August 31, 2011

Ms. Kirsten Walli
Ontario Energy Board
PO Box 2319
27th Floor, 2300 Yonge Street
Toronto, Ontario M4P 1E4

Re: <u>Section 86(1)(c) MAAD Application</u>

Dear Ms. Walli:

Please find enclosed the Chatham-Kent Hydro Inc. (the "Applicant") Section 86(1)(c) MAAD application for leave to amalgamate with Middlesex Power Distribution Corporation ("MPDC"), effective at the close of business December 31, 2011.

Contemporaneously with this Application, the Applicant and MPDC have jointly filed an application for the amendment of the licence of the Applicant and the cancellation of the licence of MPDC.

Background

The Applicant is a local distribution company servicing the Ontario communities of Blenheim, Bothwell, Chatham, Dresden, Erieau, Merlin, Ranleigh, Ridgetown, Thamesville, Tilbury, Wallaceburg and Wheatley, as well as the Bloomfield Business Park in Chatham-Kent.

MPDC is a local distribution company servicing the Ontario communities of Strathroy, Mount Brydges, Parkhill, Dutton and Newbury.

The two service territories are not geographically contiguous.

The Applicant and MPDC are both 100% owned by Chatham-Kent Energy ("CKE"). Both LDCs are currently separate legal entities under separate licences with common corporate and financial oversight by CKE.

CKE has owned the Applicant since its incorporation on September 22, 2000.

On March 24, 2005, CKE submitted MAAD application EB-2005-0255 requesting Board approval to acquire all shares of the former MPDC. The Board approved this acquisition in its Decision and Order issued on June 24, 2005. CKE's acquisition of MPDC subsequently closed June 30, 2005.

On October 15, 2008, MPDC submitted MAAD applications EB-2008-0332 and EB-2008-0350 requesting Board approval to acquire all shares of the former Dutton Hydro Limited and the former Newbury Power Corporation and to subsequently amalgamate all entities into MPDC. The Board approved these acquisitions and subsequent amalgamation in its Decision and Order issued February 9, 2009. MPDC subsequently closed the purchase transaction on April 30, 2009. Since that date, MPDC has been serving the distribution areas formerly licensed to each of MPDC, Dutton Hydro Limited & Newbury Power Corporation and has maintained separate rates for each of the three former areas.

The Transaction

The transaction proposed in this application would involve the amalgamation of the Applicant and MPDC into one legal entity ("Amalgamated LDC") operating under a single Electricity Distribution License. Concurrently with this application, CKH and MPDC have jointly filed an application for an amendment to the license of CKH to include the service territory currently included in MPDC's license and the subsequent cancellation of MPDC's license. Accordingly, the Amalgamated LDC would continue to operate under CKH's licence.

The proposed transaction would be completed via an amalgamation pursuant to Section 175 of the *Business Corporation Act (Ontario)*. The Applicant's and MPDC's intentions are to close the proposed transaction at December 31, 2011. Upon completion of the proposed amalgamation, the operations, governance and management of the Applicant and MPDC, already commonly controlled, would be further consolidated. The Applicant's intention regarding rates is described in section 1.6.2 below.

Shortly following this amalgamation, it is the Applicant's intention to adopt a new name that is not specific to CKH or MPDC and to subsequently file an application with the Board to amend the Applicant's licence to reflect the change of the Applicant's name.

The incremental costs of the proposed amalgamation will be borne by the Applicant's shareholder. Accordingly, the Applicant proposes that it be permitted to defer the timeline for rebasing of the Amalgamated LDC's rates by two years. This would move the rebasing dates currently applicable for each of the Applicant and MPDC from May 1, 2014 to May 1, 2016. A two year rebasing deferral is supported by the following facts:

- The payback period for the incremental costs of the proposed amalgamation would be achieved by the close of the 2016 rate year;
- Both the Applicant and MPDC are currently earning within prescribed regulated return levels; and;
- Both the Applicant and MPDC are efficient LDCs, having both been recognized in 2011 with the Board's lowest applied efficiency stretch factor (Stretch Factor Group 1).

The proposed transaction would allow the Amalgamated LDC to continue to reduce costs through reduced administrative requirements and, as importantly, sharpen focus by providing the opportunity to serve customers under one common banner.

Yours truly,

David C. Ferguson
Director of Regulatory Affairs & Risk Management
Chatham-Kent Hydro Inc.
(519) 352-6300 x 558
davidferguson@ckenergy.com

cc: Jim Hogan, CEO – Chatham-Kent Energy
Dan Charron, President of Chatham-Kent Hydro and Middlesex Power Distribution Corporation
Christopher Cowell, Chief Financial & Regulatory Officer
Ian Mondrow, Gowling Lafleur Henderson LLP

Print Form

Ontario Energy Board
Commission de l'énergie de l'Ontario

Application Form for Applications under Section 86 of the *Ontario Energy Board Act, 1998*

Application Instructions

1. Purpose of this Form

This form is to be used by parties applying under section 86 of the *Ontario Energy Board Act, 1998* (the "Act"). Please note that the Board may require information that is additional or supplementary to the information filed in this form and that the filing of the form does not preclude the applicant from filing additional or supplementary information.

For applications made under section 86(1)(b) of the Act that involve the sale of assets between licensed distributors or transmitters, the applicant must use the application form for Applications Under Section 86(1)(b) of the *Ontario Energy Board Act, 1998*. For transactions involving a non-licensed entity, please contact Market Operations at market.operations@oeb.gov.on.ca for further guidance.

Persons required to provide a Notice of Proposal under section 80 or 81 of the Act must also complete the "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the *Ontario Energy Board Act, 1998*" form in addition to this form.

Depending on the nature of the proposed transaction, the parties to the proposed transaction may be required to apply for the cancellation of an existing licence, an amendment to an existing licence, the issuance of a new licence or any combination thereof. Such applications are to be made under separate cover; however, parties may apply for the cancellation of an existing licence, an amendment to an existing licence, the issuance of a new licence or any combination thereof at the same time the parties apply for approval of the proposed transaction.

2. Completion Instructions

The applicant must:
(a) provide responses to all questions; and
(b) print and sign two copies of the form.

Please send both copies of the completed form and two copies of the responses and attachments to:

Board Secretary
Ontario Energy Board
P.O Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

If you have any questions regarding the completion of this application, please contact the Market Operations Hotline by telephone at 416-440-7604 or 1-888-632-6273 or e-mail at market.operations@oeb.gov.on.ca .

The Board's "Performance Standards for Processing Applications" are indicated on the "Corporate Information and Reports" section of the Board's website at www.oeb.gov.on.ca . Applicants are encouraged to consider the timelines required to process applications to avoid submitting applications too late. If the submitted application is incomplete, it may be returned by the Board or there may be a delay in processing the application.

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto ON M4P 1E4
Telephone: 1-888-632-6273
Facsimile: (416) 440-7656

Commission de l'énergie l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4
Téléphone: 1-888-632-6273
Télécopieur: (416) 440-7656

Ontario

Application Form for Applications under Section 86 of the *Ontario Energy Board Act, 1998*

For Office Use Only	
Application Number	EB -
Date Received	

PART I : GENERAL INFORMATION

1.1 Nature of Application

1.1.1 Application Type

- ☐ For leave for a transmitter or distributor to sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety (section 86(1)(a))
- ☐ For leave for a transmitter or distributor to sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public (section 86(1)(b))
- ☒ For leave for a transmitter or distributor to amalgamate with any other corporation (section 86(1)(c))
- ☐ For leave for a person to acquire voting securities that will exceed 20% of a distributor or transmitter (section 86(2)(a))
- ☐ For leave for a person to acquire control of a company that holds more than 20% of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of the corporation (section 86(2)(b))

1.1.2 Notice under section 80 or 81 of the Act

Is a notice of proposal required under section 80 or 81 of the Act?

- ☐ Yes
- ☒ No

If yes, the applicant must also file a completed "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the *Ontario Energy Board Act, 1998*" with the Board.

1.2 Identification of the Parties

1.2.1 Name of Applicant

Legal name of the applicant: Chatham-Kent Hydro Inc.

Name of Primary Contact:

Mr. (selected) Mrs. Miss Ms. Other

Last Name	First Name	Initial
Ferguson	David	

Title/Position: Director of Regulatory Affairs & Risk Management

Address of Head Office:

City	Province/State	Country	Postal/Zip Code
Chatham	Ontario	Canada	N7M 5K2

Phone Number	Fax Number	E-mail Address
519-352-6300	519-351-4059	regulatory@ckenergy.com

1.2.2 Other Party to the Transaction (if more than one attach a list)

Name of the other party: Middlesex Power Distribution Corp.

Name of Primary Contact:

Mr. (selected) Mrs. Miss Ms. Other

Last Name	First Name	Initial
Ferguson	David	

Title/Position: Director of Regulatory Affairs & Risk Management

Address of Head Office:

City	Province/State	Country	Postal/Zip Code
Chatham	Ontario	Canada	N7M 5K2

Phone Number	Fax Number	E-mail Address
519-352-6300	519-351-4056	regulatory@ckenergy.com

1.3 Description of the Business of Each of the Parties

1.3.1 Please provide a description of the business of each of the parties to the proposed transaction, including each of their affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity ("Electricity Sector Affiliates").

1.3.2 Please provide a description of the geographic territory served by each of the parties to the proposed transaction, including each of their Electricity Sector Affiliates, if applicable.

1.3.3 Please provide a description of the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.

1.3.4 Please provide a description of the proposed geographic service area of each of the parties after completion of the proposed transaction.

1.3.5 Please attach a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

1.4 Description of the Proposed Transaction

1.4.1 Please provide a detailed description of the proposed transaction.

1.4.2 Please provide the details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.

1.4.3 Please attach the financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.

1.4.4 Please attach the pro forma financial statements for each of the parties (or if amalgamation, the one party) for the first full year following the completion of the proposed transaction.

1.5 Documentation

1.5.1 Please provide copies of all annual reports, proxy circulars, prospectuses or other information filed with securities commissions or similar authorities or sent to shareholders for each of the parties to the proposed transaction and their affiliates within the past 2 years.

1.5.2 Please list all legal documents (including those currently in draft form if not yet executed) to be used to implement the proposed transaction.

1.5.3 Please list all Board issued licences held by the parties and confirm that the parties will be in compliance with all licence, code and rule requirements both before and after the proposed transaction. If any of the parties will not be in compliance with all applicable licences, codes and rules after completion of the proposed transaction, please explain the reasons for such non-compliance. (Note: any application for an exemption from a provision of a rule or code is subject to a separate application process.)

1.6 Consumer Protection

1.6.1 Please explain whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.

1.6.2 Please indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.

1.6.3 Please describe the steps, including details of any capital expenditure plans, that will be taken to ensure that operational safety and system integrity are maintained after completion of the proposed transaction.

1.6.4 Please provide details, including any capital expenditure plans, of how quality and reliability of service will be maintained after completion of the proposed transaction. Indicate where service centres will be located and expected response times.

1.6.5 Please indicate whether the parties to the proposed transaction intend to undertake a rate harmonization process after the proposed transaction is completed. If yes, please provide a description of the plan.

1.6.6 If the application is for an amalgamation, please provide a proposal for the time of rebasing the consolidated entity in accordance with the five-year limit set by the Board.

1.6.7 Please identify all incremental costs that the parties to the proposed transaction expect to incur. These may include incremental transaction costs, (i.e., legal), incremental merged costs (i.e., employee severances), and incremental ongoing costs (i.e., purchase and maintenance of new IT systems). Please explain how the new utility plans to finance these costs.

1.6.8 Please describe the changes, if any, in distribution or transmission rate levels (as applicable) and the impact on the total bill that may result from the proposed transaction.

1.6.9 Please provide details of the costs and benefits of the proposed transaction to the customers of the parties to the proposed transaction.

1.7 Economic Efficiency

1.7.1 Please indicate the impact the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity). Details on the impacts of the proposed transaction on economic efficiency and cost effectiveness should include, but are not limited to, impacts on administration support functions such as IT, accounting, and customer service.

1.8 Financial Viability

1.8.1 Please provide a valuation of any assets or shares that will be transferred in the proposed transaction. Provide details on how this value was determined, including any assumptions made about future rate levels.

1.8.2 If the price paid as part of the proposed transaction is significantly more than the book value of the assets of the selling utility, please provide details as to why this price will not have an adverse affect on the economic viability of the acquiring utility.

1.8.3 Please provide details of the financing of the proposed transaction.

1.8.4 If the proposed transaction involves a leasing arrangement , please identify separately any assets in the service area that are owned, from those assets that are encumbered by any means, e.g., subject to a lease or debt covenant.

1.8.5 Please outline the capital (debt /equity) structure, on an actual basis, of the parties to the proposed transaction prior to the transaction and on a pro forma basis after completion of the proposed transaction. In order to allow the Board to assess any potential impacts on the utility's financial viability, please include the terms associated with the debt structure of the utility as well as the utility's dividend policy after the completion of the proposed transaction. Please ensure that any debt covenants associated with the debt issue are also disclosed.

1.8.6 Please provide details of any potential liabilities associated with the proposed transaction in relation to public health and safety matters or environmental matters. These may be matters that have been identified in the audited financial statements or they may be matters that the parties have become aware of since the release of the most recently audited financial statements. If there are any pre-existing potential liabilities regarding public health and safety matters or environmental matters for any party to the proposed transaction, provide details on how the parties propose to deal with those potential liabilities after the transaction is completed. Specify who will have on-going liability for the pre-existing potential liabilities.

1.9 Other Information

1.9.1 If the proposed transaction requires the approval of a parent company, municipal council or any other entity please provide a copy of appropriate resolutions indicating that all such parties have approved the proposed transaction.

1.9.2 Please list all suits, actions, investigations, inquiries or proceedings by any government body, or other legal or administrative proceeding, except proceedings before the Board, that have been instituted or threatened against each of the parties to the proposed transaction or any of their respective affiliates.

1.9.3 Regarding net metering thresholds, the Board will, absent exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Please indicate the current net metering thresholds of the utilities involved in the proposed transaction. Please also indicate if there are any special circumstances that may warrant the Board using a different methodology to determine the net metering threshold for the new or remaining utility.

1.9.4 Please provide the Board with any other information that is relevant to the application. When providing this additional information, please have due regard to the Board's objectives in relation to electricity.

PART II : CERTIFICATION AND ACKNOWLEDGMENT

2.1.1 Certification and Acknowledgment

I certify that the information contained in this application and in documents provided are true and accurate.

Signature of Key Individual	Print Name of Key Individual Chris Cowell	Title/Position CFO
[signature]	Date 8/31/11	Company Chatham-Kent Hydro

(Must be signed by a key individual. A key individual is one that is responsible for executing the following functions for the applicant: matters related to regulatory requirements and conduct, financial matters and technical matters. These key individuals may include the Chief Executive Officer, the Chief Financial Officer, other officers, directors or proprietors.)

1.3 Description of the Business of Each of the Parties

1.3.1 Please provide a description of the business of each of the parties to the proposed transaction, including each of their affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity ("Electricity Sector Affiliates").

Chatham-Kent Hydro Inc. ("CKH" or the "Applicant")
CKH owns, operates and manages the assets associated with the distribution of electrical power within the territory set out in Electricity Distribution License ED-2002-0563. Please see section 1.3.2 for CKH's service territory.

The mission of CKH is to deliver electricity from the transmission grid to customers in a safe, reliable and efficient manner. CKH is committed to competitive rates, environmental responsibility and to being on the leading edge of technical innovation. This commitment was demonstrated by CKH being one of the first LDCs to install smart meters in Ontario, as well as having a distribution system that is integrated with GIS and SCADA.

Middlesex Power Distribution Corporation ("MPDC")
MPDC owns, operates and manages the assets associated with the distribution of electrical power within the territory set out in Electricity Distribution License ED-2003-0059. Please see section 1.3.2 for MPDC's service territory.

The mission of MPDC is to deliver electricity from the transmission grid to customers in a safe, reliable and efficient manner. MPDC is committed to competitive rates, environmental responsibility and to being on the leading edge of technical innovation.

Chatham-Kent Transmission Inc. ("CKT")

CKT is a licenced Ontario electrical transmitter, as described in Electricity Transmission Licence ET-2010-0351.

The goal of CKT is to own and operate electrical transmission systems to enable the development and connection of renewable energy generation in Ontario and to improve the overall reliability, safety and cost-effectiveness of electrical transmission in this province.

Chatham-Kent Utility Services Inc. ("CKUS")
CKUS provides billing, collection, administration, financial and regulatory services to CKH, MPDC, CKT and Chatham-Kent Public Utilities Commission, which operates the water and waste-water systems in the Municipality of Chatham-Kent.

The mission of CKUS is to provide responsive service levels at a reasonable cost.

Ownership
All the companies identified above are wholly owned by Chatham-Kent Energy Inc. (“CKE”). For details regarding the ownership and acquisition of these companies please see Section 1.4.1.

1.3.2 Please provide a description of the geographic territory served by each of the parties to the proposed transaction, including each of their Electricity Sector Affiliates, if applicable.

Chatham-Kent Hydro Inc.
- The former Town of Blenheim,
- The former Town of Bothwell,
- The former City of Chatham,
- The former Town of Dresden,
- The former Village of Erieau,
- The former Police Village of Merlin,
- The former Town of Ridgetown,
- The former Village of Thamesville,
- The former Town of Tilbury,
- The former Town of Wallaceburg,
- The former Village of Wheatley, and
- The Bloomfield Business Park in Chatham-Kent.

Middlesex Power Distribution Corporation
- The former Town of Strathroy as of December 31, 2000,
- The former Police Village of Mount Brydges as of December 31, 2000,
- The former Town of Parkhill as of December 31, 2000,
- The Village of Dutton as of December 31, 1997, now within the Municipality of Dutton/Dunwich, and
- The Village of Newbury as of November 7, 1998.

Chatham-Kent Transmission
- CKT is currently a licensed transmitter within the province of Ontario but does not own or operate any assets at this time.

1.3.3 Please provide a description of the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.

Please see Attachment 1.3.3-A for the Applicant’s customer information and Attachment 1.3.3-B for MPDC’s customer information.

1.3.4 Please provide a description of the proposed geographic service area of each of the parties after completion of the proposed transaction.

Please see section 1.3.2 for a description of the parties' service territories. There would be no change in the total geographical service area. However, the geographical service area would be combined into one area as a result of the proposed amalgamation and related license amendments, as further described in Section 1.4.1 below.

1.3.5 Please attach a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

Please see Attachment 1.3.5

1.4 Description of the Proposed Transaction

1.4.1 Please provide a detailed description of the proposed transaction.

The Applicant and MPDC are both 100% owned by CKE. Both LDCs are currently separate legal entities operating under separate licences with common corporate and financial oversight by CKE.

CKE has owned the Applicant since its incorporation on September 22, 2000.

On March 24, 2005, CKE submitted MAAD application EB-2005-0255 requesting Board approval to acquire all shares of the former MPDC. The Board approved this acquisition in its Decision and Order issued on June 24, 2005. Please see attachment 1.4.1-A for a copy of this Decision and Order. CKE's acquisition of MPDC subsequently closed June 30, 2005.

On October 15, 2008, MPDC submitted MAAD applications EB-2008-0332 and EB-2008-0350 requesting Board approval to acquire all shares of the former Dutton Hydro Limited and Newbury Power Corporation and subsequently amalgamate all entities into MPDC. The Board approved these acquisitions and subsequent amalgamation in Decision and Order issued February 9, 2009. Please see Attachment 1.4.1-B for a copy of this Decision and Order. MPDC subsequently closed the purchase transaction on April 30, 2009. Since that date, MPDC has been serving the distribution areas formerly licensed to each of MPDC, Dutton Hydro Limited and Newbury Power Corporation and has maintained separate rates for each of these three areas.

The transaction proposed in this application would involve the amalgamation of the Applicant and MPDC into one legal entity ("Amalgamated LDC") operating under a single Electricity Distribution License. Concurrently with this application, CKH and MPDC have jointly filed an application for an amendment to the license of CKH to include the service territory currently included in MPDC's license and the subsequent cancellation of MPDC's license. Accordingly, the Amalgamated LDC would continue to operate under CKH's licence.

The proposed transaction would be completed via an amalgamation pursuant to Section 175 of the *Business Corporation Act (Ontario)*. The Applicant and MPDC's intention is to close the proposed transaction at December 31, 2011 pending Board approval. Upon completion of the proposed amalgamation, the operations, governance and management of the Amalgamated LDC would be combined. The Amalgamated LDC's intentions regarding rates are described in section 1.6.2 below.

Shortly following this amalgamation, it is the Applicant's intention to adopt a new name that is not specific to CKH or MPDC and to subsequently file an application with the Board to change the Applicant's name.

1.4.2 Please provide the details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.

Not applicable.

1.4.3 Please attach the financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.

Please see Attachment 1.4.3-A for the Applicant's financial Statements and Attachment 1.4.3-B for MPDC's financial statements.

1.4.4 Please attach the pro forma financial statements for each of the parties (or if amalgamation, the one party) for the first full year following the completion of the proposed transaction.

Please see Attachment 1.4.4 for pro-forma statements.

The pro-forma statements are based on forecasted 2012 results of the Applicant and MPDC on a combined basis. The pro-forma statements have been prepared on the basis of Canadian Generally Accepted Accounting Principles and reflect the incremental costs and benefits summarized in Section 1.6.6 below relating to the proposed amalgamation transaction.

1.5 Documentation

1.5.1 Please provide copies of all annual reports, proxy circulars, prospectuses or other information filed with securities commissions or similar authorities or sent to shareholders for each of the parties to the proposed transaction and their affiliates within the past 2 years.

Neither party to the transaction has publicly filed proxy circulars, prospectuses or other information with securities commissions or other similar authorities nor has either party sent these documents to their shareholders. Neither party produces an Annual Report.

1.5.2 Please list all legal documents (including those currently in draft form if not yet executed) to be used to implement the proposed transaction.

As described in Section 1.4.1, the proposed transaction would be completed via amalgamation pursuant to section 175 of the *Business Corporations Act (Ontario)*. Accordingly, the following legal documents will be required:

1. Special resolution of shareholders of each amalgamating corporation authorizing the amalgamation in accordance with the amalgamation agreement pursuant to section 176 of the Business Corporations Act (Ontario)
2. Statement of Director or Officer of each amalgamating corporation pursuant to section 178(2) of the Business Corporations Act (Ontario)
3. Articles of Amalgamation pursuant to section 178(1) of the Business Corporations Act (Ontario)

1.5.3 Please list all Board issued licences held by the parties and confirm that the parties will be in compliance with all licence, code and rule requirements both before and after the proposed transaction. If any of the parties will not be in compliance with all applicable licences, codes and rules after completion of the proposed transaction, please explain the reasons for such non-compliance. (Note: any application for an exemption from a provision of a rule or code is subject to a separate application process.)

The following Electricity Distribution Licenses are held by the named Parties:

- CKH – ED-2002-0563 (Attachment 1.5.3-A)
- MPDC – ED-2003-0059 (Attachment 1.5.3-B)

As disclosed in section 1.4.1 above, concurrently with this application, CKH and MPDC have jointly filed an application with the Board for an amendment to the license of CKH to include MPDC's territory and for the cancellation of MPDC's license as a result of the proposed amalgamation.

To the best knowledge of management, both the Applicant & MPDC are in compliance with all applicable licenses, codes and rules, and the Amalgamated LDC will remain compliant after the closing of this transaction.

1.6 Consumer Protection

1.6.1 Please explain whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.

The proposed transaction will not result in a change of control of distribution system assets as both LDCs are 100% owned by CKE.

1.6.2 Please indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.

The Applicant & MPDC submit that the proposed transaction:

i. Clearly meets the "no harm test" established by the Board ("No Harm Test") in separate applications (RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257); and
ii. Will not have an adverse effect relative to the status quo of the parties when considering the Board's statutory objectives.

Since the acquisition of MPDC in 2005, management has focused on improving reliability and quality of electrical service and operations in the MPDC service territory. Specifically, prior to the acquisition of MPDC in 2005, management embarked on a rigorous environmental and asset risk assessment process to identify and prioritize capital requirements. Significant capital investment was undertaken (see chart below), including: the development of an additional feeder in Strathroy to ensure increased system reliability, the mapping and implementation of a GIS system, the implementation of a new SCADA system, the upgrading of wholesale metering to IESO standards and the implementation of smart meters.

