Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2016-0025
EB-2016-0360

ENERSOURCE HYDRO MISSISSAUGA INC. HORIZON UTILITIES CORPORATION & POWERSTREAM INC.

Application for approval to amalgamate to form LDC Co and for LDC Co to purchase and amalgamate with Hydro One Brampton Networks Inc.

BEFORE: Ken Quesnelle
Presiding Member and Vice-Chair

Christine Long
Vice-Chair

Cathy Spoel
Member

December 8, 2016

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

This is the Decision of the Ontario Energy Board (OEB) regarding an application filed by Enersource Hydro Mississauga Inc. (Enersource), Horizon Utilities Corporation (Horizon), and PowerStream Inc. (PowerStream), (collectively, the applicants) requesting approval to amalgamate to form LDC Co and for LDC Co to purchase and amalgamate with Hydro One Brampton Networks Inc. (Hydro One Brampton) under section 86 of the *Ontario Energy Board Act,1998* (Act).

As part of the application, approvals were requested for: (a) transfer of the distribution licences and rate orders for each of the applicants and Hydro One Brampton to LDC Co; (b) an electricity distributor licence for LDC Co; and (c) temporary exemptions from section 2.6.1A of the *Distribution System Code* (DSC).

Section 86 of the Act requires that the OEB review applications for a merger, acquisition of shares, divestiture or amalgamation that result in a change of ownership or control of an electricity transmitter or distributor and approve applications which are in the public interest.

The OEB issued a Handbook to Electricity Distributor and Transmitter Consolidation in January 2016 (Handbook) which provides guidance on the process for the review of an application, the information the OEB expects to receive in support of an application, and the approach it will take in assessing whether the transaction is in the public interest.

In reviewing an application, the OEB applies a no harm test, first established in the OEB's Combined Decision[1]. The no harm test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB's statutory objectives as set out in section 1 of the Act. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.

The OEB has determined that the proposed amalgamation meets the no harm test and therefore the OEB approves this transaction.

The OEB also approves the LDC Co licence application and the transfer of the rate orders for each of the applicants and Hydro One Brampton to LDC Co but finds that a

[1] RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257

transfer of the distribution licences of each of the amalgamating entities to LDC Co is no longer required. The licences of the amalgamating entities will be cancelled upon the effective date of LDC Co's licence.

The OEB approves temporary exemptions from section 2.6.1A of the DSC until June 30, 2017 for Horizon and until December 31, 2018 for Enersource.

2 THE APPLICATION

Enersource, Horizon and PowerStream filed an application with the OEB on April 18, 2016 seeking approval for several transactions under section 86 of the Act:

1. Amalgamation of Enersource, Horizon, and PowerStream to form LDC Co
2. LDC Co share purchase and amalgamation with Hydro One Brampton
3. Enersource Holdings Inc. share purchase of Enersource
4. Transfer of PowerStream's existing shares of Collus PowerStream Utility Services Corp to LDC Co
5. Transfer of Hydro One Brampton's distribution system to LDC Co

As part of the application, approval was requested for:

a) Transfer of the distribution licences and rate orders for each of the applicants and Hydro One Brampton to LDC Co under section 18 of the Act

b) An electricity distributor licence for LDC Co under section 60 of the Act

c) Temporary exemptions from section 2.6.1A of the DSC under section 74 of the Act

The applicants made several confidentiality requests with respect to the filed evidence and interrogatory responses. The OEB issued two decisions on August 12, 2016 and September 2, 2016 setting out its determination on the confidentiality requests.

The proposed amalgamation of the four distributors will create the largest municipally-owned distributor in Ontario, serving over 960,000 customers, with a total rate base of approximately $2.5 billion. The consolidation involves the amalgamation of Enersource, Horizon and PowerStream to form LDC Co, followed by LDC Co's acquisition of the shares of Hydro One Brampton at a purchase price of $607 million and subsequent amalgamation of Hydro One Brampton with LDC Co.

Process

The OEB issued a Notice of Application and Hearing on May 16, 2016, inviting intervention and comment. The OEB approved intervention requests by the Association of Major Power Consumers in Ontario (AMPCO), Energy Probe Research Foundation (Energy Probe), Power Workers' Union (PWU), School Energy Coalition (SEC), Vulnerable Energy Consumers Coalition (VECC), Building Owners and Managers Association, Greater Toronto (BOMA), Consumers Council of Canada (CCC), Electrical Contractors Association of Ontario (ECAO), and International Brotherhood of Electrical Workers, Local 636 (IBEW).

A presentation of the application was provided to the OEB Panel and intervenors on June 23, 2016. The OEB provided for interrogatories and a transcribed technical conference took place on August 24, 2016 to clarify matters arising from the interrogatories. The OEB held five days of oral hearing. The OEB received submissions from OEB staff and the parties.

3 REGULATORY PRINCIPLES

3.1 The No Harm Test

As set out in the Handbook, the OEB applies the no harm test in its assessment of consolidation applications. The OEB considers whether the no harm test is satisfied based on an assessment of the cumulative effect of the transaction on the attainment of its statutory objectives. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.

The statutory objectives to be considered are those set out in section 1 of the Act:

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

   1.1 To promote the education of consumers.

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

3 To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario.

4 To facilitate the implementation of a smart grid in Ontario.

5 To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

While the OEB has broad statutory objectives, in applying the no harm test, the OEB's review primarily focuses on the impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and financial viability of the consolidating utilities. The OEB considers this an appropriate approach, given the performance-based regulatory framework under which regulated entities are required to operate and the OEB's existing performance monitoring framework.

The OEB has implemented a number of instruments, such as codes and licences that ensure regulated utilities continue to meet their obligations with respect to the OEB's statutory objectives relating to conservation and demand management, implementation of smart grid, and the use and generation of electricity from renewable resources. With these tools and the existing performance monitoring framework, the OEB is satisfied that the attainment of these objectives will not be adversely affected by a consolidation and the no harm test will be met following a consolidation.

3.2 OEB Policy on Rate-Making Associated with Consolidation

To encourage consolidations, the OEB has put in place policies on rate-making that provide consolidating distributors with an opportunity to offset transaction costs with savings achieved as a result of the consolidation. The OEB sets out its policies on rate-making associated with consolidation in a report entitled *Rate-making Associated with Distributors Consolidation*, issued July 23, 2007[2] (the 2007 Report) and a further report issued under the same name on March 26, 2015 (the 2015 Report).

The 2015 Report permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction. The extent of the deferred rebasing period is at the option of the distributor and no supporting evidence is required to justify the selection of the deferred rebasing period. Consolidating entities, must, however, select a definitive timeframe for the deferred rebasing period.

The 2015 Report sets out the rate-setting mechanisms during the deferred rebasing period, requiring consolidating entities that propose to defer rebasing beyond five years to implement an earnings sharing mechanism for the period beyond five years to protect customers and ensure that they share in increased benefits from consolidation.

The 2015 Report extended the availability of the Incremental Capital Module (ICM), an additional mechanism under the Price Cap IR rate-setting option to consolidating distributors on Annual IR Index, to allow adjustment to rates for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. This provides consolidating

[2] Report of the Board on Rate-making Associated with Distributor Consolidation, July 23, 2007

distributors with the ability to finance capital investments during the deferred rebasing period without being required to rebase earlier than planned.

