# Hydro 2000 Inc.
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ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Hydro 2000 Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2008.

## APPLICATION

The Applicant is Hydro 2000 Inc. The Applicant is an Ontario corporation with its office in the village of Alfred. The Applicant carries on the business of distributing electricity within the limits of former villages of Alfred and Plantagenet.

The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to section 78 of the Ontario Energy Board Act, 1998 for approval of its proposed distribution rates and other charges, effective May 1, 2008.

Except where specifically identified in the Application, the Applicant followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated November 14, 2006 (the "Filing Requirements") in order to prepare this application

The Schedule of Rates and Charges proposed in this Application is identified in Exhibit 9; Tab 1; Schedule 6 attached to this Summary.

The Applicant requests that the OEB make its Rate Order effective May 1, 2008 in accordance with the Filing Requirements.

The Applicant submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

(i) the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;

(ii) the proposed adjusted rates are necessary to meet the Applicant's Market Based Rate of Return and PILs requirements;

(iii) there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant; and

(iv) other grounds as may be set out in the material accompanying this Application Summary.

The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in this Application to be effective May 1, 2008, or as soon as possible thereafter. The Applicant submits these rates and charges are just and reasonable pursuant to section 78 of the Ontario Energy Board Act, 1998 being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15,

The address of service for the Applicant is: Hydro 2000 Inc
265, St-Philippe Street
P.O. Box 370
Alfred, On
K0B 1A0

DATED at Alfred, Ontario, this 7th day of September, 2007.

*The Applicant*
Rene C. Beaulne
*Manager*
*("Signature")*

**<u>Hydro 2000 Inc.</u>**

Electricity Distribution Licence

Ontario

# Electricity Distribution Licence

## ED-2002-0542

## Hydro 2000 Inc.

**Valid Until**
**November 12, 2023**

**Mark C. Garner**
**Secretary**
**Ontario Energy Board**

**Date of Issuance: November 13, 2003**

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
26e étage
Toronto ON M4P 1E4

## 1 Definitions 1

In this Licence: 2

"**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; 3

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B; 4

"**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; 5

"**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; 6

"**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; 7

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A; 8

"**Licensee**" means: Hydro 2000 Inc.; 9

"**Market Rules**" means the rules made under section 32 of the Electricity Act; 10

"**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; 11

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge; 12

"**regulation**" means a regulation made under the Act or the Electricity Act; 13

**4 Obligation to Comply with Legislation, Regulations and Market Rules** 25

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. 26

4.2 The Licensee shall comply with all applicable Market Rules. 27

**5 Obligation to Comply with Codes** 28

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: 29

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 30

b) the Distribution System Code; 31

c) the Retail Settlement Code; and 32

d) the Standard Supply Service Code. 33

5.2 The Licensee shall: 34

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 35

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. 36

**6 Obligation to Provide Non-discriminatory Access** 37

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. 38

**7 Obligation to Connect** 39

7.1 The Licensee shall connect a building to its distribution system if: 40

a) the building lies along any of the lines of the distributor's distribution system; and 41

b) the owner, occupant or other person in charge of the building requests the connection in writing. 42

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 43

a) the building is within the Licensee's service area as described in Schedule 1; and 44

b) the owner, occupant or other person in charge of the building requests the connection in writing. 45

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. 46

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. 47

## 8 Obligation to Sell Electricity 48

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. 49

## 9 Obligation to Maintain System Integrity 50

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. 51

## 10 Market Power Mitigation Rebates 52

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 53

## 11 Distribution Rates 54

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. 55

## 12 Separation of Business Activities 56

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. 57

## 13 Expansion of Distribution System 58

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. 59

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. 60

## 14 Provision of Information to the Board 61

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. 62

14.2 Without limiting the generality of condition 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. 63

## 15 Restrictions on Provision of Information 64

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. 65

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: 66

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 67

b) for billing, settlement or market operations purposes; 68

c) for law enforcement purposes; or 69

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 70

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. 71

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. 72

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. 73

## 16 Customer Complaint and Dispute Resolution 74

16.1 The Licensee shall: 75

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 76

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 77

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; 78

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 79

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. 80

## 17 Term of Licence 81

17.1 This Licence shall take effect on November 12, 2003 and expire on November 11, 2023. The term of this Licence may be extended by the Board. 82

## 18 Fees and Assessments 83

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 84

## 19 Communication 85

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. 86

19.2 All official communication relating to this Licence shall be in writing. 87

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 88

a) when delivered in person to the addressee by hand, by registered mail or by courier; 89

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 90

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 91

## 20 Copies of the Licence 92

20.1 The Licensee shall: 93

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 94

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 95

## SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA 96

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence. 97

1. The former Village of Alfred as of December 31, 1996, as described in Schedule A of By-Law 1388 of the Corporation of the United Counties of Prescott and Russell, dated October 18, 1951. 98

2. The former Village of Plantagenet as of December 31, 1996, as described in Schedule A of the Ontario Municipal Board Order N-2361-61 as amended, dated November 6, 1963. 99

## SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE 100

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the 101
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 102
in accordance with condition 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 103

This Schedule specifies any specific Code requirements from which the Licensee has been 104
exempted.

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply 105
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 106

## 1 Definitions and Interpretation 107

In this Licence, 108

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity; 109

"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; 110

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant. 111

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO. 112

## 2 Information Given to IMO 113

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to: 114

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 115

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* 116

b Prior to the payment of a rebate amount by the IMO 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 IMO 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: 117

i consumers served by a retailer where a service transaction request as defined in the Retail 118
Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed 119
price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity con- 120
sumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IMO may issue instructions or directions providing for any information to be given under this 121
section. The IMO 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 gen- 122
eration, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-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 IMO-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 123

A distributor shall promptly pass through, with the next regular bill or settlement statement after the 124
rebate amount is received, any rebate received from the IMO, 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 125
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 and 79.5 of the *Ontario* 126
*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. 127

The amounts paid out to the recipients listed above shall be based on energy consumed and calcu- 128
lated 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: 129

"ONTARIO POWER GENERATION INC. rebate" 130

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 IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt. 131

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 132

Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account. 133

Ontario

# Electricity Distribution Licence

# ED-2002-0542

# Hydro 2000 Inc.

**Valid Until**
**November 12, 2023**

**Mark C. Garner**
**Secretary**
**Ontario Energy Board**

**Date of Issuance: November 13, 2003**


Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
26e étage
Toronto ON M4P 1E4

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"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A; 8

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"**Market Rules**" means the rules made under section 32 of the Electricity Act; 10

"**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; 11

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"**regulation**" means a regulation made under the Act or the Electricity Act; 13

## 4 Obligation to Comply with Legislation, Regulations and Market Rules 25

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. 26

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## 7 Obligation to Connect 39

7.1 The Licensee shall connect a building to its distribution system if: 40

a) the building lies along any of the lines of the distributor's distribution system; and 41

b) the owner, occupant or other person in charge of the building requests the connection in writing. 42

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 43

a) the building is within the Licensee's service area as described in Schedule 1; and 44

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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. 46

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. 47

## 8 Obligation to Sell Electricity 48

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. 49

## 9 Obligation to Maintain System Integrity 50

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. 51

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## 12 Separation of Business Activities 56

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. 57

## 13 Expansion of Distribution System 58

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. 59

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. 60

## 14 Provision of Information to the Board 61

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. 62

14.2 Without limiting the generality of condition 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. 63

## 15 Restrictions on Provision of Information 64

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. 65

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: 66

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 67

b) for billing, settlement or market operations purposes; 68

c) for law enforcement purposes; or 69

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 70

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. 71

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. 72

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. 73

## 16 Customer Complaint and Dispute Resolution 74

16.1 The Licensee shall: 75

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 76

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 77

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; 78

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 79

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. 80

## 17 Term of Licence 81

17.1 This Licence shall take effect on November 12, 2003 and expire on November 11, 2023. The term of this Licence may be extended by the Board. 82

## 18 Fees and Assessments 83

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 84

## 19 Communication 85

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. 86

19.2 All official communication relating to this Licence shall be in writing. 87

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 88

a) when delivered in person to the addressee by hand, by registered mail or by courier; 89

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 90

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 91

## 20 Copies of the Licence 92

20.1 The Licensee shall: 93

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 94

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 95

## SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA 96

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity 97
in accordance with condition 8.1 of this Licence.

1. The former Village of Alfred as of December 31, 1996, as described in Schedule A of By- 98
Law 1388 of the Corporation of the United Counties of Prescott and Russell, dated October 18, 1951.

2. The former Village of Plantagenet as of December 31, 1996, as described in Schedule A of 99
the Ontario Municipal Board Order N-2361-61 as amended, dated November 6, 1963.

## SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE 100

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the 101
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 102
in accordance with condition 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 103

This Schedule specifies any specific Code requirements from which the Licensee has been exempted. 104

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. 105

# APPENDIX A MARKET POWER MITIGATION REBATES 106

## 1 Definitions and Interpretation 107

In this Licence, 108

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity; 109

"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; 110

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant. 111

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO. 112

## 2 Information Given to IMO 113

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to: 114

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 115

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* 116

b Prior to the payment of a rebate amount by the IMO 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 IMO 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: 117

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 118

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. 119

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2. 120

The IMO may issue instructions or directions providing for any information to be given under this section. The IMO 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. 121

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 IMO-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 IMO-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. 122

## 3 Pass Through of Rebate 123

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 IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to: 124

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; 125

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 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 126

c embedded distributors to whom the distributor distributes electricity. 127

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. 128

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: 129

"ONTARIO POWER GENERATION INC. rebate" 130

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 IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt. 131

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 132

Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account. 133

# Hydro 2000 Inc.

Electricity Distribution Licence

# Hydro 2000 Inc.

## CONTACT INFORMATION


| | | | |
|---|---|---|---|
| NAME: | Rene C. Beaulne | Direct line: | 613-679-4093 |
| TITLE: | Manager | Direct Fax: | 613-679-4939 |
| | | E-mail: | aphydro@hawk.igs.net |

**Hydro 2000 Inc.**

## SPECIFIC APPROVALS REQUESTED
**The following are examples which need to reviewed and revised by the Applicant**

- Approval to charge rates effective May 1, 2008 to recover a revenue sufficiency of $165,866 Exhibit 7, Tab 1, Schedule 1.

- Approval of the Applicant's proposed change in capital structure, decreasing/increasing the Applicant's deemed common equity component from ("50%") to ("40%") (Exhibit 6, Tab 1, Schedule 1,) consistent with Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006

- Approval to continue the following deferral/variance accounts on May 1, 2008 (Exhibit 5, Tab 1, Schedule 1):

| | |
|---|---|
| Other Regulatory Assets | 1508 |
| LV variance | 1550 |
| Smart meter | 1555 |
| Deferred Payments in Lieu of Taxes | 1562 |
| PILS Contra Account | 1563 |
| CDM | 1565 |
| RSVA - Wholesale Market Service Charge | 1580 |
| RSVA - One-time Wholesale Market Service | 1582 |
| RSVA - Retail Transmission Network Charge | 1584 |
| RSVA - Retail Transmission Connection Charge | 1586 |
| RSVA - Power | 1588 |
| Recovery of Regulatory Asset Balances | 1590 |
| PILS Variance Deferral | 1592 |

**Hydro 2000 is requesting a deferral account to capture capital expenses in future years 2009 and 2010 that will be dispose in the next rebasing in 2011.**

- Approval of the proposed lost factor (Exhibit 4, Tab 2, Schedule 9):

# Hydro 2000 Inc.

## DRAFT ISSUES LIST
## To be completed by LDC based on final review of Application

# Hydro 2000 Inc.

## PROCEDURAL ORDERS/MOTIONS/NOTICES

A place holder – to be included when received

## Hydro 2000 Inc.

## ACCOUNTING ORDERS REQUESTED

As part of this proceeding, the Applicant is requesting the following accounting orders:

**A Deferral account to capture capital expenses in future years 2009 and 2010 that will be dispose in the next rebasing in 2011.**

**Hydro 2000 Inc.**

## NON-COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

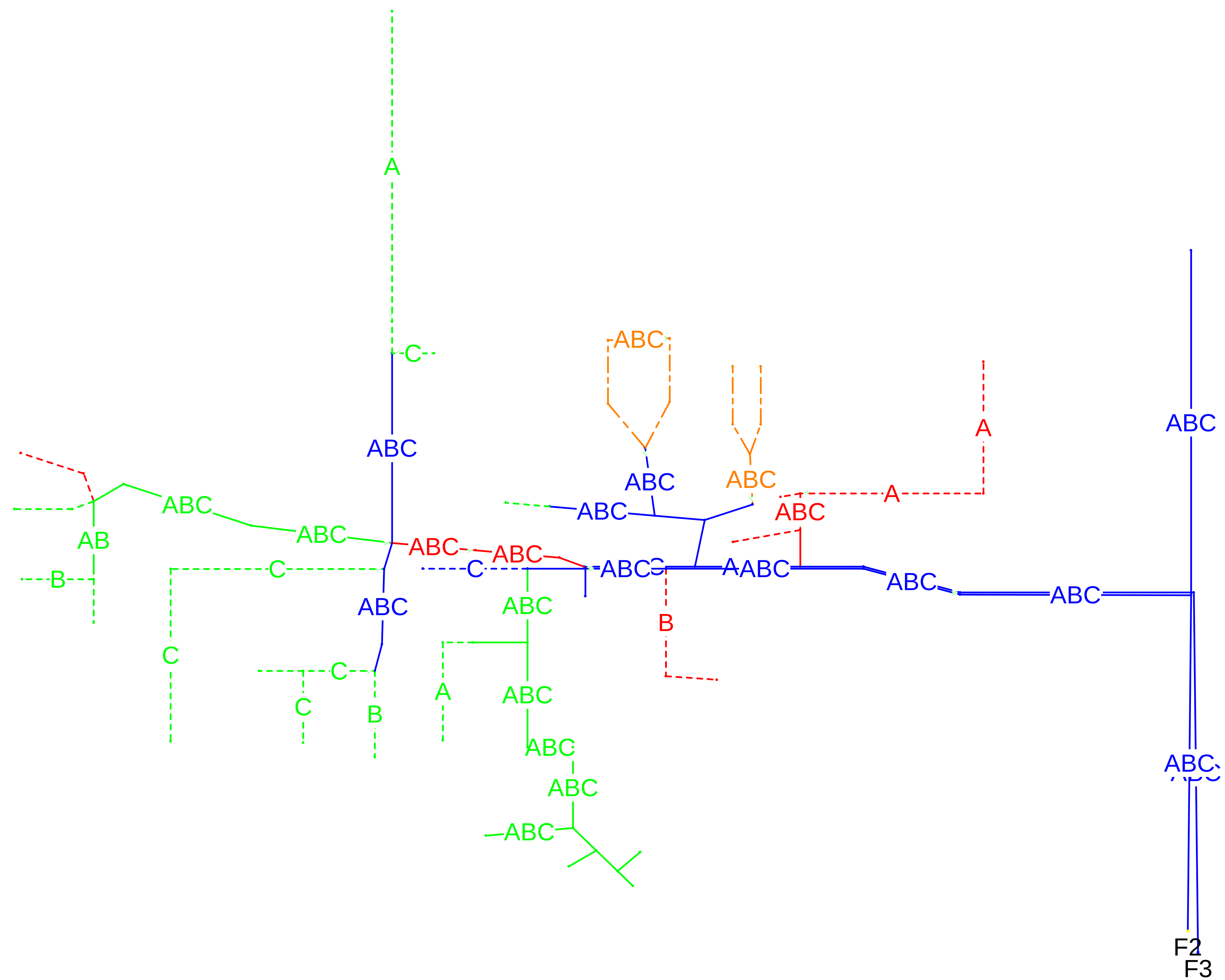
The Applicant follows the main categories and accounting guidelines as stated in the Uniform System of Accounts.

**Hydro 2000 Inc.**

**MAP OF DISTRIBUTION SYSTEM**

*(Insert System Map here)*

# ALFRED DISTRIBUTION MAP




**Legend**

Default Layer:
Conductor size

Colors :
- #2/0 AWG cable
- #2 AWG ACSR
- #1/0 AWG ACSR
- #3/0 AWG ACSR
- 336 kcmil ACSR

Line Types:
- 3-OH
- 3-UG
- 2-OH
- 2-UG
- A-OH
- B-OH
- C-OH
- A-UG
- B-UG
- C-UG

Symbols :
- Switch, (C)
- Load
- Switch, (O)

# PLANTAGENET DISTRIBUTION MAP

**Hydro 2000 Inc.**

## LIST OF NEIGHBORING UTILITIES

LIST OF ADJACENT DISTRIBUTORS

| | | |
|---|---|---|
| UTILITY NAME | Hydro One Networks | Direct line: 613-274-6327 |
| ADDRESS | 483, Bay Street | Direct Fax: 613-224-1726 |
| | Toronto, On | E-mail:mike.ritchie@HydroOne.com |
| | M5G 2P5 | |

DESCRIPTION OF HYDRO 2000 INC.

| | | |
|---|---|---|
| COMMUNITY SERVED: | City: | Alfred and Plantagenet |
| TOTAL SERVICE AREA | sq km: | 9km |
| RURAL SERVICE AREA | sq km: | 4km |
| DISTRIBUTION TYPE | | 4.8 kV WYE |
| SERVICE AREA POPULATION | | 2460 |
| MUNICIPAL POPULATION | | 9314 |
| BOUNDARIES | West: | Hydro One Networks Inc |
| | North: | Hydro One Networks Inc |
| | East: | Hydro One Networks Inc |
| | South: | Hydro One Networks Inc |

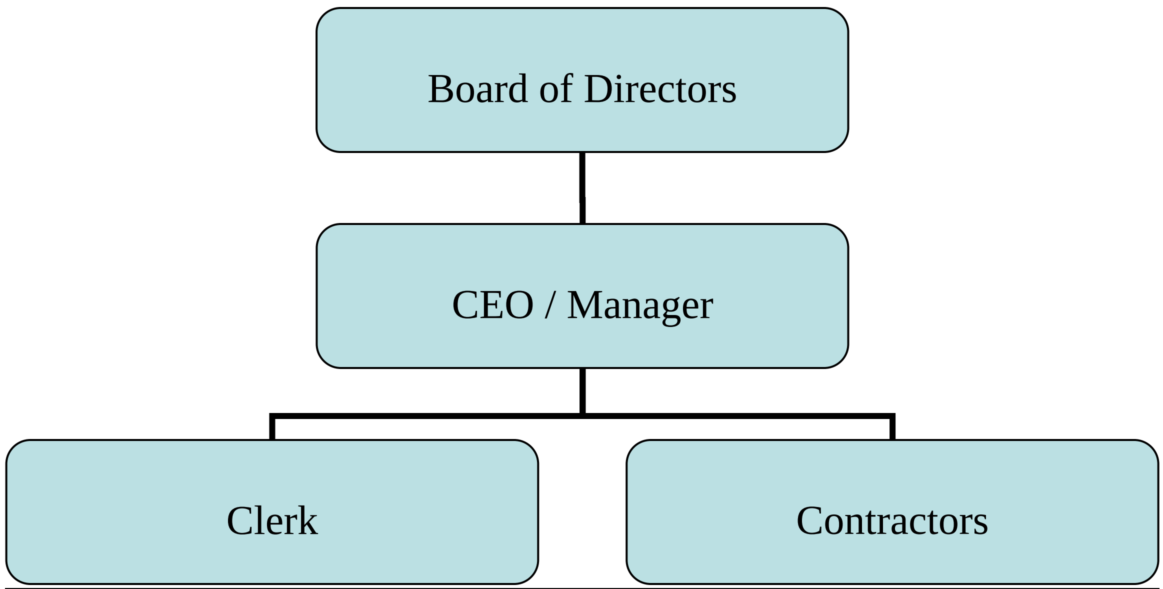
## Hydro 2000 Inc.

## EXPLANATION OF HOST AND EMBEDDED UTILITIES

Hydro 2000 Inc. is an embedded utility and Hydro One Networks Inc. is its Host distributor.

**Hydro 2000 Inc.**

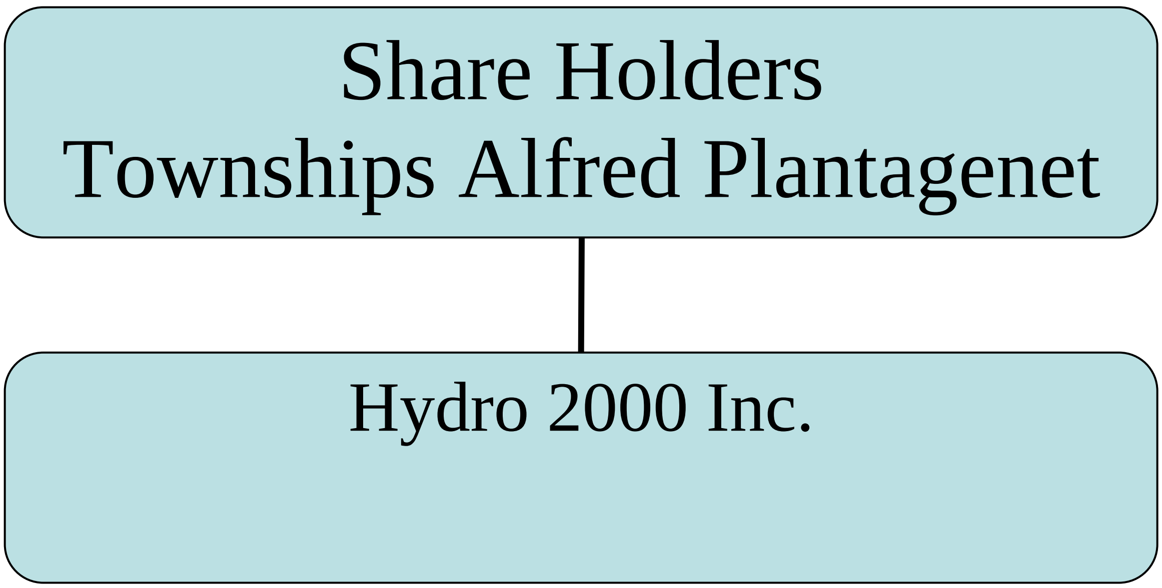
**UTILITY ORGANIZATIONAL CHART**




Hydro 2000 Inc. is a Local Distribution Company and has no affiliates.

**Hydro 2000 Inc.**

**CORPORATE ENTITIES RELATIONSHIP CHARTS**



**Hydro 2000 Inc.**

## PLANNED CHANGES IN CORPORATE OR OPERATIONAL STRUCTURE

No changes are planned in corporate or operational structure.

## Hydro 2000 Inc.

## STATUS REPORT ON BOARD DIRECTIVES

Not applicable.

# Hydro 2000 Inc.

## CONDITIONS OF SERVICE

**Hydro 2000 Inc.** a member of

Cornerstone Hydro Electric Concepts Association Inc.

# *CONDITIONS OF SERVICE*

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**Disconnection Policy**

**Collections Policy**

# SECTION 1 INTRODUCTION

## 1.1 Identification of Distributor and Territory

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

The Distributor is licensed by the Ontario Energy Board "OEB" to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the Electricity Act and the Ontario Energy Board Act.

The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

### 1.1.1 General

Nothing contained in this document or in any contract for the supply of electricity by the Distributor shall prejudice or affect any rights, privileges, or powers vested in the Distributor by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

The Distributor will normally provide one electrical service to each customer location at a nominal service voltage.

Modifications to an existing service must comply with the requirements of the standards in effect at the time of the modifications.

The customer or their authorized representative must make application for new or upgraded electric services and temporary power services.

The customer or their representative shall consult with the Distributor concerning the availability of supply, the voltage of supply, service location, metering and any other details. These requirements are separate from and in addition to those of the Electrical Inspection Authority. The Distributor will confirm, in writing, the Characteristics of Electric Supply available at a specific site.

The customer is required to provide the Distributor sufficient lead-time in order to ensure:

(a) *the timely provision of supply to new and upgraded premises or*
(b) *the availability of adequate capacity for additional loads to be connected in existing premises.*

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. The customer will be notified of any extended lead times.

Customers will be required to pay the cost of repair or replacement of the Distributors' equipment that has been damaged through the customers' action or neglect.

The supply of electricity is conditional upon the Distributor being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should the Distributor not be permitted to supply or not be able to do so, it is under no responsibility to the customer whatsoever.

The Customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of the Distributor, interfere with the proper and safe operation of the Distributor's facilities or adversely affect compliance with any applicable legislation in the sole opinion of the Distributor.

Prior to commencing any service work, the customer must consult with the Distributor to ensure compliance with current requirements.

The Distributor, at the expense of the Owner, reserves the right to provide an Inspector who will be on duty for the duration of the work, and the Contractor shall supply him such accommodations as he may require. The Inspector shall have the authority to stop work at any time he feels the Contractor is not proceeding in accordance with these "conditions of service". Work shall not recommence until the Distributor has been notified and the Inspector is present at the site.

Customers may be required to pay Capital Contributions for the addition of new electrical services in accordance to calculations on overall system cost impact.

## 1.2 Related Codes and Governing Laws

The Distributor is limited in its scope of operation by the:

1. *Electricity Act, 1998*
   http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm
2. *Ontario Energy Board Act, 1998*
   http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98o15_e.htm
3. *Distribution Licence*
   Licence Numbers
4. *Affiliate Relationships Code*
   http://www.oeb.gov.on.ca/documents/affiliatecode_amendedcode.112403.pdf
5. *Distribution System Code*
   http://www.oeb.gov.on.ca/documents/cases/EB-2005-0488/dsccode_20070627.pdf
6. *Retail Settlements Code*
   http://www.oeb.gov.on.ca/documents/cases/RP-1999-0032/code_231104.pdf
7. *Standard Service Supply Code*
   http://www.oeb.gov.on.ca/documents/cases/EB-2004-0205/sssc/rpp_sssc_revised_20070627.pdf
8. *Transmission System Code*
   http://www.oeb.gov.on.ca/documents/cases/RP-2004-0220/tsc_finalclean.pdf

In the event of a conflict between this document and the Distribution Licence or regulatory Codes issued by the OEB, or the Electricity Act, the provisions of the Act, the Distribution License and associated regulatory Codes shall prevail.

When planning and designing for electricity service, Customers and their agents must refer to all applicable provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. The work shall be conducted in accordance with the Ontario Occupational Health and Safety Act, the Regulations for Construction Projects and the E&USA (or the OHSC Safety) rulebook.

## 1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- *Headings and underlining are for convenience only and do not affect the interpretation of these Rules.*
- *Words referring to the singular include the plural and vice versa.*
- *Words referring to a gender include any gender.*

## 1.4 Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of any Contract made between the Distributor and any connected Customer, Generator or their agents.

In the event of changes to this Conditions of Service, a Public notice shall be made in the form of either a notice in the local newspaper, or a notice on the Distributors' Website.

The Customer is responsible for contacting the Distributor to ensure that the Customer has, or to obtain the current version of the Conditions of Service. The Distributor may charge a reasonable fee for providing the Customer with more than one copy of this document.

## 1.5 Contact Information

The Distributor and its agents can be contacted during normal working hours (Monday to Friday between 8:30 and 4:30). Please refer to the Contact Listing in the Appendices for the phone number of the Local Distribution Company servicing your area.

## 1.6 Customer Rights

In those instances where the Customer will own their secondary or primary service, the Customer has the right to hire a Contractor to supply and install the service.

The customer has the right to demand identification from any person purporting to be an authorized agent or employee of the distributor.

A customer, who believes that he has suffered damages to his property or equipment as a result of negligence on the part of the Distributor, may submit a written claim for damages to the Distributor. The Distributor will investigate the claim and respond in writing within 10 business days of the receipt of the claim.

## 1.7 Distributor Rights

In those instances where the Customer has the authority to hire a Contractor to construct plant which will become part of the Distributors' system, the Distributor shall have the right to require the Contractor to submit proof of previous experience and satisfactory performance, and, the Distributor shall have the right to investigate such proof and approve the Contractor prior to the Owner awarding a contract for the work to the Contractor.

The Distributor shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998*.

## 1.8 Disputes

If, following good faith negotiations between a customer or other market participant and the Distributor, a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

Any dispute which shall arise between the Distributor and a customer(s) and other market participants subject to the terms of these Conditions of Service concerning the rights, duties or obligations of the Distributor or others subject to these Conditions of Service, shall be subject to the following dispute resolution procedure:

**Mediation**

- Either party (the "Initiating Party") may invoke the dispute resolution procedure by sending a written notice to the other party (the "Respondent Party") describing the nature of the dispute and designating a representative of the Initiating Party with appropriate authority to be its representative in negotiations relating to the dispute. The responding Party shall, within five business days of the receipt of such notice, send a written notice to the Initiating Party, designating a representative of the Responding party with the appropriate authority to be its representative in negotiations relating to the dispute.

- Within ten business days of the receipt by the Initiating Party of the written notice of the Responding Party the designated representatives shall enter into good faith negotiations with a view to resolving the dispute. If the dispute is not resolved in thirty days of the commencement of such negotiations, or such longer period as may be agreed upon, either party may, by written notice to the other party, require that the parties be assisted in their negotiations by a mediator. The mediator shall be acceptable to both parties and have knowledge and experience in the matter under dispute, or professional qualifications, or experience in alternative dispute resolution, or both. The parties shall thereafter participate in mediation with the mediator through such process as the mediator, in consultation with the parties, may determine.

- None of the parties shall be deemed to be in default of any matter being mediated, until effective or after the date mediation fails.

**Referral to Dispute Resolution**

Any dispute that is not resolved through mediation as described above shall be referred to the Ontario Energy Board for dispute resolution according to the following procedure:

- Upon the written demand of either of the parties, the dispute shall be referred to the Ontario Energy Board for resolution of the dispute.

- The Ontario Energy Board disputes resolution process shall immediately proceed to hear the matter or matters in dispute. The decision of the Ontario Energy Board disputes resolution process shall be made within 45 days of the selection, subject to any reasonable delay due to unforeseen circumstances.

- The decision of the Ontario Energy Board disputes resolution process shall be in writing and signed by the Ontario Energy Board staff. It shall be final and binding upon all the parties hereto as to any matter or matters so submitted to the Ontario Energy Board disputes resolution panel and shall observe and implement the terms and conditions thereof.

- The compensation and expenses of the Ontario Energy Board disputes resolution panel, (unless otherwise determined by the Board) shall be paid equally by the parties.

# SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

## 2.1 Connections and Expansions

This section includes information that is applicable to all customer classes of the distributor. Items that are applicable to only a specific customer class are covered in Section 3.

### 2.1.1 Building that Lies Along

As provided in **Section 28** of the Electricity Act 1998 the Distributor has the Obligation to Connect any Building that 'lies along" its distribution system. A building 'lies along" a distribution line if it can be connected to the distributor distribution system without an expansion or enhancement, and meets the conditions listed in the Distribution System Code.

A Building that 'lies along' a distribution line may be refused connection to that line should the distribution line not have sufficient capacity for the requested connection.

A Building that 'lies along" a distribution line may be refused connection to that line should the connection be bad or unsafe for the system.

### 2.1.2 Expansions / Offer to Connect

Under the terms of the Distribution System Code Section 3.1, a Distributor has the Obligation to make an Offer to Connect any Building that 'lies along" its distribution system yet may be excluded due to being outside of the Service Territory. The Offer to connect must be Fair and Reasonable and be based on the distributors' design standard. The Offer to Connect must also be made within a reasonable time from the request for connection.

The Distributor may require a customer to pay all or a part of the costs of electrical plant installed to supply only that customer. Such capital contributions will be calculated using the guidelines set out by the OEB in the Distribution System Code.

### 2.1.3 Connection Denial

The Distribution System Code in section 3.1 sets outs the conditions for a Distributor to deny connections. A Distributor is not obligated to connect a building within its service territory if the connection would result in any of the following:

- Contravention of existing Canadian Laws, and those of the Province of Ontario.
- Violations of conditions in a Distributors' Licence.
- Use of a distribution system line for a purpose that it does not serve and that the Distributor does not

intend to serve.

- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributors' distribution system.
- A material adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Potential increases in monetary amounts that already are in arrears with the distributor
- Any other conditions documented in the distributors Conditions of Service document that are consistent with the conditions identified above and with the goals delineated in the Energy Competition Act, 1998.

### 2.1.4 Inspections Before Connections

The Distributor has the right to request an inspection prior to any connection.

All customer electrical installations shall be inspected and approved by the Electrical Safety Authority, referred to herein as the ESA.

The Distributor requires notification from the ESA of this approval prior to the connection of a customer's service.

Services that have been disconnected for a period of six months or longer shall also be re-inspected and approved by the ESA prior to reconnection.

Temporary services, for construction purposes, are approved by the ESA for a period of twelve months and must be re-inspected should the period of use exceed twelve months.

The Distributor reserves the right to inspect and approve Transformer rooms, Vaults and Pads prior to during and following the installation of equipment.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

Customer owned substations must be inspected by both the Electrical Safety Authority and the Distributor, prior to connection to the Distribution system.

Duct banks and road crossings shall be inspected and approved by the Distributor prior to the pouring of concrete and again before backfilling.

The Distributor reserves the right to inspect any underground trenches prior to backfilling.

The Distributor reserves the right to approve the installation and location of all submarine cable. All documentation and permits required for laying of submarine cable must be provided to the Distributor. The installation of submarine cable must meet the requirements of all governing legislation.

All work done on existing Distributor plant must be authorized by the Distributor and carried out in accordance with all applicable safety acts and regulations.

In accordance with the Distribution System Code, if the Distributor refuses to connect a building in its service territory that lies along one of its distribution lines, the distributor shall inform the person requesting the connection of the reasons for not connecting, and where the distributor is able to provide a remedy, make an offer to connect. If the Distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection can be made.

### 2.1.5 Relocation of Plant

The Distributor will, where feasible, accommodate requests to relocate electrical plant such as poles and metal enclosed equipment.

The customer will be required to pay all of the costs incurred by the relocation.

Requests by civic authorities to relocate distribution facilities will be done so in accordance with the appropriate regulations.

### 2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, the Distributor has the right to have supply facilities on private property registered against title to the property. Easements are required whenever the Distributors' underground or overhead plant is to be located on private property or crosses over an adjacent private property to service a Customer.

The Customer shall acquire and grant in the distributors name, at no cost to the Distributor, where required, an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by the Distributor. The easement shall be granted prior to connection of the service.

The Owner shall furnish to the Distributor, free and clear of all encumbrances, sufficient easements to enable the servicing of all existing or proposed developments or subdivisions from plants located on the Owners' property.

Sufficient property at suitable locations shall be made available for the purpose of the installation of distributors' assets.

The Customer will prepare at its own costs a reference plan and associated easement documents to the satisfaction of the Distributors' solicitor prior to its registration and register the easement plan. Details will be provided upon application for service.

Where surface restoration by the Distributor is required following any repairs or maintenance to a service, the Distributor will in so far as is practicable, restore the property to its original condition; and provide compensation for any damages caused by the entry that cannot be repaired.

### 2.1.7 Contracts

**<u>Standard Form of Contract</u>** - Connection to the electrical distribution system will be provided upon completion of a signed contract between the customer and the distributor, and receipt of approval by the Electrical Safety Authority.

All customers will be required to complete and sign the standard form of contract to apply for the supply of an electrical energy connection. A Standard Contract for service shall be considered as being in force from the date it is signed by the Customer and the Distributor and shall remain in force until terminated by either party.

**<u>Implied Contract</u>** - In all cases, notwithstanding the absence of a formal contract, the taking and using of electrical energy from the Distributor by any Person or Persons constitutes the acceptance of the terms and conditions of all regulations, conditions and rates as established by the Distributor. Such acceptance and use of energy shall be deemed to be the acceptance of a binding contract with the Distributor and the Person so accepting shall be liable for payment for such energy and the contract shall be binding upon the Person's heirs, administrators, executors, successors or assigns.

**<u>Special Contracts</u>** - Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- *construction sites*
- *mobile facilities*
- *non-permanent structures*
- *special occasions, etc.*
- *generation*

## 2.2 Disconnection

The Distributor has the right and/or obligation to disconnect the supply of electrical energy to a Customer for causes including but not limited to:

- *Overdue amounts payable to the Distributor, Retailer, or Wholesaler (provided the Distributor provides the Customer with reasonable notice of the proposed shut off of electricity).*
- *Hazardous conditions.*
- *Electrical disturbance propagation caused by Customer equipment that is not corrected in a timely fashion.*
- *Energy diversion, fraud or abuse on the part of the Customer.*
- *When ordered to do so by any authority having the legal right to issue such an order.*
- *Adverse effect on the reliability and safety of the distribution system.*
- *Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.*
- *A material decrease in the efficiency of the distributor's distribution system.*
- *A materially adverse effect on the quality of distribution services received by an existing connection.*

- *Inability of the distributor to perform planned inspections and maintenance.*
- *Failure of the consumer or customer to comply with a directive of a distributor that the distributor makes for purposes of meeting its licence obligations.*

## 2.3 Conveyance of Electricity

### 2.3.1 Guaranty of Supply

The Distributor agrees to use reasonable diligence in providing a regular and uninterrupted supply but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Customer by reason of any failure in respect thereof.

Customers requiring a higher degree of security than that of normal supply are responsible to provide their own back-up or standby facilities.

When power is interrupted, or the Customer is experiencing power quality problems the Customer or their electrical contractor shall first ensure that interruption is not due to problems within the customer owned installation. If after verifying that the cause of the problem does not reside on the customers' installation, the customer shall contact the Distributor. The Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

Although it is the Distributors' policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve the Distributors' system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by the Distributor, arrangements suitable to the Customer and the Distributor may be made to minimize any inconvenience. The Distributor will endeavor to provide the Customer with reasonable advance notice, except in cases of emergency, involving danger to life and limb, or impending severe equipment damage.

The Distributor will endeavor to notify Customers prior to interrupting the supply to any individual service. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to the Distributor or the public, service may be discontinued without notice.

Depending on the outage duration and the number of Customers affected, the Distributor may issue a news release to advise the general public of the outage.

### 2.3.2 Power Quality

The distributor will respond to and take reasonable steps to investigate consumer power quality complaints and report to the consumer on the results of the investigation. The method and level of investigation will be at the discretion of the Distributor.

If the source of a power quality problem is caused by the consumer making the complaint, the distributor may seek reimbursement for the time and cost spent to investigate the complaint.

If the source of a power quality problem is caused by a consumer, the Distributor may direct the consumer to take corrective action. If the Consumer does not take such action within a reasonable time, the Distributor may disconnect the supply of power to the Customer. (*see* *section 2.2*)

### 2.3.3 Electrical Disturbances

There are levels of voltage fluctuation and other disturbances that can cause flickering lights and more serious difficulties for Customers connected to the Distributor distribution system.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms.

No electrical equipment, which may produce an undesirable system disturbance, shall be connected by a customer to a customer's service without prior approval of the Distributor.
Examples of equipment, which may cause disturbance, are large motors, welders and variable speed drives. In planning the installation of such equipment, the customer is required to consult with the Distributor.

The Distributor will endeavour to maintain voltage variation limits, under normal operating conditions, at the Customers' Delivery Points, as specified by the latest edition of the Canadian Standards Association, C235. However, more sensitive electronic equipment such as computers can be seriously affected by variations in quality of supply voltage. Customers who need electrical power of high quality and with rigid voltage tolerances are responsible for providing their own power conditioning equipment.

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of the Distributors' supply.

The customer shall provide such protective devices as may be necessary to protect his property or equipment from any disturbance beyond the control of the distributor.

### 2.3.4 Standard Voltage Offerings

#### 2.3.4.1 For Secondary Voltage

The Supply Voltage governs the limit of supply capacity for any Customer. General guidelines for supply from overhead street circuits are as follows:

- *at 120/240 V. single phase, or*
- *347/600 V. three phase, four wire, or*

- *120/208 V three phase, four wire,*

**OR**

Where street circuits are buried, the Supply Voltage and limits will be determined upon application to the Distributor.

**OR**

Where the Customer or Developer provides a pad on private property;

- *at 120/240 V single phase, or*
- *at 120/208 V three phase, four wire, or*
- *at 347/600 V three-phase, four-wire*

#### 2.3.4.2 For Primary Voltage

Primary supplies to transformers or customer-owned substations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *27,600 volts 3 phase 3 wire delta*
- *44,000 volts 3 phase 3 wire*

An electrical requirement in excess of 300 kVA may require a customer owned Substation supplied at the voltage as determined by the distributor.

### 2.3.5 Voltage Guidelines

The Distributor maintains service voltage at the Customers' service entrance within the guidelines of C.S.A. Standard CAN3-C235 (latest edition) which allows variations from nominal voltage of: http://www.csa-intl.org/onlinestore/GetCatalogDrillDown.asp?Parent=542,

*6% for Normal Operating Conditions*
*8% for Extreme Operating Conditions*

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis.

Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

### 2.3.6 Back-up Generators

Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back-feed on the Distributors' system.
http://www.esainspection.net/pdf/Ontario_Amendments_Canadian_Electrical_Code.pdf

Customers with permanently connected emergency generation equipment shall notify the Distributor regarding the presence of such equipment.

The distributor reserves the right to have the connection of this equipment inspected.

Generation systems found to be feeding into the Distribution system without proper approval of the Distributor shall be subject to immediate disconnection.

### 2.3.7 Metering

### 2.3.7.1 General

#### *2.3.7.1.1 Access*

The Distributor or its agents shall have the right to access and read any of the Distributors' electricity meters on the Customer's premises.

All metering installations shall be accessible from a public area.

#### *2.3.7.1.2 Costs*

All the Distributor metering equipment located on the Customer's premises are in the care and at the risk of the Customer and if destroyed or damaged, other than by normal usage, the Customer will pay for the cost of repair or replacement.

Regardless of any charges for metering installations, all meters and meter instrumentation equipment shall remain the property of the Distributor and maintenance of this equipment shall be the Distributors' responsibility.

***2.3.7.1.3 Voltage***

Generally, metering will be at utilization voltage. Where the Distributor provides primary transformation, primary voltage metering will be allowed only in special circumstances following full discussion with the Distributor.

Customer-owned substations may require primary metering. The provisions required for these installations shall be specified and approved by the Distributor for each application.

***2.3.7.1.4 Primary / Bulk Metering***

Primary metering units may be installed outdoors or within and electrical vault as outlined in the current Electrical Safety Code. Where the Owner prefers not to provide an approved electrical vault, the Distributor at additional cost can provide a metering unit with non-flammable coolant.

Non-residential or mixed-use buildings will normally be bulk metered by a single meter. However, where specific areas are clearly and permanently defined and in other respects as a separate entity, individual metering of the loads will be considered.

In all installations where the Customer requests revenue metering remote from the secondary entrance equipment or downstream from a Customer-owned dry-core transformer, provisions are required for a bulk meter directly after the main switch. This bulk metering is required in addition to any public metering provisions. The Customer will be required to contribute to the cost of the metering installation.

Where more than one meter exists, the meters shall be grouped where practicable.

The customer/contractor shall permanently and legibly identify all metered services with respect to correct municipal 911 address and unit #. The identification shall be applied to all service switches and breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to the service switch. The customer/contractor shall insure that all service identifications are accurate and by not doing so will be held totally responsible. The Distributor shall issue a Meter Verification Sheet for this purpose to the owner or contractor.

In any case, a copy of the metering layout plan shall be forwarded to the Distributor for review and approval.

If the distribution of the metered load circuit is in dispute, (ie: circuits from one premise is found to supply a second premise) the Distributor reserves the right to transfer all accounts into the Property Owners' name until such time as the problem has been resolved, and the individual metering can be clearly identified with the individual units.

***2.3.7.1.5 Locks***

All devices on the line side of the Distributor metering shall have provisions for padlocking.

For commercial and industrial services the Customer's main switch shall have provisions for padlocking the switch handle in the open position and the switch cover or door in the closed position.

When a disconnect device has been locked in the "OFF" position by the Distributor, under no circumstances shall anyone remove the lock and energize it without first receiving approval from the Distributor.

At the discretion of the Distributor, a dual locking arrangement, a Distributor master key arrangement, a key box arrangement, or a copy of the access key will be required for access.

### 2.3.7.2 Current Transformer Boxes

Where a current transformer box is required, it shall be CSA approved, of a size and type as stipulated by the Distributor, and include a provision for padlocks. A removable plate shall be provided in the box for mounting the equipment.

As an alternative to a separate CT box and meter, a single enclosure combining both functions may be feasible. Contact the Distributor for details.

In cases where the CTs only meter a portion of the metal clad switchgear (such as house loads), a separate disconnect switch must be installed ahead of the metering compartment so that the service can be de-energized without any interruption to the main service supply.

Generally, one house load meter only will be allowed. Additional house load meters will require authorization from the Distributor.

Conductors should enter the current transformer box at the top and leave at the bottom, or vice versa. If this cannot be arranged, the next largest CT box must be used to enable conductors to be trained in place. Where parallel conductors are used, the sum of the conductors will determine the size of the CT box to use. In all cases the Customer shall supply suitable cable termination lugs.

On all electrical services that require current transformers and the neutral for metering, an isolated neutral block shall be provided in the current transformer box.

### 2.3.7.3 Interval Metering

The Distribution System Code, as amended from time to time, requires the Distributor to meter Customers of specific load levels with pulse-recording meters, or interval meters, which are interrogated remotely. The Distributor, at its' sole discretion, may also require such metering on any customer whose load characteristics may have a significant impact on the Net System Load Shape, or where reasonable access to the meter for the purpose of acquiring metering data may be limited due to location.

A customer that requests interval metering shall compensate a distributor for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and re-verification of the meter, installation and ongoing provision of communication line or communication link with the customer' s meter, and cost of metering made redundant by the customer requesting interval metering. The communication system utilized for interval meters shall be in accordance with the distributors' requirements.

Where such metering exists the Distributor will consider customer requests to provide a secondary pulse for load control or customer-owned metering at the customers' expense.

In keeping with the intent of the Legislation and accompanying amendments, once an interval meter installation is processed as part of the distributors' settlement process, and has affected the relevant changes to the distributors net system load, the installation must not be changed back to a non-interval meter installation.

Where a customer submits a request to read their own interval meter, the Distributor shall make this access available given the following conditions are met:

- The meter has the capability of read-only password protection
- The customer provides a signed copy of the "Interval Metering Access Agreement" to the Distributor.

#### 2.3.7.3.1 Interval Metering Communications

- Solid-state recorders and/or Electronic Interval Meters installed by the Distributor have provision for remote interrogation over a telephone line. To accommodate this feature the Owner will provide shared access to a telephone line for the Distributors' metering purposes.
- At its' sole discretion, for metering installations where loss of metering data would cause a substantial impact on the Distributors Settlement System, the Distributor may require the phone line to be dedicated for metering purposes only.
- A voice quality telephone line, which is active 24 hours a day to the metering location extension jack, which is mounted on the metering board.
- Phone lines must be installed and functioning prior to the new service being energized.

### 2.3.7.4 Meter Reading

The Distributor will read all meters on a regularly scheduled basis whenever possible. If an actual meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

### 2.3.7.5 Final Meter Reading

When a service is no longer required, or the Customer is switching Energy Providers, the Customer shall provide the Distributor sufficient notice of the date so that a final meter reading can be obtained. The Customer shall provide access to the Distributor or its agents for this purpose.

If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

### 2.3.7.6 Faulty Registration of Meters

Metering electricity usage for the purpose of billing is governed by the Federal Electricity and Gas Inspection Act and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. The Distributors' revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, the Distributor will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay for all the energy supplied, a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by the Distributor, due regard being given to any change in the character of the installation and/or the demand.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the billing correction will apply for the duration of the error. The Distributor will correct the bills for that period in accordance with the regulations under the Act. http://lois.justice.gc.ca/en/ShowFullDoc/cr/SOR-86-131///en?noCookie.

### 2.3.7.7 Meter Dispute Testing

The Distributor will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, the Distributor will conduct an internal investigation to verify the accuracy of any meter the Customer believes to be recording incorrectly. If the internal investigation does not resolve the matter, the Customer or the Distributor may request Measurement Canada to test the meter.
http://strategis.ic.gc.ca/epic/site/mc-mc.nsf/en/h_lm02112e.html.
.

If the test indicates that the meter is not accurate, the Customer's historic billing will be adjusted, and the Distributor shall pay the full costs of the meter dispute testing.

### 2.3.7.8 Location

The location of the indoor or outdoor meter shall be readily accessible at all times and acceptable to the Distributor. If a meter is recessed or enclosed after installation, without the prior approval of the Distributor, the service may be subject to disconnection.

The location of the service entrance, routing of duct banks, metering, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

In all locations where Commercial/Industrial revenue metering is accessible to the general public, a lockable enclosure or a room for service equipment and meters, shall be provided by the Owner at the discretion of the Distributor, as follows:

- *An electrical room reserved solely for metering equipment or*
- *Metal enclosed switchgear approved by the Distributor or*
- *A suitable metal metering cabinet or*
- *A vandal proof cage.*

### 2.3.7.9 Meter Mounting Heights

Provision for metering shall facilitate a practical mounting height for revenue meters in compliance with all applicable codes and regulations.

### 2.3.7.10 Environment

The following requirements apply to the areas allocated for revenue metering.

The customer to the satisfaction of the Distributor shall provide where there is the possibility of danger to workmen, or damage to equipment from moving machinery, dust, fumes, or moisture, protective arrangements.

A clear safe working space of not less than 1.2 m (48") in front of the installation from the floor to ceiling with a minimum ceiling height of 2.1 m (84") provided to insure the safety of the Distributor or other authorized employee(s) who may be required to work on the installation.

Where excessive vibration may affect or damage metering equipment, adequate shock-absorbing mounting shall be provided and installed by the customer.

### 2.3.7.11 Meter Sockets

The owner will supply and install a meter socket as specified by the Distributor. Meter sockets will be directly accessible to the Distributors' staff.

A listing of approved revenue metering sockets is available from the Distributor.

### 2.3.7.12 Cabinets

Where required by these Conditions of Service the Owner shall supply and install a meter cabinet to The Distributors' requirements.

Meter cabinets shall be installed indoors, except where special permission is granted by the Distributor to install the meter cabinet outside. In such cases, an approved weather proof, lockable, C.S.A. approved meter cabinet shall be provided by the Customer.

### 2.3.7.13 Metering Loops

Three-phase, four-wire services will require a loop for metering, within the meter cabinet, for all three phases.

Mineral insulated, solid, or hard drawn wire conductors are not acceptable as metering loops.

### 2.3.7.14 Metal Enclosed Switchgear

The following regulations apply to the installation of instrument transformers and metering equipment within metal enclosed switchgear.

The Distributor will provide the following revenue metering equipment as required:

- Colour coded secondary wiring
- Revenue meters

The Owner shall:

- Consult with The Distributor regarding the metering equipment to be provided which may include,
    - Potential transformers
    - Potential transformer fuse holders and fuses
    - Current transformers
    - Phone line for remote interrogation of meters
    - Duplicate Pulse Initiators
    - Provide complete shipping instructions for instrument transformers for those projects where these are to be provided by the Distributor for installation by the switchboard manufacturer.
    - Install instrument transformers, metering cabinet and conduit.
    - Each main bus bar to be drilled and tapped (10-32) or (10-24) on the line side of the removable current transformer link.
- Submit two copies of the manufacturer's switchboard drawings, for approval, dimensioned to show provision for and arrangement of The Distributors' metering equipment.

Meters shall be installed by the Distributor in a customer-owned metal cabinet of a size and type pre-approved by the Distributor, mounted at an approved location separate from the switchgear.

Tamper proof or sealable rigid conduit or any equally approved conduit of a size and type specified by the Distributor shall be installed between the CT compartment of the switchgear and the meter cabinet.

For conduit installations greater than 30 m (100'), in length or where several bends are necessary, larger conduits or other special provision may be required, at the discretion of the Distributor.

#### 2.3.7.15 Switchgear Connected to Wye Source

Where a Wye source neutral connection is to be used or grounded, the Owner shall provide a conductor sized to the requirements of the Ontario Electrical Safety Code from the instrument transformer compartment to the neutral connection.

#### 2.3.7.16 Four Quadrant Metering (Generation)

All Ontario Energy Board-licensed generators connected to the distribution system that sell energy and settle through the distributor's retail settlement process shall be required to install metering that meets the requirements of the Distribution System Code as approved by the Ontario Energy Board, and/or the Market Rules as approved by the Independent Electricity Market Operator. http://www.ieso.ca/

## 2.4 Tariffs and Charges

### 2.4.1 Service Connection

Charges for Service Connections are set out in the Distributors approved rates, (Miscellaneous Rates and Charges) and may be obtained by request from the Distributor. Notice of Rate revisions may be published in the local newspapers and or mailed out to all customers with the first billing issued at revised rates.

### 2.4.2 Energy Supply

The Distributor shall provide Customers connected to the Distribution System with access to electricity through Standard Supply Service as defined in the Retail Settlement Code published by the OEB or as mandated though Legislation or Regulations issued by the Ministry of Energy.

Disputes arising from charges relating to Standard Supply Service shall be directed to the Distributor.

Customers will be switched to their Retailer of choice only if the retailer has a Service Agreement with the Distributor. The Customer's authorized Retailer through the Electronic Business Transaction system (EBT) must make the Service Transfer Request (STR) in accordance with the rules established and amended from time to time by the Ontario Energy Board.

Disputes arising from charges relating to Retailer Service shall be directed to the Retailer.

The Distributor may, at its discretion, refuse to process a Service Transfer Request for a Customer to switch to a Retailer if that Customer owes money to the Distributor for Distribution Services and or Standard Supply Service.

### 2.4.2.1 Wheeling of Power

Customers considering delivery of electricity through the Distributors' Distribution System shall contact the Distributor for technical requirements and current applicable Rates.

## 2.4.3 Supply Deposits & Agreements

Whenever required by the Distributor, the Customer shall provide and maintain security in an amount that the Distributor has been mandated to collect, or deems necessary and reasonable. The Distributor shall require security amounts based on the existing security and deposit policies. The current deposit policy shall be provided to the Customer upon request.

Where a customer proposes the development of premises that requires the Distributor to place equipment orders for special projects, the customer is required to sign the necessary Supply Agreements and furnish a suitable deposit before such equipment is ordered by the Distributor.

## 2.4.4 Billing

The Distributor may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis. The option applicable to the customer shall be identified to the customer at the time of application for service.

Prorating of Service and Demand charges will be performed at the discretion of the Distributor.

### 2.4.4.1 Competitive Charges:

Are based on rates as determined by:

i. the Hourly Ontario Spot Market Price (HOEP); or
ii. the utilities Weighted Average Price (WAP) as determined by net system load; or
iii. the customers retailer contract rate; or
iv. the rates published by the OEB; or
v. Legislation or Regulations issued by the Ministry of Energy.

#### 2.4.4.2 Non-competitive Charges:

Are based on rates approved by the Ontario Energy Board, and fall outside the scope of this document. Approved rates as they relate to the transmission, distribution and other non-competitive elements may be attained through the utilities rate documents. These documents will be provided by the utility at the customer's request.

#### 2.4.4.3 Billable Engineering Units:

Customers will be billed on:

i. actual or estimated meter reading data; or
ii. derived consumption data (Streetlights, sentinel lights and other scattered loads); or
iii. a flat rate, depending on the type of load being billed.

#### 2.4.4.4 Use of Estimates:

In months where a bill is issued, but no reading is obtained, the Distributor estimates usage in order to determine billing quantities. The estimate is based on historical usage for the premise, or a pre-determined quantity if there is no historical usage information available.

### 2.4.5 Payments and Late Payment Charges

Bills are rendered for distribution services and electrical energy used by the Customer. Bills are payable in full by the due date.

Bills are due when rendered by the utility. A customer may pay the bill without the application of a late payment charge up to a due date, which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill. This due date shall be identified clearly on the customer's bill.

Where payment is made by mail, payment will be deemed to be made on the date post-marked. Where payment is made at a financial institution acceptable to the utility, payment will be deemed to be made when stamped/acknowledged by the financial institution or an equivalent transaction record is made.
A partial payment will be applied to any outstanding arrears before being applied to the current billing, unless special considerations have been made by the utility.

Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued or limited. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

The Distributor shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge may apply where the service has been disconnected due to non-payment.

The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

### 2.4.6 Unauthorized Energy Use

The Distributor shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, the Distributor shall notify, if appropriate, Measurement Canada, The Electrical Safety Authority, Police Officials, Retailers that service customers affected by an authorized energy use, or other entities.

The Distributor may recover from the parties responsible for the unauthorized energy use all costs incurred by the Distributor arising from unauthorized energy use, including an estimate of the energy used, inspection and repair costs.

A service disconnected due to unauthorized use of energy shall not be reconnected until such time as all arrears resulting from the unauthorized use has been resolved to the satisfaction of the Distributor.

Prior to reconnection, the Distributor shall require proper authorization from applicable authorities.

## 2.5 Customer Information

The Distributor reserves the right to request specific information from the customer in order to facilitate the normal operation of its business. Failure of a customer to supply such information may prevent the normal continuation of service.

The Retail Settlement Code as amended from time to time specifies the rights of customers and their retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information.

Under these requirements, the Distributor shall upon authorization by a customer make the following information available to the Customer or the Retailer that provides electricity to a customer connected to the Distributors' distribution system:

- The Distributors' account number for the customer,
- The Distributors' meter number for the meter or meters located at the customer's service address
- The customer's service address,
- The date of the most recent meter reading,
- The date of the previous meter reading,
- Multiplied kilowatt-hours recorded at the time of the most recent meter reading,
- Multiplied kilowatt-hours recorded at the time of the previous meter reading,
- Multiplied kW for the billing period (if demand metered),
- Multiplied kVA for the billing period (if available),
- Usage (kWh's) for each hour during the billing period for interval-metered customers

- An indicator of the read type (e.g., distributor read, consumer read, distributor estimate, etc.)
- Average distribution loss factor for the billing period

This information will be provided to the Customer / Retailer upon request twice per year at no charge. The Distributor may request a fee to recover costs for additional requests. A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

The Distributor acknowledges that no confidential information regarding its' customers shall be released to a third party without the expressed prior written consent of the customer unless the request is rightfully received from the third party requesting the information, or the Distributor is legally required to disclose such information under the terms and in accordance with the Freedom of Information and Protection of Privacy Act, R.S.O. 1990, c. F.31.
HOTLINK http://www.privcom.gc.ca/legislation/02_07_01_e.asp

# SECTION 3 CUSTOMER SPECIFIC

## 3.1 Residential

This section refers to the supply of electrical energy to Customers residing in residential dwelling units.

### 3.1.1 General

Energy is generally supplied as single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts.

There shall be only one Delivery Point to a dwelling.

In circumstances where two existing services are installed to a dwelling, and one service is to be upgraded, the upgraded service will replace both of the existing services.

All new single-family homes will be required to install their primary and secondary service wires to the specifications contained within the Distributors' technical specification document.

