2	0	0	115.7
55F3	55F3-S146	HH_3P_336ACSR_2	COND	ABC	0.972	0.948	0.941	7.4	2.5	2.5	1	0.3	0.3	47.3	15.8	15.8	21.1	7	7	51.8	17.3	17.3
55F3	55F3-S136	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.948	0.941	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F3	55F3-S129	HH_200	Switch	ABC	0.972	0.95	0.945	4.3	4.2	4.7	1.7	1.7	1.9	27.2	26.1	29.5	12	11.5	13.1	0	0	0

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
55F3	55F3-S129	15KV_1/0CU_XLPE	CAB	ABC	0.972	0.949	0.945	4.3	4.2	4.7	2	1.9	2.2	27.2	26.1	29.5	12	11.5	13.1	29.8	28.6	32.3
55F3	55F3-S124	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.949	0.945	21.8	27.1	22.1	5.2	6.5	5.3	139.6	169.1	137.3	62.4	75.5	61.3	152.9	185.2	150.4
55F3	55F3-S095	HH_1P_#2ACSR_#4	COND	C			0.946			16.5			7.2			102.5			45.8	0	0	112.2
55F3	55F3-S080	HH_3P_3/0ACSR_#	COND	ABC	0.973	0.954	0.953	27.1	27.6	27.7	6.5	6.6	6.6	173.4	173.5	173.5	77.5	77.5	77.5	0	0	0
55F3	55F3-S092	HH_3P_3/0ACSR_#	COND	ABC	0.973	0.954	0.953	27.1	27.6	27.7	6.5	6.6	6.6	173.4	173.4	173.4	77.5	77.5	77.5	189.9	189.9	189.9
55F3	55F3-S078	HH_3P_336ACSR_2	COND	ABC	0.974	0.955	0.955	6.2	6.3	18.8	0.8	0.9	2.6	39.4	39.4	118.2	17.6	17.6	52.8	43.2	43.2	129.5
55F3	55F3-S076	HH_3P_3/0ACSR_#	COND	ABC	0.974	0.956	0.956	0	0	6.3	0	0	1.5	0	0	39.4	0	0	17.6	0	0	43.2
55F3	55F3-S073	HH_3P_3/0ACSR_#	COND	ABC	0.974	0.956	0.956	13.7	2.5	8.5	3.3	0.6	2	87.6	15.8	53.7	39.1	7	24	17.3	17.3	58.8
55F3	55F3-S074	HH_1P_3/0ACSR_#	COND	A	0.974			11.2			2.7			71.9			32.1			78.7	0	0
55F3	55F3-S052	HH_3P_336ACSR_2	COND	ABC	0.975	0.959	0.962	66.9	110.4	44.9	9.1	15.1	6.1	429.6	695.3	283.9	191.6	314.8	126.8	0	0	0
55F3	55F3-S054	HH_800	Switch	ABC	0.975	0.959	0.962	62.1	103.2	38.4	6.2	10.3	3.8	398.7	649.6	243.1	177.8	293.5	108.6	0	0	0
55F3	55F3-S054	HH_3P_3/0ACSR_#	COND	ABC	0.974	0.957	0.962	62.1	103.2	38.4	14.8	24.6	9.2	398.7	649.6	243.1	177.8	293.5	108.6	0	0	0
55F3	55F3-S063	HH_3P_3/0ACSR_#	COND	ABC	0.974	0.957	0.962	0.5	14.1	0.5	0.1	3.4	0.1	3.4	88.9	3.4	1.5	39.7	1.5	3.7	97.4	3.7
55F3	55F3-S055	HH_3P_3/0ACSR_#	COND	ABC	0.974	0.957	0.962	61.6	89.1	37.9	14.7	21.3	9	394.9	560.2	239.7	176.1	252.8	107	0	0	0
55F3	55F3-S065	HH_3P_3/0ACSR_#	COND	ABC	0.974	0.957	0.962	0	7.5	0	0	1.8	0	0	47.3	0	0	21.1	0	0	51.8	0
55F3	55F3-S056	HH_3P_3/0ACSR_#	COND	ABC	0.973	0.956	0.962	61.6	81.6	37.9	14.7	19.5	9	394.8	512.7	239.7	176.1	231.3	107.1	0	0	0
55F3	55F3-S066	HH_3P_3/0ACSR_#	COND	ABC	0.973	0.956	0.962	17.1	0	0	4.1	0	0	109.5	0	0	48.9	0	0	119.9	0	0
55F3	55F3-S057	HH_3P_3/0ACSR_#	COND	ABC	0.973	0.956	0.962	44.5	81.6	37.9	10.6	19.5	9	285.1	512.5	239.7	127.1	231	107.1	0	0	0
55F3	55F3-S058	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.955	0.962	44.5	81.6	37.9	10.6	19.5	9	285	512.2	239.7	127	230.5	107	34.5	0	0
55F3	55F3-S060	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.954	0.962	34.7	81.6	37.9	8.3	19.5	9	221.8	511.9	239.7	98.8	230	107	0	0	0
55F3	55F3-S067	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.954	0.961	6.6	5.8	13.8	1.6	1.4	3.3	42	36.3	87.4	18.7	16.2	39	22.4	22.4	51.8
55F3	55F3-S068	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.954	0.961	3.4	2.5	6.3	0.8	0.6	1.5	21.5	15.8	40.1	9.6	7	17.9	23.6	17.3	43.9
55F3	55F3-S061	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.953	0.962	28.1	75.8	24.1	6.7	18.1	5.7	179.7	475.3	152.3	80.1	213.3	68	177.8	0	24.9
55F3	55F3-S102	HH_3P_336ACSR_2	COND	ABC	0.972	0.952	0.962	2.7	73.2	20.5	0.4	10	2.8	17.3	458.3	129.6	7.6	205.3	57.8	0	0	0
55F3	55F3-S110	HH_1P_3/0ACSR_#	COND	B		0.952			61.2			14.6			382.9			172		0	34.5	0
55F3	55F3-S122	HH_1P_3/0ACSR_#	COND	B		0.952			4.4			1.1			27.6			12.3		0	30.3	0
55F3	55F3-S111	HH_1P_3/0ACSR_#	COND	B		0.951			51.7			12.3			323.7			145.4		0	0	0
55F3	55F3-S112	HH_1P_3/0ACSR_#	COND	B		0.95			51.7			12.3			323.6			145.1		0	72.5	0
55F3	55F3-S113	HH_1P_3/0ACSR_#	COND	B		0.949			41.1			9.8			257.1			115		0	36.3	0
55F3	55F3-S118	HH_200	Switch	B		0.949			25.2			10.1			157.7			70.4		0	0	0
55F3	55F3-S118	HH_1P_3/0ACSR_#	COND	B		0.949			25.2			6			157.7			70.4		0	0	0
55F3	55F3-S119	HH_1P_3/0ACSR_#	COND	B		0.949			12.6			3			78.9			35.2		0	21.6	0
55F3	55F3-S120	HH_1P_3/0ACSR_#	COND	B		0.949			9.5			2.3			59.1			26.4		0	21.6	0
55F3	55F3-S121	HH_1P_3/0ACSR_#	COND	B		0.949			6.3			1.5			39.4			17.6		0	21.6	0
55F3	55F3-S151	HH_1P_3/0ACSR_#	COND	B		0.949			3.2			0.8			19.7			8.8		0	21.6	0
55F3	55F3-S152	HH_1P_3/0ACSR_#	COND	B		0.949			0			0			0			0		0	0	0
55F3	55F3-S116	HH_1P_3/0ACSR_#	COND	B		0.949			12.6			3			78.8			35.2		0	43.2	0
55F3	55F3-S117	HH_1P_3/0ACSR_#	COND	B		0.949			6.3			1.5			39.4			17.6		0	43.2	0
55F3	55F3-S114	HH_1P_3/0ACSR_#	COND	B		0.949			10.6			2.5			66.2			29.6		0	36.3	0
55F3	55F3-S115	HH_1P_3/0ACSR_#	COND	B		0.949			5.3			1.3			33.1			14.8		0	36.3	0
55F3	55F3-S103	HH_3P_336ACSR_2	COND	ABC	0.972	0.952	0.962	2.7	12	20.5	0.4	1.6	2.8	17.3	75.3	129.6	7.7	33	57.8	0	0	0
55F3	55F3-S125	HH_1P_#2ACSR_#4	COND	C			0.962			4.7			2			29.5			13.2	0	0	32.3
55F3	55F3-S104	HH_3P_336ACSR_2	COND	ABC	0.972	0.952	0.962	2.7	12	15.8	0.4	1.6	2.2	17.3	75.3	100.1	7.7	33	44.6	0	0	0
55F3	55F3-S104	HH_600	Switch	ABC	0.972	0.952	0.962	2.7	12	15.8	0.4	1.6	2.1	17.3	75.3	100.1	7.7	33.1	44.6	0	0	0
55F3	55F3-S126	HH_1P_#2ACSR_#4	COND	C			0.961			10.6			4.6			67			29.9	0	0	34.5
55F3	55F3-S127	HH_1P_#2ACSR_#4	COND	C			0.961			5.6			2.5			35.4			15.8	0	0	38.8
55F3	55F3-S105	HH_3P_336ACSR_2	COND	ABC	0.972	0.952	0.962	2.7	12	5.2	0.4	1.6	0.7	17.3	75.3	33.1	7.7	33.1	14.7	19	19	19
55F3	55F3-S106	HH_3P_336ACSR_2	COND	ABC	0.972	0.952	0.962	0	9.2	2.5	0	1.3	0.3	0	57.9	15.8	0	25.3	7	0	0	0
55F3	55F3-S109	HH_3P_336ACSR_2	COND	ABC	0.972	0.952	0.962	0	0	2.5	0	0	0.3	0	0	15.8	0	0	7	0	0	17.3

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
55F3	55F3-S108	HH_1P_#2ACSR_#4	COND	B		0.952			9.2			4			57.9			25.4		0	17.3	0
55F3	55F3-S149	15KV_#2CU_XLPE	CAB	B		0.952			4.2			2.6			26.4			11.3		0	0	0
55F3	55F3-S150	15KV_#2CU_XLPE	CAB	B		0.952			4.2			2.6			26.4			11.4		0	28.9	0
55F3	55F3-S148	HH_1P_#2ACSR_#4	COND	B		0.952			2.5			1.1			15.8			7		0	17.3	0
55F3	55F3-S107	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.952	0.962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F3	55F3-S101	HH_1P_3/0ACSR_#	COND	B		0.953			2.6			0.6			16.6			7.4		0	18.2	0
55F3	55F3-S059	HH_3P_3/0ACSR_#	COND	ABC	0.972	0.955	0.962	4.9	0	0	1.2	0	0	31.5	0	0	14.1	0	0	34.5	0	0
55F3	55F3-S053	HH_3P_3/0ACSR_#	COND	ABC	0.975	0.958	0.962	4.8	7.2	6.5	1.1	1.7	1.5	30.6	45.4	40.9	13.6	20.2	18.2	33.6	49.7	44.8
55F3	55F3-S091	HH_3P_3/0ACSR_#	COND	ABC	0.982	0.97	0.973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F3	55F3-S044	HH_200	Switch	A	0.986			1.7			0.7			11			4.6			0	0	0
55F3	55F3-S044	1/0_XLPE	CAB	A	0.986			1.7			0.8			11			4.6			12.1	0	0
55F3	55F3-S044	HH_200	Switch	A	0.986			0			0			0			0			0	0	0
55F3	55F3-S043	HH_200	Switch	A	0.987			1.7			0.7			11			4.6			0	0	0
55F3	55F3-S043	1/0_XLPE	CAB	A	0.987			1.7			0.8			11			4.6			12.1	0	0
55F3	55F3-S043	HH_200	Switch	A	0.987			0			0			0			0			0	0	0
55F3	55F3-S042	HH_200	Switch	A	0.988			2.9			1.2			18.9			8.1			0	0	0
55F3	55F3-S042	1/0_XLPE	CAB	A	0.988			2.9			1.3			18.9			8.1			20.7	0	0
55F3	55F3-S042	HH_200	Switch	A	0.988			0			0			0			0			0	0	0
55F3	55F3-S041	HH_200	Switch	A	0.989			1.7			0.7			11			4.6			0	0	0
55F3	55F3-S041	1/0_XLPE	CAB	A	0.989			1.7			0.8			11			4.6			12.1	0	0
55F3	55F3-S041	HH_200	Switch	A	0.989			0			0			0			0			0	0	0
55F3	55F3-S006	1/0_XLPE	CAB	B		0.983			56.3			25.9			366.1			157.7		0	23.6	0
55F3	55F3-S010	1/0_XLPE	CAB	B		0.982			39.7			18.3			258.3			111.6		0	47.1	0
55F3	55F3-S011	1/0_XLPE	CAB	B		0.982			33.1			15.3			215.2			92.8		0	47.1	0
55F3	55F3-S011	HH_200	Switch	B		0.982			26.5			10.6			172.1			74.3		0	0	0
55F3	55F3-S016	1/0_XLPE	CAB	B		0.981			26.5			12.2			172.1			74.6		0	0	0
55F3	55F3-S018	1/0_XLPE	CAB	B		0.981			19.9			9.2			129.1			56		0	23.6	0
55F3	55F3-S023	HH_200	Switch	B		0.981			3.3			1.3			21.5			9.4		0	0	0
55F3	55F3-S023	1/0_XLPE	CAB	B		0.981			3.3			1.5			21.5			9.4		0	23.6	0
55F3	55F3-S023	HH_200	Switch	B		0.981			0			0			0			0		0	0	0
55F3	55F3-S019	1/0_XLPE	CAB	B		0.981			13.3			6.1			86			37.3		0	23.6	0
55F3	55F3-S020	1/0_XLPE	CAB	B		0.981			9.9			4.6			64.5			28		0	23.6	0
55F3	55F3-S021	1/0_XLPE	CAB	B		0.981			6.6			3.1			43			18.8		0	23.6	0
55F3	55F3-S022	1/0_XLPE	CAB	B		0.981			3.3			1.5			21.5			9.4		0	23.6	0
55F3	55F3-S017	1/0_XLPE	CAB	B		0.981			6.6			3.1			43			18.8		0	47.1	0
55F3	55F3-S013	1/0_XLPE	CAB	B		0.982			0			0			0			-0.3		0	0	0
55F3	55F3-S013	HH_200	Switch	B		0.982			0			0			0			0		0	0	0
55F3	55F3-S007	1/0_XLPE	CAB	B		0.983			13.2			6.1			86			36.8		0	0	0
55F3	55F3-S012	1/0_XLPE	CAB	B		0.983			6.6			3.1			43			18.6		0	23.6	0
55F3	55F3-S015	1/0_XLPE	CAB	B		0.983			3.3			1.5			21.5			9.2		0	23.6	0
55F3	55F3-S015	HH_200	Switch	B		0.983			0			0			0			0		0	0	0
55F3	55F3-S008	1/0_XLPE	CAB	B		0.982			6.6			3			43			18.4		0	23.6	0
55F3	55F3-S014	1/0_XLPE	CAB	B		0.982			3.3			1.5			21.5			9.5		0	23.6	0
55F3	55F3-S009	HH_200	Switch	B		0.982			0			0			0			-0.2		0	0	0
55F3	55F3-S009	1/0_XLPE	CAB	B		0.982			0			0			0			-0.2		0	0	0
55F3	55F3-S004	HH_3P_336ACSR_2	COND	ABC	0.991	0.983	0.987	0	0	8.2	0	0	1.1	0	0	53.6	-0.2	-0.2	23.6	0	0	0
55F3	55F3-S024	HH_3P_336ACSR_2	COND	ABC	0.991	0.983	0.987	0	0	4.1	0	0	0.6	0	0	26.8	-0.1	-0.1	11.7	0	0	0
55F3	55F3-S027	HH_200	Switch	C			0.987			4.1			1.6			26.8			11.9	0	0	0
55F3	55F3-S027	#2_XLPE	CAB	C			0.987			4.1			2.6			26.8			11.9	0	0	0