As set out in the Handbook, rate-setting following a consolidation will not be addressed in an application for approval of a consolidation transaction unless there is a rate proposal that is an integral aspect of the consolidation, e.g. a temporary rate reduction. Rate-setting for a consolidated entity will be addressed in a separate rate application, in accordance with the rate setting policies established by the OEB.

4 APPLICATION OF THE PRINCIPLES TO THE APPLICATION

4.1 The No Harm Test

Price, Cost Effectiveness and Economic Efficiency

The Handbook states that to demonstrate no harm, applicants must show that there is a reasonable expectation based on underlying cost structures that the costs to serve customers following a consolidation will be no higher than they would otherwise have been. The Handbook also states that the impact the proposed transaction will have on economic efficiency and cost effectiveness will be assessed based on an applicant's identification of the various aspects of utility operations where it expects sustained operational efficiencies, both quantitative and qualitative.

In this case, the applicants submit that the effect of the consolidation on underlying cost structures will be positive, that costs to serve customers will not be higher as a result of the consolidation and that the consolidation will have a positive effect on economic efficiency and cost effectiveness.

The applicants submit that these positive outcomes are confirmed by the evidence identifying synergies and savings that the applicants are able to achieve as a result of the proposed consolidation. These synergies arise from specific, concrete initiatives to lower underlying cost structures and to promote economic efficiency and cost effectiveness, by reducing the number of call centres and control rooms, by integrating back-office functions and reducing the number of back-office employees, and by moving to single, common information systems.

The applicants' evidence is that during the proposed ten-year rebasing deferral period, customers will benefit from distribution rates that are lower than they would be under the status quo scenario (in the absence of a consolidation). The status quo assumes that each of the LDCs continue to rebase their rates once their current plans have expired and thereafter have 5-year Custom Incentive Regulation plans in place. The applicants submit that the interests of consumers with respect to price will be protected because rates for the Horizon Utilities and PowerStream rate zones will continue to be charged in accordance with previous rebasing-related OEB decisions, until the effective period of each of those decisions has come to an end. Otherwise, during the rebasing deferral period, the OEB's Price Cap Incentive Regulation model will be used to determine rates for LDC Co's rate zones, in accordance with the OEB's policies.

The applicants provide a year over year distribution revenue trend analysis of the merged entity compared to the status quo that shows the relative benefit to customers as follows:

- Average decrease of $19.5 million per year or 3.3% in the first 10 years
- Average decrease of $69.3 million per year or 8% post rebasing
- Average decrease of $ 48.6 million per year or 5.9% across the forecast period[3]

The applicants assert that ratepayers benefit from a $195 million reduction in revenues during the ten year deferred rebasing period, simply based on the fact that the entities would otherwise file rate applications in the absence of the merger. This amounts to a net present value of $98 million during the deferred rebasing period[4].

The applicants project that overall anticipated savings net of transaction costs (approximately $96 million) amount to $426 million over the deferred rebasing period and confirmed that all of these synergies are to the benefit of the shareholder for the duration of the 10 year period[5]. The applicants state that upon rebasing in 2027, customers will benefit from the $69 million in sustainable savings relative to the status quo. The applicants anticipate the net present value of savings for ratepayers beyond the 10 year rebasing deferral period to be approximately $306 million[6].

Intervenors submit that the applicants have provided high level estimates of the projected net synergies in the first ten years without detailed evidence to support these estimates and have not provided credible evidence that savings realized in the deferred rebasing period are sustainable in perpertuity. Consequently, intervenors submit that the OEB should give little weight to the projected net present savings of $98 million during the rebasing deferral period and the post rebasing net present value of savings of $306 million. Intervenors argue that the high level estimated net synergies provided in the evidence is likely a very conservative estimate of the savings to be achieved,

---

[3] Forecast Period (2016-2039),Application, Exh B/T6/S1, p.4
[4] Transcript, Vol. 1, pp.82-83
[5] Transcript, Vol. 1, p. 27
[6] Transcript, Vol. 1, p. 82

noting that through-out cross-examination, it became evident that there are many potential synergies and savings that have not been counted nor was any attempt made to quantify them[7].

CCC and BOMA submit that the status quo scenario assumes that each of these LDCs will get approval for successive 5-year Custom IR plans over the next ten years, arguing that the OEB has approved very few Custom IR plans over the last few years. CCC also submits that if during the course of the next ten years the OEB did not approve the implementation of successive 5-year Custom IR plans for each of the four LDCs then the projected savings would be reduced or essentially eliminated. CCC argues that this is the one financial benefit the applicants are claiming for their customers during the deferred rebasing period, and the full realization of this benefit is highly questionable. SEC submitted that based on the evidence, the OEB should conclude that the status quo rate increases forecast by the applicants are overstated.

Energy Probe submits that the approach taken by the applicants in calculating status quo revenues only takes into account the distributor's forecasts (revenue and costs, inflation and productivity) and does not reflect the OEB's inflation and productivity analyses or any benchmarking to assess the reasonableness of the forecasts as required by the October 2012 *Report of the Board on the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*.

The applicants expect to file an ICM in each year for each rate zone under Price Cap IR during the deferred rebasing period. During the course of the hearing, the applicants updated the total forecasted ICM revenue from $130 million to $168.4 million as a result of the OEB's PowerStream Decision (EB-2015-0003) and used a 10% deadband in place of a 20% deadband in calculating the ICM materiality threshold. The total incremental capital that is expected to be sought through the ICM is $414.2 million, plus an additional $173.5 million of incremental capital as a result of the PowerStream Decision and the use of a 10% deadband, resulting in a total of $587.7 million[8].

Intervenors submit that any incremental increases in the ICM projections negatively impact the projected annual savings for customers. Intervenors also express concern that the ICM projections are not based on the Distribution System Plans (DSP) that

[7] SEC submissions p. 26; AMPCO submissions p.7
[8] Technical conference undertaking responses - JTC 1.8, J1.1

have been approved by the OEB, are not informed by a new DSP for LDC Co, and do not reflect reductions in existing capital.

Intervenors argue that the applicants' proposal to share benefits with customers only upon rebasing, while acknowledging that these savings are not guaranteed to materialize for ratepayers, means that there is no certainty that ratepayers will receive these benefits and creates intergenerational equity issues. Intervenors submit that given that the regulatory framework in place at that time is unknown, there is also uncertainty as to whether these savings will serve to reduce costs to customers in perpetuity.

OEB staff submits that the evidence provided by the applicants supports the claim that the proposed amalgamation can reasonably be expected to result in cost savings and operational efficiencies. OEB staff, however, notes that the degree of certainty regarding forecast savings diminishes over the length of the forecast period.

BOMA submits that Hydro One Brampton's OM&A/customer in 2014 was $178.92, 23% lower than the lowest of the three merging utilities, with PowerStream at $242.92, Horizon at $251.24 and Enersource at $260.39. BOMA argues that the need to insulate Hydro One Brampton ratepayers from spillover effects from the higher cost utilities is obvious but the applicants have not filed evidence on how they will do this.

SEC submits that Hydro One Brampton customers have the lowest rates of the four LDCs and their rates will have to increase substantially if there is a harmonization of rates. SEC asserts that according to the Handbook, for an acquisition the OEB focuses its attention in the no harm test on the customers of the acquired LDC. SEC argues that in this case, the acquired customers of Hydro One Brampton will face a greater rate increase through harmonization. SEC submits that application of the no harm test necessitates consideration by the OEB of how to ensure that those customers are specifically protected, particularly since these customers will not have a municipal shareholder protecting them.