Similarly, management has focused on system enhancements subsequent to the acquisition of Dutton Hydro and Newbury Power in 2009. In Dutton, this has included the prompt remedying of ESA non-compliance orders involving pole replacement and other items, as well as ensuring compliance with Measurement Canada standards. In Dutton and Newbury, it has also involved detailed vegetation management, the launch of CDM programs and the implementation of smart meters.

MPDC Capital Investment	Fiscal 2005 *	Fiscal 2006	Fiscal 2007	Fiscal 2008	Fiscal 2009	Fiscal 2010	Total
Distribution system	$136k	$819k	$500k	$535k	$341k	$748k	$3,079k
Computer and system supervisory	$24k	$75k	$96k	$120k	$221k	$145k	$681k
Rolling stock	$13k	$224k	$53k	$40k	-	$80k	$410k
Smart meters	-	-	$558k	$421k	-	-	$979k
Total – actual	**$173k ***	**$1,118k**	**$1,207k**	**$1,116k**	**$562k**	**$973k**	**$5,149k**
Per EB-2005-0255 capital plan	**$605k***	**$601k**	**$578k**	**$585k**	**n/a**	**n/a**	**n/a**

* Note that the EB-2005-0255 capital plan for 2005 represented a full year of capital additions. The actual amounts shown above represent the post-acquisition date amounts from July 1, 2005 to December 31, 2005.

Following the acquisition of MPDC, the focus of the shareholder and MPDC's resources was on capital investments required to improve the integrity and reliability of the MPDC system, as reflected in the foregoing table.

The amalgamation proposed in this application will result in savings and operational efficiencies due to a reduction in the administrative requirements resulting from moving to one legal entity operating under a single licence. Following recovery by the shareholder of the costs associated with the proposed transaction, these savings and operational efficiencies will accrue to the rate payers from and after the time of rebasing.

1.6.3 Please describe the steps, including details of any capital expenditure plans that will be taken to ensure that operational safety and system integrity are maintained after completion of the proposed transaction.

The transaction proposed in this application will not have a negative or harmful impact on the Applicant's and/or MPDC's operational safety and system integrity. The previous MAAD applications (EB-2005-0255, EB-2008-0332, and EB-2008-0350) identified a number of investments necessary to improve MPDC's operational safety and system integrity. Progress continues on these improvements and will continue after the proposed amalgamation.

1.6.4 Please provide details, including any capital expenditure plans, of how quality and reliability of service will be maintained after completion of the proposed transaction. Indicate where service centres will be located and expected response times.

Please see Sections 1.6.2 and 1.6.3 above. There are no planned changes to delivery of services. It is management's current intention to maintain the existing service centres in each of the non-contiguous service territories.

1.6.5 Please indicate whether the parties to the proposed transaction intend to undertake a rate harmonization process after the proposed transaction is completed. If yes, please provide a description of the plan.

There are no immediate plans for rate harmonization and the Applicant expects to maintain the existing set of four separate rates (one for the Applicant, one for each of the pre-April 30, 2009 service areas of MPDC, MPDC-Dutton and MPDC-Newbury) for the immediate future. In preparation for its next cost of service application, management will consider whether rate harmonization would provide overall customer benefits and be in accordance with good rate-making practices.

1.6.6 If the application is for an amalgamation, please provide a proposal for the time of rebasing the consolidated entity in accordance with the five-year limit set by the Board.

The Applicant most recently rebased for rates effective May 1, 2010. MPDC was originally intended to rebase for rates effective May 1, 2011. However, the MPDC rebasing was rescheduled to up to May 1, 2014 subsequent to the acquisition of Dutton Hydro Limited and Newbury Power Corporation on April 30, 2009.

Accordingly, the Applicant and MPDC are both currently scheduled for rebasing of rates effective May 1, 2014. The Applicant requests a rebasing deferral of two years, to May 1, 2016, to allow it to realize anticipated efficiencies and recover the costs associated with the proposed transaction.

Please see Attachment 1.6.6 for an analysis of the estimated incremental external costs and one-time and ongoing benefits of the proposed amalgamation. Internal costs are excluded from the analysis. Note the schedule shows that when simple, undiscounted cash flows are applied, payback will be nearly reached by fiscal 2016.

As noted in Section 1.6.7 below, the incremental costs of the proposed amalgamation will be shareholder costs. Accordingly, the Applicant proposes that rebasing be reset to May 1, 2016 in order to align with the payback period shown above.

The Applicant's proposed reset rebasing schedule is supported by the fact that both the Applicant and MPDC are earning within prescribed regulated return levels, as shown in the table below:

Return on Equity – Accounting Basis	**Chatham-Kent Hydro**		**Middlesex Power**	
Per Annual Audited Financial Statements	**2009**	**2010**	**2009**	**2010**
Net Earnings After Tax	$2,102k	$2,290k	$504k	$479k
Shareholder's Equity	$29,308k	$23,848k	$4,913k	$4,692k
Return on Equity	**7.2%**	**9.6%**	**10.3%**	**10.2%**

Return on Equity – Regulatory Basis	**Chatham-Kent Hydro**		**Middlesex Power**	
Per Regulatory Filing	**2009**	**2010**	**2009**	**2010**
Net Earnings After Tax	$2,102k	$2,290k	$504k	$479k
Less: Non-utility earnings *	$(364k)	$(238k)	$(122k)	$(125k)
Regulatory Earnings	$1,738k	$2,052k	$382k	$354k
Deemed Equity	$22,480k	$22,480k	$4,173k	$4,173k
Return on Equity	**7.7%**	**9.1%**	**9.2%**	**8.5%**
ROE – Regulated Deadband Range	6.0% - 12.0%	6.85% - 12.85%	6.0% - 12.0%	6.0% - 12.0%

* Non-utility earnings = (OPA revenue – OPA expense) X (1 - effective tax rate)
CKH 2009 = ($1,681k – $1,142k) X (1 – 32.5%) = $364k / CKH 2010= ($1,097k - $746k) X (1 – 32.2%) = $238k
MPDC 2009 = ($416k - $263k) X (1 – 20.0%) = $122k / MPDC 2010 = ($389k - $204k) X (1 – 32.2%) = $125k

In addition, it should be noted that the both the Applicant and MPDC are already efficient LDCs and follow good utility practice. This is evident in the Board's March 10, 2011 "Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors". This report details the 2011 IRM3 stretch factors for 76 Ontario electrical LDCs. Both the Applicant and MPDC were recognized in the Stretch Factor Group 1, receiving the lowest applied efficiency stretch factor, in recognition of already relatively efficient operations. Specifically, the Applicant ranked 4th and MPDC ranked 10th.

1.6.7 Please identify all incremental costs that the parties to the proposed transaction expect to incur. These may include incremental transaction costs, (i.e., legal), incremental merged costs (i.e., employee severances), and incremental ongoing costs (i.e., purchase and maintenance of new IT systems). Please explain how the new utility plans to finance these costs.

Please refer to Attachment 1.6.6 for the one-time incremental costs of the proposed amalgamation. No incremental ongoing costs are anticipated.

The incremental costs of the proposed amalgamation will be funded by the shareholder.

1.6.8 Please describe the changes, if any, in distribution or transmission rate levels (as applicable) and the impact on the total bill that may result from the proposed transaction.

Please refer to Sections 1.6.2, 1.6.5 and 1.6.6 above. No near term rate changes are proposed. In the longer term, efficiency gains are expected to flow through to the ratepayers.

1.6.9 Please provide details of the costs and benefits of the proposed transaction to the customers of the parties to the proposed transaction.

Please refer to Section 1.6.6 above regarding costs and benefits of the proposed amalgamation.

1.7 Economic Efficiency

1.7.1 Please indicate the impact the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity). Details on the impacts of the proposed transaction on economic efficiency and cost effectiveness should include, but are not limited to, impacts on administration support functions such as IT, accounting, and customer service.

Please refer to Section 1.6.6 above regarding costs and benefits of the proposed amalgamation. As the Applicant and MPDC service territories are non-contiguous, the proposed transaction will mainly result in a reduction in administrative requirements as a result of moving to one legal entity operating under a single license.

1.8 Financial Viability

1.8.1 Please provide a valuation of any assets or shares that will be transferred in the proposed transaction. Provide details on how this value was determined, including any assumptions made about future rate levels.

Not applicable.

1.8.2 If the price paid as part of the proposed transaction is significantly more than the book value of the assets of the selling utility, please provide details as to why this price will not have an adverse affect on the economic viability of the acquiring utility.

Not applicable.

1.8.3 Please provide details of the financing of the proposed transaction.

Not applicable.

1.8.4 If the proposed transaction involves a leasing arrangement, please identify separately any assets in the service area that are owned, from those assets that are encumbered by any means, e.g., subject to a lease or debt covenant.

Not applicable.

1.8.5 Please outline the capital (debt /equity) structure, on an actual basis, of the parties to the proposed transaction prior to the transaction and on a pro forma basis after completion of the proposed transaction. In order to allow the Board to assess any potential impacts on the utility's financial viability, please include the terms associated with the debt structure of the utility as well as the utility's dividend policy after the completion of the proposed transaction. Please ensure that any debt covenants associated with the debt issue are also disclosed.

The current capital structure of the parties can be found in the Applicant's and MPDC's financial statements enclosed (see Attachment 1.4.3-A and Attachment 1.4.3-B).

The 2009 and 2010 capital structure ratios are summarized as follows:

Return on Equity – Accounting Basis	**Chatham-Kent Hydro**		**Middlesex Power**	
Per Annual Audited Financial Statements	**2009**	**2010**	**2009**	**2010**
Long-Term Debt	$23,523k	$31,273k	$5,300k	$5,800k
Shareholder's Equity	$29,308k	$23,848k	$4,913k	$4,691k
Debt Ratio	**44.5%**	**56.7%**	**51.9%**	**55.3%**
Equity Ratio	**55.5%**	**43.3%**	**48.1%**	**44.7%**

Aside from the fact that the capital structures of the Applicant and MPDC will be combined, no impact on capital structure from the proposed amalgamation is anticipated. See Attachment 1.4.4 for the proforma combined financial statements and associated capital structure ratios. Note that the 2012 proforma debt ratio is 59%, versus an equity ratio of 41%.

1.8.6 Please provide details of any potential liabilities associated with the proposed transaction in relation to public health and safety matters or environmental matters. These may be matters that have been identified in the audited financial statements or they may be matters that the parties have become aware of since the release of the most recently audited financial statements. If there are any pre-existing potential liabilities regarding public health and safety matters or environmental matters for any party to the proposed transaction, provide details on how the parties propose to deal with those potential liabilities after the transaction is completed. Specify who will have on-going liability for the pre-existing potential liabilities.

To the best of the Applicant's and MPDC's knowledge, there are no potential liabilities associated with the proposed transaction in relation to public health and safety matters or environmental matters. As there is no change of control, CKH will remain liable for any potential or pre-existing liabilities of either entity after closing of the proposed amalgamation.

1.9 Other Information

1.9.1 If the proposed transaction requires the approval of a parent company, municipal council or any other entity please provide a copy of appropriate resolutions indicating that all such parties have approved the proposed transaction.

The documents identified in Section 1.5.2 will be prepared and approved once Board approval is received. As per normal course, these documents will be passed immediately before amalgamation. Given the current ownership, no municipal council approvals are required.

1.9.2 Please list all suits, actions, investigations, inquiries or proceedings by any government body, or other legal or administrative proceeding, except proceedings before the Board, that have been instituted or threatened against each of the parties to the proposed transaction or any of their respective affiliates.

To the best knowledge of the Applicant and MPDC there are no legal, administrative or other proceedings outstanding, pending or threatened against themselves or their affiliates.

1.9.3 Regarding net metering thresholds, the Board will, absent exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Please indicate the current net metering thresholds of the utilities involved in the proposed transaction. Please also indicate if there are any special circumstances that may warrant the Board using a different methodology to determine the net metering threshold for the new or remaining utility.

The current net metering thresholds for the Applicant and MPDC are as follows:

Company:	**kW Threshold**
Chatham-Kent Hydro	1,760
Middlesex Power Distribution	463
Total	**2,223**

There are no special circumstances to warrant employing a different methodology for the Amalgamated LDC.

1.9.4 Please provide the Board with any other information that is relevant to the application. When providing this additional information, please have due regard to the Board's objectives in relation to electricity.

Not applicable.

Attachment 1.3.3-A

Chatham-Kent Hydro Inc.
Customer Information

Chatham-Kent Hydro Inc.
Customer Information

Rate Class	Description	No. of Customers *
Residential	This classification applies to an account taking electricity at 750 volts or less and includes: 1) All services supplied to a single-family dwelling units for domestic or household purposes, 2) All multi-unit residential establishments such as apartments of 6 or less units. 3) If a service supplies a combination of residential and commercial load and wiring does not permit separate metering, the classification of this customer will be determined individually by the distributor.	28,512
General Service <50 kW	This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and includes multi-unit residential establishments such as apartment buildings supplied through one service (bulk-metered).	3,118
General Service 50 to 999 kW	This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than 50 kW bus less than 1,000 kW. Note that for the application of the Retail Transmission Rate – Network Service and the Retail Transmission Rate – Line and Connection Service Rate the following sub-classifications apply: General Service 50 to 999 kW non-interval metered General Service 50 to 999 kW interval metered	386
Intermediate 1,000 to 4,999 kW	This classification applies to non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This classification includes the former Time-of-Use Chatham classification, the former Large Use classification customers and the former General Service >50 kW classification customers with loads between 1,000 and 4,999 kW.	15
Intermediate with Self Generation	This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service.	1
Unmetered Scattered Load	This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.	192
Standby Power	This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service.	
Sentinel Lighting	This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. (Number of Connections)	340
Street Lighting	This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape templates. (Number of Connections)	10,679
Total		**43,244**

* Customer numbers based of 2010 RRR filing 2.1.5 submitted April 30, 2011. Note Sentinel Lighted and Street Lighting classes are reported as number of connections, not customers.

Attachment 1.3.3-B

Middlesex Power Distribution Corporation
Customer Information

Middlesex Power Distribution Corp.
Customer Information

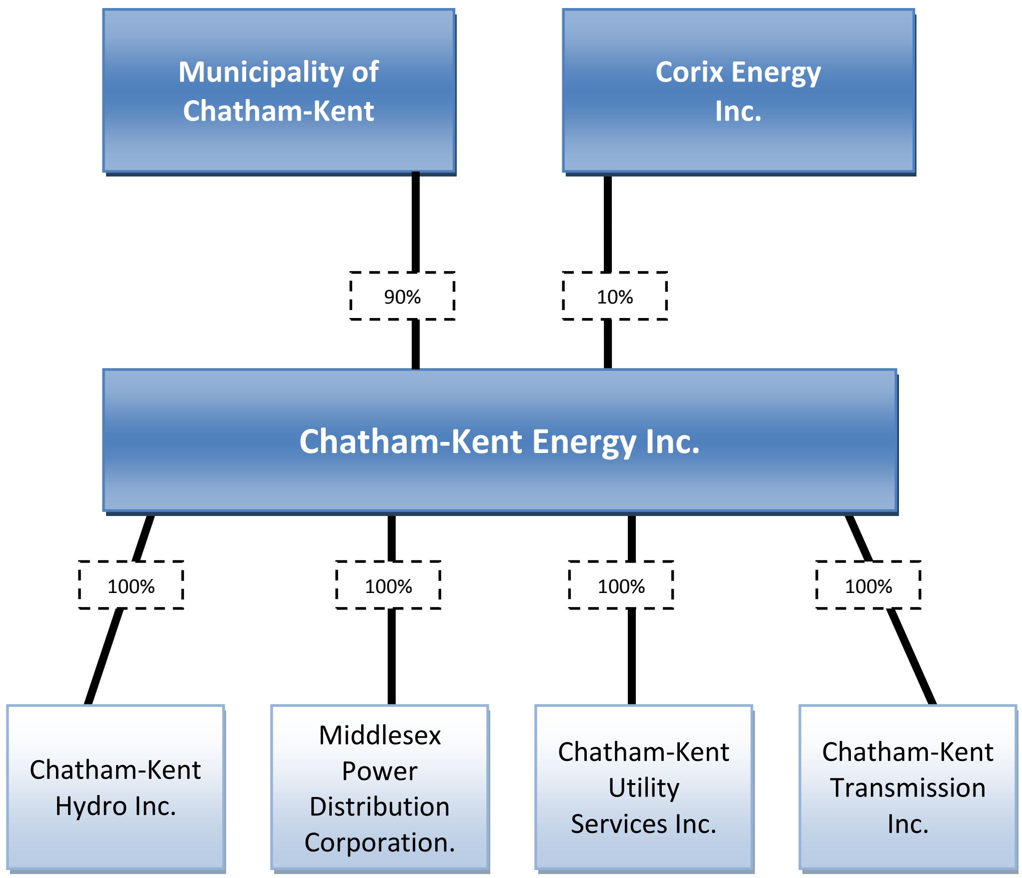
Rate Class	Description	No. of Customers **
Residential	This classification applies to an account taking electricity at 750 volts or less and includes: 1) All services supplied to a single-family dwelling units for domestic or household purposes, 2) All multi-unit residential establishments such as apartments of 6 or less units. If a service supplies a combination of residential and commercial load and wiring does not permit separate metering, the classification of this customer will be determined individually by the distributor.	6,984
General Service <50 kW	This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and includes multi-unit residential establishments such as apartment buildings supplied through one service (bulk-metered).	779
General Service 50 to 999 kW	This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than 50 kW bus less than 1,000 kW. Note that for the application of the Retail Transmission Rate – Network Service and the Retail Transmission Rate – Line and Connection Service Rate the following sub-classifications apply: General Service 50 to 999 kW non-interval metered General Service 50 to 999 kW interval metered	95
Large User	This classification applies to an account whose average monthly maximum demand used for billing purposes over the most recent 12 consecutive months is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.	1
Unmetered Scattered Load	This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.	53
Sentinel Lighting	This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. (Number of Connections)	48
Street Lighting	This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape templates. (Number of Connections)	2,252
Total		10,212

** Combined total for MPDC – Main, MPDC – Dutton and MPDC – Newbury as reported in 2010 RRR filing 2.1.5 submitted April 30, 2011. Note Sentinel Lighted and Street Lighting classes are reported as number of connections, not customers.

Attachment 1.3.5

Chatham-Kent Energy Inc.
Corporate Structure

Corporate Structure



Attachment 1.4.1-A

Decision and Order
EB-2005-0255

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0255

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

AND IN THE MATTER OF an application by Chatham-Kent Energy Inc. and Middlesex Power Distribution Corporation under section 86 of the *Ontario Energy Board Act*, *1998* seeking an order granting Chatham-Kent Energy Inc. leave to acquire all outstanding shares in Middlesex Power Distribution Corporation.

BEFORE: Paul Sommerville
Presiding Member

Cynthia Chaplin
Member

Paul Vlahos
Member

DECISION AND ORDER

On March 24, 2005, Chatham-Kent Energy Inc. ("CKEI") and Middlesex Power Distribution Corporation ("MPDC") (collectively, the "Applicants") filed an application with the Ontario Energy Board (the "Board") seeking leave for CKEI to acquire all outstanding shares in MPDC (the "Application"). CKEI is a holding company that holds all of the shares of Chatham-Kent Hydro Inc. ("CKHI"). Both CKHI and MPDC are licensed electricity distributors.

CKEI is wholly owned by the Municipality of Chatham-Kent. Currently, the Township of Strathroy-Caradoc and the Township of North Middlesex hold 100 percent of the outstanding shares in MPDC, through a holding company called Middlesex Power Corporation.

Upon approval and completion of the proposed transaction, the Municipality of Chatham-Kent would hold 100 percent of the outstanding shares in MPDC through CKEI.

Following the acquisition of shares, MPDC would be a subsidiary of CKEI. MPDC and CKHI would serve approximately 6,700 and 32,000 customers respectively in the service territories that they currently serve. These service territories are not geographically contiguous.

The Applicants have stated that CKHI and MPDC will maintain separate rate bases and will not harmonize rates.

A Notice of Application and Written Hearing was published as directed by the Board. No interventions were filed in response to the Notice, and the Board has proceeded by way of a written hearing.

The full record of this proceeding is available for review at the Board's offices. While the Board has considered the full record, the Board has summarized and referred only to those portions of the record that it considers helpful to provide context to its findings.

Board Findings

The acquisition of certain interests in electricity distributors is governed by the *Ontario Energy Board Act, 1998* (the "Act"). Section 86 of the Act provides, among other things, that no person may acquire voting securities in an electricity distributor without leave of the Board if, as a result of the acquisition, the person would hold more than 20 percent of these voting securities of the distributor.

Section 1 of the Act states that the Board, in carrying out its responsibilities under the Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; and

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

The Applicants stated that Chatham-Kent Utilities Services Inc., an affiliate of CKEI, began providing management, administrative and billing and collection services to MPDC in June 2002. The Applicants further stated that as a result of this arrangement, MPDC's operating costs decreased by 23 percent between 2002 and 2004.

The Applicants submitted that by completing the proposed transaction, further efficiency gains can be realized in areas such as conservation and demand management programs, a smart meter pilot project that would be initiated in MPDC's service area, and billing system updates. The Applicants also note that CKEI has an A- rating from Standard and Poors, which would assist MPDC in its future financial requirements.

Based on a capital expenditure plan that outlines projected capital expenditures to the year 2008, the Applicants submit that many of the planned capital projects will improve quality and reliability of service in the MPDC service territory. In addition, the Applicants intend to maintain service centres in Strathroy-Caradoc and Chatham.

The Board accepts the Applicants' uncontested evidence and concludes that the proposed transaction is consistent with the Board's objectives.

THE BOARD ORDERS THAT:

1. Chatham-Kent Energy Inc. is granted leave to acquire all outstanding shares in Middlesex Power Distribution Corporation.

2. Notice of completion of the transaction shall be promptly given to the Board.

3. The Board's leave to acquire the shares shall expire 18 months from the date of this Decision and Order. If the transaction has not been completed by that date, a new application for leave to acquire the shares will be required in order for the transaction to proceed.

ISSUED at Toronto, June 24, 2005.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

Attachment 1.4.1-B

Decision and Order
EB-2008-0332/EB-2008-0350

Ontario Energy Board | **Commission de l'Énergie de l'Ontario**

Ontario

EB-2008-0332
EB-2008-0350

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

AND IN THE MATTER OF an application by Middlesex Power Distribution Corporation under section 86(2)(a) of the *Ontario Energy Board Act, 1998* seeking an order for leave to acquire Dutton Hydro Limited and Newbury Power Inc.;

AND IN THE MATTER OF an application by Middlesex Power Distribution Corporation under section 74 of the *Ontario Energy Board Act, 1998* seeking an order to amend Middlesex Power Distribution Corporation's distribution licence;

AND IN THE MATTER OF a request by Middlesex Power Distribution Corporation under section 77(5) of the *Ontario Energy Board Act, 1998* seeking the cancellation of the distribution licences of Dutton Hydro Limited and Newbury Power Inc.

BEFORE: Pamela Nowina
Vice-Chair and Presiding Member

Paul Vlahos
Member

Paul Sommerville
Member

DECISION AND ORDER

Middlesex Power Distribution Corporation (“Middlesex Power” or the “Applicant”), a licensed electricity distributor, filed an application with the Ontario Energy Board, received on October 15, 2008, under section 86(2)(a) of the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15 (Schedule B) (the “Act”), seeking leave to acquire Dutton Hydro Limited (“Dutton Hydro”) and Newbury Power Inc. (“Newbury Power”). The Board has assigned file number EB-2008-0332 to the application to acquire Dutton Hydro and file number EB-2008-0350 to the application to acquire Newbury Power. Pursuant to its power under section 21(5) of the Act, the Board will consider these applications together through a consolidated hearing.

Middlesex Power has requested, under section 77(5) of the Act, that the electricity distribution licenses of Dutton Hydro and Newbury Power be canceled and, pursuant to section 74 of the Act, that its distribution licence be amended to include in its service area the areas currently served by Dutton Hydro and Newbury Power. The closing date for the proposed transactions is March 31, 2009.