Load Flow Output

Feeder Id	Section Id	Equipment Id	Code	Phase	VA (pu)	VB (pu)	VC (pu)	IA (Amps)	IB (Amps)	IC (Amps)	Loading A (%)	Loading B (%)	Loading C (%)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Thru Power A (kVAR)	Thru Power B (kVAR)	Thru Power C (kVAR)	Load A (kVA)	Load B (kVA)	Load C (kVA)
55F3	55F3-S028	#2_XLPE	CAB	C			0.987			4.1			2.6			26.8			11.9	0	0	29.4
55F3	55F3-S025	HH_3P_336ACSR_2	COND	ABC	0.991	0.983	0.987	0	0	0	0	0	0	0	0	0	-0.1	-0.1	-0.1	0	0	0
55F3	55F3-S026	HH_3P_336ACSR_2	COND	ABC	0.991	0.983	0.987	0	0	0	0	0	0	0	0	0	-0.1	-0.1	-0.1	0	0	0
55F3	55F2-3TIE	HH_3P_336ACSR_2	COND	ABC	0.991	0.983	0.987	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F3	55F2-3TIE	HH_800	Switch	ABC	0.991	0.983	0.987	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55F3	55F3-S005	HH_200	Switch	C			0.987			4.1			1.6			26.8			11.9	0	0	0
55F3	55F3-S005	#2_XLPE	CAB	C			0.987			4.1			2.6			26.8			11.9	0	0	0
55F3	55F3-S029	#2_XLPE	CAB	C			0.987			4.1			2.6			26.8			11.9	0	0	29.4

Appendix 5 – Opinion of Costs

OPINION OF PROBABLE COST - Upgrade Lines 43F1 Sub to Tessier				17-Jan-06
Construction Budget				
ITEMS	UNIT PRICE	UNIT	QTY	TOTAL COST
Upgrade 3/0 to 336kcmil	$20,000.00	3ph/km	0.1	$2,000.00
Subtotal				$2,000.00
Subtotal				$2,000.00
Contingency +20%				$400.00
Total				$2,400.00

Notes:

1. Does not include engineering design or construction services.
2. Does not include any taxes
3. Assuming no poles or hardware need replacing
4. Assuming existing ducts for underground cables

OPINION OF PROBABLE COST - Upgrade Lines 43F1 Sub to Spence and Cameron				17-Jan-06
Construction Budget				
ITEMS	UNIT PRICE	UNIT	QTY	TOTAL COST
Upgrade 3/0 to 336kcmil	$20,000.00	3ph/km	1.08	$21,600.00
Subtotal				$21,600.00
Subtotal				$21,600.00
Contingency +20%				$4,320.00
Total				$25,920.00

Notes:

1. Does not include engineering design or construction services.
2. Does not include any taxes
3. Assuming no poles or hardware need replacing
4. Assuming existing ducts for underground cables

OPINION OF PROBABLE COST - Upgrade Lines 43F2 Sub to Spence and Cameron				17-Jan-06
Construction Budget				
ITEMS	UNIT PRICE	UNIT	QTY	TOTAL COST
Upgrade 3/0 to 336kcmil	$20,000.00	3ph/km	0.94	$18,800.00
Subtotal				$18,800.00
Subtotal				$18,800.00
Contingency +20%				$3,760.00
Total				$22,560.00

Notes:
1. Does not include engineering design or construction services.
2. Does not include any taxes
3. Assuming no poles or hardware need replacing

OPINION OF PROBABLE COST - Upgrade Lines 55F1 along Main from Chartrand to West 17-Jan-06

Construction Budget

ITEMS	UNIT PRICE	UNIT	QTY	TOTAL COST
Upgrade 3/0 to 336kcmil	$20,000.00	3ph/km	0.433	$8,660.00
Subtotal				$8,660.00

Subtotal	$8,660.00
Contingency +20%	$1,732.00
Total	$10,392.00

Notes:

1. Does not include engineering design or construction services.
2. Does not include any taxes
3. Assuming no poles or hardware need replacing

OPINION OF PROBABLE COST - Upgrade Lines 55F2 along Main from Chartrand to West				17-Jan-06
Construction Budget				
ITEMS	UNIT PRICE	UNIT	QTY	TOTAL COST
Upgrade 3/0 to 336kcmil	$20,000.00	3ph/km	0.433	$8,660.00
Subtotal				$8,660.00
Subtotal				$8,660.00
Contingency +20%				$1,732.00
Total				$10,392.00

Notes:
1. Does not include engineering design or construction services.
2. Does not include any taxes
3. Assuming no poles or hardware need replacing

OPINION OF PROBABLE COST - Upgrade Lines 55F3 McGill from Regent to Pasteur 17-Jan-06

Construction Budget

ITEMS		UNIT PRICE	UNIT	QTY	TOTAL COST
Upgrade 3/0 to 336kcmil		$20,000.00	3ph/km	0.152	$3,040.00
	Subtotal				$3,040.00
Subtotal					$3,040.00
Contingency +20%					$608.00
Total					$3,648.00

Notes:
1. Does not include engineering design or construction services.
2. Does not include any taxes
3. Assuming no poles or hardware need replacing

OPINION OF PROBABLE COST - New 15kV Recloser and Line connection				26-Sep-06
Construction Budget				
ITEMS	UNIT PRICE	UNIT	QTY	TOTAL COST
Supply 1 x 560A recloser	$15,000.00	ea.	1	$15,000.00
Install and commission	$4,000.00	ea.	1	$4,000.00
Connections	$8,000.00	ea.	1	$8,000.00
Subtotal				$27,000.00
Subtotal				$27,000.00
Contingency +10%				$2,700.00
Total				$29,700.00

Notes:
1. Does not include engineering design or construction services.
2. Does not include any taxes

OPINION OF PROBABLE COST - Addition of New Transformer 43T2 in Existing Substation				29-Jun-05
Construction Budget				
ITEMS	UNIT PRICE	UNIT	QTY	TOTAL COST
New 10/13.3/16.7 MVA 44/12.48kV Transformer	$225,000.00	ea.	1	$225,000.00
New Tower Structure and hardware, installation	$35,000.00	ea.	1	$35,000.00
Recloser lineup, two reclosers, metering	$75,000.00	ea.	1	$75,000.00
Recloser and Transformer pads	$10,000.00	ea.	1	$10,000.00
Fence Extension	$6,000.00	ea.	1	$6,000.00
Ground Grid Extension	$15,000.00	ea.	1	$15,000.00
Construction	$50,000.00	ea.	1	$50,000.00
Feeders??				$0.00
				$0.00
				$0.00
Subtotal				$416,000.00
Subtotal				$416,000.00
Contingency +10%				$41,600.00
Total				$457,600.00

Notes:

1. Does not include engineering design or construction services.
2. Does not include any taxes
3. Assuming no poles or hardware need replacing

Appendix 6 – System Switching Procedures

Hawkesbury Hydro

SWITCHING PROCEDURE

OPERATIONS

1. The operations must be listed in the sequence in which they will be carried out. The sequence must be followed without any deviation to the specific equipment identified, performing the specific operation identified.

INSTRUCTIONS

1. **Request Number:** Identify the number of the Request.
2. **Date:** State the approved date for the performance of the Switching Procedure.
3. **Time:** State the approved time for the performance of the Switching Procedure.
4. **Purpose of Switching Procedure:** State the purpose of the Switching Procedure.
5. **Operation Number:** List the sequence of operations in the order in which the operations must proceed.
6. **Equipment:** Equipment affected.
7. **Operation:** Specific operation to be performed.
8. **Initials:** Initials to confirm that the specified operation is complete.
9. **Prepared by:** Name and signature of person that prepared the switching procedures, including time and date.
10. **Checked and Issued by:** Name and signature of person that verified the procedures and is issuing it to the contractor performing the isolation, including time and date.
11. **Performed by:** Name and signature of person physically performing the switching procedures, including time and date.

RULES

1. The person performing the Switching Procedure will be the designated Supervisor as outlined by the Ontario Health and Safety Act.
2. Only a qualified contactor that has been trained and certified to the Electrical Utility Safety Association (EUSA) of Ontario will perform the Switching Procedure. Equivalent training certification may be accepted on a case by case basis.
3. Comply with EUSA rule book. Always use approved procedures and wear approved personal protective equipment during all operations. Never work alone.
4. Identify, Isolate, Lock-Out, and Tag *all* possible voltage sources that feed or back feed, or can *potentially* feed or back feed, the electrical equipment to be isolated and removed from service.
5. Perform voltage potential tests using calibrated, rated, and approved test equipment at all isolation points potentially able to feed or back feed the equipment. Ensure zero voltage potential before applying grounds.
6. De-energize all isolated points of the electrical equipment to be removed from service by applying rated and approved temporary ground equipment. Always work between temporary ground sets.

Request Number:	**Date:**	**Time:**

Purpose of Switching Procedure:

Supply backfeed power from 44kV substation in the event of 115kV substation outage.

NOTE: The following switching procedure is applicable only when all system switches are initially in the state reflected in the Primary Electrical Distribution System Map (drawing E-1), dated January 8, 2007.

Operation Number	Equipment	Operation	Initials
1	Isolate transformer 55T1.	Open and lock out 55T1-L.	
2	Isolate transformer 55T2.	Open and lock out 55T2-L.	
3	Isolate transformer 55T1.	Open and lock out 55T1-B.	
4	Isolate transformer 55T2.	Open and lock out 55T2-B.	
5	Disconnect feeder 55F1 from main 12.5kV bus.	Open and lock out 55F1-BC/*/LC.	
6	Disconnect feeder 55F2 from main 12.5kV bus.	Open and lock out 55F2-BC/*/LC.	
7	Disconnect feeder 55F3 from main 12.5kV bus.	Open and lock out 55F3-BC/*/LC.	
8	Energize feeder 55F1 circuit via feeder 43F1.	Close switch S-032 (Spence).	
9	Energize feeder 55F2 circuit via feeder 43F2.	Close switch S-029 (Chamberlain).	
10	Energize feeder 55F3 circuit via feeder 43F2.	Close switch S-028 (Lansdowne).	
11	Capacity Check 44kV substation feeders.	Confirm loading on equipment (44kV substation transformer, switches, and conductors) is within system capacity.	

Prepared by:

Name:	Signature:	Time:	Date:

Checked and Issued by:

Name:	Signature:	Time:	Date:

Performed by:

Name:	Signature:	Time:	Date:

THIS RECORD MUST BE KEPT FOR ONE YEAR

SWITCHING PROCEDURE

OPERATIONS

1. The operations must be listed in the sequence in which they will be carried out. The sequence must be followed without any deviation to the specific equipment identified, performing the specific operation identified.

INSTRUCTIONS

1. **Request Number:** Identify the number of the Request.
2. **Date:** State the approved date for the performance of the Switching Procedure.
3. **Time:** State the approved time for the performance of the Switching Procedure.
4. **Purpose of Switching Procedure:** State the purpose of the Switching Procedure.
5. **Operation Number:** List the sequence of operations in the order in which the operations must proceed.
6. **Equipment:** Equipment affected.
7. **Operation:** Specific operation to be performed.
8. **Initials:** Initials to confirm that the specified operation is complete.
9. **Prepared by:** Name and signature of person that prepared the switching procedures, including time and date.
10. **Checked and Issued by:** Name and signature of person that verified the procedures and is issuing it to the contractor performing the isolation, including time and date.
11. **Performed by:** Name and signature of person physically performing the switching procedures, including time and date.

RULES

1. The person performing the Switching Procedure will be the designated Supervisor as outlined by the Ontario Health and Safety Act.
2. Only a qualified contactor that has been trained and certified to the Electrical Utility Safety Association (EUSA) of Ontario will perform the Switching Procedure. Equivalent training certification may be accepted on a case by case basis.
3. Comply with EUSA rule book. Always use approved procedures and wear approved personal protective equipment during all operations. Never work alone.
4. Identify, Isolate, Lock-Out, and Tag *all* possible voltage sources that feed or back feed, or can *potentially* feed or back feed, the electrical equipment to be isolated and removed from service.
5. Perform voltage potential tests using calibrated, rated, and approved test equipment at all isolation points potentially able to feed or back feed the equipment. Ensure zero voltage potential before applying grounds.
6. De-energize all isolated points of the electrical equipment to be removed from service by applying rated and approved temporary ground equipment. Always work between temporary ground sets.

Request Number:	**Date:**	**Time:**

Purpose of Switching Procedure:

Supply power to feeders 55F1 & 55F2 from transformer 55T2 in the event of transformer 55T1 outage.

NOTE: The following switching procedure is applicable only when all system switches are initially in the state reflected in the Primary Electrical Distribution System Map (drawing E-1), dated January 8, 2007.

Operation Number	Equipment	Operation	Initials
1	**Isolate transformer 55T1.**	**Open and lock out 55T1-L.**	
2	**Isolate transformer 55T1.**	**Open and lock out 55T1-B.**	
3	**Energize feeders 55F1 & 55F2.**	**Close 55B1-B2.**	
4	**Capacity Check 55T2.**	**Confirm loading on equipment (transformer 55T2, switches, and conductors) is within system capacity.**	

Prepared by:

Name:	**Signature:**	**Time:**	**Date:**

Checked and Issued by:

Name:	**Signature:**	**Time:**	**Date:**

Performed by:

Name:	**Signature:**	**Time:**	**Date:**

THIS RECORD MUST BE KEPT FOR ONE YEAR

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RULES

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3. Comply with EUSA rule book. Always use approved procedures and wear approved personal protective equipment during all operations. Never work alone.
4. Identify, Isolate, Lock-Out, and Tag *all* possible voltage sources that feed or back feed, or can *potentially* feed or back feed, the electrical equipment to be isolated and removed from service.
5. Perform voltage potential tests using calibrated, rated, and approved test equipment at all isolation points potentially able to feed or back feed the equipment. Ensure zero voltage potential before applying grounds.
6. De-energize all isolated points of the electrical equipment to be removed from service by applying rated and approved temporary ground equipment. Always work between temporary ground sets.

Request Number:	**Date:**	**Time:**

Purpose of Switching Procedure:

Supply power to feeder 55F3 from transformer 55T1 in the event of transformer 55T2 outage.