OEB Findings

The OEB notes that this merger application is the first transaction that involves multiple entities coming together to form a single utility and it is also the first merger application since the release of the Handbook. The Handbook provides guidance on how the OEB reviews consolidation applications and clarifies the OEB's rate-making policy associated with consolidation. As with any articulated OEB policy, the OEB examines the facts of a specific application. The OEB has considered the specific facts in this application and is of the view that the features of this transaction are anticipated within the framework of the OEB's policy and the outcomes are aligned with the articulated policy objective of improving the efficiency of electricity distribution. The OEB finds that the scale enhancements of service delivery embedded in this transaction can be expected to result in long term benefits to customers.

The OEB considers the long term effect of a proposed transaction on cost structures. This is aligned with the long-term investment cycles of the distribution sector where most distribution assets have life expectancies in the 40 year range. Hydro One Brampton is identified as being the lowest cost entity involved in this transaction. The OEB notes that Hydro One Brampton will have additional scale available to it in the long term and its existing cost structures are embedded in its rates for the next 10 years. The OEB will consider the matter of its rates and the impact of rate harmonization in the context of a rate application. In the OEB's view, there will be no net negative impact on Hydro One Brampton's customers in the long term in comparison to the status quo.

The intervenors submit that the amounts proposed by the applicants in terms of costs and potential savings are estimates and do not reflect the amounts with certainty. The OEB takes notes of these arguments, but is satisfied that the estimates are sufficiently accurate for the purposes of the analysis under the no harm test.

The applicants' evidence suggests potential savings from the proposed merger flowing to shareholders of $426 million over the ten year period on a rate base of $2.5 billion. This is approximately 1.7 percent on an annualized basis. Earnings of LDC Co that, on an annual basis are more than 300 basis points above the applicable rate of return for LDC Co, will be shared with customers on a 50:50 basis. In the OEB's view, this result may be compared to the status quo scenario, from an earnings potential perspective, whereby each entity could rebase at least once more within 10 years, and any earnings above 300 basis points over the regulated rate of return would all flow to the shareholder until the rates are reset. The OEB therefore finds that customers will be not be harmed by the proposed transaction in the short term, and will, in fact, be better off and will likely benefit from the enduring benefits of scale in the long term.

Reliability and Quality of Electricity Service

The Handbook sets out that under the OEB's regulatory framework, consolidating utilities are expected to deliver continuous improvement for both reliability and quality of service performance to benefit customers.

The applicants submit that they are committed to maintaining the quality, reliability, and adequacy of electricity service for customers, stating that they currently have a total of six service centres across their service areas which will continue to be used for de-centralized functions such as construction and maintenance, trouble response, logistics, fleet services, and metering, such that the adequacy, reliability, and quality of electricity service will be maintained.

The applicants further expect LDC Co to maintain and improve upon the five-year average reliability indices and the OEB customer service standard metrics for its customers. During the oral hearing, the applicants testified that LDC Co will be accountable for meeting performance metrics relating to service quality and reliability and compliance with licence conditions, in relation to the individual rate zones of each of the amalgamating distributors that will continue after consolidation. The applicants submit that customers will benefit from being served by a larger utility that will have an expanded ability to monitor, report on and improve system reliability and power quality, given its greater resources.

OEB staff submits that LDC Co can reasonably be expected to maintain the service quality and reliability standards currently provided by each of the amalgamating utilities. OEB staff also submits that the OEB is able to monitor the performance of LDC Co on an ongoing basis through performance scorecards as well as the OEB's Electricity Reporting and Record Keeping Requirements (RRRs) which constitute the OEB's requirements to maintain and file information under the licence conditions.

AMPCO submits that based on the evidence, LDC Co can reasonably be expected to maintain service quality and reliability standards so that reliability and service quality will not deteriorate as a result of the consolidation. However, AMPCO also asserts that given the level of proposed capital spending over ten years identified in the application, a forecast of improved reliability over time would be a better proposition for customers to accept.

Energy Probe submits that the applicants have indicated that they cannot guarantee that none of the service quality indicators will deteriorate but have also indicated that as a merged entity, more resources would be available to deal with issues that may arise in one area or in one rate zone. Energy Probe submits that this is a reasonable assumption and the OEB should interpret this to mean that service quality should not deteriorate as a result of the merger.

BOMA expressed concern that the applicants have not targeted higher SAIDI and SAIFI and asserted that SAIDI and SAIFI should not be averaged for reporting, scorecard formulation or any other purpose because, in BOMA's view, that would ultimately lead to a degradation of Hydro One Brampton's SAIDI results. BOMA submits that the OEB should require the applicants to set reliability targets for each of the four utilities, with the possible exception of Hydro One Brampton which is better than the average of the other three. BOMA submits that the OEB should require the applicants to file an annual customer survey which deals separately with each of the four predecessor utilities, so as to measure their level of satisfaction with LDC Co's services to each of the four ratepayer groups. BOMA states that the summary and the detailed results should be filed each year with the OEB and intervenors, as part of the four divisions' annual rate adjustment applications and that LDC Co should consult with the intervenors and OEB staff prior to starting the consultation process.

OEB Findings

The OEB finds that no issues of concern have been raised regarding the transaction resulting in a potential deterioration of overall reliability. The OEB has the ability to monitor the reliability performance of licensed entities on an ongoing basis and also has the authority to intervene and impose corrective action where a licensed entity does not meet established performance expectations.

The OEB also finds that reporting as a licensed entity on reliability is appropriate in the circumstances of this case and does not accept BOMA's view that each customer group must be monitored to ensure its current reliability status is maintained. As set out in the Handbook, in considering the impact of a proposed transaction on the quality and reliability of electricity service, and whether the no harm test has been met, the OEB will be informed by the metrics provided by the distributor in its annual reporting to the OEB and published in its annual scorecard.

Financial Viability

The Handbook states that the OEB's primary considerations in assessing the impact of a proposed transaction on the financial viability of the consolidating entities are: (1) the effect of the purchase price, including any premium paid above the historic (book) value of the assets involved; and (2) the financing of incremental costs (transaction and integration costs) to implement the consolidation transaction.

The application indicates that of the $607 million purchase price payable for the shares of Hydro One Brampton, a premium of $202 million is being paid. The applicants acknowledge that the rate base portion of the consideration payable is recoverable from ratepayers whereas the premium is not recoverable from ratepayers.

The applicants propose to finance the share acquisition through debt financing of $424.9 million, while the remaining $182.1 million will be financed by shareholder contributions. The applicants anticipate maintaining a capital structure of approximately 60% debt as a result of the acquisition of Hydro One Brampton. The applicants submit that the financial ratios and indicators will continue to be consistent with an A-range credit rating and therefore the purchase price will not have an adverse effect on the financial viability of LDC Co.

The applicants submit that incremental transaction costs for items such as data and other IT systems integration, regulatory approvals and legal advice will be financed through productivity gains associated with the transaction and are not expected to be recovered through rates.

The applicants submit, however, that while incremental transaction costs are self-financing by the associated savings, there will be timing differences between expense outlays and their recovery. The applicants have arranged a $500 million commitment for a 364-Day credit facility from two large banks. This facility is expected to be sufficient to finance: i) the temporary shortfall between implementation costs and their recovery through corresponding savings; and ii) the ongoing working capital requirements of LDC Co.