Whether the method of supply will be overhead or underground will be at the discretion of the distributor. The Distributor will adhere to any existing regulations subject to requirements of authorities.

Unless specifically documented otherwise to the Customer, where the distributor has taken ownership of such plant all services installed by the Distributor or by an approved contractor using approved materials, will be maintained by the Distributor.

### 3.1.2 Early Consultation

The Customer shall supply a completed Site Planning document and related information to the Distributor well in advance of installation commencement. (see appendix) The information shall be supplied in a manner requested by the Distributor at the time of the application.

### 3.1.3 Standard Connection Allowance

For the purposes of calculating customer connection fees, the Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service.

The basic connection for each customer shall include;

- **i.** supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
- **ii.** up to 30 meters of overhead conductor or an equivalent credit for underground services.

In the case of an upgrade to an existing service, where the existing service is below the basic connection, the credit up to the basic connection will apply.

Secondary services exceeding the basic 30 meter length may require specific design approved by the Distributor to ensure power quality.

### 3.1.4 Variable Connection Fees

Any requirements above the defined basic connection shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. The distributor may recover this amount from a customer through a connection charge or equivalent payment.

### 3.1.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

#### 3.1.5.1 Secondary Service Connections

The Point of Demarcation for residential services up to 400 amps is at the line side of the Meter Base for Underground services, and at the top of the stack for Overhead services, beyond which the customer bears full responsibility for installation and maintenance.

The Point of Demarcation for residential services over 400 amps is at the secondary side of the transformer.

For Secondary Services wholly owned and maintained by the Customer, the Demarcation Point is the secondary connection at the transformer or the service bus.

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

(a) conductor terminations are inside the Customer's building;
(b) conductor is installed beyond the service entrance;
(c) conductor is connected to a Primary Service; or
(d) conductor is a non-standard installation.

#### 3.1.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

### 3.1.6 Supply Voltage

*(a)* A Residential building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

### 3.1.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

### 3.1.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Local Distribution Company and:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

*For more details refer to section 2.3.7 in these Conditions of Service.*

### 3.1.9 Overhead Service

The Owner will provide service equipment to both the Distributors' and ESA requirements, and be of sufficient height to maintain proper minimum clearances. The Owner's main switch and the overhead service conductors will be of compatible capacity.

### 3.1.10 Underground Service

Underground secondary services will be installed at the Owners' expense, to the Distributor's specifications. The Owner's main switch and the underground service conductors will be of compatible capacity.

### 3.1.11 Street Townhouses and Condominiums:

***NOTE:*** Street Townhouses and Condominiums requiring centralized bulk metering will be covered under section 3.2 of these Conditions of Service. Also 3.1.11.2

#### 3.1.11.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system and services will be designed and installed.

The Owner will provide all of the civil works to accommodate the Distributor and will pay the complete cost of the electrical distribution system, design and services.

- The distribution system and services shall be underground unless otherwise approved.
- One service will be provided for each unit.
- The nominal service voltage will be 120/240 volts, 1 phase, 3 wire.
- The Distributor will approve the location of duct banks, service routings and meter bases.
- Distribution plant shall not be installed until grade is at +/- 150 mm of final grade unless otherwise approved by the Distributor.
- Street lighting will be to Municipal standards and installed at the Owner's expense.

#### 3.1.11.2 Metering:

The Owner will supply and install meter sockets specified by the Distributor.

Multiple or grouped meter bases will be accepted only when prior approval has been given by the Distributor both as to type and proposed location. A completed meter verification form shall be provided to the distributor prior to energization.

Meter sockets will be located on the exterior front wall of the units and will be directly accessible to the Distributor.

- Mounted on the front wall 1.7 metres above finished grade to the centre of the meter
- Installed ahead of (on the line side of) the main disconnect switch
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

Normally the service will not be energized until the outside finish in the area of the revenue meter has been completed. If exceptions are made to this, then the general contractor will be responsible for ensuring that the meter is suitably protected while work is being done on the exterior wall adjacent to the meter. The general contractor will be entirely responsible for all costs for materials and labour for repairing or replacing a damaged meter.

### 3.1.12 Seasonal and Remote Dwellings:

Due to the varied nature of Seasonal and Remote Dwellings some special arrangements may be required to service these locations. Arrangements will be made in such a manner to provide services such as restoring power, maintenance of equipment or new construction requests to water access or remote customers, without endangering personnel or the public.

#### 3.1.12.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system services will be provided.

In the event of a power interruption, the Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

### 3.1.12.2 Access:

- **Night crossings**

  The Distributors' transportation equipment will not be used to cross any water ½ hour before sunset and ½ hour after sunrise due to safety concerns. It will be at the discretion of the Distributor whether they will board customer owned transportation equipment in these circumstances.

- **Ice conditions**

  Recognizing seasonal ice hazards, the Distributor reserves the right to suspend water passage during freeze up and spring thaw, as well as any such time deemed unsafe by the Distributor.

- **Severe weather conditions**

  Recognizing that severe weather conditions may pose undue safety hazards, the Distributor reserves the right to postpone attempts to restore power until restoration can be performed in a safe manner.

## 3.1.13 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

*(Refer to section 2.1.4 for further inspection details)*

# 3.2 General Service (Below 50 kW)

## 3.2.1 General

This section refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section 3.1.8 that require centralized bulk metering.

General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

## 3.2.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

## 3.2.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Below 50 kW) shall be recovered through a variable connection Fee.

## 3.2.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment.

## 3.2.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

#### 3.2.5.1 Secondary Service Demarcations

A General Service Customer Demarcation Point is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Demarcation Point at the top of stack for overhead services or at the meter base for underground services.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

#### 3.2.5.2 Primary Service Demarcations

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

### 3.2.6 Supply Voltage

*(a)* A General Service building is supplied at one service voltage per land parcel.

*(b)* Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

*(c)* The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

### 3.2.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

### 3.2.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Distributor and unless otherwise specified during the early consultation process:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

*For more details refer to section 2.3.7 in these Conditions of Service.*

### 3.2.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

### 3.2.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

### 3.2.11 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.

- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

### 3.2.12 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

*(Refer to section 2.1.4 for further inspection details)*

# 3.3 General Service (Above 50 kW)

## 3.3.1 General

This section refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load greater than 50 kW.

## 3.3.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

## 3.3.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 50 kW) shall be recovered through a variable connection fee.

## 3.3.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment.

## 3.3.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

#### 3.3.5.1 Secondary Service Connections

A General Service Customer Demarcation Point for customers above 50 kW is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Delivery point at the top of stack for overhead services or at the meter base for underground services.

The location of the service entrance, routing of duct banks and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

#### 3.3.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

In some circumstances the owner may be required to construct a private pole line. Primary conductors will be terminated complete with cut-out(s) at the Demarcation Point by the Distributor at the owners' expense.

Where a private pole line is to be constructed by the Owner with an approved contractor, this shall be constructed to the ESA and the Distributors' requirements.

An electrical requirement in excess of 300 kVA may require a customer owned substation.

In some instances primary metering may be required.

### 3.3.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.
Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*

- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

Depending upon the location of the building Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

### 3.3.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

### 3.3.8 Metering:

Meter installations will be directly accessible to the Distributor. The owner will consult with the Distributor well in advance of installation commencement to allow the Distributor time for proper planning and ordering of equipment.

*For more details refer to section 2.3.7 in these Conditions of Service.*

### 3.3.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

### 3.3.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

### 3.3.11 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line. The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

### 3.3.12 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

### 3.3.13 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

### 3.3.14 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

*(Refer to section 2.1.4 for further inspection details)*

# 3.4 General Service (Above 500 kW)

## 3.4.1 General

This section refers to the supply of electrical energy to General Service Services requiring a connection at a connected load greater than 500 kW.

## 3.4.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Customer shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

The Distributor will:

- *Advise the customer of the suitability of the in-service date*
- *Arrange with the customer for a Service Contract*
- *Review the submitted drawings; return one set to the customer with comments and/or approval. If requested by the Distributor, the customer shall resubmit the drawings where the comments are extensive and require major changes*
- *Specify the required main fuse link or relay setting for co-ordination with the system. In case of multiple transformer stations, a complete co-ordination study shall be submitted by the customer for approval.*
- *Make the final connection to the source of supply*
- *Determine metering requirements*
- *Advise the Transmitter of the particulars of the customer owned substation*

## 3.4.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 500 kW) shall be recovered through a variable connection fee.

## 3.4.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment.

## 3.4.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Primary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

The Distributor reserves the right to direct the operations of any customer owned switchgear connected to the distribution system including those located beyond the point of demarcation.

### 3.4.5.1 Service Installation

In General, the Demarcation Point for a General Service Customer with a demand of over 500 kW is on the primary side of the transformer at the first available distributor owned point of isolation, or as otherwise set by the distributor. This delivery point might be located on an adjacent property from which the Distributor has an authorized easement. In all cases the final Demarcation Point will be the decision of the Distributor.

The location of the service entrance, routing of duct banks, metering facilities, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Distributor will install overhead supply lines and required cut-outs to the first point of support on private property. The location of this support must be approved by the Distributor and shall be within 30 metres of the Distributors' existing overhead plant. All costs for materials and labour shall be at the customers' expense.

The service pole or first point of support on private property shall be considered self-supported and shall be complete with suitable hardware for attaching the suspension insulators. The Customer shall be responsible for all costs associated with equipment, installation, and inspection.

Where the customer wishes an underground supply, the customer shall supply and install the underground cables and termination pole complete with primary switch, fuses and lightning arresters. The installation shall be subject to ESA inspection and specific approval of the Distributor. The customer owned termination pole must comply with items as prescribed by the Distributor.

At the Distributors' discretion, the customers' underground service may be connected to a termination pole owned by the distributor. In such cases, the Distributor shall supply and install at the customers expense, any required primary switch, fuses, and lightning arrestors.

When requested, the customer shall make provision in the substation switchgear or transformer, for loop feeding the Distributors' supply cables via load interrupter switches.

In some instances, primary metering may be required.

### 3.4.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.

General Service connections above 500 kW may require a customer owned substation.

Depending upon the location of the building, Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

### 3.4.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

Where the high voltage interrupting switches are located inside a building, a direct outside entrance to the switchgear room must be provided.

The outside door providing direct access to the transformer or switchgear room must be compliant with all applicable codes and requirements, and of a quality to be approved by the Distributor.

### 3.4.8 Metering:

The owner will supply and install provisions for metering following the details outlined both in these Conditions of Service, and technical documents provided to the customer during the consultation process.

*For more details refer to section 2.3.7 in these Conditions of Service.*

### 3.4.9 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line.

The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

### 3.4.10 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

### 3.4.11 Drawings

Apart from the regular drawings submission to the ESA, the customer shall provide two sets of the following drawings and details to the Distributor.

**Survey Plan:** prepared by an Ontario Land Surveyor, showing the property limits, registered plan and existing buildings or easements if any.

**Site Plan:** showing the location of the station relative to buildings, structures and set backs from adjacent property lines. The site plan shall also include the exact location of existing Distributor owned plant and the proposed route of the incoming supply.

**Schematic or Single-Line Diagram:** indicating the major components of the station and their electrical ratings. Where additions or alterations are being made, these shall be clearly distinguished from unchanged portions of the installation.

**Electrical Details:** sufficient details shall be provided in order to enable fast processing and approval of the station drawings. The following represents the minimum data required.

- Plan, elevation and profile views of the station structure, switchgear, transformer(s), termination poles, duct banks, etc.

- Dimensions to clearly indicate the electrical, physical and working clearances as well as relative location of all equipment.

- Pole or structure for dead-ending the Distributor lines shall be complete with suitable hardware for attaching the suspension insulators that will be supplied and installed by the Distributor.

- Fencing arrangement.

- Grounding details. (In the case of indoor metal enclosed switchgear, when the Distributor has operating control of any interrupter switches, the assembly shall further incorporate ground rod parking stands and stirrups per the Distributors Specifications.)

- Details of vault construction (if indoor substation).

- Manufacturer's drawings of metal-enclosed switchgear showing internal arrangement of equipment, clearances, means of access, interlocking and provision for personal safety. Where the Distributors' cables terminate in the switchgear, the customer shall provide suitable terminators for the size and type of cable as specified by the Distributor.

- When the customer's switchgear is used for loop feeding the Distributors' supply cables, provision for padlocking the in and out load interrupter switches and the associated bay doors shall be required.

- Indoor and outdoor switchgear assemblies shall contain a space heater and protective guard in each bay, along with thermostat(s), sized to promote air circulation and to prevent condensation from forming.

- At the discretion of the distributor, the customer shall make provisions for a future system neutral connection to the customer's dead-ending pole or structures installed by the Distributor. Where the Distributors' neutral terminates in the customer's switchgear, the customer shall provide a suitable connector on the ground bus for the size and type of cable specified by the Distributor.

### 3.4.12 Pre-Service Inspection

The customer shall present to the Distributor a final "Pre-service Inspection Report" a minimum of 3 working days before connection can be affected.

The "Pre-Service Inspection Report" shall outline and document the results of all tests and inspection carried out on the substation components. The information contained in the report must be to the satisfaction of the Distributor before connection can be authorized.

The "Pre-Service Inspection Report" shall be required in case of:

- ***New Substation***: *in which case all components of the substation shall be reported upon.*
- ***Modified substation***: *in which case all components of the substation shall be reported upon.*

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

*(Refer to section 2.1.4 for further inspection details)*

# 3.5 Embedded Generation

## 3.5.1 General

An Embedded Generator shall provide the Distributor with proof of compliance of IESO or OEB registration Requirements, appropriate Licences and completion of an application form provided by the distributor.

The Distributor shall collect costs reasonably incurred with making an offer to connect a generator from the entity requesting the connection. Costs reasonably incurred include costs associated with:

- Preliminary review for connection requirements.
- Detailed study to determine connection requirements.
- Final proposal to the generator.

A Generator that is or wishes to become connected to the distributors' distribution system shall enter into a Connection Agreement with the Distributor.

If damage or increased operating costs result from a connection with a Generator, the Generator shall reimburse the Distributor for these costs.

The Embedded Generator is responsible for providing suitable embedded generator equipment to protect his plant and equipment for any conditions on the distributor and interconnected transmission systems such as reclosing, faults and voltage unbalance.

To incorporate the connection of embedded generator to the distribution system, the line/feeder protection including settings and breaker reclosing circuits must be reviewed and modified if necessary by the distributor or transmission authority. This process may be complex and may require significant time.

The embedded generator must submit a proposed single line diagram and protection scheme for review to the distributor contact as identified by the distributor.

Based on the transformer connection proposed by the embedded generator additional significant protection cost may be incurred (e.g. delta HV transformer winding may require 3 phase HV breaker / reclosure device). The embedded generator shall not order the protection equipment and transformer until the station line diagram is reviewed and accepted by the distributor.

The purpose of the distributor review is to establish that the embedded generator electrical interface design meets the distributor requirements.

The protection schemes shall incorporate adequate facilities for testing/maintenance.

Negative phase sequence protection shall be installed where required, to detect abnormal system condition as well as to protect the generator.

The embedded generator may be required to install utility grade relays for those protections that could affect the distributor or transmission authority system.

The embedded generator may be required to submit a Ground Potential Rise study for review by the distributor, if telecommunications circuits are specified for remote transfer trip protection.

## 3.5.2 Protection

The embedded generator should provide protection systems to cover the following conditions:

### 3.5.2.1 Internal Faults:

The Generator should provide adequate protections to detect and isolate generator and station faults.

### 3.5.2.2 External Faults:

The protection system should be designed to provide full feeder coverage complete with a reliable DC supply. In some cases redundancy in protection schemes may be required.

Normally the following fault detection devices are required for synchronous generator(s) installation(s).

### 3.5.2.3 Ground Faults:

When the HV winding of the Generator station transformer is wye connected with the neutral solidly grounded, then ground over-current protection in the neutral is required to detect ground faults.

If the Embedded generator station transformer HV winding connected to the Distributor system is ungrounded wye or delta, then ground under-voltage and ground over-voltage protections shall be required to detect ground faults.

Depending on the size, type of generator and point of connection, a distributor may require the relaying system to be duplicated, complete with separate auxiliary trip relays and separately fused DC supplies to ensure reliable protection operation and successful isolation of the embedded generator.

### 3.5.2.4 Phase Faults:

To detect phase faults, at least one of the following protections should be installed with acceptable redundancy where required depending on fault values:

- Distance
- Phase directional over-current

- Voltage-restrained over-current
- Over-current
- Under-voltage

#### 3.5.2.5 Islanding/Abnormal Conditions:

Voltage and frequency protections are required to separate the embedded generator from the distribution system for an islanded condition and thus maintain the quality of supply to distribution system customers. This also will enable speedy restoration of the distribution system.

Typically, the protections required to detect islanding/abnormal conditions are:

- Over-voltage
- Under-voltage
- Over-frequency
- Under-frequency
- Voltage-balance

The above protections should be timed to allow them to ride through minor disturbances.

### 3.5.3 Induction Generator

Due to the operating characteristics of the induction generator the protection package required is normally less complex than the synchronous generator. An embedded generator should design the protection scheme to trip for the same conditions as stated for synchronous generators. An induction generator is an asynchronous machine that requires an external source such as a healthy distribution system to produce normal 60 Hz power. Alternatively, if there is an outage in the distribution system then there is unlikely to be 60 Hz output from the induction generator. In certain instances, an induction generator may continue to generate electric power after the source is removed. This phenomenon, known as self-excitation, can occur whenever there is sufficient capacitance in parallel with the induction generator to provide the necessary excitation and when the connected load has certain resistive characteristics.

### 3.5.4 DC Remote Tripping / Transfer Tripping

Remote or transfer tripping may be required between the Generator and the feeder circuit breaker if the Generator is connected at a critical location in the distribution system. This feature will provide for isolation of the embedded generator when certain faults or system disturbances are detected at the feeder circuit breaker location.

Additional Protection Features, such as Remote Trip and Generator end open signal, may be required in some applications.

### 3.5.5 Maintenance

An Embedded Generator shall have a regular scheduled maintenance plan to assure the Distributor that all connection devices and protection & control systems are maintained in good working order. These provisions shall be included in the Connection Agreement. A complete copy of the inspection report shall be delivered to the Distributor within 30 days.

In developing a maintenance plan, the Generator should consider the following requirements:

- Qualified personnel should carry out all inspections and repairs.
- Periodic tests should be performed on protection systems to verify that the system operates as designed. Testing intervals for protection systems should not exceed four (4) years for microprocessor-based systems and two (2) years for electro-mechanical based systems.
- Isolating devices at the point of connection should be operated at least once per year.
- The Generator facility should be inspected visually at least once per year to note obvious maintenance problems such as broken insulators or other damaged equipment.
- Any deficiencies identified during inspections shall be noted and repairs scheduled as soon as possible, with timing dependent on the severity of the problem, due diligence concerns (of both the Distributor and the Generator) and financial and material requirements. The Distributor shall be notified of any deficiencies involving critical protective equipment.
- The Distributor shall be provided with copies of all relevant inspection and repair reports that may affect the protection and performance of the Distributors' systems. The Distributor has the right to witness any relevant test being performed by the generator.

## 3.6 Embedded Market Participant

An Embedded Market Participant shall provide the Distributor with proof of compliance of IESO registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Market Participant must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

## 3.7 Embedded Distributor

An Embedded Distributor shall provide the Distributor with proof of compliance of IESO and OEB registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Distributor must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

# 3.8 Miscellaneous Small Services

This section pertains to the supply of electrical energy for Street Lighting, Traffic Signals, Bus Shelters, Telephone Booths, Cable T.V. Amplifiers, Decorative Street Lighting, Bill Boards, and other similar small loads.

## 3.8.1 General

At the discretion of the Distributor, the service voltage will be:

120/240 volts, single phase three wire or
120 volts, single phase two wire or
347/600V three phase, four wire

The method and location of the supply will vary based on the conditions present on the Distributors' plant, and will be established for each application through consultation with the Distributor.

Where specified by the Distributor during the Early Consultation process, the Customer will provide underground ducts to the Distributor's specifications.

The Owner shall be responsible for all costs associated with the supply and installation of service conductors

The Distributor at the Owners' expense will install required transformation.

Where at the discretion of the Distributor, a meter is not installed, energy consumption will based on the connected wattage and the calculated hours of use.

Prior to energization of a service the Distributor will require notification from the ESA that the installation has been inspected and approved for connection.

## 3.8.2 Early Consultation

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc. Information required includes:

- Required in-service date
- Requested Service Entrance Capacity and voltage rating of the service entrance equipment
- Locations of other services, gas, telephone, water and cable TV
- Survey plan and site plan indicating the proposed location of the service equipment with respect to public rights-of way and lot lines.

### 3.8.3 Street Lighting

Town street-lighting that is designed, installed, and maintained by the Distributor shall be fully funded by the Municipality to ensure adherence to the Affiliate Relationship Code and the Distributors' Licence.

### 3.8.4 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority.

### 3.8.5 Bus Shelters

Bus Shelter Lighting is owned and maintained by the Customer.

### 3.8.6 Decorative Street Lighting

Such installations could be lighting for festive occasions or "neighbourhood character" street-scaping and will be maintained by the Customer.

# SECTION 4 GLOSSARY OF TERMS

**“Conditions of Service”** means the document developed by the distributor in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for the distributor;

**“Condominiums”** are located on common land, which is the property of a condominium corporation or is owned by the Owner of all of the units (rental property). These units usually front onto internal roads that are also privately owned;

**“Condominium Development”** is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit and have direct outside access at ground level;

**“Connection”** means the process of installing and activating connection assets in order to distribute electricity;

**“Connection Agreement”** means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

**“Connection assets”** means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributors’ main distribution system and the ownership Demarcation Point with that customer;

**“Consumer”** means a person who uses, for the person’s own consumption, electricity that the person did not generate;

**“Customer”** means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions;

**“Demand meter”** means a meter that measures a consumers’ peak usage during a specified period of time;

**“Demarcation Point”** means the point at which the obligation of the Distributor ends and those of the Customer begin for the purposes of maintenance and repair of the distribution service;

**“Disconnection”** means a deactivation of connection assets, which results in cessation of distribution services to a consumer;

**“Distribute”**, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

**“Distribution losses”** means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows;

**"Distribution loss factor"** means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.;

**"Distribution services"** means services related to the distribution of electricity and the services the Board has required distributors to carry out.

**"Distribution system / plant"** means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect a customer to the main distribution system;

**"Distribution System Code,"** means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a 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;

**"Distributor"** means a person who owns or operates a distribution system;

***"Electricity Act"*** means the *Electricity Act, 199*8, S.O. 1998, c.15, Schedule A;

**"Energy Competition Act"** means the *Energy Competition Act, 199*8, S.O. 1998, c. 15;

**"Electrical Safety Authority"** or **"ESA"** means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

**"Embedded Distributor"** means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

**"Embedded Generation Facility"** means a generator whose generation facility is not directly connected to the IESO-controlled grid but instead is connected to a distribution system;

**"Embedded Load Displacement Generation Facility"** means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale;

**"Embedded Market Participant"** means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

**"Emergency"** means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity, or that could adversely affect the reliability of the electricity system;

**"Emergency backup generation facility"** means a generation facility that has a transfer switch that isolates it from a distribution system;

**"Enhancement"** means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth;

**"Expansion"** means an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system;

**"Four-quadrant Interval Meter"** means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

**"Generate"**, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

**"Generation Facility"** means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

**"Generator"** means a person who owns or operates a generation facility;

**"Geographic Distributor"** with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

**"Good Utility Practice"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

**"Holiday"** means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

**"IESO"** means the Independent Electricity System Operator established under the Electricity Act;

**"IESO-Controlled Grid"** means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation;

**"Interval meter"** means a meter that measures and records electricity use on an hourly or sub-hourly basis;

**"Large Embedded Generation Facility"** means an embedded generation facility with a name-plate rated capacity of 10MW or more;

**"Lies Along"** means a property can be connected to the distributor distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of the distributor who owns or operates the distribution line.

**"Load Transfer"** means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

**"Load Transfer Customer"** means a customer that is provided distribution services through a load transfer;

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

**"Measurement Canada"** means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Ac*t, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131);

**"Medium Sized Embedded Generation Facility"** means an embedded generation facility with a name-plate rated capacity of less than 10 MW and:

a) more than 500 kW in the case of a facility connected to a less than 15kV line;
b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

**"Meter Service Provider"** means any entity that performs metering services on behalf of a distributor, generator, or registered market participant;

**"Meter Installation"** means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

**"Metering Services"** means installation, testing, reading and maintenance of meters;

**"Micro Embedded Load Displacement Generation Facility"** means an embedded load displacement generation facility with a name-plate rated capacity of 10 kW or less;

**"Ontario Electrical Safety Code"** means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

**"Ontario Energy Board Act"** means the *Ontario Energy Board Act, 199*8, S.O. 1998, c.15, Schedule B;

**"Operational Demarcation Point"** means the physical location at which a distributors' responsibility for operational control of distribution equipment including connection assets ends at the customer;

**"Ownership Demarcation Point"** means the physical location at which a distributors' ownership of distribution equipment including connection assets ends at the customer;

**"Physical Distributor"** with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly;

**"Point of Supply"** with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into a distribution system;

**"Rate"** means any rate, charge or other consideration, and includes a penalty for late payment;

**"Rate Handbook"** means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

**"Regulations"** means the regulations made under the *Act or the Electricity Act*;

**"Retail"**, with respect to electricity means,

a) To sell or offer to sell electricity to a consumer
b) To act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) To act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity.

**"Retail Settlement Code"** means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors' obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

**"Retailer"** means a person who retails electricity;

**"Service Area"** with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity;

**"Small Embedded Generation Facility"** means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

**"Total losses"** means the sum of distribution losses and unaccounted for energy;

**"Townhouses"** are usually a free hold property, the land is owned by the individual Owners of each unit, fronting onto a municipal street;

**"Townhouse Development"** is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit, and have direct outside access at ground level;

**"Transmission System"** means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

**“Transmission System Code”** means the Board approved code that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

**“Transmit”** with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

**“Transmitter”** means a person who owns or operates a transmission system;

**“Unaccounted-for Energy”** means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and un-metered loads, energy theft and non-attributable billing errors;

**“Un-metered loads”** means electricity consumption that is not metered and is billed based on estimated usage;

**“Validating, Estimating and Editing (VEE)”** means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;

**“Wholesale Market Participant”** means a person that sells or purchases electricity or ancillary services through the IESO-administered markets;

# SECTION 5 APPENDICIES

**Electrical Planning Requirements Document**

**Electric Service Meter Base/ Service Verification Form**

**Contact Information**

**Deposit Policy**

**Disconnection Policy**

**Collection Policy**

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## Electrical Planning Requirements

It is essential that the following information be provided to:

a) enable an assessment to be made on the impact of the proposed project on the Electrical Distribution System.

b) enable the Distributor to prepare pertinent information for the developer.

Please supply answers to the following questions as soon as possible as electrical planning cannot proceed until the Distributor has reviewed this information.

Preliminary electrical site plan drawings are to be submitted together with this form. Electrical drawings are to be submitted to the Distributor for approval prior to any related job tenders or the commencement of any electrical construction. The drawings shall be drawn to a scale usable by the Distributor, shall show local pole locations, proposed transformer location, proposed electrical room/metering location and show how access to the metering would be gained (i.e.: the path to the metering).

Electrical site plan drawings are to be submitted to the Distributor on one (1) Paper copy and in an electronic format as approved by the Distributor.

**Project Location:** **(Municipal Address)** ______________________________

**Name of Project:** ______________________________

**Name of Applicant:** ______________________________

**Address:** ______________________________

**Contact Name:** ______________________________

**Address:** ______________________________

**E-Mail:** ______________________________

**Telephone:** ( ) ______________________ **Fax:** ( ) ______________

**Service Classification (☒ as many as apply):**

☐ Residential

☐ General Service < 50kW

☐ General Service > 50kW

☐ General Service >500kW

☐ Unmetered os Miscellaneous Load

☐ Temporary Service

**What service voltage is required (☒ one only):**

☐ 120/240 Volt Single Phase

☐ 120/208 Volt Three Phase

☐ 347/600 Volt Three Phase

☐ Primary

**Required In-Service Date:**

Month / Day / Year ______/_______/_________

**Service Entrance Switchboard with Utility CT and PT Compartment** ☐ Yes ☐ No

**Capacity of Main Service (in Amperes):**

Maximum rated capacity: ____________

**Estimated Connected Load - Demand in kW:**

Maximum initial Demand: ___________ kW

Maximum Future Demand: ___________ kW

**Metering Type (☒ one only):**

☐ Single Meter

☐ Multiple Meters

Quantity of Meter installations

100A or less: _________

101A to 200A: _________

more than 200A: _________

**Comments:** **Please use the back of this form for comments**

**Signed:** ______________________________ **Date:** ______________________

(Representative of Applicant)

**Name:** ______________________________ **Title:** ______________________

______________________________

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# Electric Service Meter Base/ Billing Address Verification Form

This form **must** be completed by the Owner and/or their Electrical Contractor if applicable prior to service connection.

**Electric Service Municipal Address:** ______________________

**Name of Owner:** ______________________

**Telephone:** (   ) ______________ **Fax:** (   ) ______________

**Name of Contractor:** ______________________

**Telephone:** (   ) ______________ **Fax:** (   ) ______________

**In area (A) provided below, carefully sketch the Front View layout of the Electric Meter Base(s).**
**Match the corresponding (B) BILLING ADDRESS for each meter base(s) shown in (A).**

| (A) FRONT VIEW OF ELECTRIC METER BASE(S) | (B) BILLING ADDRESS |
|---|---|
| | 1) |
| | |
| | 2) |
| | |
| | 3) |
| | |
| | 4) |
| | |
| | 5) |
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| | |
| | 8) |
| | |
| | 9) |
| | |
| | 10) |
| | |
| | 11) |
| | |

**I/We the undersigned, acknowledge the information provided above has been verified and is accurate.**

**Signature of Owner:** ______________________ **Date:** ______________

**Signature of Contractor:** ______________________ **Date:** ______________

**Hydro 2000 Inc.** a member of

Cornerstone Hydro Electric Concepts Association Inc.

## Contact Information

| Local Distribution Company | Contact Phone Number |
| --- | --- |
| **Centre Wellington Hydro Ltd.**<br>Licence # ED-2002-0498 | Phone: (519) 843-2900 |
| **COLLUS Power Corp.**<br>Licence # ED-2002-0518 | Phone: (705) 445-1800 |
| **Grand Valley Energy Inc.**<br>Licence # ED-2002-0512 | Phone: (519) 928-3112 |
| **Hydro 2000**<br>Licence # ED-2002-0542 | Phone: (613) 679-4093 |
| **Innisfil Hydro Distribution Systems Ltd.**<br>Licence # ED-2002-0520 | Phone: (705) 431-6870 |
| **Lakefront Utilities Inc.**<br>Licence # ED-2002-0545 | Phone: (905) 372-2193 |
| **Lakeland Power Distribution Ltd.**<br>Licence # ED-2002-0540 | Phone: (705) 789-5442 |
| **Midland Power Utility Corporation**<br>Licence # ED-2002-0541 | Phone: (705) 526-9361 |
| **Orangeville Hydro Ltd.**<br>Licence # ED-2002-0500 | Phone: (519) 942-8000 |
| **Orillia Power**<br>Licence # ED-2002-0530 | Phone: (705) 326-2495 |
| **Parry Sound Power Corporation**<br>Licence # ED-2003-0006 | Phone: (705) 746-5866 |
| **Rideau St. Lawrence Distribution Inc.**<br>Licence # ED-2003-0003 | Phone: (613) 925-3851 |
| **Wasaga Distribution Inc.**<br>Licence # ED-2002-0544 | Phone: (705) 429-2517 |
| **Wellington North Power Inc.**<br>Licence # ED-2002-0511 | Phone: (519) 323-1710 |
| **Westario Power Inc.**<br>Licence # ED-2002-0515 | Phone: (519) 396-3471<br>Toll Free: 1-866-978-2746 |
| **West Coast Huron Energy Inc.**<br>Licence # ED-2002-0510 | Phone: (519) 524-7371 |
| **Woodstock Hydro Services Inc.**<br>Licence # ED-2003-0011 | Phone: (519) 537-3488 |

*Note: Licence Numbers published by OEB as of May 1, 2003*

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| **Policy 6.0**<br>**Security Deposits** | **Version 3.0**<br>*Created: June, 2002*<br>*Latest Revision: June 21, 2004* |
|---|---|

## 6.0.1 PURPOSE:

This policy describes the terms and conditions distributors will use for collection, maintaining and returning customer security deposits while complying with the applicable legislation and codes.

In accordance with the Distribution System Code and Retail Settlement Code it must include:

- a list of all potential types/forms of security accepted;
- a detailed description of how the security is calculated;
- limits on the amount of security required;
- the planned frequency, process and timing of updating security;
- a description of how interest payable to customers is determined;
- criteria customer must meet to have security deposit waived and/or returned;

  and
- methods of enforcements where a security deposit is not paid.

## 6.0.2 POLICY STATEMENT:

A distributor may use any risk mitigation options available to manage customer non-payment risk.  A distributor shall not discriminate among customers with similar risk profiles or risk related factors except where expressly permitted under the Distribution System Code.

A distributor will comply with the deposit requirements as defined in the Distribution System and Retail Settlement Codes but may waive these requirements in favour of a customer or potential customer.

## 6.0.3 FORM OF SECURITY DEPOSIT:

***Residential***

The form of payment of a security deposit for a residential customer shall be cash or cheque at the discretion of the customer or such other form as is acceptable to the distributor.

***General Service***

The security deposit will be in the form of cash, cheque or an automatically renewing, irrevocable letter of credit from a bank for non residential customers.

The distributor may also accept other forms of security.

The distributor shall permit customer to pay security deposit in 4 equal monthly instalments, the first instalment being due on the implementation of an implied contract or the signing of service agreement. The customer may pay the security deposit over a shorter period of time.

The reasons for requiring the security deposit must be disclosed to the customer.

### 6.0.4 METHOD OF CALCULATION AND LIMIT OF SECURITY DEPOSIT:

The maximum amount of the security deposit that a customer is required to pay is calculated using:

- the billing cycle factor times the estimated bill based on the customer's average monthly load with the distributor in the most recent 12 consecutive months within the last two years.
- Where relevant usage information is not available for the customer for 12 consecutive months within the past two years or the billing system is not capable of making the calculation, the customer's average monthly load shall be based on a reasonable estimate made by the distributor.

Where a customer has a payment history which discloses more than one disconnection notice in a relevant 12 month period, the distributor may use the customer's highest actual or estimated monthly load for the most recent 12 consecutive months within the past 2 years for the purposes of calculating the maximum amount of the security deposit.

For a low-volume consumer or designated consumer the price estimate used in calculating competitive electricity costs shall be the same as the price used by the IMO for the purpose of determining maximum net exposures and prudential support obligations for distributors.

If a non-residential customer with a >50kW demand rate can provide a credit rating from a recognized credit rating agency, the maximum amount of the security deposit required by the distributor shall be reduced in accordance with the following table:

**Credit Rating**
(Using Standard and Poor's Rating Terminology)
**Allowable Reduction in Security Deposit**

AAA- and above or equivalent 100%
AA-, AA, AA+ or equivalent 95%
A-, From A, A+ to below AA or equivalent 85%
BBB-, From BBB, BBB+ to below A or equivalent 75%
Below BBB- or equivalent 0%

### 6.0.5 PLANNED FREQUENCY, PROCESS AND TIMING OF UPDATING SECURITY DEPOSITS:

The distributor shall review every customer's security deposit at least once every calendar year to determine whether the entire amount of the security deposit is to be returned to the customer or adjusted based on a re-calculation of the maximum amount of the security deposit.

When the distributor determines in conducting a review that the maximum amount of the security deposit is to be adjusted upward, the distributor may require the customer to pay this additional amount at the same time the customer's next regular bill comes due.

A customer may demand in writing, no earlier than 12 months after payment of a security deposit or the making of a prior demand for a review, that the distributor undertake a review to determine whether the amount of the security deposit is to be returned to the customer or adjusted based on a re-calculation of the maximum amount of the security deposit. If some or all of the security deposit is to be returned to the customer, the distributor shall promptly return this amount.

Any security deposit received from the customer upon closure of the customer account, shall be applied to the final bill prior to change in service and can be used to off-set other amounts owing by the customer to the distributor. The balance shall be returned within six weeks of closure of the account.

### 6.0.6 INTEREST PAYABLE:

The interest shall accrue monthly on security deposits made by cash or cheque commencing on receipt of the total deposit. The interest shall be at the Prime Business Rate as published on the Bank of Canada website less 2 percent, updated quarterly. The interest accrued shall be paid at least once every 12 months or on return or application of the security deposit or closure of the account, whichever comes first, and may be credited to the account.

## 6.0.7 CRITERIA REQUIRED FOR WAIVERED AND/OR RETURN OF SECURITY DEPOSIT:

The distributor reserves the right to collect a security deposit from a customer that is not billed by a competitive retailer under retailer-consolidated billing unless the customer has a good payment history of:

- 1 year in the case of a residential customer,
- 5 years in the case of a non-residential customer in < 50 kW demand rate class, or
- 7 years in the case of a non-residential customer in ay other rate class.

The time period that makes up the good payment history must be the most recent period of time and some of the time period must occur in the previous 24 months.

A customer is deemed to have a good payment history, unless, during the relevant time period the customer has received:

- more than one disconnection notice from the distributor, or
- more than one cheque given to the distributor by the customer has been returned for insufficient funds, or
- more than one pre-authorized payment to the distributor has been returned for insufficient funds, or
- a disconnection/collection trip has occurred**.**

The distributor shall not require a security deposit if the customer provides the following prior to the implementation of service:

- the customer provides a letter from another distributor or gas distributor in Canada confirming a good payment history for the most recent relevant time period, some of this time period must have incurred within the last 24 months,
- a customer, other than a customer in a >5,000 kW demand rate class, that provides a satisfactory credit check made at the customer’s expense,
- If a non-residential customer with a >50kW demand rate can provide a credit rating from a recognized credit rating agency, the maximum amount of the security deposit required by the distributor shall be reduced in accordance with the following table:

**Credit Rating**
(Using Standard and Poor's Rating Terminology)
**Allowable Reduction in Security Deposit**

AAA- and above or equivalent 100%
AA-, AA, AA+ or equivalent 95%
A-, From A, A+ to below AA or equivalent 85%
BBB-, From BBB, BBB+ to below A or equivalent 75%
Below BBB- or equivalent 0%

However, when the distributor determines in conducting a review that the maximum amount of the security deposit is to be adjusted upward, the distributor may require the customer to pay this additional amount at the same time the customer's next regular bill comes due.

In the case of a customer in a >5,000kW demand rate class, where the customer is now in a position that it would be exempt from paying a security deposit, however, had previously paid a security deposit to the distributor, the distributor is only required to return 50% of the security deposit.

**6.0.8 METHOD OF ENFORCEMENT WHERE SECURITY DEPOSIT IS NOT PAID:**

Failure to pay the security deposit as required will result in the immediate implementation of the distributor's collection policy process which may lead to the discontinuation of electrical service.

**6.0.9 DEFINITIONS:**

**"The Billing Cycle Factor"** is 2.5 if the customer is billed monthly, 1.75 if the customer is billed bi-monthly and 1.5 if the customer is billed quarterly.

**"Disconnection/Collection Trip"** is a visit to a customer's premises by an employee or agent of the distributor to demand payment of an outstanding amount or to shut off or limit distribution of electricity of the customer failing payment.

**6.0.10 RESPONSIBILITIES:**

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

**6.0.11 REFERENCES:**

*The Electricity Act, 1998* – Province of Ontario, Ministry of Energy, Science and Technology

*Market Rules* – The Independent Electricity Market Operator

*Distribution System Code* – The Ontario Energy Board

*Retail Settlement Code* – The Ontario Energy Board

*Electricity Distribution Rates Handbook* – The Ontario Energy Board

| Policy 8.0<br>**DISCONNECTION/RECONNECTION OVERVIEW** | **Version 3.0**<br>*Created: September, 2002*<br>*Latest Revision: June 21, 2004* |
|---|---|

## 8.0.1 PURPOSE:

The detailed policies in this set are intended to establish and document a process that will provide guidance to the LDC's management and staff to help them make operational decisions when disconnecting and/or reconnecting the electrical service of a consumer.

## 8.0.2 POLICY STATEMENT:

The LDC will ensure that it has developed a physical and business process for disconnection ensuring safety and reliability as a primary requirement. The LDC will not be held liable for any damages or loss as the result of disconnection or limiting of service.

The LDC shall follow the regulation and direction set out in the Distribution Rate Handbook Chapter 9 when implementing the disconnection and/or reconnection process.

- A disconnection notice will be issued in writing not less than seven days after the date specified on the bill as the due date. Notice must be given by hand delivery or by registered mail. Both the customer and tenants of the customer will receive seven days' notice before cut-off.
- Prior to the disconnection of the electricity service, a representative of the utility will make reasonable efforts to establish direct contact with the customer. The utility should also where possible, notify the occupants of each separately occupied unit in the premises. The electricity service will not be disconnected by reason of the non-payment of bills until seven days after a disconnection notice has been given to the customer and as set out in Chapter 9 of the Distribution Rate Handbook.
- Where the electricity service has been disconnected on order to collect the account and then reconnected, a reconnection of service charge may be applied to the customers account.

The LDC reserves the right to physically disconnect or limit the amount of electricity that a customer can consume.

8.1.1 Disconnection/Reconnection

8.1.2 Seasonal Connections

8.1.3 Disconnection/Reconnection by Request

8.1.4 Safety and Reliability

8.5 Unauthorized use of Electricity

## 8.0.3 DEFINITIONS:

**Current Limiting Device** is a device that will limit the electrical current available to the customer.

**Customer and Consumer** will be understood herein as one and the same.

**Disconnection** is when the LDC discontinues the delivery of electricity to a property and/or premise.

**Reconnection** is when a property or premise has electrical service energized or re-established by the LDC.

**Security Deposit** is an amount collected by the LDC and is held by the distributor to ensure that all monies owed to the Corporation are collected at the time of the final billing. Interest payments will be applied at least annually on all cash deposits.

## 8.0.4 RESPONSIBILTIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

## 8.0.5 REFERENCES:

*The Electricity Act, 1998* – Province of Ontario, Ministry of Energy, Science and Technology

*Electricity Distribution Rate Handbook* – The Ontario Energy Board

*Retail Settlement Code* – The Ontario Energy Board

*Distribution System Code* – The Ontario Energy Board

*Electricity Gas and Inspection Act* – Government of Canada

*Condition of Service* – The Distributor

| **Policy 8.1** | **Version 3.0** |
|---|---|
| **DISCONNECTION/RECONNECTION** | *Created: September, 2002*<br>*Latest Revision: June 21, 2004* |

## 8.1.1 PURPOSE:

This policy confirms that the LDC has established a process for the disconnection and/or reconnection of a property and/or premise, and the specific timing and means of notification consistent with the Electricity Act, 1998.

The detailed policies in this set are intended to establish and document a process that will provide guidance to the LDC's management and staff, that will help them make operational decisions to disconnect and/or reconnect the electrical service of a consumer.

## 8.1.2. POLICY STATEMENT:

The LDC shall follow the regulation and direction set out in the Distribution Rate Handbook Chapter 9 when implementing disconnect or reconnection process.

- A disconnection notice will be issued in writing not less than seven days after the date specified on the bill as the due date. Notice must be given by hand delivery or by registered mail. Both the customer and tenants of the customer will receive seven days' notice before disconnection.
- Prior to the disconnection of the electricity service, a representative of the utility will make reasonable efforts to establish direct contact with the customer. The utility should also where possible, notify the occupants of each separately occupied unit in the premises. The electricity service will not be disconnected by reason of the non-payment of bills until seven days after a disconnection notice has been given to the customer and as set out in Chapter 9 of the Distribution Rate Handbook.
- Where the electricity service has been disconnected on order to collect the account and then reconnected, a reconnection of service charge may be applied to the customers account.

The LDC will ensure that it has developed a physical and business process for disconnection and/or reconnection ensuring safety and reliability as a primary requirement.

The LDC shall treat all customers in a non-discriminatory fashion when disconnecting and/or reconnecting an electrical service.

The LDC shall have the right to limit or discontinue service without further notification to the customer for payment default, including default of payment arrangements, bankruptcy, receivership, or property foreclosure.

The LDC shall have the right to limit or discontinue service for non-payment of a security deposit from customers that have defaulted on payment arrangements.

The LDC shall have the right to refuse the reconnection if there are any outstanding amounts owed by the consumer or if the service is found to have an adverse effect on the safety and/or reliability of the system.

The LDC shall have the right to discontinue electrical service of a consumer if the service causes safety or reliability risk to the distributor's system.

The LDC shall insist that electrical services that have been disconnected for six (6) or more months have an inspection certificate from the Electrical Safety Authority prior to reconnection. Not withstanding the LDC reserves the right to require, an Electrical Safety Authority inspection certificate at any time prior to reconnection at the expense of the customer.

The LDC shall insist that a responsible representative of the property be present in order for reconnection of service to be established.

### 8.1.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

### 8.1.4 REFERENCES:

*The Electricity Act, 1998* – Province of Ontario, Ministry of Energy, Science and Technology

*Retail Settlement Code* – The Ontario Energy Board

*Electricity Distribution Rates Handbook* – The Ontario Energy Board

*Distribution System Code* – The Ontario Energy Board

*Electricity Gas and Inspection Act* – Government of Canada

*Condition of Service* – The Distributor

| **Policy 8.3** | **Version 3.0** |
|---|---|
| **DISCONNECTION/RECONNECTION BY REQUEST** | *Created: September, 2002*<br>*Latest Revision: June 21, 2004* |

## 8.3.1 PURPOSE:

This policy confirms that the LDC has established a process for the disconnection and/or reconnection of an electrical service and may require a written request from the consumer.

## 8.3.2 POLICY STATEMENT:

The LDC shall respond to a customer's request for a disconnection and reconnection of an electrical service in a prompt and efficient manner.

The LDC shall have the right to refuse the reconnection of and electrical service if there is an outstanding amount of money owed by the consumer or if the connection is found to have an adverse effect on the safety and/or reliability of the distribution system.

The LDC shall insist that electrical services that have been disconnected for six (6) or more months have an inspection certificate from the Electrical Safety Authority prior to reconnection. Not withstanding the LDC reserves the right to require an Electrical Safety Authority certificate at any time prior to reconnection at the customer expense.

The LDC shall insist that a responsible representative of the property be present when electrical service is energized or reconnected.

## 8.3.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

## 8.3.4 REFERENCES:

*The Electricity Act, 1998* – Province of Ontario, Ministry of Energy, Science and Technology

*Retail Settlement Code* – The Ontario Energy Board

*Electricity Distribution Rates Handbook* – The Ontario Energy Board

*Distribution System Code* – The Ontario Energy Board

*Electricity Gas and Inspection Act* – Government of Canada

*Condition of Service* – The Distributor

| **Policy 8.4.0** | **Version 3.0** |
|---|---|
| **SAFETY AND RELIABILITY** | *Created: September, 2002*<br>*Latest Revision: June 21, 2004* |

## 8.4.1 PURPOSE:

This policy confirms that the LDC has established a process for ensuring the safety and reliability of the distribution system.

## 8.4.2 POLICY STATEMENT:

The LDC shall respond to and take reasonable steps to investigate all consumer power quality complaints and report to the consumer on the results of the investigation.

The LDC may direct a consumer connected to its distribution system to take corrective or preventive action on the consumer's electric system when there is a direct hazard to the public or the consumer is causing or could cause adverse effects on the reliability of the LDC's distribution system.

The LDC may require that any consumer conditions that adversely affect the distribution system be corrected immediately by the consumer and at the consumer's expense.

The LDC shall insist that electrical services that have been disconnected for six (6) or more months have an inspection certificate from the Electrical Safety Authority prior to reconnection. Not withstanding the LDC reserves the right to require an Electrical Safety Authority certificate at any time prior to reconnection at the customer expense.

The LDC shall have the right to refuse the reconnection of an electrical service to their distribution system if the connection is found to have an adverse effect on the safety and/or reliability of the system.

The LDC shall have the right to disconnect the electrical service of a consumer if the service causes safety or reliability risk to the distributor's system.

The LDC shall insist that a responsible representative of the property be present when electrical service is energized or reconnected.

## 8.4.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the service quality of the distribution system is safe and reliable.

## 8.4.4 REFERENCES:

*The Electricity Act, 1998* – Province of Ontario, Ministry of Energy, Science and Technology
*Retail Settlement Code* – The Ontario Energy Board

*Electricity Distribution Rates Handbook* – The Ontario Energy Board

*Distribution System Code* – The Ontario Energy Board

*Electricity Gas and Inspection Act* – Government of Canada

*Condition of Service* – The Distributor

| **Policy 8.5.0** | **Version 3.0** |
|---|---|
| **UNAUTHORIZED USE OF ELECTRICITY** | *Created: September, 2002*<br>*Latest Revision: June 21, 2004* |

## 8.5.1 PURPOSE:

This policy confirms that the LDC has established a process that management and staff can follow if it is discovered that there is unauthorized use of electricity.

## 8.5.2 POLICY STATEMENT:

The LDC shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, the LDC shall notify, if appropriate, Measurement Canada, the Electrical Safety Authority, police officials, retailers that service the customers affected by the unauthorized energy use, or other entities.

The LDC shall monitor losses and unaccounted for energy use on an annual basis to detect any upward trends.

The LDC may recover from the parties responsible for the unauthorized energy use all energy and other applicable charges incurred by the distributor arising from the unauthorized energy use, including inspection, administration fees and repair costs.

## 8.5.3 RESPONSIBILITIES:

The management of the company is responsible for monitoring losses and unaccounted for energy.

## 8.5.4 REFERENCES:

*The Electricity Act, 1998* – Province of Ontario, Ministry of Energy, Science and Technology

*Retail Settlement Code* – The Ontario Energy Board

*Electricity Distribution Rates Handbook* – The Ontario Energy Board

*Distribution System Code* – The Ontario Energy Board

*Electricity Gas and Inspection Act* – Government of Canada

*Conditions of Service* – The Distributor

| **Policy 7.0** | **Version 3.0** |
|---|---|
| **COLLECTION OVERVIEW** | *Created: September, 2002*<br>*Latest Revision: June 21, 2004* |

## 7.0.1 PURPOSE:

The purpose of this policy is to establish a process to ensure money owed to the LDC by consumers is collected.

## 7.0.2 POLICY STATEMENT:

The LDC shall follow the regulation and direction set out in the Distribution Rate Handbook Chapter 9 when implementing the collection process.

The LDC will collect all outstanding money owed from Customers and Retailers served by the LDC's distribution system in accordance with the principles defined in the *Electricity Act (1998), the Electricity Distribution Rate Handbook* and the *Retail Settlement Code*. The policies in this set are intended to provide guidance to the LDC's managers and staff, and to help them make operational decisions that are consistent with applicable codes and regulations.

7.1 Customer Collections

7.2 Retailer Collections

The LDC will collect all outstanding money owed from Customers and Retailers served by the LDC's distribution system in accordance with the principles defined in the *Electricity Act*

## 7.0.3 DEFINITIONS:

**Licensed Competitive Retailer** is a company that has a valid electricity retailer's license from the Ontario Energy Board.

**Standard Service Supply Customer** is a company or person who purchases electricity at spot market price or statutory pricing from a LDC's distribution system as a direct pass through from the IMO.

**Customer and Consumer** will be understood herein as one and the same.

**Non-Competitive Charges** is made up of the Wholesale Market Service charge, the Debt Retirement charge, Transmission Connection charge, Transmission Network charge and Distribution charges.

**Distributor-Consolidated Billing** is when a retailer marketer who has signed contracts in the LDC service area and has opted for the distributor to do the billing and collection of the electricity commodity and all related non-competitive charges.

**Retailer-Consolidated Billing** is when the retail marketer opts to do the billing and collection of the electricity commodity and all related non-competitive charges.

**Split Billing** is when the retail marketer bills the customer for the electricity charges and the LDC bills for the customer for non-competitive, debt retirement and distribution charges. The retailer and the distributor shall each be responsible for the collection of their own accounts.

**Late Payment Charge** is an OEB approved interest charge that is applied after a specified date or a due date on a customer's bill.

**Errors and Omissions Excepted** the LDC shall reserve the right to make adjustments to any bill issued in error either in whole or in part.

**Non-Payment Risk Mitigation** the LDC may use any risk mitigation options available to manage consumer non-payment risk.

## 7.0.4 COLLECTION PAYMENT METHODS:

The LDC may accept one or more of the following methods of payment but are not obligated to offer all methods:

Cash
Payment made through most Financial Institutions including telephone & computer banking
Certified Cheque
Money Order or Bank Draft
Credit Card
Interac
Preauthorized Chequing

## 7.0.5 RESPONSIBILTIES:

The Board of Directors are responsible for the approval of the policies contained in this manual.

## 7.0.6 REFERENCES:

*The Electricity Act, 1998* – Province of Ontario, Ministry of Energy, Science and Technology

*Electricity Distribution Rate Handbook* – The Ontario Energy Board

*Retail Settlement* – The Ontario Energy Board

*Distribution System Code* – The Ontario Energy Board

*Electricity Gas and Inspection Act* – Government of Canada

| **Policy 7.1** | **Version 3.0** |
|---|---|
| **CUSTOMER COLLECTIONS** | *Created: September, 2002*<br>*Latest Revision: June 21, 2004* |

## 7.1.1 PURPOSE:

This policy confirms that the LDC must be prudent in their collection process to protect the corporation from unpaid invoices. The detailed policies in this set are intended to establish and document a process that will provide guidance to the LDC's management and staff, to help them make operational decisions to ensure that monies owed to the LDC by the consumer or retailer are collected in a timely manner.

## 7.1.2 POLICY STATEMENT:

The LDC will take steps to collect the total amount for the customer's bill, if not paid within the time specified, which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill. A collection of account charge may be made if a representative of the utility is dispatched to collect the account.

The customer shall be subject either to a collection of account charge or a reconnection charge in the event service has been interrupted in order to collect outstanding amounts owed in any billing period, unless partial payment of the account has been accepted by the LDC.

The LDC may apply more than one collection of account charge or reconnection charge in one billing period if a partial payment has been accepted through a collection trip.

The LDC shall begin the collection process immediately following the application of late payment charge.

The LDC shall treat all customers in the same rate class in a non-discriminatory fashion when collecting unpaid accounts.

The LDC shall have the right to limit or disconnect service for non-payment, theft of power and/or failing to keep payment arrangements.

The LDC shall reserve the right to make adjustments to any bill issued in error either in whole or in part.

## 7.1.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

## 7.1.4 REFERENCES:

*The Electricity Act, 1998* – Province of Ontario, Ministry of Energy, Science and Technology

*Retail Settlement Code* – The Ontario Energy Board

*Electricity Distribution Rates Handbook* – The Ontario Energy Board

*Distribution System Code* – The Ontario Energy Board

*Electricity Gas and Inspection Act* – Government of Canada

| **Policy 7.2** | **Version 3.0** |
| --- | --- |
| **RETAILER COLLECTIONS** | *Created: September, 2002*<br>*Latest Revision: June 21, 2004* |

## 7.2.0 PURPOSE:

This policy describes the processes to collect outstanding balances from retailers who have signed sales agreements with consumers served by the LDC's distribution system and to ensure that the Retailer meets the prudential requirements based on the billing option selected and the Retailer's magnitude of financial exposure. This process also applies to collection of past due Retail settlement and market participant invoices.

## 7.2.1 POLICY STATEMENT:

The LDC requires Retailers to pay invoices on the due date as specified in the code.

The LDC reserves the right to refuse service transaction requests, requests for information, invoices or other transactions from retailers with whom the LDC does <u>not</u> have an up-to-date service agreement and/or financial security arrangements.

The LDC shall review the required level of deposit from a Retailer for customers served through Distributor Consolidated Billing on a quarterly basis as a minimum.

The LDC shall immediately notify the retailer the day after a settlement payment was due if funds were not received and work with the retailer to remedy the situation.

The LDC shall not access the funds available through the relevant security arrangement until five business days have elapsed.

The LDC shall issue to the Retailer a Notice of Payment Default prior to returning the consumer that is signed with said Retailer back to Standard Service Supply (SSS).

## 7.2.2 RESPONSIBILITIES:

The management of the company is responsible for ensuring that prudential monitoring and payments from a Retailer are collected within the guidelines specified in the service agreement.

## 7.2.3 REFERENCES:

*The Electricity Act, 1998* – Province of Ontario, Ministry of Energy, Science and Technology

*Market Rules* – The Independent Electricity Market Operator

*Retail Settlement Code* – The Ontario Energy Board

*Electricity Distribution Rates Handbook* – The Ontario Energy Board

*Electricity Gas and Inspection Act* – Government of Canada

## Hydro 2000 Inc.

## PLANNED CHANGES IN CONDITIONS OF SERVICE AND SERVICE CHARGES

Hydro 2000 Inc. has joined the CHEC group and is submitting the same Conditions of Service. Version 5.3 of the Conditions of service is attached in Exhibit 1; Tab 1; Schedule 17. At the present time a version 5.4 is in the process to be approved by the OEB Board.

## Hydro 2000 Inc.

## LIST OF WITNESSES

## To be provided if oral hearing occurs

Name : Rene C. Beaulne
Title : Manager
Company: Hydro 2000 Inc.

Name : Gerald Gauthier
Title : Auditors
Company: Deloitte

Name : James Cochrane
Title : Consultant
Company: Elenchus Research Associates

Name : Bruce Bacon
Title : Consultant
Company: Elenchus Research Associates

Name : Dave Proctor
Title : Consultant
Company: CHEC

Name : Patrick Moran
Title : Consultant / Lawyer
Company: Ogilvy Renault

# Hydro 2000 Inc.

## SUMMARY OF THE APPLICATION

### PURPOSE AND NEED

The Applicant estimates that its present rates will produce a deficiency in distribution revenue of $165,866 for the 2008 Test Year. Excluded from this estimate is the impact of energy costs. The Applicant therefore seeks the Board's approval to revise its rates applicable to its distribution of electricity. The issues to be reviewed in this case, as the applicant sees them, are discussed below.

Through this Application, the Applicant seeks:

- To recover all outstanding Deferral Variance Accounts, to have fair rates to customers and Hydro 2000 Inc. and its shareholders without jeopardizing safety reliability and service to customers.
- To change the common equity from 50% to 40%.
- To reflect the accurate portrait of Hydro 2000 Inc. operations through the Model

The information used in this Application is the Applicant's forecasted results for its 2008 Test Year. With the rates presently in effect, the Applicant estimates that its revenue for 2008 would not be sufficient to provide a reasonable return. The Applicant is also presenting the historical actual information for fiscal year 2006, information for the current approved test year and six months actual and six months forecast for the fiscal 2007 bridge year.