NOTE: The following switching procedure is applicable only when all system switches are initially in the state reflected in the Primary Electrical Distribution System Map (drawing E-1), dated January 8, 2007.

Operation Number	Equipment	Operation	Initials
1	**Isolate transformer 55T2.**	**Open and lock out 55T2-L.**	
2	**Isolate transformer 55T2.**	**Open and lock out 55T2-B.**	
3	**Energize feeder 55F3.**	**Close 55B1-B2.**	
4	**Capacity Check 55T1.**	**Confirm loading on equipment (transformer 55T1, switches, and conductors) is within system capacity.**	

Prepared by:

Name:	**Signature:**	**Time:**	**Date:**

Checked and Issued by:

Name:	**Signature:**	**Time:**	**Date:**

Performed by:

Name:	**Signature:**	**Time:**	**Date:**

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6. De-energize all isolated points of the electrical equipment to be removed from service by applying rated and approved temporary ground equipment. Always work between temporary ground sets.

Request Number:	**Date:**	**Time:**

Purpose of Switching Procedure:

Supply power to feeder 55F1 loads from feeder 43F2 in the event of 55F1 failure.

NOTE: The following switching procedure is applicable only when all system switches are initially in the state reflected in the Primary Electrical Distribution System Map (drawing E-1), dated January 8, 2007.

Operation Number	Equipment	Operation	Initials
1	**Isolate feeder 55F1.**	**Open and lock out 55F1-BC/*/LC.**	
2	**Energize feeder 55F1 circuit from feeder 43F2.**	**Close switch S-032 (Spence).**	
3	**Capacity Check 43F2.**	**Confirm loading on equipment (44kV transformer, switches, conductors, etc.) is within system capacity.**	

Prepared by:

Name:	**Signature:**	**Time:**	**Date:**

Checked and Issued by:

Name:	**Signature:**	**Time:**	**Date:**

Performed by:

Name:	**Signature:**	**Time:**	**Date:**

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6. De-energize all isolated points of the electrical equipment to be removed from service by applying rated and approved temporary ground equipment. Always work between temporary ground sets.

Request Number:	**Date:**	**Time:**

Purpose of Switching Procedure:

Supply power to feeder 55F2 loads from feeders 55F3 & 43F2 in the event of 55F2 failure.

NOTE: The following switching procedure is applicable only when all system switches are initially in the state reflected in the Primary Electrical Distribution System Map (drawing E-1), dated January 8, 2007.

Operation Number	Equipment	Operation	Initials
1	**Isolate feeder 55F2.**	**Open and lock out 55F2-BC/*/LC.**	
2	**Isolate feeder 55F2 circuit into 2 separate segments.**	**Open and lock out switch S-036 (Main between Hampden & Phillipe).**	
3	**Energize segment of feeder 55F2 circuit from feeder 55F3.**	**Close switch S-058 (Prospect).**	
4	**Energize segment of feeder 55F2 circuit from feeder 43F2.**	**Close switch S-029 (Chamberlain).**	
5	**Capacity Check.**	**Confirm loading on equipment (transformers, switches, conductors, etc.) is within system capacity.**	

Prepared by:

Name:	**Signature:**	**Time:**	**Date:**

Checked and Issued by:

Name:	**Signature:**	**Time:**	**Date:**

Performed by:

Name:	**Signature:**	**Time:**	**Date:**

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5. Perform voltage potential tests using calibrated, rated, and approved test equipment at all isolation points potentially able to feed or back feed the equipment. Ensure zero voltage potential before applying grounds.
6. De-energize all isolated points of the electrical equipment to be removed from service by applying rated and approved temporary ground equipment. Always work between temporary ground sets.

Request Number:	**Date:**	**Time:**

Purpose of Switching Procedure:

Supply power to feeder 55F3 loads from feeders 55F2 & 43F2 in the event of 55F3 failure.

NOTE: The following switching procedure is applicable only when all system switches are initially in the state reflected in the Primary Electrical Distribution System Map (drawing E-1), dated January 8, 2007.

Operation Number	Equipment	Operation	Initials
1	Isolate feeder 55F3.	Open and lock out 55F3-BC/*/LC.	
2	Isolate feeder 55F3 circuit into 2 separate segments.	Open and lock out switch S-025 (Hampden & Higginson).	
3	Energize segment of feeder 55F3 circuit from feeder 55F2.	Close switch S-058 (Prospect).	
4	Energize segment of feeder 55F2 circuit from feeder 43F2.	Close switch S-028 (Lansdowne).	
5	Capacity Check.	Confirm loading on equipment (transformers, switches, conductors, etc.) is within system capacity.	

Prepared by:

Name:	Signature:	Time:	Date:

Checked and Issued by:

Name:	Signature:	Time:	Date:

Performed by:

Name:	Signature:	Time:	Date:

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6. De-energize all isolated points of the electrical equipment to be removed from service by applying rated and approved temporary ground equipment. Always work between temporary ground sets.

Request Number:	**Date:**	**Time:**

Purpose of Switching Procedure:

Supply backfeed power from 115kV substation in the event of 44kV substation outage.

NOTE: The following switching procedure is applicable only when all system switches are initially in the state reflected in the Primary Electrical Distribution System Map (drawing E-1), dated January 8, 2007.

Operation Number	Equipment	Operation	Initials
1	**Isolate 44kV transformer.**	**Open and lock out 44kV transformer primary switch.**	
2	**Disconnect feeder 43F1 from 44kV transformer.**	**Open and lock out 43F1-LB.**	
3	**Disconnect feeder 43F2 from 44kV transformer.**	**Open and lock out 43F2-LB.**	
4	**Energize feeder 43F1 circuit via feeder 55f1.**	**Close switch S-032 (Spence).**	
5	**Energize feeder 43F2 circuit via feeder 55f2.**	**Close switch S-029 (Chamberlain).**	
6	**Capacity Check 115kV substation feeders.**	**Confirm loading on equipment (115kV substation transformers, switches, and conductors) is within system capacity.**	

Prepared by:

Name:	**Signature:**	**Time:**	**Date:**

Checked and Issued by:

Name:	**Signature:**	**Time:**	**Date:**

Performed by:

Name:	**Signature:**	**Time:**	**Date:**

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6. De-energize all isolated points of the electrical equipment to be removed from service by applying rated and approved temporary ground equipment. Always work between temporary ground sets.

Request Number:	**Date:**	**Time:**

Purpose of Switching Procedure:

Supply power to feeder 43F1 loads from feeder 43F2 in the event of 43F1 failure.

NOTE: The following switching procedure is applicable only when all system switches are initially in the state reflected in the Primary Electrical Distribution System Map (drawing E-1), dated January 8, 2007.

Operation Number	Equipment	Operation	Initials
1	Isolate feeder 43F1.	Open and lock out 43f1-LB.	
2	Re-energize feeder 43F1.	Close switch S-050.	
3	Re-energize feeder 43F1.	Close switch S-051.	
4	Capacity Check 43F2.	Confirm loading on equipment (switches, conductors, etc.) is within system capacity.	

Prepared by:

Name:	Signature:	Time:	Date:

Checked and Issued by:

Name:	Signature:	Time:	Date:

Performed by:

Name:	Signature:	Time:	Date:

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6. De-energize all isolated points of the electrical equipment to be removed from service by applying rated and approved temporary ground equipment. Always work between temporary ground sets.

Request Number:	**Date:**	**Time:**

Purpose of Switching Procedure:

Supply power to feeder 43F2 loads from feeder 43F1 in the event of 43F2 failure.

NOTE: The following switching procedure is applicable only when all system switches are initially in the state reflected in the Primary Electrical Distribution System Map (drawing E-1), dated January 8, 2007.

Operation Number	Equipment	Operation	Initials
1	**Isolate feeder 43F2.**	**Open and lock out 43F2-LB.**	
2	**Re-energize feeder 43F2.**	**Close switch S-050.**	
3	**Re-energize feeder 43F2.**	**Close switch S-051.**	
4	**Capacity Check 43F1.**	**Confirm loading on equipment (switches, conductors, etc.) is within system capacity.**	

Prepared by:

Name:	**Signature:**	**Time:**	**Date:**

Checked and Issued by:

Name:	**Signature:**	**Time:**	**Date:**

Performed by:

Name:	**Signature:**	**Time:**	**Date:**

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Exhibit 8: Rate Design

Tab 4 (of 4): Rate Schedules and Bill Impacts

BASE REVENUE CALCULATIONS AND RECONCILIATIONS

This exhibit documents the calculation of HHI's proposed distribution rates by rate class for the 2010 test year based on rate design as proposed below.

HHI's has determined its total 2010 total service revenue requirement to be $1,484,214 The total revenue offsets amount to $179,998 and serves to reduce HHI' s total service revenue requirement to a base revenue requirement of $1,304,216, which is used to determine the proposed distribution rates. The base revenue requirement is derived from the 2010 capital and operating forecasts, weather normalized consumption, forecasted customer counts, and the regulated return on rate base.

Reconciliation of revenue from distribution charges can be found at Tab 4, schedule 1, Attachment 1, of this Exhibit.

Hydro Hawkesbury Inc. (ED-2003-0027)

2010 EDR Application (EB-2009-0186) version: v0.1
November 4, 2009

F6 Reconciliation of Rates with Revenue / Recovery Requirements

Review reconciliations (no input on this sheet)

DISTRIBUTION CHARGES

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
Customer Class Name	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	$5.96	56,460	336,502	$0.0080	53,559,119	428,473	764,975	763,767	1,207
General Service Less Than 50 kW	$13.80	6,792	93,730	$0.0056	20,562,650	115,151	208,880	208,157	723
General Service 50 to 4,999 kW	$94.41	948	89,501	$1.7049	229,814	391,810	481,311	481,320	(10)
Sentinel Lighting	$1.71	252	431	$3.2418	325	1,054	1,485	1,484	0
Street Lighting	$0.60	13,896	8,338	$6.8897	3,096	21,331	29,668	29,668	0
Unmetered Scattered Load	$7.19	48	345	$0.0023	220,667	508	853	862	(10)
TOTAL			**528,846**			**958,325**	**1,487,171**	**1,485,259**	**1,912**

[1] From sheet F5, rounded off to decimals displayed
[2] Fixed Charge = # Customers (Connections) multiplied by 12 (months); Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
[3] Rate x Volume

* Sum of 'Revenue' columns
** From sheet F4 (Gross Base Revenue Requirement)

DEFERRAL/VARIANCE ACCOUNT RECOVERY CHARGES (CREDITS)

	Variable Charge (Credit)			Proceeds from Recovery Charges (Credits)		
Customer Class Name	**Rate [1]**	**Volume [2]**	**Proceeds [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	($0.0054)	53,559,119	(289,219)	(289,219)	(290,112)	893
General Service Less Than 50 kW	($0.0059)	20,562,650	(121,320)	(121,320)	(121,608)	288
General Service 50 to 4,999 kW	($2.2926)	229,814	(526,872)	(526,872)	(526,871)	(1)
Sentinel Lighting	($1.5489)	325	(503)	(503)	(503)	0
Street Lighting	($2.3842)	3,096	(7,381)	(7,381)	(7,381)	(0)
Unmetered Scattered Load	($0.0060)	220,667	(1,324)	(1,324)	(1,324)	(0)
TOTAL			**(946,619)**	**(946,619)**	**(947,799)**	**1,180**

[1] From sheet C7 ('Proposed Rate Rider'), rounded off to decimals displayed
[2] Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
[3] Rate x Volume

* = 'Proceds' column
** From sheet C7 ('Annual Recovery Amounts')

TOTAL SERVICE REVENUE REQUIREMENT

In addition to the base revenue requirement, distribution rates need to include the recovery of low voltage charges as well as revenue from the smart meter adder and the effects of the proposed disposal of variance account.

The table below indicates that the gross base revenue requirement, including these factors, is $518,823.

Rate Base		
2009 ending Net Fixed Assets	2,024,338	
2010 ending Net Fixed Assets	2,215,058	
Average Net Fixed Assets		2,119,698
Working Capital Allowance Base	13,509,281	
Working Capital Allowance	15.0%	2,026,392
Rate Base		4,146,090
Return On Rate Base		
Deemed Short-Term Debt %	4.00%	165,844
Deemed Long-Term Debt %	56.00%	2,321,810
Deemed Equity %	40.00%	1,658,436
Short-Term Interest	1.33%	2,206
Long-Term Interest	7.62%	176,922
Return On Equity	8.01%	132,841
Return On Rate Base		311,968
Distribution Expenses & Taxes		
OM&A	965,143	
Amortization	175,480	
PILs/Taxes	31,623	1,172,246
Revenue Offsets		(179,998)
Distribution Revenue Requirement		1,304,216
Distribution Revenue at Existing Rates	*909,761*	
Revenue Sufficiency (Deficiency)	*(394,455)*	
Rate Adders		
Low Voltage Charges	70,600	
Transformer Allowances	(110,443)	
Transformer Allowance Recoveries	110,443	
Smart Meters	91,806	
Utility-funded CDM expenses		
		162,406
Variance / Deferral Account Rate Riders		
Variance Accounts	(947,799)	
LRAM & SSM		
		(947,799)
Proceeds from Rate Adders / Riders		(785,393)

RATE CHANGES AND BILL IMPACTS

Exhibit 8, Tab 4, Schedule 3, Attachment 2 details the rate impacts by volume for each rate class. The rate impacts are calculated for Residential customers using 800 kWh per month, and General Service <50 kW using 2000 kWh per month, with a percentage change and dollar per month change on the ‘delivery line charges’ in accordance with the Board’s filing guidelines. The rate impacts for the General Service 50 to 4999 kW are based on customers in that class using 100 kW per month. Delivery charges include the monthly servicecharge, variable distribution charges, deferral/variance account disposition and retail transmission network and retail transmission connection charges.

There are many factors that affect the bill impacts resulting from HHI proposed rates, with one of the most significant changes being the loss of their sole large user. The loss of this customer represents an 18% reduction in HHI’s annual revenue. A loss of this magnitude would adversely affect HHI's ability to meet its obligations to its customers unless the loss is offset by adjustments to the distribution rates of the remaining customers. As a result of this loss, and the proposed changes in the revenue to cost ratios, distribution charges are expected to increase by 26.2% for the GS < 50kW class and by over 100% for the GS > 50 to 4999 kW class.

Fortunately, when other factors are taken into consideration, such as the disposition of RS variance account and the decrease in the Retail Transmission Service Rates, customers in all classes, with the exception of Street Lights, will realize a reduction in their total bills.

Two tables showing the sequencing of the bill Impacts are presented below. The first table entitled “Summary of Bill Impact including Rate Rider” presents the summary of the initial rate impacts that will be experienced by rate class. The second table entitled “Summary of Bill Impact excluding Rate Rider” shows the impact (comparable to current bills) following the rate rider termination in 2012, i.e. without the impact from the disposition of the variance accounts. The key point to note in the tables is that even when the rate rider ends, the total bill impact on the GS > 50 to 4999 kW class is only 1.6% and all other customer classes except Street Lights continue to benefit from a reduction in their total bill, albeit to a smaller extent.