OEB staff submits that the applicants' evidence regarding the proposed financing of the Hydro One Brampton acquisition and the premium to be paid demonstrates that no adverse impact on the applicants' financial viability is anticipated and accepts the applicants' assertions that the use of credit facilities as proposed by the applicants will be adequate to finance timing differences between receivables and payables and to bridge capital expenditures for a period of time.

The submissions by intervenors do not raise any issue regarding the impact of the proposed consolidation on the financial viability of the consolidating entities and LDC Co.

The applicants submit in their reply submissions that altering the proposed deferred rebasing period or the earnings sharing mechanism would have an impact on financial viability. The applicants state that the associated borrowing for the Hydro One Brampton acquisition and ongoing capital program is supported by shareholder cashflows expected during the rebasing deferral period and that such cash flows provide interest coverage and manage debt and equity levels in a manner that supports a financial profile consistent with the current credit ratings of the predecessor entities.

OEB Findings

The OEB accepts OEB staff's submissions that the evidence relating to the proposed financing of the Hydro One Brampton acquisition and the premium to be paid will not impact the applicants' financial viability and finds that the proposed transaction therefore meets the no harm test with respect to financial viability.

4.2 Rate-making Considerations

Deferred Rate Rebasing and Earnings Sharing Mechanism

In the consultation with distributors leading up to the issuance of the 2015 Report, distributors indicated that incremental transaction and integration costs are significant and that recovery of these costs can be a barrier to consolidation. To address distributors' concerns, the 2015 Report allows distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction in order to realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction. The 2015 Report requires that consolidating entities that propose to defer rebasing beyond five years implement an earning sharing mechanism (ESM) for the period beyond five years, whereby excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual return on equity (ROE).

The applicants choose to defer rebasing for LDC Co for ten years from the date of closing of the last of the proposed transactions and propose an ESM for years six to ten of the deferred rebasing period whereby earnings of LDC Co that, on an annual basis, are more than 300 basis points above the applicable ROE for the consolidated entity will be shared with customers on a 50:50 basis. The applicants submit that these proposals are consistent with the OEB's consolidation policies, including the guidance provided in the Handbook.

OEB staff submits that the applicants' proposed ESM aligns with the expectations of the OEB as set out in the Handbook and also submits that the applicants should file plans for ESM, rate structures and rate harmonization by December 31, 2019, in order to provide sufficient time to plan for any ESM implementation.

The applicants submit that they do not expect rates to be harmonized and intend to operate individual rate zones with separate rate-setting methods for each of the existing distributors until rate differences are immaterial. The applicants submit that at the time of rebasing, rate harmonization options will be evaluated, with a view to available OEB policies and tools. The applicants submit that if the OEB finds it to be helpful, the applicants will accept OEB staff's suggestion and, to the extent possible, file plans for the ESM by December 31, 2019.

Intervenors submit that the selection of the 10 year deferred rebasing period is not appropriate and poses a threat of harm to customers. Intervenors submit that the proposed ten year rebasing period is not required to offset the costs of the transaction as the evidence in this case is that the transition and integration costs will be recovered by the end of year three of the consolidation. Intervenors submit that the proposed ESM does not adequately benefit customers and results in a significant imbalance between the incentives provided to the shareholders and the protection provided to customers. Intervenors further submit that if the OEB approves the consolidation, adjustments to the proposed ESM are required.

Intervenors submit a number of proposals for the OEB's consideration which include the following: approve a deferral period of five years rather than 10 years, amend the ESM to provide for no deadband, require an ESM where savings are shared with customers earlier than year six, reduce rates by an amount sufficient to share the benefits over the first ten years, and adjust the sharing of the savings on a 75:25 ratepayer/shareholder basis.

SEC argues that the OEB is required to determine if (or to what extent) the OEB's rate-making policy should be applied on the facts of the current case and that the legal test for doing so is whether the resulting rates will be just and reasonable. SEC submits that the policy cannot be applied unmodified to this case as the resulting rates would not be just and reasonable. SEC submits that the application of the policy unmodified would result in LDC Co exacting monopoly rents from the customers, unprotected by the regulatory process.

In reply submissions, the applicants argue that a change to the ten year rebasing deferral period could fundamentally alter the proposed transaction and the basis on which it has been accepted by shareholders as providing adequate incentive for entering into the transaction. The applicants submit that there is no basis in the evidence in this case to expect that, without a ten year rebasing deferral period, the applicants and their shareholders will assume the consolidation risks and absorb the Hydro One Brampton premium, nor is there any evidence offered by intervenors upon which it can be expected that this could be done without any adverse impact on financial viability.

The applicants submit that intervenor arguments with regard to the relative balance of impacts overlook the risks taken on by the distributors and their shareholders and the premium they incur to complete the transaction. The applicants argue that the impact of reducing the rebasing deferral period or altering the ESM relative to the Business Plan as proposed by the intervenors will likely result in the rejection of the deal by shareholders on the basis of insufficient consolidation incentives and unacceptable impairment of financial viability.

OEB Findings

The intervenors argue that the application of the policy with its 10 year term results in too much of the realized saving being to the benefit of the shareholder. The applicants have structured their proposal as a comparison of the cost structures of the merged entity operating within the OEB's incentive rate plan in the deferral period versus the anticipated cost structures of the individual utilities in the status quo scenario. The

OEB's incentive framework is intended to provide sufficient financial gains over and above the status quo to incent utilities to seek out merger or acquisition efficiency gains opportunities. The incentive framework is also intended to have customers share in large savings through earnings sharing beyond the 5-year deferred rebasing period.

As set out earlier in the no harm analysis, the OEB finds that this transaction is within the range of transactions anticipated by the OEB's policy. The outcomes are aligned with the policy's objective of improving the efficiency of electricity distribution. As discussed earlier, the proposal should be compared to the status quo scenario, from an earnings potential perspective, whereby each utility could rebase at least once more within the 10 years, and any earnings above 300 basis points over the regulated rate of return would all flow to the shareholder until rates were reset. The OEB finds that customers will be not be harmed and will likely benefit in the long term from the enduring benefits of scale enhancements of service delivery arising from this transaction. In view of the policy objectives of this incentive scheme, the OEB does not consider the particular outcomes related to potential earnings relative to the status quo to be unreasonable.

5 LICENCE APPLICATION

As part of the consolidation application, the applicants request the OEB's approval for an electricity distributor licence that would allow LDC Co to own and operate the distribution systems serving the former Enersource, Horizon, PowerStream and Hydro One Brampton service areas.

The applicants provided a draft form of licence, containing several proposals.

OEB Findings

The OEB is prepared to grant the licence application for LDC Co but notes that the incorporation of the merged entity will only occur within thirty days of the OEB's decision on the merger application. Consequently, while the OEB approves the licence application, the licence for the merged entity will only be effective once the applicants have notified the OEB that the merged entity has been incorporated and provided to the OEB the legal name of the merged company.

The OEB's findings on each of the applicants' proposals regarding the licence are set out below.