### TIMING

The financial information supporting the Test Year for this Application will be the Applicant's fiscal year ending December 31, 2008 (the "2008 Test Year"). However, this information will be used to set rates for the period May 1, 2008 to April 30, 2009. The Test Year revenue requirement is that forecast by the Applicant as needed to enable it to earn a reasonable return for fiscal 2008. For the required revenues to match and appropriately offset the expected costs of service for the Test Year, revised rates reflecting the Board's decision must be effective for volumes consumed on and after May 1, 2008.

### CUSTOMER IMPACT

The following table is a comparator between the current rates and the proposed rates in 2008 test year for typical customers in their classes.

| Class | Consumption | Current Bill | Proposed Bill | Bill Impact | Bill Impact |
|---|---|---|---|---|---|
| | | 2007 approved rates | 2008 Proposed Rates | $ | % |
| Residential | 1000 kWh | $111.98 | $112.14 | $0.15 | 0.1% |
| GS less than 50 kW | 2000 kWh | $215.05 | $227.3 | $12.26 | 5.4% |
| GS over than 50 kW | 100 kW, 40000 kWh | $3,899.5 | $3,968.39 | $68.89 | 1.7% |
| Unmeterd Scattered Load | 500 kWh | $56.63 | $66.63 | $10.00 | 15.0% |
| Street Light | 77 kW, 25,000 kWh | $2,112.39 | $2,708.98 | $596.60 | 22.0% |

# Hydro 2000 Inc.

Residential

A typical residential customer with a consumption of 1000 kWhs will see its invoice increase by 0.1%. In this increase a re-allocation of revenues from other classes of -2.82% contributed to decrease the increase to the class. In the cost allocation it showed that the Residential contribution to revenue was over sufficient. The revenue-to-cost ratios for the rate for Residential was decrease from 66.35% to 63.52%. Please refer to the previous table and Exhibit 9, Tab 1, Schedule 7.

General Service less than 50kW

A typical General Service less than 50 kW with a consumption of 2000 kWhs will see its invoice increase by 5.4%. In this increase a re-allocation of revenues from other classes of 2.27% contributed to boost the increase to the class. In the cost allocation it showed that the General Service less than 50 kW contribution to revenue was deficient. The revenue-to-cost ratios for the rate for General Service less than 50 kW was increase from 21.63% to 23.9%. Please refer to the previous table and Exhibit 9, Tab 1, Schedule 7.

General Service over 50 kW

A typical General Service over than 50 kW with a consumption of 100 kWs and 40,000 kWhs will see its invoice increase by 1.7%. In this increase a re-allocation of revenues from other classes of -1.0% contributed to decrease the increase to the class. In the cost allocation it showed that the General Service over than 50 kW contribution to revenue was over sufficient. The revenue-to-cost ratios for the rate for General Service over than 50 kW was decrease from 11.25% to 10.25%. Please refer to the previous table and Exhibit 9, Tab 1, Schedule 7.

Unmetered Scattered Load

A typical Unmetered Scattered Load with a consumption of 500 kWhs will see its invoice increase by 6.7%. In this increase a re-allocation of revenues from other classes of .08% contributed to boost the increase to the class. In the cost allocation it showed that the Unmetered Scattered Load contribution to revenue was deficient. The revenue-to-cost ratios for the rate for Unmetered Scattered Load was increase from 0.17% to 0.25%. Please refer to the previous table and Exhibit 9, Tab 1, Schedule 7.

Street Light

The Street Light Class is composed of one customer with an average consumption of 77 kWs and 25,000 kWhs will see its invoice increase by 22.0%. In this increase a re-allocation of revenues from other classes of 1.3% contributed to boost the increase to the class. In the cost allocation it showed that the Street Light class contribution to revenue was deficient. The revenue-to-cost ratios for Street Light was increase from 0.79% to 2.09%. Please refer to the previous table and Exhibit 9, Tab 1, Schedule 7.

## Hydro 2000 Inc.

MAJOR ISSUES

There are a number of issues that, although they may not all be defined as major, are anticipated to be examined in this case. These issues are listed below.

Examples

Capital Structure

The Applicant is requesting a change in its deemed capital structure. Specifically, the Applicant is requesting a decrease in the deemed equity ratio from 60% to 40% consistent with the 3 year phase in of Applicant's capital structure from 50% to 40% equity as outlined in the Report of the Board on Cost of Capital and 2$^{nd}$ Generation Incentive Regulation fro Ontario Electricity Distributors dated December 20, 2006.

Return on Equity

In addition, the Applicant has assumed a return on equity of 8.68% consistent with the methodology outlined in Appendix B of the Report of the Board on Cost of Capital and 2$^{nd}$ Generation Incentive Regulation from Ontario Electricity Distributors dated December 20, 2006. The Applicant understands the OEB will be finalizing the return on equity for 2008 rates based on January 2008 market interest rate information.

Capital Expenditures

*The Applicant* continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase in demand comes both from currently un-serviced areas as well as existing areas needing upgrades.

Operating and Maintenance Costs

Operating and maintenance costs have been updated to reflect the impact of inflation and expected changes in costs.

# Hydro 2000 Inc.

## BUDGET DIRECTIVES

The Applicant compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information is compiled for both the bridge and test years.

Revenue Forecast
The energy sales and revenue forecast model was updated to reflect more recent information. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2007 and 2008. The forecast is weather normalized as outlined in Exhibit 3; Tab2 Schedule 1,2,3,4,5,6 and considers such factors as new customer additions and load profiles for all classes of customers.

Operating and Maintenance Expense Forecast
The operating and maintenance expenses for fiscal 2007 bridge year and the 2008 test year have been forecast using a zero based methodology and is strongly influenced by prior year experience. Each item is reviewed account by account for each of the forecast years.

Capital Budget
The capital budgeting process begins with a review of all the accounts.
All other capital expenditures are budgeted on a line by line basis based on need and forecasted customer growth.

# Hydro 2000 Inc.

## CHANGES IN METHODOLOGY

The following is a summary of the changes in methodology requested by the Applicant in the current proceeding:

a) Capital Structure
Hydro 2000 Inc. is following Board directive and will go from a 50% debt and 50% common equity to a 60% debt and 40 % common equity.

b) Return on Equity
Hydro 2000 Inc. is following Board directive

c) Interest Rate Applicable to Deferral/Variance Accounts
Hydro 2000 Inc. is following Board directive and will apply the interest rates prescribe.

e) Cost Allocation & Fully Allocated Costing Study
Hydro 2000 Inc. will use its cost allocation to move its rates toward the recommendation of the cost allocation.

## Hydro 2000 Inc.

### NUMERICAL DETAILS OF CAUSES OF DEFICIENCY/SUFFICIENCY
### 2008 TEST YEAR

This will come from the rate section of the model

| | Per existing Rates | | | | Application Test Year | Revenue Sufficiency Deficiency |
|---|---|---|---|---|---|---|
| | 2006 EDR | IRM Rate Changes | Load Changes | Test Year | | |
| Distribution Expenses | $336,799 | $339,897 | - | $467,313 | $467,313 | -$127,410 |
| Return On Capital | 9.0% | 9.0% | - | 8.68% | 8.68% | |
| PILS | $0.00 | $0.00 | - | $39,350 | | -$39,350 |
| Distribution Expenses | $384,336 | $387,872 | - | $527,084 | $527,084 | |

## Hydro 2000 Inc.

## CAUSES OF REVENUE DEFFICIENCY

The following table will demonstrate the revenue deficiency.

| **Determination Revenue Surplus or Deficiency** | | | |
|---|---|---|---|
| Expenses | 2006 Approved<br>Existing Rates | 2008 Test<br>Proposed Rates | Revenue Surplus or Defficiency |
| PILS | $ - | $ 39,350 | $ (39,350) |
| LV Charges | $ 106,241 | $ 121,000 | $ (14,759) |
| Depreciation & Amortization | $ 44,364 | $ 56,569 | $ (12,205) |
| Wages Increase | $ 85,192.00 | $ 98,864.00 | $ (13,672) |
| Wages Burden | $ 9,183.00 | $ 7,888.00 | $ 1,295 |
| Bad debts | $ 3,800.00 | $ 7,600.00 | $ (3,800) |
| regulatory expense | $ 6,571.00 | $ 66,500.00 | $ (59,929) |
| ESA expense | $ - | $ 3,800.00 | $ (3,800) |
| | | | |
| Revenues | | | |
| Interest and dividend income | $ 35,560.00 | $ 16,314.00 | $ (19,246) |
| Total | Deficiency | | $ (165,466) |

The Revenue Deficiency is mainly caused by 7 items.

Hydro 2000 Inc. had a big loss carry forward and did not pay PILS until the end of 2006.
In EDR-2006 based on the 2004 PILS which was $0 no PILS Amount was collected in the rates.

LV Charges cost were under estimated by Hydro One Networks Inc.

Employees at Hydro 2000 Inc. received the cost of living and re-classification in wages scale.

Wages Burden went down because of WSIB and a surcharge in EHT.

Bad debts are in increasing every year the 2007 actual bad debts have double the total in 2006 in the first 7 months.

The regulatory expenses increase is the cost of 2008 rebasing application.

In the interest and dividend income the RSVA interest are remove from OM&A and accounted in DVAD Model.

With new regulatory from ESA new expenses are incurred that was not accounted for in edr-2006.

# Hydro 2000 Inc.

## AUDITED FINANCIAL STATEMENTS
## AT
## DECEMBER 31 2006

*Financial Statements of*
*États financiers de*

**HYDRO 2000 INC.**

*December 31, 2006*
*31 décembre 2006*

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

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

## Auditors' Report

To the Directors of Hydro 2000 Inc.

We have audited the balance sheet of Hydro 2000 Inc. as at December 31, 2006 and the statements of earnings and retained earnings and cash flows for the year then ended. These financial statements are the responsebility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles

Deloitte & Touche LLP

Licensed Public Accountants

Hawkesbury, Ontario
February 20, 2007

## Rapport des vérificateurs

Aux administrateurs de Hydro 2000 Inc.

Nous avons vérifié le bilan de Hydro 2000 Inc. au 31 décembre 2006 et les états des résultats et bénéfices non répartis et des flux de trésorerie de l'exercice terminé à cette date. La responsabilité de ces états financiers incombe à la direction de la Société. Notre responsabilité consiste à exprimer une opinion sur ces états financiers en nous fondant sur notre vérification.

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

À notre avis, ces états financiers donnent, à tous les égards importants, une image fidèle de la situation financière de la Société au 31 décembre 2006 ainsi que des résultats de son exploitation et de ses flux de trésorerie pour l'exercice terminé à cette date selon les principes comptables généralement reconnus du Canada.

Titulaire d'un permis d'expertise comptable

Hawkesbury, Ontario
Le 20 février 2007

**HYDRO 2000 INC.**
**Financial Statements**
**December 31, 2006**

**HYDRO 2000 INC.**
**États financiers**
**31 décembre 2006**


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**HYDRO 2000 INC.**
**Statement of Earnings and Retained Earnings**
**year ended December 31, 2006**

**HYDRO 2000 INC.**
**État des résultats et bénéfices non répartis**
**exercice terminé le 31 décembre 2006**

| | **2006** | 2005 | |
|---|---|---|---|
| REVENUE (note 10) | | | REVENUS (note 10) |
| Energy | **$ 1 982 253** | $ 1 931 698 | Énergie |
| Distribution | **237 706** | 291 908 | Distribution |
| | **2 219 959** | 2 223 606 | |
| COST OF POWER | **1 982 253** | 1 931 698 | COÛT DE L'ÉNERGIE |
| | **237 706** | 291 908 | |
| OTHER OPERATING REVENUE | **50 649** | 57 590 | AUTRES PRODUITS |
| | **288 355** | 349 498 | |
| EXPENSES | | | DÉPENSES |
| Operation maintenance | **74 283** | 102 814 | Exploitation |
| Billing and collection | **121 173** | 177 978 | Facturation et perception |
| Administration | **43 684** | 39 541 | Administration |
| Depreciation of capital assets | **46 492** | 39 693 | Amortissement des immobilisations corporelles |
| Depreciation of contribution for capital assets | **(2 591)** | - | Amortissement des apports pour immobilisations corporelles |
| Depreciation of incorporation fees | **463** | 463 | Amortissement des frais d'incorporation |
| | **283 504** | 360 489 | |
| EARNINGS (LOSS) BEFORE INCOME TAXES | **4 851** | (10 991) | BÉNÉFICE (PERTE) AVANT IMPÔTS SUR LE REVENU |
| Income taxes | | | Impôts sur le revenu |
| Current | **26 424** | 7 942 | Courant |
| Recovery due to loss carryover | **(16 213)** | (7 942) | Recouvrement lié aux pertes des années antérieures |
| Future | **(9 287)** | (2 025) | Futurs |
| | **924** | (2 025) | |
| NET EARNINGS (LOSS) | **3 927** | (8 966) | BÉNÉFICE NET (PERTE) |
| RETAINED EARNINGS, BEGINNING OF YEAR | **409 582** | 418 548 | BÉNÉFICES NON RÉPARTIS AU DÉBUT DE L'EXERCICE |
| RETAINED EARNINGS, END OF YEAR | **$ 413 509** | $ 409 582 | BÉNÉFICES NON RÉPARTIS À LA FIN DE L'EXERCICE |

**HYDRO 2000 INC.**
**Balance Sheet**
**as at December 31, 2006**

**HYDRO 2000 INC.**
**Bilan**
**au 31 décembre 2006**

| | **2006** | 2005 | |
|---|---|---|---|
| CURRENT ASSETS | | | ACTIF À COURT TERME |
| Cash | **$ 480 727** | $ 716 982 | Encaisse |
| Accounts receivable (note 3) | **198 374** | 137 345 | Débiteurs (note 3) |
| Inventories | **15 606** | 15 606 | Stocks |
| Unbilled revenue | **380 119** | 399 765 | Revenus non facturés |
| Income taxes recoverable | **-** | 18 000 | Impôts sur le revenu à recevoir |
| Prepaid expenses | **7 759** | 39 224 | Frais payés d'avance |
| | **1 082 585** | 1 326 922 | |
| INCORPORATION FEES | **1 804** | 2 267 | FRAIS D'INCORPORATION |
| OTHER ASSETS (note 4) | **443 132** | 590 502 | AUTRES ACTIFS (note 4) |
| CAPITAL ASSETS (note 5) | **371 625** | 364 164 | IMMOBILISATIONS CORPORELLES (note 5) |
| | **$ 1 899 146** | $ 2 283 855 | |
| CURRENT LIABILITIES | | | PASSIF À COURT TERME |
| Accounts payable | **$ 302 740** | $ 517 833 | Créditeurs |
| Other current liabilities | **177 811** | 222 555 | Autres frais courus |
| Income taxes payable | **10 211** | - | Impôts sur le revenu à payer |
| Current portion of note payable (note 7) | **23 803** | 22 546 | Tranche de billet à payer échéant à moins d'un an (note 7) |
| Current portion of other long-term liabilities (note 8) | **137 511** | 137 130 | Tranche des autres passifs à long terme échéant à moins d'un an (note 8) |
| | **652 076** | 900 064 | |
| NOTE PAYABLE (note 7) | **324 713** | 348 516 | BILLET À PAYER (note 7) |
| FUTURE INCOME TAXES | **66 955** | 76 242 | IMPÔTS FUTURS |
| OTHER LONG-TERM LIABILITIES (note 8) | **133 158** | 240 716 | AUTRES PASSIFS À LONG TERME (note 8) |
| | **1 176 902** | 1 565 538 | |
| SHAREHOLDER'S EQUITY | | | CAPITAUX PROPRES |
| Share capital (note 9) | **308 735** | 308 735 | Capital-actions (note 9) |
| Retained earnings | **413 509** | 409 582 | Bénéfices non répartis |
| | **722 244** | 718 317 | |
| | **$ 1 899 146** | $ 2 283 855 | |

ON BEHALF OF THE BOARD — AU NOM DU CONSEIL

Director ______________________ Administrateur

Director ______________________ Administrateur

**HYDRO 2000 INC.**
**Statement of Cash Flows**
**year ended December 31, 2006**

**HYDRO 2000 INC.**
**État des flux de trésorerie**
**exercice terminé le 31 décembre 2006**

| | | **2006** | | 2005 | |
|---|---|---|---|---|---|
| OPERATING | | | | | EXPLOITATION |
| Net earnings (loss) | **$** | **3 927** | $ | (8 966) | Bénéfice net (perte) |
| Adjustments for: | | | | | Ajustements pour: |
| Depreciation of incorporation fees | | **463** | | 463 | Amortissement des frais d'incorporation |
| Depreciation of capital assets | | **46 492** | | 39 693 | Amortissement des immobilisations corporelles |
| Depreciation of contribution for capital assets | | **(2 591)** | | - | Amortissement des apports pour immobilisations corporelles |
| Future income taxes | | **(9 287)** | | (2 025) | Impôts futurs |
| Changes in non-cash operating working capital items (note 11) | | **(241 544)** | | 291 544 | Variation des éléments hors caisse du fonds de roulement d'exploitation (note 11) |
| | | **(202 540)** | | 320 709 | |
| FINANCING | | | | | FINANCEMENT |
| Increase (decrease) of other long-term liabilities | | **(107 177)** | | 26 547 | Augmentation (diminution) des autres passifs à long terme |
| Repayment of note payable | | **(22 546)** | | (21 356) | Remboursement du billet à payer |
| Increase of contribution for capital assets | | **64 783** | | - | Augmentation des apports pour immobilisations corporelles |
| | | **(64 940)** | | 5 191 | |
| INVESTING | | | | | INVESTISSEMENT |
| Acquisition of capital assets | | **(116 145)** | | (53 641) | Acquisition d'immobilisations corporelles |
| Decrease of other assets | | **147 370** | | 66 352 | Diminution des autres actifs |
| | | **31 225** | | 12 711 | |
| NET CASH INFLOW (OUTFLOW) | | **(236 255)** | | 338 611 | AUGMENTATION (DIMINUTION) DE L'ENCAISSE |
| CASH, BEGINNING OF YEAR | | **716 982** | | 378 371 | ENCAISSE AU DÉBUT DE L'EXERCICE |
| CASH, END OF YEAR | **$** | **480 727** | $ | 716 982 | ENCAISSE À LA FIN DE L'EXERCICE |

Additional information is presented in note 11.

Des renseignements complémentaires sont présentés à la note 11.

## 1. DESCRIPTION OF BUSINESS

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

## 2. ACCOUNTING PRINCIPLES

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

*INVENTORIES*

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

*CAPITAL ASSETS AND DEPRECIATION*

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

| | Years |
|---|---|
| Distribution equipment | 25 |
| Office equipment | 10 |
| Computer equipment | 5 |

*INCORPORATION FEES*

Incorporation fees are accounted at cost and amortized using the straight-line method over a ten year period.

*CUSTOMERS' DEPOSITS*

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

*IMPAIRMENT OF LONG-LIVED ASSETS*

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



## 1. DESCRIPTION DE L'ENTREPRISE

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

## 2. PRINCIPES COMPTABLES

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

*STOCKS*

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

*IMMOBILISATIONS CORPORELLES ET AMORTISSEMENT*

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

| | Années |
|---|---|
| Équipement de distribution | 25 |
| Équipement de bureau | 10 |
| Équipement informatique | 5 |

*FRAIS D'INCORPORATION*

Les frais d'incorporation sont comptabilisés au coût et amortis linéairement sur une période de dix ans.

*DÉPÔTS DE CLIENTS À LONG TERME*

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

*DÉPRÉCIATION D'ACTIFS À LONG TERME*

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

## 2. ACCOUNTING PRINCIPLES (following)

*OTHER ASSETS*

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between forecast and actual purchased power costs in the rate year are held until the following year, when their final disposition is decided. Hydro 2000 Inc. recognizes purchased power cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, customers. In the absence of rate regulation, generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred.

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

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

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

The financial statements effects of rate regulation are presented in note 13.

*USE OF ESTIMATES*

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



## 2. PRINCIPES COMPTABLES (suite)

*AUTRES ACTIFS*

Les coûts associés à l'énergie achetée sont pris en compte dans les tarifs autorisés, sur une base prévisionnelle. Aux fins de l'établissement des tarifs, les écarts entre les coûts prévus et les coûts réels associés à l'énergie achetée au cours de l'année de tarification sont laissés en suspens jusqu'à l'année suivante, au cours de laquelle leur traitement définitif est déterminé. Hydro 2000 Inc. comptabilise les écarts de coûts associés à l'énergie achetée à titre d'actif ou de passif réglementaire, parce que la Société s'attend à obtenir l'autorisation de recouvrer auprès des clients futurs les montants laissés en suspens d'une année à l'autre aux fins de l'établissement des tarifs, ou à devoir rembourser les montants à ces clients. Si les tarifs n'étaient pas réglementés, les coûts réels associés à l'énergie achetée devraient être passés en charges au moment où ils sont engagés, selon les principes comptables généralement reconnus.

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

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

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

Les effets de la règlementation des tarifs sont décris à la note 13.

*UTILISATION D'ESTIMATIONS*

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

## 3. ACCOUNTS RECEIVABLE / 3. DÉBITEURS

| | 2006 | 2005 | |
|---|---|---|---|
| Electrical energy | **$ 180 664** | $ 71 409 | Énergie électrique |
| Other | **21 373** | 69 772 | Autres |
| | **202 037** | 141 181 | |
| Allowance for doubtful account | **(3 663)** | (3 836) | Provision pour mauvaises créances |
| | **$ 198 374** | $ 137 345 | |

## 4. OTHER ASSETS / 4. AUTRES ACTIFS

| | 2006 | 2005 | |
|---|---|---|---|
| Smart meters | **$ (2 402)** | $ - | Compteurs intelligents |
| LV - Wheeling | **21 012** | - | Distribution à faible tension |
| Other regulatory assets | **39 141** | 35 684 | Autres actifs réglementés |
| Transition costs | **156 397** | 154 714 | Frais de transition |
| Pre-market opening energy variance | **186 893** | 179 673 | Écarts de prix avant ouverture du marché |
| Retail settlement variance account | **428 915** | 406 830 | Écarts de prix avec les détaillants |
| Recoveries | **(386 824)** | (186 399) | Recouvrements |
| | **$ 443 132** | $ 590 502 | |

## 5. CAPITAL ASSETS / 5. IMMOBILISATIONS CORPORELLES

| | 2006 | | | 2005 | |
|---|---|---|---|---|---|
| | Cost/coût | Accumulated depreciation/ Amortissement cumulé | Net book value/ Valeur nette | Net book value/ Valeur nette | |
| Distribution equipment | **$ 614 070** | **$ 203 824** | **$ 410 246** | $ 348 265 | Équipement de distribution |
| Office equipment | **3 246** | **2 910** | **336** | 390 | Équipement de bureau |
| Computer equipment | **48 217** | **24 982** | **23 235** | 15 509 | Équipement informatique |
| Capital contribution | **(64 783)** | **(2 591)** | **(62 192)** | - | Apports en immobilisations |
| | **$ 600 750** | **$ 229 125** | **$ 371 625** | $ 364 164 | |

## 6. LETTER OF GUARANTEE

The Corporation has a letter of guarantee of $ 500 000 in favour of Hydro One. It is secured by the accounts receivable and some equipment.

## 6. LETTRE DE GARANTIE

La Société a une lettre de garantie en faveur de Hydro One pour un montant de $ 500 000. Elle est garantie par les comptes à recevoir et certains équipements.

## 7. NOTE PAYABLE / 7. BILLET À PAYER

| | 2006 | 2005 | |
|---|---|---|---|
| Note payable to the Township of Alfred-Plantagenet, 5.5% interest, payable in semi-annual payments of $ 21 324, including interest | **$ 348 516** | $ 371 062 | Billet à payer au Canton d'Alfred-Plantagenet, au taux de 5.5%, en versements semi-annuels de $ 21 324 incluant les intérêts |
| Current portion | **23 803** | 22 546 | Portion à court terme |
| | **$ 324 713** | $ 348 516 | |

Principal repayments to be made during the next five years are as follows: 2007, $ 23 803; 2008, $ 25 131; 2009, $ 26 532; 2010, $ 28 011 and 2011 $ 29 573.

Les versements en capital à effectuer au cours des cinq prochains exercices sont les suivants : 2007, $ 23 803 ; 2008, $ 25 131 ; 2009, $ 26 532 ; 2010 $ 28 011 et 2011 $ 29 573.

## 8. OTHER LONG-TERM LIABILITIES / 8. AUTRES PASSIFS À LONG TERME

| | 2006 | 2005 | |
|---|---|---|---|
| Customer deposits | **$ 21 126** | $ 20 789 | Dépôts de clients |
| Hydro One | **249 543** | 357 057 | Hydro One |
| | **270 669** | 377 846 | |
| Current portion | **137 511** | 137 130 | Portion à court terme |
| | **$ 133 158** | $ 240 716 | |

Amount owed to Hydro One is to be repaid as follows: 2007, $ 120 516; 2008, $ 63 440; 2009, $ 52 008 and 2010, $ 13,579.

Les sommes dues à Hydro One doivent être remboursées de la façon suivante : 2007, $ 120 516; 2008, $ 63 440; 2009, $ 52 008 et 2010, $ 13 579.

## 9. SHARE CAPITAL / 9. CAPITAL-ACTIONS

*Authorized*
Unlimited number of Class "A" voting shares
Unlimited number of Class "B" voting shares, non-participating
Unlimited number of Class "C" non-voting shares, non-participating

*Autorisé*
Nombre illimité d'actions de classe "A", votantes
Nombre illimité d'actions de classe "B", votantes, non participantes
Nombre illimité d'actions de classe"C", non votantes, non participantes

| | 2006 | 2005 | |
|---|---|---|---|
| *Issued* | | | *Émis* |
| 1 Class "A" share | **$ 308 735** | $ 308 735 | 1 action de classe "A", |

## 10. REVENUE / 10. REVENUS

| | 2006 | 2005 | |
|---|---|---|---|
| *ENERGY* | | | *ÉNERGIE* |
| Residential | **$ 1 175 656** | $ 1 126 243 | Résidentiel |
| General < 50 KW | **409 340** | 389 996 | Général < 50 KW |
| General > 50 KW | **362 845** | 389 585 | Général > 50 KW |
| Street light | **34 412** | 25 874 | Éclairage des rues |
| | **$ 1 982 253** | $ 1 931 698 | |
| *DISTRIBUTION* | | | *DISTRIBUTION* |
| Residential | **$ 162 628** | $ 209 063 | Résidentiel |
| General < 50 KW | **53 072** | 61 971 | Général < 50 KW |
| General > 50 KW | **12 271** | 16 202 | Général > 50 KW |
| Street light | **9 735** | 4 672 | Éclairage des rues |
| | **$ 237 706** | $ 291 908 | |

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

| | **2006** | 2005 | |
|---|---|---|---|
| *Changes in non-cash operating working capital items* | | | *Variation des éléments hors caisse du fonds de roulement d'exploitation* |
| Accounts receivable | **$ (61 029)** | $ 50 424 | Débiteurs |
| Unbilled revenue | **19 646** | (23 723) | Revenus non facturés |
| Prepaid expenses | **31 465** | (34 780) | Frais payés d'avance |
| Accounts payable | **(215 093)** | 219 707 | Créditeurs |
| Other current liabilities | **(44 744)** | 53 292 | Autres frais courus |
| Income taxes | **28 211** | 26 624 | Impôts sur le revenu |
| | **$ (241 544)** | $ 291 544 | |
| *Other information* | | | *Autres renseignements* |
| Interest paid | **$ 20 102** | $ 21 292 | Intérêts payés |
| Income taxes recovered | **$ (18 000)** | $ (26 624) | Impôts recouvrés |

## 12. RELATED PARTY TRANSACTIONS / 12. OPÉRATIONS ENTRE APPARENTÉS

The following amounts were paid to the Township of Alfred-Plantagenet, the only shareholder of the Corporation

Les montants suivants ont été versés au Canton d'Alfred-Plantagenet, l'unique actionnaire de la Société

| | **2006** | 2005 | |
|---|---|---|---|
| Long-term debt | | | Dette à long terme |
| Principal | **$ 22 546** | $ 21 356 | Principal |
| Interest | **20 102** | 21 292 | Intérêts |
| Rent | **7 873** | 7 711 | Loyer |
| | **$ 50 521** | $ 50 359 | |

## 13. FINANCIAL STATEMENT'S EFFECTS OF RATE REGULATION / 13. EFFETS DE LA RÉGLEMENTATION DES TARIFS SUR LES ÉTATS FINANCIERS

| | **2006** | 2005 | |
|---|---|---|---|
| Earnings (loss) before income taxes in accordance with accounting principles for electricity distributers as required by the Ontario Energy Board | **$ 4 851** | $ (10 991) | Bénéfice (perte) avant impôts sur le revenu conformément aux principes comptables pour les distributeurs d'électricité tels que requis par la Commission de l'Énergie de l'Ontario |
| Expenses included in other assets | **(19 846)** | (28 500) | Dépenses incluses dans les autres actifs |
| Carrying charges on other assets | **(19 336)** | (36 083) | Frais d'intérêts sur les autres actifs |
| Depreciation of capital assets included in other assets | **(5 701)** | (7 014) | Amortissement des immobilisations corporelles inclus dans les autres actifs |
| Amortization of a billing contract | **(19 258)** | (19 258) | Amortissement d'un contrat pour la facturation |
| Recoveries | **186 552** | 130 935 | Recouvrements |
| Adjusted earnings before income taxes and before the effect of the regulation on the financial statements | **$ 127 262** | $ 29 089 | Bénéfice avant impôts sur le revenu et avant l'effet de la réglementation sur les états financiers |

**14. RECLASSIFICATION**

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

**14. RECLASSEMENT**

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

# Hydro 2000 Inc.

## PRO FORMA FINANCIAL STATEMENTS AT DECEMBER 31, 2007

### BRIDGE YEAR

| **FinStmt** | **BS** |
|---|---|

| **Sum of Amount** | | | |
|---|---|---|---|
| **GroupDesc** | **Total** | **Adjustment** | **Pro-Forma** |
| 1050-Current Assets | 1,058,096 | 0 | 1,058,096 |
| 1100-Inventory | 15,606 | | 15,606 |
| 1200-Other Assets and Deferred Charges | 292,955 | | 292,955 |
| 1300-Intangible Plant | 1,341 | | 1,341 |
| 1450-Distribution Plant | 693,250 | | 693,250 |
| 1500-General Plant | (13,703) | | (13,703) |
| 1550-Other Capital Assets | 0 | | 0 |
| 1600-Accumulated Amortization | (277,959) | | (277,959) |
| 1650-Current Liabilities | (652,579) | (24,278) | (676,857) |
| 1700-Non-Current Liabilities | (4,131) | | (4,131) |
| 1800-Long-Term Debt | (324,713) | | (324,713) |
| 1850-Shareholders' Equity | (788,163) | 24,278 | (763,885) |
| **Balance Sheet Total** | **(0)** | | (0) |

| FinStmt | PL |
|---|---|

| Sum of Amount | | | |
|---|---|---|---|
| GroupDesc | Total | Adjustment | Pro-Forma |
| 3000-Sales of Electricity | -2,051,911 | 0 | -2,051,911 |
| 3050-Revenues From Services - Distirbution | -346,100 | | -346,100 |
| 3100-Other Operating Revenues | -14,404 | | -14,404 |
| 3150-Other Income & Deductions | -596 | | -596 |
| 3200-Investment Income | -16,314 | | -16,314 |
| 3350-Power Supply Expenses | 2,051,911 | | 2,051,911 |
| 3500-Distribution Expenses - Operation | 738 | | 738 |
| 3550-Distribution Expenses - Maintenance | 3,717 | | 3,717 |
| 3650-Billing and Collecting | 85,914 | | 85,914 |
| 3800-Administrative and General Expenses | 136,340 | | 136,340 |
| 3850-Amortization Expense | 48,834 | | 48,834 |
| 3900-Interest Expense | 15,895 | | 15,895 |
| 4000-Income Taxes | -8,326 | 24,278 | 15,952 |
| 4100-Extraordinary & Other Items | 300 | | 300 |
| Net Income | -94,000 | | -94,000 |

# Hydro 2000 Inc.

## PRO FORMA FINANCIAL STATEMENTS AT DECEMBER 31, 2008

### TEST YEAR

| FinStmt | BS |
|---|---|

| Sum of Amount | | | |
|---|---|---|---|
| **GroupDesc** | **Total** | **Adjustment** | **Pro-Forma** |
| 1050-Current Assets | 1,058,096 | 0 | 1,058,096 |
| 1100-Inventory | 15,606 | | 15,606 |
| 1200-Other Assets and Deferred Charges | 175,548 | | 175,548 |
| 1300-Intangible Plant | 1,341 | | 1,341 |
| 1450-Distribution Plant | 833,250 | | 833,250 |
| 1500-General Plant | (13,703) | | (13,703) |
| 1550-Other Capital Assets | 0 | | 0 |
| 1600-Accumulated Amortization | (334,528) | | (334,528) |
| 1650-Current Liabilities | (801,815) | (5,095) | (806,910) |
| 1700-Non-Current Liabilities | (4,131) | | (4,131) |
| 1800-Long-Term Debt | (299,582) | | (299,582) |
| 1850-Shareholders' Equity | (630,083) | 5,095 | (624,988) |
| **Balance Sheet Total** | **0** | | 0 |

| FinStmt | PL |
|---|---|

| Sum of Amount | | | |
|---|---|---|---|
| **GroupDesc** | **Total** | **Adjustment** | **Pro-Forma** |
| 3000-Sales of Electricity | (2,061,630) | 0 | (2,061,630) |
| 3050-Revenues From Services - Distribution | (362,699) | | (362,699) |
| 3100-Other Operating Revenues | (14,404) | | (14,404) |
| 3150-Other Income & Deductions | (596) | | (596) |
| 3200-Investment Income | (16,314) | | (16,314) |
| 3350-Power Supply Expenses | 2,061,630 | | 2,061,630 |
| 3500-Distribution Expenses - Operation | 738 | | 738 |
| 3550-Distribution Expenses - Maintenance | 3,717 | | 3,717 |
| 3650-Billing and Collecting | 87,657 | | 87,657 |
| 3800-Administrative and General Expenses | 197,631 | | 197,631 |
| 3850-Amortization Expense | 56,569 | | 56,569 |
| 3900-Interest Expense | 11,933 | | 11,933 |
| 4000-Income Taxes | 697 | 5,095 | 5,792 |
| 4100-Extraordinary & Other Items | 300 | | 300 |
| **Net Income** | **(34,770)** | | (34,770) |

# Hydro 2000 Inc.

## RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED

Deloitte.

Deloitte & Touche LLP
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Ontario Energy Board
PO Box 2319
26th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

September 10, 2007

Sir, Madam:

This letter is to confirm the changes made to the 2006 audited balances of Hydro 2000 Inc. (License number EB-2007-0704) pursuant to RP-2005-0020. Regulations assets amounts approved by the Board for recovery in rates were recorded in 2006. Those changes affected only note 4 of the audited financial statements. The changes are shown below:

| | 2006 Audited Financial Statements | Adjustments | 2006 Adjusted Financial Statements |
|---|---|---|---|
| OTHER ASSETS | | | |
| 1555 Smart meters variance | $ (2,402) | $ - | $ (2,402) |
| 1550 LV Variance | 21,012 | - | 21,012 |
| 1508,1525,1565,1566 Other regulatory assets | 39,141 | (34,596) | 4,545 |
| 1570 Qualifying Transition Costs | 156,397 | (156,397) | - |
| 1571 Pre-market Opening Energy Variance | 186,893 | (186,893) | - |
| 1580-1588 Retail Settlement Variance Account | 428,915 | (404,322) | 24,593 |
| 1590 Recovery of Regulators Asset Balances | (386,824) | 782,208 | 395,384 |
| | $ 443,132 | $ - | $ 443,132 |

We hope the above to be to your entire satisfaction.

Yours truly,

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

GDH/dr

## Hydro 2000 Inc.

### PROPOSED ACCOUNTING TREATMENT

Not applicable all projects are less than a year or decompose in phase less than a year.

### INFORMATION ON PARENT AND SUBSIDIARIES

Not applicable no affiliates.

# Hydro 2000 Inc.

## 2 – Rate Base

| | | |
|---|---|---|
| 1 | | **Overview** |
| | 1 | Rate Base Overview |
| | 2 | Rate Base Summary Table |
| | 3 | Variance Analysis on Rate Base Table |
| 2 | | **Gross Assets – Property, Plant and Equipment Accumulated Depreciation** |
| | 1 | Continuity Statements |
| | 2 | Gross Assets Table |
| | 3 | Materiality Analysis on Gross Assets |
| | 4 | Accumulated Depreciation Table |
| | 5 | Materiality Analysis on Accumulated Depreciation |
| 3 | | **Capital Budget** |
| | 1 | Capital Budget by Project |
| | 2 | Materiality Analysis on Capital Additions |
| | 3 | System Expansions |
| | 4 | Capitalization Policy |
| 4 | | **Allowance for Working Capital** |
| | 1 | Overview and Calculation by Account |

# Hydro 2000 Inc.

## RATE BASE OVERVIEW

A projection of the Applicant's rate base is provided for both the Bridge Year (2007) and the Test Year (2008). Historical data pertaining to rate base is also presented for 2002 through to 2006 Actual.

The Applicant's forecast rate base for the test year is $799,349. The rate base underlying the test year revenue requirement includes a forecast of net fixed assets, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated depreciation and contributed capital. Details for the utility's working capital allowance is provided at Exhibits 2, Tab 4, Schedule 1.

Continuity schedules for Historical Board Approved, Historical Actual, Bridge and Test years are provided at Exhibit 2, Tab 2, Schedule 1.

Gross Asset – Property, Plant and Equipment and Accumulated Depreciation
The bridge and test year's gross asset balance reflects the capital expenditure programs forecast for both years. These programs are described in detail in the company's written evidence at Exhibits 2, Tab 2, Schedule 1. The justification for capital projects in excess of 1% of the net fixed assets are filed at Exhibit 2, Tab 3, Schedule 1.

Capital Budget
The Capital Budget Section is composed of Capital Budget by Project ( Exhibit 2, Tab 3, Schedule 1), Materiality Analysis on Capital Addition ( Exhibit 2, Tab 3, Schedule 2), System Expansion ( Exhibit 2, Tab 3, Schedule 3) and Capitalization Policy ( Exhibit 2, Tab 3, Schedule 4).

Allowance for Working Capital
Overview and Calculation by account for Allowance for Working Capital is provided at Exhibit 2, Tab 4, Schedule 1.

| | |
|---|---|
| 2006 Board Approved | $304,312 |
| 2006 Actual | $330,114 |
| 2007 Bridge Year | $331,344 |
| 2008 Test Year | $356,047 |

# Hydro 2000 Inc.

## RATE BASE SUMMARY TABLE

| RATE BASE SUMMARY | 2006 Board Approved ($'s) | 2006 Actual ($'s) | Variance form 2006 Board Approved ($'s) | 2006 Actual ($'s) | 2007 Bridge ($'s) | Variance form 2006 Actual ($'s) | 2007 Bridge ($'s) | 2008 Test ($'s) | Variance form 2007 Bridge ($'s) |
|---|---|---|---|---|---|---|---|---|---|
| Gross Asset<br>Asset Values at Cost | $ 478,722 | $ 575,069 | $ 96,347 | $ 575,069 | $ 640,149 | $ 65,080 | $ 640,149 | $749,548 | $109,399 |
| Accumulated Depreciation Depreciation | $ 127,354 | $ 207,175 | $ 79,821 | $ 207,175 | $ 253,543 | $ 46,369 | $ 253,543 | $306,246 | $ 52,703 |
| Net Fixed Asset | $ 351,368 | $ 367,895 | $ 16,527 | $ 367,895 | $ 386,606 | $ 18,712 | $ 386,606 | $443,302 | $ 56,696 |
| Allowance for Working Capital | $ 304,312 | $ 330,114 | $ 25,802 | $ 330,114 | $ 331,344 | $ 1,230 | $ 331,344 | $356,047 | $ 24,703 |
| Utility Rate Base | $ 655,680 | $ 698,009 | $ 42,329 | $ 698,009 | $ 717,950 | $ 19,942 | $ 717,950 | $799,349 | $ 81,399 |

# Hydro 2000 Inc.

## VARIANCE ANALYSIS ON RATE BASE SUMMARY TABLE

A summary of utility rate base is presented in Exhibit 2, Tab 2, Schedule 1.

### 2008 Test Year

As shown in Exhibit 2, Tab 2, Schedule 1, the total rate base in the 2008 test year is forecast to be $799,349. Net fixed assets accounts for $443,302 of this total. The allowance for working capital totals $356,047.

### Comparison to 2007 Bridge Year

The total rate base is expected to be $799,349 or 11.33% higher in the 2008 test year than in the 2007 bridge year. This increase is shown in Exhibit 2, Tab 2, Schedule 1. This increase is the result of several capital projects in the 200 7 Bridge and 2008 Test Year. Net fixed assets accounts for $486,606 of this total. The allowance for working capital totals $356,047.

### 2007 Bridge Year

The total rate base is expected to be $717,950 or 2.85% higher in the 2007 Bridge Year than in the 2006 Actual Year. This increase is shown in Exhibit 2, Tab 2, Schedule 1. This increase is the result of several capital projects in the 2006 Actual and 2007 Bridge Year. Net fixed assets accounts for $443,302 of this total. The allowance for working capital totals $331,344.

### 2006 Actual

The total rate base is $698,009 or 6.45% higher in the 2006 Actual Year than in the 2006 Board Approved Year. This increase is shown in Exhibit 2, Tab 2, Schedule 1. This increase is the result of several capital projects in the 2006 Actual Year. Net fixed assets accounts for $367,895 of this total. The allowance for working capital totals $330,114.

### 2006 Board Approved

The total rate base for 2006 Board Approved Year is $655,680. Net fixed assets accounts for $351,368 of this total. The allowance for working capital totals $304,312.

# Hydro 2000 Inc.

## CONTINUITY STATMENTS

| CONTINUITY STATEMENTS | 2006 Actual | | | 2007 Bridge | | | 2008 Test | | |
|---|---|---|---|---|---|---|---|---|---|
| | Gross Asset Value | Accumulated Depreciation | Net Book Value | Gross Asset Value | Accumulated Depreciation | Net Book Value | Gross Asset Value | Accumulated Depreciation | Net Book Value |
| **Land and Buildings** | | | | | | | | | |
| 1805-Land -Opening Balance | | | - | - | - | - | - | - | - |
| 1805-Land -Additions | | | - | | | - | | | - |
| 1805-Land -Depreciation | | | - | | | - | | | - |
| 1805-Land -Adjustments | | | - | | | - | | | - |
| 1805-Land -Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |
| 1806-Land Rights -Opening Balance | | | - | - | - | - | - | - | - |
| 1806-Land Rights -Additions | | | - | | | - | | | - |
| 1806-Land Rights -Depreciation | | | - | | | - | | | - |
| 1806-Land Rights -Adjustments | | | - | | | - | | | - |
| 1806-Land Rights -Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |
| 1905-Land -Opening Balance | | | - | - | - | - | - | - | - |
| 1905-Land -Additions | | | - | | | - | | | - |
| 1905-Land -Depreciation | | | - | | | - | | | - |
| 1905-Land -Adjustments | | | - | | | - | | | - |
| 1905-Land -Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1906-Land Rights-Opening Balance | | | - | - | - | - | - | - | - |
| 1906-Land Rights-Additions | | | - | | | - | | | - |
| 1906-Land Rights-Depreciation | | | - | | | - | | | - |
| 1906-Land Rights -Adjustments | | | - | | | - | | | - |
| 1906-Land Rights -Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |
| | | | | | | | | | |
| 1810-Leasehold Improvements-Opening Balance | | | - | - | - | - | - | - | - |
| 1810-Leasehold Improvements-Additions | | | - | | | - | | | - |
| 1810-Leasehold Improvements-Depreciation | | | - | | | - | | | - |
| 1810-Leasehold Improvements -Adjustments | | | - | | | - | | | - |
| 1810-Leasehold Improvements -Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |
| Total | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | |
| TS Primary Above 50 | | | | | | | | | |
| 1815-Transformer Station Equipment - Normally Primary above 50 kV-Opening Balance | | | - | - | - | - | - | - | - |
| 1815-Transformer Station Equipment - Normally Primary above 50 kV-Additions | | | - | | | - | | | - |
| 1815-Transformer Station Equipment - Normally Primary above 50 kV-Depreciation | | | - | | | - | | | - |
| 1815-Transformer Station Equipment - Normally Primary above 50 kV-Adjustments | | | - | | | - | | | - |
| 1815-Transformer Station Equipment - Normally Primary above 50 kV-Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |
| Total | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | |
| DS | | | | | | | | | |
| 1820-Distribution Station Equipment - Normally Primary below 50 kV-Opening Balance | | | - | - | - | - | - | - | - |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **1820-Distribution Station Equipment - Normally Primary below 50 kV-Additions** | | | - | | | - | | | - |
| **1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation** | | | - | | | - | | | - |
| **1820-Distribution Station Equipment - Normally Primary below 50 kV-Adjustments** | | | - | | | - | | | - |
| **1820-Distribution Station Equipment - Normally Primary below 50 kV-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **Total** | - | - | - | - | - | - | - | - | - |
| **Poles and Wires** | | | | | | | | | |
| **1830-Poles, Towers and Fixtures-Opening Balance** | 187,032 | 57,005 | 130,027 | 194,996 | 69,756 | 125,240 | 194,996 | 82,506 | 112,490 |
| **1830-Poles, Towers and Fixtures-Additions** | 7,964 | | 7,964 | | | - | | | - |
| **1830-Poles, Towers and Fixtures-Depreciation** | | 12,751 | (12,751) | | 12,750 | (12,750) | | 12,750 | (12,750) |
| **1830-Poles, Towers and Fixtures-Adjustments** | | | - | | | - | | | - |
| **1830-Poles, Towers and Fixtures-Closing Balance** | 194,996 | 69,756 | 125,240 | 194,996 | 82,506 | 112,490 | 194,996 | 95,256 | 99,740 |
| **Average** | | | | 194,996 | 76,131 | 118,865 | 194,996 | 88,881 | 106,115 |
| **1835-Overhead Conductors and Devices-Opening Balance** | 161,091 | 54,758 | 106,333 | 179,684 | 66,897 | 112,787 | 179,684 | 79,036 | 100,648 |
| **1835-Overhead Conductors and Devices-Additions** | 18,593 | | 18,593 | | | - | 40,000 | | 40,000 |
| **1835-Overhead Conductors and Devices-Depreciation** | | 12,139 | (12,139) | | 12,139 | (12,139) | | 12,939 | (12,939) |
| **1835-Overhead Conductors and Devices-Adjustments** | | | - | | | - | | | - |
| **1835-Overhead Conductors and Devices-Closing Balance** | 179,684 | 66,897 | 112,787 | 179,684 | 79,036 | 100,648 | 219,684 | 91,975 | 127,709 |
| **Average** | | | | 179,684 | 72,967 | 106,718 | 199,684 | 85,506 | 114,179 |
| **1840-Underground Conduit-Opening Balance** | | | - | 13,405 | 536 | 12,869 | 13,405 | 1,072 | 12,333 |
| **1840-Underground Conduit-Additions** | 13,405 | | 13,405 | | | - | | | - |
| **1840-Underground Conduit-Depreciation** | | 536 | (536) | | 536 | (536) | | 536 | (536) |
| **1840-Underground Conduit-Adjustments** | | | - | | | - | | | - |
| **1840-Underground Conduit-Closing Balance** | | | | | | | | | |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 13,405 | 536 | 12,869 | 13,405 | 1,072 | 12,333 | 13,405 | 1,608 | 11,797 |
| **Average** | | | | 13,405 | 804 | 12,601 | 13,405 | 1,340 | 12,065 |
| **1845-Underground Conductors and Devices-Opening Balance** | 63,209 | 17,412 | 45,797 | 64,201 | 21,180 | 43,021 | 127,182 | 26,209 | 100,973 |
| **1845-Underground Conductors and Devices-Additions** | 992 | | 992 | 62,981 | | 62,981 | | | - |
| **1845-Underground Conductors and Devices-Depreciation** | | 3,768 | (3,768) | | 5,029 | (5,029) | | 6,288 | (6,288) |
| **1845-Underground Conductors and Devices-Adjustments** | | | - | | | - | | | - |
| **1845-Underground Conductors and Devices-Closing Balance** | 64,201 | 21,180 | 43,021 | 127,182 | 26,209 | 100,973 | 127,182 | 32,497 | 94,685 |
| **Average** | | | | 95,692 | 23,695 | 71,997 | 127,182 | 29,353 | 97,829 |
| **Total** | 452,286 | 158,369 | 293,917 | 515,267 | 188,823 | 326,444 | 555,267 | 221,336 | 333,931 |
| **Line Transformers** | | | | | | | | | |
| **1850-Line Transformers-Opening Balance** | 57,033 | 18,533 | 38,500 | 60,495 | 22,545 | 37,950 | 76,694 | 26,881 | 49,813 |
| **1850-Line Transformers-Additions** | 3,462 | | 3,462 | 16,199 | | 16,199 | | | - |
| **1850-Line Transformers-Depreciation** | | 4,012 | (4,012) | | 4,336 | (4,336) | | 4,660 | (4,660) |
| **1850-Line Transformers-Adjustments** | | | - | | | - | | | - |
| **1850-Line Transformers-Closing Balance** | 60,495 | 22,545 | 37,950 | 76,694 | 26,881 | 49,813 | 76,694 | 31,541 | 45,153 |
| **Average** | | | | 68,595 | 24,713 | 43,882 | 76,694 | 29,211 | 47,483 |
| **Total** | 60,495 | 22,545 | 37,950 | 76,694 | 26,881 | 49,813 | 76,694 | 31,541 | 45,153 |
| **Services and Meters** | | | | | | | | | |
| **1855-Services-Opening Balance** | | | - | 52,400 | 2,096 | 50,304 | 52,400 | 4,192 | 48,208 |
| **1855-Services-Additions** | 52,400 | | 52,400 | | | - | | | - |
| **1855-Services-Depreciation** | | 2,096 | (2,096) | | 2,096 | (2,096) | | 2,096 | (2,096) |
| **1855-Services-Adjustments** | | | - | | | - | | | - |
| **1855-Services-Closing Balance** | 52,400 | 2,096 | 50,304 | 52,400 | 4,192 | 48,208 | 52,400 | 6,288 | 46,112 |
| **Average** | | | | 52,400 | 3,144 | 49,256 | 52,400 | 5,240 | 47,160 |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **1860-Meters-Opening Balance** | 44,839 | 17,231 | 27,608 | 48,889 | 20,814 | 28,075 | 48,889 | 24,397 | 24,492 |
| **1860-Meters-Additions** | 4,050 | | 4,050 | | | - | 100,000 | | 100,000 |
| **1860-Meters-Depreciation** | | 3,583 | (3,583) | | 3,583 | (3,583) | | 5,583 | (5,583) |
| **1860-Meters-Adjustments** | | | - | | | - | | | - |
| **1860-Meters-Closing Balance** | 48,889 | 20,814 | 28,075 | 48,889 | 24,397 | 24,492 | 148,889 | 29,980 | 118,909 |
| **Average** | | | | 48,889 | 22,606 | 26,284 | 98,889 | 27,189 | 71,701 |
| **Total** | 101,289 | 22,910 | 78,379 | 101,289 | 28,589 | 72,700 | 201,289 | 36,268 | 165,021 |
| **General Plant** | | | | | | | | | |
| **1908-Buildings and Fixtures-Opening Balance** | | | - | - | - | - | - | - | - |
| **1908-Buildings and Fixtures-Additions** | | | - | | | - | | | - |
| **1908-Buildings and Fixtures-Depreciation** | | | - | | | - | | | - |
| **1908-Buildings and Fixtures-Adjustments** | | | - | | | - | | | - |
| **1908-Buildings and Fixtures-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **1910-Leasehold Improvements-Opening Balance** | | | - | - | - | - | - | - | - |
| **1910-Leasehold Improvements-Additions** | | | - | | | - | | | - |
| **1910-Leasehold Improvements-Depreciation** | | | - | | | - | | | - |
| **1910-Leasehold Improvements-Adjustments** | | | - | | | - | | | - |
| **1910-Leasehold Improvements-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **Total** | - | - | - | - | - | - | - | - | - |
| **IT Assets** | | | | | | | | | |
| **1920-Computer Equipment - Hardware-Opening Balance** | 19,127 | 13,622 | 5,505 | 24,819 | 16,495 | 8,324 | 24,819 | 19,368 | 5,451 |
| **1920-Computer Equipment - Hardware-Additions** | | | | | | | | | |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 5,692 | | 5,692 | | | - | | | - |
| **1920-Computer Equipment - Hardware-Depreciation** | | 2,873 | (2,873) | | 2,873 | (2,873) | | 2,870 | (2,870) |
| **1920-Computer Equipment - Hardware-Adjustments** | | | - | | | - | | | - |
| **1920-Computer Equipment - Hardware-Closing Balance** | 24,819 | 16,495 | 8,324 | 24,819 | 19,368 | 5,451 | 24,819 | 22,238 | 2,581 |
| **Average** | | | | 24,819 | 17,932 | 6,888 | 24,819 | 20,803 | 4,016 |
| **1925-Computer Software-Opening Balance** | 13,811 | 3,807 | 10,004 | 23,398 | 8,487 | 14,911 | 65,398 | 17,366 | 48,032 |
| **1925-Computer Software-Additions** | 9,587 | | 9,587 | 42,000 | | 42,000 | | | - |
| **1925-Computer Software-Depreciation** | | 4,680 | (4,680) | | 8,879 | (8,879) | | 13,079 | (13,079) |
| **1925-Computer Software-Adjustments** | | | - | | | - | | | - |
| **1925-Computer Software-Closing Balance** | 23,398 | 8,487 | 14,911 | 65,398 | 17,366 | 48,032 | 65,398 | 30,445 | 34,953 |
| **Average** | | | | 44,398 | 12,927 | 31,472 | 65,398 | 23,906 | 41,493 |
| **Total** | 48,217 | 24,982 | 23,235 | 90,217 | 36,734 | 53,483 | 90,217 | 52,683 | 37,534 |
| **Equipment** | | | | | | | | | |
| **1915-Office Furniture and Equipment-Opening Balance** | 3,246 | 2,856 | 390 | 3,246 | 2,910 | 336 | 3,246 | 2,964 | 282 |
| **1915-Office Furniture and Equipment-Additions** | | | - | | | - | | | - |
| **1915-Office Furniture and Equipment-Depreciation** | | 54 | (54) | | 54 | (54) | | 54 | (54) |
| **1915-Office Furniture and Equipment-Adjustments** | | | - | | | - | | | - |
| **1915-Office Furniture and Equipment-Closing Balance** | 3,246 | 2,910 | 336 | 3,246 | 2,964 | 282 | 3,246 | 3,018 | 228 |
| **Average** | | | | 3,246 | 2,937 | 309 | 3,246 | 2,991 | 255 |
| **1930-Transportation Equipment-Opening Balance** | | | - | - | - | - | - | - | - |
| **1930-Transportation Equipment-Additions** | | | - | | | - | | | - |
| **1930-Transportation Equipment-Depreciation** | | | - | | | - | | | - |
| **1930-Transportation Equipment-Adjustments** | | | - | | | - | | | - |
| **1930-Transportation Equipment-Closing Balance** | - | - | - | - | - | - | - | - | - |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Average** | | | | - | - | - | - | - | - |
| **1935-Stores Equipment-Opening Balance** | | | - | - | - | - | - | - | - |
| **1935-Stores Equipment-Additions** | | | - | | | - | | | - |
| **1935-Stores Equipment-Depreciation** | | | - | | | - | | | - |
| **1935-Stores Equipment-Adjustments** | | | - | | | - | | | - |
| **1935-Stores Equipment-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **1940-Tools, Shop and Garage Equipment-Opening Balance** | | | - | - | - | - | - | - | - |
| **1940-Tools, Shop and Garage Equipment-Additions** | | | - | | | - | | | - |
| **1940-Tools, Shop and Garage Equipment-Depreciation** | | | - | | | - | | | - |
| **1940-Tools, Shop and Garage Equipment-Adjustments** | | | - | | | - | | | - |
| **1940-Tools, Shop and Garage Equipment-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **1945-Measurement and Testing Equipment-Opening Balance** | | | - | - | - | - | - | - | - |
| **1945-Measurement and Testing Equipment-Additions** | | | - | | | - | | | - |
| **1945-Measurement and Testing Equipment-Depreciation** | | | - | | | - | | | - |
| **1945-Measurement and Testing Equipment-Adjustments** | | | - | | | - | | | - |
| **1945-Measurement and Testing Equipment-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **1950-Power Operated Equipment-Opening Balance** | | | - | - | - | - | - | - | - |
| **1950-Power Operated Equipment-Additions** | | | - | | | - | | | - |
| **1950-Power Operated Equipment-Depreciation** | | | - | | | - | | | - |
| **1950-Power Operated Equipment-Adjustments** | | | - | | | - | | | - |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **1950-Power Operated Equipment-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **1955-Communication Equipment-Opening Balance** | | | - | - | - | - | - | - | - |
| **1955-Communication Equipment-Additions** | | | - | | | - | | | - |
| **1955-Communication Equipment-Depreciation** | | | - | | | - | | | - |
| **1955-Communication Equipment-Adjustments** | | | - | | | - | | | - |
| **1955-Communication Equipment-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **1960-Miscellaneous Equipment-Opening Balance** | | | - | - | - | - | - | - | - |
| **1960-Miscellaneous Equipment-Additions** | | | - | | | - | | | - |
| **1960-Miscellaneous Equipment-Depreciation** | | | - | | | - | | | - |
| **1960-Miscellaneous Equipment-Adjustments** | | | - | | | - | | | - |
| **1960-Miscellaneous Equipment-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **Total** | 3,246 | 2,910 | 336 | 3,246 | 2,964 | 282 | 3,246 | 3,018 | 228 |
| **Other Distribution Assets** | | | | | | | | | |
| **1825-Storage Battery Equipment-Opening Balance** | | | - | - | - | - | - | - | - |
| **1825-Storage Battery Equipment-Additions** | | | - | | | - | | | - |
| **1825-Storage Battery Equipment-Depreciation** | | | - | | | - | | | - |
| **1825-Storage Battery Equipment-Adjustments** | | | - | | | - | | | - |
| **1825-Storage Battery Equipment-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **1970-Load Management Controls - Customer Premises-Opening Balance** | | | - | - | - | - | - | - | - |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1970-Load Management Controls - Customer Premises-Additions | | | - | | | - | | | - |
| 1970-Load Management Controls - Customer Premises-Depreciation | | | - | | | - | | | - |
| 1970-Load Management Controls - Customer Premises-Adjustments | | | - | | | - | | | - |
| 1970-Load Management Controls - Customer Premises-Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |
| 1975-Load Management Controls - Utility Premises-Opening Balance | | | - | - | - | - | - | - | - |
| 1975-Load Management Controls - Utility Premises-Additions | | | - | | | - | | | - |
| 1975-Load Management Controls - Utility Premises-Depreciation | | | - | | | - | | | - |
| 1975-Load Management Controls - Utility Premises-Adjustments | | | - | | | - | | | - |
| 1975-Load Management Controls - Utility Premises-Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |
| 1980-System Supervisory Equipment-Opening Balance | | | - | - | - | - | - | - | - |
| 1980-System Supervisory Equipment-Additions | | | - | | | - | | | - |
| 1980-System Supervisory Equipment-Depreciation | | | - | | | - | | | - |
| 1980-System Supervisory Equipment-Adjustments | | | - | | | - | | | - |
| 1980-System Supervisory Equipment-Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |
| 1985-Sentinel Lighting Rental Units-Opening Balance | | | - | - | - | - | - | - | - |
| 1985-Sentinel Lighting Rental Units-Additions | | | - | | | - | | | - |
| 1985-Sentinel Lighting Rental Units-Depreciation | | | - | | | - | | | - |
| 1985-Sentinel Lighting Rental Units-Adjustments | | | - | | | - | | | - |
| 1985-Sentinel Lighting Rental Units-Closing Balance | - | - | - | - | - | - | - | - | - |
| Average | | | | - | - | - | - | - | - |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **1990-Other Tangible Property-Opening Balance** | | | - | - | - | - | - | - | - |
| **1990-Other Tangible Property-Additions** | | | - | | | - | | | - |
| **1990-Other Tangible Property-Depreciation** | | | - | | | - | | | - |
| **1990-Other Tangible Property-Adjustments** | | | - | | | - | | | - |
| **1990-Other Tangible Property-Closing Balance** | - | - | - | - | - | - | - | - | - |
| **Average** | | | | - | - | - | - | - | - |
| **1995-Contributions and Grants - Credit-Opening Balance** | | | - | (64,783) | (2,591) | (62,192) | (107,165) | (6,030) | (101,135) |
| **1995-Contributions and Grants - Credit-Additions** | (64,783) | | (64,783) | (42,382) | | (42,382) | | | - |
| **1995-Contributions and Grants - Credit-Depreciation** | | (2,591) | 2,591 | | (3,439) | 3,439 | | (4,286) | 4,286 |
| **1995-Contributions and Grants - Credit-Adjustments** | | | - | | | - | | | - |
| **1995-Contributions and Grants - Credit-Closing Balance** | (64,783) | (2,591) | (62,192) | (107,165) | (6,030) | (101,135) | (107,165) | (10,316) | (96,849) |
| **Average** | | | | (85,974) | (4,311) | (81,664) | (107,165) | (8,173) | (98,992) |
| **Total** | (64,783) | (2,591) | (62,192) | (107,165) | (6,030) | (101,135) | (107,165) | (10,316) | (96,849) |
| **Total Opening Balance** | 549,388 | 185,224 | 364,164 | 600,750 | 229,125 | 371,625 | 679,548 | 277,961 | 401,587 |
| **Total Additions** | 51,362 | - | 51,362 | 78,798 | - | 78,798 | 140,000 | - | 140,000 |
| **Total Depreciation** | - | 43,901 | (43,901) | - | 48,836 | (48,836) | - | 56,569 | (56,569) |
| **Total Adjustments** | - | - | - | - | - | - | - | - | - |
| **Total Closing Balance** | 600,750 | 229,125 | 371,625 | 679,548 | 277,961 | 401,587 | 819,548 | 334,530 | 485,018 |
| **Average** | | | | 640,149 | 253,543 | 386,606 | 749,548 | 306,246 | 443,303 |