THE APPLICATION

Middlesex Power is wholly owned by Chatham-Kent Energy Inc. The Municipality of Chatham-Kent and Corix Utilities own 90% and 10% of the shares of Chatham-Kent Energy Inc. respectively. Dutton Hydro is wholly owned by the Municipality of Dutton/Dunwich. The Village of Newbury holds 80% of the shares of Newbury Power, and Newbury Community Services owns 20% of the shares of Newbury Power. Middlesex Power, Dutton Hydro, Newbury Power and their respective shareholders are parties to the proposed transaction.

Upon completion of the proposed transactions, Middlesex Power will purchase 100% of the issued and outstanding shares of Dutton Hydro and Newbury Power and the two electrical distribution companies will be merged into Middlesex Power.

Middlesex Power has stated that the proposed acquisitions will improve the reliability and quality of electricity service for Dutton Hydro and Newbury Power customers and will result, over the long term, in lower rates than would otherwise be the case if the utilities remained as stand alone entities.

Middlesex Power states that the purchase price for acquiring shares of Dutton Hydro is expected to be approximately $490,000. The purchase price for acquiring shares of Newbury Power is approximately $163,350. Middlesex Power expects to incur approximately $45,000 in transaction costs to complete the proposed transactions. Middlesex Power states that as part of its transaction with the Village of Newbury, it expects to pay an amount of $71,000 which represents a Long Term Note payable to The Village of Newbury. This amount will be paid upon completion of the proposed transaction.

Currently, the rates charged for the delivery of electricity to customers in Middlesex Power, Dutton Hydro and Newbury Power service areas are not equal. The application states that Middlesex Power will seek to harmonize rates within five years from the date of closing the proposed transactions. The *Board Report on Ratemaking Associated with Distributor Consolidation* (EB-2007-0028) (the "Board Report") permits a merged utility to forego rebasing for a period of five years following the closing date of the transaction. Middlesex Power states that it plans to file for rate rebasing on a merged basis in 2014.

THE PROCEEDING

A Notice of Application and Hearing was issued on October 30, 2008 and published on November 12, 2008 in the affected service areas as directed by the Board. No persons requested intervenor status in this proceeding.

Procedural Order No. 1, along with Board staff interrogatories, was issued on December 19, 2008. The Applicant filed responses to the interrogatories on January 9, 2009.

BOARD FINDINGS

The "No Harm" Test

Section 86(2)(a) of the Act provides that no person, without first obtaining an order from the Board granting leave, shall acquire such number of voting securities of a transmitter or distributor that together with voting securities already held by such person and one or more affiliates or associates of that person, will in the aggregate exceed 20 percent of the voting securities of the transmitter or distributor.

In determining whether to approve this application, the Board has been guided by the principles set out in the Board's decision in the combined MAADs proceeding (Board File Numbers RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257). In that decision, the Board ruled that the "no harm" test is the relevant test for purposes of applications for leave to acquire shares or amalgamate under section 86 of the Act. The "no harm" test consists of a consideration as to whether the proposed transaction would have an adverse effect relative to the status quo in relation to the Board's statutory objectives. If the proposed transaction would have a positive or neutral effect on the attainment of the statutory objectives, then the application should be granted. The factors to be considered are those set out in section 1 of the Act, namely:

1. to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; and
2. to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

Middlesex Power provided the following information in support of its application:

- Dutton Hydro has been found deficient in its compliance with some of the standards promulgated by the Electrical Safety Authority. Through the adoption of Middlesex Power's operating practices and engineering expertise, Dutton Hydro will become compliant within a reasonable period of time;
- Following the proposed transaction, Middlesex Power will make investments to reduce system losses, implement Supervising Control and Data Acquisition ("SCADA") systems and provide conservation and demand management programs ("CDM") for the areas currently served by Dutton Hydro and Newbury Power;
- Service levels will be maintained for Middlesex Power customers and improved for Dutton Hydro and Newbury Power customers;
- Middlesex Power's service centre is situated in the Township of Strathroy-Caradoc. The distance between the service centre and the newly proposed service areas is 44 km. As such it will not impede Middlesex Power's ability to meet the Board's service quality indicator guidelines for Dutton Hydro's and Newbury Power's service areas;
- The roll out of Middlesex Power's smart meter solution will also be applied to the Newbury and Dutton service areas and will meet the Ministry of Energy's guidelines for installing smart meters by 2010; and

- The proposed transaction will enable fixed costs to be allocated over more customers, thereby resulting in lower rates for Dutton Hydro and Newbury Power's customers in the long term.

In summary, Middlesex Power states that the proposed transactions will improve the reliability and quality of electricity service and will result in lower rates for Dutton Hydro and Newbury Power customers over the long term than would be the case if the utilities remained stand alone entities.

Based on the evidence in this proceeding, and the Board's findings elsewhere in this decision regarding a proposal for a deferral account and the plan to apply for an adjustment in rates for Dutton, the Board concludes that the proposed acquisitions will not have an overall adverse effect in terms of the factors identified in the Board's objectives in section 1 of the Act. Accordingly, the Board finds that the proposed transactions reasonably meet the "no harm" test.

Rate Rebasing and Rate Harmonization for the Consolidated Entity

The Board finds that the Applicant's proposal to delay rebasing and rate harmonization for the consolidated entity for up to five years is acceptable. This proposal is consistent with the Board's Report referenced above. However, as discussed below, the Applicant is proposing an adjustment to Dutton Hydro's rates in the near term.

Rate Rebasing Proposal for Dutton Hydro

Dutton Hydro's rates have not been adjusted since 2001. Most distributors updated their base distribution rates in 2006 based on an historical test year cost of service application. In the interim period 2002-2005, most distributors received rate adjustments related to (among other matters) regulatory asset recoveries and an updating of their respective Payments in Lieu of Taxes proxies. Since 2006, distributors that have not rebased based on a future test year application have received rate adjustments based on the 2nd generation Incentive Regulatory Mechanism ("IRM").

In its application, Middlesex Power has proposed to address this matter by proposing to file a cost of service application solely for Dutton Hydro based on an historical test year. In response to Board staff interrogatory #3, Middlesex Power stated that the proposed acquisitions are based on the rationale of providing a safe and reliable system that would benefit the customers and the public generally. Specifically, Middlesex Power stated that Dutton Hydro is facing the following issues:

- It is not compliant with certain Electricity Safety Authority standards;
- It has not been engaged in removing PCB contaminated transformers;
- It has not generated much information respecting its service quality standards; and
- The line losses are 6.6% which is above the threshold that the Board has established as an action level.

Middlesex Power stated that it intends to propose rates for Dutton Hydro's service area at a level that will recover the costs and earn a fair and reasonable return. Middlesex Power further stated that it believes a rate application for Dutton Hydro using the 2006 EDR model and then implementing the 2nd generation IRM adjustments for 2007, 2008 and 2009, will provide the necessary financial underpinning to ensure that a safe and reliable distribution system is provided to the customers and the community. This level of rates would bring the customers in the Dutton Hydro service area into a position comparable to that experienced by consumers in Newbury and Middlesex.

The Board notes that Dutton Hydro submitted a letter dated January 26, 2009 confirming its intention to submit rate applications in accordance with the proposed rate plan above regardless of the outcome of this application. Therefore, it is reasonable to view such rate adjustments in Dutton's service area as being unaffected by the proposed transaction. Further, the Board makes the following comments.

The Board notes that the Board Report presumes that distributors would have rebased in 2006 and would therefore be eligible to participate in the Board's 2nd generation IRM plan (sec. 2.2.1, p.6). The proposal by Middlesex Power is aimed at rationalizing Dutton Hydro's rates using the identical rate adjustment processes that were used by Middlesex Power and Newbury Power over the 2006 to 2009 period. This would bring Dutton Hydro to the same level as the other two service areas so that a rebasing of the consolidated entity would be possible in the future. The proposal does not involve a future test year application but is designed to enable the Applicant to deal with the technical and financial obligations arising out of the Dutton Hydro service area going forward to 2014.

The Board notes that this situation is different than the recent amalgamation proceeding for PowerStream Inc. and Barrie Hydro Distribution Inc. (EB-2008-0335). In that proceeding one of the distributors had already had rates reset under a cost-of-service hearing. In this case all three entities will have their first rebasing after the 2006 test year delayed until 2014.

Deferral Account for Transaction Costs

Middlesex Power has requested that a deferral account be established to cover the transaction costs for the newly merged utility. In response to Board staff interrogatory #4, the Applicant stated that the transaction costs are relatively significant due to the small size of Dutton Hydro and Newbury Power and the fact that the majority of the transaction costs are fixed. Middlesex Power further stated that the synergies required to create savings on a forward going basis may not transpire in this case.

The transactions are intended to provide the customers of Dutton Hydro and Newbury Power with a safe and reliable system while meeting regulatory requirements. Consequently, Middlesex Power stated that the customers of Dutton Hydro and Newbury Power should share in some of the transaction costs if Middlesex Power does not attain additional benefits arising from the consolidation to cover the costs of the transactions.

Furthermore, Middlesex Power stated that it will only seek recovery of those transaction costs that are over and above any benefits that may be attained through the transaction.

The Board finds that it is appropriate in the specific circumstances of this case to allow the Applicant to track the transaction costs related to the acquisition of Dutton Hydro and Newbury Power in a deferral account, the disposition of which will be dealt with in a future proceeding. The Board notes that the Board Report indicates that either a distributor retains the benefits of consolidation over the deferral period to offset the costs or the distributor can apply to recover the costs net of the benefits in rates (sec. 2.2.2, p.7). In this case, Middlesex Power has indicated that despite the delaying of the rebasing of the consolidated entity for up to five years, benefits may not arise out of this transaction. If however benefits do arise, Middlesex Power will ensure that the costs will be offset accordingly when requesting disposition of the deferral account.

Middlesex Power may wish to track its transaction costs in Account 1508, Other Regulatory Assets, Sub-account MAADs Transaction Costs. Consideration of the disposition of the deferral account will occur in the normal manner in the rate setting process. The Board's finding that the amounts may be tracked in a deferral account should not be construed in any manner or degree as predictive of its authorization to dispose of the amounts so tracked in a future proceeding. For example, the disposition of any net costs will consider to what extent the "no harm" test has been reasonably met or will be reasonably met.

Net Metering Thresholds

The current net metering thresholds for Middlesex Power, Dutton Hydro and Newbury Power are 368 kW, 19 kW, and 8 kW respectively. Middlesex Power has submitted that there are no special circumstances that warrant using a different methodology to determine the net metering threshold. The Board accepts that there are no special circumstances present in this regard and will therefore add together the net metering thresholds for Middlesex Power, Dutton Hydro and Newbury Power to determine the net metering threshold for the newly merged utility.

THE BOARD ORDERS THAT:

1. Middlesex Power Distribution Corporation is hereby granted leave to acquire Dutton Hydro Limited and Newbury Power Inc. pursuant to section 86 of the Act.

2. The Board's leave to acquire shall expire 18 months from the date of this Decision and Order. If the transaction has not been completed by that date, a new application for leave to acquire will be required in order for the transaction to proceed.

3. Middlesex Power Distribution Corporation shall promptly notify the Board of the completion of the transaction.

4. Once the notice referred to in number 3 above has been provided to the Board, the Board will amend the electricity distribution licence of Middlesex Power Distribution Corporation to include the service areas formerly served by Dutton Hydro Limited and Newbury Power Inc.

5. Once the notice referred to in number 3 above has been provided to the Board, the Board will cancel the electricity distribution licences of Dutton Hydro Limited (ED-2003-0025) and Newbury Power Limited (ED-2002-0526).

6. Once the notice referred to in number 3 above has been provided to the Board, the net metering threshold for the newly merged Middlesex Power Distribution Corporation will be 395 kW.

DATED at Toronto, February 9, 2009

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Attachment 1.4.3-A

Chatham-Kent Hydro
2009 & 2010 Financial Statements

Financial Statements of

CHATHAM-KENT HYDRO INC.

December 31, 2009

Management's Responsibility for Financial Reporting

Chatham-Kent Hydro's management is responsible for the preparation and presentation of the financial statements and all other information included in this annual report. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board exercises this responsibility through the Audit Committee of the Board. This committee is comprised of four directors of companies within the Chatham-Kent Energy group, one of whom is a director of the Chatham-Kent Hydro Inc. Board. This committee meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements and other information included in the annual report before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Deloitte & Touche LLP, an independent firm of Chartered Accountants, has been appointed by the audit committee and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.

Dave Kenney	**Chris Cowell**
President	**Chief Financial & Regulatory Officer**

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Auditors' Report

To the Chairman and Board Members of Chatham-Kent Hydro Inc.

We have audited the balance sheet of Chatham-Kent Hydro Inc. as at December 31, 2009 and the statements of earnings, comprehensive income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Approved to insert electronic signature 3/24/10 AS

Chartered Accountants
Licensed Public Accountants
February 26, 2010

CHATHAM-KENT HYDRO INC.
Balance Sheet
December 31, 2009

	2009	2008
	$	$
ASSETS		
CURRENT		
Cash and cash equivalents	**4,824,338**	6,340,035
Accounts receivable (Note 4)	**3,492,600**	3,383,525
Accounts receivable - unbilled revenue	**10,084,184**	8,987,257
Taxes receivable	**213,822**	109,388
Due from Middlesex Power Distribution Corporation	**611,977**	383,262
Inventories	**631,201**	676,263
Prepaid expenses	**12,240**	91,079
	19,870,362	19,970,809
CAPITAL ASSETS (Note 5)	**46,262,465**	46,125,163
OTHER		
Deferred assets (Note 6)	**3,596,405**	2,565,256
Future income tax (Note 16)	**2,320,990**	-
Computer software (Note 5)	**312,648**	305,533
	6,230,043	2,870,789
	72,362,870	68,966,761
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**8,318,461**	9,036,529
Due to the Municipality of Chatham-Kent	**3,455,554**	2,248,214
Current portion of customer deposits	**1,757,153**	1,116,267
	13,531,168	12,401,010
LONG-TERM		
Regulatory future income tax liability (Note 16)	**2,320,990**	-
Note payable (Note 7)	**23,523,326**	23,523,326
Asset retirement obligation	**15,000**	15,000
Employee future benefits (Note 8)	**917,524**	858,565
Long-term portion of customer deposits	**2,746,918**	3,463,476
	29,523,758	27,860,367
	43,054,926	40,261,377
CONTINGENCY AND COMMITMENTS (Notes 11 and 17)		
SHAREHOLDER'S EQUITY		
Share capital (Note 12)	**23,523,425**	23,523,425
Retained earnings	**5,784,519**	5,181,959
	29,307,944	28,705,384
	72,362,870	68,966,761

CHATHAM-KENT HYDRO INC.
Statement of Earnings, Comprehensive Income and Retained Earnings
December 31, 2009

	2009	2008
	$	$
SERVICE REVENUE		
Residential	**23,385,768**	22,355,009
General service	**38,069,919**	42,194,791
Street lighting	**656,704**	624,942
	62,112,391	65,174,742
Change in unbilled revenue	**1,212,181**	(77,358)
	63,324,572	65,097,384
Retailer energy sales	**5,087,629**	9,659,952
	68,412,201	74,757,336
COST OF POWER	**55,844,977**	61,185,688
GROSS MARGIN ON SERVICE REVENUE	**12,567,224**	13,571,648
OTHER OPERATING REVENUE	**1,696,453**	1,444,621
OPERATING INCOME	**14,263,677**	15,016,269
OPERATING AND MAINTENANCE EXPENSE		
Distribution	**2,288,251**	2,475,778
ADMINISTRATIVE EXPENSE		
Billing and collection	**1,571,480**	1,416,110
General administration	**1,917,080**	2,117,686
Interest	**1,748,341**	1,985,886
DEPRECIATION AND AMORTIZATION	**3,625,261**	3,595,770
	11,150,413	11,591,230
EARNINGS BEFORE PAYMENTS IN LIEU OF TAXES	**3,113,264**	3,425,039
Provisions for payments in lieu of taxes (Note 16)	**1,010,704**	1,009,826
NET EARNINGS AND COMPREHENSIVE INCOME	**2,102,560**	2,415,213
RETAINED EARNINGS, BEGINNING OF YEAR	**5,181,959**	3,916,746
LESS DIVIDENDS PAID	**(1,500,000)**	(1,150,000)
RETAINED EARNINGS, END OF YEAR	**5,784,519**	5,181,959

CHATHAM-KENT HYDRO INC.
Statement of Cash Flows
Year Ended December 31, 2009

	2009	2008
	$	$
OPERATING ACTIVITIES		
Net earnings	**2,102,560**	2,415,213
Adjustments for:		
Depreciation of capital assets	**3,979,125**	3,876,504
Depreciation of computer software	**134,390**	128,457
Amortization of contributed capital	**(167,368)**	(156,138)
Allowance for deferred assets	**-**	(84,582)
Gain on disposal of capital assets	**(11,683)**	(35,721)
Employee future benefits	**58,959**	57,656
Changes in non-cash working capital items (Note 13)	**(285,092)**	825,256
Change in long-term customer deposits	**(716,558)**	480,583
	5,094,333	7,507,228
INVESTING ACTIVITIES		
Change in deferred assets	**(1,340,073)**	1,553,057
Recovery of deferred assets	**308,924**	(351,952)
Proceeds on disposal of capital assets	**11,683**	37,743
Additions to capital assets	**(3,949,059)**	(5,188,898)
Additions to computer software	**(141,505)**	(158,221)
	(5,110,030)	(4,108,271)
FINANCING ACTIVITIES		
Dividends paid	**(1,500,000)**	(1,150,000)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**(1,515,697)**	2,248,957
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**6,340,035**	4,091,078
CASH AND CASH EQUIVALENTS, END OF YEAR	**4,824,338**	6,340,035

See Note 13 for supplemental cash flow information.

1. NATURE OF OPERATIONS

a) Incorporation of Chatham-Kent Hydro Inc.

Chatham-Kent Hydro Inc. ("the Company") was incorporated September 22, 2000 under the *Business Corporations Act (Ontario).*

The Company is wholly-owned by Chatham-Kent Energy Inc. which in turn is owned 90% by the Municipality of Chatham-Kent ("the Municipality") and 10% by Corix Utilities ("Corix").

The principal activity of the Company is to distribute electricity to customers within the Municipality of Chatham-Kent, under the licence issued by the OEB.

b) Rate Regulated Entity

The Company is a regulated Local Distribution Company ("LDC") and has a distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. *The Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity.
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return.
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by Company in respect of the transmission of electricity from generating stations to the local areas.
- Wholesale Market Service Charge – The wholesale market service charge represents the various wholesale market support costs.

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the Independent Electricity System Operator ("IESO"), which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

1. NATURE OF OPERATIONS (continued)

Market Based Rate of Return

The Company had reset their rates and received approval from the OEB for a change in rates effective May 1, 2006 which approved rates that included a rate of return of 9.0% on equity and rebased the rate base and operating costs at the 2004 historical levels. The rate of return of 9.0% was the maximum allowed by the OEB at that time.

Incentive Rate Mechanism

The OEB regulates the rates of the Company in an Incentive Rate Mechanism ("IRM") regime for 2007-2010. The process includes a formulae approach to establishing 2007 rates with a rate rebasing approach (cost-of-service) to be staggered across all Ontario distributors between 2008 and 2010. The Company self-nominated for a rate rebasing in 2010.

The IRM rate setting process provides an increase in rates for inflationary cost increases with a 1% offset for productivity gains. The IRM process also includes changes in the tax rates and a movement from the 2006 approved capital structure of 50% long-term debt and 50% equity to 4% short-term debt, 56% long-term debt and 40% equity.

The distribution rates increased by 0.24% in 2009 using the OEB's approved IRM.

Regulatory Assets and Liabilities

Electricity distributors are required to reflect certain prescribed costs on their balance sheets until the manner and timing of distribution is determined by the OEB. These costs are:

- Transition costs resulting from preparation of Open Access;
- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- The deferral of OEB annual cost assessments for the OEB's fiscal year 2004 and 2005;
- The deferral of incremental OMERS pension expenditures for fiscal years starting after January 1, 2005;
- Costs incurred to invest in and install a smart meter at all our customer premises;
- Payment-in-lieu of taxes ("PILS") variances since the Company became taxable October 2002; and
- Cost related to the Green Energy and Green Economy Act of 2009.

The regulatory assets and liabilities balances are detailed in Note 6. The regulatory asset balances have been recovered in rates on an interim basis since April 2004. The Company on an annual basis will continue to apply to the OEB for rate recovery of the investments made in smart meters. The recovery of variances for the PILS will occur sometime after the OEB completes their generic regulatory proceeding which will provide the filing guidelines for this regulatory asset or liability.

2. CHANGES IN ACCOUNTING POLICIES

Current Accounting Changes

The Company adopted the following recommendations of the Canadian Institute of Chartered Accountants ("CICA") Handbook:

a) Section 3064, Goodwill and Intangible Assets

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section is applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Company has adopted the new standards for its fiscal year beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The adoption of this new Section has not had a material impact on the financial statements.

b) Section 3465, Accounting for Income Taxes

CICA Section 3465, Income Taxes has been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities. This amendment also requires that a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers, and to present these amounts on a pre-tax basis in the financial statements. This accounting policy was applied prospectively without restatement beginning January 1, 2009. The impact of these changes resulted in an increase in long-term liabilities and an increase in future income tax assets of approximately $2,320,990 as at December 31, 2009.

c) Rate Regulated Accounting

Effective January 1, 2009, the temporary exemption from CICA Handbook Section 1100 ''Generally Accepted Accounting Principles'', which permits the recognition and measurement of assets and liabilities arising from rate regulation was withdrawn. The Company has chosen to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's Financial Accounting Standard (FAS) 71 ''Accounting for the Effects of Certain Types of Regulation''. Accordingly, Chatham-Kent Hydro will retain its current method of accounting for its rate-regulated operations, The removal of the temporary exemption had no effect on the Corporation's results of operations as of December 31, 2009.

Future accounting changes

a) International Financial Reporting Standards ("IFRS")

On February 13, 2008 the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for fiscal years beginning on or after January 1, 2011. As

2. CHANGES IN ACCOUNTING POLICIES (continued)

Future accounting changes (continued)

a) International Financial Reporting Standards ("IFRS")(continued)

such, the Company will apply IFRS to its financial statements for the year ending December 31, 2011 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2010, for comparative purposes. At this time, the impact on the Company's future financial position and results of operations are not reasonably determinable or estimable.
In anticipation of the changes to reporting standards due to the implementation of IFRS we commenced our IFRS conversion project. An external advisor has been engaged to assist with this project. The project has four separate phases: diagnostic, design and planning, solution development, and implementation. In 2009, we completed the diagnostic, design and planning, and solution development phases. We are currently engaged in the implementation phase which is the final phase of our project. The areas with the highest potential to significantly impact our company, identified during the diagnostic phase, are rate regulated assets and liabilities, property, plant and equipment, impairment of assets, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS*.

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. The OEB held public meetings and a formal stakeholder conference in May 2009. We participated at each opportunity offered to the public to communicate with the OEB. On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

3. SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with GAAP and reflect the following policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the *Ontario Energy Board Act, 1998:*

Regulation

The Company is regulated by the OEB and any rate adjustments require OEB approval.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Inventories

Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

Capital assets

Capital assets are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

Buildings and fixtures	25 – 50 years
Distribution station equipment	30 years
Distribution lines	25 years
Distribution transformers	25 years
Distribution meters	25 years
General office equipment	10 years
Computer equipment	5 years
Rolling stock	4 - 8 years
Tools	10 years
System supervisory equipment	15 years
Automated mapping facility management	15 years
Services	25 years
Contributions in aid of construction	25 years
Supervisory control and data acquisition	15 years
Smart Meters	3 - 15 years

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.

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. For the year ended December 31, 2009 $280,764 (2008 - $36,029) of contributed capital has been charged to capital assets and recorded as an offset to capital assets. Amortization is on a straight-line basis over 25 years.

Computer software

Computer software is stated at cost less accumulated depreciation. Distribution software is depreciated over 5 years on a straight-line basis. Smart meter software is depreciated over 3 years on a straight-line basis.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Deferred assets

Deferred assets consist of qualifying capital costs and related expenditures incurred in the preparation for market opening, costs for conservation programs which meet the Minister of Energy's Directive and investments in smart meters, other expenditures that are not currently recovered in rates and variances for PILS.

Also included in deferred assets are retail settlement variance accounts. These variances are for non-competitive energy services which are a pass through for the Company.

Recovery of the deferred assets requires regulatory approval from the OEB.