Proposed Deletions

The applicants propose deletions relating to certain temporary exemptions previously granted by the OEB to each of the amalgamating distributors and which have now expired. The applicants have also proposed that the following Code and Reporting and Record-Keeping Requirements (RRR) exemptions set out in the four amalgamating distributors' licences should be eliminated as they are no longer needed and/or because they have expired:

> The Hydro One Brampton, Enersource and PowerStream licences contain the following exemption:
>
> "1. The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code [the "SSS 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 ReferencePrice, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it."

The applicants submit that section 2.5.3 was removed from the SSS Code, and is no longer applicable. As a result, that exemption is no longer needed and propose that this be deleted from the proposed Schedule 3 (List of Code Exemptions) to the LDC Co. licence

The Hydro One Brampton licence contains the following exemption:

2. The Licensee is exempt from the requirements of section 6.5.4 of the Distribution System Code [the "DSC"] until June 30, 2009 in relation to 15 load transfer customers located within the City of Brampton with the following municipal addresses:

(a) 2868 Bovaird Drive;

(b) 10221, 10231 &10245 Old Pine Crest; and

(c) 10253, 10315, 10333, 10431, 10451, 10475, 10605, 10625, 10827, 11507 and 11511Winston Churchill Blvd.

The applicants submit that the exemption, which expired on June 30, 2009, applied to a version of section 6.5.4 of the DSC that would have required the elimination of long term load transfers by October of 2008. The OEB's requirements (including the deadlines) related to the elimination of long term load transfers have changed over time, and the deadline for the elimination of those load transfers was extended a number of times. The applicants submit that the DSC currently provides (at section 6.5.3) that "All load transfer arrangements shall be eliminated by transferring the load transfer customers to the physical distributor by June 21, 2017."

The applicants submit that they do not require an exemption from this requirement at this time, and the current exemption may be removed.

The Enersource licence contains the following exemption:

2. The Licensee is exempt from the requirement to implement time-of-use pricing as of the mandatory date for its RPP customers with eligible time-of-use

meters as required under the Standard Supply Service Code for Electricity Distributors. The mandatory time-of-use pricing date exemption expires on May 31, 2012.

The applicants submit that Enersource has implemented time-of-use pricing as of the mandatory date for its RPP customers with eligible time-of-use meters. The applicants further submit that this exemption has expired and is no longer applicable.

The PowerStream licence contains the following exemption:

The Licensee is exempt from the following sections of the Electricity Reporting and Record Keeping Requirements:

1. Section 2.1.8, sub-sections, b) ii; c) i, ii, iii, iv, vi, viii, ix, x; d) i, ii, iv; e) ii, iv; f) iii, iv and g). This exemption will expire on June 30, 2014.

The applicants submit that the exemption has expired, and is no longer needed in respect of the PowerStream rate zone in any event and should not be included in the LDC Co. licence.

The applicants submit that there are other provisions in the standard form of licence that may be outdated, such as certain provisions in Appendix A related to Market Power Mitigation Rebates. However, the applicants state that they have only proposed to eliminate certain exemptions specific to the four consolidating distributors and do not propose to remove generic provisions of the licence, as they believe that it would be more appropriate for the OEB to deal with those matters on a generic basis.

OEB staff submits that the elimination of the exemptions specific to each of the amalgamating distributors as set out by the applicants is appropriate. OEB staff submits that many of the other provisions in the standard form of licence that may be outdated were incorporated as a result of Ministerial directives and it is more appropriate for the OEB to consider the removal of these provisions on a generic basis.

OEB Findings

The OEB accepts the deletions proposed by the applicants identified in each of the amalgamating distributors' existing distribution licences.

Proposed Exemptions

The applicants are requesting exemptions from section 2.6.1A of the DSC, as the applicants will not be able to bill former Enersource and Horizon Residential and General Service <50kW customers on a monthly basis as required by this section of the Code, which comes into force on December 31, 2016. The applicants submit that as Enersource and Horizon will be migrating to the PowerStream customer information system (CIS), it will be necessary to complete that migration for a rate zone before monthly billing can be implemented and because that migration will be staggered, the applicants do not expect to be able to bill Residential and GS < 50 kW customers in the Enersource rate zone and Horizon rate zone on a monthly basis until later in 2018 (for Enersource) and until later in 2019 (for Horizon). The applicants submit that they are requesting these exemptions so as to not strand assets or to make unnecessary investments in the predecessor companies' existing systems.

The applicants request that the OEB approve exemptions from section 2.6.1A that would expire December 31, 2018 in the case of the Enersource rate zone and December 31, 2019 in the case of the Horizon rate zone, as part of its disposition of the licence application for LDC Co. The applicants have proposed that the requested exemptions be included in the new Schedule 3 to the LDC Co licence.

OEB staff submits that the OEB should only approve the exemptions for monthly billing requested by the applicants for a limited period of time – three to six months from the closing of the transaction. SEC agrees with the proposal to phase in monthly billing as CIS systems are harmonized, submitting that the avoidance of additional costs and transitional billing issues through a staged approach outweigh the goal of getting to monthly billing as soon as possible.

In response to submissions, the applicants propose to advance the migration of Horizon's customers to monthly billing by 30 months to June 30, 2017 but propose to maintain the December 2018 date for the migration of Enersource customers stating that they will not have sufficient resources to support both the monthly billing implementation and CIS convergence and that there is a high potential for customer billing errors.

OEB Findings

The OEB's requirement that distributors provide monthly billing flows from the concern that customers receive billing information on a timely basis. The exemptions sought by the applicants would not achieve this goal. However, the OEB recognizes that the exemption request is for a limited period of time. The applicants have committed to advance the migration of Horizon's customers to monthly billing by June 30, 2017 and to make monthly billing available to Enersource customers by December 31, 2018. The applicants have stated that there is a high potential for customer billing errors if they are required to implement CIS convergence and monthly billing at the same time. While timely billing information is important, so too is accurate billing information. Given the high potential for customer billing errors, the OEB will not force the applicants to achieve monthly billing at earlier dates than they can reasonably commit to. As a result, the OEB will allow the exemptions to June 30, 2017 for Horizon and December 31, 2018 for Enersource.

Proposed conditions

The applicants have proposed three conditions that they submit would allow the OEB to consider the operations of the consolidated utility in the context of the OEB's statutory objectives related to adequacy, reliability and quality of electricity service, as that service is provided to customers in each of the four proposed rate zones:

1. LDC Co. shall track its operations in four separate rate zones (equivalent to the service areas of the former Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, PowerStream Inc. and Hydro One Brampton Networks Inc.) until the end of the third year following the completion of the consolidation of the four predecessor utilities. The end of the third year following the completion of the consolidation is expected to be December 31, 2019.

2. LDC Co. shall report to the OEB on Electricity Service Quality Requirements (ESQRs) and other reportable financial metrics as set out in the OEB's Reporting and Record-Keeping Requirements (RRR) separately for each of the four rate zones for that three-year period.

3. LDC Co. may, at its option, report to the OEB under the RRR on a consolidated basis, instead of separately for the four rate zones, after the end of the third year following the completion of the consolidation of the four predecessor utilities.

Energy Probe and OEB staff support conditions 1 and 2 and Energy Probe submits that LDC Co should be required to report on a consolidated basis in addition to each of the four rate zones. OEB staff submits that the OEB should revise Condition 3 to clarify what happens going forward from year four. OEB staff also submits that, while the consolidation will be complete after three years, the OEB may wish to consider whether the reporting of certain metrics, such as reliability, is still required on an individual rate zone basis. Energy Probe disagrees with the proposed Condition 3, arguing that this should be at the OEB’s option not the applicants’ option.