If the rates are approved as proposed, HHI plans to notify its customers of the expected bill impacts and point out the benefits of the two-year rate rider (earlier recovery of the credit). Prior to the rider termination, HHI will also remind customers that even though their 2012 bills will be roughly 5 to 6 percent higher than in 2011, their future payments will continue to be lower than what they were paying in 2009.

Summary of Bill Impact Including Rate Rider

	Volume		RPP	Distribution Charges		Delivery Sub-total		Total Bill	
Customer Class Name	**kWh**	**kW**	**Rate Class**	**$ change**	**% change**	**$ change**	**% change**	**$ change**	**% change**
Residential	800		Summer	$0.58	4.4%	($4.60)	(23.2%)	($5.58)	(6.8%)
	800		Winter	$0.58	4.4%	($4.60)	(23.2%)	($5.47)	(6.9%)
General Service Less Than 50 kW	2,000		Non-res.	$5.51	26.2%	($8.41)	(23.4%)	($10.87)	(5.5%)
General Service 50 to 4,999 kW	90,000	240	Non-res.	$327.47	>100%	($308.82)	(36.1%)	($419.10)	(5.0%)
Sentinel Lighting	430	1.30	Non-res.	($1.80)	(23.3%)	($4.42)	(37.9%)	($4.88)	(11.2%)
Street Lighting	85	0.23	Non-res.	$1.38	>100%	$0.77	59.1%	$0.68	8.9%
Unmetered Scattered Load	4,600		Non-res.	($15.42)	(46.5%)	($47.90)	(71.0%)	($53.54)	(12.0%)

Summary of Bill Impact Excluding Rate Rider

	Volume		RPP	Distribution Charges		Delivery Sub-total		Total Bill	
Customer Class Name	**kWh**	**kW**	**Rate Class**	**$ change**	**% change**	**$ change**	**% change**	**$ change**	**% change**
Residential	800		Summer	$0.58	4.4%	($0.28)	(1.4%)	($1.26)	(1.5%)
	800		Winter	$0.58	4.4%	($0.28)	(1.4%)	($1.15)	(1.4%)
General Service Less Than 50 kW	2,000		Non-res.	$5.51	26.2%	$3.39	9.4%	$0.93	0.5%
General Service 50 to 4,999 kW	90,000	240	Non-res.	$327.47	>100%	$241.40	28.2%	$131.12	1.6%
Sentinel Lighting	430	1.30	Non-res.	($1.80)	(23.3%)	($2.41)	(20.6%)	($2.87)	(6.6%)
Street Lighting	85	0.23	Non-res.	$1.38	>100%	$1.32	>100%	$1.23	16.1%
Unmetered Scattered Load	4,600		Non-res.	($15.42)	(46.5%)	($20.30)	(30.1%)	($25.94)	(5.8%)

As presented at Exhibit 9, Tab 1, HHI proposes to dispose of the majority of its deferral and variance accounts. The net result is a ratepayer credit in the amount of $1,895,598 to be refunded over a two year period. After the two year refund period expires, all rate classes will continue to show a total bill impact of less than 10%. The deferral and variance rate rider offsets a portion of the increase in distribution charges, however, the primary reason for the decrease in the total bill is the reduction of Retail Transmission Service Rates.

The increase in the Street Lighting class is driven primarily by Cost Allocation and since the bill impacts in 2010 and 2012 will remain under 10% and the proposed rate is based on cost causality, HHI has not proposed any rate mitigation for this customer class.

Appendix 1-1

Monthly Rates and Charges

		Effective May 1/10
Residential		
Service Charge	$	7.47
Distribution Volumetric Rate	$/kWh	0.0080
Regulatory Asset Recovery	$/kWh	(0.0054)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service Less Than 50 kW		
Service Charge	$	15.31
Distribution Volumetric Rate	$/kWh	0.0056
Regulatory Asset Recovery	$/kWh	(0.0059)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0021
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service 50 to 4,999 kW		
Service Charge	$	95.92
Distribution Volumetric Rate	$/kW	1.7049
Regulatory Asset Recovery	$/kW	(2.2926)
Retail Transmission Rate – Network Service Rate	$/kW	1.6115
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8547
Retail Transmission Rate – Network Service Rate - Interval	$/kW	0.8547
Retail Transmission Rate – Line and Transformation Connection Service Rate - Interval	$/kW	1.0193
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Sentinel Lighting		
Service Charge (per connection)	$	1.71
Distribution Volumetric Rate	$/kW	3.2418
Regulatory Asset Recovery	$/kW	(1.5489)
Retail Transmission Rate – Network Service Rate	$/kW	1.2159
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3492
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1-1

Monthly Rates and Charges

		Effective May 1/10
Street Lighting		
Service Charge (per connection)	$	0.60
Distribution Volumetric Rate	$/kW	6.8897
Regulatory Asset Recovery	$/kW	(2.3842)
Retail Transmission Rate – Network Service Rate	$/kW	1.2154
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6618
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Unmetered Scattered Load		
Service Charge	$	7.19
Distribution Volumetric Rate	$/kWh	0.0023
Regulatory Asset Recovery	$/kWh	(0.0060)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0021
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1-1

Monthly Rates and Charges

		Effective May 1/10
Specific Service Charges		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Duplicate invoices for previous billing	$	15.00
New Services	$	250.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque charge (plus bank charges)	$	25.50
Account set up charge / change of occupancy charge	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Late Payment - per month	%	1.50
Collection of account charge – no disconnection	$	15.00
Disconnect/Reconnect at meter – during regular hours	$	30.00
Disconnect/Reconnect at meter – after regular hours	$	130.00
Disconnect/Reconnect at pole – during regular hours	$	100.00
Disconnect/Reconnect at pole – after regular hours	$	300.00
Install / remove load control device – during regular hours	$	30.00
Install / remove load control device – after regular hours	$	130.00
Service call – after regular hours	$	130.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Retailer Service Agreement -- standard charge	$	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	(0.30)
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)
LOSS FACTORS		
Secondary Metered Customer < 5,000 kW		1.0466
Secondary Metered Customer > 5,000 kW		
Primary Metered Customer < 5,000 kW		1.0466
Primary Metered Customer > 5,000 kW		

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Residential

Volume		RPP	Distribution Charges		Total Bill	
kWh *	kW	Rate Class	$ change	% change	$ change	% change
800		Summer	$0.58	4.4%	($5.58)	(6.8%)
800		Winter	$0.58	4.4%	($5.47)	(6.9%)

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Residential **RPP: Summer**

800 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$5.96			$7.47	$1.51	25.3%
†	Distribution	kWh	800	$0.0092	$7.33	800	$0.0080	$6.40	($0.93)	(12.7%)
	Sub-Total (Distribution)				**$13.29**			**$13.87**	**$0.58**	**4.4%**
†	Deferral/Variance	kWh	800			800	($0.0054)	($4.32)	($4.32)	
	Electricity (Commodity)	kWh	851	RPP-Summer	$50.75	837	RPP-Summer	$49.86	($0.89)	(1.8%)
†	Transmission - Network	kWh	851	$0.0047	$4.00	837	$0.0044	$3.68	($0.32)	(8.0%)
†	Transmission - Connection	kWh	851	$0.0030	$2.55	837	$0.0024	$2.01	($0.54)	(21.2%)
	Wholesale Market Service	kWh	851	$0.0052	$4.42	837	$0.0052	$4.35	($0.07)	(1.6%)
	Rural Rate Protection	kWh	851	$0.0013	$1.11	837	$0.0013	$1.09	($0.02)	(1.8%)
	Debt Retirement Charge	kWh	800	$0.0070	$5.60	800	$0.0070	$5.60		
	TOTAL BILL				**$81.72**			**$76.14**	**($5.58)**	**(6.8%)**
†	*Delivery Only*				*$19.84*			*$15.24*	*($4.60)*	*(23.2%)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Residential RPP: Winter
800 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$5.96			$7.47	$1.51	25.3%
†	Distribution	kWh	800	$0.0092	$7.33	800	$0.0080	$6.40	($0.93)	(12.7%)
	Sub-Total (Distribution)				**$13.29**			**$13.87**	**$0.58**	**4.4%**
†	Deferral/Variance	kWh	800			800	($0.0054)	($4.32)	($4.32)	
	Electricity (Commodity)	kWh	851	RPP-Winter	$48.50	837	RPP-Winter	$47.72	($0.78)	(1.6%)
†	Transmission - Network	kWh	851	$0.0047	$4.00	837	$0.0044	$3.68	($0.32)	(8.0%)
†	Transmission - Connection	kWh	851	$0.0030	$2.55	837	$0.0024	$2.01	($0.54)	(21.2%)
	Wholesale Market Service	kWh	851	$0.0052	$4.42	837	$0.0052	$4.35	($0.07)	(1.6%)
	Rural Rate Protection	kWh	851	$0.0013	$1.11	837	$0.0013	$1.09	($0.02)	(1.8%)
	Debt Retirement Charge	kWh	800	$0.0070	$5.60	800	$0.0070	$5.60		
	TOTAL BILL				**$79.47**			**$74.00**	**($5.47)**	**(6.9%)**
†	*Delivery Only*				*$19.84*			*$15.24*	*($4.60)*	*(23.2%)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

General Service Less Than 50 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
2,000		Non-res.	$5.51	26.2%	($10.87)	(5.5%)

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

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General Service Less Than 50 kW **RPP: Non-res.**

2,000 kWh's		Metric	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
†	Monthly Service Charge				$10.73			$15.31	$4.58	42.7%
†	Distribution	kWh	2,000	$0.0051	$10.27	2,000	$0.0056	$11.20	$0.93	9.0%
	Sub-Total (Distribution)				**$21.00**			**$26.51**	**$5.51**	**26.2%**
†	Deferral/Variance	kWh	2,000			2,000	($0.0059)	($11.80)	($11.80)	
	Electricity (Commodity)	kWh	2,127	RPP-Non-res.	$133.63	2,093	RPP-Non-res.	$131.40	($2.23)	(1.7%)
†	Transmission - Network	kWh	2,127	$0.0043	$9.15	2,093	$0.0040	$8.37	($0.78)	(8.5%)
†	Transmission - Connection	kWh	2,127	$0.0027	$5.74	2,093	$0.0021	$4.40	($1.34)	(23.3%)
	Wholesale Market Service	kWh	2,127	$0.0052	$11.06	2,093	$0.0052	$10.88	($0.18)	(1.6%)
	Rural Rate Protection	kWh	2,127	$0.0013	$2.77	2,093	$0.0013	$2.72	($0.05)	(1.8%)
	Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
	TOTAL BILL				**$197.35**			**$186.48**	**($10.87)**	**(5.5%)**
†	*Delivery Only*				*$35.89*			*$27.48*	*($8.41)*	*(23.4%)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

General Service 50 to 4,999 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
90,000	240	Non-res.	$327.47	>100%	($419.10)	(5.0%)

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

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General Service 50 to 4,999 kW **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
90,000	**kWh's**									
240	**kW's**	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$47.50			$95.92	$48.42	>100%
†	Distribution	kW	240	$0.5422	$130.13	240	$1.7049	$409.18	$279.05	>100%
	Sub-Total (Distribution)				**$177.63**			**$505.10**	**$327.47**	**>100%**
†	Deferral/Variance	kW	240			240	($2.2926)	($550.22)	($550.22)	
	Electricity (Commodity)	kWh	95,715	RPP-Non-res.	$6,310.44	94,194	RPP-Non-res.	$6,210.05	($100.39)	(1.6%)
†	Transmission - Network	kW	240	$1.7399	$417.58	240	$1.6115	$386.76	($30.82)	(7.4%)
†	Transmission - Connection	kW	240	$1.0849	$260.38	240	$0.8547	$205.13	($55.25)	(21.2%)
	Wholesale Market Service	kWh	95,715	$0.0052	$497.72	94,194	$0.0052	$489.81	($7.91)	(1.6%)
	Rural Rate Protection	kWh	95,715	$0.0013	$124.43	94,194	$0.0013	$122.45	($1.98)	(1.6%)
	Debt Retirement Charge	kWh	90,000	$0.0070	$630.00	90,000	$0.0070	$630.00		
	TOTAL BILL				**$8,418.18**			**$7,999.08**	**($419.10)**	**(5.0%)**
†	*Delivery Only*				*$855.59*			*$546.77*	*($308.82)*	*(36.1%)*

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RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Sentinel Lighting

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
430	1.30	Non-res.	($1.80)	(23.3%)	($4.88)	(11.2%)

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

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Sentinel Lighting **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
	430 kWh's									
	1.30 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$1.00			$1.71	$0.71	71.0%
†	Distribution	kW	1	$5.1688	$6.72	1	$3.2418	$4.21	($2.51)	(37.3%)
	Sub-Total (Distribution)				**$7.72**			**$5.92**	**($1.80)**	**(23.3%)**
†	Deferral/Variance	kW	1			1	($1.5489)	($2.01)	($2.01)	
	Electricity (Commodity)	kWh	457	RPP-Non-res.	$26.07	450	RPP-Non-res.	$25.65	($0.42)	(1.6%)
†	Transmission - Network	kW	1	$1.3127	$1.71	1	$1.2159	$1.58	($0.13)	(7.6%)
†	Transmission - Connection	kW	1	$1.7125	$2.23	1	$1.3492	$1.75	($0.48)	(21.5%)
	Wholesale Market Service	kWh	457	$0.0052	$2.38	450	$0.0052	$2.34	($0.04)	(1.7%)
	Rural Rate Protection	kWh	457	$0.0013	$0.59	450	$0.0013	$0.59		
	Debt Retirement Charge	kWh	430	$0.0070	$3.01	430	$0.0070	$3.01		
	TOTAL BILL				**$43.71**			**$38.83**	**($4.88)**	**(11.2%)**
†	*Delivery Only*				*$11.66*			*$7.24*	*($4.42)*	*(37.9%)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Street Lighting

Volume			Distribution Charges		Total Bill	
kWh *	**kW**	**RPP?**	**$ change**	**% change**	**$ change**	**% change**
85	0.23	Non-res.	$1.38	>100%	$0.68	8.9%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

`

Street Lighting RPP: Non-res.