# Hydro 2000 INC.

## GROSS ASSETS TABLE

| GROSS ASSET | 2006 Board Approved ($'s) | 2006 Actual ($'s) | Variance form 2006 Board Approved | 2006 Actual ($'s) | 2007 Bridge ($'s) | Variance form 2006 Actual | 2007 Bridge ($'s) | 2008 Test ($'s) | Variance form 2007 Bridge |
|---|---|---|---|---|---|---|---|---|---|
| **Land and Buildings** | | | | | | | | | |
| 1805-Land | | | - | - | | - | - | | - |
| 1806-Land Rights | | | - | - | | - | - | | - |
| 1808-Buildings and Fixtures | | | - | - | | - | - | | - |
| 1905-Land | | | - | - | | - | - | | - |
| 1906-Land Rights | | | - | - | | - | - | | - |
| 1810-Leasehold Improvements | | | - | - | | - | - | | - |
| **Sub-Total-Land and Buildings** | - | - | - | - | - | - | - | - | - |
| **TS Primary Above 50** | | | | | | | | | |
| 1815-Transformer Station Equipment - Normally Primary above 50 kV | | | - | - | | - | - | | - |
| **Sub-Total-TS Primary Above 50** | - | - | - | - | - | - | - | - | - |
| **DS** | | | | | | | | | |
| 1820-Distribution Station Equipment - Normally Primary below 50 kV | | | - | - | | - | - | | - |
| **Sub-Total-DS** | - | - | - | - | - | - | - | - | - |
| **Poles and Wires** | | | | | | | | | |
| 1830-Poles, Towers and Fixtures | 160,743 | 194,996 | 34,253 | 194,996 | 194,996 | - | 194,996 | 194,996 | - |
| 1835-Overhead Conductors and Devices | 149,656 | 179,684 | 30,028 | 179,684 | 179,684 | - | 179,684 | 219,684 | 40,000 |
| 1840-Underground Conduit | | 13,405 | 13,405 | 13,405 | 13,405 | - | 13,405 | 13,405 | - |
| 1845-Underground Conductors and Devices | 52,075 | 64,201 | 12,126 | 64,201 | 127,182 | 62,981 | 127,182 | 127,182 | - |

# Hydro 2000 INC.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Sub-Total-Poles and Wires** | 362,474 | 452,286 | 89,812 | 452,286 | 515,267 | 62,981 | 515,267 | 555,267 | 40,000 |
| **Line Transformers** | | | | | | | | | |
| 1850-Line Transformers | 52,828 | 60,495 | 7,667 | 60,495 | 76,694 | 16,199 | 76,694 | 76,694 | - |
| **Sub-Total-Line Transformers** | 52,828 | 60,495 | 7,667 | 60,495 | 76,694 | 16,199 | 76,694 | 76,694 | - |
| **Services and Meters** | | | | | | | | | |
| 1855-Services | - | 52,400 | 52,400 | 52,400 | 52,400 | - | 52,400 | 52,400 | - |
| 1860-Meters | 43,687 | 48,889 | 5,202 | 48,889 | 48,889 | - | 48,889 | 148,889 | 100,000 |
| **Sub-Total-Services and Meters** | 43,687 | 101,289 | 57,602 | 101,289 | 101,289 | - | 101,289 | 201,289 | 100,000 |
| **General Plant** | | | | | | | | | |
| 1908-Buildings and Fixtures | | | - | - | | - | - | | - |
| 1910-Leasehold Improvements | | | - | - | | - | - | | - |
| **Sub-Total-General Plant** | - | - | - | - | - | - | - | - | - |
| **IT Assets** | | | | | | | | | |
| 1920-Computer Equipment - Hardware | 14,037 | 24,819 | 10,782 | 24,819 | 24,819 | - | 24,819 | 24,819 | - |
| 1925-Computer Software | 2,612 | 23,398 | 20,786 | 23,398 | 65,398 | 42,000 | 65,398 | 65,398 | - |
| **Sub-Total-IT Assets** | 16,649 | 48,217 | 31,568 | 48,217 | 90,217 | 42,000 | 90,217 | 90,217 | - |
| **Equipment** | | | | | | | | | |
| 1915-Office Furniture and Equipment | 3,084 | 3,246 | 162 | 3,246 | 3,246 | - | 3,246 | 3,246 | - |
| 1930-Transportation Equipment | | | - | - | | - | - | | - |
| 1935-Stores Equipment | | | - | - | | - | - | | - |
| 1940-Tools, Shop and Garage Equipment | | | - | - | | - | - | | - |
| 1945-Measurement and Testing Equipment | | | - | - | | - | - | | - |
| 1950-Power Operated Equipment | | | - | - | | - | - | | - |
| 1955-Communication Equipment | | | - | - | | - | - | | - |

# Hydro 2000 INC.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1960-Miscellaneous Equipment | | | - | - | | - | - | | - |
| **Sub-Total-Equipment** | 3,084 | 3,246 | 162 | 3,246 | 3,246 | - | 3,246 | 3,246 | - |
| **Other Distribution Assets** | | | | | | | | | |
| 1825-Storage Battery Equipment | | | - | - | | - | - | | - |
| 1970-Load Management Controls - Customer Premises | | | - | - | | - | - | | - |
| 1975-Load Management Controls - Utility Premises | | | - | - | | - | - | | - |
| 1980-System Supervisory Equipment | | | - | - | | - | - | | - |
| 1985-Sentinel Lighting Rental Units | | | - | - | | - | - | | - |
| 1990-Other Tangible Property | | | - | - | | - | - | | - |
| 1995-Contributions and Grants - Credit | | (64,783) | (64,783) | (64,783) | (107,165) | (42,382) | (107,165) | (107,165) | - |
| **Sub-Total-Other Distribution Assets** | - | (64,783) | (64,783) | (64,783) | (107,165) | (42,382) | (107,165) | (107,165) | - |
| **GROSS ASSET TOTAL** | 478,722 | 600,750 | 122,028 | 600,750 | 679,548 | 78,798 | 679,548 | 819,548 | 140,000 |

## Hydro 2000 Inc.

## MATERIALITY ANALYSIS ON GROSS ASSET

For any rate base related variance exceeding the materiality threshold of 1%, a detailed explanation is required.

| **Materiality calculation** | |
|---|---|
| 2006 Board approved gross assets | 478,722 |
| 2006 Board approved accumulated depreciation | (127,354) |
| 2006 Board approved capital assets | 351,368 |
| | |
| Materiality = 1% of capital assets | 3,514 |

## General explanation

The 2006 board approved amounts were the average of the actual amounts for the year 2003 and 2004. Variances are the results of 2004 (50%), 2005 and 2006 acquisitions.

## Variances explanations

| GROSS ASSET | 2006 Board Approved | 2006 Actual | Variance from 2006 Board Approved | 50% of 2004 Acquisitions | 2005 Acquisitions | 2006 Acquisitions | Total Acquisitions |
|---|---|---|---|---|---|---|---|
| | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) |
| 1830-Poles, Towers and Fixtures | 160,743 | 194,996 | 34,253 | 3,766 | 22,523 | 7,964 | 34,253 |
| 2004: Replace poles and fixtures<br>2005: Line extension West End of Alfred<br>2006: Replace poles and fixtures | | | | | | | |
| 1835-Overhead Conductors and Devices | 149,656 | 179,684 | 30,028 | 4,027 | 7,408 | 18,593 | 30,028 |
| 2004: Upgrade<br>2005: Line extension West End of Alfred and others<br>2006: Upgrade | | | | | | | |
| 1840-Underground Conduit | - | 13,405 | 13,405 | - | - | 13,405 | 13,405 |
| 2006: Subdivision Yvon Lalande | | | | | | | |

## Hydro 2000 Inc.

# Variances explanations

| GROSS ASSET | 2006 Board Approved | 2006 Actual | Variance from 2006 Board Approved | 50% of 2004 Acquisitions | 2005 Acquisitions | 2006 Acquisitions | Total Acquisitions |
|---|---|---|---|---|---|---|---|
| | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) |
| 1845-Underground Conductors and Devices | 52,075 | 64,201 | 12,126 | - | 11,133 | 993 | 12,126 |
| 2005: Subdivision Yvon Lalande and others | | | | | | | |
| 1850-Line Transformers | 52,828 | 60,495 | 7,667 | 1,722 | 2,483 | 3,462 | 7,667 |
| 2004-2006: Purchase of transformers | | | | | | | |
| 1855-Services | - | 52,400 | 52,400 | - | - | 52,400 | 52,400 |
| 2006: New services | | | | | | | |
| 1860-Meters | 43,687 | 48,889 | 5,202 | 1,152 | - | 4,050 | 5,202 |
| 2006: Replace meters | | | | | | | |
| 1920-Computer Equipment - Hardware | 14,037 | 24,819 | 10,782 | 3,583 | 1,507 | 5,692 | 10,782 |
| 2004: Purchase 2 PCs<br>2006: Purchase laptop and backup system, 2 monitors | | | | | | | |
| 1925-Computer Software | 2,612 | 23,398 | 20,786 | 2,614 | 8,586 | 9,586 | 20,786 |
| 2005: Upgrade Advance CIS<br>2006: Updgrade database to SQL | | | | | | | |
| 1995-Contributions and Grants - Credit | | (64,783) | (64,783) | - | - | (64,783) | (64,783) |
| 2006: Capital contributions made by developers for new projects through economic evaluation model and condition of service. | | | | | | | |

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**Exhibit: 2**
**Tab: 2**
**Schedule: 4**
**Page: 1**

# Hydro 2000 Inc.

## ACCUMULATED DEPRECIATION TABLE

| ACCUMULATED DEPRECIATION TABLE | 2006 Board Approved ($'s) | 2006 Actual ($'s) | Variance form 2006 Board Approved | 2006 Actual ($'s) | 2007 Bridge ($'s) | Variance form 2006 Actual | 2007 Bridge ($'s) | 2008 Test ($'s) | Variance form 2007 Bridge |
|---|---|---|---|---|---|---|---|---|---|
| **Land and Buildings** | | | | | | | | | |
| 1805-Land-Depreciation | | | - | - | | - | - | | - |
| 1806-Land Rights-Depreciation | | | - | - | | - | - | | - |
| 1808-Buildings and Fixtures-Depreciation | | | - | - | | - | - | | - |
| 1905-Land-Depreciation | | | - | - | | - | - | | - |
| 1906-Land Rights-Depreciation | | | - | - | | - | - | | - |
| 1810-Leasehold Improvements-Depreciation | | | - | - | | - | - | | - |
| **Sub-Total-Land and Buildings** | - | - | - | - | - | - | - | - | - |
| **TS Primary Above 50** | | | | | | | | | |
| 1815-Transformer Station Equipment - Normally Primary above 50 kV-Depreciation | | | - | - | | - | - | | - |
| **Sub-Total-TS Primary Above 50** | - | - | - | - | - | - | - | - | - |
| **DS** | | | | | | | | | |
| 1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation | | | - | - | | - | - | | - |
| **Sub-Total-DS** | - | - | - | - | - | - | - | - | - |
| **Poles and Wires** | | | | | | | | | |
| 1830-Poles, Towers and Fixtures-Depreciation | 38,809 | 69,756 | 30,947 | 69,756 | 82,506 | 12,750 | 82,506 | 95,256 | 12,750 |
| 1835-Overhead Conductors and Devices-Depreciation | 37,812 | 66,897 | 29,085 | 66,897 | 79,036 | 12,139 | 79,036 | 91,975 | 12,939 |
| 1840-Underground Conduit-Depreciation | | 536 | 536 | 536 | 1,072 | 536 | 1,072 | 1,608 | 536 |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1845-Underground Conductors and Devices-Depreciation | 12,041 | 21,180 | 9,139 | 21,180 | 26,209 | 5,029 | 26,209 | 32,497 | 6,288 |
| **Sub-Total-Poles and Wires** | 88,662 | 158,369 | 69,707 | 158,369 | 188,823 | 30,454 | 188,823 | 221,336 | 32,513 |
| **Line Transformers** | | | | | | | | | |
| 1850-Line Transformers-Depreciation | 12,773 | 22,545 | 9,772 | 22,545 | 26,881 | 4,336 | 26,881 | 31,541 | 4,660 |
| **Sub-Total-Line Transformers** | 12,773 | 22,545 | 9,772 | 22,545 | 26,881 | 4,336 | 26,881 | 31,541 | 4,660 |
| **Services and Meters** | | | | | | | | | |
| 1855-Services-Depreciation | - | 2,096 | 2,096 | 2,096 | 4,192 | 2,096 | 4,192 | 6,288 | 2,096 |
| 1860-Meters-Depreciation | 12,100 | 20,814 | 8,714 | 20,814 | 24,397 | 3,583 | 24,397 | 29,980 | 5,583 |
| **Sub-Total-Services and Meters** | 12,100 | 22,910 | 10,810 | 22,910 | 28,589 | 5,679 | 28,589 | 36,268 | 7,679 |
| **General Plant** | | | | | | | | | |
| 1908-Buildings and Fixtures-Depreciation | | | - | - | | - | - | | - |
| 1910-Leasehold Improvements-Depreciation | | | - | - | | - | - | | - |
| **Sub-Total-General Plant** | - | - | - | - | - | - | - | - | - |
| **IT Assets** | | | | | | | | | |
| 1920-Computer Equipment - Hardware-Depreciation | 11,077 | 16,495 | 5,418 | 16,495 | 19,368 | 2,873 | 19,368 | 22,238 | 2,870 |
| 1925-Computer Software-Depreciation | 522 | 8,487 | 7,965 | 8,487 | 17,366 | 8,879 | 17,366 | 30,445 | 13,079 |
| **Sub-Total-IT Assets** | 11,599 | 24,982 | 13,383 | 24,982 | 36,734 | 11,752 | 36,734 | 52,683 | 15,949 |
| **Equipment** | | | | | | | | | |
| 1915-Office Furniture and Equipment-Depreciation | 2,220 | 2,910 | 690 | 2,910 | 2,964 | 54 | 2,964 | 3,018 | 54 |
| 1930-Transportation Equipment-Depreciation | | | - | - | | - | - | | - |
| 1935-Stores Equipment-Depreciation | | | - | - | | - | - | | - |
| 1940-Tools, Shop and Garage Equipment-Depreciation | | | - | - | | - | - | | - |
| 1945-Measurement and Testing Equipment- | | | - | - | | - | - | | - |
| 1945-Measurement and Testing Equipment-Depreciation | | | - | - | | - | - | | - |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1950-Power Operated Equipment-Depreciation | | | - | - | | - | - | | - |
| 1955-Communication Equipment-Depreciation | | | - | - | | - | - | | - |
| 1960-Miscellaneous Equipment-Depreciation | 2,220 | 2,910 | 690 | 2,910 | 2,964 | 54 | 2,964 | 3,018 | 54 |
| **Sub-Total-Equipment** | | | | | | | | | |
| **Other Distribution Assets** | | | - | - | | - | - | | - |
| 1825-Storage Battery Equipment-Depreciation | | | - | - | | - | - | | - |
| 1970-Load Management Controls - Customer Premises-Depreciation | | | - | - | | - | - | | - |
| 1975-Load Management Controls - Utility Premises-Depreciation | | | - | - | | - | - | | - |
| 1980-System Supervisory Equipment-Depreciation | | | - | - | | - | - | | - |
| 1985-Sentinel Lighting Rental Units-Depreciation | | | - | - | | - | - | | - |
| 1990-Other Tangible Property-Depreciation | | (2,591) | (2,591) | (2,591) | (6,030) | (3,439) | (6,030) | (10,316) | (4,286) |
| 1995-Contributions and Grants - Credit-Depreciation | - | (2,591) | (2,591) | (2,591) | (6,030) | (3,439) | (6,030) | (10,316) | (4,286) |
| **Sub-Total-Other Distribution Assets** | | | | | | | | | |
| **ACCUMULATED DEPRICIATION TOTAL** | 127,354 | 229,125 | 101,771 | 229,125 | 277,961 | 48,836 | 277,961 | 334,530 | 56,569 |

# Hydro 2000 Inc.

## MATERIALITY ANALYSIS ON ACCUMULATED DEPRICIATION

For any rate base related variance exceeding the materiality threshold of 1%, a detailed explanation is required.

## Materiality calculation

| | | | |
|---|---|---|---|
| 2006 Board approved gross assets | | | 478,722 |
| 2006 Board approved accumulated depreciation | | | (127,354) |
| 2006 Board approved net capital assets | | | 351,368 |
| | | | |
| Materiality = 1% of net capital assets | | | 3,514 |

## General explanation

The 2006 board approved amounts were the average of the actual amounts for the year 2003 and 2004. Variances are the results of 2004 (50%), 2005 and 2006 depreciations.

## Variances explanations

| GROSS ASSET | 2006 Board Approved | 2006 Actual | Variance from 2006 Board Approved | 50% of 2004 Depreciation | 2005 Depreciation | 2006 Depreciation | Total Depreciation |
|---|---|---|---|---|---|---|---|
| | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) |
| 1830-Poles, Towers and Fixtures-Depreciation | 38,809 | 69,756 | 30,947 | 5,765 | 12,431 | 12,751 | 30,947 |
| **Capital assets amortized over 25 years** | | | | | | | |
| 1835-Overhead Conductors and Devices-Dep. | 37,812 | 66,897 | 29,085 | 5,550 | 11,396 | 12,139 | 29,085 |
| **Capital assets amortized over 25 years** | | | | | | | |
| 1845-Underground Conductors and Devices-Dep. | 12,041 | 21,180 | 9,139 | 1,641 | 3,729 | 3,769 | 9,139 |
| **Capital assets amortized over 25 years** | | | | | | | |
| 1850-Line Transformers-Depreciation | 12,773 | 22,545 | 9,772 | 1,887 | 3,873 | 4,012 | 9,772 |
| **Capital assets amortized over 25 years** | | | | | | | |
| 1860-Meters-Depreciation | 12,100 | 20,814 | 8,714 | 1,711 | 3,420 | 3,583 | 8,714 |
| **Capital assets amortized over 25 years** | | | | | | | |
| 1920-Computer Equipment - Hardware-Dep. | 11,077 | 16,495 | 5,418 | 780 | 1,765 | 2,873 | 5,418 |
| **Capital assets amortized over 25 years** | | | | | | | |
| 1925-Computer Software-Depreciation | 522 | 8,487 | 7,965 | 524 | 2,762 | 4,679 | 7,965 |
| **Capital assets amortized over 25 years** | | | | | | | |

# Hydro 2000 Inc.

## CAPITAL BUDGET BY PROJECT

### 2006 Actual,2007 Bridge, 2008 Test Year and 2009 Future Year

| Project Description | Year | USoA Account | Expansion or Enhancement | Amount |
|---|---|---|---|---|
| P0001 New Subdivision - Val Alain | 2007 | 1845 | Expansion | 62,981 |
| P0001 New Subdivision - Val Alain | 2007 | 1850 | Expansion | 16,199 |
| P0001 New Subdivision - Val Alain | 2007 | 1995 | Expansion | (42,382) |
| Economic evaluation performed | | | | |

| Project Description | | USoA Account | Expansion or Enhancement | Amount |
|---|---|---|---|---|
| P0002 Smart meters implementation | 2008 | 1860 | | 100,000 |
| P0002 Smart meters implementation | 2009 | 1860 | | 85,000 |
| Other future capital will be captured in variance accounts for 2009 and after | | | | |
| Expenses for MDMR and operating expenses will also be captured in variance accounts for 2009 and after | | | | |

| Project Description | | USoA Account | Expansion or Enhancement | Amount |
|---|---|---|---|---|
| P0003 Billing conversion | 2007 | 1925 | Expansion | 42,000 |
| Conversion of Advance Billing System to Harris Billing System including modules for Smart Meters and E-Care | | | | |

| Project Description | | USoA Account | Expansion or Enhancement | Amount |
|---|---|---|---|---|
| P0004 Overhead Upgrade | 2008 | 1835 | Enhancement | 40,000 |
| P0005 Overhead Upgrade | 2009 | 1835 | Enhancement | 40,000 |
| To increase safety and reliability of distribution system | | | | |

| Project Description | | USoA Account | Expansion or Enhancement | Amount |
|---|---|---|---|---|
| P0006 Phase 3 of Lalande Subdivision | 2009 | 1845 | Expansion | 25,000 |
| P0006 Phase 3 of Lalande Subdivision | 2009 | 1995 | Expansion | (20,000) |

| Project Description | | USoA Account | Expansion or Enhancement | Amount |
|---|---|---|---|---|
| P1-2006 Phase 2 of Lalande New-Sub.&New Services | 2006 | 1830 | Expansion | 7,964 |
| P1-2006 Phase 2 of Lalande New-Sub.&New Services | 2006 | 1835 | Expansion | 18,593 |
| P1-2006 Phase 2 of Lalande New-Sub.&New Services | 2006 | 1845 | Expansion | 14,398 |
| P1-2006 Phase 2 of Lalande New-Sub.&New Services | 2006 | 1850 | Expansion | 3,462 |
| P1-2006 Phase 2 of Lalande New-Sub.&New Services | 2006 | 1855 | Expansion | 52,400 |
| P1-2006 Phase 2 of Lalande New-Sub.&New Services | 2006 | 1860 | Expansion | 4,050 |
| P1-2006 Phase 2 of Lalande New-Sub.&New Services | 2006 | 1995 | Expansion | (64,783) |

| Project Description | | USoA Account | Expansion or Enhancement | Amount |
|---|---|---|---|---|
| P2-2006 Hard & Software upgrade CIS Advanced | 2006 | 1920 | Expansion | 5,692 |
| P2-2006 Hard & Software upgrade CIS Advanced | 2006 | 1925 | Expansion | 9,586 |

**Hydro 2000 Inc.**

**MATERIALITY ANALYSIS ON CAPITAL BUDGETS**

For each projects over the materiality threshold of 1% of the total net fixed assets should include the following information

| | |
|---|---|
| Project Description: | P-0001 New Subdivision Val-Alain |
| Need: | System Expansion |
| Scope: | Transfer Overhead line to Underground, Install two dip pole, Replace Bell Canada pole and install complete underground with transformers to accommodate 45 new units. |
| Capital Costs: | $79,180 |
| Contributed Capital: | $42,382 |
| Start Date: | April, 2007 |
| In-Service Date: | June, 2007 |

| | |
|---|---|
| Project Description: | P-0002 Smart meter Part-1 |
| Need: | Installation of smart meter |
| Scope: | To meet the 2010 deadline impose by Ministry of Energy |
| Capital Costs: | $100,000 |
| Start Dates: | April, 2008 |
| In-Service Date: | September, 2008 |

**Hydro 2000 Inc.**

| | |
|---|---|
| Project Description: | P-0002 Smart meter Part-2 |
| Need: | Installation of smart meter |
| Scope: | To meet the 2010 deadline impose by Ministry of Energy |
| Capital Costs: | $85,000 |
| Start Dates: | April, 2009 |
| In-Service Date: | September, 2009 |

| | |
|---|---|
| Project Description: | P-0003 Billing System Conversion |
| Need: | Replace CIS Advanced System by Harris Upgraded Smart meter CIS Billing System. Advanced System Purchased by Harris System and Advanced CIS system is discontinued |
| Scope: | Install new billing system perform data conversion integrated new wholesale settlement system and EBT software. Trained all the employees. |
| Capital Costs: | $42,000 |
| Start Date: | September, 2007 |
| In-Service Date: | December, 2007 |

| | |
|---|---|
| Project Description: | P-0004 Overhead Upgrade |
| Need: | Safety and reliability |
| Scope: | Replace poles and upgrade |
| Capital Costs: | $40,000 |
| Start Dates: | April, 2008 |
| In-Service Date: | May, 2008 |

**Hydro 2000 Inc.**

| | |
|---|---|
| Project Description: | P-0005 Overhead Upgrade |
| Need: | Safety and reliability |
| Scope: | Replace poles and upgrade |
| Capital Costs: | $40,000 |
| Start Dates: | April, 2009 |
| In-Service Date: | May, 2009 |

| | |
|---|---|
| Project Description: | P-0006 Lalande Subdivision phase 3 Future(Maybe) |
| Need: | System expansion |
| Scope: | Finish underground Primary and secondary and loop system with phase-1 and phase-2 |
| Capital Costs: | $25,000 |
| Contributed Capital: | $20,000 |
| Start Dates: | April, 2009 |
| In-Service Date: | May, 2009 |

| | |
|---|---|
| Project Description: | P1-2006 Lalande Subdivision phase 2 and New Services |
| Need: | System expansion |
| Scope: | Finish underground Primary and secondary and loop system with phase-1. |
| Capital Costs: | $100,867 |
| Contributed Capital: | $64,783 |
| Start Dates: | February, 2006 |
| In-Service Date: | May, 2006 |

**Hydro 2000 Inc.**

| | |
|---|---|
| Project Description: | P2-2006 Hardware and software upgrade CIS Advanced |
| Need: | A laptop was purchase for training and all burden of regulatory compliance and seminar for outside office work accommodations. Hardware was upgrade to comply with minimum system requirement for advance.<br>Data Base was converted to SQL to better performed and rely on. |
| Scope: | Replace required hardware and software. |
| Capital Costs: | $15,278 |
| Start Dates: | April, 2006 |
| In-Service Date: | September, 2006 |

# Hydro 2000 Inc.

## SYSTEM EXPANSIONS

### 2008 Test Year

No system expansion in 2008.

### 2007 Bridge Year

One Expansion in 2007 it's Val-Alain Subdivision. An economic evaluation was performed based on developer project and forecast and the contributed capital required by developer was $42,382 out of a total capital expenditure of $79,180. The developer forecast is realistic. Documents are available at Hydro 2000 Inc. office.

### 2006 Actual

One Expansion and in 2007 it's Lalande Phase-2 Subdivision and new services capital cost and contributions. An economic evaluation was performed based on developer project and forecast and the contributed capital required by developer and contributed capital required for all the new services was $64,783 out of a total capital expenditure of $100,867. The developer forecast is realistic. Documents are available at Hydro 2000 Inc. office.

# Hydro 2000 Inc.

## CAPITALIZATION POLICY

**All capital assets expenses are recorded in the proper asset account which is over the materiality of 0.25% of next fixed assets. All work is performed by a contractor as single project within the same year. There is no Construction Work in Progress. There is no administration cost added except special project that may required a lot of time like smart meters where there is a project manager required.**

# Hydro 2000 Inc.

# Hydro 2000 Inc.

## WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT

| WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT | 2006 Actual | 15% | Allowance for Working Capital | 2007 Bridge | 15% | Allowance for Working Capital | 2008 Test | 15% | Allowance for Working Capital |
|---|---|---|---|---|---|---|---|---|---|
| **Operation (Working Capital)** | | | | | | | | | |
| 5005-Operation Supervision and Engineering | | 15% | - | - | 15% | - | - | 15% | - |
| 5010-Load Dispatching | | 15% | - | - | 15% | - | - | 15% | - |
| 5012-Station Buildings and Fixtures Expense | | 15% | - | - | 15% | - | - | 15% | - |
| 5014-Transformer Station Equipment - Operation Labour | | 15% | - | - | 15% | - | - | 15% | - |
| 5015-Transformer Station Equipment - Operation Supplies and Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5016-Distribution Station Equipment - Operation Labour | | 15% | - | - | 15% | - | - | 15% | - |
| 5017-Distribution Station Equipment - Operation Supplies and Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5020-Overhead Distribution Lines and Feeders - Operation Labour | | 15% | - | - | 15% | - | - | 15% | - |
| 5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5030-Overhead Sub transmission Feeders - Operation | | 15% | - | - | 15% | - | - | 15% | - |
| 5035-Overhead Distribution Transformers- Operation | | 15% | - | 463.00 | 15% | 69.45 | 463.00 | 15% | 69.45 |
| 5040-Underground Distribution Lines and Feeders - Operation Labour | | 15% | - | - | 15% | - | - | 15% | - |
| 5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5050-Underground Sub transmission Feeders - Operation | | 15% | - | - | 15% | - | - | 15% | - |
| 5055-Underground Distribution Transformers - Operation | | 15% | - | - | 15% | - | - | 15% | - |
| 5060-Street Lighting and Signal System Expense | | 15% | - | - | 15% | - | - | 15% | - |
| 5065-Meter Expense | 275.00 | 15% | 41.25 | 275.00 | 15% | 41.25 | 275.00 | 15% | 41.25 |
| 5070-Customer Premises - Operation Labour | | 15% | - | - | 15% | - | - | 15% | - |
| 5075-Customer Premises - Materials and Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5085-Miscellaneous Distribution Expense | | 15% | | - | 15% | | - | 15% | |

## Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | - | | | - | | | - |
| 5090-Underground Distribution Lines and Feeders - Rental Paid | | 15% | - | - | 15% | - | - | 15% | - |
| 5095-Overhead Distribution Lines and Feeders - Rental Paid | | 15% | - | - | 15% | - | - | 15% | - |
| 5096-Other Rent | | 15% | - | - | 15% | - | - | 15% | - |
| **Sub-Total** | 275.00 | | 41.25 | 738.00 | | 110.70 | 738.00 | | 110.70 |
| **Maintenance (Working Capital)** | | | | | | | | | |
| 5105-Maintenance Supervision and Engineering | | 15% | - | - | 15% | - | - | 15% | - |
| 5110-Maintenance of Buildings and Fixtures - Distribution Stations | | 15% | - | - | 15% | - | - | 15% | - |
| 5112-Maintenance of Transformer Station Equipment | | 15% | - | - | 15% | - | - | 15% | - |
| 5114-Maintenance of Distribution Station Equipment | | 15% | - | - | 15% | - | - | 15% | - |
| 5120-Maintenance of Poles, Towers and Fixtures | | 15% | - | - | 15% | - | - | 15% | - |
| 5125-Maintenance of Overhead Conductors and Devices | 2,064.40 | 15% | 309.66 | 2,064.40 | 15% | 309.66 | 2,064.40 | 15% | 309.66 |
| 5130-Maintenance of Overhead Services | | 15% | - | - | 15% | - | - | 15% | - |
| 5135-Overhead Distribution Lines and Feeders - Right of Way | | 15% | - | - | 15% | - | - | 15% | - |
| 5145-Maintenance of Underground Conduit | | 15% | - | - | 15% | - | - | 15% | - |
| 5150-Maintenance of Underground Conductors and Devices | | 15% | - | - | 15% | - | - | 15% | - |
| 5155-Maintenance of Underground Services | | 15% | - | - | 15% | - | - | 15% | - |
| 5160-Maintenance of Line Transformers | | 15% | - | - | 15% | - | - | 15% | - |
| 5165-Maintenance of Street Lighting and Signal Systems | | 15% | - | - | 15% | - | - | 15% | - |
| 5170-Sentinel Lights - Labour | | 15% | - | - | 15% | - | - | 15% | - |
| 5172-Sentinel Lights - Materials and Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5175-Maintenance of Meters | 1,652.91 | 15% | 247.94 | 1,652.91 | 15% | 247.94 | 1,652.91 | 15% | 247.94 |
| 5178-Customer Installations Expenses- Leased Property | | 15% | - | - | 15% | - | - | 15% | - |
| 5185-Water Heater Rentals - Labour | | 15% | - | - | 15% | - | - | 15% | - |
| 5186-Water Heater Rentals - Materials and Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5190-Water Heater Controls - Labour | | 15% | - | - | 15% | - | - | 15% | - |
| 5192-Water Heater Controls - Materials and Expenses | | 15% | | - | 15% | | - | 15% | |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | - | | | - | | | - |
| 5195-Maintenance of Other Installations on Customer Premises | | 15% | - | - | 15% | - | - | 15% | - |
| **Sub-Total** | 3,717.31 | | 557.60 | 3,717.31 | | 557.60 | 3,717.31 | | 557.60 |
| **Billing and Collections** | | | | | | | | | |
| 5305-Supervision | | 15% | - | - | 15% | - | - | 15% | - |
| 5310-Meter Reading Expense | | 15% | - | - | 15% | - | - | 15% | - |
| 5315-Customer Billing | 76,967.74 | 15% | 11,545.16 | 78,507.09 | 15% | 11,776.06 | 80,077.24 | 15% | 12,011.59 |
| 5320-Collecting | | 15% | - | - | 15% | - | - | 15% | - |
| 5325-Collecting- Cash Over and Short | | 15% | - | - | 15% | - | - | 15% | - |
| 5330-Collection Charges | 93.52 | 15% | 14.03 | 93.52 | 15% | 14.03 | 120.52 | 15% | 18.08 |
| 5335-Bad Debt Expense | 3,656.64 | 15% | 548.50 | 7,313.28 | 15% | 1,096.99 | 7,459.55 | 15% | 1,118.93 |
| 5340-Miscellaneous Customer Accounts Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| **Sub-Total** | 80,717.90 | | 12,107.69 | 85,913.89 | | 12,887.08 | 87,657.31 | | 13,148.60 |
| **Community Relations** | | | | | | | | | |
| 5405-Supervision | | 15% | - | - | 15% | - | - | 15% | - |
| 5410-Community Relations - Sundry | | 15% | - | - | 15% | - | - | 15% | - |
| 5415-Energy Conservation | | 15% | - | - | 15% | - | - | 15% | - |
| 5420-Community Safety Program | | 15% | - | - | 15% | - | - | 15% | - |
| 5425-Miscellaneous Customer Service and Informational Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5505-Supervision | | 15% | - | - | 15% | - | - | 15% | - |
| 5510-Demonstrating and Selling Expense | | 15% | - | - | 15% | - | - | 15% | - |
| 5515-Advertising Expense | | 15% | - | - | 15% | - | - | 15% | - |
| 5520-Miscellaneous Sales Expense | | 15% | - | - | 15% | - | - | 15% | - |
| **Sub-Total** | - | | - | - | | - | - | | - |
| **Administrative and General Expenses** | | | | | | | | | |
| 5605-Executive Salaries and Expenses | | 15% | | | 15% | | | 15% | |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 8,870.86 | | 1,330.63 | 8,870.86 | | 1,330.63 | 8,870.86 | | 1,330.63 |
| 5610-Management Salaries and Expenses | 57,751.66 | 15% | 8,662.75 | 60,061.73 | 15% | 9,009.26 | 61,262.96 | 15% | 9,189.44 |
| 5615-General Administrative Salaries and Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5620-Office Supplies and Expenses | 9,012.83 | 15% | 1,351.92 | 9,012.83 | 15% | 1,351.92 | 9,012.83 | 15% | 1,351.92 |
| 5625-Administrative Expense Transferred Credit | | 15% | - | - | 15% | - | - | 15% | - |
| 5630-Outside Services Employed | 28,733.48 | 15% | 4,310.02 | 28,733.48 | 15% | 4,310.02 | 28,733.48 | 15% | 4,310.02 |
| 5635-Property Insurance | 3,409.56 | 15% | 511.43 | 3,409.56 | 15% | 511.43 | 3,409.56 | 15% | 511.43 |
| 5640-Injuries and Damages | | 15% | - | - | 15% | - | - | 15% | - |
| 5645-Employee Pensions and Benefits | 7,766.29 | 15% | 1,164.94 | 7,999.28 | 15% | 1,199.89 | 8,159.26 | 15% | 1,223.89 |
| 5650-Franchise Requirements | | 15% | - | - | 15% | - | - | 15% | - |
| 5655-Regulatory Expenses | 6,570.62 | 15% | 985.59 | 6,570.62 | 15% | 985.59 | 66,500.00 | 15% | 9,975.00 |
| 5660-General Advertising Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5665-Miscellaneous General Expenses | | 15% | - | - | 15% | - | - | 15% | - |
| 5670-Rent | 7,873.08 | 15% | 1,180.96 | 7,873.08 | 15% | 1,180.96 | 7,873.08 | 15% | 1,180.96 |
| 5675-Maintenance of General Plant | | 15% | - | - | 15% | - | - | 15% | - |
| 5680-Electrical Safety Authority Fees | 3,808.88 | 15% | 571.33 | 3,808.88 | 15% | 571.33 | 3,808.88 | 15% | 571.33 |
| 5685-Independent Market Operator Fees and Penalties | | 15% | - | - | 15% | - | - | 15% | - |
| **Sub-Total** | 133,797.26 | | 20,069.57 | 136,340.32 | | 20,451.03 | 197,630.91 | | 29,644.62 |
| **Amortization Expenses** | | | | | | | | | |
| 5705-Amortization Expense - Property, Plant, and Equipment | 43,900.88 | 0% | - | 48,836.00 | 0% | - | 56,569.00 | 0% | - |
| 5710-Amortization of Limited Term Electric Plant | | 15% | - | - | 15% | - | - | 15% | - |
| 5715-Amortization of Intangibles and Other Electric Plant | 463.00 | 0% | - | - | 0% | - | - | 0% | - |
| 5720-Amortization of Electric Plant Acquisition Adjustments | | 15% | - | - | 15% | - | - | 15% | - |
| 5725-Miscellaneous Amortization | | 15% | - | - | 15% | - | - | 15% | - |
| 5730-Amortization of Unrecovered Plant and Regulatory Study Costs | | 15% | - | - | 15% | - | - | 15% | - |
| 5735-Amortization of Deferred Development Costs | | 15% | - | - | 15% | - | - | 15% | - |

# Hydro 2000 Inc.

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 5740-Amortization of Deferred Charges | | 15% | - | - | 15% | - | - | 15% | - |
| **Sub-Total** | 44,363.88 | | - | 48,836.00 | | - | 56,569.00 | | - |
| **Cost of Power** | | | | | | | | | |
| 4705-Power Purchased | 1,499,578.22 | 15% | 224,936.73 | 1,499,578.22 | 15% | 224,936.73 | 1,601,226.00 | 15% | 240,183.90 |
| 4708-Charges-WMS | 160,329.25 | 15% | 24,049.39 | 160,329.25 | 15% | 24,049.39 | 160,329.25 | 15% | 24,049.39 |
| 4710-Cost of Power Adjustments | | 15% | - | - | 15% | - | - | 15% | - |
| 4712-Charges-One-Time | | 15% | - | - | 15% | - | - | 15% | - |
| 4714-Charges-NW | 142,156.56 | 15% | 21,323.48 | 142,156.56 | 15% | 21,323.48 | 142,156.56 | 15% | 21,323.48 |
| 4716-Charges-CN | 123,624.38 | 15% | 18,543.66 | 123,624.38 | 15% | 18,543.66 | 123,624.38 | 15% | 18,543.66 |
| 4730-Rural Rate Assistance Expense | | 15% | - | - | 15% | - | - | 15% | - |
| 4750-LV Charges Costs | 56,564.98 | 15% | 8,484.75 | 56,564.98 | 15% | 8,484.75 | 56,564.98 | 15% | 8,484.75 |
| 5685-Independent Market Operator Fees and Penalties | | 15% | - | - | 15% | - | - | 15% | - |
| **Sub-Total** | 1,982,253.39 | | 297,338.01 | 1,982,253.39 | | 297,338.01 | 2,083,901.17 | | 312,585.18 |
| **WORKING CAPITAL ALLOWANCE TOTAL** | | | **330,114.12** | | | **331,344.42** | | | **356,046.70** |

## Hydro 2000 Inc.

**Hydro 2000 Inc.**

| Ex. | Tab | Schedule | Contents of Schedule |
|---|---|---|---|
| **3 - Operating Revenue** | | | |
| | 1 | 1 | Overview of Operation Revenue |
| | | 2 | Summary of Operating Revenue Table |
| | | 3 | Variance Analysis on Operating Revenue |
| | 2 | | **Throughput Revenue** |
| | | 1 | Weather Normalized Forecasting Methodology |
| | | 2 | Normalized Volume Forecast Table |
| | | 3 | Variance Analysis on Normalized Volume Forecast |
| | | 4 | Customer Count Forecast Table |
| | | 5 | Variance Analysis on Customer Count Forecast |
| | | 6 | Historical Average Consumption |
| | 3 | | **Other Revenue** |
| | | 1 | Other Distribution Revenue |
| | | 2 | Materiality Analysis on Distribution Revenue |
| | | 3 | Rate of Return on Other Distribution Revenue |
| | | 4 | Distribution Revenue Data |
| | 4 | | **Revenue Sharing** |
| | | 1 | Description of Revenue Sharing |

## Hydro 2000 Inc.

## OVERVIEW OF OPERATING REVENUE

This exhibit provides the details on the Applicant's operating revenue for Historical, Historical Board Approved, Bridge and Test years. This exhibit also provides a detailed variance analysis by rate class of the operating revenue components.

Distribution revenues have been calculated using the most recently approved rates. In particular, delivery rates are based on the RP-2005-0020 and EB-2005-0380 Rate Order, dated May 1st, 2007. Distribution revenue included the Fixed Charge, Variable Charge and Low Voltage Charges. The distribution revenues Fixed and Variable Charges plus Other Revenues should recover all the expenses, PILS and profit allowed. A summary of normalized operating revenues is presented in Exhibit 3, Tab 3, Schedule 4.

Throughput Revenue

Information related to the utility's throughput revenue include details such as weather normalized forecasting methodology, normalized volume and customer counts forecast tables. Detailed variance analysis on the forecast information is also provided.

Other Revenue

Other revenues include revenues such as Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. A summary of these operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

# Hydro 2000 Inc.

## SUMMARY OF OPERATING REVENUE TABLE

| SUMMARY OF OPERATING REVENUE TABLE | 2006 Board Approved | 2006 Actual | Variance form 2006 Board Approved | 2006 Actual | 2007 Actual | Variance form 2006 Actual | 2007 Bridge | 2008 Test | Variance form 2007 Actual |
|---|---|---|---|---|---|---|---|---|---|
| | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) |
| | | | | | | | | | |
| **Distribution Revenues** | | | | | | | | | |
| Residential | 223,233 | 200,714 | -22,519 | 200,714 | 206,376 | 5,662 | 206,376 | 261,615 | 56,849 |
| G.S. < 50 | 73,603 | 62,370 | -11,233 | 62,370 | 62,916 | 546 | 62,916 | 97,150 | 34,839 |
| G.S. > 50 | 39,042 | 24,091 | -14,951 | 24,091 | 25,297 | 1,206 | 25,297 | 41,682 | 16,645 |
| Unmetered | 357 | 3,199 | 2,842 | 3,199 | 3,228 | 29 | 3,228 | 1,017 | -2,205 |
| Streetlight | 2,587 | 11,052 | 8,465 | 11,052 | 11,332 | 280 | 11,332 | 8,499 | -2,780 |
| | | | | | | | | | |
| **Other Distribution Revenue** | | | | | | | | | |
| Late Payment Charges | 4,039 | 4,403 | 364 | 4,403 | 4,403 | - | 4,403 | 4,403 | - |
| Specific Service Charges | 2,741 | 1,359 | -1,382 | 1,359 | 1,359 | - | 1,359 | 1,359 | |
| Other Distribution Revenue | 38,735 | 46,246 | 7,511 | 46,246 | 26,910 | -19,336 | 26,910 | 26,910 | - |
| | | | | | | | | | |
| Total | 384,337 | 353,434 | -30,903 | 353,434 | 341,821 | -11,613 | 341,821 | 442,635 | 103,348 |

## Hydro 2000 Inc.

## VARIANCE ANALYSIS ON OPERATING REVENUE

The Applicant's distribution revenue has been calculated using the most recently approved rates. In particular, delivery rates are based on the RP-2005-0020 and EB-2005-0380 Rate Order, dated May 1st 2007. Distribution revenue does not include commodity related revenue.

A summary of normalized operating revenues is presented in Exhibit 3, Tab 1 , Schedule 2, which is a summary of the information provided in Tab 3, Schedule 1 of Exhibits 3 and in Tab 3, Schedule 4, of Exhibit 3.

**2008 Test Year**

Hydro 2000 Inc operating revenue is forecast to be $442,635 in Fiscal 2008, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $406,655 or 91.87% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $35,980.
.

**Comparison to 2007 Bridge Year**

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $100,814 above the bridge year level in fiscal 2007. This increase is the result of PILS that we did not pay up to this point because of a lost carry forwards ($ 39,350), LV Charges under estimated by Hydro One Networks Inc. ( $15,000), wages Increased to employees ($5,000) and capital project expenses in 2007 and 2008.

**2007 Bridge Year**

Hydro 2000 Inc operating revenue is forecast to be $341,821 in Fiscal 2007, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $305,841 or 89.47% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $35,980.

**Comparison to Fiscal 2006 Actual**

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $11,613 below the 2006 Actual year level in fiscal 2007. This decrease is mostly the result delayed expenditure of capital assets in 2002 to 2006 because of challenges of opening market.

# Hydro 2000 Inc.

**2006 Actual**

Hydro 2000 Inc. operating revenue was $353,434 in Fiscal 2007, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue total $301,426 or 85.28% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $52,008.

**Comparison to 2006 Board Approved**

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is to be $30,903 below the 2006 Board Approved year level in fiscal 2006. This decrease is mostly the result of distribution revenues short fall of $37,396. Total sales were down because of milder temperature in winter and summer.

**2006 Board Approved**

Hydro 2000 Inc. operating revenue of $384,337 was anticipated in 2006 Board Approved Model , as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue total $338,822 or 88.15% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $45,515.

## Hydro 2000 Inc.

## WEATHER NORMALIZED FORECASTING METHODOLOGY

This exhibit discusses the methodology used to determine The Applicant's customer and load forecast. A projection for the number of customers in each customer class is provided for both the Bridge Year (2007) and the Test Year (2008). Historical data for the annual number of customers in each rate class is available for 2002 through to 2006. Due to significant restructuring, accurate customer data prior to 2002 is not currently available. As a result of the limited amount of data available, time series techniques that are often used to help estimate forecast values cannot be used. Rather, the Applicant has used a simple trend growth in customer connections, by class, to forecast Bridge and Test Year customer numbers. Given the slow growth and consistent trend in customer numbers in The Applicant's service territory over the past five years, the resulting customer forecast is likely not materially different than what would result from using more sophisticated time series techniques. In recent history, there has been very little year-to-year variation in customer growth by class. Historical and forecast customer numbers, by class, are displayed in the next section.

As required by the OEB Filing Requirements for Transmission and Distribution Applications, we are providing normalized historical and forecast (Bridge Year and Test Year) throughput data. Weather normalization (where required) is based on normalized average use per customer ("NAC") calculated from the weather-normalized throughput of the utility from 2004. This weather-normalized throughput was generated by Hydro One using their weather normalization model for the Cost Allocation process previously undertaken by the Board. The process to obtain these weather normal data was an intensive effort for all parties involved, and we are leveraging the value of this work by using it for this process.

# Hydro 2000 Inc.

## Customer Forecast

Table 1 below presents historical and forecast customer numbers, by class, for The Applicant.

***Table 1 – Customers by Class, The Applicant Utilities***

| | 2002 | 2003 | 2004 | 2005 | 2006 | *2007* | *2008* |
|---|---|---|---|---|---|---|---|
| Residential | 955 | 955 | 969 | 974 | 979 | 997 | 1,005 |
| Per cent chg | 1.60% | 0.00% | 1.47% | 0.52% | 0.51% | 1.84% | 0.80% |
| GS < 50kW | 147 | 150 | 147 | 144 | 147 | 147 | 147 |
| Per cent chg | (0.01)% | 0.02% | - 0.02% | (0.02) | 0.02 | - | - |
| GS (>50 to 5000) | 11 | 11 | 12 | 12 | 12 | 12 | 12 |
| Per cent chg | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| USL | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Per cent chg | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Street Lighting | 347 | 351 | 351 | 362 | 362 | 368 | 368 |
| Per cent chg | 0.02% | 0.01% | 0.0% | 0.03% | 0.0% | 0.02% | 0.0% |

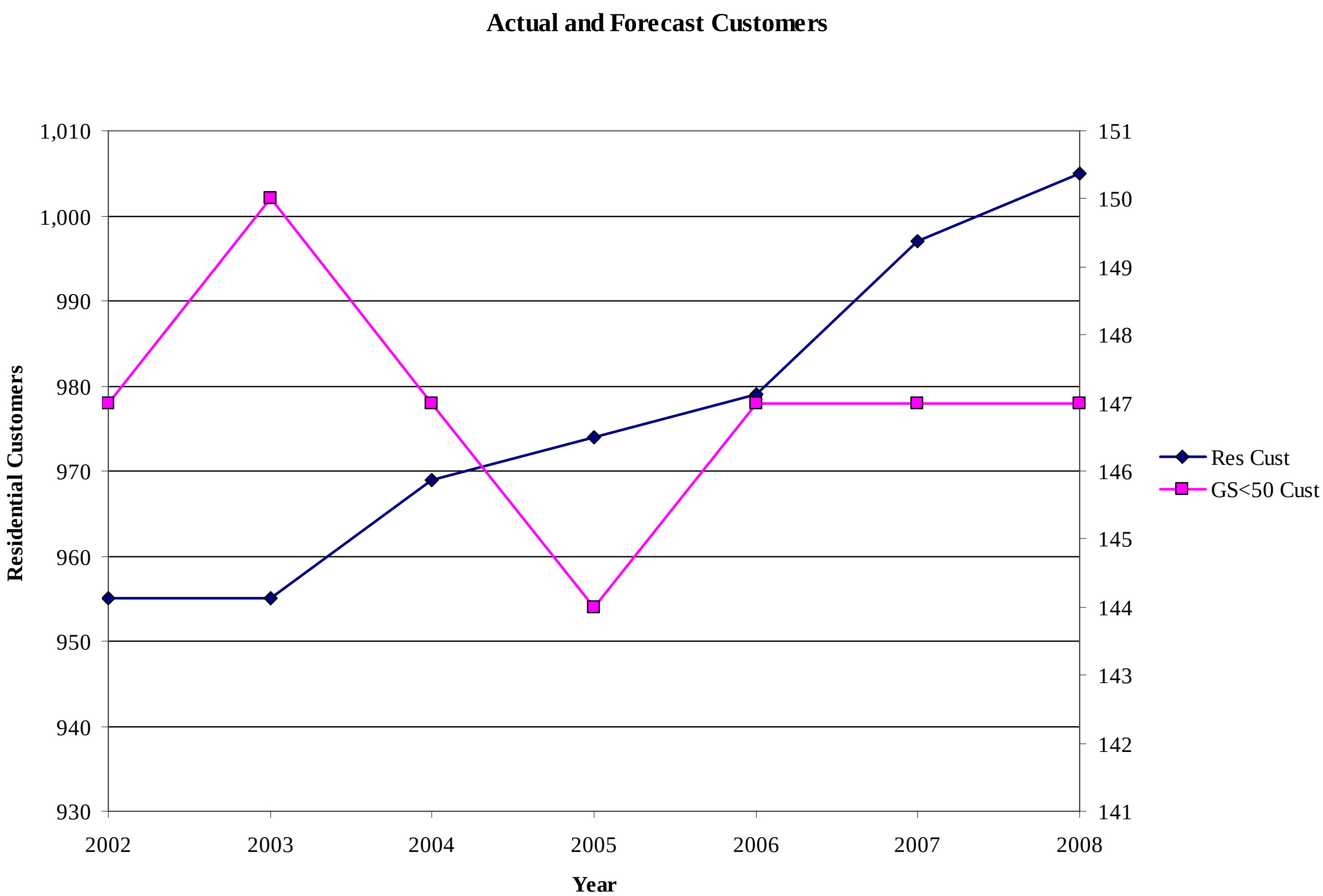
Annual percentage change is presented for Residential, GS<50, and GS 50-5000 classes. For Residential and GS<50 customer classes, the blue highlighted percentage change for 2007 represents the annual average geometric mean growth rate for 2002 to 2006. The annual trend growth rate is used to project customer growth into 2007 and 2008. For the GS>50 to 5000 customer class, an annual growth rate of 0% was assumed for 2007 and 2008. From the table above, it can be seen that 2004-05 were anomalous years for growth (0% in 2003 followed by 0% in 2004). This anomalous growth was excluded from the trend line.

The large use class contains only 12 customers ( 11 in 2002 falling to 12 in 2007). The 2007 customer number is the current actual number of customers in this class. The Applicant does not expect the number of customers in this class to change within the next year to 18 months, and has used this for the number of customers expected at Bridge Year end and Test Year.

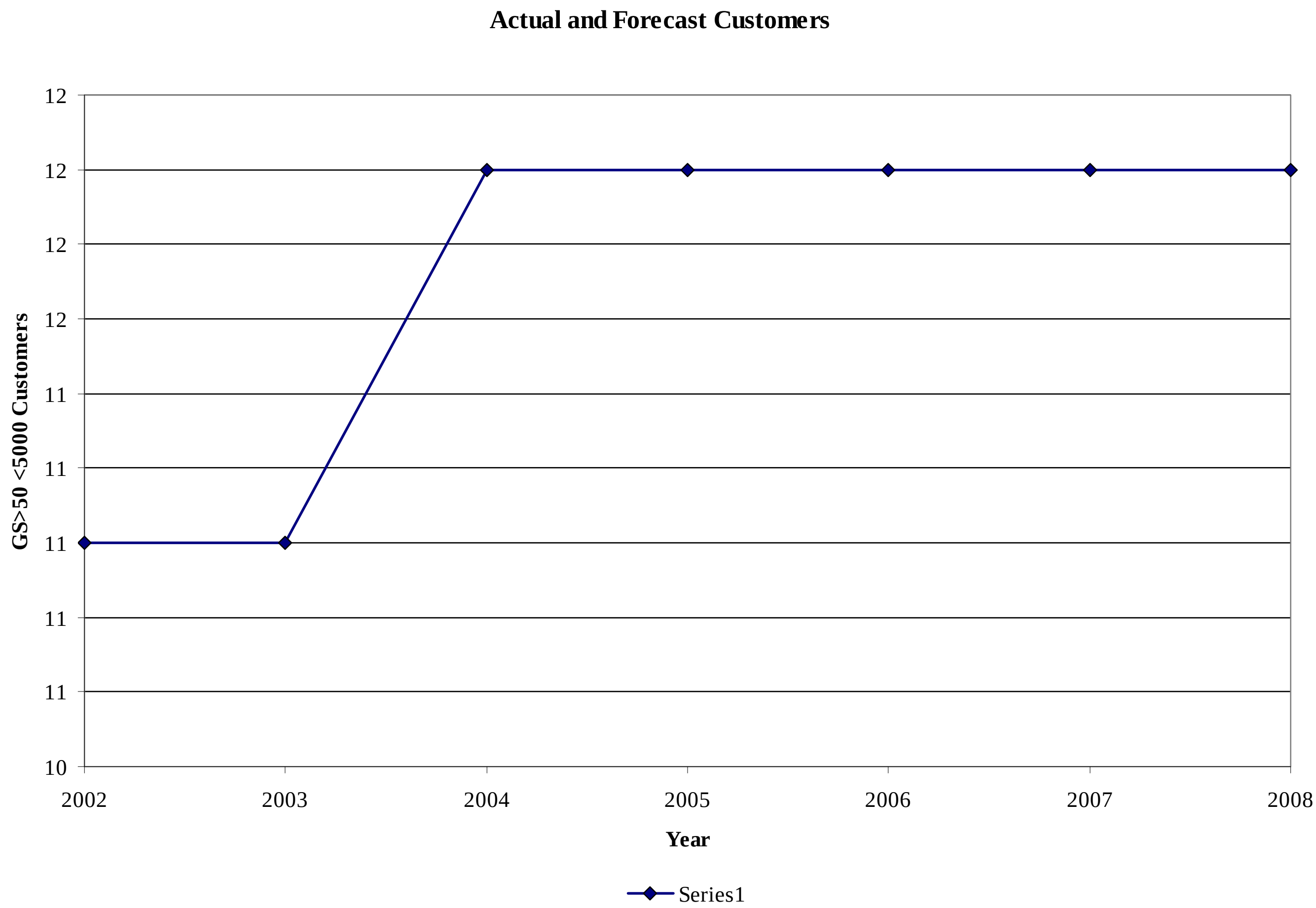
## Hydro 2000 Inc.