VECC argues that the proposed licence amendments were made at the end of the proceeding without the aid of discovery and makes no submissions on the merits of the proposed amendments. VECC and CCC submit that parties should be given a further opportunity to make submissions on any licence conditions.

SEC submits that the proposed reporting requirements are inadequate to ensure that the OEB has sufficient information to protect the customers. SEC proposes that , as long as the rates for each of the consolidating distributors is different, LDC Co should be required to file full annual reporting of accounting results, and scorecard results, on a segmented basis for each of the four service areas.

SEC submits that it has concerns with the applicants’ proposal to delay the filing of a combined DSP until 2019, arguing that this represents insufficient prioritization of the DSP in the transitional period. SEC submits that the DSP is a central element of distributor planning and operational effectiveness. SEC submits that the OEB should require, as a condition of the new licence for LDC Co, that it file a DSP for the combined entity no later than December 31, 2017.

The applicants submit that there is insufficient time to develop a DSP by the end of 2017. The applicants submit that they are able to report on reliability on an individual rate zone basis until the end of the rebasing deferral period.

BOMA submits that the OEB should require that a coherent governance plan be put in place and filed with the OEB and intervenors prior to closing and that the OEB approve the governance plan prior to the closing, and prior to the issuance of a licence for the new utility. In support of its submission, BOMA submits that the Board of Directors for LDC Co has not yet been appointed and there is no evidence on the composition of this Board. BOMA further submits that the applicants' evidence is that key executives of LDC Co are being appointed by and will report to different people which complicates the accountability and could lead to confusion of mandates.

OEB Findings

The OEB notes that the applicants have proposed that LDC Co track the operations of each of the four predecessor utilities and that reporting to the OEB take place separately until December 31, 2019, when the completion of the consolidation of the four predecessor utilities is expected to occur. The Handbook, however, sets out that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers. The OEB is of the view that this principle continues to be applicable in this case. The OEB does not require, nor encourage reporting on a "separate" utility basis. Rather the expectation of the OEB is that LDC Co shall report in accordance with the requirements of its licence. Consequently, the OEB considers that the applicants' proposed conditions are not necessary and will not be included in the LDC Co licence.

BOMA has submitted that the OEB should approve a governance plan for LDC Co prior to the issuance of a licence arguing that the process for appointing key executives of LDC Co and the proposed reporting structure complicates the accountability and could lead to confusion of mandates. The applicants have confirmed in oral testimony[9] that Mr. Max Cananzi, in his role as president of LDC Co, will be responsible for the certification of all RRR and electricity distribution rate applications and will also be accountable for compliance matters and regulations. Mr. Cananzi further attests in the licence application to his accountability for compliance with all of LDC Co's licence conditions and OEB Codes[10]**.** As a result, the OEB is satisfied that accountability has been established and will not require a governance plan to be filed and approved by the OEB.

[9] Transcript, Vol. 4, pp. 35-36 and Undertaking J3.1
[10] LDC Co licence application, p. 22

6 OTHER REQUESTS

The applicants make the following requests for approval by the OEB:

1. Transfer of the distribution licences and rate orders for each of the applicants and Hydro One Brampton to LDC Co

   OEB staff submits that if the OEB approves the licence application for LDC Co., the requested transfer of the licences of each of the applicants and Hydro One Brampton to LDC Co. is not necessary as the licence granted to LDC Co. permits LDC Co. to own and operate the distribution systems serving the former Enersource, Horizon, PowerStream and Hydro One Brampton service areas. SEC submits that the applicants have provided a draft distribution licence for LDC Co so that the licences of the merging entities can be cancelled when the new licence is issued.

   OEB staff support the applicants' request for the transfer of the rate orders of each of the amalgamating distributors to LDC Co. SEC submits that the rate order only applies to the company for whom it was originally made and that if a successor to the business, whether by acquisition of assets, or by amalgamation or other re-organization, wants to rely on the rate order, it must get a new order of the OEB allowing them to do so.

2. Continue to track costs to the regulatory asset accounts or deferral and variance accounts (DVAs) currently approved by the OEB for each of the applicants and Hydro One Brampton and to seek disposition of their balances at a future date and to seek disposition of Group 2 accounts in Annual Custom IR updates or in IRM applications, should the balances in these accounts become material.

   OEB staff submits that the OEB should approve the tracking of costs to the DVAs and that the disposition of Group 2 accounts should be consistent with the OEB's policy on disposition of Group 2 DVAs. OEB staff commented that ten years is a long time for Group 2 accounts not to be disposed and submits that Group 2 accounts should be cleared at least every five years, as would be the case for a non-consolidating distributor on the Price Cap IR rate-setting option and that this can be done through a stand-alone application. OEB staff further submits that the applicants should continue to maintain the capability to track the DVAs separately, so as to enable the appropriate disposition of the DVAs should the OEB decide that the DVAs are to be disposed separately to each rate zone in a future rates proceeding.

OEB Findings

The OEB approves the requested transfer of the rate orders of each of the applicants and Hydro One Brampton to LDC Co. The OEB agrees with OEB staff that the requested transfer of the licences to LDC Co is not required as the licence granted to LDC Co permits LDC Co to own and operate the distribution systems of the predecessor utilities.

The OEB grants approval to the applicants to continue to track costs to the deferral and variance accounts currently approved by the OEB for each of the applicants and Hydro One Brampton and to seek disposition of their balances at a future date. The OEB supports the OEB staff submission that the applicants should continue to maintain the capability to track the DVAs separately. Doing so will allow the DVAs to be disposed of separately by rate zone if such a determination is made in a future rates proceeding. In this application the OEB will not make a determination regarding future rate issues, but the OEB wants to ensure that the necessary information is available for a future panel to consider in a rates application.

7 CONCLUSION

The OEB concludes that the proposed amalgamation of Enersource, Horizon, PowerStream and Hydro One Brampton meets the no harm test and therefore the OEB approves this transaction.

The OEB also approves the LDC Co licence application and the transfer of the rate orders for each of the applicants and Hydro One Brampton to LDC Co but finds that a transfer of the distribution licences of each of the amalgamating entities to LDC Co is no longer required. The licences of the amalgamating entities will be cancelled upon the effective date of LDC Co's licence.

The OEB approves temporary exemptions from section 2.6.1A of the DSC until June 30, 2017 for Horizon and until December 31, 2018 for Enersource.

8 ORDER

THE BOARD ORDERS THAT:

1. Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, and PowerStream Inc. are granted leave to amalgamate to form LDC Co.

2. LDC Co is granted leave to purchase all of the issued and outstanding shares of Hydro One Brampton Networks Inc.

3. LDC Co and Hydro One Brampton Networks Inc. are granted leave to amalgamate and continue as LDC Co.

4. Enersource Holdings Inc. is granted leave to purchase all of the issued and outstanding shares of Enersource Hydro Mississauga Inc.

5. LDC Co is granted leave to purchase PowerStream Inc.'s existing shares of Collus PowerStream Utility Services Corp.

6. Hydro One Brampton Networks Inc. is granted leave to transfer its distribution system to LDC Co

7. The applicants shall promptly notify the OEB of the completion of the transactions referred to in paragraphs 1-5 above.