			2009 BILL			2010 BILL			CHANGE IMPACT	
85 kWh's										
0.23 kW's		Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
†	Monthly Service Charge				$0.04			$0.60	$0.56	>100%
†	Distribution	kW	0	$3.3563	$0.77	0	$6.8897	$1.58	$0.81	>100%
	Sub-Total (Distribution)				**$0.81**			**$2.18**	**$1.38**	**>100%**
†	Deferral/Variance	kW	0			0	($2.3842)	($0.55)	($0.55)	
	Electricity (Commodity)	kWh	90	RPP-Non-res.	$5.15	89	RPP-Non-res.	$5.07	($0.08)	(1.6%)
†	Transmission - Network	kW	0	$1.3122	$0.30	0	$1.2154	$0.28	($0.02)	(6.7%)
†	Transmission - Connection	kW	0	$0.8387	$0.19	0	$0.6618	$0.15	($0.04)	(21.1%)
	Wholesale Market Service	kWh	90	$0.0052	$0.47	89	$0.0052	$0.46	($0.01)	(2.1%)
	Rural Rate Protection	kWh	90	$0.0013	$0.12	89	$0.0013	$0.12		
	Debt Retirement Charge	kWh	85	$0.0070	$0.60	85	$0.0070	$0.60		
	TOTAL BILL				**$7.64**			**$8.31**	**$0.68**	**8.9%**
†	*Delivery Only*				*$1.30*			*$2.06*	*$0.77*	*59.1%*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Unmetered Scattered Load

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
4,600		Non-res.	($15.42)	(46.5%)	($53.54)	(12.0%)

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Enter example volumes in kWh's (and kW's if applicable) for each customer class

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Unmetered Scattered Load **RPP: Non-res.**

4,600 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
†	Monthly Service Charge				$9.73			$7.19	($2.54)	(26.1%)
†	Distribution	kWh	4,600	$0.0051	$23.46	4,600	$0.0023	$10.58	($12.88)	(54.9%)
	Sub-Total (Distribution)				**$33.19**			**$17.77**	**($15.42)**	**(46.5%)**
†	Deferral/Variance	kWh	4,600			4,600	($0.0060)	($27.60)	($27.60)	
	Electricity (Commodity)	kWh	4,892	RPP-Non-res.	$316.13	4,814	RPP-Non-res.	$311.00	($5.13)	(1.6%)
†	Transmission - Network	kWh	4,892	$0.0043	$21.04	4,814	$0.0040	$19.26	($1.78)	(8.5%)
†	Transmission - Connection	kWh	4,892	$0.0027	$13.21	4,814	$0.0021	$10.11	($3.10)	(23.5%)
	Wholesale Market Service	kWh	4,892	$0.0052	$25.44	4,814	$0.0052	$25.03	($0.41)	(1.6%)
	Rural Rate Protection	kWh	4,892	$0.0013	$6.36	4,814	$0.0013	$6.26	($0.10)	(1.6%)
	Debt Retirement Charge	kWh	4,600	$0.0070	$32.20	4,600	$0.0070	$32.20		
	TOTAL BILL				**$447.57**			**$394.03**	**($53.54)**	**(12.0%)**
†	*Delivery Only*				*$67.44*			*$19.54*	*($47.90)*	*(71.0%)*

Proposed Changes to Conditions of Service

The filing requirements stipulate that in this section, an applicant must provide an explanation of proposed changes to the conditions of service. At the time of this application, HHI is not proposing any changes to its conditions of service.

Exhibit 9:

DEFERRAL AND VARIANCE ACCOUNTS

Exhibit 9: Deferral And Variance Accounts

Tab 1 (of 3): Status of Deferral and Variance Accounts

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

HHI is proposing to dispose of its variance accounts in accordance with the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) issued July 31, 2009 where the Board gives specific instructions on how to dispose of deferral and variance accounts in a rebasing year.

In its report, the Board specifically segregates the accounts into two groups. The list of accounts from both groups that are applicable to HHI and that HHI proposes to dispose of in its 2010 rebasing application is presented below.

<u>Revised Group 1:</u>

- 1550 Low Voltage Account;
- 1580 RSVA Wholesale Market Service Charge Account;
- 1584 RSVA Retail Transmission Network Charges Account;
- 1586 RSVA Retail Transmission Connection Charge Account;
- 1588 RSVA Power (Including Global Adj. Sub a/c) Account;
- 1590 Recovery of Regulatory Asset Balances Account; and

<u>Revised Group 2:</u>

- 1508 Other Regulatory Assets Account;
- 1518 RCVA Retail Account;
- 1525 Miscellaneous Deferred Debits Account;

- 1548 RCVA Service Transaction Account;
- 1555 Smart Meter Capital Account;
- 1562 Deferred PILs Account;
- 1563 Contra Account-PILs Account;
- 1570 Qualifying transition costs Account;
- 1571 Market Opening Variance Account;

The EDDVAR report proposes the following treatment for the accounts in both of these groups;

Group 1: Includes Accounts that do not require a prudence review;

Group 2: Includes Accounts that require a prudence review and lend themselves to a disposition threshold;

Notwithstanding the prudence review required on accounts in Group 2, the Board suggests that at the time of rebasing, all account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline. HHI supports the Board's suggestion and therefore proposes to dispose of all applicable variance and deferral account balances in this proceeding.

The total amount being requested for disposition is $1,895,598. This total includes the disposal of account 1590 – Recovery of Regulatory Asset Balances (residual), in the amount of ($26,217). This amount is not presented in the *Continuity Statement* but is included in the *Proposed Deferral/Variance Account Balance Recoveries.* The list of deferral and variance accounts that HHI proposes to dispose of, as well as their balances are presented at Exhibit 9, Tab 1, Schedule 1, Schedule 2.

DEFERRAL AND VARIANCE ACCOUNT BALANCES

The following table depicts the deferral and variance account and balances HHI proposes to recover.

Deferral / Variance Account	Recover Balance as at?	Additional Interest to 30 Apr/10?	Balance for Recovery [1]	Additional Interest for Recovery	Total Recovery Amount
1508-Other Regulatory Assets	31-Dec-08	YES	46,165	535	46,700
1518-RCVARetail	31-Dec-08	YES	2,165	27	2,193
1525-Miscellaneous Deferred Debits	31-Dec-08	YES	269,647	3,215	272,863
1548-RCVASTR	31-Dec-08	YES	10,500	130	10,630
1550-LV Variance Account	31-Dec-08	YES	144,670	1,822	146,492
1555-Smart Meters Capital Variance Account	No Recovery	NO			
1556-Smart Meters OM&A Variance Account	No Recovery	NO			
1562-Deferred Payments in Lieu of Taxes	No Recovery	NO			
1563-Account 1563 - Deferred PILs Contra Account	No Recovery	NO			
1565-Conservation and Demand Management Expenditures and Recoveries	No Recovery	NO			
1566-CDM Contra Account	No Recovery	NO			
1570-Qualifying Transition Costs	No Recovery	NO			
1571-Pre-market Opening Energy Variance	No Recovery	NO			
1580-RSVAWMS	31-Dec-08	YES	(315,210)	(4,256)	(319,467)
1582-RSVAONE-TIME	31-Dec-08	YES	13,303	134	13,436
1584-RSVANW	31-Dec-08	YES	(231,432)	(2,890)	(234,322)
1586-RSVACN	31-Dec-08	YES	(1,446,760)	(16,593)	(1,463,352)
1588-RSVAPOWER	31-Dec-08	YES	(391,204)	(5,785)	(396,988)
Sub-Total for Recovery					**(1,921,815)**
1590-Recovery of Regulatory Asset Balances (residual)	31-Dec-08	YES	25,872	345	26,217
Total Recoveries Required					**(1,895,598)**
Annual Recovery Amounts **# years:**	**2**				**(947,799)**

Hydro Hawkesbury did not record carrying charges on its deferral and variance accounts before 2008. A table was prepared to calculate the carrying charges back to year 2005 based on the interest rate provided by the OEB and adjustments were made to the recovery amounts where appropriate. The table is presented at Exhibit 9, Tab 1, Schedule 2, Attachment 1.

All of the interest expense was recorded in year 2008. Hydro Hawkesbury will continue to calculate the carrying charges quarterly going forward as per OEB regulations.

The total interest expense for the 4 year period is in the amount of $ 88,024.66. As can been seen from the evidence, the majority of the interest expense ($55,209.70) occurred in year 2008.

Carrying Charges

Variance Explanation

		YEAR 2005			
		2005 Year End Balance	Average Total Balance	2005 Interest Expense	Average Applicable Interest Rate
DEFERRAL & VARIANCE ACCOUNTS					
Other Regulatory Assets	1508	46,095.95	3,841.33	561.62	5.57%
Retail Services	1518	4,248.00	354.00	-	0.00%
Miscelleneous Deferred Debits	1525	273,603.46	22,800.29	-	0.00%
RCVA STR	1548	6,220.60	518.38	-	0.00%
Low Voltage	1550	-	-	-	0.00%
SMART METER	1555	-	-	-	0.00%
Def Payments in Lieu of Taxes	1562	(235,803.00)	(19,650.25)	(18,712.16)	7.25%
Deferred Pil's - Contra Acct	1563	235,803.00	19,650.25	18,712.16	7.25%
CDM Program	1565	(60,670.10)	(5,055.84)	(23.71)	5.75%
CDM Contra Account	1566	60,670.10	5,055.84	23.71	5.75%
Trans Costs-Billing Activities	1570	204,089.53	17,007.46	16,334.41	7.25%
Pre-market Opening Energy	1571	(103,455.68)	(8,621.31)	(7,500.55)	7.25%
Wholesale Market Service	1580	279,818.61	23,318.22	17,349.60	7.25%
RSVA - One Time	1582	24,850.95	2,070.91	1,386.73	7.25%
Transmission Network	1584	(64,906.51)	(5,408.88)	(2,673.45)	7.25%
Transmission Connection	1586	(1,062,491.30)	(88,540.94)	(59,464.51)	7.25%
Power-Energy	1588	213,932.82	17,827.74	42,429.80	7.25%
RSVA - Rate Rider	1590	139,329.35	11,610.78	10,256.54	7.25%
				18,680.19	

Carrying Charges
Variance Explanation

		YEAR 2006			
DEFERRAL & VARIANCE ACCOUNTS		2006 Year End Balance	Average Total Balance	2006 Interest Expense	Average Applicable Interest Rate
Other Regulatory Assets	1508	40,111.38	3,342.62	1,996.34	5.60%
Retail Services	1518	1,057.54	88.13	62.72	4.44%
Miscelleneous Deferred Debits	1525	241,154.92	20,096.24	7,473.31	4.44%
RCVA STR	1548	4,691.21	390.93	129.64	4.44%
Low Voltage	1550	53,395.46	4,449.62	1,141.09	4.44%
SMART METER	1555	(9,330.14)	(777.51)	(111.20)	4.44%
Def Payments in Lieu of Taxes	1562	(93,073.66)	(7,756.14)	(11,882.53)	5.53%
Deferred Pil's - Contra Acct	1563	93,073.66	7,756.14	11,882.53	5.53%
CDM Program	1565	(13,145.84)	(1,095.49)	-	0.00%
CDM Contra Account	1566	13,145.84	1,095.49	-	0.00%
Trans Costs-Billing Activities	1570	-	-	6,276.69	5.53%
Pre-market Opening Energy	1571	-	-	(3,181.73)	5.53%
Wholesale Market Service	1580	(114,353.32)	(9,529.44)	5,730.07	5.53%
RSVA - One Time	1582	10,043.68	836.97	996.68	5.53%
Transmission Network	1584	(33,655.92)	(2,804.66)	(2,463.29)	5.53%
Transmission Connection	1586	(790,736.16)	(65,894.68)	(51,721.49)	5.53%
Power-Energy	1588	41,636.78	3,469.73	2,409.89	5.53%
RSVA - Rate Rider	1590	139,103.09	11,591.92	8,724.62	5.53%
				(22,536.66)	

Carrying Charges
Variance Explanation

DEFERRAL & VARIANCE ACCOUNTS		YEAR 2007 2007 Year End Balance	Average Total Balance	2007 Interest Expense	Average Applicable Interest Rate
Other Regulatory Assets	1508	40,111.38	3,342.62	1,896.72	4.73%
Retail Services	1518	213.77	17.81	42.90	4.73%
Miscelleneous Deferred Debits	1525	241,154.92	20,096.24	11,403.33	4.73%
RCVA STR	1548	7,211.01	600.92	282.24	4.73%
Low Voltage	1550	76,887.90	6,407.33	2,947.38	4.73%
SMART METER	1555	(25,879.97)	(2,156.66)	(775.46)	4.73%
Def Payments in Lieu of Taxes	1562	(53,138.73)	(4,428.23)	(4,142.42)	4.73%
Deferred Pil's - Contra Acct	1563	53,138.73	4,428.23	4,142.42	4.73%
CDM Program	1565	(805.44)	(67.12)	-	0.00%
CDM Contra Account	1566	805.44	67.12	-	0.00%
Trans Costs-Billing Activities	1570	-	-	-	4.73%
Pre-market Opening Energy	1571	-	-	-	4.73%
Wholesale Market Service	1580	(255,652.06)	(21,304.34)	(7,835.20)	4.73%
RSVA - One Time	1582	10,043.68	836.97	474.93	4.73%
Transmission Network	1584	(98,991.67)	(8,249.31)	(2,711.43)	4.73%
Transmission Connection	1586	(1,075,452.46)	(89,621.04)	(43,509.92)	4.73%
Power-Energy	1588	(141,152.80)	(11,762.73)	3,839.33	4.73%
RSVA - Rate Rider	1590	71,707.21	5,975.60	4,986.69	4.73%
				(28,958.49)	

Carrying Charges
Variance Explanation

		YEAR 2008			
		2008 Year End Balance	Average Total Balance	2008 Interest Expense	Average Applicable Interest Rate
DEFERRAL & VARIANCE ACCOUNTS					
Other Regulatory Assets	1508	40,111.38	3,342.62	1,599.42	3.98%
Retail Services	1518	2,034.68	169.56	25.15	3.98%
Miscelleneous Deferred Debits	1525	241,154.92	20,096.24	9,615.93	3.98%
RCVA STR	1548	9,756.15	813.01	332.01	3.98%
Low Voltage	1550	136,667.89	11,388.99	3,913.14	3.98%
SMART METER	1555	(42,527.36)	(3,543.95)	(1,308.88)	3.98%
Def Payments in Lieu of Taxes	1562	(58,833.10)	(4,902.76)	(2,118.87)	3.98%
Deferred Pil's - Contra Acct	1563	58,833.10	4,902.76	2,118.87	3.98%
CDM Program	1565	(805.44)	(67.12)	-	0.00%
CDM Contra Account	1566	805.44	67.12	-	0.00%
Trans Costs-Billing Activities	1570	-	-	-	3.98%
Pre-market Opening Energy	1571	-	-	-	3.98%
Wholesale Market Service	1580	(319,236.53)	(26,603.04)	(11,218.15)	3.98%
RSVA - One Time	1582	10,043.68	836.97	400.49	3.98%
Transmission Network	1584	(216,773.17)	(18,064.43)	(6,810.66)	3.98%
Transmission Connection	1586	(1,244,442.97)	(103,703.58)	(47,620.78)	3.98%
Power-Energy	1588	(433,840.88)	(36,153.41)	(6,041.80)	3.98%
RSVA - Rate Rider	1590	37,130.56	3,094.21	1,904.43	3.98%
				(55,209.70)	