Customer numbers for Street Lighting, and USL classes in 2007 also represent current (early 2007) number of connections in each of these classes. The Applicant does not expect the number of customers in the USL class to change within the next year) and the 2007 current figures are used for 2008. Customer growth for the Street Lighting Class is calculated based on the annual average geometric mean of growth from 2002 to current year (2007)

The figures below illustrate the historical and forecast customer trend in Residential, GS<50, and G S>50 to 5000classes.



## Hydro 2000 Inc.




### Load Forecast

Weather sensitive load (Residential, GS<50, and GS>50 classes) is calculated by using a retail normalized average use per customer ("retail NAC"). This is calculated by dividing the class weather normal retail kWh for 2004 by the number of customers in class in 2004. Class weather normal retail kWh for 2004 is determined by dividing the class weather normal wholesale kWh for 2004 reported in the Hydro One weather normalization analysis by the class loss factor. The class loss factor is calculated for 2004 by dividing the class weather actual wholesale consumption for 2004 (Hydro One file) by the class weather actual retail consumption (utility data). Weather sensitive class weather actual wholesale and retail kWh and associated loss factors are reported in the following table below.

**Hydro 2000 Inc.**

**Hydro 2000 Inc.**

| ***2004 Weather Actual kWh and Loss Factors for Weather Sensitive Load The Applicant Utilities*** | | | |
|---|---|---|---|
| Class | Weather Actual Wholesale kWh | Weather Actual Retail kWh | Loss Factor |
| Residential | 16,239,145 | 15,223,723 | 1.0667 |
| GS < 50 | 5,585,359 | 5,236,111 | 1.0667 |
| GS >50 to 5,000 | 5,347,264 | 5,012,904 | 1.0667 |

Weather sensitive class wholesale weather normal kWh, number of customers, and retail NAC for 2004 is reported in the table below.

| Class | Weather Normalize kWh (2004) | Customer Connections (2004) | Retail NAC |
|---|---|---|---|
| Residential | 16,086,959 | 979 | 16,432 |
| GS < 50 | 5,682,016 | 147 | 38,653 |
| GS >50 to 5,000 | 5,496,281 | 12 | 458,023 |

Annual class kWh for weather sensitive load (Residential, GS<50, GS>50) for Bridge Year and Test Year are calculated by multiplying retail NAC by forecast number of customers in class. Class kWh for the Large User (“LU”) class, Unmetered Scattered Load (“USL”), and Sentinel Lighting is not weather sensitive and is not expected to differ in 2008 from current 2007 levels. Utility budgeted throughput for these classes based on year-to-date consumption is used to estimate Bridge Year and Test Year values for these classes. Consumption for Street Lighting is not weather sensitive. Street Lighting kWh is estimated using forecast number of connections for the Bridge Year and Test Year multiplied the average use per connection, which is calculated to be approximately 767 kWh per annum.

Several classes are billed based on demand charges (GS>50, LU, Sentinel, Street Lighting) and require an estimate of billed kW. Billed kW is estimated based on a load factor calculated using a ratio of historical billed kW to historical retail kWh, by class. The following table summarizes the results of The Applicant’s customer and load forecast.

## Hydro 2000 Inc.

| The Applicant Utilities Corporation | | Historical Actual | Historical Board Approved | Historical Actual Normalized | Bridge Year -Est. | Bridge Year Forecast Normalized | Test Year Normalized Forecast |
|---|---|---|---|---|---|---|---|
| Year | | 2006 | 2004 | 2006 | 2007 | 2007 | 2008 |
| | | | | | | | |
| Customer Class | # | 979 | 969 | 969 | 997 | 997 | 1005 |
| Residential | kWh | 15,223,723 | 15,567,706 | 16,086,959 | 15,503,628 | 16,382,735 | 16,514,191 |
| | | | | | | | |
| GS < 50 kW | # | 147 | 147 | 147 | 147 | 147 | 147 |
| | kWh | 5,236,111 | 5,504,335 | 5,682,016 | 5,236,111 | 5,682,016 | 5,682,016 |
| | | | | | | | |
| GS >50 to 5000 | # | 12 | 11 | 12 | 12 | 12 | 12 |
| | kWh | 5,012,904 | 5,258,719 | 5,496,281 | 5,012,904 | 5,496,281 | 5,496,281 |
| | kW | 11,583 | 12,536 | 12,700 | 12112 | 13280 | 13280 |
| | | | | | | | |
| USL | # | 6 | 3 | 6 | 6 | 6 | 6 |
| | kWh | 19,951 | 12,536 | 19,951 | 19951 | 19951 | 19951 |
| | | | | | | | |
| Street Lighting | # | 362 | 351 | 362 | 368 | 368 | 368 |
| | kWh | 351,709 | 325,313 | 351,709 | 359,553 | 359,553 | 359,553 |
| | kW | 925 | 855 | 925 | 941 | 941 | 941 |

# Hydro 2000 Inc.

## NORMALIZED VOLUME FORECAST TABLE

| NORMALIZED VOLUME FORECAST | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | 2006 Board Approved | 2006 Board Approved | 2006 Actual | 2006 Actual | Variance from 2006 Board Approved | Variance from 2006 Board Approved |
| | (kWh) | (kW) | (kWh) | (kW) | (kWh) | (kW) |
| | | | | | | |
| Rate Classes | | | | | | |
| Residential | 15,567,706 | | 15,223,723 | | (343,983) | - |
| G.S. < 50 | 5,504,335 | | 5,236,111 | | (268,224) | - |
| G.S. > 50 | 5,258,719 | 13,164 | 5,012,904 | 11,583 | (245,815) | (1,581) |
| Unmetered | 12,536 | | 19,951 | | 7,415 | - |
| Streetlight | 325,313 | 855 | 351,709 | 925 | 26,396 | 70 |
| Total | 26,668,609 | 14,019 | 25,844,398 | 12,508 | (824,211) | (1,511) |

| NORMALIZED VOLUME FORECAST | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | 2006 Actual | 2006 Actual | 2007 Bridge | 2007 Bridge | Variance from 2006 Actual | Variance from 2006 Actual |
| | (kWh) | (kW) | (kWh) | (kW) | (kWh) | (kW) |
| | | | | | | |
| Rate Classes | | | | | | |
| Residential | 15,223,723 | - | 16,382,735 | | 1,159,012 | - |
| G.S. < 50 | 5,236,111 | - | 5,682,016 | | 445,905 | - |
| G.S. > 50 | 5,012,904 | 11,583 | 5,496,281 | 13,280 | 483,377 | 1,697 |
| Unmetered | 19,951 | - | 19,951 | | - | - |
| Streetlight | 351,709 | 925 | 359,553 | 941 | 7,844 | 16 |
| Total | 25,844,398 | 12,508 | 27,940,536 | 14,221 | 2,096,138 | 1,713 |

# Hydro 2000 Inc.

| | 2007 Bridge | 2007 Bridge | 2008 Test | 2008 Test | Variance from 2007 Bridge | Variance from 2007 Bridge |
|---|---|---|---|---|---|---|
| | (kWh) | (kW) | (kWh) | (kW) | (kWh) | (kW) |
| | | | | | | |
| | | | | | | |
| Rate Classes | 16,382,735 | - | 16,514,191 | | 131,456 | - |
| Residential | 5,682,016 | - | 5,682,016 | | - | - |
| G.S. < 50 | 5,496,281 | 13,280 | 5,496,281 | 13,280 | - | - |
| G.S. > 50 | 19,951 | - | 19,951 | | - | - |
| Unmetered | 359,553 | 941 | 359,553 | 941 | - | - |
| Streetlight | - | - | | | | |
| Total | 27,940,536 | 14,221 | 28,071,992 | 14,221 | 131,456 | - |

# Hydro 2000 Inc.

## VARIANCE ANALYSIS ON NORMALIZED VOLUME FORECAST

The purpose of the evidence contained in Tab 2, of Exhibits 3, is to provide the Board with a review of Hydro 2000 Inc. actual and forecasted customers, consumption and revenues for the historical, bridge and test years. Test year revenues have been calculated using the approved RP-2005-0020 and EB-2005-0380 Rate Order May 1st, 2007.

Exhibit3, Tab 2, Schedule 1, provides a summary of the normalized throughput and customer numbers from the schedules noted above.

### Fiscal 2008 Test Year

The weather normalized numbers generated by the 30 year load forecast are way above the average of the 8 years of Hydro 2000 Inc. average consumption. With the price of electricity increasing all new customers since 2006 went to another source of heating than electrical with is dropping the average. With global warming winter are warming up which make hydro 2000 Inc. sales drop because of its nature of being a winter peaking utility caused by the electrical heating. CDM programs and better house construction and removal of old houses are contributing too, to the reduction of sales of Hydro 2000 Inc.

The forecast for 2008 test year normalized volume is 28,071,992 kWhs

The following tables give you a comparison between actual and forecast in the last 9 years.

| Year | Volume 8 yr forecast Hydro 2000 | 30 Yr load forecast HONI | Forecast |
|---|---|---|---|
| | | | |
| 1999 | 23,504,170 | | Actual |
| 2000 | 25,830,657 | | Actual |
| 2001 | 24,876,233 | | Actual |
| 2002 | 25,646,934 | | Actual |
| 2003 | 26,571,085 | | Actual |
| 2004 | 27,530,422 | | Actual |
| 2005 | 26,270,837 | | Actual |
| 2006 | 25,844,398 | | Actual |
| 2007 | 26,535,009 | 27,940,536 | Forecast |
| 2008 | 26,741,396 | 28,071,992 | Forecast |

If we compared the volume from 2002 to 2007 except for 2004 which was a special cold winter and hot summer the median is around 26,000,000 kwhs.

# Hydro 2000 Inc.

## 2007 Bridge Year

The forecast for 2007 Bridge year normalized volume is 27,940,536 kWhs. The actual consumption for 2007 bridge year for January 1st to August 31, 2007 as and increase of 580,000 kWhs on the consumption and if the remaining year stay the same than the total Actual consumption should approximately 26,424,398 kwhs. The comparison of the actual with approximation is closer to the prediction of Hydro 2000 Inc. forecast than the 30 year load forecast of Hydro One Networks.

## 2006 Actual

The actual 2006 volume was 25,844,898 kWhs compared to a Board Approved 26,668,609 kWhs projected by 2006 Board Approved Model a 3% decrease in volume of consumption.

## 2006 Board Approved

The 2006 Board Approved volume was 26,668,609 based on the average of 2002, 2003 and 2004.

Hydro 2000 Inc. will compile statistic and compare its 8 years forecast to actual data for Bridge, Test and Future years. If the data are closer to 8 years forecast in the next rebasing Hydro 2000 Inc. will submit its application based on its on forecast. Evidence will show that the 30 years model is not the best solution for a small utility with winter peaking In an environment that global warming is affecting winter and that CDM contribute to save on the volume of consumption.

## Hydro 2000 Inc.

## CUSTOMER COUNT FORECAST TABLE

| CUSTOMER COUNT FORECAST TABLE | 2006 Board Approved | 2006 Actual | Variance form 2006 Board Approved | 2006 Actual | 2007 Bridge | Variance form 2006 Actual | 2007 Bridge | 2008 Test | Variance form 2007 Actual |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| Residential | 969 | 979 | 10 | 979 | 997 | 18 | 997 | 1005 | 8 |
| G.S. < 50 | 147 | 147 | 0 | 147 | 147 | 0 | 147 | 147 | 0 |
| G.S. > 50 | 11 | 12 | 1 | 12 | 12 | 0 | 12 | 12 | 0 |
| Unmetered | 3 | 6 | 3 | 6 | 6 | 0 | 6 | 6 | 0 |
| Streetlight | 351 | 362 | 11 | 362 | 368 | 6 | 368 | 368 | 0 |
| | | | | | | | | | |
| Total | 1481 | 1506 | 25 | 1506 | 1530 | 24 | 1530 | 1538 | 8 |

## Hydro 2000 Inc

## VARIANCE ANALYSIS ON CUSTOMER COUNT FORECAST

The purpose of the evidence contained in Tab 2, of Exhibits 3, is to provide the Board with a review of Hydro 2000 Inc. actual and forecasted customers, consumption and revenues for the historical, bridge and test years. Test year revenues have been calculated using the approved RP-2005-0020 and EB-2005-0380 Rate Order May 1st, 2007.

Exhibit 3, Tab 2, Schedule 4, provides a summary of the normalized throughput and customer numbers from the schedules noted above.

Hydro 2000 Inc. is a very small utility with a very minimal growth. Hydro 2000 Inc. manager is also a municipal councilor for the last 16 years. He knows very well the area and all future projects incoming in the municipality and in Hydro 2000 Inc. service area. Hydro 2000 Inc. employee knows almost all its customers on a family basis.

### Fiscal 2008 Test Year

Hydro 2000 Inc. total customers forecast maybe at most 8 new residential customers.

### 2007 Bridge Year

Hydro 2000 Inc. actual customers for 2007 bridge year is 17 new residential and 6 new street-light connection and does not anticipate any more construction. The comparison between forecast and the actual is a differential of 1 customer in the residentia1.

### 2006 Actual

Hydro 2000 Inc. 2006 Actual customer count was 1506 customers and connections. The year 2006 was very special with a small boom in construction. 10 new Residential units was built with 11 new street-light connection, 3 Unmetered Scattered Load customers accounts was transferred into 6 accounts, one new customer in General Service less 50 kW and one customer transferred from GS less than 50kW to the Over 50kW.

-

### 2006 Board Approved

The total customer count for 2006 Board Approved was 1481 customers and connection.

# Hydro 2000 Inc

## HISTORICAL AVERAGE CONSUMPTION

| HISTORICAL AVERAGE CONSUMPTION | | | | |
|---|---|---|---|---|
| **Residential** | | | | |
| | | | | |
| Year | Weather Actual | Weather Normalized | Difference | Actual % Diff |
| 2002 | 14,810,717 | | | |
| 2003 | 15,460,530 | | | |
| 2004 | 15,988,104 | 15,334,552 | (653,552) | -4.09% |
| 2005 | 14,960,326 | | | |
| 2006 | 15,223,723 | 16,086,959 | 863,236 | 5.67% |
| 2007 | 15,463,945 | 16,382,735 | 918,790 | 5.94% |
| 2008 | 15,667,418 | 16,514,191 | 846,773 | 5.40% |

| HISTORICAL AVERAGE CONSUMPTION | | | | |
|---|---|---|---|---|
| **G.S. < 50** | | | | |
| | | | | |
| Year | Weather Actual | Weather Normalized | Difference | Actual % Diff |
| 2002 | 5,536,583 | | | |
| 2003 | 5,405,561 | | | |
| 2004 | 5,678,973 | 5,443,481 | (235,492) | -4.15% |
| 2005 | 5,503,436 | | | |
| 2006 | 5,236,111 | 5,682,016 | 445,905 | 8.52% |
| 2007 | 5,269,938 | 5,682,016 | 412,078 | 7.82% |
| 2008 | 5,269,938 | 5,682,016 | 412,078 | 7.82% |

| HISTORICAL AVERAGE CONSUMPTION | | | | |
|---|---|---|---|---|
| **G.S. > 50** | | | | |
| | | | | |
| Year | Weather Actual | Weather Normalized | Difference | Actual % Diff |
| 2002 | 4,941,278 | | | |
| 2003 | 5,338,264 | | | |
| 2004 | 5,338,264 | 5,243,124 | (95,140) | -1.78% |
| 2005 | 5,441,728 | | | |
| 2006 | 5,012,904 | 5,496,281 | 483,377 | 9.64% |
| 2007 | 5,269,938 | 5,496,281 | 226,343 | 4.29% |
| 2008 | 5,269,938 | 5,496,281 | 226,343 | 4.29% |

# Hydro 2000 Inc

| HISTORICAL AVERAGE CONSUMPTION | | | | |
|---|---|---|---|---|
| **Unmetered** | | | | |
| | | | | |
| Year | Weather Actual | Weather Normalized | Difference | Actual % Diff |
| 2002 | 18,804 | | | |
| 2003 | 18,804 | | | |
| 2004 | 18,804 | 18,807 | 3 | 0.02% |
| 2005 | 19,951 | | | |
| 2006 | 19,951 | 19,951 | - | 0.00% |
| 2007 | 19,951 | 19,951 | - | 0.00% |
| 2008 | 19,951 | 19,951 | - | 0.00% |

| HISTORICAL AVERAGE CONSUMPTION | | | | |
|---|---|---|---|---|
| **Streetlight** | | | | |
| | | | | |
| Year | Weather Actual | Weather Normalized | Difference | Actual % Diff |
| 2002 | 339,552 | | | |
| 2003 | 347,926 | | | |
| 2004 | 347,926 | 325,918 | (22,008) | -6.33% |
| 2005 | 345,396 | | | |
| 2006 | 351,709 | 351,709 | - | 0.00% |
| 2007 | 354,624 | 359,553 | 4,929 | 1.39% |
| 2008 | 357,538 | 359,553 | 2,015 | 0.56% |

## Hydro 2000 Inc.

## OTHER DISTRIBUTION REVENUE

| OTHER DISTRIBUTION REVENUE | 2006 Board Approved | 2006 Actual | Variance form 2006 Board Approved | 2006 Actual | 2007 Bridge | Variance form 2006 Actual | 2007 Bridge | 2008 Test | Variance form 2007 Actual |
|---|---|---|---|---|---|---|---|---|---|
| | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) | ($'s) |
| | | | | | | | | | |
| Distribution Services Revenue | 232,580 | 236,347 | 3,767 | 236,347 | 236,348 | 1 | 236,348 | 288,963 | 52,615 |
| LV Charges | 106,241 | 56,565 | (49,676) | 56,565 | 106,241 | 49,676 | 106,241 | 121,000 | 14,759 |
| Retail Services Revenues | 494 | 1,329 | 835 | 1,329 | 1,329 | - | 1,329 | 1,329 | - |
| Service Transaction Requests (STR) Revenues | 1 | 30 | 29 | 30 | 30 | - | 30 | 30 | - |
| SSS Admin | | | - | - | | - | - | - | - |
| Electric Services Incidental to Energy Sales | | | - | - | | - | - | | - |
| Transmission Charges Revenue | | | - | - | | - | - | | - |
| Transmission Services Revenue | | | - | - | | - | - | | - |
| Interdepartmental Rents | | | - | - | | - | - | | - |
| Rent from Electric Property | 5,923 | 6,526 | 603 | 6,526 | 6,526 | - | 6,526 | 6,526 | - |
| Other Utility Operating Income | 27,706 | 35,650 | 7,944 | 35,650 | 16,314 | (19,336) | 16,314 | 16,314 | - |
| Other Electric Revenues | 5,106 | 4,070 | (1,036) | 4,070 | 4,070 | - | 4,070 | 4,070 | - |
| Late Payment Charges | 4,039 | 4,403 | 364 | 4,403 | 4,403 | - | 4,403 | 4,403 | - |
| Sales of Water and Water Power | | | - | - | | - | - | | - |
| Miscellaneous Service Revenues | 2,246 | | (2,246) | - | | - | - | | - |
| Provision for Rate Refunds | | | - | - | | - | - | | - |
| | | | | | | | | | |
| **TOTAL** | 384,336 | 344,920 | (39,416) | 344,920 | 375,261 | 30,341 | 375,261 | 442,635 | 67,374 |

## Hydro 2000 Inc

## MATERIALITY ANALYSIS ON OTHER DISTRIBUTION REVENUE

For any rate base related variance exceeding the materiality threshold of 1%, a detailed explanation is required.

| Materiality calculation | |
|---|---|
| | |
| 2006 Board approved distribution expenses | 292,511 |
| | |
| Materiality = 1% of distribution expenses | 2,925 |

**Variances explanations**

| GROSS ASSET | 2006 Board Approved | 2006 Actual | Variance from 2006 Board Approved |
|---|---|---|---|
| | ($'s) | ($'s) | ($'s) |
| | | | |
| Distribution Services Revenue | 232,580 | 236,347 | 3,767 |
| 25 new customers and connections | | | |
| | | | |
| LV Charges | 106,241 | 56,565 | (49,676) |
| Amounts approved was for 12 months but only 7 months charged because rates approved on May 25. Hydro 2000 is a winter peaking utility. | | | |
| | | | |
| Other Utility Operating Income | 27,706 | 35,650 | 7,944 |
| Increase in regulatory assets. Therefore, increase in interests on regulatory assets. | | | |

**Variances explanations**

| GROSS ASSET | 2006 Actual | 2007 Bridge | Variance from 2006 Actual |
|---|---|---|---|
| | ($'s) | ($'s) | ($'s) |
| | | | |
| LV Charges | 56,565 | 106,241 | 49,676 |
| Amount billed for 12 months vs 7 months in 2006 | | | |
| | | | |
| Other Utility Operating Income | 35,650 | 16,314 | (19,336) |
| Interests on regulatory assets are not considered in the new 2008 rebasing model | | | |

## Hydro 2000 Inc

| Variances explanations | | | |
|---|---|---|---|
| **GROSS ASSET** | **2007 Bridge** | **2008 Test** | **Variance from 2007 Bridge** |
| | **($'s)** | **($'s)** | **($'s)** |
| | | | |
| Distribution Services Revenue | 236,348 | 288,963 | 52,615 |
| Distribution revenues based on the new 2008 rebasing model. The increase is mostly due to the rebasing costs of $60,000. | | | |
| | | | |
| LV Charges | 106,241 | 121,000 | 14,759 |
| The 2008 LV Charges is a more realistic forecast. The amount submitted by Hydro One for the 2004 model was understated. | | | |

## Hydro 2000 Inc

## RATE OF RETURN ON OTHER DISTRIBUTION ACTIVITIES

Hydro 2000 Inc does not have affiliates and does not do any non-core deliver activities.

# Hydro 2000 Inc.

## DISTRIBUTION REVENUE DATA

| 2006 Board Approved | | | | | | |
|---|---|---|---|---|---|---|
| | Customers | Consumption | Distribution Revenues | Distribution revenues - LV Charges | Total Revenues | Unit Revenues |
| | (Year-End) | (kWh / KW) | ($) | ($) | ($) | $/kWh |
| | | | | | | |
| | | | | | | |
| **Residential** | 969 | 15,567,706 | 159,375 | 63,858 | 223,233 | 0.0085 |
| **G.S. < 50** | 147 | 5,504,335 | 50,921 | 22,682 | 73,603 | 0.0097 |
| **G.S. > 50** | 11 | 13,164 | 20,295 | 18,747 | 39,042 | 2.3345 |
| **Unmetered** | 3 | 12,536 | 282 | 75 | 357 | 0.0097 |
| **Streetlight** | 351 | 855 | 1,708 | 879 | 2,587 | 2.2085 |
| TOTAL | 1,481 | 21,098,596 | 232,581 | 106,241 | 338,822 | |

| 2006 Actual | | | | | | |
|---|---|---|---|---|---|---|
| | Customers | Consumptio n | Distributio n Revenues | Distribution revenues - LV Charges | Total Revenues | Unit Revenues |
| | (Year-End) | (kWh / KW) | ($) | ($) | ($) | $/kWh |
| | | | | | | |
| | | | | | | |
| **Residential** | 979 | 15,223,723 | 155,659 | 34,285 | 189,944 | 0.0085 |
| **G.S. < 50** | 147 | 5,236,111 | 48,787 | 8,688 | 57,475 | 0.0097 |
| **G.S. > 50** | 12 | 11,583 | 10,271 | 11,701 | 21,972 | 2.3345 |
| **Unmetered** | 6 | 19,951 | 2,738 | 462 | 3,199 | 0.0097 |
| **Streetlight** | 362 | 925 | 9,649 | 1,403 | 11,052 | 2.2085 |
| TOTAL | 1,506 | 20,492,293 | 227,104 | 56,539 | 283,643 | |

# Hydro 2000 Inc.

| 2006 Actual - Normalized | | | | | | |
|---|---|---|---|---|---|---|
| | **Customers** | **Consumption** | **Distribution Revenues** | **Normalized Consumption** | **Normalized Distribution Revenues** | **Unit Revenues** |
| | **(Year-End)** | **(kWh / KW)** | **($)** | **(kWh / KW)** | **($)** | **$/kWh** |
| | | | | | | |
| | | | | | | |
| **Residential** | 979 | 15,223,723 | 155,659 | 16,086,959 | 160,551 | 0.0085 |
| **G.S. < 50** | 147 | 5,236,111 | 48,787 | 5,682,016 | 53,955 | 0.0097 |
| **G.S. > 50** | 12 | 11,583 | 10,271 | 12,700 | 16,414 | 2.3345 |
| **Unmetered** | 6 | 19,951 | 2,738 | 19,951 | 2,738 | 0.0097 |
| **Streetlight** | 362 | 925 | 9,649 | 925 | 9,649 | 2.2085 |
| TOTAL | 1,506 | 20,492,293 | 227,104 | 21,802,551 | 243,307 | |

| 2007 Bridge - Normalized | | | | | | |
|---|---|---|---|---|---|---|
| | **Customers** | **Consumption** | **Distribution Revenues** | **Normalized Consumption** | **Normalized Distribution Revenues** | |
| | **(Year-End)** | **(kWh / KW)** | **($)** | **(kWh / KW)** | **($)** | |
| | | | | | | |
| | | | | | | |
| **Residential** | 997 | 15,503,628 | 160,386 | 16,382,735 | 169,480 | 0.0086 |
| **G.S. < 50** | 147 | 5,236,111 | 49,290 | 5,682,016 | 53,488 | 0.0098 |
| **G.S. > 50** | 12 | 1,212 | 1,084 | 13,280 | 11,882 | 2.3555 |
| **Unmetered** | 6 | 19,951 | 2,766 | 19,951 | 2,766 | 0.0098 |
| **Streetlight** | 368 | 941 | 9,904 | 941 | 9,904 | 2.2284 |
| TOTAL | 1,530 | 20,761,843 | 223,431 | 22,098,923 | 247,520 | |

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Exhibit: 3
Tab: 3
Schedule: 4
Page: 3

# Hydro 2000 Inc.

| | 2008 Test - Normalized | | | | | |
|---|---|---|---|---|---|---|
| | Customers | Consumption | Distribution Revenues | Forecast Normalized Consumption | Forecast Normalized Distribution Revenues | Unit Revenues |
| | (Year-End) | (kWh / KW) | ($) | (kWh / KW) | ($) | $/kWh |
| | | | | | | |
| | | | | | | |
| **Residential** | 1,005 | | | 16,514,191 | 259,917 | 0.0123 |
| **G.S. < 50** | 147 | | | 5,682,016 | 97,755 | 0.0135 |
| **G.S. > 50** | 12 | | | 13,280 | 41,942 | 3.4844 |
| **Unmetered** | 6 | | | 19,951 | 1,023 | 0.0334 |
| **Streetlight** | 368 | | | 941 | 8,552 | 7.7596 |
| TOTAL | 1,538 | | | 22,230,379 | 409,189 | |

# Hydro 2000 Inc.

## DESCRIPTION OF REVENUE SHARING

Not Applicable.

**Hydro 2000 Inc.**

## 4 - Operating Costs


| | | |
|---|---|---|
| 1 | | **Overview** |
| | 1 | Overview of Operating Costs |
| | 2 | Summary of Operating Costs Table |
| 2 | | **OM&A Costs** |
| | 1 | OM&A Detailed Costs Table |
| | 2 | Variance Analysis on OM&A Table |
| | 3 | Materiality Analysis on OM&A Costs |
| | 4 | Shared Services |
| | 5 | Corporate Cost Allocation |
| | 6 | Purchase of Services |
| | 7 | Employee Compensation, Incentive Plan Expenses, Pension Expense and Post Retirement Benefits |
| | 8 | Depreciation, Amortization and Depletion |
| | 9 | Loss Adjustment Factor |
| | 10 | Materiality Analysis on Loss Adjustment Factor |
| 3 | | **Income Tax, Large Corporation Tax** |
| | 1 | Tax Calculations |
| | 2 | Interest Expense |
| | 3 | Capital Cost Allowance (CCA) |

**Hydro 2000 Inc.**

## OVERVIEW OF OPERATING COSTS

Operating Costs

The operating costs presented in this exhibit represent the annual expenditures required for to sustain The Applicant's Distribution Operations. The information presented in this exhibit is grouped into two different categories: Operation & Maintenance and Other Costs which include items such as Administration & General, Sales Promotion & Customer Accounting, Depreciation, Amortization and Depletion, Shared Services and Loss Adjustment Factor.

The second category includes Income Tax, Large Corporation Tax and Ontario Capital Taxes. Exhibit, Tab, Schedule provides a summary of The Applicant's Operating Costs for the historical, bridge and test years.

OM&A Costs

The OM&A costs in this exhibit represents The Applicant's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and Government direction; and to maintain distribution business service quality and reliability at targeted performance levels. These costs also include providing services to customers connected to the Applicant's Distribution system, and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

The proposed OM&A cost expenditures for the 2008 test year result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place.

OM&A expenditures totaled $2,065,563 in 2006 Board Approved, $2,245,125 in 2006 Actual and are forecast to be $2,257,797 in 2007 and $ 2,430,214 in 2008.

Income Tax, Large Corporation Tax and Ontario Capital Taxes

This information consists of detailed calculations of income taxes, and indemnity payments to the Province. Details of the expenditures are filed at Exhibit 4, Tab 3, Schedule 1.

The Income Taxes, Large Corporation Taxes and Ontario Capital Taxes expenditures totaled $ 0 in 2006 Board Approved, $26,425 in 2006 Actual and are forecast to be $21,970 in 2007 and $32,660 in 2008.

**Hydro 2000 Inc.**

## SUMMARY OF OPERATING COSTS

| SUMMARY OF OPERATING COSTS | 2006 Board Approved | 2006 Actual | 2007 Bridge | 2008 Test |
|---|---|---|---|---|
| **OM&A expenses** | | | | |
| Operation (Working Capital) | 439 | 275 | 738 | 738 |
| Maintenance (Working Capital) | 7,031 | 3,717 | 3,717 | 3,717 |
| Billing and Collections | 78,009 | 80,719 | 85,914 | 87,658 |
| Community Relations | - | - | - | - |
| Administrative and General Expenses | 214,502 | 133,798 | 136,341 | 197,631 |
| Amortization Expenses | 36,818 | 44,364 | 48,834 | 56,569 |
| Cost of Power | 1,728,764 | 1,982,252 | 1,982,253 | 2,083,901 |
| | | | | |
| Other Operating Costs | 18,031 | 20,103 | 18,846 | 17,518 |
| | | | | |
| LCT,OCT and Income Taxes | - | 26,425 | 21,970 | 32,660 |
| **Total Operating Costs** | **2,083,594** | **2,291,653** | **2,298,613** | **2,480,392** |

# Hydro 2000 Inc.

## OM&A COSTS TABLE

| OM&A COSTS | 2006 Board Approved | 2006 Actual | Variance form 2006 Board Approved | 2006 Actual | 2007 Bridge | Variance form 2006 Actual | 2007 Bridge | 2008 Test | Variance form 2007 Bridge |
|---|---|---|---|---|---|---|---|---|---|
| **Operation (Working Capital)** | | | | | | | | | |
| 5005-Operation Supervision and Engineering | - | - | - | - | - | - | - | - | - |
| 5010-Load Dispatching | - | - | - | - | - | - | - | - | - |
| 5012-Station Buildings and Fixtures Expense | - | - | - | - | - | - | - | - | - |
| 5014-Transformer Station Equipment - Operation Labour | - | - | - | - | - | - | - | - | - |
| 5015-Transformer Station Equipment - Operation Supplies and Expenses | - | - | - | - | - | - | - | - | - |
| 5016-Distribution Station Equipment - Operation Labour | - | - | - | - | - | - | - | - | - |
| 5017-Distribution Station Equipment - Operation Supplies and Expenses | - | - | - | - | - | - | - | - | - |
| 5020-Overhead Distribution Lines and Feeders - Operation Labour | - | - | - | - | - | - | - | - | - |
| 5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses | - | - | - | - | - | - | - | - | - |
| 5030-Overhead Subtransmission Feeders - Operation | - | - | - | - | - | - | - | - | - |
| 5035-Overhead Distribution Transformers- Operation | - | - | - | - | 463.00 | 463.00 | 463.00 | 463.00 | - |
| 5040-Underground Distribution Lines and Feeders - Operation Labour | - | - | - | - | - | - | - | - | - |
| 5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses | - | - | - | - | - | - | - | - | - |
| 5050-Underground Subtransmission Feeders - Operation | - | - | - | - | - | - | - | - | - |
| 5055-Underground Distribution Transformers - Operation | - | - | - | - | - | - | - | - | - |
| 5060-Street Lighting and Signal System Expense | - | - | - | - | - | - | - | - | - |
| 5065-Meter Expense | 439.00 | 275.00 | (164.00) | 275.00 | 275.00 | - | 275.00 | 275.00 | - |
| 5070-Customer Premises - Operation Labour | - | - | - | - | - | - | - | - | - |
| 5075-Customer Premises - Materials and Expenses | - | - | - | - | - | - | - | - | - |
| 5085-Miscellaneous Distribution Expense | - | - | - | - | - | - | - | - | - |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 5090-Underground Distribution Lines and Feeders - Rental Paid | - | - | - | - | - | - | - | - | - |
| 5095-Overhead Distribution Lines and Feeders - Rental Paid | - | - | - | - | - | - | - | - | - |
| 5096-Other Rent | - | - | - | - | - | - | - | - | - |
| **Sub-Total** | **439.00** | **275.00** | **(164.00)** | **275.00** | **738.00** | **463.00** | **738.00** | **738.00** | **-** |
| **Maintenance (Working Capital)** | | | | | | | | | |
| 5105-Maintenance Supervision and Engineering | - | - | - | - | - | - | - | - | - |
| 5110-Maintenance of Buildings and Fixtures - Distribution Stations | - | - | - | - | - | - | - | - | - |
| 5112-Maintenance of Transformer Station Equipment | - | - | - | - | - | - | - | - | - |
| 5114-Maintenance of Distribution Station Equipment | - | - | - | - | - | - | - | - | - |
| 5120-Maintenance of Poles, Towers and Fixtures | - | - | - | - | - | - | - | - | - |
| 5125-Maintenance of Overhead Conductors and Devices | 6,046.00 | 2,064.00 | (3,982.00) | 2,064.00 | 2,064.00 | - | 2,064.00 | 2,064.00 | - |
| 5130-Maintenance of Overhead Services | - | - | - | - | - | - | - | - | - |
| 5135-Overhead Distribution Lines and Feeders - Right of Way | - | - | - | - | - | - | - | - | - |
| 5145-Maintenance of Underground Conduit | - | - | - | - | - | - | - | - | - |
| 5150-Maintenance of Underground Conductors and Devices | - | - | - | - | - | - | - | - | - |
| 5155-Maintenance of Underground Services | - | - | - | - | - | - | - | - | - |
| 5160-Maintenance of Line Transformers | - | - | - | - | - | - | - | - | - |
| 5165-Maintenance of Street Lighting and Signal Systems | - | - | - | - | - | - | - | - | - |
| 5170-Sentinel Lights - Labour | - | - | - | - | - | - | - | - | - |
| 5172-Sentinel Lights - Materials and Expenses | - | - | - | - | - | - | - | - | - |
| 5175-Maintenance of Meters | 985.00 | 1,653.00 | 668.00 | 1,653.00 | 1,653.00 | - | 1,653.00 | 1,653.00 | - |
| 5178-Customer Installations Expenses- Leased Property | - | - | - | - | - | - | - | - | - |
| 5185-Water Heater Rentals - Labour | - | - | - | - | - | - | - | - | - |
| 5186-Water Heater Rentals - Materials and Expenses | - | - | - | - | - | - | - | - | - |
| 5190-Water Heater Controls - Labour | - | - | - | - | - | - | - | - | - |
| 5192-Water Heater Controls - Materials and Expenses | - | - | - | - | - | - | - | - | - |
| 5195-Maintenance of Other Installations on Customer Premises | | | | | | | | | |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | - | - | - | - | - | - | - | - | - |
| **Sub-Total** | **7,031.00** | **3,717.00** | **(3,314.00)** | **3,717.00** | **3,717.00** | **-** | **3,717.00** | **3,717.00** | **-** |
| **Billing and Collections** | | | | | | | | | |
| 5305-Supervision | - | - | - | - | - | - | - | - | - |
| 5310-Meter Reading Expense | - | - | - | - | - | - | - | - | - |
| 5315-Customer Billing | 76,206.00 | 76,968.00 | 762.00 | 76,968.00 | 78,507.00 | 1,539.00 | 78,507.00 | 80,077.00 | 1,570.00 |
| 5320-Collecting | - | - | - | - | - | - | - | - | - |
| 5325-Collecting- Cash Over and Short | - | - | - | - | - | - | - | - | - |
| 5330-Collection Charges | (1,256.00) | 94.00 | 1,350.00 | 94.00 | 94.00 | - | 94.00 | 121.00 | 27.00 |
| 5335-Bad Debt Expense | 3,059.00 | 3,657.00 | 598.00 | 3,657.00 | 7,313.00 | 3,656.00 | 7,313.00 | 7,460.00 | 147.00 |
| 5340-Miscellaneous Customer Accounts Expenses | - | - | - | - | - | - | - | - | - |
| **Sub-Total** | **78,009.00** | **80,719.00** | **2,710.00** | **80,719.00** | **85,914.00** | **5,195.00** | **85,914.00** | **87,658.00** | **1,744.00** |
| **Community Relations** | | | | | | | | | |
| 5405-Supervision | - | - | - | - | - | - | - | - | - |
| 5410-Community Relations - Sundry | - | - | - | - | - | - | - | - | - |
| 5415-Energy Conservation | - | - | - | - | - | - | - | - | - |
| 5420-Community Safety Program | - | - | - | - | - | - | - | - | - |
| 5425-Miscellaneous Customer Service and Informational Expenses | - | - | - | - | - | - | - | - | - |
| 5505-Supervision | - | - | - | - | - | - | - | - | - |
| 5510-Demonstrating and Selling Expense | - | - | - | - | - | - | - | - | - |
| 5515-Advertising Expense | - | - | - | - | - | - | - | - | - |
| 5520-Miscellaneous Sales Expense | - | - | - | - | - | - | - | - | - |
| **Sub-Total** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **Administrative and General Expenses** | | | | | | | | | |
| 5605-Executive Salaries and Expenses | 9,455.00 | 8,871.00 | (584.00) | 8,871.00 | 8,871.00 | - | 8,871.00 | 8,871.00 | - |
| 5610-Management Salaries and Expenses | 50,075.00 | 57,752.00 | 7,677.00 | 57,752.00 | 60,062.00 | 2,310.00 | 60,062.00 | 61,263.00 | 1,201.00 |

# Hydro 2000 Inc.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 5615-General Administrative Salaries and Expenses | 3,333.00 | - | (3,333.00) | - | - | - | - | - | - |
| 5620-Office Supplies and Expenses | 9,345.00 | 9,013.00 | (332.00) | 9,013.00 | 9,013.00 | - | 9,013.00 | 9,013.00 | - |
| 5625-Administrative Expense Transferred Credit | - | - | - | - | - | - | - | - | - |
| 5630-Outside Services Employed | 8,058.00 | 28,733.00 | 20,675.00 | 28,733.00 | 28,733.00 | - | 28,733.00 | 28,733.00 | - |
| 5635-Property Insurance | 3,807.00 | 3,410.00 | (397.00) | 3,410.00 | 3,410.00 | - | 3,410.00 | 3,410.00 | - |
| 5640-Injuries and Damages | 919.00 | - | (919.00) | - | - | - | - | - | - |
| 5645-Employee Pensions and Benefits | 9,183.00 | 7,766.00 | (1,417.00) | 7,766.00 | 7,999.00 | 233.00 | 7,999.00 | 8,159.00 | 160.00 |
| 5650-Franchise Requirements | - | - | - | - | - | - | - | - | - |
| 5655-Regulatory Expenses | 6,526.00 | 6,571.00 | 45.00 | 6,571.00 | 6,571.00 | - | 6,571.00 | 66,500.00 | 59,929.00 |
| 5660-General Advertising Expenses | - | - | - | - | - | - | - | - | - |
| 5665-Miscellaneous General Expenses | 106,241.00 | - | (106,241.00) | - | - | - | - | - | - |
| 5670-Rent | 7,560.00 | 7,873.00 | 313.00 | 7,873.00 | 7,873.00 | - | 7,873.00 | 7,873.00 | - |
| 5675-Maintenance of General Plant | - | - | - | - | - | - | - | - | - |
| 5680-Electrical Safety Authority Fees | - | 3,809.00 | 3,809.00 | 3,809.00 | 3,809.00 | - | 3,809.00 | 3,809.00 | - |
| 5685-Independent Market Operator Fees and Penalties | - | - | - | - | - | - | - | - | - |
| **Sub-Total** | **214,502.00** | **133,798.00** | **(80,704.00)** | **133,798.00** | **136,341.00** | **2,543.00** | **136,341.00** | **197,631.00** | **61,290.00** |
| **Amortization Expenses** | | | | | | | | | |
| 5705-Amortization Expense - Property, Plant, and Equipment | 36,355.00 | 43,901.00 | 7,546.00 | 43,901.00 | 48,834.00 | 4,933.00 | 48,834.00 | 56,569.00 | 7,735.00 |
| 5710-Amortization of Limited Term Electric Plant | - | - | - | - | - | - | - | - | - |
| 5715-Amortization of Intangibles and Other Electric Plant | 463.00 | 463.00 | - | 463.00 | - | (463.00) | - | - | - |
| 5720-Amortization of Electric Plant Acquisition Adjustments | - | - | - | - | - | - | - | - | - |
| 5725-Miscellaneous Amortization | - | - | - | - | - | - | - | - | - |
| 5730-Amortization of Unrecovered Plant and Regulatory Study Costs | - | - | - | - | - | - | - | - | - |
| 5735-Amortization of Deferred Development Costs | - | - | - | - | - | - | - | - | - |
| 5740-Amortization of Deferred Charges | - | - | - | - | - | - | - | - | - |
| **Sub-Total** | **36,818.00** | **44,364.00** | **7,546.00** | **44,364.00** | **48,834.00** | **4,470.00** | **48,834.00** | **56,569.00** | **7,735.00** |

# Hydro 2000 Inc.

**Cost of Power**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 4705-Power Purchased | 1,333,304.00 | 1,499,578.00 | 166,274.00 | 1,499,578.00 | 1,499,578.00 | - | 1,499,578.00 | 1,601,226.00 | 101,648.00 |
| 4708-Charges-WMS | 170,252.00 | 160,329.00 | (9,923.00) | 160,329.00 | 160,329.00 | - | 160,329.00 | 160,329.00 | - |
| 4710-Cost of Power Adjustments | (53,765.00) | - | 53,765.00 | - | - | - | - | - | - |
| 4712-Charges-One-Time | - | - | - | - | - | - | - | - | - |
| 4714-Charges-NW | 149,261.00 | 142,157.00 | (7,104.00) | 142,157.00 | 142,157.00 | - | 142,157.00 | 142,157.00 | - |
| 4716-Charges-CN | 129,712.00 | 123,624.00 | (6,088.00) | 123,624.00 | 123,624.00 | - | 123,624.00 | 123,624.00 | - |
| 4730-Rural Rate Assistance Expense | - | - | - | - | - | - | - | - | - |
| 4750-LV Charges Costs | - | 56,564.00 | 56,564.00 | 56,564.00 | 56,565.00 | 1.00 | 56,565.00 | 56,565.00 | - |
| 5685-Independent Market Operator Fees and Penalties | - | - | - | - | - | - | - | - | - |
| **Sub-Total** | **1,728,764.00** | **1,982,252.00** | **253,488.00** | **1,982,252.00** | **1,982,253.00** | **1.00** | **1,982,253.00** | **2,083,901.00** | **101,648.00** |

**Hydro 2000 Inc.**

# VARIANCE ANALYSIS ON OM&A COSTS TABLE

A summary of operating and maintenance costs is presented in Exhibit 4, Tab 2, Schedule 2.

**2008 Test year**
The 2008 test year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1-2. The total net cost is expected to be $2,430,214. Net wages and benefits make up 4.39% of the total net Operating & Maintenance costs. Administration and General costs total a further 8.12%. Customer Accountings costs accounts for 0.25% of the total Operating and Maintenance costs.

**Comparison to Fiscal 2007 Bridge Year**
Exhibit 4, Tab 2, Schedule 3, provides a comparison of the 2008 test year forecast of Operation & Maintenance expenses to that forecast for the 2007 bridge year. Total net Operation & Maintenance costs are forecast to increase $172,417 or 7.6%.

**2007 Bridge Year**
The 2007 Bridge year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1-2. The total net cost is expected to be $2,257,797. Net wages and benefits make up 4.63% of the total net Operating & Maintenance costs. Administration and General costs total a further 6.04%. Customer Accountings costs accounts for 0.28% of the total Operating and Maintenance costs.

**Comparison to 2006 Actual**
Exhibit 4, Tab 2, Schedule 3, provides a comparison of the 2007 Bridge year forecast of Operation & Maintenance expenses to that forecast for the 2006 Actual year. Total net Operation & Maintenance costs are forecast to increase $12,762 or 0.56%.

**2006 Actual**
The 2006 Actual year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1-2. The total net cost is expected to be $2,245,125. Net wages and benefits make up 4.51% of the total net Operating & Maintenance costs. Administration and General costs total a further 5.96%. Customer Accountings costs accounts for 0.27% of the total Operating and Maintenance costs.

**Comparison to 2006 Board Approved**
Exhibit 4, Tab 2, Schedule 3, provides a comparison of the 2006 Actual year forecast of Operation & Maintenance expenses to that forecast for the 2006 Board Approved year. Total net Operation & Maintenance costs are forecast to increase $179,562 or 8.69%.

**Hydro 2000 Inc.**

## 2006 Board Approved

The 2006 Actual year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1-2. The total net cost is expected to be $2,065,563. Net wages and benefits make up 4.56% of the total net Operating & Maintenance costs. Administration and General costs total a further 10.38%. Customer Accountings costs accounts for 0.27% of the total Operating and Maintenance costs.

**Hydro 2000 Inc.**

**MATERIALITY ANALYSIS ON OM&A COSTS**

A written explanation is required for operating costs related information when a variance greater or equal to 1% of the total distribution expenses before PILs, whichever is larger.

## Materiality calculation

| | | | |
|---|---|---|---|
| | | | |
| 2006 Board approved distribution expenses | | 292,511 | |
| | | | |
| Materiality = 1% of distribution expenses | | 2,925 | |

## Variances explanations

| OM&A | 2006 Board Approved | 2006 Actual | Variance from 2006 Board Approved |
|---|---|---|---|
| | ($'s) | ($'s) | ($'s) |
| | | | |
| 5125-Maintenance of Overhead Conductors and Devices | 6,046.00 | 2,064.00 | (3,982) |
| There were less unpredicted weather damages to distribution system. | | | |
| | | | |
| 5610-Management Salaries and Expenses | 50,075.00 | 57,752.00 | 7,677 |
| There was a 2% salary increase for 2005 and 3% for 2006. The change of salary class also increased the salaries by 2% each year. There was more traveling due to cost allocation, EDR and smart meters. | | | |
| | | | |
| 5615-General Administrative Salaries and Expenses | 3,333.00 | - | (3,333) |
| $3,000 of the approved amount was for the EDA 2004 membership. In 2006, this amount was classified in account 5630. | | | |
| | | | |
| 5630-Outside Services Employed | 8,058.00 | 28,733.00 | 20,675 |
| There was approximately $10,000 in 2006 for the cost allocation and $7,500 for EDR 2006 for written hearings and questions from the board. The EDA membership was included in account 5615 when approved by the board. The EDA membership for 2006 was $4,200. | | | |

**Hydro 2000 Inc.**

# Variances explanations

| OM&A | 2006 Board Approved | 2006 Actual | Variance from 2006 Board Approved |
|---|---|---|---|
| | ($'s) | ($'s) | ($'s) |
| 5665-Miscellaneous General Expenses | 106,241.00 | - | (106,241) |
| LV charges included in EDR 2006 rates. Per accounting procedures, the actual amount was included in account 4750. | | | |
| | | | |
| 5680-Electrical Safety Authority Fees | - | 3,809.00 | 3,809 |
| This account includes the ESA membership which started in 2005 and the audit fees for 2006. | | | |
| | | | |
| 5705-Amortization Expense - Property, Plant, and Equipment | 36,355.00 | 43,901.00 | 7,546 |
| There is more amortization than the approved amount due to acquisitions of the capital assets. | | | |
| | | | |
| 4705-Power Purchased | 1,333,304.00 | 1,499,578.00 | 166,274 |
| Increase in the cost of power per kwh even though there was a reduction in the consumption. | | | |
| | | | |
| 4708-Charges-WMS | 170,252.00 | 160,329.00 | (9,923) |
| Reduction in the consumption. | | | |
| | | | |
| 4710-Cost of Power Adjustments | (53,765.00) | - | 53,765 |
| Adjustment included in EDR 2006. | | | |
| | | | |
| 4714-Charges-NW | 149,261.00 | 142,157.00 | (7,104) |
| Reduction in the consumption. | | | |
| | | | |
| 4716-Charges-CN | 129,712.00 | 123,624.00 | (6,088) |
| Reduction in the consumption. | | | |
| | | | |
| 4750-LV Charges Costs | - | 56,564.00 | 56,564 |
| LV charges were charged since May 2006 with the new rates. The amount approved for 12 months is included in account 5665. | | | |

## Hydro 2000 Inc.

## SHARED SERVICES

Hydro 2000 Inc. does not have any affiliates and is not sharing any services.

## Hydro 2000 Inc.

## CORPORATE COST ALLOCATION

Hydro 2000 Inc. does not have any affiliates and is not sharing any services.

## Hydro 2000 Inc.

## PURCHASE OF SERVICES

**The following table shows all the purchase of services and a description of the nature of the activity transacted with a summary of tendering process for 2006 Actual, 2007 Bridge and 2008 Test Year.**

| PURCHASE OF SERVICES | | | | | |
|---|---|---|---|---|---|
| | | | **2006 Actual** | **2007 Bridge** | **2008 Test** |
| | | | | | |
| | | | | | |
| | | | | | |
| Name of Company transacting with the Applicant | Summary of the nature of the activity transacted | Summary of tendering process/summary of cost approach | | | |
| - | - | - | | | |
| Township of Alfred and Plantagenet | Office space Rented | Lease Contract | 7,873 | 8,160 | 8,400 |
| Sproule Powerline | Lines maintenance | Hourly and / or tender | 46,324 | 90,000 | 75,000 |
| ORES | Billing | Contract | 27,660 | 28,000 | 28,000 |
| Marcel Gaudreault | Metering | Hourly | 1,100 | 1,100 | 7,500 |
| RCS | Regulatory compliance with OEB Board | Hourly | 3,425 | 3,425 | 5,500 |
| Deloitte | Regulatory compliance with OEB Board and audit | Hourly | 11,033 | 11,033 | 30,000 |
| EDA | Membership fee | Membership fee | 4,200 | 4,200 | 4,200 |
| Hydro One | Cost allocation review - Weather normalization | Contract | 9,776 | - | - |
| Elenchus Research Associates | Regulatory compliance with OEB Board | Hourly | - | - | 30,000 |
| Canpage | Answering Service | Tender | 2,054 | 2,400 | 2,400 |
| IGS Hawkesbury | Internet Provider | Tender | 840 | 780 | 780 |
| Imprimerie Serge | Printing Shop | Tender | | 1,500 | 1,500 |
| Stantec | Line loss study | Tender | 14,660 | | |
| Quasar | ESA Audit | Tender | 1,950 | 1,950 | 2,000 |
| Vi-tech Systems | IT | Hourly/Tender | 6,026 | 2,000 | 2,000 |

# Hydro 2000 Inc.

## EMPLOYEE DESCRIPTION

### Number of employees (Full-time equivalents (FTE's):

| EMPLOYEE DESCRIPTION<br>Number of employees (Full-time equivalents (FTE's): | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 2006 Board Approved | | 2006 Actual | | 2007 Bridge | | 2008 Test |
| Executive | | 1 | | 1 | | 1 | | 1 |
| Management | | 0 | | 0 | | 0 | | 0 |
| Non-Unionized | | 1 | | 1 | | 1 | | 1 |
| Unionized | | 0 | | 0 | | 0 | | 0 |
| | | | | | | | | |
| total | | 2 | | 2 | | 2 | | 2 |

### Number of employees (Part-time equivalents (PTE's):

| | 2006 Board Approved | 2006 Actual | 2007 Bridge | 2008 Test |
|---|---|---|---|---|
| Executive | 0 | 0 | 0 | 0 |
| Management | 0 | 0 | 0 | 0 |
| Non-Unionized | 0 | 0 | 0 | 0 |
| Unionized | 0 | 0 | 0 | 0 |

### Compensation (Total Salary and Wages ($)):

| Compensation (Total Salary and Wages ($)): | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2006 Board Approved | Average | 2006 Actual | Average | 2007 Bridge | Average | 2008 Test | Average |
| Executive | 50,075 | 50,075 | 56,152 | 56,152 | 58,398 | 58,398 | 59,566 | 59,566 |
| Management | | | | | | | | |
| Non-Unionized | 35,117 | 35,117 | 37,772 | 37,772 | 38,527 | 38,527 | 39,298 | 39,298 |
| Unionized | | | | | | | | |
| | | | | | | | | |
| Total | 85,192 | 42,596 | 93,924 | 46,962 | 96,926 | 48,463 | 98,864 | 49,432 |

**File Number: EB-2007-0704**
**Exhibit: 4**
**Tab: 2**
**Schedule: 7**
**Page: 2**

## Hydro 2000 Inc.

## Compensation (Total Benefits ($)):

| Compensation (Total Benefits ($)): | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2006 Board Approved | Average | 2006 Actual | Average | 2007 Bridge | Average | 2008 Test | Average |
| **Executive** | 4,883 | 4,883 | 4,056 | 4,056 | 4,218 | 4,218 | 4,303 | 4,303 |
| **Management** | | | | | | | | |
| **Non-Unionized** | 4,300 | 4,300 | 3,446 | 3,446 | 3,515 | 3,515 | 3,585 | 3,585 |
| **Unionized** | | | | | | | | |
| | | | | | | | | |
| **Total** | 9,183 | 4,592 | 7,502 | 3,751 | 7,733 | 3,867 | 7,888 | 3,944 |

## Compensation (Total Incentives ($)): Not Applicable

| | 2006 Board Approved | Average | 2006 Actual | Average | 2007 Bridge | Average | 2008 Test | Average |
|---|---|---|---|---|---|---|---|---|
| **Executive** | | | | | | | | |
| **Management** | | | | | | | | |
| **Non-Unionized** | | | | | | | | |
| **Unionized** | | | | | | | | |

## Total of Costs charged to O&M ($)): Not Applicalbe

| | 2006 Board Approved | Average | 2006 Actual | Average | 2007 Bridge | Average | 2008 Test | Average |
|---|---|---|---|---|---|---|---|---|
| **TOTAL** | | | | | | | | |

## Status of pension funding

**Not applicable.**

## Hydro 2000 Inc.

## DEPRECIATION, AMORTIZATION AND DEPLETION

| DEPRECIATION, AMORTIZATION AND DEPLETION | 2006 Board Approved ($'s) | Depreciation Rate | Depreciation ($'s) | 2006 Actual ($'s) | Depreciation Rate | Depreciation ($'s) | 2007 Bridge ($'s) | Depreciation Rate | Depreciation ($'s) | 2008 Test ($'s) | Depreciation Rate | Depreciation ($'s) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Land and Buildings | - | | - | - | | - | - | | - | - | | - |
| TS Primary Above 50 | - | | - | - | | - | - | | - | - | | - |
| DS | - | | - | - | | - | - | | - | - | | - |
| | | | | | | | | | | | | |
| Poles and Wires | 362,474 | 4% | 26,038 | 452,286 | 4% | 29,194 | 515,267 | 4% | 30,454 | 555,267 | 4% | 32,513 |
| | | | | | | | | | | | | |
| Line Transformers | 52,828 | 4% | 3,795 | 60,495 | 4% | 4,012 | 76,694 | 4% | 4,336 | 76,694 | 4% | 4,660 |
| | | | | | | | | | | | | |
| Services and Meters | 43,687 | 4% | 3,138 | 101,289 | 4% | 5,679 | 101,289 | 4% | 5,679 | 201,289 | 4% | 7,679 |
| | | | | | | | | | | | | |
| General Plant | - | | - | - | | - | - | | - | - | | - |
| | | | | | | | | | | | | |
| IT Assets | 16,649 | 20% | 3,330 | 48,217 | 20% | 7,553 | 90,217 | 20% | 11,752 | 90,217 | 20% | 15,949 |
| | | | | | | | | | | | | |
| Equipment | 3,084 | 10% | 54 | 3,246 | 10% | 54 | 3,246 | 10% | 54 | 3,246 | 10% | 54 |
| | | | | | | | | | | | | |
| Other Distribution Assets | - | 4 - 20 % | - | (64,783) | 4 - 20 % | (2,591) | (107,165) | 4 - 20 % | (3,439) | (107,165) | 4 - 20 % | (4,286) |
| | | | | | | | | | | | | |
| **GROSS ASSET TOTAL** | **478,722** | | **36,355** | **600,750** | | **43,901** | **679,548** | | **48,836** | **819,548** | | **56,569** |

# Hydro 2000 Inc.

## LOSS ADJUSTMENT FACTOR CALCULATION

| | **LOSS ADJUSTMENT FACTOR CALCULATION** | **2002** | **2003** | **2004** | **2005** | **2006** | **TOTAL** |
|---|---|---|---|---|---|---|---|
| A | "Wholesale" kWh (HONI) | 25,219,307 | 27,395,339 | 26,939,359 | 26,811,027 | 25,425,732 | 131,790,764 |
| | **Total loss factor (HONI) TLF of 3.4%** | 857,447 | 931,442 | 915,938 | 911,574 | 864,475 | 4,480,876 |
| B | Wholesale kWh for Large Use customer(s) (HONI) | 0 | 0 | 0 | 0 | 0 | - |
| C | Net "Wholesale" kWh (A)-(B) | 25,219,307 | 27,395,339 | 26,939,359 | 26,811,027 | 25,425,732 | 131,790,764 |
| D | Retail kWh (Distributor) | 24,715,774 | 26,545,865 | 25,950,063 | 25,663,602 | 24,327,396 | 127,202,700 |
| D1 | Load Transfer Reduction | 73,148 | 150,824 | 144,260 | 146,520 | 140,090 | 654,842 |
| E | Retail kWh for Large Use Customer(s) (1% loss) | 6,203 | 7,232 | 7,184 | 5,721 | 5,570 | 31,910 |
| F | Net "Retail" kWh (D)+(D1)-(E) | 24,782,719 | 26,689,457 | 26,087,139 | 25,804,401 | 24,461,916 | 127,825,632 |
| G | Loss Factor [(C)/(F)] | 1.76% | 2.64% | 3.27% | 3.90% | 3.94% | |
| | HONI TLF of 3.4% | 3.40% | 3.40% | 3.40% | 3.40% | 3.40% | |
| H | Distribution Loss Adjustment Factor | 5.16% | 6.04% | 6.67% | 7.30% | 7.34% | **1.0661%** |

## Hydro 2000 Inc.

### Total Utility Loss Adjustment Factor

| | LAF |
|---|---|
| Supply Facility Loss Factor | |
| | |
| Distribution Loss Factors | |
| Secondary Metered Customer | |
| Total Loss Factor - Secondary Metered Customer < 5,000kW | |
| Total Loss Factor - Secondary Metered Customer > 5,000kW | |
| | |
| Primary Metered Customer | |
| Total Loss Factor - Primary Metered Customer < 5,000kW | |
| Total Loss Factor - Primary Metered Customer > 5,000kW | |
| | |
| Total Loss Factor | |
| Secondary Metered Customer | |
| Total Loss Factor - Secondary Metered Customer < 5,000kW | 1.0610 |
| Total Loss Factor - Secondary Metered Customer > 5,000kW | N/A |
| | |
| Primary Metered Customer | |
| Total Loss Factor - Primary Metered Customer < 5,000kW | 1.0503 |
| Total Loss Factor - Primary Metered Customer > 5,000kW | N/A |
| | |
| TOTAL LOSS FACTOR | |

## Hydro 2000 Inc.

## MATERIALITY ANALYSIS ON DISTRIBUTION LOSSES

Hydro 2000 loss factor for the period from the year 2002 up to 2006 is **1.0661%.** In the table of calculation for Loss Adjustment factor in Exhibit 4, Tab, 2, Schedule 9 page 1, you can notice that the table has been modified to reflect Hydro One Networks Inc. Total Loss Factor charge to Hydro 2000 Inc. If you remove the TLF from LAF you will notice that we are well below the 5% at 3.1%.