In the absence of regulatory treatment, net earnings in the current year would have decreased by $736,367 (2008 - decrease of $454,074). Refer to Note 6 for additional details.

Payments in lieu of taxes

Under the *Electricity Act, 1998*, the Company is required to make payments-in-lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are recorded in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations.

For 2009, the Company adopted the liability method of accounting for payments in lieu of taxes. Effective January 1 2009, CICA Section 3465, Income Taxes had been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities. The amendment also required the recognition of a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers and to present these amounts on a pre-tax basis in the financial statements. Accordingly, the Company has recorded a regulatory liability that has been included in long-term liabilities and an associated future income tax asset of $2,320,990. The liability will be paid through future rate reductions.

Prior to 2009, the Company accounted for payments-in-lieu of taxes using the taxes payable method instead of the liability method. Under the taxes payable method, no provisions were made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes.

Customer deposits

Customer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

Asset retirement obligations

The Company recognizes the liability for an asset retirement that results from acquisition, construction, development or normal operations. The liability for an asset retirement is initially recorded at its fair value in the year in which it is incurred and when a reasonable

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Asset retirement obligations (continued)

estimate of fair value can be made. The corresponding cost is capitalized as part of the related asset and is amortized over the asset's useful life. In subsequent years the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. The accretion of the liability to its fair value as a result of the passage of time is charged to earnings.

Post employment benefits other than pension

The Company provides its current and retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The cost of these benefits is expensed as earned through employment service.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue recognition and cost of power

Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power related to distribution are charged to deferred assets.

In accordance with EIC 123, costs to provide OPA programs have been netted against OPA revenues included in Other Operating Revenue. In 2009, costs of $1,141,940 were netted against revenues (2008 - $374,584).

Financial instruments

The Accounting Standards Board ("ACSB") of the CICA decided that rate-regulated enterprises that are not public enterprises as defined in Section 1300, Differential Reporting, will not be required to apply Sections 3862 and 3863 and would continue to apply Section 3861, Financial Instruments – Disclosure and Presentation. Therefore, in accordance with this decision, the Company continues to apply Section 3861.

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.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial instruments (continued)

<u>Classification</u>

Cash and cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Due from Middlesex Power Distribution Company	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Due to the Municipality of Chatham-Kent	Other liabilities
Current portion of customer deposits	Other liabilities
Note payable	Other liabilities
Long-term portion of customer deposits	Other liabilities

<u>Held for trading</u>

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.

Financial liabilities designated as held for trading are those non-derivative financial liabilities that the Company elects to designate on initial recognition as instruments that it will measure at fair value through other interest expense. These are accounted for in the same manner as held for trading assets. The Company has not designated any non-derivative financial liabilities as held for trading.

<u>Loans and receivables</u>

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

<u>Other liabilities</u>

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

<u>Effective interest method</u>

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.

4. ACCOUNTS RECEIVABLE

	2009	2008
	$	$
Electrical energy	**2,849,767**	3,126,055
Other	**748,555**	362,914
	3,598,322	3,488,969
Allowance for doubtful accounts	**(105,722)**	(105,444)
Net accounts receivable	**3,492,600**	3,383,525

5. CAPITAL ASSETS AND COMPUTER SOFTWARE

	2009			2008
	Cost	**Accumulated Depreciation**	**Net Book Value**	Net Book Value
	$	**$**	**$**	$
Plant and distribution system:				
Land	**742,237**	**-**	**742,237**	686,357
Buildings and fixtures	**3,790,631**	**918,818**	**2,871,813**	2,877,387
Distribution station equipment	**856,006**	**220,717**	**635,289**	137,668
Station retirement obligation	**20,599**	**5,599**	**15,000**	15,000
Distribution system:				
Overhead	**24,448,491**	**8,642,015**	**15,806,476**	15,609,466
Underground	**16,600,831**	**7,059,368**	**9,541,463**	9,636,543
Transformers	**14,974,648**	**5,658,938**	**9,315,710**	9,418,673
Meters	**2,821,199**	**1,227,481**	**1,593,718**	2,049,066
General office equipment	**131,282**	**83,431**	**47,851**	48,603
Computer equipment	**399,470**	**354,288**	**45,182**	43,794
Rolling stock	**2,770,547**	**1,708,534**	**1,062,013**	958,145
Tools	**685,665**	**526,748**	**158,917**	140,519
System supervisory equipment	**802,591**	**600,753**	**201,838**	240,322
Automated mapping facility	**1,831,076**	**1,057,181**	**773,895**	843,885
Services	**3,701,746**	**809,817**	**2,891,929**	2,692,799
Smart meters	**4,617,600**	**907,742**	**3,709,858**	3,764,265
	79,194,619	**29,781,430**	**49,413,189**	49,162,492
Contributions in aid of construction	**(4,167,517)**	**(1,016,793)**	**(3,150,724)**	(3,037,329)
Capital assets	**75,027,102**	**28,764,637**	**46,262,465**	46,125,163
Computer software	**690,779**	**378,131**	**312,648**	305,533

Depreciation and amortization in the amount of $252,949 (2008 - $214,588) for rolling stock and $67,937 (2008 - $38,465) for computer software is included with relevant cost centres.

6. DEFERRED ASSETS

Deferred assets and liabilities arise as a result of the rate-making process. As described in this note, the Company has recorded the following regulatory assets and related provisions.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process.

	2009	2008
	$	$
Costs		
Retail settlement variance accounts	**(1,392,311)**	(1,600,214)
Conservation and demand management & renewable energy	**34,071**	12,364
PIL's recoverable	**1,053,073**	1,113,200
Other deferred/transition costs	**1,766,307**	1,429,479
Smart meter	**2,243,008**	1,409,246
Gross deferred assets	**3,704,148**	2,364,075
Recoveries		
Regulatory asset prior to 2004 recovery	**134,554**	134,554
Conservation and demand management recovery	**-**	(4,589)
Smart meter recovery	**(242,297)**	71,216
Net deferred assets	**3,596,405**	2,565,256

a) Regulatory Costs/Recoveries

(i) Regulatory assets prior to 2004

The introduction of Bill 210 in November 2002 deferred future rate increases until 2007. However Bill 4 was introduced in December 2003 which allowed for the recovery of deferred assets over a four year period beginning in April 2004. The Company obtained full and final recovery of the deferred assets balances at December 31, 2004. The recovery was over a four-year period ended April 30, 2008. At December 31, 2008 the revenue collected was not sufficient to cover all the regulatory asset cost. The balance owing from customers is $134,554, of which $53,863 is interest. In the absence of regulatory treatment, net earnings in 2008 would have increased by $159,323. The absence of regulatory treatment would have no effect on 2009 net earnings.

(ii) Retail settlement variance accounts

These accounts represent the variance between the revenue collected, using OEB approved rates for the non–competitive components of energy, and the corresponding cost of these non-competitive charges, beginning January 1, 2004 to the present. These variances will be held as a regulatory asset or liability, based on the expectation that the amounts held from one year to the next for rate

6. DEFERRED ASSETS (continued)

(ii) Retail settlement variance accounts (continued)

setting purposes will be approved for collection from, or refund to, future customers. In the absence of regulatory treatment, net earnings in the current year would have decreased by $139,295 (2008 - increase of $32,309).

(iii) Conservation and demand management & renewable energy

During 2009, the Company incurred no costs for conservation and demand management (2008 - $12,364). These approved programs were completed by December 2008. During 2009, the Company incurred Green Energy initiative costs of $34,071 (2008 - $ nil). These costs related to the Green Energy and Green Economy Act, 2009 passed by the Ontario government. Also in 2009 the Ontario Energy Board approved a new deferral account #1531 to collect these costs. In the absence of regulatory treatment, net earnings in the current year would have been decreased by $22,828 (2008 - $ nil).

(iv) Payments in Lieu of Taxes

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between tax basis of assets and liabilities and their carrying amounts for accounting purposes. Balance in the PILS account is $1,053,073 (2008 - $1,113,200). In the absence of regulatory treatment, the net earnings effect in the current and prior year would have been $ nil.

(v) Regulatory Future Income Tax Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory liabilities which correspond to future income taxes that flow through the rate-making process. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts set up for taxes to be paid through future rates. As a result the provision for PILs would have been higher by approximately $115,000 (2008 - $238,000) including the impact of a change in substantively enacted tax rates.

(vi) Other deferred/transition costs

These balances represent OEB specific costs incurred up to 2005 not currently in rates. These costs will be applied for in the next rate rebasing application to the OEB. The OEB specific costs for 2009 are a credit of $908,417 (2008 - $1,000,213). As well the OEB has authorized distributors to apply for other deferred costs including Loss Revenue Adjustment Mechanism ("LRAM") due to Demand Management Programs to their customers that have resulted in decreased

6. DEFERRED ASSETS (continued)

(vi) Other deferred/transition costs (continued)

kWh consumption. This amount may be claimed in a subsequent rate year as compensation for loss of revenue. LRAM balance for 2009 is $548,332 (2008 – $418,901). Other new Deferred items for 2009 included, 2010 rebasing $173,723 (2008 - $10,365), Time of Use Billing $8,072 (2008 - $ nil) and International Financial Reporting costs of $127,762 (2008 - $ nil). In the absence of regulatory treatment, net earnings in the current year would have decreased by $225,675 (2008 - $220,580).

(vii) Smart meters

The Company incurred costs for the implementation of smart meters of $2,243,008 (2008 - $1,409,296). The year-end balance in the smart meter recovery account is a credit of $242,297 (2008 - $71,216 debit). In 2009 the Company capitalized the General Service greater than 50 customer class, of smart meter costs $106,952 (2008 - $ nil). In the absence of regulatory treatment, net earnings in the current year would have decreased by $348,569 (2008 - $301,154).

7. NOTE PAYABLE

The note payable is due to the Municipality with no set repayment terms and interest payable monthly at 7.04%. Interest expense for the year amounted to $1,654,320 (2008 - $1,654,320).

8. EMPLOYEE FUTURE BENEFITS

The Company measures its accrued benefit obligation as at December 31 of each year. The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The accrued benefit liability at December 31, 2009 was $917,524 (2008 - $858,565). The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2007 and the next required valuation will be as of December 31, 2010.

Information about the Company's defined benefit plan is as follows:

	2009	2008
	$	$
Accrued benefit liability, beginning of year	**858,565**	800,909
Expense for the year	**58,959**	57,656
Estimated accrued benefit liability, end of year	**917,524**	858,565

8. EMPLOYEE FUTURE BENEFITS (continued)

The main actuarial assumptions employed for the valuation are as follows:

General inflation

Future inflation levels, as measured by changes in the Consumers Price Index ("CPI"), were assumed to be 2.5% in 2009 and thereafter.

Interest (discount) rate

The present value of the future benefits, and the expense for the year ended December 31, 2009 was determined using a discount rate of 7.62%. This corresponds to the OEB approved non-arm's length cost of debt rate for 2009.

Health costs

Health costs were assumed to increase at 10% per year for 10 years, and then at the CPI rate plus 1% thereafter.

Dental costs

Dental costs were assumed to increase at the CPI rate plus 1% for 2009 and thereafter.

Salary Growth Rate

Salary growth rate was assumed to increase at a rate of 3.5% for 2009 and thereafter.

9. PENSION AGREEMENT

The Company provides a pension plan for its employees through the Ontario Municipal Employees' Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company's contribution for employees' current service in 2009 was $197,010 (2008 - $191,617).

10. RELATED PARTY TRANSACTIONS

The Company provided the following services in the normal course of operations to the Municipality of Chatham-Kent:

	2009	2008
	$	$
Energy (at commercial rates)	**4,069,792**	4,467,487
Streetlight maintenance	**168,042**	196,152
	4,237,834	4,663,639

The Municipality provided the following services in the normal course of operations to the Company:

	2009	2008
	$	$
Asset management	**152,146**	119,002

Chatham-Kent Utility Services Inc. is wholly owned by Chatham-Kent Energy Inc. Chatham-Kent Utility Services Inc. has provided the following services in the normal course of operations to the Company:

	2009	2008
	$	$
Billing, collection & administrative services	**3,463,805**	2,984,887

Included in the costs above are deferred costs of $205,068 (2008 - $62,139) that are reflected on the balance sheet.

Middlesex Power Distribution Corporation is wholly owned by CKE. Middlesex Power Distribution Corporation received the following services in the normal course of operations from the Company.

	2009	2008
	$	$
Administrative services	**78,024**	77,415
Other services provided	**69,801**	104,297
	147,825	181,712

11. CONTINGENCY

Class Action Suit

This action has been brought under the Class Proceedings Act, 1992. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Enbridge Gas Distribution case rejecting all of the defenses which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.
In 2007, Enbridge filed an application to the OEB to recover the Court-approved amount and related amounts from ratepayers. In February 2008, the OEB approved recovery of these amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Enbridge Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDC's. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDC's situation may be distinguishable from that of Enbridge Gas.

The Company collected total late payment penalties of $2,736,198 from customers between 1994 until April 2002 when the Company implemented an interest rate penalty. Although recent settlement models for Union Gas and Enbridge have been decided, it remains unclear as to the settlement models for LDC's.

12. SHARE CAPITAL

The share capital of the Company consists of the following:

	2009	2008
Authorized	**$**	$
Unlimited common shares		
Issued		
2,000 common shares	**23,523,425**	23,523,425

13. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital items

	2009	2008
	$	$
Accounts receivable	**(109,075)**	24,181
Accounts receivable - unbilled revenue	**(1,096,927)**	349,486
Taxes receivable	**(104,434)**	729,593
Due from Middlesex Power Distribution Corporation	**(228,715)**	(58,269)
Due from Chatham-Kent Energy	**-**	250,000
Inventories	**45,062**	104,311
Prepaid expenses	**78,839**	(22,720)
Accounts payable and accrued liabilities	**(718,068)**	(345,879)
Due to Municipality of Chatham-Kent	**1,207,340**	(479,015)
Increase in current portion of customer deposits	**640,886**	273,568
	(285,092)	825,256

Payments in lieu of taxes of $1,210,272 (2008 - $1,338,060) and interest of $1,748,341 (2008 - $1,986,124) were paid during the year.

14. FINANCIAL INSTRUMENTS

Fair value

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, due from related parties, accounts payable and accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical. The Company has a long term promissory note payable with the Municipality in the amount of $23,523,326. The promissory note was issued upon incorporation on September 22, 2000 with interest at 7.04%. There is no “term length” associated with the promissory note.

In order to determine fair value, comparison was made to the approved interest rate from the OEB. The OEB approved the rate of return on the debt portion of “Cost of Capital” for non-arms length transactions. The 7.04% interest rate has been approved by the OEB through the rate setting process on a number of occasions since May 2001.

Using the OEB approved non-arm’s length cost of debt of 7.62% the annual interest expense would be increased by approximately $136,000 which is well within current OEB materiality threshold of $2,324,000. If the interest rate on the note payable changed as noted above, the OEB would most likely increase the revenue in a rate proceeding therefore the impact to the net income would be much less. As a result, no changes have been made to the current financial statements.

14. FINANCIAL INSTRUMENTS (continued)

Credit risk

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing based corporations that pose a significant increase in risk due to the current economy as well as the future outlook of the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk.

15. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC;
- maintain an A-credit rating on stand alone basis;
- maintain a capital structure comparable for regulated activities as approved by the OEB's deemed debt to equity structure in our rates.

As at December 31, 2009 the Company's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2008. As at December 31, 2009 shareholder's equity amounts to $29,307,944 (2008 - $28,705,384) and long-term debt amounts to $23,523,326 (2008 - $23,523,326).

The 2009 capital structure approved by the OEB in rates was 43% Equity (2008 - 47%) and 57% Long-Term Debt (2008 - 53%). The Company's 2009 actual capital structure was 56% Equity (2008 - 55%) with 44% Long-Term Debt (2008 - 45%).

16. PAYMENTS IN LIEU OF TAXES

The provision for payments in lieu of taxes consists of the following:

	2009	2008
	$	$
Current income taxes	**865,304**	864,426
Capital tax	**145,400**	145,400
	1,010,704	1,009,826

Reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

16. PAYMENTS IN LIEU OF TAXES (continued)

	2009	2008
	$	$
Income before payments in lieu of taxes	**3,113,264**	3,425,039
Capital tax	**145,400**	145,400
Income before income taxes	**2,967,864**	3,279,639
Statutory income tax rate (percent)	**33.0%**	33.5%
Statutory income tax rate applied to accounting income	**979,395**	1,098,679
Increase / (decrease) resulting from:		
Temporary differences between accounting and tax basis of assets and liabilities	**(115,257)**	(237,677)
Permanent differences	**1,166**	3,424
Provision for income taxes	**865,304**	864,426
Effective rate of income tax (percent)	**29.2%**	26.4%

Future income taxes

The long-term future income tax asset of $2,320,990 includes the following:

	2009
	$
Temporary differences related to capital assets and deferred assets	**2,010,149**
Temporary differences related to employee future benefits	**310,841**
	2,320,990

If the liability method of accounting for income taxes were used in 2008, a future tax asset of $2,152,782 would have been recorded.

17. COMMITMENTS

The Company has entered into Service Level agreements with Chatham-Kent Utility Services Inc., on a year to year basis, to have them provide the services of billing, account collections, customer inquiries and meter reading as well as administrative services such as office space usage, rate submission support, accounting and budgeting support. The value of this contract is $3,463,805 (2008 - $2,984,887).

The Company has entered into a Service Level agreement with Middlesex Power Distribution Corporation, on a year to year basis, to provide them management, engineering and material purchasing services. The value of this contract is $78,024 (2008 - $77,415).

Financial Statements of

CHATHAM-KENT HYDRO INC.

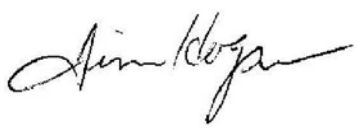
December 31, 2010

Management's Responsibility for Financial Reporting

Chatham-Kent Hydro's management is responsible for the preparation and presentation of the financial statements and all other information included in this annual report. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board exercises this responsibility through the Audit Committee of the Board. This committee is comprised of four directors of companies within the Chatham-Kent Energy group, one of whom is a director of the Chatham-Kent Hydro Inc. Board. This committee meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements and other information included in the annual report before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Deloitte & Touche LLP, an independent firm of Chartered Accountants, has been appointed by the audit committee and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.



Jim Hogan
Director

Chris Cowell
Chief Financial & Regulatory Officer

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Independent Auditor's Report

To the Chairman and Board Members of
Chatham-Kent Hydro Inc.

We have audited the accompanying financial statements of Chatham-Kent Hydro Inc. which comprise the balance sheet as at December 31, 2010, and the statements of earnings, comprehensive income and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Chatham-Kent Hydro Inc. as at December 31, 2010 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants
Licensed Public Accountants
April 1, 2011

CHATHAM-KENT HYDRO INC.
Balance Sheet
December 31, 2010

	2010	2009
	$	$
ASSETS		
CURRENT		
Cash and cash equivalents	**5,322,258**	4,824,338
Accounts receivable (Note 4)	**3,867,393**	3,492,600
Accounts receivable - unbilled revenue	**9,722,658**	10,084,184
Taxes receivable	**-**	213,822
Due from Middlesex Power Distribution Corporation	**581,849**	611,977
Inventories	**618,109**	631,201
Prepaid expenses	**58,258**	12,240
	20,170,525	19,870,362
CAPITAL ASSETS (Note 5)	**48,062,309**	46,262,465
OTHER		
Deferred assets (Note 6)	**3,573,114**	3,596,405
Future income taxes (Note 16)	**2,448,286**	2,320,990
Intangible assets	**84,736**	-
Computer software (Note 5)	**283,102**	312,648
	6,389,238	6,230,043
	74,622,072	72,362,870
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**9,326,721**	8,318,461
Taxes payable	**127,703**	-
Due to the Municipality of Chatham-Kent	**3,108,137**	3,455,554
Current portion of customer deposits	**1,833,001**	1,757,153
	14,395,562	13,531,168
LONG-TERM		
Regulatory future income tax liability (Note 16)	**2,448,286**	2,320,990
Notes payable (Note 7)	**31,273,326**	23,523,326
Asset retirement obligation	**15,000**	15,000
Employee future benefits (Note 8)	**954,707**	917,524
Long-term portion of customer deposits	**1,686,860**	2,746,918
	36,378,179	29,523,758
	50,773,741	43,054,926
CONTINGENCY AND COMMITMENTS (Notes 11 and 17)		
SHAREHOLDER'S EQUITY		
Share capital (Note 12)	**23,523,425**	23,523,425
Retained earnings	**324,906**	5,784,519
	23,848,331	29,307,944
	74,622,072	72,362,870

CHATHAM-KENT HYDRO INC.
Statement of Earnings, Comprehensive Income and Retained Earnings
December 31, 2010

	2010	2009
	$	$
SERVICE REVENUE		
Residential	**27,913,357**	23,385,768
General service	**42,459,615**	38,069,919
Street lighting	**679,490**	656,704
	71,052,462	62,112,391
Change in unbilled revenue	**(273,473)**	1,212,181
	70,778,989	63,324,572
Retailer energy sales	**5,636,425**	5,087,629
	76,415,414	68,412,201
COST OF POWER	**62,065,218**	55,844,977
GROSS MARGIN ON SERVICE REVENUE	**14,350,196**	12,567,224
OTHER OPERATING REVENUE	**1,287,331**	1,696,453
OPERATING INCOME	**15,637,527**	14,263,677
OPERATING AND MAINTENANCE EXPENSE		
Distribution	**2,942,713**	2,288,251
ADMINISTRATIVE EXPENSE		
Billing and collection	**1,757,562**	1,571,480
General administration	**2,165,814**	1,917,080
Interest	**1,727,477**	1,748,341
DEPRECIATION AND AMORTIZATION	**3,666,128**	3,625,261
	12,259,694	11,150,413
EARNINGS BEFORE PAYMENTS IN LIEU OF TAXES	**3,377,833**	3,113,264
Provisions for payments in lieu of taxes (Note 16)	**1,087,446**	1,010,704
NET EARNINGS AND COMPREHENSIVE INCOME	**2,290,387**	2,102,560
RETAINED EARNINGS, BEGINNING OF YEAR	**5,784,519**	5,181,959
LESS DIVIDENDS	**(7,750,000)**	(1,500,000)
RETAINED EARNINGS, END OF YEAR	**324,906**	5,784,519

CHATHAM-KENT HYDRO INC.
Statement of Cash Flows
Year Ended December 31, 2010

	2010	2009
	$	$
OPERATING ACTIVITIES		
Net earnings	**2,290,387**	2,102,560
Adjustments for:		
Depreciation of capital assets	**4,128,270**	3,979,125
Depreciation of computer software	**116,763**	134,390
Amortization of contributed capital	**(172,917)**	(167,368)
Loss (gain) on disposal of capital assets	**72,888**	(11,683)
Employee future benefits	**37,183**	58,959
Changes in non-cash working capital items (Note 13)	**1,062,151**	(285,092)
Change in long-term customer deposits	**(1,060,058)**	(716,558)
	6,474,667	5,094,333
INVESTING ACTIVITIES		
Change in deferred assets	**382,489**	(1,340,073)
Change in deferred asset recoveries	**(359,198)**	308,924
Additions to intangible assets	**(84,736)**	-
Proceeds on disposal of capital assets	**49,731**	11,683
Additions to capital assets	**(5,877,815)**	(3,949,059)
Additions to computer software	**(87,218)**	(141,505)
	(5,976,747)	(5,110,030)
FINANCING ACTIVITIES		
Loan from CKE	**7,750,000**	-
Dividends	**(7,750,000)**	(1,500,000)
	-	(1,500,000)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**497,920**	(1,515,697)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**4,824,338**	6,340,035
CASH AND CASH EQUIVALENTS, END OF YEAR	**5,322,258**	4,824,338

See Note 13 for supplemental cash flow information.

1. NATURE OF OPERATIONS

a) Incorporation of Chatham-Kent Hydro Inc.

Chatham-Kent Hydro Inc. ("the Company") was incorporated September 22, 2000 under the *Business Corporations Act (Ontario).*

The Company is wholly-owned by Chatham-Kent Energy Inc. ("CKE") which in turn is owned 90% by the Municipality of Chatham-Kent ("the Municipality") and 10% by Corix Utilities ("Corix").