B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 1.00%	1-Jan-2005 to 31-Dec-2005					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	5,429	40,667	46,096			
1518-RCVARetail	3,337	911	4,248			
1525-Miscellaneous Deferred Debits	88,476	185,127	273,603			
1548-RCVASTR	4,345	1,876	6,221			
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1562-Deferred Payments in Lieu of Taxes	(261,314)	25,511	(235,803)			
1563-Account 1563 - Deferred PILs Contra Account	261,314	(25,511)	235,803			
1565-Conservation and Demand Management Expenditures and Recoveries	745	(61,415)	(60,670)			
1566-CDM Contra Account		60,670	60,670			
1570-Qualifying Transition Costs	228,362	(24,272)	204,090			
1571-Pre-market Opening Energy Variance	(103,456)		(103,456)			
1580-RSVAWMS	189,779	90,039	279,819			
1582-RSVAONE-TIME	14,807	10,044	24,851			
1584-RSVANW	(32,687)	(32,220)	(64,907)			
1586-RSVACN	(578,533)	(483,958)	(1,062,491)			
1588-RSVAPOWER	271,445	(57,513)	213,933			
TOTAL	**92,049**	**(270,043)**	**(177,994)**			

B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 1.00%

	1-Jan-2006 to 31-Dec-2006					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	46,096	(5,985)	40,111			
1518-RCVARetail	4,248	(3,190)	1,058			
1525-Miscellaneous Deferred Debits	273,603	(32,449)	241,155			
1548-RCVASTR	6,221	(1,529)	4,691			
1550-LV Variance Account		53,395	53,395			
1555-Smart Meters Capital Variance Account		(9,330)	(9,330)			
1556-Smart Meters OM&A Variance Account						
1562-Deferred Payments in Lieu of Taxes	(235,803)	142,729	(93,074)			
1563-Account 1563 - Deferred PILs Contra Account	235,803	(142,729)	93,074			
1565-Conservation and Demand Management Expenditures and Recoveries	(60,670)	47,524	(13,146)			
1566-CDM Contra Account	60,670	(47,524)	13,146			
1570-Qualifying Transition Costs	204,090	(204,090)				
1571-Pre-market Opening Energy Variance	(103,456)	103,456				
1580-RSVAWMS	279,819	(394,172)	(114,353)			
1582-RSVAONE-TIME	24,851	(14,807)	10,044			
1584-RSVANW	(64,907)	31,251	(33,656)			
1586-RSVACN	(1,062,491)	271,755	(790,736)			
1588-RSVAPOWER	213,933	(172,296)	41,637			
TOTAL	**(177,994)**	**(377,991)**	**(555,985)**			

B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 1.00%

	1-Jan-2007 to 31-Dec-2007					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	40,111		40,111			
1518-RCVARetail	1,058	(844)	214			
1525-Miscellaneous Deferred Debits	241,155		241,155			
1548-RCVASTR	4,691	2,520	7,211			
1550-LV Variance Account	53,395	23,492	76,888			
1555-Smart Meters Capital Variance Account	(9,330)	(16,550)	(25,880)			
1556-Smart Meters OM&A Variance Account						
1562-Deferred Payments in Lieu of Taxes	(93,074)	39,935	(53,139)			
1563-Account 1563 - Deferred PILs Contra Account	93,074	(39,935)	53,139			
1565-Conservation and Demand Management Expenditures and Recoveries	(13,146)	12,340	(805)			
1566-CDM Contra Account	13,146	(12,340)	805			
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1580-RSVAWMS	(114,353)	(141,299)	(255,652)			
1582-RSVAONE-TIME	10,044		10,044			
1584-RSVANW	(33,656)	(65,336)	(98,992)			
1586-RSVACN	(790,736)	(284,716)	(1,075,452)			
1588-RSVAPOWER	41,637	(182,790)	(141,153)			
TOTAL	**(555,985)**	**(665,522)**	**(1,221,506)**			

B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 1.00%

	1-Jan-2008 to 31-Dec-2008					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	40,111		40,111		6,054	6,054
1518-RCVARetail	214	1,821	2,035		131	131
1525-Miscellaneous Deferred Debits	241,155		241,155		28,493	28,493
1548-RCVASTR	7,211	2,545	9,756		744	744
1550-LV Variance Account	76,888	59,780	136,668		8,002	8,002
1555-Smart Meters Capital Variance Account	(25,880)	(16,647)	(42,527)		(2,196)	(2,196)
1556-Smart Meters OM&A Variance Account						
1562-Deferred Payments in Lieu of Taxes	(53,139)		(53,139)			
1563-Account 1563 - Deferred PILs Contra Account	53,139		53,139			
1565-Conservation and Demand Management Expenditures and Recoveries	(805)		(805)			
1566-CDM Contra Account	805		805			
1570-Qualifying Transition Costs					22,611	22,611
1571-Pre-market Opening Energy Variance					(10,682)	(10,682)
1580-RSVAWMS	(255,652)	(63,584)	(319,237)		4,026	4,026
1582-RSVAONE-TIME	10,044		10,044		3,259	3,259
1584-RSVANW	(98,992)	(117,782)	(216,773)		(14,659)	(14,659)
1586-RSVACN	(1,075,452)	(168,991)	(1,244,443)		(202,317)	(202,317)
1588-RSVAPOWER	(141,153)	(292,688)	(433,841)		42,637	42,637
TOTAL	**(1,221,506)**	**(595,546)**	**(1,817,052)**		**(113,897)**	**(113,897)**
					(88,025)	

B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 1.00%	31-Dec-2008 Balance			1-Jan-09 to 30-Apr-09		
Deferral / Variance Account	**Principal**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1508-Other Regulatory Assets	40,111	6,054	46,165	134		46,299
1518-RCVARetail	2,035	131	2,165	7		2,172
1525-Miscellaneous Deferred Debits	241,155	28,493	269,647	804		270,451
1548-RCVASTR	9,756	744	10,500	33		10,533
1550-LV Variance Account	136,668	8,002	144,670	456		145,125
1555-Smart Meters Capital Variance Account	(42,527)	(2,196)	(44,723)	(142)		(44,865)
1556-Smart Meters OM&A Variance Account						
1562-Deferred Payments in Lieu of Taxes	(53,139)		(53,139)	(177)		(53,316)
1563-Account 1563 - Deferred PILs Contra Account	53,139		53,139	177		53,316
1565-Conservation and Demand Management Expenditures and Recoveries	(805)		(805)			(805)
1566-CDM Contra Account	805		805			805
1570-Qualifying Transition Costs		22,611	22,611			22,611
1571-Pre-market Opening Energy Variance		(10,682)	(10,682)			(10,682)
1580-RSVAWMS	(319,237)	4,026	(315,210)	(1,064)		(316,274)
1582-RSVAONE-TIME	10,044	3,259	13,303	33		13,336
1584-RSVANW	(216,773)	(14,659)	(231,432)	(723)		(232,155)
1586-RSVACN	(1,244,443)	(202,317)	(1,446,760)	(4,148)		(1,450,908)
1588-RSVAPOWER	(433,841)	42,637	(391,204)	(1,446)		(392,650)
TOTAL	**(1,817,052)**	**(113,897)**	**(1,930,949)**	**(6,057)**		**(1,937,006)**

B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 1.00%

Deferral / Variance Account	1-May-09 to 31-Dec-09 Interest	Other	Balance	1-Jan-10 to 30-Apr-10 Interest	Other	Balance
1508-Other Regulatory Assets	267		46,567	134		46,700
1518-RCVARetail	14		2,186	7		2,193
1525-Miscellaneous Deferred Debits	1,608		272,059	804		272,863
1548-RCVASTR	65		10,598	33		10,630
1550-LV Variance Account	911		146,036	456		146,492
1555-Smart Meters Capital Variance Account	(284)		(45,148)	(142)		(45,290)
1556-Smart Meters OM&A Variance Account		15,091	15,091	50	16,718	31,859
1562-Deferred Payments in Lieu of Taxes	(354)		(53,670)	(177)		(53,847)
1563-Account 1563 - Deferred PILs Contra Account	354		53,670	177		53,847
1565-Conservation and Demand Management Expenditures and Recoveries			(805)			(805)
1566-CDM Contra Account			805			805
1570-Qualifying Transition Costs			22,611			22,611
1571-Pre-market Opening Energy Variance			(10,682)			(10,682)
1580-RSVAWMS	(2,128)		(318,403)	(1,064)		(319,467)
1582-RSVAONE-TIME	67		13,403	33		13,436
1584-RSVANW	(1,445)		(233,600)	(723)		(234,322)
1586-RSVACN	(8,296)		(1,459,204)	(4,148)		(1,463,352)
1588-RSVAPOWER	(2,892)		(395,542)	(1,446)		(396,988)
TOTAL	**(12,114)**	**15,091**	**(1,934,029)**	**(6,007)**	**16,718**	**(1,923,317)**

B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 1.00%

Deferral / Variance Account	31-Dec-08 Balance + Interest to 30-Apr-10			1-May-10 to 31-Dec-10		
	31-Dec-08	Interest	Total	Interest	Other	Balance
1508-Other Regulatory Assets	46,165	535	46,700	267		46,968
1518-RCVARetail	2,165	27	2,193	14		2,206
1525-Miscellaneous Deferred Debits	269,647	3,215	272,863	1,608		274,471
1548-RCVASTR	10,500	130	10,630	65		10,695
1550-LV Variance Account	144,670	1,822	146,492	911		147,403
1555-Smart Meters Capital Variance Account	(44,723)	(567)	(45,290)	(284)		(45,573)
1556-Smart Meters OM&A Variance Account		50	50	212	50,152	82,223
1562-Deferred Payments in Lieu of Taxes	(53,139)	(709)	(53,847)	(354)		(54,202)
1563-Account 1563 - Deferred PILs Contra Account	53,139	709	53,847	354		54,202
1565-Conservation and Demand Management Expenditures and Recoveries	(805)		(805)			(805)
1566-CDM Contra Account	805		805			805
1570-Qualifying Transition Costs	22,611		22,611			22,611
1571-Pre-market Opening Energy Variance	(10,682)		(10,682)			(10,682)
1580-RSVAWMS	(315,210)	(4,256)	(319,467)	(2,128)		(321,595)
1582-RSVAONE-TIME	13,303	134	13,436	67		13,503
1584-RSVANW	(231,432)	(2,890)	(234,322)	(1,445)		(235,767)
1586-RSVACN	(1,446,760)	(16,593)	(1,463,352)	(8,296)		(1,471,649)
1588-RSVAPOWER	(391,204)	(5,785)	(396,988)	(2,892)		(399,880)
TOTAL	**(1,930,949)**	**(24,177)**	**(1,955,126)**	**(11,902)**	**50,152**	**(1,885,067)**

Exhibit 9: Deferral And Variance Accounts

Tab 2 (of 3): Clearance of Deferral and Variance Accounts

CALCULATION OF RATE RIDERS

An appropriate allocator has been assigned to each variance/deferral account. These allocators are described in Exhibit 9, Tab 2, Schedule 2, Attachment 1. Account balances are then apportioned to each customer class based on Test Year volume projections for the allocator. For each customer class, the sum of the allocated balances is calculated for all Accounts selected for disposition. For each customer class, the sum of allocated balances is the recovery amount needed to clear the balances.

For each customer class, the rate rider is calculated as the annual recovery amount divided by the 2010 Test Year forecast for the distribution rate volume metric, with the result rounded to the nearest one-hundredth of a cent.

HHI has calculated the ending balance for each variance account as the actual balance as at December 31, 2005, 2006, 2007 and 2008. These balances agree with our audited financial statements for the years 2005, 2006, 2007 and 2008.

Carrying Costs up to April 30, 2010 have been calculated and added to the account balances to determine the final totals for disposal in this Rate Application. The net result is a ratepayer credit in the amount of $1,895,598. In its report entitled EDDVAR, the Board stipulates that in a rebasing year, a distributor should be required to dispose of all Account balances. Because of the significant amount of the total disposition, HHI proposes to dispose of these balances over two years, commencing May 1, 2010 and ending on April 30, 2011. Balances proposed for disposition were recorded as of December 31, 2008.

HHI recognizes that ratepayers would normally prefer to receive a credit balance as soon as possible, but given the size of the balance relative to the size of HHI’s customer base, a one year disposition would expose ratepayers to larger bill increases in year two of the IRM term than they would otherwise experience if the credit was spread over two years. HHI considered disposing the credit balance over four years to smooth the bill impact even further, but thought ratepayers would prefer a two year disposition during the economic recovery. Ratepayers would of course continue to earn interest on the outstanding balances.

The proposed rate rider table can be found at Exhibit 9, Tab 2, Schedule 1, Attachment 1. The option of a proposed rate rider table excluding recovery of RSVA accounts can be found at Exhibit 9, Tab 2, Schedule 1, Attachment 2. Excluding RSVA accounts, HHI would be looking to recover $478,878 from its ratepayers while retaining a credit balance of $2,374,476, which is almost 5 times that amount.

C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Large Use
1508-Other Regulatory Assets	46,700	Distribution Revenue (existing rates)	31,981	7,123	6,998	
1518-RCVARetail	2,193	Customer Count	1,927	233	32	
1525-Miscellaneous Deferred Debits	272,863	kWh's	90,298	34,667	145,306	
1548-RCVASTR	10,630	# Customers w/ Rebate Cheques	9,475	1,155		
1550-LV Variance Account	146,492	Transmission Connection Revenue	51,983	17,463	75,897	
1580-RSVAWMS	(319,467)	kWh's	(105,720)	(40,588)	(170,123)	
1582-RSVAONE-TIME	13,436	kWh's	4,446	1,707	7,155	
1584-RSVANW	(234,322)	kWh's	(77,543)	(29,771)	(124,782)	
1586-RSVACN	(1,463,352)	kWh's	(484,262)	(185,920)	(779,269)	
1588-RSVAPOWER	(396,988)	kWh's	(131,374)	(50,438)	(211,405)	
Sub-Total for recovery	**(1,921,815)**		**(608,790)**	**(244,368)**	**(1,050,191)**	
1590-Recovery of Regulatory Asset Balances (residual)	26,217	2006 EDR Approved Recoveries	28,566	1,153	(3,551)	
Total Recoveries Required (2 years)	**(1,895,598)**		**(580,224)**	**(243,216)**	**(1,053,742)**	
Annual Recovery Amounts	(947,799)		(290,112)	(121,608)	(526,871)	
Annual Volume			53,559,119	20,562,650	229,814	
Proposed Rate Rider			**($0.0054)**	**($0.0059)**	**($2.2926)**	
per			kWh	kWh	kW	kW

[1] per sheet C6

C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Sentinel Lighting	Street Lighting	Unmetered Scattered Load
1508-Other Regulatory Assets	46,700	Distribution Revenue (existing rates)	80	452	66
1518-RCVARetail	2,193	Customer Count	0	0	
1525-Miscellaneous Deferred Debits	272,863	kWh's	183	2,037	372
1548-RCVASTR	10,630	# Customers w/ Rebate Cheques			
1550-LV Variance Account	146,492	Transmission Connection Revenue	169	792	187
1580-RSVAWMS	(319,467)	kWh's	(214)	(2,385)	(436)
1582-RSVAONE-TIME	13,436	kWh's	9	100	18
1584-RSVANW	(234,322)	kWh's	(157)	(1,749)	(319)
1586-RSVACN	(1,463,352)	kWh's	(981)	(10,926)	(1,995)
1588-RSVAPOWER	(396,988)	kWh's	(266)	(2,964)	(541)
Sub-Total for recovery	**(1,921,815)**		**(1,176)**	(14,643)	(2,648)
1590-Recovery of Regulatory Asset Balances (residual)	26,217	2006 EDR Approved Recoveries	169	(120)	
Total Recoveries Required (2 years)	**(1,895,598)**		**(1,007)**	(14,763)	(2,648)
Annual Recovery Amounts	(947,799)		(503)	(7,381)	(1,324)
Annual Volume			325	3,096	220,667
Proposed Rate Rider			**($1.5489)**	**($2.3842)**	**($0.0060)**
per			kW	kW	kWh