Most of our system loses are incurred outside of our Distribution Area. If you refer to the Distribution Map Area in Exhibit 1, Tab 1, Schedule 10 you will notice that both Distribution Station are outside of Hydro 2000 Inc. Service Area.

Hydro One Networks Shared both DS with Hydro 2000 Inc. A line lost study was perform by Stantec Consulting Ltd. and shows that most of our system loses in Alfred Service Area occurs outside. One of the feeders is metered at the DS and the others feeder a split feeder between Hydro One Networks and Hydro 2000 is metered before the Alfred Service Area.

In the Line loss study on page 6 and page 17 of the report the total losses for F2 is 2.24% and F3 is 3.07% in Alfred Service Area and in Plantagenet Service Area total loses is 3.65% on the feeder.

The following pages contain the **LOAD FLOW STUDY FINDINGD AN RESULTS** AND **RECOMMENDATIONS** of Hydro 2000 Inc. Utility Load flow and Evaluation Study.

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# INTRODUCTION

## UTILITY LOAD FLOW STUDY

Stantec Consulting Ltd. is pleased to submit this Utility Load Flow Study of the electrical distribution systems of both Alfred and Plantagenet for Hydro 2000 Inc. This study has been prepared in accordance with relevant standards, including the Ontario Electrical Safety Authority (ESA), National Electrical Manufacturer's Association (NEMA), Institute of Electrical and Electronic Engineers (IEEE), Municipal Electrical Association (MEA), Canadian Standards Authority (CSA), and the American National Standards Institute (ANSI).

## OBJECTIVES

There were a number of objectives for this study, including:

- Determining the acceptability of the system with current and future load growth and to identify any voltage support problems, overloaded equipment, etc.
- Finding whether the system would operate acceptably during Emergency situations.
- Optimizing the system arrangement (cable sizes, load balancing, open points, etc.) to minimize losses, maximize voltage support, and to distribute loading evenly.
- The optimal placement and effects of a future substation to allow for a municipally owned substation.

## SCOPE OF STUDY

The Load Flow Study for both systems includes all feeders into each town from the Hydro One 44kV Utility Substation down to each major tap at the 8.32(4.8)kV level, no secondary lines were included. All loads were represented as either point or distributed loads over the segment that they were modelled on, and are shown on the system model layouts under Appendix 1.

**ASSUMPTIONS AND GENERALIZATIONS**

A number of assumptions and generalizations are made when modelling a complex system. Some of the ones made in this study are as follows:

- In most cases, loads were modelled as spot loads, sized using current measurements made at strategic points within the system. For longer sections with multiple transformers, loads were distributed evenly across the section of line.
- Each feeder's loads were modelled at a Power Factor of 0.9.
- There were some discrepancies in the phasing observed between the drawing and the measurements taken. Where the actual phasing of taps or transformers could not be verified, other measurements taken within the system were examined to determine the likely phasing arrangement actually implemented. The areas of discrepancy are listed in the table below, Hydro personnel should check the devices to confirm their phasing and update the drawings if necessary.

| ***Feeder*** | ***Section*** | ***Phase shown in drawing*** | ***Phase indicated by measurements*** |
|---|---|---|---|
| Alfred, Fdr 2 | St. Marie & St. Placide - Single Phase | Red | Blue |
| Alfred, Fdr 3 | St. Joseph - Single-phase at end of 3 phase | Red | White |
| Alfred, Fdr 3 | Single-phase transformers on St. Joseph between Quesnel & Murray | Blue | Red |

- The drawings 'Village of Plantagenet, Electrical Distribution System' completed on October 25, 1999 and the 'Village of Alfred, Electrical Distribution System' completed in June 30, 1999 were used as the basis of the system models, with site inspections to determine line loading and feeder sizes.

- The ratings used in this study to assess the loading of various conductors are listed in the table below. Please note, while insulated cables have a fairly limited set of current ratings (typically free air, raceway, or direct buried ratings), ACSR cables have a wide range of ratings, based on ambient temperatures, peak conductor temperatures, cross winds, emissivity of the conductor, and sun heating. The following conductor ratings are standard ratings, based on maximum absolute conductor temperatures of 105˚C, ambient temperatures of 30˚C (Summer) and 10˚C (Winter), 0.6m/sec (2feet/sec) of cross wind, 0.7 coefficient of emissivity, and full sun.

| ***Cable Type*** | ***Rating*** | ***Ampacity @ 30 ˚ C Ambient*** | ***Ampacity @ 10 ˚ C Ambient*** |
|---|---|---|---|
| Cable - 2/0 AWG 1/C Alum TR-XLP 100% | Continuous Amps | 245 | 245 |
| ACSR - 336 kcmil 26/7 | Continuous Amps | 647 | 733 |
| ACSR - 3/0 AWG | Continuous Amps | 370 | 419 |
| ACSR - 1/0 AWG | Continuous Amps | 288 | 326 |
| ACSR - #2 AWG | Continuous Amps | 228 | 285 |
| ACSR - #4 AWG | Continuous Amps | 172 | 215 |

# LOAD FLOW STUDY FINDINGS AND RESULTS

## ALFRED ELECTRICAL DISTRIBUTION SYSTEM

### SYSTEM EQUIPMENT RATINGS

The main equipment within the Hydro 2000 substation is listed below, along with the ratings that are used to evaluate these components for various loading scenarios. Ratings and information that could not be verified were estimated for the purposes of the study and are marked in table with an asterisk (*).

| ***System Component*** | ***Rating*** | ***Ampacity @ 8.32kV*** |
|---|---|---|
| 44kV Primary Fuses<br>S&C Electric SMD-1A, 125E<br>Slow Speed, TCC 119-1 | Continuous Amps<br>Daily 8 hour peak<br>Emergency 8 hour peak | 761.5A (144A)<br>772.1A (146A)<br>835.6A (158A) |
| 44,000/8,800V Transformer<br>Delta/Wye (Grnd.), 7.5 MVA (ONAN)<br>Z = 5.56% | Continuous Amps | 520A (98.4A) |
| 8.32kV Secondary Switchgear | Continuous Amps | *600A |
| 8.32kV Hydraulic Oil Circuit Reclosers<br>Cooper Type 'L' with 280A Trips | Continuous Amps | 280A |

The size of the switches in the system, and their fuse sizes, where applicable, could not be confirmed. The ratings of most feeder level switches within this system were estimated as 100 or 200 Amps, based on the cable size they were connected to. Most aggregated backbone switches are solid-blade type and their ratings were estimated at 300 Amps, based on the cable size they were connected to. These conservative values will allow us to ensure that all normal and emergency situations which may be above that level are flagged properly. Typically winter ratings of these switches are at least 25% higher than summer ratings due to the lower ambient temperature, and are rated that way within this study. It would be beneficial to confirm and add all switch and fuse ampacities to the system utility diagram at some point in the future.

### SYSTEM LOADING UNDER NORMAL OPERATION

Load measurements were taken at strategic points along the distribution network for feeder 3, and the Hydro 2000 portion of feeder 2 at two times; the first was mid January, 2003, the most recent was late October, 2005. Some of these measurements required minor adjustment in order to account for loading variations exhibited during the measurement period. Using the data provided, best efforts were made to obtain an accurate model of the Hydro 2000 system exhibiting typical loading levels to use as the nominal, base-case for analysis, as shown in the table below. Summer and winter peak loading values for each feeder were determined from an extrapolation of the base case to the metered peak recorded for each month from January 2003 through July 2005. The proportion of the total demand attributed to each phase in all models was the same as that observed for the spot measurements taken in 2005.

| ***Feeder*** | ***Phase*** | ***Measured Data*** | | ***Nominal*** | | ***Summer*** | | ***Winter*** | |
|---|---|---|---|---|---|---|---|---|---|
| | | ***Amps-Measured*** | ***kVA - Measured*** | ***Amps - Adjusted*** | ***kVA - Adjusted*** | ***Peak Amps Summer*** | ***Peak kVA - Summer*** | ***Peak Amps Winter*** | ***Peak kVA - Winter*** |
| Feeder 1 | R | - | - | 84.4 | 405.3 | 170.8 | 820.1 | 257.2 | 1234.7 |
| Hydro One | W | - | - | 84.4 | 405.3 | 170.8 | 820.1 | 257.2 | 1234.7 |
| | B | - | - | 84.4 | 405.3 | 170.8 | 820.1 | 257.2 | 1234.7 |
| Feeder 1 Total | - | - | - | - | 1217.2 | - | 2462.7 | - | 3707.8 |
| Feeder 2 | R | - | - | 21.8 | 104.8 | 44.2 | 212.1 | 66.5 | 319.3 |
| Hydro One | W | - | - | 21.8 | 104.8 | 44.2 | 212.1 | 66.5 | 319.3 |
| | B | - | - | 21.8 | 104.8 | 44.2 | 212.1 | 66.5 | 319.3 |
| | Total | - | - | - | 314.8 | - | 636.9 | - | 958.9 |
| Feeder 2 | R | 50 | 240.0 | 50.4 | 241.9 | 102.0 | 489.4 | 150.9 | 724.1 |
| Hydro 2000 | W | 44 | 211.2 | 44.3 | 212.6 | 89.6 | 430.1 | 132.8 | 637.2 |
| | B | 34 | 163.2 | 32.1 | 154.1 | 64.9 | 311.7 | 102.6 | 492.4 |
| | Total | - | 614.4 | - | 608.6 | - | 1231.2 | - | 1853.6 |
| Feeder 2 | R | - | - | 72.2 | 346.7 | 146.1 | 701.5 | 217.4 | 1043.4 |
| Hydro 2000 & | W | - | - | 66.1 | 317.5 | 133.8 | 642.2 | 199.3 | 956.5 |
| Hydro One | B | - | - | 53.9 | 258.9 | 109.1 | 523.8 | 169.1 | 811.7 |
| Feeder 2 Total | - | - | - | - | 923.1 | - | 1867.5 | - | 2811.6 |
| Feeder 3 | R | 90 | 432.0 | 93.3 | 448.0 | 158.8 | 762.3 | 230.5 | 1106.4 |
| | W | 86 | 412.8 | 87.7 | 421.2 | 149.3 | 716.6 | 216.7 | 1040.1 |
| | B | 96 | 460.8 | 103.86 | 498.5 | 176.7 | 848.3 | 256.5 | 1231.2 |
| Feeder 3 Total | - | - | 1305.6 | - | 1367.7 | - | 2327.1 | - | 3377.8 |
| kVA Total | | | | | 3508.0 | | 6657.3 | | 9897.2 |

The Hydro One rural section of feeder 2 was also modeled so that the impact of this additional load on the main feeder 2 circuit conductors could be considered in our analysis. The Hydro One loads in the Alfred system, both feeders 1 and 2, also had to be estimated for the purposes of providing proper assessment of the loading on the 7.5MVA substation transformer, and a determination as to whether the transformer will be adequate to support future anticipated load growth. Thus, similar nominal, summer, and winter models were constructed for feeder 1, which supports exclusively Hydro One customers, and Hydro One's portion of the feeder 2 network, which is shared with Hydro 2000, as indicated in the table. Winter peak loading conditions for feeder 1, and Hydro One's portion of feeder 2, extending north on

County Rd. #15 were approximated using the following measurements recorded in February of 2005, during peak loading conditions. Peak demand for the entire network was recorded at 7,870 kW (or 8,744 kVA), and 4,200 kW (or 4,666.7 kVA) of this demand was attributed to Hydro One customers. Peak loading on feeder 2, including both Hydro One and Hydro 2000 customers, was 2,400 kVA. While the peak loading of the total network and the peak loading of feeder 2 did not necessarily occur at the same time, the peaks were assumed to be concurrent to simplify the calculations. The peak demand recorded for Hydro 2000 for feeders 2 and 3 in February 2005 was also assumed to coincide with this peak overall substation loading. All of these figures were used together to approximate the peak winter loading levels for the Hydro One portions of the distribution network, from which peak summer and nominal loading conditions were then derived.

As can be seen, the kVA peaks for all feeders are significantly higher in winter, indicative of substantial electrical baseboard heating in older residential neighbourhoods. The total winter peak demand is shown in the table to be 9,897 kVA; it should be noted, however, that this figure is conservative in that it represents the case where the peaks on each feeder within the network, and the peaks in Hydro 2000 and Hydro One loading will be concurrent but, in reality, there will be some degree of diversity. As mentioned previously, the peak demand for the entire system was 7,870 kW (or 8,744 kVA), recorded in February of 2005, about 11% lower than the winter peak total calculated in the table above. During the winter months, the 7.5MVA transformer should be able to provide for some overloading due to reduced ambient temperatures. That being said, while the peak load may exceed the nameplate rating of the transformer, it should be within its capabilities to service it for a short period of time since the heaviest loading periods are expected in the winter.

### FEEDER VOLTAGES UNDER NORMAL OPERATION

As per CAN3-C235-83 ‘Preferred Voltage Levels for AC Systems, 0 to 50 000V’ all service entrance voltages should be no less than 91.7% of nominal (110V) and no higher than 104.2% of nominal (125V) during normal operating conditions. During extreme operating conditions the voltages may fall to 88.3% (106V) or rise to 105.8% (127V) of nominal. Feeders 2 and 3 were simulated under nominal, summer peak and winter peak loading conditions to identify any present voltage support issues within the network. The results are summarized below and the corresponding voltage profile maps can be seen on the relevant graphs under Appendix 2.

Feeder 2, when subjected to combined Hydro 2000 and Hydro One nominal loading of 923.1 kVA, experienced a minimum feeder voltage of 99% of nominal. Under summer peak loading of 1,867.5 kVA and winter peak loading of 2,811.6 kVA, worst-case voltages were 97.9% and 96.9% of nominal, respectively. All feeder 2 voltages were within the acceptable range.

For feeder 3, with nominal loading of 1,367.7 kVA, the minimum voltage was 97.8% of nominal. At summer peak loads of 2,327.1 kVA, the worst case feeder voltage was 96.3% of nominal. At peak winter loading of 3,377.8 kVA the worst case feeder voltage was 94.4%. For all cases, the worst-case voltages within the feeder 3 network were within the acceptable range.

### SYSTEM LOSSES

With feeder 2's nominal system loading estimated at 923.1 kVA, 608.6 kVA (or 547.7 kW) of this base load is attributable to the Hydro 2000 portion of the network. Distribution losses incurred on the Hydro 2000 portion of the feeder total 3.8 kW, approximately 0.69% of the Hydro 2000 load. The Hydro 2000 component of the peak summer loading on feeder 2 is 1231.2 kVA (or 1108.1 kW) with 16.2 kW or 1.46% in losses. At peak winter loading of 1853.6 kVA (or 1668.2 kW), losses total 37.4 kW, or 2.24% of the feeder 2 Hydro 2000 component of the peak winter load.

For feeder 3, the dedicated Hydro 2000 feeder, under nominal loading of 1,367.7 kVA (or 1230.9 kW), the losses were calculated to be 14.3 kW, 1.16% of the load. During summer peak loading of 2,327.1 kVA (or 2094.4 kW), losses were 43.1 kW, 2.06% of the system load, and at peak winter loading of 3,377.8 kVA (or 3040.0 kW), losses were 93.4 kW, or 3.07 %.

There were some unbalanced currents as shown on the following table. For feeder 2, in particular, the spot measurements indicate a very significant imbalance among the phases. Transferring load to balance the currents will reduce energy losses, as return currents travel through undersized neutrals and the overall inductance of the line is higher. Optimizing the balance between the phases of a distribution network typically improves the voltage support within the system as well. The system will be able to sustain heavier loading before one of the phases is burdened to the extent that its voltages begin to drop below 91.7% of nominal levels.

| ***Feeder*** | ***Phase*** | ***Amps-Measured*** | ***Avg.*** | ***Unb. (%)*** | ***Preferred Rephasing*** | ***Final*** | ***Avg. (%)*** |
|---|---|---|---|---|---|---|---|
| Feeder 2 | R | 50 | | | -7 | 43 | |
| (Hydro 2000 | W | 44 | 42.7 | 20.3 | -1 | 43 | 1.6 |
| portion only) | B | 34 | | | 8 | 42 | |
| Feeder 3 | R | 90 | | | 0 | 90 | |
| | W | 86 | 90.7 | 5.9 | 5 | 91 | 0.7 |
| | B | 96 | | | -5 | 91 | |

Possible options to rebalance the feeders include the following:

1. F2: 54-75 R to B (Telegraph & Dumoulin Street)
2. F2: 76-75 W to B (Dumoulin Street)
3. F3: 44-75, B to W (Bolt Rd., between St. Joseph & Chatelaine)

If these changes are implemented, the system main feeders should be measured before the changes are implemented to re-verify the imbalance, and then the rebalancing changes should be done.

During peak winter loading, total Hydro 2000 losses for feeders 2 and 3 are expected to be reduced from 130.8 kW to 130.0 kW, resulting in only minor savings of 0.8 kW. Analyzing the proposed rebalanced system under typical loading conditions, the losses are 17.9 kW, as compared to the 18.1 kW losses observed in the original system. Assuming costs of $0.10/kWhr, these changes could result in an estimated annual savings of $175. Although the cost to transfer these loads will likely outweigh the energy savings due to the small reduction in losses, this rebalanced system shall be used as the new default system for all further studies. If the phase re-balancing is done in conjunction with other system changes, the reduction in system losses and the resultant cost savings should be more significant. The expansion of the distribution system to provide service to the new subdivisions may help to correct the phase imbalance on feeder 3. When the new subdivisions are added, the loading should be distributed among the phases with the present imbalance in mind.

For example, there is only a single-phase circuit running along Landriault St., in the area of one of the proposed subdivisions. This happens to be the white phase of the F3 circuit, which is currently supporting the smallest load as per the spot measurements. If the entire subdivision is serviced by the white phase, and the white phase is also used to partially service the other subdivisions, this will help to more evenly distribute the load among the phases, reducing the proportion of stress on the blue phase conductors. It is recommended that the service requirements for the new developments be allocated to circuit phases in the following approximate proportions:

Red Phase: 33%
White Phase: 50%
Blue Phase: 16.7%

This means that for every single-phase transformer that is added to the circuit on the blue phase, two transformers of approximately equal size and loading should be added on the red phase, and three should be added on the white phase. Note that this recommendation is based on an anticipated increase in nominal load by 375 kW (414 kVA), as a result of the new subdivisions. If the actual nominal load is determined to be sufficiently greater than as estimated, then the three phases share in servicing the new loads in more equal proportions; if the load is significantly smaller, then more than half of the new load should be allocated to the white phase, and less to the others. The proportions given should be used as a guideline only and new measurements should be taken to confirm the imbalance between the phases at the time of additions to determine the optimal phasing arrangement.

### SYSTEM UPGRADES TO MINIMIZE LOSSES AND SUPPORT VOLTAGE

A significant factor impacting system losses is the conductor sizes, especially in the main sections of each feeder supplying the bulk of the power. Studying the balanced system, losses of 9.3 kW are incurred in the feeder 3 system along the main line between the substation and Fournier Street. This amounts to approximately 65% of the total losses for that feeder. For feeder 2, more than 80% of the losses are incurred in the same section of line. Losses are expected to be greater in these sections due to the length of the lines but can be reduced considerably by replacing the ACSR 3/0 AWG conductors with larger 336kcmil conductors. This will also improve the voltage support throughout the distribution system.

Analyzing the system under peak winter loading conditions with the 336kcmil ACSR conductors running from the substation to Fournier St. for both feeders 2 and 3, the losses were 21.2 kW for feeder 2 and 61.3 kW for feeder 3 for a total of 82.5 kW, or 1.75% of the total Hydro 2000 load. Recall that the losses calculated for the rebalanced system with the original ACSR 3/0 AWG conductors subjected to the same loading conditions were 130 kW, or 2.76% of the load. Under typical loading conditions (the rebalanced base model) the resultant losses were 2.0 kW for feeder 2 and 8.9 kW for feeder 3, totalling 10.9 kW, or 0.61% of the load. If we assume that the average kWHr use of this system is about 17,500,000 kWHr, the actual average losses of 17.9kW are reduced by 39%, and assuming costs of $0.10/kWHr, this change results in annual savings of $6,132. Please note, the cost for this upgrade would be approximately $44,000, resulting in a payback of about 12.6 years, and would not be a cost effective use of capital. Also, while this upgrade will reduce losses, the change may not increase capacity, as the line switches and metering unit may still be a limiting factor on the circuit.

Reconductoring the remainder of the main line sections for F2 and F3 will reduce the losses further, and result in more savings. Under nominal loading, the losses with the main 3/0 feeder sections for both F2 and F3 replaced in their entirety with 336kcmil conductors are estimated at 1.8 kW for feeder 2, and 8 kW for feeder 3, totalling 9.8 kW. This will result in an additional annual savings of $963. However, the cost and effort to replace all of the primary lines on Philip and Telegraph St. would be prohibitive and would not be worth these additional savings.

The possibility of moving the substation to the end of Dumoulin Street would also be an opportunity to reduce system losses. Assuming the transformer is sized similarly to the one existing, and the new main cables along the length of Dumoulin Street are 336 kcmil, the system losses are reduced to 16.3 kW for feeder 2 and 33.8 kW for feeder 3, for a total of 50.1 kW under peak winter loading conditions, approximately 39% of the losses calculated for the present system with the rebalancing changes implemented. Under nominal loading conditions, the losses are reduced to 1.6 kW for feeder 2 and 5.1 kW for feeder 3, for a total of 6.7 kW. This results in annual savings of $9,811 over the rebalanced base case.

#### FEEDER LOADING UNDER NORMAL CONDITIONS

To evaluate all the feeders under current nominal and current peak loading conditions, we evaluated each feeder by their limiting factor, which for both was the main 3/0 ACSR run from the substation. For feeder 2, both the Hydro 2000 and the estimated Hydro One rural portion of the loading were considered in the evaluation. As can be seen, all the feeders are sized acceptably for normal conditions.

| | | ***Nominal*** | | | ***Summer*** | | | ***Winter*** | | |
|---|---|---|---|---|---|---|---|---|---|---|
| ***Feeder*** | ***Phase*** | ***Feeder Limits*** | ***Amps*** | ***Pass/Fail*** | ***Feeder Limits*** | ***Amps*** | ***Pass/Fail*** | ***Feeder Limits*** | ***Amps*** | ***Pass/Fail*** |
| Feeder 2 | R | 419 | 72.24 | 17.24% | 370 | 146.14 | 39.50% | 419 | 217.38 | 51.88% |
| | W | 419 | 66.14 | 15.79% | 370 | 133.80 | 36.16% | 419 | 199.27 | 47.56% |
| | B | 419 | 32.10 | 7.66% | 370 | 109.12 | 29.49% | 419 | 169.11 | 40.36% |
| Feeder 3 | R | 419 | 93.33 | 22.27% | 370 | 158.80 | 42.92% | 419 | 230.50 | 55.01% |
| | W | 419 | 87.74 | 20.94% | 370 | 149.29 | 40.35% | 419 | 216.70 | 51.72% |
| | B | 419 | 103.86 | 24.79% | 370 | 176.72 | 47.76% | 419 | 256.51 | 61.22% |

The ratings of the solid blade switches located just past the tie switch on County Rd. #17 for feeders 2 and 3 could not be determined with the documentation provided. The solid blade switches for the F2 feeder circuit are not expected to experience overloading, provided they are rated for 200 amps (summer duty), as they are only subjected to the Hydro 2000 component of the load, which is a maximum of 150.9 amps (on the red phase for peak winter conditions). It should be noted however, that if the switches for the F3 circuit are rated for 200A or less, they will be overdutied during winter peak loading conditions by almost 30% However, using their winter duty factor of 1.25 of nominal due to the lower ambient temperature, the overload is significantly smaller at 1.03%. Implementation of the proposed rebalancing changes should further reduce the stress on the switch of the heaviest loaded blue phase so none of the switches will be overdutied.

Fused switches, AS-2 and AS-4, both on Telegraph St. on the F3 feeder circuit may be slightly overdutied at times during peak winter loading if they are rated for 200A or less. With the addition of the new subdivision off Landriault St., and natural load growth, the stress on the switches will become more severe. It is recommended that the size of the switches and fusing be confirmed and the switches upgraded to 300A units with appropriate fusing.

### Feeder Configurations Under Existing Loading and Emergency Conditions

The main scenario evaluated in this section is the loss of either feeder F2 or F3, assuming the tie switch will be usable. If either F2 or F3 is lost at some point between the tie switch and the substation, closing the tie switch will allow the entire load to be serviced from the remaining feeder. During such emergency operating conditions, voltage levels are permitted to drop as low as 88.3% of nominal. The distribution system, given the loss of either feeder, is evaluated under both peak summer and winter conditions to ensure that voltage levels are acceptable and equipment is not severely stressed.

Under peak summer loading conditions, there are no voltage support issues and none of the main conductors from the substation to the tie switch, supporting the extra burden, are overloaded. The minimum voltage is 95.2% of nominal, which is well within the acceptable range, and the blue phase conductor of the main 3/0 ACSR feeder section, which is the most heavily loaded, is carrying 83.1% of its rated (summer) current.

Subjected to peak winter loading conditions, voltage support is still not a concern, as the worst-case voltage at 92.3% of nominal. Feeder voltages will reach this minimum in the area of Johnston and Butterfield streets. The main conductors running along Peat Moss Rd. from the substation are more stressed, the blue phase conductor loaded at 110.5% of its winter current-carrying capacity. The conductors should be able to support this additional load for a short period of time.

However, one limitation is that both the F2 and F3 circuits have single-phase reclosers at the substation with 280A trip coils. The recloser on each circuit will prevent one feeder from supporting the entire load during peak winter conditions. During this single feeder emergency condition, the highest current expected to flow through the recloser during peak summer loading conditions is 301 amps, and the maximum current during winter peak loading is 463 amps. The circuit reclosers will be the limiting factor in providing emergency service in the event that one of the feeders is lost.

### Load Growth

There are a number of methods by which a utility's load will grow over time; the typical ones are listed below, with the trending graphs following:

- New in-fill customers are added within the Utility boundary.
- Existing customers add load (pool pumps, new air conditioners, etc.).
- Expansion of the Utility boundaries.

As there are no known plans for expansion of the Utility boundary, the main changes in loading to be expected in the coming years will be as a result of the first two factors listed above. To predict the growth for the system, we first evaluate future known growth.

There are a few new subdivisions currently in the planning and/or development stages in areas currently serviced by feeder 3. The subdivision currently being added is in the Richard & Pitre area, with a possible future infill subdivision in the Landriault area, and a future potential addition north of the Alexandre area. To estimate the additional loading that will result, we have estimated that each subdivision will contain the equivalent to 25 houses. Assuming a nominal load of 5 kW per house at 0.9 power factor, this will result in 125 kW, or 138 kVA per subdivision, for a total of 375 kW, or 417 kVA. For forecasting purposes, we have assumed the first subdivision will be added this year, the second in two year, the third in four years. This loading is added to the nominal, summer, and winter peak loading. The forecast can be adjusted as required to account for differences between the projected development and that which will actually take place using the approximation of 5 kW per house used herein.

The second factor, or annual load growth, is typically assumed at around 3%. This is due to the natural addition of new electrical loads such as air conditioning systems, pools, electronic devices, and other energy consuming products. This is often balanced by a decline in loading for the majority of the winter months, probably due to increased energy efficiency and transitioning from baseboard heating to forced air. The natural load growth may also be substantially affected by the proposal to bring in smart metering. This should offset the peak loading to non peak-load times and thus reduce the overall peak demand, and is estimated by the government to bring about a 5% reduction when implemented. Therefore, our load growth estimates should be conservative.

In the forecast for feeder 2, both the Hydro 2000 and Hydro One components of the loading have been taken into consideration and assumed to grow at the same rate of 3% annually. The load growth on the Hydro One feeder (feeder 1) was also approximated at 3% per year as shown in the third table below.

The forecasts for all three feeders were combined so that the anticipated future loading levels of the 7.5 MVA Hydro One substation transformer could be assessed, as shown in the final table below. A 10% diversity factor was applied to account for non-concurrent peaks in the loading of the feeders. Levels indicative of heavy loading (in excess of 90% of the applicable transformer rating) are highlighted in orange, and cases where the loading is expected to exceed the capabilities of the transformer are shown in red.

Nominal and summer peak loading levels were compared against the nameplate rating (7.5MVA) of the Hydro One substation transformer. Although there is no fan rating on the nameplate of the existing transformer, only the 7.5MVA rating is shown, we evaluated winter peak loading assuming that the transformer can provide up to 10MVA of loading, 33% higher than its nominal rating. It is expected that the transformer will be able to provide for some overloading during lower ambient temperatures provided by the winter months, but there is no guarantee that 10MVA can be supported. The documentation provided upon purchase of the transformer should provide some indication as to its overload capabilities; Hydro One should have the information necessary to evaluate the transformer's ability to provide for the anticipated loading and determine when/if it will require replacement.

FEEDER 2 – DEMAND FORECAST (in kW)

| kW Demand | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nominal | 782 | 806 | 831 | *856* | *881* | *908* | *935* | *963* | *992* | *1,022* | *1,052* | *1,084* | *1,117* |
| Summer Peak | 1,108 | 1,095 | 1,681 | *1,731* | *1,783* | *1,837* | *1,892* | *1,948* | *2,007* | *2,067* | *2,129* | *2,193* | *2,259* |
| Winter Peak | 1,653 | 1,668 | 2,530 | *2,606* | *2,685* | *2,765* | *2,848* | *2,933* | *3,021* | *3,112* | *3,205* | *3,302* | *3,401* |

FEEDER 3 – DEMAND FORECAST (in kW)

| kW Demand | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nominal | 1,158 | 1,194 | 1,231 | *1,393* | *1,435* | *1,603* | *1,651* | *1,825* | *1,880* | *1,937* | *1,995* | *2,054* | *2,116* |
| Summer Peak | 2,094 | 2,053 | 2,094 | *2,282* | *2,350* | *2,546* | *2,622* | *2,826* | *2,911* | *2,998* | *3,088* | *3,180* | *3,276* |
| Winter Peak | 2,846 | 3,040 | 3,040 | *3,256* | *3,354* | *3,580* | *3,687* | *3,922* | *4,040* | *4,161* | *4,286* | *4,415* | *4,547* |

FEEDER 1 (HYDRO ONE) – DEMAND FORECAST (in kW)

| kW Demand | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nominal | 1,031 | 1,063 | 1,095 | *1,128* | *1,162* | *1,197* | *1,233* | *1,270* | *1,308* | *1,347* | *1,388* | *1,429* | *1,472* |
| Summer Peak | 1,108 | 1,095 | 2,216 | *2,283* | *2,351* | *2,422* | *2,495* | *2,569* | *2,647* | *2,726* | *2,808* | *2,892* | *2,979* |
| Winter Peak | 1,653 | 1,668 | 3,337 | *3,437* | *3,540* | *3,646* | *3,756* | *3,869* | *3,985* | *4,104* | *4,227* | *4,354* | *4,485* |

TOTAL SUBSTATION DEMAND FORECAST – INCLUDING 10% DIVERSITY FACTOR (in kVA)

| kVA Demand | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nominal | *2,695* | *2,778* | *2,864* | *3,075* | *3,167* | *3,387* | *3,489* | *3,719* | *3,830* | *3,945* | *4,064* | *4,185* | *4,311* |
| Summer Peak | *4,310* | *4,243* | *5,418* | *5,706* | *5,877* | *6,178* | *6,364* | *6,680* | *6,880* | *7,087* | *7,299* | *7,518* | *7,744* |
| Winter Peak | *6,152* | *6,376* | *8,045* | *8,411* | *8,664* | *9,049* | *9,320* | *9,725* | *10,016* | *10,317* | *10,626* | *10,945* | *11,274* |

The peak summer load total for all feeders in 2015 is estimated at 7,744 kVA, exceeding the capabilities of the existing transformer by 3.3%. Total peak winter loading in 2015 is expected to be 11,274 kVA, exceeding the estimated fan rating of the transformer by 12.7%. This indicates that, given the accuracy of the forecast, the 7.5MVA transformer will require upgrading before the year 2015. In fact, an upgrade is expected to be required around the year 2010. The existing transformer is expected to be adequate to support the future load growth until that time under normal conditions. The loading should be reviewed in the coming years to ensure that the capacity is acceptable, especially if further developments and/or significant changes to the distribution network are undertaken that have not been considered in this forecast.

The summer peak loading in 2015 was simulated and the worst-case system voltage for feeder 2 was 97.75%, well within the acceptable range; distribution losses are responsible for approximately 28.8 kW or 1.93% of system loading. Analyzing the feeder 2 network under the peak winter loading conditions expected in 2015, the worst-case voltage drop is 95.7% of nominal, which is acceptable, and the distribution losses total 72.8 kW, approximately 3.25% of the load. Note that only the Hydro 2000 portion of the load and the distribution losses are considered in the figures provided. Hydro One's loading and losses are only considered to evaluate the loading on the main circuit conductors running along Peat Moss Rd. and to evaluate the loading on the substation transformer. Voltage support and overloading are not expected to be issues of concern in the feeder 2 network under normal (peak summer and winter) loading conditions expected through the year 2015.

The worst-case voltage within the feeder 3 circuit under the peak summer loading conditions projected for 2015 was within the acceptable range at 93.08% and was found on the white phase conductor in the area to feed the proposed new subdivision off Landriault St. Feeder 3 losses under peak summer loading were determined to be 110 kW, about 3.36% of the total feeder 3 load. Under peak winter loading conditions, system voltages on the white phase conductor are expected to fall outside the acceptable range in a large area, as indicated by the voltage support results under Appendix 2. The worst-case voltage in the network, found in the area of the new subdivision off Landriault St., is 90% of nominal. All unacceptable voltages within the network are restored to acceptable levels by applying a 2.5% tap boost to the 7.5 MVA substation transformer.

In order to determine whether or not the main circuit conductors for both feeders in the distribution system will be able to handle peak summer and winter loading, the additional load expected must be allocated to each phase. These conductor ampacities are evaluated against expected loads from 2005 through 2015 based on the assumption that the feeders will be perfectly balanced. This represents the best-case scenario. Cases in which the conductor is carrying more than 90% rated current are flagged in orange.

| ***Feeder*** | ***Season*** | ***Rated Amps*** | ***Year & Amps Per Phase (Balanced System)*** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ***2006*** | ***2007*** | ***2008*** | ***2009*** | ***2010*** | ***2011*** | ***2012*** | ***2013*** | ***2014*** | ***2015*** |
| ***F2*** | Win | 419 | 200.9 | 207.0 | 213.2 | 219.6 | 226.1 | 232.9 | 239.9 | 247.1 | 254.5 | 262.2 |
| | Sum | 370 | 133.5 | 137.5 | 141.6 | 145.9 | 150.3 | 154.8 | 159.4 | 164.2 | 169.1 | 174.2 |
| | Winter (kW) | | 2605.9 | 2684.1 | 2764.6 | 2847.5 | 2933.0 | 3021.0 | 3111.6 | 3204.9 | 3301.1 | 3400.1 |
| | Summer (kW) | | 1731.4 | 1783.4 | 1836.9 | 1892.0 | 1948.7 | 2007.2 | 2067.4 | 2129.4 | 2193.3 | 2259.1 |
| ***F3*** | Win | 419 | 251.1 | 258.6 | 276.0 | 284.3 | 302.4 | 311.5 | 320.9 | 330.5 | 340.4 | 350.6 |
| | Sum | 370 | 175.9 | 181.2 | 196.3 | 202.2 | 217.9 | 224.4 | 231.1 | 238.1 | 245.2 | 252.6 |
| | Winter (kW) | | 3256.2 | 3353.9 | 3579.5 | 3686.9 | 3922.5 | 4040.2 | 4161.4 | 4286.2 | 4414.8 | 4547.2 |
| | Summer (kW) | | 2281.8 | 2350.3 | 2545.8 | 2622.2 | 2825.8 | 2910.6 | 2997.9 | 3087.9 | 3180.5 | 3275.9 |

As can be seen, the main 3/0 ACSR conductors are not expected to experience overloading, or even loading in excess of 90%, during either winter and summer peak conditions through 2015. The heaviest loading is expected on the main feeder 3 circuit conductors running along Peat Moss Rd. and Telegraph St. which are expected to be loaded at 83.7% of rated (winter) ampacity. As indicated in the table, the main 3/0 ACSR conductors are expected to carry 350.6 amps on each phase. While this level of loading is not of concern, it assumes a perfectly balanced distribution of loading between the phases. Any significant imbalance between the phases may cause the most heavily loaded phase conductor to experience overloading at times. As loads are added to the network as a result of the new developments, the loading on each of the phases of the feeder should be measured frequently to ensure they are reasonably balanced, and loads should be transferred as necessary.

Earlier in this report, it was suggested that loading be transferred from the blue to the white phase on Bolt Rd. between St. Joseph & Chatelaine to correct the present imbalance between the phases. Since only the white phase is present in the area of the proposed subdivision off Landriault, it is assumed that the entire new subdivision will be supplied from this phase. It is expected that this will serve to correct the imbalance between the phases without the need to relocate the transformer on Bolt Rd. to the white phase. In fact, transferring this load back to the blue phase, in our analysis, lead to slightly better voltage support results and more balanced loading between phase conductors within the network. Therefore, transferring loads is not necessary and not recommended at this time, provided the addition of loading will occur in the near future and is allocated to the phases appropriately to correct the problem. The remaining analyses within the study, and the corresponding voltage support and loading results in the appendices, reflect the phasing presently in place for feeder 3. The rebalancing changes recommended for feeder 2 remain, however.

### SYSTEM LOADING UNDER EMERGENCY CONDITIONS

The scenario evaluated in this section is the same as the emergency loading situation evaluated earlier in the study, except for, this time, one feeder is subjected to projected peak summer and winter loading in 2015. In the event of a loss of either F2 or F3 between the substation and the tie switch, the tie switch shall be closed and the entire Alfred load serviced by one feeder. Under peak summer loading conditions in 2015, the worst-case system voltage is 91.5% of nominal, which is within the acceptable range for emergency loading conditions. Subjected to peak winter loading, the worst-case voltage is 87.2%, and the voltages are expected to be outside the acceptable range for emergency conditions in feeder sections south of the intersection of St. Phillipe & Laniel. Voltage also falls just outside acceptable range at the intersection of Bolt Rd. & Chatelaine, the feed to the pharmacy. However, an application of a 2.5% tap boost to the substation transformer is expected to restore the worst-case voltage within the network to 90.1% of nominal, which is within the suitable range for emergency situations. Thus, voltage support under emergency situations is not expected to be an issue in the future.

As indicated by the loading results figures included in Appendix 3, the main 3/0 ACSR conductors are expected to be severely overloaded if a feeder is lost in 2015 under peak summer or winter loading conditions. The figures show that loading is in excess of 125% of the conductors' rated ampacity in some cases. These figures represent the worst-case scenario, however, being that the seasonal peaks on both feeders are concurrent, which is extremely unlikely. In the table below, the conductors are evaluated under peak winter and summer loading with a 10% diversity factor applied to account for different peak loading times for each feeder. Cases in which the conductors are expected to be heavily loaded, at more than 90% of their applicable rating, are coloured in orange. Scenarios in which the conductors are expected to be overloaded are shown in red.

| ***Feeder*** | ***Season*** | ***Rated Amps*** | ***Year & Amps Per Phase*** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ***2006*** | ***2007*** | ***2008*** | ***2009*** | ***2010*** | ***2011*** | ***2012*** | ***2013*** | ***2014*** | ***2015*** |
| ***F2 or F3*** | Win | 419 | 406.79 | 418.99 | 440.24 | 453.44 | 475.72 | 489.99 | 504.69 | 519.83 | 535.43 | 551.49 |
| | Sum | 370 | 278.49 | 286.85 | 304.13 | 313.25 | 331.32 | 341.26 | 351.50 | 362.04 | 372.91 | 384.09 |
| | Winter (kW) | | 5,862 | 6,038 | 6,344 | 6,534 | 6,855 | 7,061 | 7,273 | 7,491 | 7,716 | 7,947 |
| | Summer (kW) | | 4,013 | 4,134 | 4,383 | 4,514 | 4,775 | 4,918 | 5,065 | 5,217 | 5,374 | 5,535 |

As can be seen from the table, the ability for either feeder to support the entire load given an emergency situation will eventually become constrained by the main 3/0 ACSR conductors (and by the reclosers ampacities). In fact, the conductors are expected to be already heavily loaded under peak winter loading conditions. Replacing these conductors with larger conductors, and upgrading the reclosers would alleviate this problem, making each feeder reasonably equipped to support the entire system load temporarily in the event that one of the feeders is lost.

**SUBSTATION REDUNDANCY**

The issue of redundancy is problematic for the Alfred distribution system, although it is not the responsibility of Hydro 2000. Currently, the entire village is serviced by a single transformer, the failure of the transformer will result in a complete outage until Hydro One can repair or replace their transformer. Typically, Hydro One will either repair the fault on site, or install a mobile unit as soon as possible. Hydro One will probably not install a redundant transformer till required by load growth.

The possibility exists for Hydro 2000 to build their own substation, which may result in substantial savings as per the Hydro One DS charges, which are $1.60/kW. This sum totalled $53,385 in 2004. Including the reduction of losses of about $9,028 gives a total of $ 62,413 saved annually. Typically, a 7.5MVA substation could be build for about $500,000, resulting in a payback of about 9.4 years. Please note, there may be additional complication through Hydro One additional charges, stranded costs, and other difficulties negotiating this arrangement. Metering would also be an additional cost as they may require Hydro 2000 to implement primary metering at the 44,000V level, which can add a further $75,000 for the metering can and installation.

The feeders for Alfred are currently already redundant through the tie switch in the event of a failure of one of the feeders, as discussed in the previous section.

## PLANTAGENET ELECTRICAL DISTRIBUTION SYSTEM

### SYSTEM EQUIPMENT RATINGS

The main equipment within the Hydro One Plantagenet substation is listed below, along with the ratings that are used to evaluate these components for various loading scenarios. Ratings and information that could not be verified were estimated for the purposes of the study and are marked in table with an asterisk (*).

| ***System Component*** | ***Rating*** | ***Ampacity @ 8.32kV*** |
|---|---|---|
| 44kV Primary Switch | Continuous Amps | 3173A (600A) |
| 44kV Primary Fuses<br>S&C Electric SMD-1A, 125E<br>Standard Speed, TCC 153-1 | Continuous Amps<br>Daily 8 hour peak<br>Emergency 8 hour peak | 761.5A (144A)<br>772.1A (146A)<br>835.6A (158A) |
| 44,000/8,320V Transformer<br>Delta/Wye (Grnd.), 5 MVA (ONAN)<br>*Z = 5.5% | Continuous Amps | 347A (65.6A) |
| 8.32kV Secondary Switchgear | Continuous Amps | *600A |
| 8.32kV Hydraulic Oil Circuit Reclosers<br>Cooper Type 'L' | Continuous Amps | 200A |

The impedance is not marked on the nameplate of the 5 MVA substation transformer, nor could the manufacturer provide it. Based on the size and type of the transformer, a typical impedance value was estimated at 5.5%; this value was used for the purposes of this study.

The size of the switches in the system, and their fuse sizes, where applicable, could not be confirmed. The ratings of most feeder level switches within this system were estimated as 100 or 200 Amps, based on the cable size they were connected to. Most aggregated backbone switches are solid-blade type and their ratings were estimated at 300 Amps, based on the cable size they were connected to. These conservative values will allow us to ensure that all normal and emergency situations which may be above that level are flagged properly. Typically winter ratings of these switches are at least 25% higher than summer ratings due to the lower ambient temperature, and are rated that way within this study. It would be beneficial to confirm and add all switch and fuse ampacities to the system utility diagram at some point in the future.

### SYSTEM LOADING UNDER NORMAL OPERATION

The loading of the Hydro 2000 Plantagenet feeder was measured in mid January, 2003 and again in late October, 2005, on the same days as the Alfred feeder measurements were taken. Current measurements on each phase were used to determine the total power demand in the system to be 984 kVA. Using current measurements made at strategic points, this total load was allocated to the various distribution transformers as determined from the drawing of the Plantagenet distribution system and the base model for our study was constructed.

The proportion of the total power attributed to each phase in the base case, and the Hydro 2000 demand figures, in kilowatts, recorded from January 2003 to July 2005 were used to construct a model to simulate the circuit under peak summer and peak winter loading conditions. The peak summer and winter demands are estimated as 2007.5 kVA and 2992.0 kVA, respectively, based on a power factor of 90%. The loading levels for the base, peak summer, and peak winter cases are summarized in the table below.

| ***Feeder*** | ***Phase*** | ***Amps-Measured*** | ***kVA - Measured*** | ***Peak Amps Summer*** | ***Peak kVA - Summer*** | ***Peak Amps Winter*** | ***Peak kVA - Winter*** |
|---|---|---|---|---|---|---|---|
| Plnt Fdr | R | 90 | 432.0 | 183.6 | 881.3 | 273.7 | 1313.6 |
| | W | 55 | 264.0 | 112.2 | 538.6 | 167.2 | 802.7 |
| | B | 60 | 288.0 | 122.4 | 587.6 | 182.4 | 875.7 |
| | | kVA Total: | 984.0 | | 2007.5 | | 2992.0 |

As can be seen, the kVA peaks are significantly higher in winter, as expected, and as was the case with the Alfred system. All loading levels are within the capability of the existing station 44/8.32kV 5MVA transformer, but the transformer supports a Hydro One feeder as well.

As there is no data available for the Hydro One Plantagenet feeder, for the purposes of this study, it is estimated that the loading exhibited on that feeder will be similar to that observed for the Hydro 2000 feeder. If the nominal loading on the Hydro One feeder is 1,000 kVA, the peak summer loading is 2,040 kVA, and the winter peak loading is 3,040 kVA, the transformer loading is estimated at 1,984 kVA under nominal conditions, 4,047.5 kVA under summer peak loading conditions, and 6,032 kVA under winter peak loading conditions (assuming the peaks of each feeder occur at the same time). If these estimates are accurate, the 5MVA substation transformer will be loaded at 21% beyond its nameplate rating during peak winter loading conditions. However, it is not expected that the Hydro One and Hydro 2000 will reach peak loading levels at the same time, and the transformer should be able to provide for some overloading when the ambient temperature is lower in the winter months. Thus the nominal and summer peak loading conditions expected are within the capabilities of the transformer. Therefore, the transformer currently servicing Plantagenet should be adequately sized to handle the present normal loading conditions.

#### FEEDER VOLTAGES UNDER NORMAL OPERATION

As per CAN3-C235-83 'Preferred Voltage Levels for AC Systems, 0 to 50 000V' all service entrance voltages should be no less than 91.7% of nominal (110V) and no higher than 104.2% of nominal (125V) during normal operating conditions. During extreme operating conditions the voltages may fall to 88.3% (106V) or rise to 105.8% (127V) of nominal.

Running at the base load of 984 kVA, the worst-case feeder voltage is within 97.3% of nominal, which is acceptable and, at summer peak loads of 2007.5 kVA, the worst-case feeder voltage is 94.4% of nominal, which is also acceptable. Subjected to winter peak loading of 2992 kVA, however, the system voltages are outside the acceptable range in all feeder sections north of the intersection of Main St. and County Rd. No. 9 with the worst-case feeder voltage at 91.4% of nominal. The voltage profile maps can be seen on the relevant graphs under Appendix 2. If the transformer tap is set to provide a voltage 2.5% above nominal 8.32 kV, the worst-case voltage at peak winter loading will be 93.6%, within the acceptable voltage range.

### System Losses

With the existing nominal system loading of 984 kVA (losses inclusive), distribution losses total 9.5 kW and, approximately 1.07% of system loading. At peak summer loading of 2007.5 kVA, losses total 42.4 kW, approximately 2.32% of system loading. At peak winter loading of 2992 kVA (losses inclusive), losses total 98.2 kW, or 3.65% of system loading.

The spot measurements show that the red phase is much more heavily loaded than the white and blue phases. Balancing the phases results in less current flow in the system neutral conductors, reducing system losses. Voltage support in the feeder network should also be improved through correction of the imbalance. The imbalance between the phases and the preferred re-phasing is shown in the table below.

| ***Feeder*** | ***Phase*** | ***Amps-Measured*** | ***Avg.*** | ***Unb. (%)*** | ***Preferred Rephasing*** | ***Final*** | ***Avg. (%)*** |
|---|---|---|---|---|---|---|---|
| Plnt Feeder | R | 90 | 68.3 | 31.7 | -22 | 68 | -1.0 |
| | W | 55 | | | 13 | 68 | |
| | B | 60 | | | 9 | 69 | |

Possible options to rebalance include the following:

1. Main St. (between Concession & Ottawa): 20-100 R to B
2. Water St. (between L'Eglise & Concession): 13-75 R to W
3. Main St. & Concession St.: 18-50 R to W

When the rebalancing will take place, the system main feeders should be measured to re-verify the imbalance and then the rebalancing changes should be done.

With the proposed rebalanced system, under nominal loading conditions, the losses are reduced to 9 kW and 1.02% of the nominal load. This is an improvement over the unbalanced case by 0.5 kW. Assuming nominal loading on average over the year, and energy costs of $0.10/kWhr, balancing the system as suggested should result in approximately $438 annual savings, which is not significant. However, under heavier loading conditions, the reduction in losses and hence the savings will be more significant. This rebalanced system shall be used as the new default system for all further studies.

### Feeder Loading Under Normal Conditions

The loading of the main 3/0 ASCR run in the Plantagenet feeder circuit is summarized in the table below under nominal, peak summer, and peak winter loading conditions.

| ***Feeder*** | ***Phase*** | ***Nominal*** | | | ***Summer*** | | | ***Winter*** | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | ***Feeder Limits*** | ***Amps*** | ***Pass/Fail*** | ***Feeder Limits*** | ***Amps*** | ***Pass/Fail*** | ***Feeder Limits*** | ***Amps*** | ***Pass/Fail*** |
| Plnt. Fdr | R | 419 | 90.0 | 21.5% | 370.0 | 183.6 | 49.6% | 419 | 273.7 | 65.3% |
| | W | 419 | 55.0 | 13.1% | 370.0 | 112.2 | 30.3% | 419 | 167.2 | 39.9% |
| | B | 419 | 60.0 | 14.3% | 370.0 | 122.4 | 33.1% | 419 | 182.4 | 43.5% |

The conductors do not experience heavy loading under any of the simulated loading conditions. However, the circuit recloser is equipped with a 200A trip coil and so there is risk of it opening during heavy winter loading because of the unbalanced Red phase, although Hydro One practice permits a maximum anticipated load of up to 250 Amps through this recloser. However, if load is redistributed to better balance the phases, as suggested previously, then the likelihood of the recloser operating will be reduced. Replacement of the trip coil with one rated for 280 amps could also be done to further reduce the likelihood of recloser operation during heavy loading and to provide for future load growth.

#### FEEDER CONFIGURATIONS UNDER EXISTING LOADING AND EMERGENCY CONDITIONS

There is no agreement currently in place between Hydro One and Hydro 2000 to provide emergency service for another in the event that there is a failure with one of the feeders. Such an agreement would be advisable, provided that each network has sufficient capacity to support the entire Plantagenet load, as it would provide for some redundancy in the system. In order to determine whether or not either feeder is equipped to service the entire load, we constructed a model of the Hydro One feeder and connected it to our existing model of the Hydro 2000 feeder. To simulate the situation in which either the feeder out of service and the entire load must be supported by the remaining feeder, the following assumptions were made:

1. We estimated nominal loading at 1000 kVA (similar to the main Plantagenet feeder), completely balanced, and distributed evenly across the major lines throughout the feeder circuit.
2. A switch connecting the Hydro One and Hydro 2000 feeder circuits has been placed along Old Highway 17, near its intersection with County Rd. 9 so the switch may be closed, and the two networks connected under emergency conditions.
3. The routing of the Hydro One feeder is not shown completely on the electrical distribution drawing of Plantagenet, so the routing of the feeder was approximated as necessary.
4. The conductors for the main run of the Hydro One feeder circuit were assumed to be 3/0 ACSR.

Simulations were performed during which the entire Plantagenet load was serviced by the Hydro One circuit under summer and winter peak loading conditions. Under emergency loading conditions, system voltages as low as 88.3% of nominal are tolerable.

Subjected to peak summer loading, the lowest system voltage was 92.25% of nominal, which is well within the acceptable range. The most heavily loaded circuit conductors in the network are loaded to less than 80% of their rated ampacity at 30 degrees Celsius, provided our assumption that the main runs are 3/0 ACSR is correct. Therefore, given the validity of the assumptions made in constructing our model, the Hydro One feeder should be capable of supporting the Hydro 2000 circuit load under peak summer conditions (and vice versa) with no loading concerns or voltage support issues, provided that any switches or reclosers in the main portion of either feeder circuit are rated for 300 amps (at 30 degrees Celsius).

Simulating under peak winter loading conditions, however, there were some issues with regards to both voltage support and loading. For a very large portion of the circuit, the system voltage is between 88.3% and 90% of nominal, just above the minimum acceptable voltage level. Between the public school and the substation, the voltage is expected to be slightly outside the acceptable range for extreme operating conditions, dropping as low as 87.75% of nominal. Note that these regions of low voltage correspond to the case where the Hydro One feeder is supporting the entire load. If the Hydro 2000 feeder were to support the entire load, the areas of lowest voltage would be observed on the Hydro One portion of the circuit. The areas of low-voltage will also differ depending on where the two circuits are connected. As the voltage support issues are not severe, a 2.5% tap increase on the transformer should restore the problematic voltages to acceptable values. The main conductors of the Hydro One feeder circuit leaving the substation (if they are 3/0 ACSR) are expected to be slightly overloaded at 107% of their rated ampacity. The 5MVA substation transformer will also be overloaded at 129% of its nominal capacity, but since lower ambient temperatures are expected during this situation, the transformer should be able to provide this level of overloading without harm for the duration of most emergencies. Currents as high as 450 amps may flow in the conductors of the main part of the circuit under emergency peak winter loading conditions. The reclosers at the substation on the Hydro 2000 feeder circuit, and probably those on the Hydro One circuit as well, will prevent this much current flow. Although the ratings of the switches in the main sections of the feeder circuits are not known, it is unlikely that they are of adequate rating to permit this level of current flow either, even in lower ambient temperatures.

It is likely that the Hydro One and Hydro 2000 feeders could provide emergency service for one another in the event of a loss of either feeder under peak summer loading conditions. However, the reclosers and switches in either circuit would likely prevent each from doing so under peak winter loading conditions.

### LOAD GROWTH

There are no known plans for development in the Plantagenet area that will significantly affect the electricity demand in the coming years. That being said, there will be some changes in the loading levels in the future, mainly due to loading increases by existing customers and some infill. In order to predict how the loading levels will change in the next 10 years, we extrapolated using 3% load growth. As described for the Alfred section, this will probably be a conservative extrapolation unless significant changes occur within the distribution. The loading forecast is presented in the table below, with figures in kilowatts, and forecast figures shown in italics.

PLANTAGENET – LOAD FORECAST

| kW Demand | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nominal | 833 | 859 | 886 | *912* | *940* | *968* | *997* | *1,027* | *1,057* | *1,089* | *1,122* | *1,156* | *1,190* |
| Summer Peak | 1,807 | 1,748 | 1,807 | *1,861* | *1,917* | *1,975* | *2,034* | *2,095* | *2,158* | *2,222* | *2,289* | *2,358* | *2,428* |
| Winter Peak | 2,583 | 2,693 | 2,693 | *2,774* | *2,857* | *2,943* | *3,031* | *3,122* | *3,216* | *3,312* | *3,411* | *3,514* | *3,619* |

Under projected future peak summer loading conditions for 2015, the lowest system voltage was 94.25% of nominal, which is within the acceptable range. The most heavily loaded conductors in the circuit are the main 3/0 ACSR ones from the substation, the most heavily loaded at just over 50% of rated ampacity (at an ambient temperature of 30 degrees Celsius). Note that both the worst-case feeder voltage and the maximum current in each conductor are estimated based on the assumption that the balancing changes are done. Without rebalancing, voltage support and conductor overloading will likely be problems on the heavily loaded red phase of the circuit. The 5MVA transformer is loaded within its capabilities, at approximately 75%. The circuit reclosers should permit the projected peak summer loading as the maximum current expected is 190 amps.