The principal activity of the Company is to distribute electricity to customers within the Municipality of Chatham-Kent, under the licence issued by the Ontario Energy Board ("OEB").

b) Rate Regulated Entity

The Company is a regulated Local Distribution Company ("LDC") and has a distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. *The Ontario Energy Board Act*, *1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity.
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return.
- Global Adjustment – the difference between the rate paid to regulated and contracted electricity generators and the spot market price.
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by Company in respect of the transmission of electricity from generating stations to the local areas.
- Wholesale Market Service Charge – The wholesale market service charge represents the various wholesale market support costs.

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the Independent Electricity System Operator ("IESO"), which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

1. NATURE OF OPERATIONS (continued)

Market Based Rate of Return

The Company received approval from the OEB for a change in rates effective May 1, 2010 which approved rates that included a rate of return of 9.85% on equity and rebased the rate base and operating costs at 2010 test year levels. The rate of return of 9.85% was the maximum allowed by the OEB at that time.

Incentive Rate Mechanism

Between rate basing years, the OEB regulates the rates of the Company in an Incentive Rate Mechanism ("IRM") regime. The process includes a formulae approach to establishing rates with a rate rebasing approach (cost-of-service) every fourth year.

The IRM rate setting process provides an increase in rates for inflationary cost increases with an offset for productivity gains.

Deferred Assets

Electricity distributors are required to reflect certain prescribed costs on their balance sheets until the manner and timing of distribution is determined by the OEB. These costs are:

- Transition costs resulting from preparation of Open Access;
- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- The deferral of OEB annual cost assessments for the OEB's fiscal year 2004 and 2005;
- The deferral of incremental Ontario Municipal Employees' Retirement System ("OMERS") pension expenditures for fiscal years starting after January 1, 2005;
- Costs incurred to invest in and install a smart meter at all our customer premises;
- Payment-in-lieu of taxes ("PILS") variances since the Company became taxable October 2002; and
- Cost related to the Green Energy and Green Economy Act of 2009.

The deferred assets and liabilities balances are detailed in Note 6. The regulatory asset balances have been recovered in rates on an interim basis since April 2004. The Company will apply to the OEB for final rate recovery of the investments made in smart meters once the installation project is complete. The recovery of variances for the PILS will occur sometime after the OEB completes their generic regulatory proceeding which will provide the filing guidelines for this regulatory asset or liability.

2. CHANGES IN ACCOUNTING POLICIES

Future accounting changes

International Financial Reporting Standards ("IFRS")

On February 13, 2008 the Canadian Accounting Standards Board ("AcSB") confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles ("GAAP") for fiscal years beginning on or after January 1, 2011. Subsequently, on September 10, 2010, the AcSB decided to permit rate-regulated entities and certain affiliates to defer their IFRS adoption date to January 1, 2012. The Company is a qualifying entity for purposes of this deferral and has elected to use the deferral offered by the AcSB. The deferral will allow the Company to convert at the same time as many other companies in its industry.

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. In January 2011, the OEB convened an IFRS Working Group to address the particulars of implementing IFRS in an incentive regulation environment. The Company continues to assess the impact of conversion to IFRS on its results of operations.

3. SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with GAAP and reflect the following policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the *Ontario Energy Board Act, 1998:*

Regulation

The Company is regulated by the OEB and any rate adjustments require OEB approval.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

Inventories

Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Capital assets

Capital assets are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

Buildings and fixtures	25 – 50 years
Distribution station equipment	30 years
Distribution lines	25 years
Distribution transformers	25 years
Distribution meters	25 years
General office equipment	10 years
Computer equipment	5 years
Rolling stock	4 - 8 years
Tools	10 years
System supervisory equipment	15 years
Automated mapping facility management	15 years
Services	25 years
Contributions in aid of construction	25 years
Supervisory control and data acquisition	15 years
Smart meters	3 - 15 years

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.

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. For the year ended December 31, 2010 $277,450 (2009 - $280,764) of contributed capital has been charged to capital assets and recorded as an offset to capital assets. Amortization is on a straight-line basis over 25 years.

Intangible assets

Intangible assets are recorded at their fair value at the acquisition date. As the Company's intangible assets have an indefinite life they are not amortized to income. Intangible assets will be tested for impairment when events or changes in circumstances indicate that their carrying value may not be recoverable.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Computer software

Computer software is stated at cost less accumulated depreciation. Distribution software is depreciated over 5 years on a straight-line basis. Smart meter software is depreciated over 3 years on a straight-line basis.

Deferred assets

Deferred assets consist of qualifying capital costs and related expenditures incurred in the preparation for market opening, costs for conservation programs which meet the Minister of Energy's Directive and investments in smart meters, other expenditures that are not currently recovered in rates and variances for PILS.

Also included in deferred assets are retail settlement variance accounts. These variances are for non-competitive energy services which are a pass through for the Company.

Recovery of the deferred assets requires regulatory approval from the OEB.

In the absence of regulatory treatment, net earnings in the current year would have increased by $16,073 (2009 - decrease of $736,367). Refer to Note 6 for additional details.

Payments in lieu of taxes

Under the *Electricity Act, 1998*, the Company is required to make payments-in-lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are recorded in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations.

Effective January 1 2009, CICA Section 3465, Income Taxes had been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities. The amendment also required the recognition of a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers and to present these amounts on a pre-tax basis in the financial statements. Accordingly, the Company has recorded a regulatory liability that has been included in long-term liabilities and an associated future income tax asset of $2,448,286 (2009 - $2,320,990). The liability will be paid through future rate reductions.

Customer deposits

Customer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Asset retirement obligations

The Company recognizes the liability for an asset retirement that results from acquisition, construction, development or normal operations. The liability for an asset retirement is initially recorded at its fair value in the year in which it is incurred and when a reasonable estimate of fair value can be made. The corresponding cost is capitalized as part of the related asset and is amortized over the asset's useful life. In subsequent years the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. The accretion of the liability to its fair value as a result of the passage of time is charged to earnings.

Post employment benefits other than pension

The Company provides its current and retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The cost of these benefits is expensed as earned through employment service.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue recognition and cost of power

Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power related to distribution are charged to deferred assets.

In accordance with EIC 123, costs to provide Ontario Power Authority ("OPA") programs have been netted against OPA revenues included in Other Operating Revenue. In 2010, costs of $746,149 (2009 - $1,141,940) were netted against revenues $1,006,136 (2009 - $1,611,316).

Financial instruments

The Accounting Standards Board ("ACSB") of the CICA decided that rate-regulated enterprises that are not public enterprises as defined in Section 1300, Differential Reporting, will not be required to apply Sections 3862 and 3863 and would continue to apply Section 3861, Financial Instruments – Disclosure and Presentation. Therefore, in accordance with this decision, the Company continues to apply Section 3861.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial instruments (continued)

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 cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Due from Middlesex Power Distribution Company	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Due to the Municipality of Chatham-Kent	Other liabilities
Current portion of customer deposits	Other liabilities
Note payable	Other liabilities
Long-term portion of customer deposits	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.

Financial liabilities designated as held for trading are those non-derivative financial liabilities that the Company elects to designate on initial recognition as instruments that it will measure at fair value through other interest expense. These are accounted for in the same manner as held for trading assets. The Company has not designated any non-derivative financial liabilities as held for trading.

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.

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.

4. ACCOUNTS RECEIVABLE

	2010	2009
	$	$
Electrical energy	**2,805,097**	2,849,767
Other	**1,156,539**	748,555
	3,961,636	3,598,322
Allowance for doubtful accounts	**(94,243)**	(105,722)
Net accounts receivable	**3,867,393**	3,492,600

5. CAPITAL ASSETS AND COMPUTER SOFTWARE

	2010			2009
	Cost	**Accumulated Depreciation**	**Net Book Value**	Net Book Value
	$	**$**	**$**	$
Plant and distribution system:				
Land	**1,045,800**	**-**	**1,045,800**	742,237
Buildings and fixtures	**4,074,034**	**1,043,128**	**3,030,906**	2,871,813
Distribution station equipment	**853,332**	**248,954**	**604,378**	635,289
Station retirement obligation	**20,599**	**5,599**	**15,000**	15,000
Distribution system:				
Overhead	**26,161,565**	**9,769,214**	**16,392,351**	15,806,476
Underground	**17,783,907**	**7,958,517**	**9,825,390**	9,541,463
Transformers	**15,780,620**	**6,386,813**	**9,393,807**	9,315,710
Meters	**2,858,757**	**1,369,205**	**1,489,552**	1,593,718
General office equipment	**141,143**	**93,166**	**47,977**	47,851
Computer equipment	**492,556**	**380,422**	**112,134**	45,182
Rolling stock	**3,347,618**	**1,862,257**	**1,485,361**	1,062,013
Tools	**787,237**	**558,414**	**228,823**	158,917
System supervisory equipment	**822,367**	**644,400**	**177,967**	201,838
Automated mapping facility	**2,003,054**	**1,203,552**	**799,502**	773,895
Services	**4,105,563**	**965,963**	**3,139,600**	2,891,929
Smart meters	**4,781,881**	**1,252,862**	**3,529,019**	3,709,858
	85,060,033	**33,742,466**	**51,317,567**	49,413,189
Contributions in aid of construction	**(4,444,968)**	**(1,189,710)**	**(3,255,258)**	(3,150,724)
Capital assets	**80,615,065**	**32,552,756**	**48,062,309**	46,262,465
Computer software	**777,996**	**494,894**	**283,102**	312,648

Depreciation and amortization in the amount of $315,348 (2009 - $252,949) for rolling stock and $90,640 (2009 - $67,937) for computer software is included with relevant cost centres.

6. DEFERRED ASSETS

Deferred assets and liabilities arise as a result of the rate-making process. As described in this note, the Company has recorded the following regulatory assets and related provisions.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process.

	2010	2009
	$	$
Costs		
Retail settlement variance accounts	**(1,331,966)**	(1,392,311)
Conservation and demand management & renewable energy	**297,103**	34,071
PIL's recoverable	**1,053,073**	1,053,073
Other deferred/transition costs	**1,296,166**	1,766,307
Smart meters	**2,008,124**	2,243,008
Gross deferred assets	**3,322,500**	3,704,148
Recoveries		
Regulatory asset	**142,102**	134,554
Smart meter recovery	**108,512**	(242,297)
Net deferred assets	**3,573,114**	3,596,405

a) Regulatory Costs/Recoveries

(i) Retail settlement variance accounts

These accounts represent the variance between the revenue collected, using OEB approved rates for the non–competitive components of energy, and the corresponding cost of these non-competitive charges, beginning January 1, 2004 to the present. These variances will be held as a regulatory asset or liability, based on the expectation that the amounts held from one year to the next for rate setting purposes will be approved for collection from, or refund to, future customers. In the absence of regulatory treatment, net earnings in the current year would have decreased by $41,638 (2009 - decrease of $139,295).

(ii) Conservation and demand management & renewable energy

During 2010, the Company incurred no costs for conservation and demand management (2009 - $ nil). The Company incurred Green Energy initiative costs of $297,103 (2009 - $34,071). These costs related to the Green Energy and Green Economy Act, 2009 passed by the Ontario government. In 2009, the Ontario Energy Board approved a new deferral account #1531 to collect these costs. In the absence of regulatory treatment, net earnings in the current year would have been decreased by $181,492 (2009 - $22,828).

6. DEFERRED ASSETS (continued)

a) Regulatory Costs/Recoveries (continued)

(iii) Payments in Lieu of Taxes

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between tax basis of assets and liabilities and their carrying amounts for accounting purposes. Balance in the PILS account is $1,053,073 (2009 - $1,053,073). In the absence of regulatory treatment, the net earnings effect in the current and prior year would have been $ nil.

(iv) Other deferred/transition costs

These balances represent OEB specific costs incurred not currently in rates. These costs will be applied for in the next rate rebasing application to the OEB. The OEB specific costs are $261,431 (2009 - $908,417). As well the OEB has authorized distributors to apply for other deferred costs including Loss Revenue Adjustment Mechanism ("LRAM") due to Demand Management Programs to their customers that have resulted in decreased kWh consumption.

This amount may be claimed in a subsequent rate year as compensation for loss of revenue. The LRAM , 2010 rebasing, Time of Use Billing, IFRS and Late Payment Settlement costs for 2010 are $1,034,735 (2009 – $857,890). In the absence of regulatory treatment, net earnings in the current year would have increased by $324,397 (2009 - $225,675 decrease).

(v) Smart meters

The Company incurred costs for the implementation of smart meters of $2,008,124 (2009 - $2,243,008). The year-end balance in the smart meter recovery account is a debit of $108,512 (2009 - $242,297 credit). In 2010, the Company capitalized smart meter costs of $171,345 (2009 - $106,952) and transferred $423,820 (2009 - $ nil) of Operating and Maintenance costs, $668,419 (2009 - $ nil) of Smart Meter revenue, and $114,623 (2009 - $ nil) stranded meter costs out of the Deferred account. These transfers were made in accordance with the Smart Meter costs approved to December 31, 2008 by the OEB. The Company also collected Deferred Smart Meter revenue of $317,612 (2009 - $208,677) during the year. In the absence of regulatory treatment, net earnings in the current year would have decreased by $79,988 (2008 - $348,569).

(vi) Regulatory assets recovery

The Company received Ontario Energy Board OEB approval regarding the collection of regulatory assets approved up to December 31, 2008 in the Rate Order effective May 01, 2010. The balance in the account is $142,102 (2009 - $134,554). In the absence of regulatory treatment the net earnings for the current year would have decreased by $5,208.

7. NOTES PAYABLE

The notes payable include $23,523,326 due to the Municipality at an interest rate of 7.04%. In 2010, a note payable for $7,750,000 was issued to CKE at an interest rate of 5.87%. Both notes have no set repayment term and interest payable monthly. Interest expense for the year amounted to $1,673,275 (2009 - $1,654,320).

8. EMPLOYEE FUTURE BENEFITS

The Company measures its accrued benefit obligation as at December 31 of each year. The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The accrued benefit liability at December 31, 2010 was $954,707 (2009 - $917,524). The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2010 and the next required valuation will be as of December 31, 2013.

Information about the Company’s defined benefit plan is as follows:

	2010	2009
	$	$
Accrued benefit liability, beginning of year	**917,524**	858,565
Expense for the year	**37,183**	58,959
Estimated accrued benefit liability, end of year	**954,707**	917,524

The main actuarial assumptions employed for the valuation are as follows:

General inflation

Future inflation levels, as measured by changes in the Consumers Price Index (“CPI”), were assumed to be 2.5% in 2010 and thereafter.

Interest (discount) rate

The present value of the future benefits, and the expense for the year ended December 31, 2010 was determined using a discount rate of 5.87% (2009 – 7.62%). This corresponds to the OEB approved non-arm’s length cost of debt rate for 2010.

Health costs

Health costs were assumed to increase at 8% per year for 8 years, and then at the CPI rate plus 1% thereafter.

Dental costs

Dental costs were assumed to increase at the CPI rate plus 1% for 2010 and thereafter.

8. EMPLOYEE FUTURE BENEFITS (continued)

Salary Growth Rate

Salary growth rate was assumed to increase at a rate of 3.5% for 2010 and thereafter.

9. PENSION AGREEMENT

The Company provides a pension plan for its employees through the OMERS. OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”) and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company’s contribution for employees’ current service in 2010 was $207,223 (2009 - $197,010).

10. RELATED PARTY TRANSACTIONS

The Company provided the following services in the normal course of operations to the Municipality:

	2010	2009
	$	$
Energy (at commercial rates)	**4,475,114**	4,069,792
Streetlight maintenance	**200,162**	168,042
	4,675,276	4,237,834

The Municipality provided the following services in the normal course of operations to the Company:

	2010	2009
	$	$
Asset management	**152,560**	152,146

Chatham-Kent Utility Services Inc. is wholly owned by CKE. Chatham-Kent Utility Services Inc. has provided the following services in the normal course of operations to the Company:

	2010	2009
	$	$
Billing, collection, administrative & data services	**3,979,295**	3,463,805

10. RELATED PARTY TRANSACTIONS (continued)

Included in the costs above are deferred costs of $249,999 (2009 - $205,068) that are reflected on the balance sheet.

All related party transactions are recorded at the exchange amounts.

Middlesex Power Distribution Corporation is wholly owned by CKE. Middlesex Power Distribution Corporation received the following services in the normal course of operations from the Company.

	2010	2009
	$	$
Administrative services	**79,546**	78,024
Other services provided	**20,085**	69,801
	99,631	147,825

11. CONTINGENCY

Class Action Suit

An action had been brought under the *Class Proceedings Act, 1992*. The plaintiff class sought restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("MEUs") who received late payment penalties ("LPP") which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the *Criminal Code*.

On July 22, 2010, the Ontario Superior Court of Justice approved a settlement of the LPP Class Action, the principal terms of which are the following:

- Former MEUs collectively pay $17 million in damages;
- Payment is not due until June 30, 2011; and
- Amounts paid, after deduction for class counsel fee, will be paid to the Winter Warmth Fund or similar charities.

The Company will make a payment of $132,810 by June 30, 2011.

In its IRM filing for 2011 distribution rates, the Company requested that the OEB hold a generic hearing to determine if all costs and damages incurred in this litigation and settlement are recoverable from customers and, if so, the form and timing of recovery from customers.

A generic hearing on this matter was convened by the OEB. On February 22, 2011, the OEB released its Decision and Order on the LPP generic hearing. The OEB found that the costs were prudently incurred and as such could be recovered from customers. The approved recovery period for the Company is one year beginning May 2011.

12. SHARE CAPITAL

The share capital of the Company consists of the following:

	2010	2009
Authorized	**$**	$
Unlimited common shares		
Issued		
2,000 common shares	**23,523,425**	23,523,425

13. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital items

	2010	2009
	$	$
Accounts receivable	**(374,793)**	(109,075)
Accounts receivable - unbilled revenue	**361,526**	(1,096,927)
Due from Middlesex Power Distribution Corporation	**30,128**	(228,715)
Inventories	**13,092**	45,062
Prepaid expenses	**(46,018)**	78,839
Accounts payable and accrued liabilities	**1,008,260**	(718,068)
Taxes payable	**341,525**	(104,434)
Due to Municipality of Chatham-Kent	**(347,417)**	1,207,340
Current portion of customer deposits	**75,848**	640,886
	1,062,151	(285,092)

Payments in lieu of taxes of $947,736 (2009 - $1,210,272) and interest of $1,727,448 (2009 - $1,748,341) were paid during the year.

14. FINANCIAL INSTRUMENTS

Fair value

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, due from related parties, accounts payable and accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical. The Company has a long term promissory note payable with the Municipality in the amount of $23,523,326. The promissory note was issued upon incorporation on September 22, 2000 with an initial interest at 7.04%. The interest rate on the note payable will change effective January 1, 2011 to 5.87%. There is no “term length” associated with the promissory note.

14. FINANCIAL INSTRUMENTS (continued)

Fair value (continued)

In order to determine fair value, comparison was made to the approved interest rate from the OEB. The OEB approved the rate of return on the debt portion of "Cost of Capital" for non-arms length transactions. The 5.87% interest rate has been approved by the OEB through the rate setting process for rates effective May 2010.

Using the OEB approved non-arm's length cost of debt of 5.87% the annual interest expense would be decreased by approximately $275,000. As noted above, the interest rate on the note payable will change to 5.87% effective January 1, 2011. As a result, no changes have been made to the current financial statements.

The Company also has a long term promissory note payable with Chatham-Kent Energy at an interest rate of 5.87% in the amount of $7,750,000. There is no "term length" associated with either promissory note.

The interest rate on the note payable to CKE is equal to the interest rate approved by the OEB through the rate setting process for rates effective May 2010. As a result, no changes have been made to the current financial statements.

Credit risk

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing based corporations that pose a significant increase in risk due to the current economy as well as the future outlook of the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk.

15. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC;
- maintain an A-credit rating on stand alone basis;
- maintain a capital structure comparable for regulated activities as approved by the OEB's deemed debt to equity structure in our rates.

As at December 31, 2010 the Company's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2009. As at December 31, 2010 shareholder's equity amounts to $23,848,331 (2009 - $29,307,944) and long-term debt amounts to $31,273,326 (2009 - $23,523,326).

15. CAPITAL DISCLOSURES (continued)

The 2010 capital structure approved by the OEB in rates was 40% Equity (2009 - 43%), 56% Long-Term Debt (2009 - 57%) and 4% Short-Term Debt (2009 – 0%). The Company's 2010 actual capital structure was 43% Equity (2009 - 56%) with 57% Long-Term Debt (2009 - 44%).

16. PAYMENTS IN LIEU OF TAXES

The provision for payments in lieu of taxes consists of the following:

	2010	2009
	$	$
Current income taxes	**1,047,129**	865,304
Capital tax	**40,317**	145,400
	1,087,446	1,010,704

Reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

	2010	2009
	$	$
Earnings before payments in lieu of taxes	**3,377,833**	3,113,264
Capital tax	**40,317**	145,400
Earnings before income taxes	**3,337,516**	2,967,864
Statutory income tax rate (percent)	**31.0%**	33.0%
Statutory income tax rate applied to earnings	**1,034,630**	979,395
Increase / (decrease) resulting from:		
Temporary differences between accounting and tax basis of assets and liabilities	**11,040**	(115,257)
Permanent differences	**1,459**	1,166
Provision for income taxes	**1,047,129**	865,304
Effective rate of income tax (percent)	**31.4%**	29.2%

16. PAYMENTS IN LIEU OF TAXES (continued)

Future income taxes

The long-term future income tax asset of $2,448,286 (2009 - $2,320,990) includes the following:

	2010	2009
	$	$
Temporary differences related to capital assets and deferred assets	**2,125,050**	2,010,149
Temporary differences related to employee future benefits	**323,236**	310,841
	2,448,286	2,320,990

17. COMMITMENTS

The Company has entered into Service Level agreements with Chatham-Kent Utility Services Inc., on a year to year basis, to have them provide the services of billing, account collections, customer inquiries and meter reading as well as administrative services such as office space usage, rate submission support, accounting and budgeting support. The value of this contract is $3,979,295 (2009 - $3,463,805).

The Company has entered into a Service Level agreement with Middlesex Power Distribution Corporation, on a year to year basis, to provide them management, engineering and material purchasing services. The value of this contract is $79,546 (2009 - $78,024).

Attachment 1.4.3-B

Middlesex Power Distribution Corporation
2009 & 2010 Financial Statements

Financial Statements of

MIDDLESEX POWER DISTRIBUTION CORPORATION

December 31, 2009

Management's Responsibility for Financial Reporting

Middlesex Power Distribution Corporation's management is responsible for the preparation and presentation of the financial statements and all other information included in this annual report. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board exercises this responsibility through the Audit Committee of the Board. This committee is comprised of four directors of companies within the Chatham-Kent Energy group. This committee meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements and other information included in the annual report before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Deloitte & Touche LLP, an independent firm of Chartered Accountants, has been appointed by the audit committee and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.

Dave Kenney
President

Chris Cowell
Chief Financial & Regulatory Officer

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Auditors' Report

To the Chairman and Board Members of Middlesex Power Distribution Corporation.