[1] per sheet C6

C7 Rate Riders

Allocators	Data Source	2010 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Large Use
Customers / Connections	C1	6,533	4,705	566	79	
kWh's	C1	161,846,035	53,559,119	20,562,650	86,186,766	
Distribution Revenue (existing rates)	C4	1,125,656	770,857	171,696	168,687	
Distribution Revenue (proposed rates)	F4	1,304,216	738,714	199,741	334,300	
Transmission Connection Revenue	C2	379,120	134,532	45,194	196,422	
Customer Count	C1	5,354	4,705	568	79	
# Customers w/ Rebate Cheques	2006 EDR	5,208	4,642	566		
2006 EDR Approved Recoveries	2006 EDR	130,642	142,346	5,744	(17,695)	
Approved Recoveries	C5					

C7 Rate Riders

Allocators	Data Source	2010 Projection Total	Sentinel Lighting	Street Lighting	Unmetered Scattered Load
Customers / Connections	C1	6,533	21	1,158	4
kWh's	C1	161,846,035	108,470	1,208,363	220,667
Distribution Revenue (existing rates)	C4	1,125,656	1,932	10,891	1,592
Distribution Revenue (proposed rates)	F4	1,304,216	1,403	29,286	772
Transmission Connection Revenue	C2	379,120	438	2,049	485
Customer Count	C1	5,354	1	1	
# Customers w/ Rebate Cheques	2006 EDR	5,208			
2006 EDR Approved Recoveries	2006 EDR	130,642	844	(598)	
Approved Recoveries	C5				

C7 Rate Rider Excluding RSVA Accounts

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Large Use
1508-Other Regulatory Assets	46,700	Distribution Revenue (existing rates)	31,981	7,123	6,998	
1518-RCVARetail	2,193	Customer Count	1,927	233	32	
1525-Miscellaneous Deferred Debits	272,863	kWh's	90,298	34,667	145,306	
1548-RCVASTR	10,630	# Customers w/ Rebate Cheques	9,475	1,155		
1550-LV Variance Account	146,492	Transmission Connection Revenue	51,983	17,463	75,897	
1580-RSVAWMS		kWh's				
1582-RSVAONE-TIME		kWh's				
1584-RSVANW		kWh's				
1586-RSVACN		kWh's				
1588-RSVAPOWER		kWh's				
Sub-Total for recovery	**478,878**		**185,663**	**60,641**	**228,234**	
1590-Recovery of Regulatory Asset Balances (residual)	26,217	2006 EDR Approved Recoveries	28,566	1,153	(3,551)	
Total Recoveries Required (2 years)	**505,095**		**214,229**	**61,794**	**224,683**	
Annual Recovery Amounts	252,547		107,115	30,897	112,341	
Annual Volume			53,559,119	20,562,650	229,814	
Proposed Rate Rider			**$0.0020**	**$0.0015**	**$0.4888**	
per			kWh	kWh	kW	kW

[1] per sheet C6

C7 Rate Rider Excluding RSVA Accounts

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Sentinel Lighting	Street Lighting	Unmetered Scattered Load
1508-Other Regulatory Assets	46,700	Distribution Revenue (existing rates)	80	452	66
1518-RCVARetail	2,193	Customer Count	0	0	
1525-Miscellaneous Deferred Debits	272,863	kWh's	183	2,037	372
1548-RCVASTR	10,630	# Customers w/ Rebate Cheques			
1550-LV Variance Account	146,492	Transmission Connection Revenue	169	792	187
1580-RSVAWMS		kWh's			
1582-RSVAONE-TIME		kWh's			
1584-RSVANW		kWh's			
1586-RSVACN		kWh's			
1588-RSVAPOWER		kWh's			
Sub-Total for recovery	**478,878**		**433**	3,281	625
1590-Recovery of Regulatory Asset Balances (residual)	26,217	2006 EDR Approved Recoveries	169	(120)	
Total Recoveries Required (2 years)	**505,095**		**602**	3,161	625
Annual Recovery Amounts	252,547		301	1,581	313
Annual Volume			325	3,096	220,667
Proposed Rate Rider			**$0.9264**	**$0.5105**	**$0.0014**
per			kW	kW	kWh

[1] per sheet C6

C7 Rate Rider Excluding RSVA Accounts

Allocators	Data Source	2010 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Large Use
Customers / Connections	C1	6,533	4,705	566	79	
kWh's	C1	161,846,035	53,559,119	20,562,650	86,186,766	
Distribution Revenue (existing rates)	C4	1,125,656	770,857	171,696	168,687	
Distribution Revenue (proposed rates)	F4	1,304,216	738,714	199,741	334,300	
Transmission Connection Revenue	C2	379,120	134,532	45,194	196,422	
Customer Count	C1	5,354	4,705	568	79	
# Customers w/ Rebate Cheques	2006 EDR	5,208	4,642	566		
2006 EDR Approved Recoveries	2006 EDR	130,642	142,346	5,744	(17,695)	
Approved Recoveries	C5					

C7 Rate Rider Excluding RSVA Accounts

Allocators	Data Source	2010 Projection Total	Sentinel Lighting	Street Lighting	Unmetered Scattered Load
Customers / Connections	C1	6,533	21	1,158	4
kWh's	C1	161,846,035	108,470	1,208,363	220,667
Distribution Revenue (existing rates)	C4	1,125,656	1,932	10,891	1,592
Distribution Revenue (proposed rates)	F4	1,304,216	1,403	29,286	772
Transmission Connection Revenue	C2	379,120	438	2,049	485
Customer Count	C1	5,354	1	1	
# Customers w/ Rebate Cheques	2006 EDR	5,208			
2006 EDR Approved Recoveries	2006 EDR	130,642	844	(598)	
Approved Recoveries	C5				

Exhibit 9: Deferral And Variance Accounts

Tab 3 (of 3): Smart Meters

SMART METER DEPLOYMENT PLAN

The following schedule present information regarding HHI's commitment to meet the Ministry's Smart Meter Initiative.

HHI is authorized by virtue of paragraph 8 of section 1 (1) of O.Reg 427/06 to procure smart meters were procured pursuant to the in compliance with the August 14, 2007 Request for Proposal issue by London Hydro Inc. At this time and as per G-2008-0002, HHI is authorized to charge the standard $1.00 funding adder.

HHI is described as a smart meter "implementing" utility. It has procured its meters in compliance with the August 14, 2007 Request for Proposal issued by London Hydro Inc. At year end 2009, HHI will have deployed and installed 1500 meters and plans to deploy the remainder (3225) during the test year.

HHI wishes to apply for a Utility-Specific Smart Meter Funding Adder of $1.51 per metered customer per month.

The following required information is presented in support of this request.

1) A detailed smart meter plan which includes the number of meters proposed to be installed and an installation schedule for each month during which the proposed smart meter funding adder is expected to be in effect.

   - New Reporting Requirements Related to Smart Meter Deployment and the Application of Time-of-Use Pricing at Tab 3, Schedule 1, Attachment 1 of this Exhibit provide details on current status of HHI's implementation status

   - Capital and Operating Costs at Tab 3, Schedule 1, Attachment 3 of this Exhibit provide details on future smart meter implementation.

2) Actual or estimated costs in total. (Tab 3, Schedule 1, Attachment 3 of this Exhibit)

- Capital Costs: $862,183
- Variable Costs: $30,922

3) Customer information system

- $22,500

4) Incremental operating and maintenance activites

- MAS Hardware cost (ORPC) $13,770.00
- Operation data Store ($.20 per meter per month) $12,902.40
- Bell phone line ($60per month per bell line) $4,320.00

5) Changes to ancillary systems

- $0

6) Stranded meters

- At year-end 2009: 1500 meters @ $41.82/meter
- At year-end 2010: 3225 meters @ $41.82/meter

Further background information on procurement and cost information is provided in the following attachments.

HHI attests that it has purchased, smart meters and/or metering infrastructure (“AMI”) whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, and an estimate of those costs.

HHI is not proposing to dispose of deferral accounts 1555 & 1556 until they have been audited as part of its regular annual audit in the spring of 2010.

Memorandum

To: Michel Poulin

From: Doug Fee

Date: September 10, 2009

Re: Elster MAS Costs

We have done a quick estimate of the costs for the provision of MAS service to Hawkesbury. It is based on the cost for ORPC prorated by the number of customers in each utility with a hardware and software life of 5 years. Costs are still being developed by Harris, IESO, etc. and the complete scope of the work is not completely known.

On this basis the estimated cost for Hawkesbury would be:

Item	Cost
MAS hardware cost, software, annual software maintenance fee and estimate for ORPC ongoing monitoring and troubleshooting system	$13,770/year
Operation Data Store (Utilismart pass though) this appears to be a new requirement that has arisen that we originally thought would be looked after by the MDMR. It will be used in the interim basis to create the file for upload to Harris until MDMR is operational and after as a data store for data to query by the utility. (Harris will also have an offering for this service. At this time they have not provided pricing)	$0.20/meter/month
MDMR – the IESO have not provided costing yet , this is guess at best	$0.20/meter/month
Elster Project Support Services – ORPC paid a fee in 2007 for this service, this year the other utilities paid a fee as well under Elster's new pricing structure	N/C
Harris Work – integration of ODS of third party vendor (ie Utilismart) for the interim transfer of data from the MAS to Harris Northstar.	Likely a cost through your CIS supplier
Harris Work – integration of the Harris Northstar, MAS and MDMR once the MDMR is ready to go.	Likely a cost through your CIS Supplier

HYDRO HAWKESBURY INC.

October 7th 2009

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Re: New Reporting Requirements Related to Smart Meter Deployment and the Application of Time-of-Use Pricing

Attached is the baseline report information (appendix A,B & C) for the quarter ending September 30th 2009 regarding smart meter deployment and TOU pricing for Hydro Hawkesbury Inc.

If you have any questions, please contact the undersigned.

Yours sincerely,

Michel Poulin
Manager.
613-632-6689

Hydro Hawkesbury Inc. - ED-1999-0233

Baseline Report: Part I

1 **SMART METER CONTRACT**: Hydro Hawkesbury Inc. has entered into a contract with Elster Canadian Meter on March 5, 2009.
One hundred percent (100%) of our meters will be acquired from them. Hydro hawkesbury is part of a group of
Utilities putting their efforts together for the full implementation of an AMI system following the participation in the London RFP

2 **IMPLEMENTATION STATUS:** The installation of smart meters will start on July 2, 2009.
The first phase will cover 1500 residential meters in 2009. Remaining in 2010

3 **AMI:** Deployment of the AMI started at the ORPC facility. Hydro Hawkesbury Inc. is part of a group of Utilities putting effort towards full deployment.

4 **MDM/R INTEGRATION**: No work has been done on the integration of meters and systems with the provincial MDM/R.
We expect our small utility will complete work in early 2011.

5 **CIS INTEGRATION:** Hydro Hawkesbury Inc. has an ASP contract with E-Caliber
We are using Harris CIS system. Preliminary discussions are underway with our CIS vendor and other vendors
regarding the integration of the Elster MAS to the Harris CIS system.

6 **WEB PRESENTMENT:** We will be using the Web presentation from our ASP provider E-Caliber
Also the IESO has indicated that they may make this a feature of the MDM/R and we have indicated an interest in this proposal.

7 **CONSUMER EDUCATION:** As part of the smart meter installation program,
a brochure (MOE authorized) was provided to each customer providing information on the smart meter and the TOU billing.
It is planned that additional consumer information will be rolled out with the implementation of TOU billing in the Spring of 2011.

Hydro Hawkesbury Inc. - ED-1999-0233

Baseline Report: Part II

	Residential				GS>50kW			
Month	Meters Installed	Meters Enrolled	ToU Notice Sent	ToU Billing	Meters Installed	Meters Enrolled	ToU Notice Sent	ToU Billing
May-09	-	-	-	-	-	-	-	-
Jun-09	-	-	-	-	-	-	-	-
Jul-09	307	-	-	-	-	-	-	-
Aug-09	200	-	-	-	-	-	-	-
Sep-09	30	-	-	-	-	-	-	-
Oct-09	planned 400	-	-	-	-	-	-	-
Nov-09	planned 400	-	-	-	-	-	-	-
Dec-09	planned 193	-	-	-	-	-	-	-
Jan-10								
Feb-10								
Mar-10								
Apr-10								
May-10								
Jun-10								
Jul-10								
Aug-10								
Sep-10								
Oct-10								
Nov-10								
Dec-10								
Jan-11								
Feb-11								
Mar-11								
Apr-11								
May-11								
Jun-11								

Quarterly Reporting - Appendix C

Hydro Hawkesbury Inc.

For quarter ending: September 30, 2009

	RPP-eligible Consumers: Residential Class	RPP-eligible Consumers: General Service less than 50kW Class	Total
Total number of RPP-eligible consumers	4725	576	5301
Number of smart meters installed in the quarter	537	0	537
Number of smart meters registered with the MDM/R in the quarter	0	0	0
Number of RPP consumers being charged TOU in the quarter	0	0	0
Total cumulative number of smart meters installed in the service area at the end of the quarter	537	0	537
Total cumulative number of smart meters registered with the MDM/R at the end of the quarter	0	0	0
Total cumulative number of consumers being charged TOU prices at the end of the quarter	0	0	0
Percentage of total RPP-eligible consumers with smart meters installed at the end of the quarter	11%	0	11%
Percentage of total smart meters installed that are registered with the MDM/R at the end of the quarter	0	0	0
Percentage of total RPP-eligible consumers being charged TOU prices at the end of the quarter	0	0	0

Date on which MDM/R testing was completed:	n/a
Date on which AMI system installation and intergration was completed:	n/a

PRP International, Inc.

Fairness Advisory Services

May 30, 2008

Mr. Michel Poulin
Manager
Hydro Hawkesbury Inc.
850 Tupper Street,
Hawkesbury, ON K6A 3S7

Dear Mr. Poulin:

Subject: Attestation of the Fairness Commissioner
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its letter report of the Fairness Commissioner for the noted Request for Proposal (RFP) evaluation and selection phase. This judgment is being provided for the information and use of each Consortium LDC Sponsor, in their consideration of the report from the Evaluation Phase, for this competitive transaction.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner, that the determinations of the two (2) highest ranked Proponents for the Hydro Hawkesbury Inc. requirements are:

- *Silver Spring Networks, as the recommended Preferred Proponent, based on its highest ranking, and*
- *Elster Metering being the second ranked Proponent.*

These determinations were made in a fair (objective and competent) manner and consistent with the evaluation and selection processes set out in the RFP, issued August 14, 2007."