The results for the anticipated 2015 peak winter loading conditions were very similar to the summer case. Minimum system voltage was 91.1%, just outside the acceptable range, correctable through 2.5% tap boost on the 5MVA transformer. The blue phase conductor in the main 3/0 ACSR portion of the feeder is the most heavily loaded in the system, at 70% of its rated (winter) ampacity, and the transformer is loaded at approximately 80%. The limiting factor for providing for future load growth will be the single-phase circuit reclosers. The highest current expected to flow through a recloser is about 290 amps, which exceeds the allowable current of 250 Amps for these 200 A trip coils. It is recommended that the trip coils of the reclosers be upgraded to the maximum 280 A to allow for as much of the anticipated load growth as possible.

The table below shows the estimated currents expected in the coming years during peak summer and winter loading, assuming perfect balance between the phases. These values are compared against the 250A trip rating of the single-phase circuit reclosers, which have been determined to be the limiting factor in supporting future load growth. Currents within 90% of the recloser trip rating are shown in orange in the table, and cases where the current exceeds the trip rating are shown in red. As indicated, the circuit reclosers will become heavily stressed within the next few years under anticipated winter peak loading conditions. The load growth is expected to exceed the capability of the circuit reclosers within the next six years. Note that this prediction assumes that the phases are balanced as suggested earlier in the report. If the rebalancing changes are not done, the demand figures indicate that the recloser on the heavily loaded red phase is could very well operate during period of heavy loading much earlier.

| | | ***Year & Amps Per Recloser (Balanced System)*** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Feeder*** | ***Season*** | ***2006*** | ***2007*** | ***2008*** | ***2009*** | ***2010*** | ***2011*** | ***2012*** | ***2013*** | ***2014*** | ***2015*** |
| ***Hydro 2000 - Plantagenet*** | Winter (A) | 213.9 | 220.3 | 226.9 | 233.7 | 240.7 | 248.0 | 255.4 | 263.0 | 270.9 | 279.0 |
| | Summer (A) | 143.5 | 147.8 | 152.3 | 156.8 | 161.5 | 166.4 | 171.3 | 176.5 | 181.8 | 187.2 |
| | Winter (kW) | 2774.0 | 2857.0 | 2943.0 | 3031.0 | 3122.0 | 3216.0 | 3312.0 | 3411.0 | 3514.0 | 3619.0 |
| | Summer (kW) | 1861.0 | 1917.0 | 1975.0 | 2034.0 | 2095.0 | 2158.0 | 2222.0 | 2289.0 | 2358.0 | 2428.0 |

### System Loading Under Emergency Conditions

Failure of the Hydro 2000 Plantagenet feeder was simulated under peak summer and winter loading conditions projected for the year 2015. In the simulations, we assumed that provisions would be made for the Hydro One feeder to service the Hydro 2000 loads on a temporary basis. The same assumptions were made here as were in our analysis done for present loading conditions. If the assumptions are valid, we found that the Hydro One circuit would have difficulty supporting the Plantagenet loading anticipated in the future under peak summer and winter loading conditions.

Subjected to peak summer loading conditions, the Hydro One main conductors, presumed to be 3/0 ACSR would be very heavily loaded, and some sections, overloaded up to 108% of rated ampacity (at 30 degrees Celsius.) Voltage support is just adequate for extreme operating conditions for the entire circuit, with a minimum system voltage at 89.2% of nominal. If the main circuit conductors for the Hydro One network are, in fact, larger than 3/0, both of these situations (the loading and voltage support) would be improved. However, the combined loading of the two circuits exceeds the capacity of the 5MVA transformer by 15% (assuming the Hydro One circuit is loaded and grows to the same extent as the Plantagenet feeder).

Under 2015 projected peak winter loading conditions, system voltages were below the acceptable range in a very large area of Plantagenet, even with a 2.5% voltage tap applied. The system voltage is expected to be as low as 85.6% on the red phase between the public school and the substation. The overloading of the main circuit conductors is more severe than in the summer case, at 145%. The 5MVA transformer is overloaded, in this case, by about 73%. (Again, this analysis assumes that the Hydro One circuit is loaded and grows to the same extent as the Plantagenet feeder).

Provided the assumptions made in constructing the model of the Hydro One circuit are valid, the conductors and the main substation transformer do not have adequate capacity to support the Hydro 2000 Plantagenet load under emergency situations expected in the future. However, the Hydro One circuit may, in fact, be capable of supporting the additional load if its main conductors are larger than 3/0 (336 kcmil), and its nominal loading levels are significantly smaller than the assumed 1000 kVA (about 500 kVA) without significant growth anticipated for the near future.

## RECOMMENDATIONS

### *Recommended Upgrades*

1. Update both the Alfred and Plantagenet system single lines to add further system information, including the ratings of all switches, the size of all conductors, and other details (Budget $6,000)

2. Rebalance Alfred feeders F2 and F3, and Plantagenet feeder F1 to minimize losses, possible options to rebalance include the following:

   Alfred

   1. F2: 54-75 R to B (Telegraph & Dumoulin Street)
   2. F2: 76-75 W to B (Dumoulin Street)
   3. *F3: 44-75, B to W (Bolt Rd., between St. Joseph & Chatelaine)*

   Plantagenet

   4. Main St. (between Concession & Ottawa): 20-100 R to B
   5. Water St. (between L'Eglise & Concession): 13-75 R to W
   6. Main St. & Concession St.: 18-50 R to W

   The system main feeders should be measured before rebalancing to verify the unbalance, then the re-phasing should be done. Note changes to rebalance feeder are not recommended if the present imbalance can be corrected in the near future through smart distribution of additional loading required for new subdivisions. (Budget $2,000)

### *Possible Future Upgrades*

3. Various capacity constraints during both normal and emergency situations will be approached in 2015 using conservative load growth factors. Before that point, the loading levels and this study should be reviewed to determine the next steps required at that point. Various items like switches, lines, meters, and other devices may have to be upgraded at that time. This is especially critical on the Plantagenet feeder with the constraints on the reclosers and the main lines. This will be updated with further Hydro One information as it is received.

4. If the level of metering data provided by Hydro One is sufficient at this time, there would be no further requirement for additional metering. However, if dedicated Hydro 2000 metering is required for any reason, it is possible to provide modern digital metering for all three feeders (Alfred F2 and F3, Plantagenet F1) at a point accessible to Hydro 2000. This metering should provide all basic electrical parameters (voltage, current, PF, power, energy, and demand), plus power quality parameters (sags and swells, harmonics, transients, flicker), data and waveform logs (triggering, min/max, trending, timestamps), communications, set points, and alarming. (Budget $18,000 if existing metering current transformers and potential transformers can be used by Hydro 2000, probably another $75,000 if additional 3 metering transformer units need to be added).

## Hydro 2000 Inc.

## INCOME TAX, LARGE CORPORATON TAX AND ONTARIO CAPITAL TAX TABLE

### Summary of Income Tax Calculation

| INCOME TAX, LARGE CORPORATON TAX AND ONTARIO CAPITAL TAX TABLE | 2006 Board Approved | 2006 Actual | 2007 Bridge | 2008 Test |
|---|---|---|---|---|
| Determination of Taxable Income | | | | |
| | | | | |
| Regulatory Net Income (before tax) | 47,530 | 4,851 | (27,158) | 32,388 |
| | | | | |
| Book to Tax Adjustments | | | | |
| | | | | |
| Additions to Accounting Income: | | | | |
| Depreciation and amortization | 36,818 | 44,364 | 48,834 | 56,569 |
| Employee Benefit Plans - accrued, not paid | - | - | - | - |
| Hedge loss - accrued | - | - | - | - |
| Meals & entertainment / Mileage | - | - | - | - |
| Research & Development ITC | - | - | - | - |
| Regulatory adjustments | - | 186,552 | 215,333 | 215,333 |
| Total Additions | 36,818 | 230,916 | 264,167 | 271,902 |
| | | | | |
| Deductions from Accounting Income: | | | | |
| Capital Cost Allowance | (36,818) | (35,408) | (53,013) | (52,586) |
| Employee Benefit Plans - amounts paid | - | - | - | - |
| Hedge loss - payment | - | - | - | - |
| Environmental costs (incl. in amortization) | - | - | - | - |
| Capitalized pension costs | - | - | - | - |
| Capitalized overhead costs | - | - | - | - |
| Surplus staff payments | - | - | - | - |
| Loss carry-forward | (87,073) | | | |
| Regulatory adjustments | (15,870) | (58,440) | (66,004) | (59,584) |
| Total Deductions | (139,761) | (93,848) | (119,017) | (112,170) |
| | | | | |
| Regulatory Taxable Income | - | 141,919 | 117,992 | 192,120 |
| | | | | |
| Corporate Income Tax Rate | 19.12% | 18.62% | 18.62% | 17.00% |
| | | | | |
| Subtotal | - | 26,425 | 21,970 | 32,660 |
| Less: R&D ITC (0.3) | - | - | - | - |
| Regulatory Income Tax | - | 26,425 | 21,970 | 32,660 |

| | | | | |
|---|---|---|---|---|
| | | | | |
| | | | | |
| Calculation of Utility Income Taxes | | | | |
| Income Taxes (Line 23) | - | 26,425 | 21,970 | 32,660 |
| Large Corporation Tax (Line 14, page 2) | - | - | - | - |
| Total Taxes | - | 26,425 | 21,970 | 32,660 |
| | | | | |
| Tax Rates | | | | |
| Federal Tax | 12.00% | 12.00% | 12.00% | 11.50% |
| Federal Surtax | 1.12% | 1.12% | 1.12% | 0.00% |
| Provincial Tax | 6.00% | 5.50% | 5.50% | 5.50% |
| Total Tax Rate | 19.12% | 18.62% | 18.62% | 17.00% |
| | | | | |
| | | | | |
| Calculation of Large Corporation Tax | | | | |
| | | | | |
| Rate Base: | - | - | - | - |
| | | | | |
| Gross Plant at Cost | - | - | - | - |
| Less Accumulated Depreciation | - | - | - | - |
| Net Utility Plant | - | - | - | - |
| | | | | |
| Cash Working Capital | - | - | - | - |
| Materials and Supplies | - | - | - | - |
| Customer Security Deposits | - | - | - | - |
| Total Working Capital Components | - | - | - | - |
| | | | | |
| Less Federal Exemption | 50,000,000 | 50,000,000 | 50,000,000 | 50,000,000 |
| | | | | |
| Net Rate Base | - | - | - | - |
| | | | | |
| LCT Rate | 0.20% | 0.20% | 0.20% | 0.20% |
| | | | | |
| Subtotal | - | - | - | - |
| Less Federal Surtax | - | (1,589) | (1,322) | - |
| Large Corporation Tax | - | - | - | - |

# Hydro 2000 Inc.

| | | | | |
|---|---|---|---|---|
| Calculation of Utility Income Taxes | | | | |
| Income Taxes (Line 23) | - | 26,425 | 22,244 | 34,093 |
| Large Corporation Tax (Line 14, page 2) | - | - | - | - |
| Total Taxes | - | 26,425 | 22,244 | 34,093 |
| | | | | |
| Tax Rates | | | | |
| Federal Tax | 12.00% | 12.00% | 12.00% | 11.50% |
| Federal Surtax | 1.12% | 1.12% | 1.12% | 0.00% |
| Provincial Tax | 6.00% | 5.50% | 5.50% | 5.50% |
| Total Tax Rate | 19.12% | 18.62% | 18.62% | 17.00% |
| | | | | |
| | | | | |
| Calculation of Large Corporation Tax | | | | |
| | | | | |
| Rate Base: | - | - | - | - |
| | | | | |
| Gross Plant at Cost | - | - | - | - |
| Less Accumulated Depreciation | - | - | - | - |
| Net Utility Plant | - | - | - | - |
| | | | | |
| Cash Working Capital | - | - | - | - |
| Materials and Supplies | - | - | - | - |
| Customer Security Deposits | - | - | - | - |
| Total Working Capital Components | - | - | - | - |
| | | | | |
| Less Federal Exemption | 50,000,000 | 50,000,000 | 50,000,000 | 50,000,000 |
| | | | | |
| Net Rate Base | - | - | - | - |
| | | | | |
| LCT Rate | 0.20% | 0.20% | 0.20% | 0.20% |
| | | | | |
| Subtotal | - | - | - | - |
| Less Federal Surtax | - | (1,589) | (1,338) | - |
| Large Corporation Tax | - | - | - | - |

**Hydro 2000 Inc.**

INTEREST EXPENSE

| INTEREST EXPENSE | ($) |
|---|---|
| **2005** | |
| 2005 Actual Interest Expense | 21,293 |
| | |
| 2005 Capitalized Interest (USoA 6040) | - |
| 2005 Capitalized Interest (USoA 6042) | - |
| Interest on capitalized lease | - |
| 2005 Actual Interest | 21,293 |
| | |
| Interest Forecast for Tier 1 or 2 Adjustments | - |
| | |
| Total Interest | 21,293 |
| | |
| Excess Interest Expense for 2005 PILs | - |
| | |
| **2006** | |
| 2006 Actual Interest Expense | 20,103 |
| | |
| 2006 Capitalized Interest (USoA 6040) | - |
| 2006 Capitalized Interest (USoA 6042) | - |
| Interest on capitalized lease | - |
| 2006 Actual Interest | 20,103 |
| | |
| Interest Forecast for Tier 1 or 2 Adjustments | - |
| | |
| Total Interest | 20,103 |
| | |
| Excess Interest Expense for 2006 PILs | - |

**Hydro 2000 Inc.**

| 2007 | |
|---|---|
| 2007 Actual Interest Expense | 18,846 |
| | |
| 2007 Capitalized Interest (USoA 6040) | - |
| 2007 Capitalized Interest (USoA 6042) | - |
| Interest on capitalized lease | - |
| 2007 Actual Interest | 18,846 |
| | |
| Interest Forecast for Tier 1 or 2 Adjustments | - |
| | |
| Total Interest | 18,846 |
| | |
| Excess Interest Expense for 2007 PILs | - |

| 2008 | |
|---|---|
| 2008 Actual Interest Expense | 17,518 |
| | |
| 2008 Capitalized Interest (USoA 6040) | - |
| 2008 Capitalized Interest (USoA 6042) | - |
| Interest on capitalized lease | - |
| 2008 Actual Interest | 17,518 |
| | |
| Interest Forecast for Tier 1 or 2 Adjustments | - |
| | |
| Total Interest | 17,518 |
| | |
| Excess Interest Expense for 2008 PILs | - |

# Hydro 2000 Inc.

## CAPITAL COST ALLOWANCE

## 2006 Board Approved

| Class | Class Description | UCC Opening Balance | Additions | Dispositions | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | CCA | UCC Ending Balance |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - 1988 to 22-Feb-2005 | 141,275 | - | - | 141,275 | - | 141,275 | 4% | 5,651 | 135,624 |
| 2 | Distribution System - pre 1988 | 255,343 | | | 255,343 | - | 255,343 | 6% | 15,321 | 240,022 |
| 8 | General Office/Stores Equip | 3,288 | | | 3,288 | - | 3,288 | 20% | 658 | 2,630 |
| 10 | Computer Hardware/ Vehicles | 7,403 | | | 7,403 | - | 7,403 | 30% | 2,221 | 5,182 |
| 10.1 | Certain Automobiles | | | | - | - | - | | - | - |
| 12 | Computer Software | 4,061 | | | 4,061 | - | 4,061 | 100% | 4,061 | - |
| 13 1 | Lease # 1 | | | | - | - | - | | - | - |
| 13 2 | Lease #2 | | | | - | - | - | | - | - |
| 13 3 | Lease # 3 | | | | - | - | - | | - | - |
| 13 4 | Lease # 4 | | | | - | - | - | | - | - |
| 14 | Franchise | | | | - | - | - | | - | - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | | - | - | - | | - | - |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | | - | - | - | | - | - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | | | | - | - | - | 45% | - | - |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | | - | - | - | | - | - |
| 47 | Distribution System - post 22-Feb-2005 | | | | - | - | - | 8% | - | - |
| 98 | No CCA | | | | - | - | - | | - | - |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | TOTAL | 411,370 | - | - | 411,370 | - | 411,370 | | 27,912 | 383,458 |

# Hydro 2000 Inc.

## 2006 Actual

| Class | Class Description | UCC Opening Balance | Additions | Dispositions | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | CCA | UCC Ending Balance |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - 1988 to 22-Feb-2005 | 178,300 | 36,084 | - | 214,384 | 18,042 | 196,342 | 4% | 7,854 | 206,530 |
| 2 | Distribution System - pre 1988 | 240,022 | | | 240,022 | - | 240,022 | 6% | 14,401 | 225,621 |
| 8 | General Office/Stores Equip | 2,630 | | | 2,630 | - | 2,630 | 20% | 526 | 2,104 |
| 10 | Computer Hardware/ Vehicles | 5,182 | | | 5,182 | - | 5,182 | 30% | 1,555 | 3,627 |
| 10.1 | Certain Automobiles | | | | - | - | - | | - | - |
| 12 | Computer Software | 4,294 | 9,586 | | 13,880 | 4,793 | 9,087 | 100% | 9,087 | 4,793 |
| 13 1 | Lease # 1 | | | | - | - | - | | - | - |
| 13 2 | Lease #2 | | | | - | - | - | | - | - |
| 13 3 | Lease # 3 | | | | - | - | - | | - | - |
| 13 4 | Lease # 4 | | | | - | - | - | | - | - |
| 14 | Franchise | | | | - | - | - | | - | - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | | - | - | - | | - | - |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | | - | - | - | | - | - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | 1,168 | 5,692 | | 6,860 | 2,846 | 4,014 | 45% | 1,806 | 5,054 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | | - | - | - | | - | - |
| 47 | Distribution System - post 22-Feb-2005 | | | | - | - | - | 8% | - | - |
| 98 | No CCA | | | | - | - | - | | - | - |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | TOTAL | 431,596 | 51,362 | - | 482,958 | 25,681 | 457,277 | | 35,229 | 447,729 |

# Hydro 2000 Inc.

## 2007 Bridge

| Class | Class Description | UCC Opening Balance | Additions | Dispositions | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | CCA | UCC Ending Balance |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - 1988 to 22-Feb-2005 | 206,530 | - | - | 206,530 | - | 206,530 | 4% | 8,261 | 198,269 |
| 2 | Distribution System - pre 1988 | 225,621 | | | 225,621 | - | 225,621 | 6% | 13,537 | 212,084 |
| 8 | General Office/Stores Equip | 2,104 | | | 2,104 | - | 2,104 | 20% | 421 | 1,683 |
| 10 | Computer Hardware/ Vehicles | 3,627 | | | 3,627 | - | 3,627 | 30% | 1,088 | 2,539 |
| 10.1 | Certain Automobiles | - | | | - | - | - | | - | - |
| 12 | Computer Software | 4,793 | 42,000 | | 46,793 | 21,000 | 25,793 | 100% | 25,793 | 21,000 |
| 13 1 | Lease # 1 | - | | | - | - | - | | - | - |
| 13 2 | Lease #2 | - | | | - | - | - | | - | - |
| 13 3 | Lease # 3 | - | | | - | - | - | | - | - |
| 13 4 | Lease # 4 | - | | | - | - | - | | - | - |
| 14 | Franchise | - | | | - | - | - | | - | - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | - | | | - | - | - | | - | - |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | - | | | - | - | - | | - | - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | 5,054 | | | 5,054 | - | 5,054 | 45% | 2,274 | 2,780 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | - | | | - | - | - | | - | - |
| 47 | Distribution System - post 22-Feb-2005 | - | 36,798 | | 36,798 | 18,399 | 18,399 | 8% | 1,472 | 35,326 |
| 98 | No CCA | - | | | - | - | - | | - | - |
| | | | | | | | | | | |
| | TOTAL | 447,729 | 78,798 | - | 526,527 | 39,399 | 487,128 | | 52,846 | 473,681 |

# Hydro 2000 Inc.

## 2008 Test

| 2008 Test | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Class** | **Class Description** | **UCC Opening Balance** | **Additions** | **Dispositions** | **UCC Before 1/2 Yr Adjustment** | **1/2 Year Rule {1/2 Additions Less Disposals}** | **Reduced UCC** | **Rate %** | **CCA** | **UCC Ending Balance** |
| 1 | Distribution System - 1988 to 22-Feb-2005 | 198,269 | - | - | 198,269 | - | 198,269 | 4% | 7,931 | 190,338 |
| 2 | Distribution System - pre 1988 | 212,084 | | | 212,084 | - | 212,084 | 6% | 12,725 | 199,359 |
| 8 | General Office/Stores Equip | 1,683 | | | 1,683 | - | 1,683 | 20% | 337 | 1,346 |
| 10 | Computer Hardware/ Vehicles | 2,539 | | | 2,539 | - | 2,539 | 30% | 762 | 1,777 |
| 10.1 | Certain Automobiles | - | | | - | - | - | | - | - |
| 12 | Computer Software | 21,000 | | | 21,000 | - | 21,000 | 100% | 21,000 | - |
| 13 1 | Lease # 1 | - | | | - | - | - | | - | - |
| 13 2 | Lease #2 | - | | | - | - | - | | - | - |
| 13 3 | Lease # 3 | - | | | - | - | - | | - | - |
| 13 4 | Lease # 4 | - | | | - | - | - | | - | - |
| 14 | Franchise | - | | | - | - | - | | - | - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | - | | | - | - | - | | - | - |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | - | | | - | - | - | | - | - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | 2,780 | | | 2,780 | - | 2,780 | 45% | 1,251 | 1,529 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | - | | | - | - | - | | - | - |
| 47 | Distribution System - post 22-Feb-2005 | 35,326 | 140,000 | | 175,326 | 70,000 | 105,326 | 8% | 8,426 | 166,900 |
| 98 | No CCA | - | | | - | - | - | | - | - |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | TOTAL | 473,681 | 140,000 | - | 613,681 | 70,000 | 543,681 | | 52,432 | 561,249 |

**Hydro 2000 Inc.**

**Hydro 2000 Inc.**

## 5 – Deferral and Variance Accounts

| | | |
|---|---|---|
| 1 | 1 | Description of Deferral and variance accounts |
| | 2 | Calculation of Balances by Account |
| | 3 | Method of Recovery |

**Hydro 2000 Inc.**

## DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

### COMMODITY ACCOUNTS ARE CLASSIFIED AS FOLLOWS:

1588 Retail Settlement Variance Account – Power
Description: Capture de variance between the cost of power billed by Hydro One Networks Inc. (H.O.N.I.) on Power bill and Power Charged to Hydro 2000 Inc. Customers in the sub-account 1588-01-05.

1588 RSVA Power, Sub-account Global Adjustments
Description: Capture de variance between the Global Adjustments billed by Hydro One Networks Inc. (H.O.N.I.) on Power bill and Global Adjustment Charged to Hydro 2000 Inc. Customers in the sub-account 1588-01-05.

### NON-COMMODITY ACCOUNTS ARE CLASSIFIED IN TWO CATEGORIES AS FOLLOWS:

Wholesale and Retail Market Variance Accounts

1518 Retail Cost Variance Account – Retail
Description: N/A at this time.

1548 Retail Cost Variance Account – STR
Description: N/A at this time.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges
Description: Capture de variance between the Wholesale Market Service Charges billed by Hydro One Networks Inc. (H.O.N.I.) on Power bill and Wholesale Market Service Charges Charged to Hydro 2000 Inc. Customers in the sub-account 1584-01.

**Hydro 2000 Inc.**

Others Wholesale Market Service Charges billed by (H.O.N.I) from May 1St, 2002 to December 31st, 2004 was charged to Embedded Utilities and was captured in sub-account 1580-01-05. Charges approved by OEB Board.

Others Wholesale Market Service Charges billed by (H.O.N.I) from January 1St, 2005 to May1st, 2006 was charged to Embedded Utilities and was captured in sub-account 1580-01-06. Charges approved by OEB Board.

1582 Retail Settlement Variance Account - One-time Wholesale Market Service
Description: One-time Wholesale Market Service was billed by (H.O.N.I.) from January 1st, 2005 to May 1st, 2006 was charged to Embedded Utilities and was captured in sub account 1582-00-06

1584 Retail Settlement Variance Account - Retail Transmission Network Charges
Description: Capture de variance between the Retail Transmission Network Charges billed by Hydro One Networks Inc. (H.O.N.I.) on Power bill and Retail Transmission Network Charges Charged to Hydro 2000 Inc. Customers in the sub-account 1584-01.

Others Retail Transmission Network Charges billed by (H.O.N.I) from May 1St, 2002 to December 31st, 2004 was charged to Embedded Utilities and was captured in sub-account 1584-01-05. Charges approved by OEB Board.

Others Retail Transmission Network Charges billed by (H.O.N.I) from January 1St, 2005 to May1st, 2006 was charged to Embedded Utilities and was captured in sub-account 1584-01-06. Charges approved by OEB Board.

**Hydro 2000 Inc.**

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Description: Capture de variance between the Retail Transmission Connection Charges billed by Hydro One Networks Inc. (H.O.N.I.) on Power bill and Retail Transmission Connection Charges Charged to Hydro 2000 Inc. Customers in the sub-account 1586-01.

Others Retail Transmission Connection Charges billed by (H.O.N.I) from May 1St, 2002 to December 31st, 2004 was charged to Embedded Utilities and was captured in sub-account 1586-01-05. Charges approved by OEB Board.

Others Retail Transmission Connection Charges billed by (H.O.N.I) from January 1St, 2005 to May1st, 2006 was charged to Embedded Utilities and was captured in sub-account 1586-01-06. Charges approved by OEB Board.

1588 Retail Settlement Variance Account - Power

Description: Refer to commodity accounts description.

1588 Retail Settlement Variance Account - Power Sub-Account Global

Description: Refer to commodity accounts description.

**Hydro 2000 Inc.**

Utility Deferral Accounts

1508 Other Regulatory Assets

Description: Other Regulatory Assets Charges billed by (H.O.N.I) from May 1$^{St}$, 2002 to December 31$^{st}$, 2004 was charged to Embedded Utilities and was captured in sub-account 1508-00-05. Charges were approved by OEB Board.

Other Regulatory Assets Charges billed by (H.O.N.I) from January 1$^{St}$, 2005 to May1$^{st}$, 2006 was charged to Embedded Utilities and was captured in sub-account 1508-00-06. Charges approved by OEB Board.

Description:

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

Description: To capture the variance between OEB Cost Assessments amount approved in 1999 versus the actual OEB Cost Assessments charged. Charges are captured in sub-account 1508-00-05.

1508 Other Regulatory Assets - Sub-account Pension Contributions

Description: N/A at this time

1525 Miscellaneous Deferred Debits

Others Miscellaneous Deferred Debits charges billed by (H.O.N.I) from May 1$^{St}$, 2002 to December 31$^{st}$, 2004 was charged to Embedded Utilities and was captured in sub-account 1525-00-05. Charges approved by OEB Board.

1550 LV Recovery Offset Variance

Description: Capture de variance between LV Charges billed by Hydro One Networks Inc. (H.O.N.I.) on Power bill and LV Charges Charged to Hydro 2000 Inc. Customers in the sub-account 1550-00.

**Hydro 2000 Inc.**

1555 Smart Meter Capital and Recovery Offset Variance

Description: To capture the amount billed to Hydro 2000 Inc. customers in sub-account 1555-00.

1565 Smart Meter OM&A Variance

Description: To capture the amount spent by Hydro 2000 Inc. in sub-account 1565-00.

1562 Deferred Payments in Lieu of Taxes

Description: Was set-up as prescribed by the Board.

1563 PILs contra account

Description: Was set-up as prescribed by the Board.

1565 Conservation and Demand Management Expenditures and Recoveries

Description: Was set-up as prescribed by the Board.

1566 CDM Contra

Description: Was set-up as prescribed by the Board.

1572 Extraordinary Event Losses

Description: N/A at this time.

1574 Deferred Rate Impact Amounts

Description: N/A at this time.

1592 PILS & Tax Variance

Description: To capture the Variance between the PILS & tax billed to Hydro 2000 Inc. customers and the amount of PILS payable in sub-account 1592-00.

**Hydro 2000 Inc.**

2425 Other Deferred Credits
Description: N/A at this time.

**Closed Accounts not classified are as follows:**

1570 Qualifying Transition Costs (closed December 31, 2005)
Description: To capture all expenses for Transition Costs in sub-account 1570-00-10, 1570-00-15 and 1570-00-90. All Qualifying Transition Costs were approved by OEB Board.

1571 Pre-Market Opening Energy Variances (closed April 30, 2002)
Description: To capture the difference between the T.O.U and Non T.O.U short fall. Charges were approved by OEB Board.

**All Deferral and Variance account have a sub-account capturing the interest calculated at the rate prescribed by the Board.**

**Hydro 2000 is requesting a deferral account to capture capital expenses in future years 2009 and 2010 that will be dispose in the next rebasing in 2011.**

Note 1:
The RSVA power account 1588 is designed to capture variances due to billing timing differences (i.e. electricity charged by IESO to LDCs vs. electricity billed by LDCs to their customers), price and quantity differences (i.e. arising from final vs. preliminary IESO settlement invoices), and line loss differences (i.e. actual vs. estimated line loss factors).

This account is not designed to capture any price differences between the regulated price plan (RPP) and spot prices applicable to RPP customers. This is the function of the Ontario Power Authority (OPA) RPP variance account which is trued-up in accordance with the terms established by the Board for the RPP.

Accordingly, since the RSVA power account is generic to all customers of an LDC, disposition of the account balance in rates is attributable to all its customers.

The 1588 RSVA power - Sub-account Global Adjustments is designed for the global adjustments applicable to non-RPP customers. Hence, the disposition of the account balance should be attributable to non-RPP customers.

**File number: ED-2007-0704**
**Exhibit: 5**
**Tab: 1**
**Schedule: 2**
**Page: 1**

## Hydro 2000 Inc.

## CALCULATION OF BALANCES BY ACCOUNT

| CALCULATION OF BALANCES BY ACCOUNT | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **OEB** | **Opening** | **Carrying Charges** | | **Net Accruals** | | **Adjustments** | | **Ending** |
| | **Account** | **Balance** | **Period** | **LTD** | **Period** | **LTD** | **Period** | **LTD** | **Balance** |
| **Commodity accounts are classified as follows:** | | | | | | | | | |
| 1588 Retail Settlement Variance Account - Power | 1588 | 44,729 | 444 | 3,819 | 31,047 | 56,608 | (15,793) | - | 60,427 |
| 1588 RSVA Power - Sub-account Global Adjustments | 1588 | - | - | - | - | - | - | - | - |
| | | | | | | | | | |
| **Non-commodity accounts are classified in two categories as follows:** | | | | | | | | | |
| <u>Wholesale and Retail Market Variance Accounts</u> | | | | | | | | | |
| 1518 Retail Cost Variance Account - Retail | 1518 | - | - | - | - | - | - | - | - |
| 1548 Retail Cost Variance Account - STR | 1548 | - | - | - | - | - | - | - | - |
| 1580 Retail Settlement Variance Account - Wholesale Market Service Charges | 1580 | 47,512 | 2,373 | 2,379 | 2,557 | 5,980 | (44,083) | - | 8,359 |
| 1582 Retail Settlement Variance Account - One-time Wholesale Market Service | 1582 | 4,156 | 191 | - | - | - | (4,347) | - | - |
| 1584 Retail Settlement Variance Account - Retail Transmission Network Charges | 1584 | (52,741) | (2,867) | (1,537) | (13,277) | (24,412) | 42,936 | - | (25,949) |
| 1586 Retail Settlement Variance Account - Retail Transmission Connection Charges | 1586 | 363,175 | 16,377 | 4,323 | (14,761) | (22,568) | (383,036) | - | (18,245) |
| | | | | | | | | | |
| <u>Utility Deferral Accounts</u> | | | | | | | | | |
| 1508 Other Regulatory Assets | 1508 | 15,707 | 708 | 277 | 391 | 391 | (16,138) | - | 668 |
| 1508 Other Regulatory Assets - Sub-account OEB Cost Assessments | 1508 | 3,089 | - | - | 1,669 | 4,038 | (720) | - | 4,038 |
| 1508 Other Regulatory Assets - Sub-account Pension Contributions | 1508 | 10,775 | - | - | - | - | (10,775) | - | - |
| 1525 Miscellaneous Deferred Debits | 1525 | 6,114 | 850 | - | - | - | (6,964) | - | - |
| 1550 LV Variance Account | 1550 | - | 290 | 290 | 20,722 | 20,722 | - | - | 21,012 |
| 1555 Smart meter $0.30 variance | 1555 | | | | | | | | |

# Hydro 2000 Inc.

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | | (34) | (34) | | (2,368) | (2,368) | | - | - | | (2,402) |
| 1556 Variance smart meter expense | 1556 | - | | - | - | | - | - | | - | - | | - |
| 1562 Deferred Payments in Lieu of Taxes | 1562 | (102,425) | | (4,812) | (9,253) | | 9,532 | (88,452) | | - | - | | (97,705) |
| 1563 PILs contra account | 1563 | 102,425 | | 4,812 | 9,253 | | (9,532) | 88,452 | | - | - | | 97,705 |
| 1565 Conservation and Demand Management Expenditures and Recoveries (CDM) | 1565 | 6,166 | | 31 | 31 | | (3,487) | 2,679 | | - | - | | 2,710 |
| 1566 Contra Account - CDM | 1566 | (6,166) | | (191) | (191) | | 3,487 | (2,679) | | - | - | | (2,870) |
| 1572 Extraordinary Event Losses | 1572 | - | | - | - | | - | - | | - | - | | - |
| 1574 Deferred Rate Impact Amounts | 1574 | - | | - | - | | - | - | | - | - | | - |
| 1592 Deferred PILs Account | 1592 | - | | - | - | | 10,211 | 10,211 | | - | - | | 10,211 |
| 2425 Other Deferred Credits | 2425 | - | | - | - | | - | - | | - | - | | - |
| | | | | | | | | | | | | | |
| Closed Accounts not classified are as follows: | | | | | | | | | | | | | |
| 1570 Qualifying Transition Costs (closed December 31, 2002) | 1570 | 154,714 | | 2,635 | - | | - | - | | (157,349) | - | | - |
| 1571 Pre-Market Opening Energy Variances (closed April 30, 2002) | 1571 | 179,673 | | 7,220 | - | | - | - | | (186,893) | - | | - |
| | | | | | | | | | | | | | |
| | | 776,903 | | 28,027 | 9,357 | | 36,191 | 48,602 | | (783,162) | - | | 57,959 |

## Hydro 2000 Inc.

## METHOD OF RECOVERY

Hydro 2000 Inc. is submitting a deferral and variance recovery model that is showing all the Deferral and Variance Accounts. The Amounts of Deferral and Variance financial statement at year end 2006 are inputted in the model. Hydro 2000 Inc. can select to recover or not the amount in the Deferral and Variance Account. Forecast amounts can be entered for different period from (January 1st, 2007 to Dec 31st, 2008) to reflect a more realistic on actual amount in Deferral and Variance Account. The forecast are used to prevent Deferral account to be cumulating large amounts and demonstrate the orientation of the account.

Hydro 2000 Inc. is applying to recover all Deferral and Variance selected in the model and the balance forecasted in account 1590 on a three year bases. By doing forecast of each account and disposing of all Deferral and Variance accounts customers rates will be more accurate with less fluctuation.

| Class | 200 Board Approved | 2008 Proposed | % change |
|---|---|---|---|
| Residential | $0.0098 | $0.0032 | -67.3% |
| GS less 50 kW | $0.0075 | $0.0029 | -61.33% |
| GS over 50 kW | $2.2403 | $1.0468 | -53.3% |
| Unmetered scattered load | $0.0075 | $0.0029 | -61.3% |
| Street light | ($1.7676) | $0.4060 | 0.0% |

All classes have will see their regulatory assets rates decrease by 53.3% to 67.3%. Only the Street Light will see an increase due to a negative regulatory assets recovery rate in previous years.

A copy of the Deferral and Variance Disposal model is attached on next page.

**Hydro 2000 Inc.**

| | | | |
|---|---|---|---|
| **DATE** | ###### | | |
| **NAME OF UTILITY** | | **LICENCE NUMBER** | ED-2007-0704 |
| **NAME OF CONTACT** | | **DOCID NUMBER** | RP-2005-0020 |
| **E-MAIL ADDRESS** | | | EB-2005-0380 |
| **PHONE NUMBER** | | | |

**Annual Interest Rate:** 4.59% Consult OEB website at:

http://www.oeb.gov.on.ca/html/en/industryrelations/rulesguidesandforms_regulatory_pre

This column should reconcile with Dec 31/06

**Deferred Charge Accounts**

| | | Dec 31/06 Balance | | | | Jan1/07 to Apr30/07 | | | May1/07 to Dec31/07 | | | Jan1 to Apr30/08 | | | May1 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Account Description** | **Account Number** | **Principal Portion** | **Accum. Interest** | **Total** | **Apply for Disposal ?** | **Interest** | **Other** | **Balance** | **Interest** | **Other** | **Balance** | **Interest** | **Other** | **Balance** | **Interest** |
| Unrecovered Plant and Regulatory Study Costs | 1505 | - | - | - | NO | - | | - | - | | - | - | | - | - |
| Other Regulatory Assets | 1508 | 4,429 | 277 | 4,705.78 | YES | 68 | 400 | 5,174 | 148 | 800 | 6,121 | 86 | 400 | 6,607 | 184 |
| Preliminary Survey and Investigation Charges | 1510 | | | - | NO | - | | - | - | | - | - | | - | - |
| Emission Allowance Inventory | 1515 | | | - | NO | - | | - | - | | - | - | | - | - |
| Emission Allowances Withheld | 1516 | | | - | NO | - | | - | - | | - | - | | - | - |
| Retail Cost Variance Account - Retail | 1518 | - | | - | NO | - | | - | - | | - | - | | - | - |
| Power Purchase Variance Account | 1520 | | | - | NO | - | | - | - | | - | - | | - | - |
| Misc. Deferred Debits - incl. Rebate Cheques | 1525 | | | - | NO | - | | - | - | | - | - | | - | - |
| Deferred Losses from Disposition of Utility Plant | 1530 | | | - | NO | - | | - | - | | - | - | | - | - |
| Unamortized Loss on Reacquired Debt | 1540 | | | - | NO | - | | - | - | | - | - | | - | - |
| Development Charge Deposits/ Receivables | 1545 | | | - | NO | - | | - | - | | - | - | | - | - |
| Retail Cost Variance Account - STR | 1548 | - | | - | NO | - | | - | - | | - | - | | - | - |
| LV Variance Account | 1550 | 20,722 | 290 | 21,012 | YES | 317 | 12,000 | 33,329 | 1,001 | 18,000 | 52,330 | 776 | 12,000 | 65,106 | 1,919 |
| Smart Meter Capital Variance Account | 1555 | (2,368) | (34) | (2,402) | NO | (36) | | (2,438) | (72) | | (2,511) | (36) | | (2,547) | (72) |
| Smart Meters OM&A Variance Account | 1556 | | | - | NO | - | | - | - | | - | - | | - | - |
| Deferred Development Costs | 1560 | | | - | NO | - | | - | - | | - | - | | - | - |
| Deferred Payments in Lieu of Taxes | 1562 | (88,451) | (9,253) | (97,705) | YES | (1,353) | | (99,058) | (2,707) | | ###### | (1,353) | | (103,118) | (2,707) |
| PILS Contra Account | 1563 | 88,451 | 9,253 | 97,705 | YES | 1,353 | | 99,058 | 2,707 | | ###### | 1,353 | | 103,118 | 2,707 |
| CDM Expenditures and Recoveries | 1565 | 2,679 | 31 | 2,710 | NO | 41 | | 2,751 | 82 | | 2,833 | 41 | | 2,874 | 82 |
| CDM Contra Account | 1566 | (2,679) | (191) | (2,871) | NO | (41) | | (2,912) | (82) | | (2,994) | (41) | | (3,035) | (82) |
| Qualifying Transition Costs | 1570 | | | - | NO | - | | - | - | | - | - | | - | - |
| Pre-Market Opening Energy Variances Total | 1571 | | | - | NO | - | | - | - | | - | - | | - | - |
| Extra-Ordinary Event Losses | 1572 | | | - | NO | - | | - | - | | - | - | | - | - |
| Deferred Rate Impact Amounts | 1574 | | | - | NO | - | | - | - | | - | - | | - | - |
| RSVA - Wholesale Market Service Charge | 1580 | 5,980 | 2,379 | 8,359 | YES | 91 | | 8,451 | 183 | | 8,634 | 91 | | 8,725 | 183 |
| RSVA - One-time Wholesale Market Service | 1582 | - | | - | NO | - | | - | - | | - | - | | - | - |
| RSVA - Retail Transmission Network Charge | 1584 | (24,412) | (1,536) | (25,949) | YES | (374) | | (26,322) | (747) | | (27,069) | (374) | | (27,443) | (747) |
| RSVA - Retail Transmission Connection Charge | 1586 | (22,569) | 4,323 | (18,245) | YES | (345) | | (18,590) | (691) | | (19,281) | (345) | | (19,626) | (691) |
| RSVA - Power | 1588 | 56,608 | 3,819 | 60,427 | YES | 866 | | 61,293 | 1,732 | | 63,025 | 866 | | 63,892 | 1,732 |
| Deferred PILs Account | 1592 | 10,211 | - | 10,211 | YES | 156 | 11,125 | 21,492 | 653 | 11,125 | 33,270 | 497 | 17,050 | 50,817 | 1,515 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Other Deferred Credits | 2425 | - | - | - | NO | - | | - | - | | - | - | | - | - |
| **Sub-totals** | | **48,602** | **9,357** | **57,959** | | **744** | **23,525** | **82,227** | **2,207** | **29,925** | **######** | **1,561** | **29,450** | **145,371** | **4,024** |
| **Recovery of Regulatory Asset Balances (acct #1590)** | | | | | | | | | | | | | | | |
| **Approved Balance** | | | | **395,384** | | | | | | | | | | | |
| Less Period Disposals | | | | | | | 76,610 | | | ###### | | | 77,039 | | |
| Plus Period Interest | | | | | | 5,463 | | | 7,577 | | | 2,143 | | | 816 |
| **Balance to (Refund) or Recover from 2006** | | | | **395,384** | | | | **324,238** | | | **######** | | | **103,699** | |

**Bridge Year (2007) Forecast**

| Customer Class | Metric | kW | kWhs | # Customers | EDR 2006 Approved Rates* | EDR 2007 Approved Rates** | Jan1/07 to Apr30/07 Disposal | May1/07 to Dec31/07 | Proportional Allocation |
|---|---|---|---|---|---|---|---|---|---|
| Residential | kWhs | | 16,382,735 | 997 | 0.0098 | 0.0098 | 53,517 | ###### | 70% |
| GS < 50 KW | kWhs | | 5,682,016 | 147 | 0.0075 | 0.0075 | 14,205 | 28,410 | 19% |
| GS > 50 Non TOU | kW | 13,280 | 5,496,281 | 12 | 2.1218 | 2.1218 | 9,393 | 18,785 | 12% |
| Small Scattered Load | kWhs | | 19,951 | 6 | 0.0075 | 0.0075 | 50 | 100 | 0% |
| Street Lighting | kW | 941 | 359,553 | 368 | -1.7676 | -1.7676 | (554) | (1,109) | -1% |
| **Totals** | | **14,221** | **27,940,536** | **1,530** | | | **76,610** | **######** | **100%** |

**Test Year (2008) Forecast**

| Customer Class | Metric | kW | kWhs | # Customers | Dx Revenue | # Customers w/Rebate Cheques | Additional Allocator 1 | Additional Allocator 2 | Additional Allocator 3 | EDR 2007 Approved Rates | Jan1/08 to Apr30/08 Disposal | May 1/08 to Dec 31/08 Disposal |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | kWhs | | 16,514,191 | 1,005 | | | | | | 0.0098 | 53,946 | 107,893 |
| GS < 50 KW | kWhs | | 5,682,016 | 147 | | | | | | 0.0075 | 14,205 | 28,410 |
| GS > 50 Non TOU | kW | 13,280 | 5,496,281 | 12 | | | | | | 2.1218 | 9,393 | 18,785 |
| Small Scattered Load | kWhs | | 19,951 | 6 | | | | | | 0.0075 | 50 | 100 |
| Street Lighting | kW | 941 | 359,553 | 368 | | | | | | -1.7676 | (554) | (1,109) |
| **Totals** | | **14,221** | **########** | **1,538** | **-** | **-** | **-** | **-** | **-** | | **77,039** | **154,079** |

* EDR Approved 2006 rates can be found at:
http://www.oeb.gov.on.ca/html/en/consumers/understanding/2006edr_decisions.htm

** EDR Approved 2007 rates can be found at:
http://www.oeb.gov.on.ca/html/en/consumers/understanding/2007edr_decisions.htm

**1 to Dec31/08**

| Other | Balance |
|---|---|
| | - |
| 800 | 7,592 |
| | - |
| | - |
| | - |
| | - |
| | - |
| | - |
| | - |
| | - |
| | - |
| | - |
| - | 67,025 |
| | (2,620) |
| | - |
| | - |
| | (105,825) |
| | 105,825 |
| | 2,956 |
| | (3,117) |
| | - |
| | - |
| | - |
| | - |
| | 8,908 |
| | - |
| | (28,190) |
| | (20,317) |
| | 65,624 |
| | 52,332 |

| | |
|---|---|
| | - |
| **800** | **150,195** |
| ##### | |
| | **(49,564)** |

| Account Description | Account Number | Dec31/06 Balance | Apr 30/08 Balance | Allocation Basis | Residential | GS < 50 KW | GS > 50 Non TOU | Small Scattered Load | Street Lighting | Totals | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Unrecovered Plant and Regulatory Study Costs | 1505 | - | - | | | | | | | - | |
| Other Regulatory Assets | 1508 | 4,706 | 6,607 | KWh | 3,887 | 1,337 | 1,294 | 5 | 85 | 6,607 | |
| Preliminary Survey and Investigation Charges | 1510 | - | - | | | | | | | - | |
| Emission Allowance Inventory | 1515 | - | - | | | | | | | - | |
| Emission Allowances Withheld | 1516 | - | - | | | | | | | - | |
| Retail Cost Variance Account - Retail | 1518 | - | - | # Customers | - | - | - | - | - | - | |
| Power Purchase Variance Account | 1520 | - | - | | | | | | | - | |
| Misc. Deferred Debits - incl. Rebate Cheques | 1525 | - | - | Customers w/Rebate Cheque | | | | | | - | |
| Deferred Losses from Disposition of Utility Plant | 1530 | - | - | | | | | | | - | |
| Unamortized Loss on Reacquired Debt | 1540 | - | - | | | | | | | - | |
| Development Charge Deposits/ Receivables | 1545 | - | - | | | | | | | - | |
| Retail Cost Variance Account - STR | 1548 | - | - | # Customers | - | - | - | - | - | - | |
| LV Variance Account | 1550 | 21,012 | 65,106 | KWh | 38,301 | 13,178 | 12,747 | 46 | 834 | 65,106 | |
| Smart Meter Capital Variance Account | 1555 | - | - | | | | | | | - | |
| Smart Meters OM&A Variance Account | 1556 | - | - | | | | | | | - | |
| Deferred Development Costs | 1560 | - | - | | | | | | | - | |
| Deferred Payments in Lieu of Taxes | 1562 | (97,705) | ###### | KWh | (60,662) | (20,872) | (20,190) | (73) | (1,321) | (103,118) | |
| PILS Contra Account | 1563 | 97,705 | 103,118 | KWh | 60,662 | 20,872 | 20,190 | 73 | 1,321 | 103,118 | |
| CDM Expenditures and Recoveries | 1565 | - | - | | | | | | | - | |
| CDM Contra Account | 1566 | - | - | | | | | | | - | |
| Qualifying Transition Costs | 1570 | - | - | # Customers | - | - | - | - | - | - | |
| Pre-Market Opening Energy Variances Total | 1571 | - | - | KWh for Non TOU Customers | - | - | - | - | - | - | |
| Extra-Ordinary Event Losses | 1572 | - | - | Dx Revenue | | | | | | - | |
| Deferred Rate Impact Amounts | 1574 | - | - | | | | | | | - | |
| RSVA - Wholesale Market Service Charge | 1580 | 8,359 | 8,725 | KWh | 5,133 | 1,766 | 1,708 | 6 | 112 | 8,725 | |
| RSVA - One-time Wholesale Market Service | 1582 | - | - | KWh | - | - | - | - | - | - | |
| RSVA - Retail Transmission Network Charge | 1584 | (25,949) | (27,443) | KWh | (16,144) | (5,555) | (5,373) | (20) | (351) | (27,443) | |
| RSVA - Retail Transmission Connection Charge | 1586 | (18,245) | (19,626) | KWh | (11,546) | (3,973) | (3,843) | (14) | (251) | (19,626) | |
| RSVA - Power | 1588 | 60,427 | 63,892 | KWh | 37,586 | 12,932 | 12,509 | 45 | 818 | 63,892 | |
| Deferred PILs Account | 1592 | 10,211 | 50,817 | KWh | 29,894 | 10,286 | 9,950 | 36 | 651 | 50,817 | |
| Other Deferred Credits | 2425 | - | - | # Customers | - | - | - | - | - | - | |
| **Sub-total to Dispose at May1/08 or Dec31/06?** | Apr30/08 | **60,521** | **148,078** | | **87,111** | **29,972** | **28,993** | **105** | **1,897** | **148,078** | **OK** |
| Clear residual 1590 balance as of April 30/08? | YES | | | | 72,440 | 19,228 | 12,714 | 68 | (750) | **103,699** | |
| **Total to Dispose at May1/08** | | | | | **159,552** | **49,200** | **41,706** | **173** | **1,146** | **251,777** | |
| Disposal period? | 3 YEARS | | | | 53,184 | 16,400 | 13,902 | 58 | 382 | **83,926** | |
| **Projected 2008 Rate Riders** | | | | | **0.0032** | **0.0029** | **1.0468** | **0.0029** | **0.4060** | | |
| Rate Determinant | | | | | kWh | kWh | kW | kWh | kW | | |

| Account Description |
|---|
| Unrecovered Plant and Regulatory Study Costs |
| Other Regulatory Assets |
| Preliminary Survey and Investigation Charges |
| Emission Allowance Inventory |
| Emission Allowances Withheld |
| Retail Cost Variance Account - Retail |
| Power Purchase Variance Account |
| Misc. Deferred Debits - incl. Rebate Cheques |
| Deferred Losses from Disposition of Utility Plant |
| Unamortized Loss on Reacquired Debt |
| Development Charge Deposits/ Receivables |
| Retail Cost Variance Account - STR |
| LV Variance Account |
| Smart Meter Capital Variance Account |
| Smart Meters OM&A Variance Account |
| Deferred Development Costs |
| Deferred Payments in Lieu of Taxes |
| PILS Contra Account |
| CDM Expenditures and Recoveries |
| CDM Contra Account |
| Qualifying Transition Costs |
| Pre-Market Opening Energy Variances Total |
| Extra-Ordinary Event Losses |
| Deferred Rate Impact Amounts |
| RSVA - Wholesale Market Service Charge |
| RSVA - One-time Wholesale Market Service |
| RSVA - Retail Transmission Network Charge |
| RSVA - Retail Transmission Connection Charge |
| RSVA - Power |
| Deferred PILs Account |
| Other Deferred Credits |

Checks Allo
Totals Agai
to Recover
May1/08 or
31/06

**Sub-total to Dispose at May1/08 or Dec31/06?**

Clear residual 1590 balance as of April 30/08?

**Total to Dispose at May1/08**

Disposal period?

**Projected 2008 Rate Riders**

Rate Determinant

**Test Year (2008) Allocations**

| Customer Class | Metric | kW | KWh | # Customers | KWh for Non TOU Customers | Dx Revenue | # Customers w/Rebate Cheques |
|---|---|---|---|---|---|---|---|
| Residential | kWhs | 0% | 59% | 65% | 60% | | |
| GS < 50 KW | kWhs | 0% | 20% | 10% | 21% | | |
| GS > 50 Non TOU | kW | 93% | 20% | 1% | 20% | | |
| #REF! | | | | | | | |
| #REF! | | | | | | | |
| #REF! | | | | | | | |
| Small Scattered Load | kWhs | 0% | 0% | 0% | 0% | | |
| #REF! | | | | | | | |
| #REF! | | | | | | | |
| Street Lighting | kW | 7% | 1% | 24% | | | |
| #REF! | | | | | | | |
| #REF! | | | | | | | |
| #REF! | | | | | | | |
| #REF! | | | | | | | |
| **Totals** | | **100%** | **100%** | **100%** | **100%** | **0%** | **0%** |

**Test Year (2008) Allocations**

| **Customer Class** |
|---|
| Residential |
| GS < 50 KW |
| GS > 50 Non TOU |
| #REF! |
| #REF! |
| #REF! |
| Small Scattered Load |
| #REF! |
| #REF! |
| Street Lighting |
| #REF! |
| #REF! |
| #REF! |
| #REF! |
| **Totals** |

**Hydro 2000 Inc.**

| Ex. | Tab | Schedule | Contents of Schedule |
|---|---|---|---|
| **6 – Cost of Capital and Rate of Return** | | | |
| | 1 | 1 | Overview |
| | | 2 | Capital Structure |
| | | 3 | Cost of Debt |
| | | 4 | Return on Equity |

## Hydro 2000 Inc.

## OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing the Applicant's capital requirements for the 2008 test years.

Capital Structure
The Applicant has a deemed capital structure of 50% debt, 50%, as approved by the Ontario Energy Board in RP-2005-0020 and a deemed return on equity of 9.0%, consistent with the return specified in the Board's Decision in EB-2005-0380, dated May 25th ,2006. The Applicant is requesting Board approval of a phased in capital structure of 60% debt, 40% equity including an equity return of 8.68%

The Applicant is requesting this change in capital structure and associated return on equity primarily to be consistent with board directive. The Applicant believes the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Return on Equity
The Applicant is requesting an equity return for the 2008 test year of 8.68%.

# Hydro 2000 Inc.

## CAPITAL STRUCTURE

### 2006 Board Approved

| 2006 Board Approved | | | | | |
|---|---|---|---|---|---|
| **Elements** | | **$** | **Ratio (%)** | **Interest Rate (%)** | **Return (%)** |
| | | | | | |
| **Long-term debt** | | 392,418 | 35.0% | 5.80% | |
| **Unfunded short-term debt** | | - | 0.0% | | |
| **Preference shares** | | - | 0.0% | | |
| **Common equity** | | 727,283 | 65.0% | | 9.00% |
| | | | | | |
| **Total** | | 1,119,701 | 100.0% | | |

### 2006 Actual

| 2006 Actual | | | | | |
|---|---|---|---|---|---|
| **Elements** | | **$** | **Ratio (%)** | **Interest Rate (%)** | **Return (%)** |
| | | | | | |
| **Long-term debt** | | 348,516 | 32.5% | 5.80% | |
| **Unfunded short-term debt** | | - | 0.0% | 4.77% | |
| **Preference shares** | | - | 0.0% | | |
| **Common equity** | | 722,244 | 67.5% | | 0.55% |
| | | | | | |
| **Total** | | 1,070,760 | 100.0% | | |

# Hydro 2000 Inc.

## 2007 Bridge

| 2007 Bridge | | | | | |
|---|---|---|---|---|---|
| **Elements** | | **$** | **Ratio (%)** | **Interst Rate (%)** | **Return (%)** |
| | | | | | |
| **Long-term debt** | | 324,713 | 31.7% | 5.80% | |
| **Unfunded short-term debt** | | - | 0.0% | 4.77% | |
| **Preference shares** | | - | 0.0% | | |
| **Common equity** | | 700,002 | 68.3% | | 8.68% |
| | | | | | |
| **Total** | | 1,024,715 | 100.0% | | |

## 2008 Test

| 2008 Test | | | | | |
|---|---|---|---|---|---|
| **Elements** | | **$** | **Ratio (%)** | **Interst Rate (%)** | **Return (%)** |
| | | | | | |
| **Long-term debt** | | 299,582 | 29.2% | 5.80% | |
| **Unfunded short-term debt** | | - | 0.0% | 4.77% | |
| **Preference shares** | | - | 0.0% | | |
| **Common equity** | | 726,740 | 70.8% | | 8.68% |
| | | | | | |
| **Total** | | 1,026,322 | 100.0% | | |

Hydro 2000 will follow Board directive and will apply for a capital structure of 60% debt and 40% common equity in its rate rebasing application.

At the current time Hydro 2000 Inc. is paying its long-term debt that will expire in 2017. The long-term Debt will decrease and common equity will increase yearly by the generated profits.

# Hydro 2000 Inc.

## COST OF DEBT

| COST OF DEBT | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 Board Approved | | | 2006 Actual | | | 2007 Bridge | | | 2008 Test | | |
| | Principle | Carrying Costs | Calculated Cost Rate | Principle | Carrying Costs | Calculated Cost Rate | Principle | Carrying Costs | Calculated Cost Rate | Principle | Carrying Costs | Calculated Cost Rate |
| **Long-Term Debt** | | | | | | | | | | | | |
| Township of Alfred and Plantagenet | 392,418 | 18,031 | 5.8% | 348,516 | 20,103 | 5.8% | 324,713 | 18,846 | 5.8% | 299,582 | 17,518 | 5.8% |
| Debt Holder 2 | | | | | | | | | | | | |
| Debt Holder 3 | | | | | | | | | | | | |
| Debt Holder 4 | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| Total | 392,418 | 18,031 | | 348,516 | 20,103 | | 324,713 | 18,846 | | 299,582 | 17,518 | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Short-Term Debt** | | | | | | | | | | | | |
| Debt Holder 1 | | | | | | | | | | | | |
| Unfunded Debt | | | | | | | | | | | | |
| Operating Loan | | | | | | | | | | | | |
| Total | - | - | | - | - | | - | - | | - | - | |

## Hydro 2000 Inc.

## RETURN ON EQUITY

The calculations used to determine the return on equity and the debt are taken from the “Report to the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario’s Electricity Distributors” issued December 20, 2006.

Excerpt from the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario’s Electricity Distributors Appendix A and Appendix B

Method to Update the Deemed Long-term Debt Rate

The Board will use the Long Canada Bond Forecast plus an average spread with “A/BBB” rated corporate bond yields to determine the updated deemed debt rate.

The following approach is consistent with the ROE method. As per the approach adopted in the 2006 EDRH, the ROE and the long-term debt rates are based on the same risk-free rate forecast. Therefore, they differ only through the risk premiums that reflect their distinct natures and for which lenders/investors seek commensurate returns. This approach simplifies the calculations and aims to make it easier to understand the numbers. Specifically, the Long Canada Bond Forecast (*LCBFt*) used will be the same as that used for updating the ROE. The average spread between “A/BBB” rated corporate bond yields and 30-year (long) Government of Canada Bond yields will be calculated as the average spread over the weeks of the month corresponding to the Consensus Forecasts.