We have audited the balance sheet of Middlesex Power Distribution Corporation as at December 31, 2009 and the statements of earnings, comprehensive income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Approved to insert electronic signature 3/24/10 AS

Chartered Accountants
Licensed Public Accountants
February 26, 2010

MIDDLESEX POWER DISTRIBUTION CORPORATION
Balance Sheet
December 31, 2009

	2009	2008
	$	$
ASSETS		
CURRENT		
Cash and cash equivalents	**1,629,721**	1,998,722
Accounts receivable (Note 5)	**1,231,581**	916,400
Accounts receivable - unbilled revenue	**1,917,099**	1,518,794
Taxes receivable	**35,695**	-
Inventories	**217,800**	340,052
Prepaid expenses	**42,388**	46,259
	5,074,284	4,820,227
CAPITAL ASSETS (Note 6)	**8,108,616**	7,826,796
OTHER		
Computer software	**13,577**	22,693
Goodwill (Note 4)	**367,304**	-
Deferred assets (Note 7)	**1,601,265**	756,340
Future income tax asset (Note 18)	**146,835**	-
	15,311,881	13,426,056
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**2,834,848**	2,498,408
Taxes payable	**-**	17,906
Due to related parties (Note 8)	**713,915**	512,412
Current portion of customer deposits	**117,131**	141,095
	3,665,894	3,169,821
LONG-TERM		
Notes payable (Note 9)	**5,300,000**	4,300,000
Regulatory future income tax liability (Note 18)	**146,835**	-
Employee future benefits (Note 10)	**53,372**	47,636
Long-term portion of customer deposits	**1,232,733**	1,099,510
	6,732,940	5,447,146
	10,398,834	8,616,967
CONTINGENCIES AND COMMITMENTS (Notes 13 and 19)		
SHAREHOLDER'S EQUITY		
Share capital (Note 14)	**4,631,198**	4,631,198
Retained earnings	**281,849**	177,891
	4,913,047	4,809,089
	15,311,881	13,426,056

MIDDLESEX POWER DISTRIBUTION CORPORATION
Statement of Earnings, Comprehensive Income and Retained Earnings
December 31, 2009

	2009	2008
	$	$
SERVICE REVENUE		
Residential	**6,311,746**	5,712,408
General service	**9,822,822**	8,702,897
Street lighting	**136,008**	120,155
	16,270,576	14,535,460
Change in unbilled revenue	**442,020**	(122,268)
	16,712,596	14,413,192
Retailer energy sales	**1,130,786**	2,945,773
	17,843,382	17,358,965
COST OF POWER	**15,129,484**	14,496,661
GROSS MARGIN ON SERVICE REVENUE	**2,713,898**	2,862,304
OTHER OPERATING REVENUE	**610,543**	541,736
OPERATING INCOME	**3,324,441**	3,404,040
OPERATING AND MAINTENANCE EXPENSE		
Distributuion	**649,023**	684,209
ADMINISTRATIVE EXPENSE		
Billing and collection	**581,528**	673,213
General administration	**414,108**	54,394
Interest	**382,163**	379,170
DEPRECIATION AND AMORTIZATION	**667,033**	626,136
	2,693,855	2,417,122
EARNINGS, BEFORE PAYMENTS IN LIEU OF TAXES	**630,586**	986,918
Provision for payments in lieu of taxes (Note 18)	**126,628**	155,556
NET EARNINGS AND COMPREHENSIVE INCOME	**503,958**	831,362
RETAINED EARNINGS (DEFICIT), BEGINNING OF YEAR	**177,891**	(167,471)
LESS DIVIDENDS PAID	**(400,000)**	(486,000)
RETAINED EARNINGS, END OF YEAR	**281,849**	177,891

MIDDLESEX POWER DISTRIBUTION CORPORATION
Statement of Cash Flows
December 31, 2009

	2009	2008
	$	$
OPERATING ACTIVITIES		
Net earnings	**503,958**	831,362
Adjustments for:		
Depreciation of capital assets	**740,371**	685,036
Depreciation of computer software	**15,466**	16,898
Amortization of contributed capital	**(37,384)**	(33,105)
Employee future benefits	**5,736**	6,223
Change in non-cash working capital items (Note 15)	**8,786**	379,026
Change in long-term customer deposits	**123,515**	342,472
	1,360,448	2,227,912
INVESTING ACTIVITIES		
Investment in Dutton Hydro Limited (Note 4) (adjustment for cash overdraft of $1,480)	**(803,994)**	-
Investment in Newbury Power Incorporation (Note 4) (net of acquired cash of $26,704)	**(321,694)**	-
Change in deferred assets	**(724,147)**	40,778
Recovery of deferred assets	**124,727**	(128,246)
Additions to capital assets	**(597,991)**	(1,113,859)
Additions to computer software	**(6,350)**	(2,523)
	(2,329,449)	(1,203,850)
FINANCING ACTIVITIES		
Loan from CK Energy	**1,000,000**	-
Dividends paid	**(400,000)**	(486,000)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**(369,001)**	538,062
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**1,998,722**	1,460,660
CASH AND CASH EQUIVALENTS, END OF YEAR	**1,629,721**	1,998,722

See Note 14 for supplemental cash flow information.

1. NATURE OF OPERATIONS

a) Incorporation of Middlesex Power Distribution Corporation

Middlesex Power Distribution Corporation ("the Company") was incorporated April 11, 2000 under the *Business Corporations Act (Ontario).*

The Company is wholly-owned by Chatham-Kent Energy Inc. ("CKE") which purchased 100% of the outstanding shares on June 30, 2005. CKE is owned 90% by the Municipality of Chatham-Kent ("the Municipality") and 10% by Corix Utilities ("Corix").

The principal activity of the Company is to distribute electricity to customers within the Township of Strathroy-Caradoc and the Municipality of North Middlesex, under the licence issued by the Ontario Energy Board ("OEB").

b) Rate Regulated Entity

The Company is a regulated electricity Local Distribution Company ("LDC") and has a distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. *The Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity.
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return.
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by Company in respect of the transmission of electricity from generating stations to the local areas.
- Wholesale Market Service Charge – The wholesale market service charge represents the various wholesale market support costs.

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the Independent Electricity System Operator ("IESO"), which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

1. NATURE OF OPERATIONS (continued)

Market Based Rate of Return

The Company had reset their rates and received approval from the OEB for a change in rates effective May 1, 2006 which approved rates that included a rate of return of 9.0% on equity and rebased the rate base and operating costs at the 2004 historical levels. The rate of return of 9.0% was the maximum allowed by the OEB at that time.

Incentive Rate Mechanism

The OEB regulates the rates of the Company in an Incentive Rate Mechanism ("IRM") regime for 2007-2010. The process includes a formulae approach to establishing 2007 rates with a rate rebasing approach (cost-of-service) to be staggered across all Ontario distributors between 2008 and 2010.

The OEB allows for the rate rebasing to be deferred for up to five years where there is a purchase or merger of LDC's. The Company on February 9, 2009 was approved by the OEB to purchase 100% of the shares of Dutton Hydro Ltd. and Newbury Power Inc. which also approved the deferral of the rate rebasing to 2014.

The IRM rate setting process provides an increase in rates for inflationary cost increases with a 1% offset for productivity gains. The IRM process also includes changes in the tax rates and a movement from the 2006 approved capital structure of 50% long-term debt and 50% equity to 4% short-term debt, 56% long-term debt and 40% equity.

The distribution rates increased by 0.7% in 2009 using the OEB's approved IRM.

Regulatory Assets and Liabilities

Electricity distributors are required to reflect certain prescribed costs on their balance sheet until the manner and timing of distribution is determined by the OEB. These costs are:

- Transition costs resulting from preparation of Open Access;
- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- The deferral of OEB annual cost assessments for the OEB's fiscal year 2004 and 2005;
- The deferral of incremental Ontario Municipal Employees Retirement System pension expenditures for fiscal years starting after January 1, 2005;
- Costs incurred to invest in and install a smart meter at all our customer premises;
- Payment-in-lieu of taxes ("PILS") variances since the Company became taxable October 2002; and
- Cost related to the Green Energy and Green Economy Act of 2009.

1. NATURE OF OPERATIONS (continued)

Regulatory Assets and Liabilities (continued)

The regulatory assets and liabilities balances are detailed in Note 7. The regulatory asset balances have been recovered in rates on an interim basis since April 2004. The Company had applied to the OEB for full and final recovery of the regulatory asset balances that were in place at December 31, 2004. The OEB approved the recovery of these assets over a two year period ending April 30, 2008.

The Company on an annual basis will continue to apply to the OEB for rate recovery of the investments made in smart meters. The recovery of variances for the PILS will occur sometime after the OEB completes their generic regulatory proceeding which will provide the filing guidelines for this regulatory asset or liability.

2. CHANGES IN ACCOUNTING POLICIES

Current Accounting Changes

The Company adopted the following recommendations of the Canadian Institute of Chartered Accountants ("CICA") Handbook:

a) Section 3064, Goodwill and Intangible Assets

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section is applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Company has adopted the new standards for its fiscal year beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The adoption of this new Section has not had a material impact on the financial statements.

b) Section 3465, Accounting for Income Taxes

CICA Section 3465, Income Taxes has been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities. This amendment also requires that a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers, and to present these amounts on a pre-tax basis in the financial statements. This accounting policy was applied prospectively without restatement beginning January 1, 2009. The impact of these changes resulted in an increase in long-term liabilities and an increase in future income tax assets of approximately $146,835 as at December 31, 2009.

2. CHANGES IN ACCOUNTING POLICIES (continued)

c) Rate Regulated Accounting

Effective January 1, 2009, the temporary exemption from CICA Handbook Section 1100 ‘‘Generally Accepted Accounting Principles’’, which permits the recognition and measurement of assets and liabilities arising from rate regulation was withdrawn. The Company has chosen to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board’s Financial Accounting Standard (FAS) 71 ‘‘Accounting for the Effects of Certain Types of Regulation’’. Accordingly, Middlesex Power Distribution Corporation will retain its current method of accounting for its rate-regulated operations, The removal of the temporary exemption had no effect on the Corporation’s results of operations as of December 31, 2009.

Future accounting changes

a) International Financial Reporting Standards (“IFRS”)

On February 13, 2008 the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for fiscal years beginning on or after January 1, 2011. As such, the Company will apply IFRS to its financial statements for the year ending December 31, 2011 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2010, for comparative purposes. At this time, the impact on the Company’s future financial position and results of operations are not reasonably determinable or estimable.

In anticipation of the changes to reporting standards due to the implementation of IFRS we commenced our IFRS conversion project. An external advisor has been engaged to assist with this project. The project has four separate phases: diagnostic, design and planning, solution development, and implementation. In 2009, we completed the diagnostic, design and planning, and solution development phases. We are currently engaged in the implementation phase which is the final phase of our project. The areas with the highest potential to significantly impact our company, identified during the diagnostic phase, are rate regulated assets and liabilities, property, plant and equipment, impairment of assets, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS*.

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. The OEB held public meetings and a formal stakeholder conference in May 2009. We participated at each opportunity offered to the public to communicate with the OEB. On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB’s report and other recommendations on our IFRS conversion project.

3. SIGNIFICANT ACCOUNTING POLICIES

Future accounting changes

a) International Financial Reporting Standards ("IFRS")(continued)

The financial statements have been prepared in accordance with GAAP and reflect the following policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the Ontario Energy Board Act, 1998:

Regulation

The Company is regulated by the OEB and any rate adjustments require OEB approval.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

Inventories

Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

Capital assets

Capital assets are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

Buildings and fixtures	25 – 50 years
Distribution station equipment	30 years
Distribution lines	25 years
Distribution transformers	25 years
Distribution meters	25 years
General office equipment	10 years
Computer equipment	5 years
Rolling stock	4 – 8 years
Tools	10 years
System supervisory equipment	15 years
Automated mapping facility management	15 years
Services	25 years
Contributions in aid of construction	25 years
Supervisory control and data acquisition	15 years
Smart meters	3-15 years

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. For the year ended December 31, 2009 $140,576 was charged (2008 - $82,351) to contributed capital that had been charged to capital assets and recorded as an offset to capital assets. Amortization is on a straight-line basis over 25 years.

Computer software

Computer software is stated at cost less accumulated depreciation. Distribution software is depreciated over 5 years on a straight-line basis. Smart meter software is depreciated over 3 years on a straight-line basis.

Goodwill

Goodwill representing the excess of purchase price over fair value of the net identifiable assets of acquired businesses is tested for impairment annually or more frequently when an event or circumstance occurs that indicates that goodwill might be impaired. When the carrying amount exceeds the fair value, an impairment loss is recognized in the statement of earnings in an amount equal to the excess.

Deferred assets

Deferred assets consist of qualifying capital costs and related expenditures incurred in the preparation for market opening, costs for conservation programs which meet the Minister of Energy's Directive and investments in smart meters, other expenditures that are not currently recovered in rates and variances for PILS.

Also included in deferred assets are retail settlement variance accounts. These variances are for non-competitive energy services which are a pass through for the Company.

Recovery of the deferred assets requires regulatory approval from the OEB.

In the absence of regulatory treatment, net earnings in the current year would have decreased by $573,717 (2008 - decrease of $473,223). Refer to Note 7 Deferred Assets for additional details.

Payments in lieu of taxes

Under the *Electricity Act, 1998,* the Company is required to make payments-in-lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are recorded in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporation Tax Act* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Payments in lieu of taxes (continued)

For 2009, the Company adopted the liability method of accounting for payments in lieu of taxes. Effective January 1 2009, CICA Section 3465, Income Taxes had been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities. The amendment also required the recognition of a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers and to present these amounts on a pre-tax basis in the financial statements. Accordingly, the Company has recorded a regulatory liability that has been included in long-term liabilities and an associated future income tax asset of $146,835. The liability will be paid through future rate reductions. Prior to 2009, the Company accounted for payments-in-lieu of taxes using the taxes payable method instead of the liability method. Under the taxes payable method, no provisions were made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes.

Customer deposits

Customer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

Post employment benefits other than pension

The Company provides its current and retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The cost of these benefits is expensed as earned through employment service.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue recognition and cost of power

Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power related to distribution are charged to deferred assets.

In accordance with EIC 123, costs to provide OPA programs have been netted against OPA revenues included in Other Operating Revenue. In 2009, costs of $292,521 were netted against revenues (2008 - $105,614).

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial instruments

The Accounting Standards Board ("ACSB") of the CICA decided that rate-regulated enterprises that are not public enterprises as defined in Section 1300, Differential Reporting, will not be required to apply Sections 3862 and 3863 and would continue to apply Section 3861, Financial Instruments – Disclosure and Presentation. Therefore, in accordance with this decision, the Company continues to apply Section 3861.

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 cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Due to related parties	Other liabilities
Current portion of customer deposits	Other liabilities
Note payable	Other liabilities
Long-term portion of customer deposits	Other liabilities

<u>Held for trading</u>

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.

Financial liabilities designated as held for trading are those non-derivative financial liabilities that the Company elects to designate on initial recognition as instruments that it will measure at fair value through other interest expense. These are accounted for in the same manner as held for trading assets. The Company has not designated any non-derivative financial liabilities as held for trading.

<u>Loans and receivables</u>

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

<u>Other liabilities</u>

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

3. SIGNIFICANT 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.

4. BUSINESS ACQUISITIONS

Purchase of Shares

Effective May 1, 2009 the Company acquired 100% of the outstanding shares of Dutton Hydro Limited and Newbury Power Incorporated. Dutton Hydro Limited and Newbury Power Incorporated were amalgamated with the Company on November 18, 2009. The results of operations are included in the financial statements from the effective date of acquisition.

The purchase price for Dutton Hydro Limited was $802,514 and was allocated as follows:

	$
Working capital (including $1,480 overdraft)	**49,692**
Capital assets	**234,397**
Goodwill	**286,375**
Other assets	**241,758**
Total assets acquired	**812,222**
Long-term debts	**(9,708)**
Net assets acquired	**802,514**

The purchase price for Newbury Power Incorporated was $348,398 and was allocated as follows:

	$
Working capital (including $26,704 in cash)	**111,303**
Capital assets	**152,419**
Goodwill	**80,929**
Other assets	**3,747**
Total assets acquired	**348,398**

5. ACCOUNTS RECEIVABLE

	2009	2008
	$	$
Electrical energy	**910,476**	757,921
Other	**333,809**	175,079
	1,244,285	933,000
Allowance for doubtful accounts	**(12,704)**	(16,600)
Net accounts receivable	**1,231,581**	916,400

6. CAPITAL ASSETS & COMPUTER SOFTWARE

	2009			2008
	Cost	**Accumulated Depreciation**	**Net Book Value**	Net Book Value
	$	**$**	**$**	$
Plant and distribution system:				
Land	**11,982**	**-**	**11,982**	11,982
Buildings and fixtures	**91,365**	**20,843**	**70,522**	72,428
Distribution station equipment	**680,891**	**527,775**	**153,116**	83,801
Distribution system:				
Overhead	**7,539,589**	**3,954,574**	**3,585,015**	3,370,852
Underground	**3,244,539**	**1,942,583**	**1,301,956**	1,253,231
Transformers	**3,507,210**	**1,946,256**	**1,560,954**	1,508,552
Meters	**1,235,705**	**680,782**	**554,923**	612,507
General office equipment	**102,220**	**81,475**	**20,745**	8,638
Computer equipment	**79,982**	**53,953**	**26,029**	22,979
Rolling stock	**813,825**	**641,761**	**172,064**	223,483
Tools	**411,209**	**380,347**	**30,862**	22,890
Scada	**129,678**	**17,054**	**112,624**	88,417
Smart meters	**973,209**	**183,553**	**789,656**	815,548
AM/FM	**33,937**	**2,262**	**31,675**	-
Services	**536,627**	**111,097**	**425,530**	368,633
	19,391,968	**10,544,315**	**8,847,653**	8,463,941
Contributions in aid of construction	**(979,322)**	**(240,285)**	**(739,037)**	(637,145)
Capital assets	**18,412,646**	**10,304,030**	**8,108,616**	7,826,796
Computer software	**55,784**	**42,207**	**13,577**	22,693

Depreciation and amortization in the amount of $51,419 (2008 - $42,694) for rolling stock was included in operating, maintenance and administrative expenses.

7. DEFERRED ASSETS

Deferred assets and liabilities arise as a result of the rate-making process. As described in this note, the Company has recorded the following regulatory assets and related provisions. Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process.

	2009	2008
	$	$
Costs		
Retail settlement variance account legacy Dutton & Newbury	**305,718**	-
Retail settlement variance accounts	**(263,808)**	(353,226)
Conservation and demand management costs	**-**	554
PILs recoverable	**199,334**	207,851
Other deferred costs	**897,156**	746,723
Smart meter	**690,872**	257,718
Gross deferred assets	**1,829,272**	859,620
Recoveries		
Regulatory assets prior to 2004 recovery	**(6,545)**	3,897
Other deferred recovery	**(92,029)**	(89,732)
Smart meter recovery	**(129,433)**	(17,445)
Net deferred assets	**1,601,265**	756,340

a) *Regulatory Costs/Recoveries*

(i) Regulatory Assets prior to 2004

The introduction of Bill 210 in November 2002 deferred future rate increases until 2007. However Bill 4 was introduced in December 2003 which allowed for the recovery of deferred assets over a four year period beginning in April 2004. The Company obtained full and final recovery of the deferred assets balances at December 31, 2004. At April 30, 2008 the revenue collected was not sufficient to cover the regulatory assets costs prior to 2004. A balance of $3,897 is required to cover the remaining costs related to the Middlesex Power Distribution customers; this would exclude the Newbury and Dutton customers acquired in 2009. Deferred asset revenue for 2009 was $10,442 (2008 - $74,764). All funds collected in 2009 were from Newbury Power customers, as the existing Ontario Energy Board approved rates for Newbury Power included the recovery of Regulatory Assets from these customers in 2009.

In the absence of regulatory treatment, net earnings in the current year would have increased by $6,996 (2008 - $49,718).

7. DEFERRED ASSETS (continued)

(ii) Retail settlement variance accounts

These accounts represent the variance between the revenue collected, using OEB approved rates for the non-competitive components of energy, and the corresponding cost of these non-competitive charges, beginning January 1, 2004 to the present. These variances will be held as a regulatory asset or liability, based on the expectation that the amounts held from one year to the next for rate setting purposes will be approved for collection from, or refund to, future customers. In the absence of regulatory treatment, net earnings for the year would have decreased by $264,741 (2008 - $13,249).

(iii) Conservation and demand management

During 2009, the Company incurred $ nil costs for conservation and demand management (2008 - $544). The approved programs were completed by December 2008. In the absence of regulatory treatment, net earnings in the current year would have changed by $ nil (2008 - $85,105).

(iv) Payments in Lieu of Taxes

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between tax basis of assets and liabilities and their carrying amounts for accounting purposes. Balance in PILS account $199,334 (2008 - $207,851).

(v) Other deferred

These balances include OEB specific costs incurred up to 2005 not currently in rates. These costs will be applied for in the next rate rebasing application to the OEB. Balance for these costs are $134,133 (2008 - $175,218). As well the OEB has authorized distributors to apply for Loss Revenue Adjustment Mechanism ("LRAM") due to Demand Management Programs to their customers that have resulted in decreased kWh consumption. This amount may be claimed in a subsequent rate year as compensation for loss of revenue. The LRAM balance was $103,300 (2008 - $84,282). In the May 2006 rate application, the OEB approved in rates additional funding or Tier 2 recovery to support capital, operation and maintenance expenditures that were required to improve the reliability of the distribution system. In 2009, the Company received approval from the OEB to remove the additional funding from its rates. Final disposition of any variance between the revenue and expenditures will be applied for when the Company applies for rate rebasing. The Tier 2 balance was $92,029 (2008 - $89,732). Ongoing other deferred projects include Line Loss Improvements, Conversions, AM/FM, Rate Rebasing and IFRS, for a 2009 total of $659,724 (2008 - $487,223). In the absence of regulatory treatment, net earnings in the current year would have decreased by $100,789 (2008 - $389,839).

7. DEFERRED ASSETS (continued)

(vi) Smart meters

The Company incurred costs for the implementation of smart meters of $690,872 (2008 - $257,718). Smart meter revenue collected to 2009 was $129,433 (2008 - $17,445). In the absence of regulatory treatment, net earnings for the current year would have decreased by $215,182 (2008 - $61,247).

8. DUE TO RELATED PARTIES

	2009	2008
	$	$
Due to Chatham-Kent Utility Services Inc.	**35,563**	19,649
Due to Chatham-Kent Hydro Inc.	**611,977**	383,262
Due to Chatham-Kent Energy Inc.	**32,330**	25,980
Due to the Municipality of Chatham-Kent	**34,045**	83,521
Net due to related parties	**713,915**	512,412

9. NOTES PAYABLE

Notes payable consist of $4,300,000 due to CKE and which was issued in relation to the acquisition of the Company by CKE on June 30, 2005. During, 2009, a further $1,000,000 was issued in relation to the acquisition of Dutton and Newbury at an interest rate of 7.62%. It has no set repayment terms and interest payable monthly at 7.25%. Interest expense on the notes was $336,580 (2008 - $311,750).

10. EMPLOYEE FUTURE BENEFITS

The Company measures its accrued benefit obligation as at December 31 of each year. The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The accrued benefit liability at December 31, 2009 was $53,372 (2008 - $47,636). The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2007 and the next required valuation will be as of December 31, 2010.

Information about the Company’s defined benefit plan is as follows:

	2009	2008
	$	$
Accrued benefit liability, beginning of year	**47,636**	41,413
Expense for the year	**10,165**	10,097
Employer contributions	**(4,429)**	(3,874)
Estimated accrued benefit liability, end of year	**53,372**	47,636

10. EMPLOYEE FUTURE BENEFITS (continued)

The main actuarial assumptions employed for the valuation are as follows:

General inflation

Future inflation levels, as measured by changes in the Consumers Price Index ("CPI"), were assumed to be 2.5% in 2009 and thereafter.

Interest (discount) rate

The present value of the future benefits, and the expense for the year ended December 31, 2009 was determined using a discount rate of 7.62% (2008 - 6.1%). This corresponds to the OEB approved non-arms length cost of debt rate for 2008.

Health costs

Health costs were assumed to increase at 10% per year for 10 years, and then at the CPI rate plus 1% thereafter.

Dental costs

Dental costs were assumed to increase at the CPI rate plus 1% for 2009 and thereafter.

Salary growth

Salary growth rate was assumed to increase at a rate of 3.5% for 2009 and thereafter.

11. PENSION AGREEMENT

The Company provides a pension plan for its employees through the Ontario Municipal Employees' Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company's contribution for employees' current service in 2009 was $52,432 (2008 - $46,167).

12. RELATED PARTY TRANSACTIONS

Chatham-Kent Hydro Inc. (wholly owned by CKE) and Chatham-Kent Utility Services Inc. (wholly owned by CKE) provided the following services in the normal course of operations to the Company:

	2009	2008
	$	$
Chatham-Kent Utility Services Inc.		
Management, financial, regulatory and customer support	**429,756**	273,336
Chatham-Kent Hydro Inc.		
Management, engineering and purchasing	**78,024**	77,415
Other services provided	**69,801**	104,297
	147,825	181,712

13. CONTINGENCIES

a) Class Action Suit

This action has been brought under the *Class Proceedings Act, 1992*. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the *Criminal Code*. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Enbridge Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the OEB to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of the said amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Enbridge case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Enbridge.