8. The applicants shall promptly notify the OEB of the completion of the transaction referred to in paragraph 6 above.

9. Once the notice referred to in paragraphs 7 and 8 is provided to the OEB, the OEB will transfer the Rate Orders of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, PowerStream Inc., and Hydro One Brampton Networks Inc. to LDC Co.

10. The leave granted in paragraphs 1-6 above shall expire 18 months from the date of this Decision and Order.

11. The application for an electricity distribution licence for LDC Co is granted, on such conditions as are contained in the attached licence.

12. The applicants shall promptly notify the OEB when the incorporation of LDC Co has occurred and provide the legal name of the merged entity to the OEB.

13. The licences of Enersource Hydro Mississauga Inc. Horizon Utilities Corporation, PowerStream Inc. and Hydro One Brampton Networks Inc. shall be cancelled upon the effective date of LDC Co's licence.

14. Temporary exemptions from section 2.6.1A of the DSC are approved for Horizon Utilities Corporation until June 30, 2017 and for Enersource Hydro Mississauga Inc. until December 31, 2018.

15. The applicants are granted approval to continue to track costs to the deferral and variance accounts currently approved by the OEB for each of the applicants and Hydro One Brampton and to seek disposition of their balances at a future date. The applicants are to continue to maintain the capability to track the DVAs separately for each rate zone.

16. The applicants shall file plans for the ESM by December 31, 2019.

17. Eligible intervenors shall file with the OEB and forward to the applicant their respective cost claims no later than 7 days from the date of issuance of this Decision and Order.

18. The applicants shall file with the OEB and forward to the intervenors any objections to the claimed costs of the intervenors within 17 days from the date of issuance of this Decision and Order.

19. Intervenors shall file with the OEB and forward to the applicant any responses to any objections for cost claims within 24 days from the date of issuance of this Decision and Order.

20. The applicants shall pay the OEB's costs of and incidental to, this proceeding immediately upon receipt of the OEB's invoice.

DATED at Toronto December 8, 2016

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario

Electricity Distribution Licence

ED-2016-0360

LDC Co

Valid Until

December 7, 2036

Original signed by

____

Kirsten Walli
Board Secretary
Ontario Energy Board

Date of Issuance: December 8, 2016

(Effective upon notification to the OEB that LDC Co is incorporated)

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

LIST OF AMENDMENTS

Board File No.	Date of Amendment

Table of Contents **Page No.**

1 Definitions

In this Licence:

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

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

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

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

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

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

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

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

"**IESO**" means the Independent Electricity System Operator;

"**Licensee**" means LDC Co

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

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

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

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

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

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

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

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

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

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

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

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

2 Interpretation

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

3 Authorization

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

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

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

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

11 Distribution Rates

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

12 Separation of Business Activities

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

13 Expansion of Distribution System

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

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

14 Provision of Information to the Board

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

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

15 Restrictions on Provision of Information

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

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

17.1 This Licence shall take effect upon notification to the OEB that LDC Co is incorporated. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

21 Conservation and Demand Management

21.1 2011-2014 Conservation and Demand Management Framework

21.1.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall:

21.1.2 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall:

a) Meet its 2014 Net Annual Peak Demand Savings Target of 45.610 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 189.540 GWh (collectively the "CDM Targets") for the Hydro One Brampton Networks Inc. Rate Zone as described in Schedule 1, over a four-year period beginning January 1, 2011.

b) Meet its 2014 Net Annual Peak Demand Savings Target of 92,980 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 147.220 GWh (collectively the "CDM Targets") to the Enersource Hydro Mississauga Inc. Rate Zone, as described in Schedule 1, over a four year period beginning January 1, 2011.

c) Meet its 2014 Net Annual Peak Demand Savings Target of 60.360 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 281.420 GWh (collectively the "CDM Targets") for the Horizon Utilities Corporation Rate Zone, as described in Schedule 1, over a four-year period beginning January 1, 2011.

d) Meet its 2014 Net Annual Peak Demand Savings Target of 95.570 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 407.340 GWh (collectively the "CDM Targets") for the PowerStream Inc. Rate Zone, over a four-year period beginning January 1, 2011.

21.1.3 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee's service area ("Board-Approved CDM Programs");

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or

c) a combination of a) and b).

21.1.4 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.1.5 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.1.6 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

21.2 2015-2020 Conservation and Demand Management Framework

21.2.1 The Licensee shall, between January 1, 2015 and December 31, 2020, make CDM programs, available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of its customer base, do so in relation to each customer segment in its service area ("CDM Requirement").

21.2.2 The CDM programs referred to in item 21.2.1 above shall be designed to achieve reductions in electricity consumption.

21.2.3 The Licensee shall meet its CDM Requirement by:

a) making Province-Wide Distributor CDM Programs, funded by the Ontario Power Authority (the "OPA"), available to customers in its licensed service area;

b) making Local Distributor CDM Programs, funded by the OPA, available to customers in its licensed service area; or

c) a combination of a) and b).

21.2.4 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to other licensed electricity distributors upon request.

21.2.5 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to any other person upon request.

21.2.6 The Licensee shall report to the OPA the results of the CDM programs in accordance with the requirements of the licensee's "CDM-related" contract with the OPA.

22 Pole Attachments

22.1 The Licensee shall provide access to its distribution poles to all Canadian carriers, as defined by the Telecommunications Act, and to all cable companies that operate in the Province of Ontario. For each attachment, with the exception of wireless attachments, the Licensee shall charge the rate approved by the Board and included in the Licensee's tariff.

22.2 The Licensee shall:

a) annually report the net revenue, and the calculations used to determine that net revenue, earned from allowing wireless attachments to its poles. Net revenues will be accumulated in a deferral account approved by the Board;

b) credit that net revenue against its revenue requirement subject to Board approval in rate proceedings; and

c) provide access for wireless attachments to its poles on commercial terms normally found in a competitive market.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

The Licensee's service area is comprised of the distribution service areas of the former Enersource Hydro Mississauga Inc. (ED-2003-0017); Horizon Utilities Corporation (ED-2006-0031); Hydro One Brampton Networks Inc. (ED-2003-0038); and PowerStream Inc. (ED-2004-0420) as they existed at the date of the completion of their consolidation, as approved by the OEB in its Decision and Order in OEB File No. EB-2016-0025. The service areas of these predecessor distributors are referred to as Rate Zones for the purposes of this Licence and for the purposes of the Rate Orders assigned to LDC Co as part of the OEB's Decision and Order in EB-2016-0025.

The Brampton Rate Zone:

1. The City of Brampton as at December 31, 1990 excluding:

    - the property with the municipal address of 7751 Winston Churchill Blvd;
    - lands located 45m south of the center-line of Castlemore Rd and 37.5m west of the center-line of Highway 50;
    - lands located 50m west of the centre-line of Mavis Road and 128m north of the City of Mississauga Boundary; and
    - lands located 70m west of the centre-line of Mavis Road and 75m north of the City of Mississauga Boundary.

2. Lots 1-78 inclusive and Parts 1-8 inclusive on the City of Brampton Draft Plan No. 21T-99002C.

The Enersource Rate Zone:

1. The City of Mississauga as of December 31, 1990, excluding:

    - the lands located on Winston Churchill Blvd, between Hwy 401 and Meadowpine Blvd with the civic address number 7575; and

    - the triangular piece of lands located between Dundas Street West to Ninth Line to Highway 403, generally between (250 metres north of) Burnhamthorpe Road to the north and Dundas Street West to the south.