The deemed Long-Term Debt Rate (*LTDRt*) will be calculated as follows:

$$LTDR_t = LCBF_t + \frac{\sum_w (CorpBonds_{w,t} - {}_{30}CB_{w,t})}{n}$$

Where:

- ***CorpBonds*** $_{w,t}$ is the average long-term corporate bond yield from Scotia Capital Inc. for week *w* of period *t* [Series V121761];

- $_{30}CB_{w,t}$ is the 30-year (long) Government of Canada bond yield for week *w* of period *t* [Series V121791]; and

- ***n*** is the number of weeks in the month for which data are reported.

**Hydro 2000 Inc.**

Method to Update ROE - ROE Update for any Period

Using March 1999 as the starting calculation and substituting for the initial ROE and Long Canada Bond Forecast approved by the Board in the Decision RP-1998-0001 the following is the adjustment formula for calculating the ROE at time *t*:

$$ROE_t = 9.35\% \quad + 0.75 \times (LCBF_t - 5.50\%)$$

The ROE must be set in advance of the approved rates. The final ROE will be factored into rates using the Long Canada Bond Forecast based on *Consensus Forecasts* (as detailed below) and Bank of Canada data three months in advance of the effective date for the rate change. Therefore, for May 1 rate changes, the ROE will be based on January data – effectively *Consensus Forecasts* published during that month and Bank of Canada data for all business days during the month of January. The necessary data is available within the first or second business days after the end of the month and thus poses no delay for determining rates.

***Long Canada Bond Forecast for any Period***

For any period *t* the Long Canada Bond Forecast *LCBFt* can be expressed as:

$$LCBF_t = \left[ \frac{{}_{10}CBF_{3,t} + {}_{10}CBF_{12,t}}{2} \right] + \frac{\sum_i ({}_{30}CB_{i,t} - {}_{10}CB_{i,t})}{I_t}$$

Where:

**$_{10}CB_{3,T}$** is the 3-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;

**$_{10}CB_{12,t}$** is the 12-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;

**$_{30}CB_{i,t}$** is the actual rate for the 30-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39056] during the month (this is the previous month data, the same as used for updating the ROE for natural gas distribution) corresponding to time *t*;

**$_{10}CB_{i,t}$** is the actual rate for the 10-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39055] during the month corresponding to time *t*; and

***It*** is the number of business days for which published 10- and 30- Government of Canada bond yields are published during the month corresponding to time *t*.

**Hydro 2000 Inc.**

**Hydro 2000 Inc.**

# Hydro 2000 Inc.

| Ex. | Tab | Schedule | Contents of Schedule |
|---|---|---|---|
| **7 - Calculation of Revenue Deficiency or Surplus** | | | |
| | 1 | 1 | Determination of Net Utility Income and Calculation of Revenue Deficiency or Surplus |

## Hydro 2000 Inc.

## OVERVIEW OF CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

This exhibit presents an overview of the revenue deficiency or surplus calculations process for the 2008 test year.

| **Rate Class 2008 test Year Proposed Rates** | **Number of Customers Or Connections** | **Volume (kWh or kW)** | **Proposed Fixed Charge** | **Proposed Volumetric Charge** | **Proposed Revenue at Proposed Rates** |
|---|---|---|---|---|---|
| **Residential** | 1005 | 16,514,191 | $ 10.71 | $0.0123 | $ 332,287.15 |
| **GS less 50kW** | 147 | 5,682,016 | $ 24.78 | $0.0135 | $ 120,419.14 |
| **GS 0ver 50 kW** | 12 | 13,280 | $ 120.28 | 3.4844 | $ 63,593.15 |
| **Unmetered scattered load** | 6 | 19,951 | $ 6.00 | $0.0334 | $ 1,098.36 |
| **STREET LIGHT** | 368 | 941 | $ 0.54 | 7.7596 | $ 9,686.42 |
| | | | | | |
| **TOTAL** | | | | | $ 527,084.22 |

| **Rate Class Bridge year Existing Rates** | **Number of Customers Or Connections** | **Volume (kWh or kW)** | **Proposed Fixed Charge** | **Proposed Volumetric Charge** | **Proposed Revenue at Proposed Rates** |
|---|---|---|---|---|---|
| **Residential** | 1005 | 16,514,191 | $ 8.20 | $0.0086 | $ 240,914.04 |
| **GS less 50kW** | 147 | 5,682,016 | $ 11.90 | $0.0098 | $ 76,675.36 |
| **GS 0ver 50 kW** | 12 | 13,280 | $ 63.79 | 2.3555 | $ 40,466.80 |
| **Unmetered scattered load** | 6 | 19,951 | $ 5.82 | $0.0098 | $ 614.56 |
| **STREET LIGHT** | 368 | 941 | $ 0.17 | 2.2284 | $ 2,847.64 |
| | | | | | |
| **TOTAL** | | | | | $ 361,518.40 |

## Hydro 2000 Inc.

| **Determination of Net Utility Income** | | | |
|---|---|---|---|
| | 2008 Test Existing Rates | 2008 Test Proposed Rates | Revenue Surplus or (Deficiency) |
| **Revenue** | | | |
| Distribution Revenue | $ 255,277 | $ 366,734 | $ -111,457 |
| PILS | $ - | $ 39,350 | $ -39,350 |
| LV Charges | $ 106,241 | $ 121,000 | $ -14,759 |
| **Distribution Revenue** | $ 361,518 | $ 527,084 | $ -165,566 |
| Other Operating Revenue (Net) | $ 35,980 | $ 35,980 | $ - |
| **Total Revenue** | $ 397,498 | $ 563,064 | $ -165,566 |
| | | | $ - |
| **Costs and Expenses** | | | $ - |
| Distribution Costs | $ 285,289 | $ 285,289 | $ - |
| Operation & Maintenance | $ 4,455 | $ 4,455 | $ - |
| Depreciation & Amortization | $ 56,569 | $ 56,569 | $ - |
| Property & Capital Taxes | $ - | $ - | $ - |
| Interest | $ 20,333 | $ 20,333 | $ - |
| **Total Costs and Expenses** | $ 366,646 | $ 366,646 | $ - |
| | | | $ - |
| Utility Income Before Income Taxes | $ 30,852 | $ 196,418 | $ -165,566 |
| others | $ 300 | $ 300 | $ - |
| Income Taxes | $ 924 | $ 924 | $ - |
| | | | $ - |
| Utility Income | $ 29,628 | $ 195,494 | $ -165,866 |

On the previous page the first table shows a $527,084 for the total distribution revenues with the proposed 2008 rates compare to a $361,518 for the total distribution revenues with the existing rates. The revenue deficiency is $165,866. Four major items are contributing to the increase of the surplus if we compare it to the old existing rates

The First item was that Hydro 2000 Inc. had a big loss carry forward until 2006 and no PILS were included in the existing rates.

## Hydro 2000 Inc.

The Second item was that the LV charges to Hydro 2000 were under estimated by H.O.N.I. The first and second items were mentioned by letter to the Board. The variances are captured in Deferral accounts as requested by the Board.

The third item was the focus on the opening market was on the operations and all the challenges associated. Capital projects on the distribution system were delayed in the future years. Those future years are 2007 and 2008. From 2002 to 2005 capital projects performed were minimal and was for system reliability and safety.

# Hydro 2000 Inc.

## DETERMINATION OF NET UTILITY INCOME

| Determination of Net Utility Income | | | |
|---|---|---|---|
| | 2008 Test Existing Rates | 2008 Test Proposed Rates | Revenue Surplus or Defficiency |
| **Revenue** | | | |
| Distribution Revenue | $ 255,277 | $ 366,734 | $ 111,457 |
| PILS | $ - | $ 39,350 | $ 39,350 |
| LV Charges | $ 106,241 | $ 121,000 | $ 14,759 |
| **Distribution Revenue** | $ 361,518 | $ 527,084 | $ 165,566 |
| Other Operating Revenue (Net) | $ 35,980 | $ 35,980 | $ - |
| **Total Revenue** | $ 397,498 | $ 563,064 | $ 165,566 |
| | | | $ - |
| **Costs and Expenses** | | | $ - |
| Distribution Costs | $ 285,289 | $ 285,289 | $ - |
| Operation & Maintenance | $ 4,455 | $ 4,455 | $ - |
| Depreciation & Amortization | $ 56,569 | $ 56,569 | $ - |
| Property & Capital Taxes | $ - | $ - | $ - |
| Interest | $ 20,333 | $ 20,333 | $ - |
| **Total Costs and Expenses** | $ 366,646 | $ 366,646 | $ - |
| | | | $ - |
| Utility Income Before Income Taxes | $ 30,852 | $ 196,418 | $ 165,566 |
| others | $ 300 | $ 300 | $ - |
| Income Taxes | $ 924 | $ 924 | $ - |
| | | | $ - |
| Utility Income | $ 29,628 | $ 195,494 | $ 165,866 |

The anticipated net profit for 2008 should be $195,494 based on load forecast consumption.

# Hydro 2000 Inc.


| Ex. | Tab | Schedule | Contents of Schedule |
|---|---|---|---|
| **8 – Cost Allocation** | | | |
| | 1 | 1 | Cost Allocation Overview |
| | | 2 | Summary of Results and Proposed Changes |

## Hydro 2000 Inc.

## COST ALLOCATION OVERVIEW

Introduction:

On September 29, 2006 the Ontario Energy Board (the "OEB") issued the Board directions on Cost Allocation Methodology for Electricity Distributors ("the Directions"). On November 15, 2006 the OEB also issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model ("the Model") and User Instruction (the Instructions") for the Model. The Applicant prepared this information filing consistent with The Applicant's understanding of the Directions, the Guidelines, the Model and the Instructions.

The main purpose of this cost allocation filing was to provide evidence to show The Applicant rate classifications that are being subsidized by other classes and those rate classifications that are over contributing based on the assumptions of the Model.

Background:

In the mid 1980's, Ontario Hydro, the regulator at the time, completed the last cost allocation study that reflected the distribution function but this was an integrated cost study. The integrated study reviewed the full costs of providing electricity to customers which included energy, transmission and distribution. Distribution represented only around 15% of the total costs reviewed. The results of this study assisted Ontario Hydro in developing the Rate Setting Guidelines that were used by Municipal Electric Utilities to develop the bundled rates they charged customers up until around 2000.

Under the Energy Competition Act, 1998, the electricity industry in Ontario was separated into Generation, Transmission and Distribution companies. Along with this separation the rates also needed to be unbundled to reflect the structure of the new companies. The unbundling of distribution from generation and transmission was completed in the 2000 to 2001 timeframe using the Electricity Distribution Rate Handbook Rate and the Rate Unbundling and Design Model (i.e. the RUD model). The Rate Handbook and RUD model provided a method to unbundle distribution rates from the other rates by rate classification but it did not determine whether the unbundled rates collected the cost of providing service to the rate classification. The current cost allocation process is the first time a cost allocation study has been conducted in Ontario that focuses completely on distribution to determine whether or not the distribution rates are collecting the cost of providing service to the rate classifications.

The filing was comprised of a first run ("Run 1") and a second run ("Run 2"). An optional Run 3 was available but in the Applicant's case, was not conducted. For The Applicant, Run 1 reflects the rate classifications as they were prior to May 1, 2006. Prior to May 1, the Unmetered Scattered Load ("USL") customers were included in the General Service < 50 kW rate classification. Run 2 has the USL customers pulled out of the General Service < 50 kW class to form a class of their own which is consistent with the current rate classifications used by The Applicant.

**Hydro 2000 Inc.**

In order to prepare this cost allocation filing, The Applicant used the services of Hydro One to prepare load data profiles by rate classification.

## Hydro 2000 Inc.

## SUMMARY OF RESULTS AND PROPOSED CHANGES

The cost/financial data used in the Model is consistent with the Applicant's cost data that supports the 2006 approved distribution rates. Consistent with the Guidelines, The Applicant assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available from The Applicant's customer and financial information systems.

The results of a cost allocation are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage shows the rate classifications that are being subsidized and those that are over contributing. A percentage of less than 100% means the rate classification is under collecting and is being subsidized by other classes. A percentage of greater than 100% indicates the rate classification is over collecting the cost assigned to the classification and is subsidizing other classes.

The following outlines the revenue to cost ratios for Run 2. The results for Run 1 are similar. In Run 1, the USL rate classification is combined with the General Service < 50 kW rate classification. As a result, the cost to revenue ratio in Run 1 for General Service < 50 kW customers is 78.27% and there is no ratio for USL. All other ratios in Run 1 are essentially the same as Run 2.

### SUMMARY OF RESULTS

| Rate Classification | Revenue to Cost Ratio | ($Being Subsidized)/ $Over Contributing |
|---|---|---|
| Residential | 115.00% | $24,623 |
| General Service <50 kW | 81.44% | -$13,543 |
| General Service >50 kW | 94.50% | -$1,438 |
| Street Lights | 50.34% | -$4,487 |
| USL | 10.49% | -$5,155 |
| Total | 100% | $0.00 |

**Hydro 2000 Inc.**

Monthly Fixed Charge Comparison

The Model produces customer unit costs per month for each rate classification. To assist with reviewing the range of current fixed monthly service charges, the Model generates three scenarios of reasonable cost-based customer unit costs for each rate classification. These unit costs are determined by the Model and compared to the current approved monthly service charge.

Scenario 1: Avoided Costs

With a strict “avoided cost” approach, only meter related costs, billing and collection costs are included. This approach has the advantage of focusing on the immediate costs of an additional customer. But no administration and general overhead costs are applied.

Scenario 2: Directly Related Customer Costs

The directly related customer costs are those costs included in the avoided cost version but an allocation of administration and general overhead costs is included.

Scenario 3: Minimum System Approach

The minimum system approach assumes that a minimum-size distribution system can be built to serve the minimum load requirements of the customer. For the purposes of this filing the minimum load requirement is assumed to be 400 watts per customer. The minimum system method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the distributor. Once determined for each plant account, the minimum size distribution system is classified as customer-related costs and then used to define the monthly unit customer cost.

There are various approaches to define the minimum system. Moreover, judgment is required to address various implementation details with this methodology. The OEB cost allocation project did not seek to develop a common minimum system methodology for use by the Ontario electricity distribution sector. Instead, the results of numerous past Ontario minimum system studies were examined and approved for use in the Model.

The minimum system results are applied to the following accounts:

- Line Transformers (Account 1850)
- “Distribution” which includes poles and conductors, and is defined as Accounts 1830 -1845
- Related O&M accounts.

The density of the distributor (i.e. customers/route kilometer of line) is the major factor that determines the percentage of the above costs which are included in the customer costs. The density of The Applicant is 56 customers/km. This means The Applicant is classified as a medium density distributor. As a result, 40% of The Applicant’s

**Hydro 2000 Inc.**

distribution costs (i.e. lines, poles and line transformers) are defined to be customer related cost. The monthly customer unit cost under the minimum system approach includes the directly related customer costs plus 100% of distribution costs with any administration and general overhead associated with the distribution costs.

The following outlines the monthly fixed cost comparison.

**SUMMARY OF MONTHLY SERVICE CHARGE**

| Rate Classification | 2006 Approved Fixed Charge | Minimum System Fixed Charge | Directly Related Fixed Charge | Avoided Cost Fixed Charge |
|---|---|---|---|---|
| Residential | 8.13 | 10.71 | 8.50 | 3.88 |
| General Service <50 kW | 11.80 | 34.78 | 34.33 | 16.19 |
| General Service >50 kW | 63.22 | 116.87 | 120.28 | 55.34 |
| Street Lights | .17 | 2.14 | .05 | .02 |
| USL | 5.77 | 151.5 | 157.24 | 70.47 |

In reviewing the results produced by the Cost Allocation Model, The Applicant proposes the following Monthly fixed Charges.

**PROPOSED MONTHLY SERVICE CHARGE**

| Rate Classification | 2006 Approved Fixed Charge | Proposed Fixed Charge |
|---|---|---|
| Residential | 8.13 | 10.71 |
| General Service <50 kW | 11.80 | 24.78 |
| General Service >50 kW | 63.22 | 120.28 |
| Street Lights | 0.17 | 0.54 |
| USL | 5.77 | 10.34 |

The Applicant proposes to move its Monthly Fixed Charges to Maximum fixed Charges of Cost Allocation in the scenario 3 of the Minimum System Approach. Some classes were move to the maximum and some classes were moved partially to the maximum to minimize major bill impact. In moving the Fixed charges the intent is to move to a 40% to 60% level of the class revenue requirement.

## Hydro 2000 Inc.


| Ex. | Tab | Schedule | Contents of Schedule |
|---|---|---|---|
| **9 - Rate Design** | | | |
| | 1 | 1 | Rate Design Overview |
| | | 2 | Rate Mitigation |
| | | 3 | Existing Rate Classes |
| | | 4 | Existing Rate Schedule |
| | | 5 | Proposed Rate Classes if different than existing |
| | | 6 | Proposed Rate Schedule |
| | | 7 | Summary of Proposed Rate Schedule |
| | | 8 | Reconciliation of Rate Class Revenue to total Revenue Requirement |
| | | 9 | Rate Impacts |
| | | 10 | Proposed Changes to Terms and Conditions of Service |

**Hydro 2000 Inc.**

## RATE DESIGN OVERVIEW

This exhibit presents an overview of the process to allocate The Applicant's related revenue requirement costs for the forecasted 2008 test year to the respective rate classes. This exhibit documents, by rate class, the proposed changes in distribution for the 2008 test year.

The total revenue requirement of $529,522 for 2008 Test, excluding miscellaneous revenues, was calculated in Exhibit 9, Tab 1, Schedule 8 and needs to be allocated to the respective customer classes for consideration in respect of rate design. The method of allocating these costs to the customer classes uses various steps to apportion the costs amongst all LDC customer class

The following steps are followed to derive the revenues collected from fixed and variable rates under the proposed 2008 rates.

Step 1 – Based on information in the cost allocation section revenues are allocated to each rate class to reflect the proposed movement in revenue cost ratios

Step 2 – Based on the proposed monthly service charge also outlined in the cost allocation section the fixed revenues for each rate class is determined.

Step 3 – The amount in step 2 is subtracted from the amount in Step 1 and divided by the 2008 forecasted energy sales by class to determine the volumetric charge by customer class.

**Hydro 2000 Inc.**

## RATE MITIGATION

**Hydro 2000 Inc. does not apply for any rate mitigation.**

# Hydro 2000 Inc.

## EXISTING RATE CLASSES

Residential

This class refers to the supply of electrical energy to detached and semi-detached residential buildings as well as farms as defined in the local zoning by-laws. Where the residential dwelling comprises the entire electrical load of a farm, it is defined as a residential service. Where electricity is provided to a combined residential and business (including agricultural usage) and the service does not provide for separate metering, the classification shall be at the discretion of Hydro 2000 and shall be based on such considerations as the estimated predominant consumption.

General Service Less Than 50kW

This class refers to customers who do not qualify as residential customers and whose monthly average peak demand in the preceding twelve months is less than 50kW. For new customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformation. Note: Apartment buildings or multi-unit complexes and subdivisions are treated as General Service (Above 50 kW).

General Service  Over 50W

This class refers to customers whose monthly average peak demand in the preceding twelve months is in over 50kW. There are two sub categories within this class, those being non-interval and interval metered accounts. For new customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformation.

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, pedestrian X-Walk signals/beacons, 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.

Street Lighting

All services supplied to street lighting equipment owned by or operated for the Municipality, the Region or the Province of Ontario shall be classified as Street Lighting Service. Street Lighting plant, facilities, or equipment owned by the customer are subject to the Electrical Safety Authority (ESA) requirements and Hydro 2000 specifications.

# Hydro 2000 Inc.

## EXISTING RATE SCHEDULE

| **Residential** | **UOM** | **Rate** |
|---|---|---|
| Service Charge | $ | $ 8.20 |
| Distribution Volumetric Rate | $/kWh | $0.0086 |
| Regulatory Asset Recovery | $/kWh | $0.0098 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $0.0057 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $0.0050 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

| **General Service less 50kW** | | |
|---|---|---|
| Service Charge | $ | $11.80 |
| Distribution Volumetric Rate | $/kWh | $0.0098 |
| Regulatory Asset Recovery | $/kWh | $0.0075 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $0.0052 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $0.0045 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

| **General Service Over 50kW** | | |
|---|---|---|
| Service Charge | $ | $63.79 |
| Distribution Volumetric Rate | $/kW | $2.3555 |
| Regulatory Asset Recovery | $/kW | $2.2403 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $2.1218 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $1.7882 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

| **Unmetered Scattered Load** | | |
|---|---|---|
| Service Charge | $ | $5.82 |
| Distribution Volumetric Rate | $/kWh | $0.0098 |
| Regulatory Asset Recovery | $/kWh | $0.0075 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $0.0052 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $0.0045 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

# Hydro 2000 Inc.

**Street Light**

| | | |
|---|---|---|
| Service Charge | $ | $0.17 |
| Distribution Volumetric Rate | $/kW | 2.2284 |
| Regulatory Asset Recovery | $/kW | -$1.7676 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $1.6002 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $1.3824 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

## Hydro 2000 Inc.

## PROPOSED RATE CLASSES

Residential

This class refers to the supply of electrical energy to detached and semi-detached residential buildings as well as farms as defined in the local zoning by-laws. Where the residential dwelling comprises the entire electrical load of a farm, it is defined as a residential service. Where electricity is provided to a combined residential and business (including agricultural usage) and the service does not provide for separate metering, the classification shall be at the discretion of Hydro 2000 and shall be based on such considerations as the estimated predominant consumption.

General Service Less Than 50kW

This class refers to customers who do not qualify as residential customers and whose monthly average peak demand in the preceding twelve months is less than 50kW. For new customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformation. Note: Apartment buildings or multi-unit complexes and subdivisions are treated as General Service (Above 50 kW).

General Service Over 50W

This class refers to customers whose monthly average peak demand in the preceding twelve months is in over 50kW. There are two sub categories within this class, those being non-interval and interval metered accounts. For new customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformation.

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, pedestrian X-Walk signals/beacons, 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.

Street Lighting

All services supplied to street lighting equipment owned by or operated for the Municipality, the Region or the Province of Ontario shall be classified as Street Lighting Service. Street Lighting plant, facilities, or equipment owned by the customer are subject to the Electrical Safety Authority (ESA) requirements and Hydro 2000 specifications.

# Hydro 2000 Inc.

## PROPOSED RATE SCHEDULE

| **Residential** | **UOM** | **Rate** |
|---|---|---|
| Service Charge | $ | $10.71 |
| Distribution Volumetric Rate | $/kWh | $0.0123 |
| Regulatory Asset Recovery | $/kWh | $0.0032 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $0.0057 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $0.0050 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

| **General Service less 50kW** | | |
|---|---|---|
| Service Charge | $ | $24.78 |
| Distribution Volumetric Rate | $/kWh | $0.0135 |
| Regulatory Asset Recovery | $/kWh | $0.0029 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $0.0052 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $0.0045 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

| **General Service Over 50kW** | | |
|---|---|---|
| Service Charge | $ | $120.28 |
| Distribution Volumetric Rate | $/kW | $3.4844 |
| Regulatory Asset Recovery | $/kW | $1.0468 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $2.1218 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $1.7882 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

| **Unmetered Scattered Load** | | |
|---|---|---|
| Service Charge | $ | $6.00 |
| Distribution Volumetric Rate | $/kWh | $0.0334 |
| Regulatory Asset Recovery | $/kWh | $0.0029 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $0.0052 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $0.0045 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

# Hydro 2000 Inc.

**Street Light**

| | | |
|---|---|---|
| Service Charge | $ | $0.54 |
| Distribution Volumetric Rate | $/kW | 7.7596 |
| Regulatory Asset Recovery | $/kW | $0.406 |
| Retail Transmission Rate – Network Service Rate | $/kWh | $1.6002 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | $1.3824 |
| Wholesale Market Service Rate | $/kWh | $0.0052 |
| Rural Rate Protection Charge | $/kWh | $0.0010 |
| Regulated Price Plan – Administration Charge | $ | $0.25 |

**Hydro 2000 Inc.**

## SUMMARY OF PROPOSED RATE SCHEDULE

The following is a summary of the proposed changes to The Applicant's rates for the 2008 test year. The Applicant is forecasting a distribution related delivery deficiency for the 2008 test year of $165,866.

**The impact on each rate class is described below.**

### Residential

The proposed changes to residential class are summarized below.

| Residential | 2006 Board Approved | 2008 Proposed | % change |
|---|---|---|---|
| Service Charge | $8.13 | $10.71 | 31.7% |
| Distribution Volumetric Rate | $0.0085 | $0.0124 | 44.7% |
| Regulatory Asset Rate | $0.0098 | $0.0032 | -67.3% |

In order to increase the fixed cost recovery through the monthly fixed charge, The Applicant's proposing to increase the monthly customer charge by $2.58 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for rate Residential customers (from 66.35% to 63.52%).

The overall bill impact on a typical residential customer with a consumption of 1000 kWhs is an increase of 0.0% shown in detail in Exhibit 9, Tab1, Schedule 10.

**Hydro 2000 Inc.**

## General Service less than 50 kW

The proposed changes to General Service less than 50 kW class are summarized below.

| GS less 50kW | 2006 Board Approved | 2008 Proposed | % change |
|---|---|---|---|
| Service Charge | $11.90 | $24.78 | 108.24% |
| Distribution Volumetric Rate | $0.0097 | $0.0136 | 39.18% |
| Regulatory Asset Rate | $0.0075 | $0.0029 | -61.33% |

In order to increase the fixed cost recovery through the monthly fixed charge, The Applicant's proposing to increase the monthly customer charge by $12.88 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for rate General Service Less Than 50 kW customers (from 21.63% to 23.89%).

The overall bill impact on a typical General Service less than 50 kW customer with a consumption of 5000 kWhs is an increase of 2.0% shown in detail in Exhibit 9, Tab1, Schedule 10.

## General Service over than 50 kW

The proposed changes to General Service over 50 kW class are summarized below.

| GS over 50kW | 2006 Board Approved | 2008 Proposed | % change |
|---|---|---|---|
| Service Charge | $63.22 | $120.28 | 90.26% |
| Distribution Volumetric Rate | $2.3345 | $3.4978 | 49.26% |
| Regulatory Asset Rate | $2.2403 | $1.0468 | -53.27% |

In order to increase the fixed cost recovery through the monthly fixed charge, The Applicant's proposing to increase the monthly customer charge by $57.06 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for rate to General Service Over 50 kW customers (from 11.25% to 10.25%).

## Hydro 2000 Inc.

The overall bill impact on a typical General Service less over 50 kW customer with a consumption of 40,000 kWhs and 100 kWs is an increase of 1.7% shown in detail in Exhibit 9, Tab1, Schedule 10.

**Unmetered Scattered Load**

The proposed changes to Unmetered Scattered Load class are summarized below.

| Unmetered scattered load | 2006 Board Approved | 2008 Proposed | % change |
|---|---|---|---|
| Service Charge | $5.77 | $6.00 | 3.99% |
| Distribution Volumetric Rate | $0.0097 | $0.0336 | 244.33% |
| Regulatory Asset Rate | $0.0075 | $0.0029 | -61.33% |

In order to increase the fixed cost recovery through the monthly fixed charge, The Applicant's proposing to increase the monthly customer charge by $4.57 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for rate to Unmetered Scattered Load customers (from .17% to .25%).

The overall bill impact on a typical Unmetered Scattered Load customer with a consumption of 500 kWhs and 0 kWs is an increase of 14.9% shown in detail in Exhibit 9, Tab1, Schedule 10.

# Hydro 2000 Inc.

Street Light
The proposed changes to Street Light are summarized below.

| Street light | 2006 Board Approved | 2008 Proposed | % change |
|---|---|---|---|
| Service Charge | $0.170 | $0.54 | 217.65% |
| Distribution Volumetric Rate | $2.2085 | $7.7980 | 251.35% |
| Regulatory Asset Rate | ($1.7676) | $0.4060 | -122.97% |

In order to increase the fixed cost recovery through the monthly fixed charge, The Applicant's proposing to increase the monthly customer charge by $0.54 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for rate to Street Light customers (from .79% to 2.09%).

The overall bill impact on a typical Unmetered Scattered Load customer with a consumption of 25,000 kWhs and 77 kWs is an increase of 21.9% shown in detail in Exhibit 9, Tab1, Schedule 10.

## Hydro 2000 Inc.

## RECONCILLIATION OF RATE CLASS REVENUE TO TOTAL REVENUE REQUIREMENT

| Rate Class | Number of Customers Or Connections | Volume (kWh or kW) | Proposed Fixed Charge | Proposed Volumetric Charge | Proposed Revenue at Proposed Rates |
|---|---|---|---|---|---|
| **Residential** | 1005 | 16,514,191 | $ 10.71 | $0.0123 | $ 332,287.15 |
| **GS less 50kW** | 147 | 5,682,016 | $ 24.78 | $0.0135 | $ 120,419.14 |
| **GS 0ver 50 kW** | 12 | 13,280 | $ 120.28 | 3.4844 | $ 63,593.15 |
| **Unmetered scattered load** | 6 | 19,951 | $ 6.00 | $0.0334 | $ 1,098.36 |
| **Rate Class 5** | 368 | 941 | $ 0.54 | 7.7596 | $ 9,686.42 |
| | | | | | |
| **TOTAL** | | | | | $ 527,084.22 |

# Hydro 2000 Inc.

## RATE IMPACTS

This exhibit presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are derived using the applicable May 1, 2007 rates and the proposed 2008 distribution rates, (including Rate Rider for the recovery of Regulatory Asset Variance Accounts) and maintaining the 2006 Retail Transmission Service Rates at existing 2006 levels.

The total bill impacts are calculated for the average customer per residential rate class and for General Service Classes at certain levels of consumption. The rates are assessed on the basis of moving to the proposed distribution rates derived in Exhibit 9, Tab 1, Schedule 7, including the Rate Rider for the recovery of regulatory asset variance accounts derived in Exhibit 5, Tab 1,Schedule 3. The total bill impacts are premised on the distribution rates arising from the new revenue requirements. All other non-distribution charges, except RTSR charges, are kept unchanged.

The bill impact includes Commodity prices.

# Hydro 2000 Inc.

| Residential<br>100 kWh | Metric | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume | Rate $ | Charge $ | Volume | Rate $ | Charge $ | Change $ | Change % | % of Total Bill |
| Monthly Service Charge | | | | 8.20000 | | | 10.71 | 2.51 | 30.6% | 12.0% |
| Distribution | kWh | 100 | 0.00860 | 0.86000 | 100 | 0.01230 | 1.23 | 0.37 | 43.0% | 1.8% |
| Regulatory Asset Recovery | kWh | 100 | 0.00980 | 0.98 | 100 | 0.00320 | 0.32 | (0.66) | -67.3% | -3.2% |
| Retail Transmission - Network | kWh | 106 | 0.00570 | 0.60 | 107 | 0.00570 | 0.61 | 0.00 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 106 | 0.00500 | 0.53 | 107 | 0.00500 | 0.53 | 0.00 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 106 | 0.00520 | 0.55 | 107 | 0.00520 | 0.55 | 0.00 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 106 | 0.00100 | 0.11 | 107 | 0.00100 | 0.11 | 0.00 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 100 | 0.00700 | 0.70 | 100 | 0.00700 | 0.70 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 106 | 0.05704 | 6.05 | 107 | 0.05704 | 6.08 | 0.03 | 0.6% | 0.2% |
| **Total Bill** | | | | **18.58** | | | **20.84** | **2.26** | **12.2%** | **10.9%** |

| Residential<br>250 kWh | Metric | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume | Rate $ | Charge $ | Volume | Rate $ | Charge $ | Change $ | Change % | % of Total Bill |
| Monthly Service Charge | | | | 8.20 | | | 10.71 | 2.51 | 30.6% | 7.0% |
| Distribution | kWh | 250 | 0.00860 | 2.15 | 250 | 0.01230 | 3.08 | 0.93 | 43.0% | 2.6% |
| Regulatory Asset Recovery | kWh | 250 | 0.00980 | 2.45 | 250 | 0.00320 | 0.80 | (1.65) | -67.3% | -4.6% |
| Retail Transmission - Network | kWh | 265 | 0.00570 | 1.51 | 267 | 0.00570 | 1.52 | 0.01 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 265 | 0.00500 | 1.33 | 267 | 0.00500 | 1.33 | 0.01 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 265 | 0.00520 | 1.38 | 267 | 0.00520 | 1.39 | 0.01 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 265 | 0.00100 | 0.27 | 267 | 0.00100 | 0.27 | 0.00 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 250 | 0.00700 | 1.75 | 250 | 0.00700 | 1.75 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 265 | 0.05704 | 15.12 | 267 | 0.05704 | 15.20 | 0.09 | 0.6% | 0.2% |
| **Total Bill** | | | | **34.15** | | | **36.04** | **1.90** | **5.6%** | **5.3%** |

# Hydro 2000 Inc.

| **Residential** 500 kWh | Metric | 2007 BILL Volume | Rate $ | Charge $ | 2008 BILL Volume | Rate $ | Charge $ | IMPACT Change $ | Change % | % of Total Bill |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | | | 8.20 | | | 10.71 | 2.51 | 30.6% | 4.1% |
| Distribution | kWh | 500 | 0.00860 | 4.30 | 500 | 0.01230 | 6.15 | 1.85 | 43.0% | 3.0% |
| Regulatory Asset Recovery | kWh | 500 | 0.00980 | 4.90 | 500 | 0.00320 | 1.60 | (3.30) | -67.3% | -5.4% |
| Retail Transmission - Network | kWh | 530 | 0.00570 | 3.02 | 533 | 0.00570 | 3.04 | 0.02 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 530 | 0.00500 | 2.65 | 533 | 0.00500 | 2.67 | 0.02 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 530 | 0.00520 | 2.76 | 533 | 0.00520 | 2.77 | 0.02 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 530 | 0.00100 | 0.53 | 533 | 0.00100 | 0.53 | 0.00 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 500 | 0.00700 | 3.50 | 500 | 0.00700 | 3.50 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 530 | 0.05704 | 30.23 | 533 | 0.05704 | 30.41 | 0.17 | 0.6% | 0.3% |
| **Total Bill** | | | | **60.09** | | | **61.37** | **1.28** | **2.1%** | **2.1%** |

| **Residential** 750 kWh | Metric | 2007 BILL Volume | Rate $ | Charge $ | 2008 BILL Volume | Rate $ | Charge $ | IMPACT Change $ | Change % | % of Total Bill |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | | | 8.20 | | | 10.71 | 2.51 | 30.6% | 2.9% |
| Distribution | kWh | 750 | 0.00860 | 6.45 | 750 | 0.01230 | 9.23 | 2.78 | 43.0% | 3.2% |
| Regulatory Asset Recovery | kWh | 750 | 0.00980 | 7.35 | 750 | 0.00320 | 2.40 | (4.95) | -67.3% | -5.7% |
| Retail Transmission - Network | kWh | 795 | 0.00570 | 4.53 | 800 | 0.00570 | 4.56 | 0.03 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 795 | 0.00500 | 3.98 | 800 | 0.00500 | 4.00 | 0.02 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 795 | 0.00520 | 4.13 | 800 | 0.00520 | 4.16 | 0.02 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 795 | 0.00100 | 0.80 | 800 | 0.00100 | 0.80 | 0.00 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 750 | 0.00700 | 5.25 | 750 | 0.00700 | 5.25 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 795 | 0.05704 | 45.35 | 800 | 0.05704 | 45.61 | 0.26 | 0.6% | 0.3% |
| **Total Bill** | | | | **86.04** | | | **86.71** | **0.67** | **0.8%** | **0.8%** |

# Hydro 2000 Inc.

| Residential 1000 kWh | Metric | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume | Rate $ | Charge $ | Volume | Rate $ | Charge $ | Change $ | Change % | % of Total Bill |
| Monthly Service Charge | | | | 8.20 | | | 10.71 | 2.51 | 30.6% | 2.2% |
| Distribution | kWh | 1,000 | 0.00860 | 8.60 | 1,000 | 0.01230 | 12.30 | 3.70 | 43.0% | 3.3% |
| Regulatory Asset Recovery | kWh | 1,000 | 0.00980 | 9.80 | 1,000 | 0.00320 | 3.20 | (6.60) | -67.3% | -5.9% |
| Retail Transmission - Network | kWh | 1,060 | 0.00570 | 6.04 | 1,066 | 0.00570 | 6.08 | 0.03 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 1,060 | 0.00500 | 5.30 | 1,066 | 0.00500 | 5.33 | 0.03 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 1,060 | 0.00520 | 5.51 | 1,066 | 0.00520 | 5.54 | 0.03 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 1,060 | 0.00100 | 1.06 | 1,066 | 0.00100 | 1.07 | 0.01 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 1,000 | 0.00700 | 7.00 | 1,000 | 0.00700 | 7.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 1,060 | 0.05704 | 60.47 | 1,066 | 0.05704 | 60.81 | 0.34 | 0.6% | 0.3% |
| **Total Bill** | | | | **111.98** | | | **112.04** | **0.05** | **0.0%** | **0.0%** |

| Residential 1500 kWh | Metric | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume | Rate $ | Charge $ | Volume | Rate $ | Charge $ | Change $ | Change % | % of Total Bill |
| Monthly Service Charge | | | | 8.20 | | | 10.71 | 2.51 | 30.6% | 1.5% |
| Distribution | kWh | 1,500 | 0.00860 | 12.90 | 1,500 | 0.01230 | 18.45 | 5.55 | 43.0% | 3.4% |
| Regulatory Asset Recovery | kWh | 1,500 | 0.00980 | 14.70 | 1,500 | 0.00320 | 4.80 | (9.90) | -67.3% | -6.1% |
| Retail Transmission - Network | kWh | 1,590 | 0.00570 | 9.06 | 1,599 | 0.00570 | 9.12 | 0.05 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 1,590 | 0.00500 | 7.95 | 1,599 | 0.00500 | 8.00 | 0.05 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 1,590 | 0.00520 | 8.27 | 1,599 | 0.00520 | 8.32 | 0.05 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 1,590 | 0.00100 | 1.59 | 1,599 | 0.00100 | 1.60 | 0.01 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 1,500 | 0.00700 | 10.50 | 1,500 | 0.00700 | 10.50 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 1,590 | 0.05704 | 90.70 | 1,599 | 0.05704 | 91.22 | 0.51 | 0.6% | 0.3% |
| **Total Bill** | | | | **163.88** | | | **162.70** | **(1.17)** | **-0.7%** | **-0.7%** |

# Hydro 2000 Inc.

| Residential<br>2000 kWh | Metric | 2007 BILL Volume | Rate $ | Charge $ | 2008 BILL Volume | Rate $ | Charge $ | IMPACT Change $ | Change % | % of Total Bill |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | | | 8.20 | | | 10.71 | 2.51 | 30.6% | 1.2% |
| Distribution | kWh | 2,000 | 0.00860 | 17.20 | 2,000 | 0.01230 | 24.60 | 7.40 | 43.0% | 3.5% |
| Regulatory Asset Recovery | kWh | 2,000 | 0.00980 | 19.60 | 2,000 | 0.00320 | 6.40 | (13.20) | -67.3% | -6.2% |
| Retail Transmission - Network | kWh | 2,120 | 0.00570 | 12.09 | 2,132 | 0.00570 | 12.15 | 0.07 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 2,120 | 0.00500 | 10.60 | 2,132 | 0.00500 | 10.66 | 0.06 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 2,120 | 0.00520 | 11.03 | 2,132 | 0.00520 | 11.09 | 0.06 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 2,120 | 0.00100 | 2.12 | 2,132 | 0.00100 | 2.13 | 0.01 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 2,000 | 0.00700 | 14.00 | 2,000 | 0.00700 | 14.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 2,120 | 0.05704 | 120.94 | 2,132 | 0.05704 | 121.62 | 0.68 | 0.6% | 0.3% |
| **Total Bill** | | | | **215.77** | | | **213.36** | **(2.40)** | **-1.1%** | **-1.1%** |

| General Service <50 kW<br>1000 kWh | Metric | 2007 BILL Volume | Rate $ | Charge $ | 2008 BILL Volume | Rate $ | Charge $ | IMPACT Change $ | Change % | % of Total Bill |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | | | 11.80 | | | 24.78 | 12.98 | 110.0% | 10.3% |
| Distribution | kWh | 1,000 | 0.00980 | 9.80 | 1,000 | 0.01350 | 13.50 | 3.70 | 37.8% | 2.9% |
| Regulatory Asset Recovery | kWh | 1,000 | 0.00750 | 7.50 | 1,000 | 0.00290 | 2.90 | (4.60) | -61.3% | -3.7% |
| Retail Transmission - Network | kWh | 1,060 | 0.00520 | 5.51 | 1,066 | 0.00520 | 5.54 | 0.03 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 1,060 | 0.00450 | 4.77 | 1,066 | 0.00450 | 4.80 | 0.03 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 1,060 | 0.00520 | 5.51 | 1,066 | 0.00520 | 5.54 | 0.03 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 1,060 | 0.00100 | 1.06 | 1,066 | 0.00100 | 1.07 | 0.01 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 1,000 | 0.00700 | 7.00 | 1,000 | 0.00700 | 7.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 1,060 | 0.05704 | 60.47 | 1,066 | 0.05704 | 60.81 | 0.34 | 0.6% | 0.3% |
| **Total Bill** | | | | **113.42** | | | **125.94** | **12.52** | **11.0%** | **9.9%** |

# Hydro 2000 Inc.

| General Service <50 kW 2000 kWh | Metric | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume | Rate $ | Charge $ | Volume | Rate $ | Charge $ | Change $ | Change % | % of Total Bill |
| Monthly Service Charge | | | | 11.80 | | | 24.78 | 12.98 | 110.0% | 5.7% |
| Distribution | kWh | 2,000 | 0.00980 | 19.60 | 2,000 | 0.01350 | 27.00 | 7.40 | 37.8% | 3.3% |
| Regulatory Asset Recovery | kWh | 2,000 | 0.00750 | 15.00 | 2,000 | 0.00290 | 5.80 | (9.20) | -61.3% | -4.1% |
| Retail Transmission - Network | kWh | 2,120 | 0.00520 | 11.03 | 2,132 | 0.00520 | 11.09 | 0.06 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 2,120 | 0.00450 | 9.54 | 2,132 | 0.00450 | 9.59 | 0.05 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 2,120 | 0.00520 | 11.03 | 2,132 | 0.00520 | 11.09 | 0.06 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 2,120 | 0.00100 | 2.12 | 2,132 | 0.00100 | 2.13 | 0.01 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 2,000 | 0.00700 | 14.00 | 2,000 | 0.00700 | 14.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 2,120 | 0.05704 | 120.94 | 2,132 | 0.05704 | 121.62 | 0.68 | 0.6% | 0.3% |
| **Total Bill** | | | | **215.05** | | | **227.10** | **12.06** | **5.6%** | **5.3%** |

| General Service <50 kW 5000 kWh | Metric | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume | Rate $ | Charge $ | Volume | Rate $ | Charge $ | Change $ | Change % | % of Total Bill |
| Monthly Service Charge | | | | 11.80 | | | 24.78 | 12.98 | 110.0% | 2.4% |
| Distribution | kWh | 5,000 | 0.00980 | 49.00 | 5,000 | 0.01350 | 67.50 | 18.50 | 37.8% | 3.5% |
| Regulatory Asset Recovery | kWh | 5,000 | 0.00750 | 37.50 | 5,000 | 0.00290 | 14.50 | (23.00) | -61.3% | -4.3% |
| Retail Transmission - Network | kWh | 5,301 | 0.00520 | 27.56 | 5,331 | 0.00520 | 27.72 | 0.16 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 5,301 | 0.00450 | 23.85 | 5,331 | 0.00450 | 23.99 | 0.14 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 5,301 | 0.00520 | 27.56 | 5,331 | 0.00520 | 27.72 | 0.16 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 5,301 | 0.00100 | 5.30 | 5,331 | 0.00100 | 5.33 | 0.03 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 5,000 | 0.00700 | 35.00 | 5,000 | 0.00700 | 35.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 5,301 | 0.05704 | 302.34 | 5,331 | 0.05704 | 304.05 | 1.71 | 0.6% | 0.3% |
| **Total Bill** | | | | **519.92** | | | **530.59** | **10.67** | **2.1%** | **2.0%** |

# Hydro 2000 Inc.

| General Service <50 kW<br>10000 kWh | Metric | 2007 BILL Volume | Rate $ | Charge $ | 2008 BILL Volume | Rate $ | Charge $ | IMPACT Change $ | Change % | % of Total Bill |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | | | 11.80 | | | 24.78 | 12.98 | 110.0% | 1.3% |
| Distribution | kWh | 10,000 | 0.00980 | 98.00 | 10,000 | 0.01350 | 135.00 | 37.00 | 37.8% | 3.6% |
| Regulatory Asset Recovery | kWh | 10,000 | 0.00750 | 75.00 | 10,000 | 0.00290 | 29.00 | (46.00) | -61.3% | -4.4% |
| Retail Transmission - Network | kWh | 10,601 | 0.00520 | 55.13 | 10,661 | 0.00520 | 55.44 | 0.31 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 10,601 | 0.00450 | 47.70 | 10,661 | 0.00450 | 47.97 | 0.27 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 10,601 | 0.00520 | 55.13 | 10,661 | 0.00520 | 55.44 | 0.31 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 10,601 | 0.00100 | 10.60 | 10,661 | 0.00100 | 10.66 | 0.06 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 10,000 | 0.00700 | 70.00 | 10,000 | 0.00700 | 70.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 10,601 | 0.05704 | 604.68 | 10,661 | 0.05704 | 608.10 | 3.42 | 0.6% | 0.3% |
| **Total Bill** | | | | **1,028.04** | | | **1,036.39** | **8.36** | **0.8%** | **0.8%** |

| General Service <50 kW<br>15000 kWh | Metric | 2007 BILL Volume | Rate $ | Charge $ | 2008 BILL Volume | Rate $ | Charge $ | IMPACT Change $ | Change % | % of Total Bill |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | | | 11.80 | | | 24.78 | 12.98 | 110.0% | 0.8% |
| Distribution | kWh | 15,000 | 0.00980 | 147.00 | 15,000 | 0.01350 | 202.50 | 55.50 | 37.8% | 3.6% |
| Regulatory Asset Recovery | kWh | 15,000 | 0.00750 | 112.50 | 15,000 | 0.00290 | 43.50 | (69.00) | -61.3% | -4.5% |
| Retail Transmission - Network | kWh | 15,902 | 0.00520 | 82.69 | 15,992 | 0.00520 | 83.16 | 0.47 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 15,902 | 0.00450 | 71.56 | 15,992 | 0.00450 | 71.96 | 0.41 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 15,902 | 0.00520 | 82.69 | 15,992 | 0.00520 | 83.16 | 0.47 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 15,902 | 0.00100 | 15.90 | 15,992 | 0.00100 | 15.99 | 0.09 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 15,000 | 0.00700 | 105.00 | 15,000 | 0.00700 | 105.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 15,902 | 0.05704 | 907.02 | 15,992 | 0.05704 | 912.16 | 5.13 | 0.6% | 0.3% |
| **Total Bill** | | | | **1,536.16** | | | **1,542.20** | **6.04** | **0.4%** | **0.4%** |

# Hydro 2000 Inc.

| General Service >50 kW<br>60 kW 15,000 kWh | Metric | 2007 BILL Volume | Rate $ | Charge $ | 2008 BILL Volume | Rate $ | Charge $ | IMPACT Change $ | Change % | % of Total Bill |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | | | 63.79 | | | 120.28 | 56.49 | 88.6% | 3.2% |
| Distribution | kW | 60 | 2.35550 | 141.33 | 60 | 3.48440 | 209.06 | 67.73 | 47.9% | 3.9% |
| Regulatory Asset Recovery | kW | 60 | 2.24030 | 134.42 | 60 | 1.04680 | 62.81 | (71.61) | -53.3% | -4.1% |
| Retail Transmission - Network | kW | 64 | 2.12180 | 134.96 | 64 | 2.12180 | 135.72 | 0.76 | 0.6% | 0.0% |
| Retail Transmission -Connection | kW | 64 | 1.78820 | 113.74 | 64 | 1.78820 | 114.38 | 0.64 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 15,902 | 0.00520 | 82.69 | 15,992 | 0.00520 | 83.16 | 0.47 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 15,902 | 0.00100 | 15.90 | 15,992 | 0.00100 | 15.99 | 0.09 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 15,000 | 0.00700 | 105.00 | 15,000 | 0.00700 | 105.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 15,902 | 0.05704 | 907.02 | 15,992 | 0.05704 | 912.16 | 5.13 | 0.6% | 0.3% |
| **Total Bill** | | | | **1,698.85** | | | **1,758.56** | **59.71** | **3.5%** | **3.4%** |

| General Service >50 kW<br>100 kW 40,000 kWh | Metric | 2007 BILL Volume | Rate $ | Charge $ | 2008 BILL Volume | Rate $ | Charge $ | IMPACT Change $ | Change % | % of Total Bill |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | | | 63.79 | | | 120.28 | 56.49 | 88.6% | 1.4% |
| Distribution | kW | 100 | 2.35550 | 235.55 | 100 | 3.48440 | 348.44 | 112.89 | 47.9% | 2.8% |
| Regulatory Asset Recovery | kW | 100 | 2.24030 | 224.03 | 100 | 1.04680 | 104.68 | (119.35) | -53.3% | -3.0% |
| Retail Transmission - Network | kW | 106 | 2.12180 | 224.93 | 107 | 2.12180 | 226.21 | 1.27 | 0.6% | 0.0% |
| Retail Transmission -Connection | kW | 106 | 1.78820 | 189.57 | 107 | 1.78820 | 190.64 | 1.07 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 42,404 | 0.00520 | 220.50 | 42,644 | 0.00520 | 221.75 | 1.25 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 42,404 | 0.00100 | 42.40 | 42,644 | 0.00100 | 42.64 | 0.24 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 40,000 | 0.00700 | 280.00 | 40,000 | 0.00700 | 280.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 42,404 | 0.05704 | 2,418.72 | 42,644 | 0.05704 | 2,432.41 | 13.69 | 0.6% | 0.3% |
| **Total Bill** | | | | **3,899.50** | | | **3,967.05** | **67.55** | **1.7%** | **1.7%** |

# Hydro 2000 Inc.

| General Service >50 kW<br>500 kW 100,000 kWh | Metric | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume | Rate $ | Charge $ | Volume | Rate $ | Charge $ | Change $ | Change % | % of Total Bill |
| Monthly Service Charge | | | | 63.79 | | | 120.28 | 56.49 | 88.6% | 0.5% |
| Distribution | kW | 500 | 2.35550 | 1,177.75 | 500 | 3.48440 | 1,742.20 | 564.45 | 47.9% | 4.7% |
| Regulatory Asset Recovery | kW | 500 | 2.24030 | 1,120.15 | 500 | 1.04680 | 523.40 | (596.75) | -53.3% | -5.0% |
| Retail Transmission - Network | kW | 530 | 2.12180 | 1,124.66 | 533 | 2.12180 | 1,131.03 | 6.37 | 0.6% | 0.1% |
| Retail Transmission -Connection | kW | 530 | 1.78820 | 947.84 | 533 | 1.78820 | 953.20 | 5.36 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 106,010 | 0.00520 | 551.25 | 106,610 | 0.00520 | 554.37 | 3.12 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 106,010 | 0.00100 | 106.01 | 106,610 | 0.00100 | 106.61 | 0.60 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 100,000 | 0.00700 | 700.00 | 100,000 | 0.00700 | 700.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 106,010 | 0.05704 | 6,046.81 | 106,610 | 0.05704 | 6,081.03 | 34.22 | 0.6% | 0.3% |
| **Total Bill** | | | | **11,838.26** | | | **11,912.12** | **73.86** | **0.6%** | **0.6%** |

| General Service >50 kW<br>1,000 kW 400,000 kWh | Metric | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume | Rate $ | Charge $ | Volume | Rate $ | Charge $ | Change $ | Change % | % of Total Bill |
| Monthly Service Charge | | | | 63.79 | | | 120.28 | 56.49 | 88.6% | 0.1% |
| Distribution | kW | 1,000 | 2.35550 | 2,355.50 | 1,000 | 3.48440 | 3,484.40 | 1,128.90 | 47.9% | 2.9% |
| Regulatory Asset Recovery | kW | 1,000 | 2.24030 | 2,240.30 | 1,000 | 1.04680 | 1,046.80 | (1,193.50) | -53.3% | -3.1% |
| Retail Transmission - Network | kW | 1,060 | 2.12180 | 2,249.32 | 1,066 | 2.12180 | 2,262.05 | 12.73 | 0.6% | 0.0% |
| Retail Transmission -Connection | kW | 1,060 | 1.78820 | 1,895.67 | 1,066 | 1.78820 | 1,906.40 | 10.73 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 424,040 | 0.00520 | 2,205.01 | 426,440 | 0.00520 | 2,217.49 | 12.48 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 424,040 | 0.00100 | 424.04 | 426,440 | 0.00100 | 426.44 | 2.40 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 400,000 | 0.00700 | 2,800.00 | 400,000 | 0.00700 | 2,800.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 424,040 | 0.05704 | 24,187.24 | 426,440 | 0.05704 | 24,324.14 | 136.90 | 0.6% | 0.4% |
| **Total Bill** | | | | **38,420.87** | | | **38,588.00** | **167.13** | **0.4%** | **0.4%** |

# Hydro 2000 Inc.

| **General Service >50 kW** | | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 3,000 kW 1,000,000 kWh | **Metric** | **Volume** | **Rate $** | **Charge $** | **Volume** | **Rate $** | **Charge $** | **Change $** | **Change %** | **% of Total Bill** |
| Monthly Service Charge | | | | 63.79 | | | 120.28 | 56.49 | 88.6% | 0.1% |
| Distribution | kW | 3,000 | 2.35550 | 7,066.50 | 3,000 | 3.48440 | 10,453.20 | 3,386.70 | 47.9% | 3.4% |
| Regulatory Asset Recovery | kW | 3,000 | 2.24030 | 6,720.90 | 3,000 | 1.04680 | 3,140.40 | (3,580.50) | -53.3% | -3.6% |
| Retail Transmission - Network | kW | 3,180 | 2.12180 | 6,747.96 | 3,198 | 2.12180 | 6,786.15 | 38.19 | 0.6% | 0.0% |
| Retail Transmission -Connection | kW | 3,180 | 1.78820 | 5,687.01 | 3,198 | 1.78820 | 5,719.20 | 32.19 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 1,060,100 | 0.00520 | 5,512.52 | 1,066,100 | 0.00520 | 5,543.72 | 31.20 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 1,060,100 | 0.00100 | 1,060.10 | 1,066,100 | 0.00100 | 1,066.10 | 6.00 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 1,000,000 | 0.00700 | 7,000.00 | 1,000,000 | 0.00700 | 7,000.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 1,060,100 | 0.05704 | 60,468.10 | 1,066,100 | 0.05704 | 60,810.34 | 342.24 | 0.6% | 0.3% |
| **Total Bill** | | | | **100,326.89** | | | **100,639.40** | **312.51** | **0.3%** | **0.3%** |

| **Street Light** | | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 77 kW 25,000 kWh | **Metric** | **Volume** | **Rate $** | **Charge $** | **Volume** | **Rate $** | **Charge $** | **Change $** | **Change %** | **% of Total Bill** |
| Monthly Service Charge | | | | 0.17 | | | 0.54 | 0.37 | 217.6% | 0.0% |
| Distribution | kW | 77 | 2.22840 | 171.59 | 77 | 7.75960 | 597.49 | 425.90 | 248.2% | 15.7% |
| Regulatory Asset Recovery | kW | 77 | -1.76760 | (136.11) | 77 | 0.40600 | 31.26 | 167.37 | -123.0% | 6.2% |
| Retail Transmission - Network | kW | 81 | 1.60020 | 129.41 | 81 | 1.60020 | 129.41 | 0.00 | 0.0% | 0.0% |
| Retail Transmission -Connection | kW | 81 | 1.38240 | 111.80 | 81 | 1.38240 | 111.80 | 0.00 | 0.0% | 0.0% |
| Wholesale Market Service | kWh | 26,258 | 0.00520 | 136.54 | 26,258 | 0.00520 | 136.54 | 0.00 | 0.0% | 0.0% |
| Rural Rate Protection Charge | kWh | 26,258 | 0.00100 | 26.26 | 26,258 | 0.00100 | 26.26 | 0.00 | 0.0% | 0.0% |
| Debt Retirement Charge | kWh | 25,000 | 0.00700 | 175.00 | 25,000 | 0.00700 | 175.00 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 26,258 | 0.05704 | 1,497.73 | 26,258 | 0.05704 | 1,497.73 | 0.00 | 0.0% | 0.0% |
| **Total Bill** | | | | **2,112.39** | | | **2,706.03** | **593.64** | **28.1%** | **21.9%** |

# Hydro 2000 Inc.

| Unmeterd Scattered Load<br>500 kWh | Metric | 2007 BILL | | | 2008 BILL | | | IMPACT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume | Rate $ | Charge $ | Volume | Rate $ | Charge $ | Change $ | Change % | % of Total Bill |
| Monthly Service Charge | | | | 5.82 | | | 6.00 | 0.18 | 3.1% | 0.3% |
| Distribution | kWh | 500 | 0.00980 | 4.90 | 500 | 0.03340 | 16.70 | 11.80 | 240.8% | 17.7% |
| Regulatory Asset Recovery | kWh | 500 | 0.00750 | 3.75 | 500 | 0.00290 | 1.45 | (2.30) | -61.3% | -3.5% |
| Retail Transmission - Network | kWh | 530 | 0.00520 | 2.76 | 533 | 0.00520 | 2.77 | 0.02 | 0.6% | 0.0% |
| Retail Transmission -Connection | kWh | 530 | 0.00450 | 2.39 | 533 | 0.00450 | 2.40 | 0.01 | 0.6% | 0.0% |
| Wholesale Market Service | kWh | 530 | 0.00520 | 2.76 | 533 | 0.00520 | 2.77 | 0.02 | 0.6% | 0.0% |
| Rural Rate Protection Charge | kWh | 530 | 0.00100 | 0.53 | 533 | 0.00100 | 0.53 | 0.00 | 0.6% | 0.0% |
| Debt Retirement Charge | kWh | 500 | 0.00700 | 3.50 | 500 | 0.00700 | 3.50 | 0.00 | 0.0% | 0.0% |
| Cost of Power Commodity | kWh | 530 | 0.05704 | 30.23 | 533 | 0.05704 | 30.41 | 0.17 | 0.6% | 0.3% |
| **Total Bill** | | | | **56.63** | | | **66.53** | **9.90** | **17.5%** | **14.9%** |

**Hydro 2000 Inc.**

## PROPOSED CHANGES TO TERMS AND CONDITIONS OF SERVICES

Please refer back to Exhibit 1, Tab 1, Schedule 17 for proposed changes to terms and conditions of service