13. CONTINGENCIES (continued)

The Company collected total late payment penalties of $276,714 from customers between 1994 until August 2001 when the Company implemented an interest rate penalty. Although recent settlement models for Union Gas and Enbridge have been decided, it remains unclear as to the settlement models for LDC's.

b) Letter of Credit

In order to obtain the electricity it requires to distribute to its customers, the Company was required to provide security to the Independent Electricity System Operator based on usage. The security obtained was a letter of credit from a financial institution for $834,984 (2008 - $834,984) and was not drawn on at December 31, 2009. The financial institution has not placed financial restrictions on the Company.

14. SHARE CAPITAL

The share capital of the Company consists of the following:

Authorized
Unlimited number of Class A preference shares without par value
Unlimited number of Class B preference shares without par value
Unlimited number of voting common shares without par value

	2009	2008
	$	$
Issued		
4,631,198 voting common shares	**4,631,198**	4,631,198

15. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital items

	2009	2008
	$	$
Accounts receivable	**(161,138)**	68,858
Accounts receivable - unbilled revenue	**(379,952)**	148,161
Inventories	**125,258**	(93,701)
Prepaid expenses	**7,312**	(31,732)
Accounts payable and accrued liabilities	**262,097**	189,254
Taxes payable	**(21,330)**	(2,493)
Due to related parties	**201,503**	80,319
Current portion of customer deposits	**(24,964)**	20,360
	8,786	379,026

Payments in lieu of taxes of $249,943 (2008 - $344,753) and interest of $382,163 (2008 - $379,170) were paid during the year.

16. FINANCIAL INSTRUMENTS

Fair Value

The Company's recognized financial instruments consist of cash and cash equivalents, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, due to related parties, customer deposits and notes payable.

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, accounts payable, accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical.

The Company has a long term promissory note payable with Chatham-Kent Energy in the amount of $4,300,000. The promissory note was issued upon Chatham-Kent Energy purchasing 100% of the shares on June 30, 2005. The interest rate on the promissory note is 7.25%. In 2009 a further $1,000,000 promissory note was issued for the purchase of Dutton and Newbury. The interest rate on the incremental note is 7.62%. There is no "term length" associated with either promissory note.

In order to determine fair value, comparison was made to the approved interest rate from the OEB. The OEB approved the rate of return on the debt portion of "Cost of Capital" for non-arms length transactions. This maximum rate was set at 7.25% to calculate electricity distributor pricing effective May 1, 2001. The interest rate has been approved by the OEB through the rate setting process on a number of occasions since May 2001.

Using the OEB approved non-arm's length cost of debt of 6.1% the annual interest expense would be reduced by approximately $50,000 which is well within current OEB materiality threshold of $413,000. If the Company was able to obtain a reduced interest rate on the Note Payable the OEB would most likely reduce the revenue in a rate proceeding therefore the impact to the net income would be much less. As a result, no changes have been made to the current financial statements.

Credit risk

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing based corporations that pose a significant increase in risk due to the current economy as well as the future outlook of the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk.

17. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC;
- maintain an A-credit rating on stand alone basis; and
- maintain a capital structure comparable to regulated activities as approved by the OEB's deemed debt to equity structure in our rates.

As at December 31, 2009 the Company's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2008. As at December 31, 2009 shareholder's equity amounted to $4,913,047 (2008 - $4,809,089) and long-term debt amounted to $5,300,000 (2008 - $4,300,000).

The 2009 capital structure approved by the OEB in rates was 43% Equity (2008 - 47%) and 57% Long-Term Debt (2008 - 53%). The Company's 2009 actual capital structure was 48% Equity (2008 - 53%) with 52% Long-Term Debt (2008 - 47%).

18. PAYMENTS IN LIEU OF TAXES

The provision for payments in lieu of taxes consists of the following:

	2009	2008
	$	$
Current income taxes	**115,528**	144,456
Capital tax	**11,100**	11,100
	126,628	155,556

Reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

18. PAYMENTS IN LIEU OF TAXES (continued)

	2009	2008
	$	$
Income before payments in lieu of taxes	**630,586**	986,918
Capital tax	**11,100**	11,100
Income before income taxes	**619,486**	975,818
Statutory income tax rate (percent)	**33.0%**	33.5%
Statutory income tax rate applied to accounting income	**204,430**	326,899
Increase / (decrease) resulting from:		
Temporary differences between accounting and tax basis of assets and liabilities	**(89,310)**	(182,664)
Permanent differences	**408**	221
Provision for income taxes	**115,528**	144,456
Effective rate of income tax (percent)	**18.6%**	14.8%

Future income taxes

The long-term future income tax asset of $146,835 includes the following:

	2009
	$
Temporary differences related to capital assets and deferred assets	**129,044**
Temporary differences related to employee future benefits	**17,791**
	146,835

If the liability method of accounting for income taxes were used in 2008, a future tax asset of $181,991 would have been recorded.

19. COMMITMENTS

The Company has entered into a letter of agreement with Chatham-Kent Utility Services Inc., a related company, on a year to year basis, to have them provide the services of certain management, human resources, financial, regulatory and customer support, rate submission support and accounting and budgeting support. The value of the agreement is $429,756 (2008 - $273,336).

The Company has entered into a Customer Agreement for the services of a data collection system, data storage and access to specific software and systems. The terms of the agreement have been extended for five years commencing April 1, 2009. Annual payments were $28,327 (2008 - $33,348).

The Company entered into an agreement with an unrelated party to perform meter reading and associated services on behalf of the Company on a year to year basis. The cost of this service to the Company was $67,219 (2008 - $84,844).

The Company has entered into an agreement with the Township of Strathroy-Caradoc to lease a portion of the premises known as 351 Frances Street, Strathroy, Ontario for a period of five years effective July 1, 2005. The cost of the lease is $37,000 (2008 - $37,000) annually plus 60% of operating costs. The Company's share of operating costs were $43,325 (2008 - $58,559).

The Company has entered into an agreement with the Township of Strathroy-Caradoc to provide the services of billing of water services for a period of five years effective July 1, 2005. Contracts for maintenance of streetlight and traffic lights as well as installation of water meters, locate services and backhoe services are renewed annually. Revenues received for these services was $327,557 (2008 - $339,160).

The Company has entered into a Service Level agreement with the Township of Strathroy-Caradoc to pay for administrative assistance on a year to year basis. The cost of this agreement was $20,708 (2008 - $16,841).

The Company has entered into a Service Level agreement with Chatham-Kent Hydro Inc., a related Company, to have them provide management, engineering and purchasing services on a year to year basis. The value of the agreement is $78,024 (2008 - $77,415).

20. COMPARATIVE FIGURES

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

Financial Statements of

MIDDLESEX POWER DISTRIBUTION CORPORATION

December 31, 2010

Management's Responsibility for Financial Reporting

Middlesex Power Distribution Corporation's management is responsible for the preparation and presentation of the financial statements and all other information included in this annual report. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board exercises this responsibility through the Audit Committee of the Board. This committee is comprised of four directors of companies within the Chatham-Kent Energy group. This committee meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements and other information included in the annual report before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Deloitte & Touche LLP, an independent firm of Chartered Accountants, has been appointed by the audit committee and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.

Jim Hogan	**Chris Cowell**
Director	**Chief Financial & Regulatory Officer**

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Independent Auditor's Report

To the Chairman and Board Members of
Middlesex Power Distribution Corporation

We have audited the accompanying financial statements of Middlesex Power Distribution Corporation which comprise the balance sheet as at December 31, 2010, and the statements of earnings, comprehensive income and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Middlesex Power Distribution Corporation as at December 31, 2010 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants
Licensed Public Accountants
April 1, 2011

MIDDLESEX POWER DISTRIBUTION CORPORATION
Balance Sheet
December 31, 2010

	2010	2009
	$	$
ASSETS		
CURRENT		
Cash and cash equivalents	**1,323,971**	1,629,721
Accounts receivable (Note 5)	**1,146,843**	1,231,581
Accounts receivable - unbilled revenue	**2,172,339**	1,917,099
Taxes receivable	**312,431**	35,695
Inventories	**220,709**	217,800
Prepaid expenses	**85,994**	42,388
	5,262,287	5,074,284
CAPITAL ASSETS (Note 6)	**8,301,533**	8,108,616
OTHER		
Computer software (Note 6)	**9,757**	13,577
Goodwill	**367,304**	367,304
Deferred assets (Note 7)	**1,727,284**	1,601,265
Future income tax asset (Note 18)	**254,213**	146,835
	15,922,378	15,311,881
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**3,014,435**	2,834,848
Due to related parties (Note 8)	**686,736**	713,915
Current portion of customer deposits	**132,754**	117,131
	3,833,925	3,665,894
LONG-TERM		
Notes payable (Note 9)	**5,800,000**	5,300,000
Regulatory future income tax liability (Note 18)	**254,213**	146,835
Employee future benefits (Note 10)	**53,515**	53,372
Long-term portion of customer deposits	**1,288,984**	1,232,733
	7,396,712	6,732,940
	11,230,637	10,398,834
CONTINGENCIES AND COMMITMENTS (Notes 13 and 19)		
SHAREHOLDER'S EQUITY		
Share capital (Note 14)	**4,631,198**	4,631,198
Retained earnings	**60,543**	281,849
	4,691,741	4,913,047
	15,922,378	15,311,881

MIDDLESEX POWER DISTRIBUTION CORPORATION
Statement of Earnings, Comprehensive Income and Retained Earnings
December 31, 2010

	2010	2009
	$	$
SERVICE REVENUE		
Residential	**7,246,675**	6,311,746
General service	**12,264,745**	9,822,822
Street lighting	**136,840**	136,008
	19,648,260	16,270,576
Change in unbilled revenue	**268,713**	442,020
	19,916,973	16,712,596
Retailer energy sales	**1,255,112**	1,130,786
	21,172,085	17,843,382
COST OF POWER	**18,334,860**	15,129,484
GROSS MARGIN ON SERVICE REVENUE	**2,837,225**	2,713,898
OTHER OPERATING REVENUE	**667,873**	610,543
OPERATING INCOME	**3,505,098**	3,324,441
OPERATING AND MAINTENANCE EXPENSE		
Distributuion	**651,624**	649,023
ADMINISTRATIVE EXPENSE		
Billing and collection	**620,286**	581,528
General administration	**438,944**	414,108
Interest	**406,092**	382,163
DEPRECIATION AND AMORTIZATION	**682,353**	667,033
	2,799,299	2,693,855
EARNINGS, BEFORE PAYMENTS IN LIEU OF TAXES	**705,799**	630,586
Provision for payments in lieu of taxes (Note 18)	**227,105**	126,628
NET EARNINGS AND COMPREHENSIVE INCOME	**478,694**	503,958
RETAINED EARNINGS, BEGINNING OF YEAR	**281,849**	177,891
LESS DIVIDENDS	**(700,000)**	(400,000)
RETAINED EARNINGS, END OF YEAR	**60,543**	281,849

MIDDLESEX POWER DISTRIBUTION CORPORATION
Statement of Cash Flows
December 31, 2010

	2010	2009
	$	$
OPERATING ACTIVITIES		
Net earnings	**478,694**	503,958
Adjustments for:		
Depreciation of capital assets	**770,656**	740,371
Depreciation of computer software	**9,017**	15,466
Amortization of contributed capital	**(39,858)**	(37,384)
Employee future benefits	**143**	5,736
Change in non-cash working capital items (Note 15)	**(325,722)**	8,786
Change in long-term customer deposits	**56,251**	123,515
	949,181	1,360,448
INVESTING ACTIVITIES		
Investment in Dutton Hydro Limited (Note 4) (adjustment for cash overdraft of $1,480)	**-**	(803,994)
Investment in Newbury Power Incorporation (Note 4) (net of acquired cash of $26,704)	**-**	(321,694)
Change in deferred assets	**(265,865)**	(724,147)
Recovery of deferred assets	**139,846**	124,727
Additions to capital assets	**(923,715)**	(597,991)
Additions to computer software	**(5,197)**	(6,350)
	(1,054,931)	(2,329,449)
FINANCING ACTIVITIES		
Loan from CKE	**500,000**	1,000,000
Dividends paid	**(700,000)**	(400,000)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**(305,750)**	(369,001)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**1,629,721**	1,998,722
CASH AND CASH EQUIVALENTS, END OF YEAR	**1,323,971**	1,629,721

See Note 15 for supplemental cash flow information.

1. NATURE OF OPERATIONS

a) Incorporation of Middlesex Power Distribution Corporation

Middlesex Power Distribution Corporation ("the Company") was incorporated April 11, 2000 under the *Business Corporations Act (Ontario).*

The Company is wholly-owned by Chatham-Kent Energy Inc. ("CKE") which purchased 100% of the outstanding shares on June 30, 2005. CKE is owned 90% by the Municipality of Chatham-Kent ("the Municipality") and 10% by Corix Utilities ("Corix").

The principal activity of the Company is to distribute electricity to certain customers within the County of Middlesex and the County of Elgin, under the licence issued by the Ontario Energy Board ("OEB").

b) Rate Regulated Entity

The Company is a regulated electricity Local Distribution Company ("LDC") and has a distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. *The Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity.
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return.
- Global Adjustment – the difference between the rate paid to regulated and contracted electricity generators and the spot market price.
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by Company in respect of the transmission of electricity from generating stations to the local areas.
- Wholesale Market Service Charge – The wholesale market service charge represents the various wholesale market support costs.

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the Independent Electricity System Operator ("IESO"), which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

1. NATURE OF OPERATIONS (continued)

Market Based Rate of Return

The Company had reset their rates and received approval from the OEB for a change in rates effective May 1, 2006 which approved rates that included a rate of return of 9.0% on equity and rebased the rate base and operating costs at the 2004 historical levels. The rate of return of 9.0% was the maximum allowed by the OEB at that time.

Incentive Rate Mechanism

The OEB regulates the rates of the Company in an Incentive Rate Mechanism ("IRM") regime. The process includes a formulae approach to establishing rates with a rate rebasing approach (cost-of-service) every fourth year.

The OEB allows for the rate rebasing to be deferred for up to five years where there is a purchase or merger of LDC's. The Company on February 9, 2009 was approved by the OEB to purchase 100% of the shares of Dutton Hydro Ltd. ("Dutton") and Newbury Power Inc. ("Newbury") which also approved the deferral of the rate rebasing to 2014.

The IRM rate setting process provides an increase in rates for inflationary cost increases with a 1% offset for productivity gains. The IRM process also includes changes in the tax rates and a movement from the 2006 approved capital structure of 50% long-term debt and 50% equity to 4% short-term debt, 56% long-term debt and 40% equity.

The distribution rates decreased by 0.8% in 2010 using the OEB's approved IRM.

Deferred Assets

Electricity distributors are required to reflect certain prescribed costs on their balance sheet until the manner and timing of distribution is determined by the OEB. These costs are:

- Transition costs resulting from preparation of Open Access;
- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- The deferral of OEB annual cost assessments for the OEB's fiscal year 2004 and 2005;
- The deferral of incremental Ontario Municipal Employees Retirement System ("OMERS") pension expenditures for fiscal years starting after January 1, 2005;
- Costs incurred to invest in and install a smart meter at all our customer premises;
- Payment-in-lieu of taxes ("PILS") variances since the Company became taxable October 2002; and
- Cost related to the Green Energy and Green Economy Act of 2009.

1. NATURE OF OPERATIONS (continued)

Deferred Assets (continued)

The regulatory assets and liabilities balances are detailed in Note 7. The Company will apply to the OEB for final rate recovery of the investments made in smart meters once the installation program is complete. The recovery of variances for the PILS will occur sometime after the OEB completes their generic regulatory proceeding which will provide the filing guidelines for this regulatory asset or liability.

2. CHANGES IN ACCOUNTING POLICIES

Future accounting changes

International Financial Reporting Standards ("IFRS")

On February 13, 2008 the Canadian Accounting Standards Board ("AcSB") confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles ("GAAP") for fiscal years beginning on or after January 1, 2011. Subsequently, on September 10, 2010, the AcSB decided to permit rate-regulated entities and certain affiliates to defer their IFRS adoption date to January 1, 2012. The Company is a qualifying entity for purposes of this deferral and has elected to use the deferral offered by the AcSB. The deferral will allow the Company to convert at the same time as many other companies in its industry.

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. In January 2011, the OEB convened an IFRS Working Group to address the particulars of implementing IFRS in an incentive regulation environment. The Company continues to assess the impact of conversion to IFRS on its results of operations.

3. SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with GAAP and reflect the following policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the Ontario Energy Board Act, 1998:

Regulation

The Company is regulated by the OEB and any rate adjustments require OEB approval.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

Inventories

Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

Capital assets

Capital assets are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

Buildings and fixtures	25 – 50 years
Distribution station equipment	30 years
Distribution lines	25 years
Distribution transformers	25 years
Distribution meters	25 years
General office equipment	10 years
Computer equipment	5 years
Rolling stock	4 – 8 years
Tools	10 years
System supervisory equipment	15 years
Automated mapping facility management	15 years
Services	25 years
Contributions in aid of construction	25 years
Supervisory control and data acquisition	15 years
Smart meters	3-15 years

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.

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. For the year ended December 31, 2010 $98,078 was charged (2009 - $140,576) to contributed capital that had been charged to capital assets and recorded as an offset to capital assets. Amortization is on a straight-line basis over 25 years.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Computer software

Computer software is stated at cost less accumulated depreciation. Distribution software is depreciated over 5 years on a straight-line basis. Smart meter software is depreciated over 3 years on a straight-line basis.

Goodwill

Goodwill representing the excess of purchase price over fair value of the net identifiable assets of acquired businesses is tested for impairment annually or more frequently when an event or circumstance occurs that indicates that goodwill might be impaired. When the carrying amount exceeds the fair value, an impairment loss is recognized in the statement of earnings in an amount equal to the excess.

Deferred assets

Deferred assets consist of qualifying capital costs and related expenditures incurred in the preparation for market opening, costs for conservation programs which meet the Minister of Energy's Directive and investments in smart meters, other expenditures that are not currently recovered in rates and variances for PILS.

Also included in deferred assets are retail settlement variance accounts. These variances are for non-competitive energy services which are a pass through for the Company.

Recovery of the deferred assets requires regulatory approval from the OEB.

In the absence of regulatory treatment, net earnings in the current year would have decreased by $82,436 (2009 - decrease of $573,717). Refer to Note 7 Deferred Assets for additional details.

Payments in lieu of taxes

Under the *Electricity Act, 1998*, the Company is required to make payments-in-lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are recorded in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporation Tax Act* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations.

Effective January 1 2009, CICA Section 3465, Income Taxes had been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities. The amendment also required the recognition of a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers and to present these amounts on a pre-tax basis in the financial statements. Accordingly, the Company has recorded a regulatory liability that has been included in long-term liabilities and an associated future income tax asset of $254,213 (2009 - $146,835). The liability will be paid through future rate reductions.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Customer deposits

Customer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

Asset retirement obligations

The Company recognizes the liability for an asset retirement that results from acquisition, construction, development or normal operations. The liability for an asset retirement is initially recorded at its fair value in the year in which it is incurred and when a reasonable estimate of fair value can be made. The corresponding cost is capitalized as part of the related asset and is amortized over the asset's useful life. In subsequent years the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. The accretion of the liability to its fair value as a result of the passage of time is charged to earnings.

Post employment benefits other than pension

The Company provides its current and retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The cost of these benefits is expensed as earned through employment service.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue recognition and cost of power

Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power related to distribution are charged to deferred assets.

In accordance with EIC 123, costs to provide Ontario Power Authority ("OPA") programs have been netted against OPA revenues included in Other Operating Revenue. In 2010, costs of $185,117 were netted against revenues (2009 - $292,521).

Financial instruments

The AcSB of the CICA decided that rate-regulated enterprises that are not public enterprises as defined in Section 1300, Differential Reporting, will not be required to apply Sections 3862 and 3863 and would continue to apply Section 3861, Financial Instruments – Disclosure and Presentation. Therefore, in accordance with this decision, the Company continues to apply Section 3861.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial instruments (continued)

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 cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Due to related parties	Other liabilities
Current portion of customer deposits	Other liabilities
Note payable	Other liabilities
Long-term portion of customer deposits	Other liabilities

<u>Held for trading</u>

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.

Financial liabilities designated as held for trading are those non-derivative financial liabilities that the Company elects to designate on initial recognition as instruments that it will measure at fair value through other interest expense. These are accounted for in the same manner as held for trading assets. The Company has not designated any non-derivative financial liabilities as held for trading.

<u>Loans and receivables</u>

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

<u>Other liabilities</u>

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

<u>Effective interest method</u>

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.

4. BUSINESS ACQUISITIONS

Purchase of Shares

Effective May 1, 2009 the Company acquired 100% of the outstanding shares of Dutton Hydro Limited and Newbury Power Incorporated. Dutton Hydro Limited and Newbury Power Incorporated were amalgamated with the Company on November 18, 2009. The results of operations are included in the financial statements from the effective date of acquisition.

The purchase price for Dutton Hydro Limited was $802,514 and was allocated as follows:

	$
Working capital (including $1,480 overdraft)	**49,692**
Capital assets	**234,397**
Goodwill	**286,375**
Other assets	**241,758**
Total assets acquired	**812,222**
Long-term debts	**(9,708)**
Net assets acquired	**802,514**

The purchase price for Newbury Power Incorporated was $348,398 and was allocated as follows:

	$
Working capital (including $26,704 in cash)	**111,303**
Capital assets	**152,419**
Goodwill	**80,929**
Other assets	**3,747**
Total assets acquired	**348,398**

5. ACCOUNTS RECEIVABLE

	2010	2009
	$	$
Electrical energy	**847,070**	910,476
Other	**312,413**	333,809
	1,159,483	1,244,285
Allowance for doubtful accounts	**(12,640)**	(12,704)
Net accounts receivable	**1,146,843**	1,231,581

6. CAPITAL ASSETS & COMPUTER SOFTWARE

	2010			2009
	Cost	**Accumulated Depreciation**	**Net Book Value**	Net Book Value
	$	**$**	**$**	$
Plant and distribution system:				
Land	**11,982**	**-**	**11,982**	11,982
Buildings and fixtures	**91,365**	**22,749**	**68,616**	70,522
Distribution station equipment	**680,891**	**534,090**	**146,801**	153,116
Distribution system:				
Overhead	**8,003,084**	**4,260,624**	**3,742,460**	3,585,015
Underground	**3,312,055**	**2,064,871**	**1,247,184**	1,301,956
Transformers	**3,810,046**	**2,067,560**	**1,742,486**	1,560,954
Meters	**1,242,761**	**716,639**	**526,122**	554,923
General office equipment	**102,220**	**84,039**	**18,181**	20,745
Computer equipment	**83,132**	**63,133**	**19,999**	26,029
Rolling stock	**893,951**	**697,433**	**196,518**	172,064
Tools	**415,993**	**390,087**	**25,906**	30,862
Scada	**130,968**	**25,742**	**105,226**	112,624
Smart meters	**929,652**	**247,195**	**682,457**	789,656
AM/FM	**79,456**	**6,042**	**73,414**	31675
Services	**626,206**	**134,768**	**491,438**	425,530
	20,413,762	**11,314,972**	**9,098,790**	8,847,653
Contributions in aid of construction	**(1,077,400)**	**(280,143)**	**(797,257)**	(739,037)
Capital assets	**19,336,362**	**11,034,829**	**8,301,533**	8,108,616
Computer software	**60,981**	**51,224**	**9,757**	13,577

Depreciation and amortization in the amount of $55,671 (2009 - $51,419) for rolling stock and $1,790 (2009 - $ nil) for computer software is included in operating, maintenance and administrative expenses.

7. DEFERRED ASSETS

Deferred assets and liabilities arise as a result of the rate-making process. As described in this note, the Company has recorded the following regulatory assets and related provisions. Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process.

7. DEFERRED ASSETS (continued)

	2010	2009
	$	$
Costs		
Retail settlement variance accounts	**56,731**	41,910
Conservation and demand management & renewable energy	**19,086**	-
PILs recoverable	**199,334**	199,334
Other deferred/transition costs	**938,530**	897,156
Smart meter	**881,456**	690,872
Gross deferred assets	**2,095,137**	1,829,272
Recoveries		
Regulatory assets	**(102,416)**	(6,545)
Other deferred recovery	**(24,303)**	(92,029)
Smart meter recovery	**(241,134)**	(129,433)
Net deferred assets	**1,727,284**	1,601,265

a) Regulatory Costs/Recoveries

(i) Retail settlement variance accounts

These accounts represent the variance between the revenue collected, using OEB approved rates for the non-competitive components of energy, and the corresponding cost of these non-competitive charges, beginning January 1, 2004 to the present. These variances will be held as a regulatory asset or liability, based on the expectation that the amounts held from one year to the next for rate setting purposes will be approved for collection from, or refund to, future customers. In the absence of regulatory treatment, net earnings for the year would have decreased by $ 10,226 (2009 - $264,741).