A detailed report for your records will be submitted to you, by August 31, 2008. Should you have any questions or require clarification of any matter contained in this letter report, please contact the undersigned.

Yours truly,

Peter Sorensen
President
cc: Mr. Gary Rains, RFP Project Director

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

PRP International, Inc.

Fairness Advisory Services

April 29, 2009

Hydro Hawkesbury Inc.
850 Tupper Street
Hawkesbury, Ontario K6A 3S7

Attention: Michel Poulin, Manager

Dear Mr. Poulin:

Subject: Attestation Letter (Negotiations) of the Fairness Commissioner
Hydro Hawkesbury - Elster Metering Contract Award
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its Attestation Letter (Negotiations) of the Fairness Commissioner for the noted negotiations and contracting phase of the London Hydro AMI Request for Proposal (RFP) procurement. This judgment is being provided for the information and use of Hydro Hawkesbury Inc., in its administration of the contract awarded to its #2 ranked Proponent, Elster Metering following unsuccessful negotiations with its #1 ranked Proponent, Silver Spring Networks.

"It is the judgment of PRP International, Inc. (as the Fairness Commissioner engaged by Hydro Hawkesbury *for the phase of negotiations and contract award) that the successful conclusion of negotiations and contract award to* Elster Metering, *was undertaken in accordance with the principles for such negotiations and contract award set out in the RFP, issued August 14, 2007 and the Fairness Protocol, issued August 2008."*

A backgrounder and summary of the Fairness Protocol is attached and forms part of this Attestation Letter (Negotiations).

Yours uly,

Pe er Sorensen
President

Attachment: Negotiations and Contract Phase Backgrounder

203 - 8 Queen Street, Summerside, PEI C1N 0A6
Direct telephone: 902.436.3930 Fax: 604-677-5409
Email: fairnessgtelus.net

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

TO WHOM IT MAY CONCERN:

Background:

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;
- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;
- RFP Provision 7.5.14 [1] provides the framework (principle) for negotiations and contracting based on the principle of "first right to negotiation and execution of a contract" being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and
- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

Fairness Coverage Objective:

Normally, fairness coverage terminates with the determination of the ranked Proponents following the evaluation and selection phase of the RFP; however, certain LDCs expressed a wish to secure additional fairness coverage during the subsequent phase of negotiations and contract award. The objective for this second phase fairness coverage is to assure that LDCs undertook a phase of negotiations and contracting that meets the RFP provisions of consecutive negotiations where required, e.g. with their top two ranked Proponents and in the event of unsuccessful negotiations with the #1 ranked Proponent, a subsequent contract award to the next ranked Proponent would be on an equitable basis as was the requirements in the negotiations with the #1 ranked Proponent.

7.5.14 Final Contract Nezotiations

Any conditions and provisions that a bidder seeks shall be a part of this proposal. Notwithstanding. nothing herein shall be interpreted to prohibit London Hydro from introducing or modifying contract terms and conditions during negotiation of :he final contract.

London Hydro has scheduled no more than t..vo weeks for contract negotiations (if necessary). and expects the successful bidder 7o maintain a prompt and responsive negotiation to accomplish and complete final contract agreement within that time period If Contract nezotiations exceed an interval acceptable to London Hydro. London Hydro retains the option to terminate negotiations and continue to the next apparent successfni bidder, at the sole discretion of London Hydro. Said interval shall in 110 event Lie less than three weeks.

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

Fairness Protocols:

- A Fairness Protocol was developed and issued to all LDCs, in August 2008 that set forth the best practices for fair consecutive-based negotiations and contract award.
  - The fundamental principle of the Protocol was the requirement for the LDC to establish the negotiations agenda for their top ranked Proponents and submit a copy to the Fairness Commissioner prior to engagement of their #1 ranked Proponent, i.e. the agenda would demonstrate a common statement of work, a LDC standard for pass/fail in their negotiations and the negotiation issues would only differ to the extent of the respective Proponent's technical solution being offered.

Form of Fairness Confirmation / Attestation2:

1. A confirmation of fair negotiations and contract award would be issued if the LDC's #1 ranked Proponent was awarded a contract; the original Attestation Letter remains in effect.

2. An Attestation of fair negotiations and contract award would be issued if the LDC determined that their #1 Proponent was to be set aside and the LDC successfully contracted with their next ranked Proponent, e.g. their #2; the original Attestation Letter is thus superseded by the Negotiations and Contract Award Attestation Letter.

Local Distribution Company:

Hydro Hawkesbury Inc.
850 Tupper Street
Hawkesbury, Ontario K6A 3S7

Attention: Michel Poulin, Manager

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[2] Conditions on the rendering of this Confirmation/Attestation.

- The two Negotiations Agenda were provided by HHI via Ottawa River Power;
- Fairness Commissioner undertook no direct participation or oversight in the negotiations between HHI and either of their #1 or #2 ranked Proponents;
- The successful contract award was based on the HHI criteria and no independent analysis nor any comparison with the evaluation results of the RFP process was carried out by the Fairness Commissioner; and
- The confirmation of the Fairness Commissioner was based on the progress report(s) provided by HHI via Ottawa River Power.

Capital and Operating Costs

2009

Meters Type	Purchased and installed	Unit price	Total meter cost	Installation labour	Total cost
Capital Cost 2009					
RX2 Residential	1500	$ 94.35	$ 141,525.00	$ 9,000.00	$ 150,525.00
Collectors	3	$ 2,296.26	$ 6,888.78	$ 2,730.00	$ 9,618.78
Capital cost 2009					**$ 160,143.78**
Capitalized Costs - 2009					
London RFP fees					$ 2,723.82
Fairness commissioner fees					$ 500.00
Elster Contract					$ 21,600.00
Smart Meter meeting with elster					$ 554.27
Advertizing to inform customer of SM installation					$ 100.00
Capitalized Costs - 2009					**$ 25,478.09**
TOTAL CAPITAL COSTS					**$ 185,621.87**

Note1: installation cost end of September is $2865.80 for 537 meters
*Note2: average installation per hours is 6 * rate (including burden) $36*

2010

Meters Type	Purchased and installed	Unit price	Total meter cost	Installation labour	Total cost
Capital Cost 2010					
RX2 Residential	3225	$ 94.35	$ 304,278.75	$ 19,350.00	$ 323,628.75
Collectors	3	$ 2,296.26	$ 6,888.78	$ 2,730.00	$ 9,618.78
A3RL general customers <50KW	576	$ 462.24	$ 266,250.24	$ 10,368.00	$ 276,618.24
A3RL general customers >50KW	75	$ 462.24	$ 34,668.00	$ 2,700.00	$ 37,368.00
AMI system					$ 22,500.00
EA Inspector Hand-Held					$ 6,828.05
TOTAL CAPITAL COST					**$ 676,561.82**

Note1: installation cost end of September is $2865.80 for 537 meters
*average installation per hours is 6 * rate (including burden) $36*
Note 2: price includes PST
Note 3:Average estimated installation of commercial metrs is 2 per hour
Note 4:average estimated meters for GE>50KW 1 per hour
Note 5: Integration MDM/R and operational data

Variable (on going cost)					
MAS Hardware cost (ORPC)					$ 13,770.00
Operation data Store			$.20 per meter per month		$ 12,902.40
Bell phone line			$60per month per bell line		$ 4,320.00
TOTAL VARIABLE COSTS					**$ 30,992.40**

SMART METER RATE ADDER AMOUNTS

HHI is applying for a Smart Meter Funding Adder for 2010 of $1.51 per metered customer per month following the Board's G-2008-0002 Guideline for Smart Meter Funding and Cost Recovery issued October 22, 2008.

This new Smart Meter Funding Adder replaces the Board-approved smart meter rate adder of $1.00 per metered customer per month. The current adder is not sufficient to recover the expected implementation costs in the test year. The proposed funding adder is based on an expected capital expenditure in the amount of $862,183 and on-going operation, maintenance and administration expenditures related to the installation of Smart Meters forecast to be in the amount of $30,922 per year.

Details of the calculations supporting the proposed increase in the adder can be found at Exhibit 9, Tab 3, Schedule 2, Attachment 1 and a breakdown of these costs is provided at Exhibit 9, Tab 3, Schedule 1, Attachment 3.

Smart Meter Costs

2010 EDR Data Information

Third-party long-term debt	0.0%
Deemed long-term debt	56.0%
Short-term debt	4.0%
Deemed Equity	40.0%
Third-party long-term debt rate	0.00%
Deemed long-term debt rate	7.62%
Short-term debt rate	1.13%
Return on Equity	8.01%
Weighted Average Cost of Capital	7.52%

2010 Tax Rate

Corporate Income Tax Rate	33.00%
Capital Tax Rate	0.225%

Capital Data:

	1-May-08 to 31-Dec-08	1-Jan-09 to 31-Dec-09	1-Jan-09 to 31-Dec-10	
Smart meter including installation			$ 862,183	<------
Tools and Equipment (Work force management)		$ -		<------
Computer Hardware Costs		$ -	$ -	<------
Computer Software		$ -	$ -	<------
Total Capital Costs	$ -	$ -	$ 862,183	

LDC Amortization Policy:

Smart Meter Amortization Rate	$ 15	Years
Tools and Equipment (Work force management)	$ 5	Years
Computer Hardware Amortization Rate	$ 5	Years
Computer Software Amortization Rate	$ 10	Years

Operating Expense Data:

	1-Jan-10 to 31-Dec-10	
Incremental OM&A Expenses	$ 30,992	<------
Total Incremental Operating Expense	$ 30,992	

Smart Meter Revenue Requirement Calculation 2010

Average Asset Values	**31-Dec-10**		
Net Fixed Assets Smart Meters	$ 416,722		
Net Fixed Assets Tools and Equipment	$ -		
Net Fixed Assets Computer Hardware	$ -		
Net Fixed Assets Computer Software	$ -		
Total Net Fixed Assets	$ 416,722	$ 416,722	
Working Capital			
Operation Expense	$ 30,992		
11.2 % Working Capital	$ 3,471	$ 3,471	
Smart Meters included in Rate Base		$ 420,193	
Return on Rate Base			
Third-party long-term debt	0.0%	$ -	
Deemed long-term debt	56.0%	$ 235,308	
Short-term debt	4.0%	$ 16,808	
Deemed Equity	40.0%	$ 168,077	
		$ 420,193	
Third-party long-term debt rate	0.00%	$ -	
Deemed long-term debt rate	7.62%	$ 17,930	
Short-term debt rate	1.13%	$ 190	
Return on Equity	8.01%	$ 13,463	
Return on Rate Base		$ 31,583	$ 31,583
Operating Expenses			
Incremental Operating Expenses			$ 30,992
Amortization Expenses			
Amortization Expenses - Smart Meters		$ 28,739	
Amortization Expenses - Tools and equirement		$ -	
Amortization Expenses - Computer Hardware		$ -	
Amortization Expenses - Computer Software		$ -	
Total Amortization Expenses			$ 28,739
Revenue Requirement Before PILs			$ 91,315
Calculation of Taxable Income			
Incremental Operating Expenses			-$ 30,992
Depreciation Expenses			-$ 28,739
Interest Expense			-$ 18,120
Taxable Income For PILs			$ 13,463
Grossed up PILs			$ 5,675
Revenue Requirement Before PILs			$ 91,315
Grossed up PILs			$ 5,675
Revenue Requirement for Smart Meters			**$ 96,990**
Net Revenue Requirement for 2010			**$ 96,990**
Average customer #		------->	5,350
Rate Adder per month per metered customer			$1.51

PILs Calculation 2010

		31-Dec-10
INCOME TAX		
Net Income	$	13,463
Amortization	$	28,739
CCA - Class 47 (8%) Smart Meters	-$	34,487
CCA - Class 8 (20%) Tools and Equipment	$	-
CCA - Class 45 (45%) Computers		
CCA - Class 12 (100%) Computers Software	$	-
Change in taxable income	$	7,715
Tax Rate		33.00%
Income Taxes Payable	$	2,546
ONTARIO CAPITAL TAX		
Smart Meters	$	833,444
Tools and Equipment	$	-
Computer Hardware	$	-
Computer Software	$	-
Rate Base	$	833,444
Less: Exemption	$	-
Deemed Taxable Capital	$	833,444
Ontario Capital Tax Rate		0.225%
Net Amount (Taxable Capital x Rate)	$	1,875

Gross Up

	PILs Payable		Gross Up	Grossed Up PILs	
Change in Income Taxes Payable	$	2,546	33.00%	$	3,800
Change in OCT	$	1,875		$	1,875
PIL's	$	4,421		**$**	**5,675**

Smart Meter Average Net Fixed Assets 2010

Net Fixed Assets - Smart Meters	01-May-08 to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ -
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ -	
Capital Investment Subsequent Years			$ 862,183
Closing Capital Investment	$ -	$ -	$ 862,183
Opening Accumulated Amortization	$ -	$ -	$ -
Amortization Year 1 (15 Years Straight Line)	$ -	$ -	$ -
Amortization Subsequent Years		$ -	$ 28,739
Closing Accumulated Amortization	$ -	$ -	$ 28,739
Opening Net Fixed Assets	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ 833,444
Average Net Fixed Assets	$ -	$ -	$ 416,722

Net Fixed Assets - Tools and Equipment	01-May-08 to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ -
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -
Amortization Year 2 (10 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -

Net Fixed Assets - Computer Hardware	01-May-08 to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ -
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -
Amortization Year 1 (5 Years Straight Line)	$ -	$ -	$ -
Amortization Year 2 (5 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -

Net Fixed Assets - Computer Software	01-May-08 to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ -
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -
Amortization Year 2 (10 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -

Total Assets

Total Fixed Assets	$ -	$ -	$ 862,183
Total Accumulated Amortization	$ -	$ -	$ 28,739
Closing Net Fixed Assets	$ -	$ -	$ 833,444

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	01-May-08 to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ -
Capital Additions	$ -	$ -	$ 862,183
UCC Before Half Year Rule	$ -	$ -	$ 862,183
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ 431,092
Reduced UCC	$ -	$ -	$ 431,092
CCA Rate Class 47	8%	8%	8%
CCA	$ -	$ -	$ 34,487
Closing UCC	$ -	$ -	$ 827,696

UCC - Tools and Equipment

CCA Class 8 (20%)	01-May-08 to 31-Dec-08	31-Dec-09	31-Dec-10

Opening UCC	$ -	$ -	$ -
Capital Additions	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -
CCA Rate Class 8	20%	20%	20%
CCA	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -

UCC - Computer Equipment

CCA Class 45 (45%)	01-May-08 to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ -
Capital Additions Hardware	$ -	$ -	$ -
Capital Additions Software			
UCC Before Half Year Rule	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -
CCA Rate Class 45	55%	55%	55%
CCA	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -

UCC - Computer Software

CCA Class 12 (100%)	01-May-08 to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ -
Capital Additions Hardware			
Capital Additions Software	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -
CCA Rate Class 12	100%	100%	100%
CCA	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -

CLEARANCE OF SMART METER VARIANCE ACCOUNTS

Unless otherwise advised by the OEB, HHI is not proposing to clear its smart meter related variance accounts in this proceeding.