(ii) Conservation and demand management & renewable energy

During 2010, the Company incurred $ 19,086 (2009 - $ nil) costs for conservation and demand management & renewable energy. These costs were directly related to the Green Energy and Green Economy Act, 2009 passed into law by the Government of Ontario in 2010. In the absence of regulatory treatment, net earnings in the current year would have decreased by $13,169 (2009 - $ nil).

(iii) Payments in Lieu of Taxes

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between tax basis of assets and liabilities and their carrying amounts for accounting purposes. Balance in PILS account $199,334 (2009 - $199,334). In the absence of regulatory treatment, the net earnings effect in the current and prior year would have been $ nil.

7. DEFERRED ASSETS (continued)

a) Regulatory Costs/Recoveries (continued)

(iv) Other deferred

These balances include OEB specific costs incurred not currently in rates. These costs will be applied for in the next rate rebasing application to the OEB. Balance for these costs are $137,938 (2009 - $134,133). As well the OEB has authorized distributors to apply for Loss Revenue Adjustment Mechanism ("LRAM") due to Demand Management Programs to their customers that have resulted in decreased kWh consumption. This amount may be claimed in a subsequent rate year as compensation for loss of revenue. The LRAM balance was $84,116 (2009 - $103,300). In the May 2006 rate application, the OEB approved in rates additional funding or Tier 2 recovery to support capital, operation and maintenance expenditures that were required to improve the reliability of the distribution system. In 2009, the Company received approval from the OEB to remove the additional funding from its rates. Final disposition of any variance between the revenue and expenditures will be applied for when the Company applies for rate rebasing. The Tier 2 balance is a payable of $24,303 (2008 - $92,029). Ongoing other deferred projects include Line Loss Improvements, Conversions, AM/FM, Rate Rebasing , IFRS, Time of Use Billing, and Late Payment Settlement costs for $736,889 (2009 - $659,724). In the May 2010 rate approval by the OEB the Company was instructed to record the value of the savings resulting from the change to Harmonized Sales Tax effective July 2010. This represents a payable of $20,413 (2009 - $ nil). In the absence of regulatory treatment, net earnings in the current year would have decreased by $75,279 (2009 - $100,789).

(v) Smart meters

The Company incurred costs for the implementation of smart meters of $881,456 (2009 - $690,872). Smart meter revenue collected to 2010 was $241,134 (2009 - $129,433). In the absence of regulatory treatment, net earnings for the current year would have decreased by $54,429 (2000 - $215,182).

(vi) Regulatory Assets Dispositions

The Company received OEB approval for the disposition of regulatory assets approved to December 31, 2004 for Dutton and Newbury, as well as approval of the Strathroy / Parkhill / Mount Brydges Retail Settlement Variance Account balances to December 31, 2009. The balance in the account at December 31, 2010 is a credit of $102,416 (2009 - $6,545). In the absence of regulatory treatment, net earnings in the current year would have increased by $70,667 (2009 - $6,996).

8. DUE TO RELATED PARTIES

	2010	2009
	$	$
Due to Chatham-Kent Utility Services Inc.	**-**	35,563
Due to Chatham-Kent Hydro Inc.	**581,849**	611,977
Due to Chatham-Kent Energy Inc.	**-**	32,330
Due to the Municipality of Chatham-Kent	**104,887**	34,045
Net due to related parties	**686,736**	713,915

9. NOTES PAYABLE

Notes payable consist of $4,300,000 due to CKE at an interest rate of 7.25% which was issued upon the acquisition of the Company by CKE on June 30, 2005. In 2009, a further $1,000,000 was issued by CKE in relation to the acquisition of Dutton and Newbury at an interest rate of 7.62%. During 2010, a further $500,000 was issued to CKE at an interest rate of 5.87%. The notes payable have no set repayment terms and interest payable monthly. Interest expense on the notes was $387,960 (2009 - $336,580).

	2010	2009
	$	$
Notes Payable	**5,800,000**	5,300,000

10. EMPLOYEE FUTURE BENEFITS

The Company measures its accrued benefit obligation as at December 31 of each year. The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The accrued benefit liability at December 31, 2010 of $53,515 (2009 - $53,372) was determined by a full actuarial valuation. The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2010 and the next required valuation will be as of December 31, 2013.

Information about the Company’s defined benefit plan is as follows:

	2010	2009
	$	$
Accrued benefit liability, beginning of year	**53,372**	47,636
Expense for the year	**9,876**	10,165
Employer contributions	**(9,733)**	(4,429)
Estimated accrued benefit liability, end of year	**53,515**	53,372

10. EMPLOYEE FUTURE BENEFITS (continued)

The main actuarial assumptions employed for the valuation are as follows:

General inflation

Future inflation levels, as measured by changes in the Consumers Price Index ("CPI"), were assumed to be 2.5% in 2010 and thereafter.

Interest (discount) rate

The present value of the future benefits, and the expense for the year ended December 31, 2010 was determined using a discount rate of 5.87% (2009 - 7.62%). This corresponds to the OEB approved non-arms length cost of debt rate for 2010.

Health costs

Health costs were assumed to increase at 8% per year for 10 years, and then at the CPI rate plus 1% thereafter.

Dental costs

Dental costs were assumed to increase at the CPI rate plus 1% for 2010 and thereafter.

Salary growth

Salary growth rate was assumed to increase at a rate of 3.5% for 2010 and thereafter.

11. PENSION AGREEMENT

The Company provides a pension plan for its employees through the OMERS. OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company's contribution for employees' current service in 2010 was $54,119 (2009 - $52,432).

12. RELATED PARTY TRANSACTIONS

Chatham-Kent Hydro Inc. (wholly owned by CKE) and Chatham-Kent Utility Services Inc. (wholly owned by CKE) provided the following services in the normal course of operations to the Company. These transactions were made in the normal course of business and have been recorded at the exchange amounts.

12. RELATED PARTY TRANSACTIONS (continued)

	2010	2009
	$	$
Chatham-Kent Utility Services Inc.		
Management, financial, regulatory, customer support and data services	**502,619**	429,756
Chatham-Kent Hydro Inc.		
Management, engineering and purchasing	**79,546**	78,024
Other services provided	**20,085**	69,801
	99,631	147,825

13. CONTINGENCIES

a) Class Action Suit

An action had been brought under the *Class Proceedings Act, 1992*. The plaintiff class sought restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("MEUs") who received late payment penalties (LPP) which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the *Criminal Code*.

On July 22, 2010, the Ontario Superior Court of Justice approved a settlement of the LPP Class Action, the principal terms of which are the following:

- Former MEUs collectively pay $17 million in damages;
- Payment is not due until June 30, 2011; and
- Amounts paid, after deduction for class counsel fee, will be paid to the Winter Warmth Fund or similar charities.

The Company will make a payment of $27,592 by June 30, 2011.

In its IRM filing for 2011 distribution rates, the Company requested that the OEB hold a generic hearing to determine if all costs and damages incurred in this litigation and settlement are recoverable from customers and, if so, the form and timing of recovery from customers.

A generic hearing on this matter was convened by the OEB. On February 22, 2011, the OEB released its Decision and Order on the LPP generic hearing. The OEB found that the costs were prudently incurred and as such could be recovered from customers. The approved recovery period for the Company is one year beginning May 2011.

b) Letter of Credit

In order to obtain the electricity it requires to distribute to its customers, the Company was required to provide security to the IESO based on usage. The security obtained was a letter of credit from a financial institution for $834,984 (2009 - $834,984) and was not drawn on at December 31, 2010. The financial institution has not placed financial restrictions on the Company.

14. SHARE CAPITAL

The share capital of the Company consists of the following:

	2010	2009
Authorized		
Unlimited number of Class A preference shares without par value		
Unlimited number of Class B preference shares without par value		
Unlimited number of voting common shares without par value		
	$	$
Issued		
4,631,198 voting common shares	**4,631,198**	4,631,198

15. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital items

	2010	2009
	$	$
Accounts receivable	**84,738**	(161,138)
Accounts receivable - unbilled revenue	**(255,240)**	(379,952)
Inventories	**(2,909)**	125,258
Prepaid expenses	**(43,606)**	7,312
Accounts payable and accrued liabilities	**179,587**	262,097
Taxes receivable	**(276,736)**	(21,330)
Due to related parties	**(27,179)**	201,503
Current portion of customer deposits	**15,623**	(24,964)
	(325,722)	8,786

Payments in lieu of taxes of $405,792 (2009 - $249,943) and interest of $406,093 (2009 - $382,163) were paid during the year.

16. FINANCIAL INSTRUMENTS

Fair Value

The Company's recognized financial instruments consist of cash and cash equivalents, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, due to related parties, customer deposits and notes payable.

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, accounts payable, accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical.

16. FINANCIAL INSTRUMENTS (continued)

Fair Value (continued)

The Company has a long term promissory note payable with Chatham-Kent Energy at an interest rate of 7.25% in the amount of $4,300,000. The promissory note was issued upon Chatham-Kent Energy purchasing 100% of the shares on June 30, 2005. In 2009 a further $1,000,000 promissory note was issued for the purchase of Dutton and Newbury at an interest rate of 7.62%. In addition, during 2010, a further $500,000 was issued to CKE at an interest rate of 5.87%. There is no "term length" associated with either promissory note.

In order to determine fair value, comparison was made to the approved interest rate from the OEB. The OEB approved the rate of return on the debt portion of "Cost of Capital" for non-arms length transactions. This maximum rate was set at 7.25% to calculate electricity distributor pricing effective May 1, 2001. The interest rate has been approved by the OEB through the rate setting process on a number of occasions since May 2001.

Using the OEB approved non-arm's length cost of debt of 5.8% the annual interest expense would be reduced by approximately $73,000 which is well within current OEB materiality threshold of $413,000. If the Company was able to obtain a reduced interest rate on the Note Payable the OEB would most likely reduce the revenue in a rate proceeding therefore the impact to the net income would be much less. As a result, no changes have been made to the current financial statements.

Credit risk

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing based corporations that pose a significant increase in risk due to the current economy as well as the future outlook of the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk.

17. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC;
- maintain an A-credit rating on stand alone basis; and
- maintain a capital structure comparable to regulated activities as approved by the OEB's deemed debt to equity structure in our rates.

As at December 31, 2010 the Company's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2009. As at December 31, 2010 shareholder's equity amounted to $4,691,741 (2009 - $4,913,047) and long-term debt amounted to $5,800,000 (2009 - $5,300,000).

17. CAPITAL DISCLOSURES (continued)

The 2010 capital structure approved by the OEB in rates was 40% Equity (2009 - 43%), 56% Long-Term Debt (2009 - 57%) and 4% Short-Term Debt (2009 – 0%). The Company's 2010 actual capital structure was 45% Equity (2009 - 48%) with 55% Long-Term Debt (2009 - 52%).

18. PAYMENTS IN LIEU OF TAXES

The provision for payments in lieu of taxes consists of the following:

	2010	2009
	$	$
Current income taxes	**218,930**	115,528
Capital tax	**8,175**	11,100
	227,105	126,628

Reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

	2010	2009
	$	$
Earnings before payments in lieu of taxes	**705,799**	630,586
Capital tax	**8,175**	11,100
Earnings before income taxes	**697,624**	619,486
Statutory income tax rate (percent)	**31.0%**	33.0%
Statutory income tax rate applied to earnings	**216,263**	204,430
Increase / (decrease) resulting from:		
Temporary differences between accounting and tax basis of assets and liabilities	**2,303**	(89,310)
Permanent differences	**364**	408
Provision for income taxes	**218,930**	115,528
Effective rate of income tax (percent)	**31.4%**	18.6%

18. PAYMENTS IN LIEU OF TAXES (continued)

Future income taxes

The long-term future income tax asset of $254,213 (2009 - $146,835) includes the following:

	2010	2009
	$	$
Temporary differences related to capital assets and deferred assets	**236,375**	129,044
Temporary differences related to employee future benefits	**17,838**	17,791
	254,213	146,835

19. COMMITMENTS

The Company has entered into a letter of agreement with Chatham-Kent Utility Services Inc., a related company, on a year to year basis, to have them provide the services of certain management, human resources, financial, regulatory and customer support, rate submission support and accounting and budgeting support. The value of the agreement is $502,619 (2009 - $429,756).

The Company has entered into an agreement with Utilismart Corporation for the services of a data collection system, data storage and access to specific software and systems. The terms of the agreement have been extended for five years commencing April 1, 2009. Annual payments were $25,859 (2009 - $28,327).

The Company entered into an agreement with an unrelated party to perform meter reading and associated services on behalf of the Company on a year to year basis. The cost of this service to the Company was $59,857 (2009 - $67,219).

The Company renewed an agreement with the Township of Strathroy-Caradoc to lease a portion of the premises known as 351 Frances Street, Strathroy, Ontario for a period of three years effective July 1, 2010. The cost of the lease is $62,535 (2009 - $37,000) annually plus 60% of shared operating costs. The Company’s share of operating costs were $35,706 (2009 - $43,325).

The Company renewed an agreement with the Township of Strathroy-Caradoc to provide the services of billing of water services for a period of three years effective July 1, 2010. Contracts for maintenance of streetlight and traffic lights as well as installation of water meters are renewed annually. Revenues received for these services was $355,011 (2009 - $327,557).

The Company has entered into a Service Level agreement with the Township of Strathroy-Caradoc to pay for administrative assistance on a year to year basis. The cost of this agreement was $17,948 (2009 - $20,708).

The Company has entered into a Service Level agreement with Chatham-Kent Hydro Inc., a related Company, to have them provide management, engineering and purchasing services on a year to year basis. The value of the agreement is $79,546 (2009 - $78,024).

Attachment 1.4.4

Pro Forma Statements of Amalgamated LDC

AMALGAMATED CHATHAM-KENT HYDRO INC.
Proforma Combined Balance Sheet
December 31, 2012

	2012
	$
ASSETS	
CURRENT	
Cash and cash equivalents	5,107,909
Accounts receivable	16,577,200
Prepaid expenses	256,300
Inventories	880,000
	22,821,409
CAPITAL ASSETS	60,873,985
OTHER	
Goodwill	367,304
Deferred assets	8,286,873
	8,654,177
	92,349,571
LIABILITIES	
CURRENT	
Accounts payable	12,379,174
Due to the Municipality of Chatham-Kent	2,642,880
Current portion of customer deposits	1,625,028
	16,647,082
LONG-TERM	
Notes payable	40,643,326
Asset retirement obligation	15,000
Employee future benefits	1,011,896
Long-term portion of customer deposits	3,283,443
Future income taxes	2,467,825
	47,421,490
SHAREHOLDER'S EQUITY	
Share capital	28,154,623
Retained earnings	126,376
	28,280,999
	92,349,571

Return on Equity - Accounting Basis	
Net Earnings	2,582,128
Equity	28,280,999
Return on Equity	**9.1%**
Return on Equity - Regulatory Basis	
Net Earnings	2,582,128
Less: Tax-effected Non-Utility Earnings	(413,580)
Regulatory Earnings	2,168,548
Deemed Equity	26,836,000
Return on Equity	**8.1%**
Capital Structure	
Debt Ratio	**59.0%**
Equity Ratio	**41.0%**

AMALGAMATED CHATHAM-KENT HYDRO INC.
Proforma Statement of Earnings and Retained Earnings
December 31, 2012

	2012
	$
SERVICE REVENUE	97,909,821
COST OF POWER	80,400,000
GROSS MARGIN ON SERVICE REVENUE	17,509,821
OTHER OPERATING REVENUE	2,389,668
OPERATING INCOME	19,899,489
OPERATING AND MAINTENANCE EXPENSE	
Distribution	3,472,889
ADMINISTRATIVE EXPENSE	
Billing and collection	2,644,722
General administration	2,866,630
Interest	2,720,869
	8,232,221
DEPRECIATION AND AMORTIZATION	4,603,966
EARNINGS BEFORE PAYMENTS IN LIEU OF TAXES	3,590,412
Provisions for payments in lieu of taxes	1,008,285
NET EARNINGS	2,582,128
RETAINED EARNINGS, OPENING	144,248
LESS DIVIDENDS	(2,600,000)
RETAINED EARNINGS, CLOSING	126,376

Attachment 1.5.3-A

Chatham-Kent Hydro Inc.
Electricity Distribution License

Electricity Distribution Licence

ED-2002-0563

Chatham-Kent Hydro Inc.

Valid Until

December 15, 2023

Original signed by

Kirsten Walli
Board Secretary
Ontario Energy Board
Date of Issuance: December 16, 2003
Date of Amendment: November 12, 2010

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th. Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

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1 Definitions

In this Licence:

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

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

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

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

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

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

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

"**Licensee**" means Chatham-Kent Hydro Inc.

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

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"**OPA**" means the Ontario Power Authority;

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

“**Provincial Brand**” means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

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

“**regulation”** means a regulation made under the Act or the Electricity Act;

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

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

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

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

2 Interpretation

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

3 Authorization

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

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

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

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

11 Distribution Rates

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

12 Separation of Business Activities

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

13 Expansion of Distribution System

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

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

14 Provision of Information to the Board

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

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

15 Restrictions on Provision of Information

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

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

17.1 This Licence shall take effect on December 16, 2003 and expire on December 15, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

21 Conservation and Demand Management

21.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 9.670 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 37.280 GWh (collectively the “CDM Targets”), over a four-year period beginning January 1, 2011.

21.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee’s service area (“Board-Approved CDM Programs”);

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee’s service area under contract with the OPA (“OPA-Contracted Province-Wide CDM Programs”); or

c) a combination of a) and b).

21.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee’s service area.

21.4 The Licensee shall comply with the rules mandated by the Board’s Conservation and Demand Management Code for Electricity Distributors.

21.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee’s own brand or marks.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

Those parts of the following former municipalities (including the former Police Village of Merlin) that the former dissolved public utilities commissions served on December 31, 1997:

1. Town of Blenheim,
2. Town of Bothwell,
3. City of Chatham,
4. Town of Dresden,
5. Village of Erieau,
6. Police Village of Merlin,
7. Town of Ridgetown,
8. Village of Thamesville,
9. Town of Tilbury,
10. Town of Wallaceburg,
11. Village of Wheatley, and
12. Part Lots 16 & 17, Concession A, Geographic Township of Ranleigh, designated as Part 1, Reference Plan 24R 7195, Municipality of Chatham-Kent, and Part Lot 17, Concession A, Geographic Township of Ranleigh, designated as Part 2, Reference Plan 7195, Municipality of Chatham-Kent as per Board Order RP-2003-0044, dated September 16, 2003.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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

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

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

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

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

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

3. Pass Through of Rebate

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

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

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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

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

“ONTARIO POWER GENERATION INC. rebate”

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

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

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

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

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

3. Pass Through of Rebate

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

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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

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

“ONTARIO POWER GENERATION INC. rebate”

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

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

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

Attachment 1.5.3-B

Middlesex Power Distribution Corporation
Electricity Distribution License

Electricity Distribution Licence

ED-2003-0059

Middlesex Power Distribution Corporation

Valid Until

December 18, 2023

Original signed by

____

Kirsten Walli
Board Secretary
Ontario Energy Board
Date of Issuance: December 19, 2003
Date of Amendment: December 3, 2009
Date of Amendment: November 12, 2010

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th. Floor	27e étage
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1 Definitions

In this Licence:

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

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

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

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

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

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

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

"**Licensee**" means Middlesex Power Distribution Corporation

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

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"**OPA**" means the Ontario Power Authority;

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

"**Provincial Brand**" means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

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

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

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

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

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

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

2 Interpretation

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

3 Authorization

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

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

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

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

11 Distribution Rates

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

12 Separation of Business Activities

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

13 Expansion of Distribution System

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

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

14 Provision of Information to the Board

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

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

14.3 The licensee shall inform the Board as soon as possible of any material changes to the service agreement with Chatham-Kent Utilities Services Inc. (the “Service Agreement”).

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

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

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

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

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

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

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

15 Restrictions on Provision of Information

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

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

17.1 This Licence shall take effect on Month day year and expire on Month day year. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

21 Conservation and Demand Management

21.1 The The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 2.450 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 9.250 GWh (collectively the “CDM Targets”), over a four-year period beginning January 1, 2011.

21.2 S The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee’s service area (“Board-Approved CDM Programs”);

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee’s service area under contract with the OPA (“OPA-Contracted Province-Wide CDM Programs”); or

c) a combination of a) and b).

21.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.4 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

1. The former Town of Strathroy as of December 31, 2000.
2. The former Police Village of Mount Brydges as of December 31, 2000.
3. The former Town of Parkhill as of December 31, 2000.
4. The Village of Dutton as of December 31, 1997, now within the Municipality of Dutton/Dunwich.
5. The Village of Newbury as of November 7, 1998.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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

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

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

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

APPENDIX A

MARKET POWER MITIGATION REBATES

21.5.1.1.1.1.1 Definitions and Interpretations

In this Licence

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

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

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

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

21.5.1.1.1.1.2 **Information Given to IESO**

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

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

3. Pass Through of Rebate

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

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

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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

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

“ONTARIO POWER GENERATION INC. rebate”

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

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

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

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

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

3. Pass Through of Rebate

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

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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

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

“ONTARIO POWER GENERATION INC. rebate”

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

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

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

Attachment 1.6.6

Analysis of Incremental External Costs and One-Time & Ongoing Benefits

Review of Potential Merger of Chatham-Kent Hydro Inc.
and Middlesex Power Development Corporation

Estimated Cost and Savings Information

	2011 (Application Period)	2012	2013	2014	2015	2016	2017
Estimated Merger Annual Cost Savings							
Regulatory							
• Eliminate 1 distribution license	-	1,000	1,000	1,000	1,000	1,000	1,000
Finance and administration							
• Reduction of Board of Director fees	-	14,000	14,000	14,000	14,000	14,000	14,000
• Reduction of audit, tax and actuary fees	-	10,000	10,000	10,000	10,000	10,000	10,000
• Eliminate 1 MEARIE report	-	1,000	1,000	1,000	1,000	1,000	1,000
• Pooling of insurance	-	1,000	1,000	1,000	1,000	1,000	1,000
	-	26,000	26,000	26,000	26,000	26,000	26,000
Operations							
• Reduction of ESA audit and license fees	-	8,000	8,000	8,000	8,000	8,000	8,000
	-	8,000	8,000	8,000	8,000	8,000	8,000
Information technology (IT)							
• Harris CIS data base merge	-	-	43,000	43,000	43,000	43,000	43,000
	-	-	43,000	43,000	43,000	43,000	43,000
Total estimated merger annual cost savings	**$ -**	**$ 35,000**	**$ 78,000**	**$ 78,000**	**$ 78,000**	**$ 78,000**	**$ 78,000**
Estimated Merger/Integration One-Time Savings (Costs)							
Operations							
• Avoided cost re creation of MPDC standards procedures manual	-	30,000	-	-	-	-	-
Regulatory							
• MAAD application & OEB hearing process	(50,000)	-	-	-	-	-	-
Finance and administration							
• Project management	(48,000)	(24,000)	-	-	-	-	-
• Legal, external accounting and consulting	(60,000)	-	-	-	-	-	-
• General administrative and rebranding costs	(38,000)	(87,000)	-	-	-	-	-
	(146,000)	(111,000)	-	-	-	-	-
Information technology (IT)							
• Harris CIS data base merge	-	(87,000)	-	-	-	-	-
Total estimated merger/integration one-time savings (costs)	**$ (196,000)**	**$ (168,000)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total period net merger savings (costs)	**$ (196,000)**	**$ (133,000)**	**$ 78,000**	**$ 78,000**	**$ 78,000**	**$ 78,000**	**$ 78,000**
Cumulative total net merger savings (costs)	**$ (196,000)**	**$ (329,000)**	**$ (251,000)**	**$ (173,000)**	**$ (95,000)**	**$ (17,000)**	**$ 61,000**

Potential payback period Year full payback completed **2017**