2 The following lands located within the City of Brampton:

    - lands located 50m west of the centre-line of Mavis Road and 128m north of the City of Mississauga Boundary; and

    - lands located 70m west of the centre-line of Mavis Road and 75m north of the City of Mississauga Boundary.

The Horizon Rate Zone:

1. The former Police Village of Ancaster in the former Town of Ancaster as of December 31, 1973, now in the City of Hamilton and described as:

- NW corner of Concession 1, Lot 42 and Old Railway Line
- Directly NNE to middle of Concession I, Lot 46
- North to Dundas boundary, along boundary NE to Hamilton boundary, along Dundas/Hamilton boundary
- SW across Filman Road to include 1245 Filman, travel SW parallel with Hwy 2 to the escarpment
- S along escarpment (include Ancaster heights survey)
- S to W border of Concession II, Lot 49 to Railway Right of Way (behind Mohawk Road)
- SW to Cayuga Drive, W to Railway Right of Way
- West along Right of Way to far west boundary of Concession III, Lot 47
- South between Lot 46 and 47 to include 38 Chancery Drive West
- West, parallel with Golf Links Road to back lot of 23 Cameron Drive in Concession III, Lot 44
- Follow back of Cameron Drive back lot to 35 Cameron, go south parallel to end of 209 Rosemary Drive, East to the back of 206 Rosemary Drive
- North along back lots to 104 Rosemary, East to back lot of 103 Rosemary
- North along back lots of St. Margarets Road to Hwy 2
- Direct line SW, crossing over Fiddlers Green to middle of Concession III, Lot 41 North back lot of Rembrandt Court to Jerseyville Road W
- SW along Jersey ville through back lots of Blair, Terrence Park and Oakhill to back lot lien of 211/220 Colleen Crescent
- SW along Jersey ville through back lots of Blair, Terrence Park and Oakhill to back lot lien of 211/220 Colleen Crescent
- NE to division of back lot along border of Concession III, Lots 41 & 42
- SW along border to lot line of 145 Terrence Park, across Terrence Park to include back lots of 51 and 55
- SE over Terrence Park between houses 94 and 90
- N along the rear lots of Terrence Park and McGregor Crescent
- NE between houses 69 & 65 McGregor, across McGregor between houses 74 and 62

- Continue rear lots East between houses 54 and 50 McGregor
- North in direct line to Sulphur Springs Road
- West 100 metres, directly NW to Concession II, Lot 42 to Old Railway Line

2. The former Town of Dundas as of December 31, 1980, now in the City of Hamilton.

3. The former Police Village of Lynden in the former Town of Ancaster as of December 31, 1973, now in the City of Hamilton.

4. The former Village of Waterdown in the former Township of Flamborough as of December 31, 1980, now in the City of Hamilton.

5. The expansion area as set out in By-law No. 96-17-H in the former Township of Flamborough as of December 31, 1980, now in the City of Hamilton and defined as :

   - East Boundary: Concession 3 East – Centreline of Kerns Road extending north along east boundary of 60' Interprovincial Pipeline easement continuing north along boundary line between Town of Flamborough and City of Burlington.
   - North Boundary: Concession 5 East – Centreline of the 50' wide Sun Canadian Pipeline Company easement – extending across Hwy. No. 6, along boundary line between properties 25.50.200.430.56400 and 25.30.200.430.56800/25.30.200.430.56600.
   - West Boundary: Boundary line between Lots 19 and 20 on Concession 1, Concession 2, Concession 3, and Concession 4 proceeding northerly to north boundary as described above.
   - South Boundary: Flamborough/Burlington/Dundas boundaries where the electrical distribution systems of Ontario Hydro and Burlington Hydro are already separated.
   - Includes to the East: The boundaries of the Town of Lynden as defined in 1. above.

6. The City of Hamilton as of December 31, 2000.

7. The former City of Stoney Creek as of December 31, 2000, now in the City of Hamilton.

8. Plan 62 R-15706, Part of Lot 3, Block 1, Concession 1, former Geographic Township of Binbrook, in the former Township of Glanbrook, now in the City of Hamilton, comprising Part 1 to Part 11 inclusive.

9. Land located "in the former Township of Binbrook, in the former Township of Glanbrook, as of December 31, 1973, now in the City of Hamilton and described as Block 1, Block 2 and Street 'A' part of a plan of "The Brooks of Rymal/20 Phase 1", being a subdivision of Part of Lots 1 and 2 - Block 4, Concession 1".

10. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lots Six (6) and Seven (7), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as Summit

Park Phase 1 on Plan 62M. These lands are bounded to the north by Rymal Road east, to the east by Fletcher Road, to the west by Dakota Boulevard and to the south by a Hydro One Networks Inc. high voltage transmission line right of way.

11. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lots Six (6) and Seven (7), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as Summit Park Phase 2, on Plan 62M.

12. The City of St. Catharines as at December 31, 1990.

13. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Seven (7), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as Summit Park Phase 3, on Plan 62M.

14. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Seven (7), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as Summit Park Phase 4, on Plan 62M.

15. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Six (6), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as The Gardens at Summit Park on Plan 62M.

16. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Five (5), Block Four (4) in the First Concession of the Geographic Township of Binbrook and known as Summit Park Phase Six.

17. Lands located in the former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Five (5), Block Five (5) in the First Concession of the Geographic Township of Binbrook, Block 139 and known as The Summit Park Phase 5 on the registered Plan 62M except for the following address (which is excluded):

    - 31 Trinity Church Road in the City of Hamilton.

18. Lands located in the former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Two (2), Blocks Three (3), Four (4), Five (5), Nine (9), Ten (10) and Eleven (11).

19. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the city of Hamilton and described as Part of Township Lots Four (4) and Five (5), Block Four (4) of the First Concession of the Geographic Township of Binbrook, City of Hamilton and known as Summit Park Phase Seven.

20. The following properties on Rymal Road East in the City of Hamilton – 2062, 2064, 2066, 2068, 2070, 2070B, 2080.

21. Lands described by Plans 62M-1154, Blocks 1 and 2, 62R-18589 Parts 8 and 9, and 62R-18707 Parts 1, 2, 3 and 4.

22. Part of Lots Four (4) and Five (5), Block Four (4) of Concession 1 of the Geographic Township of Binbrook, City of Hamilton and known as Summit Park Phase Eight.

23. 2100 Rymal Road East, Hannon, Ontario in the City of Hamilton and designated as Lot 3, Block 3, Concession 1, Binbrook, Ontario

The PowerStream Rate Zone:

1. The Town of Markham as of January 1, 1979.

2. The service area is co-terminus with the City of Vaughan municipal boundary pursuant to the Regional Municipality of York Act, R.S.O. 1990, R.18, with the exception of an area two lots north of King-Vaughan Rd. abutting 7th Concession of the Town of King, as detailed in the parcel lot descriptions noted in Appendix B.

3. The Town of Richmond Hill as of January 1, 1979, with the exception of the boundary along Bathurst St, two lots north of King-Vaughan Rd. to Bloomington Rd., noted in Appendix B.

4. The Town of Aurora as of January 1, 1979, with the exception of the boundary along Bathurst St, seven lots north of Bloomington Rd. to two lots north of St. John's Sideroad, noted in Appendix B.

5. Lands located 45m south of the center-line of Castlemore Rd and 37.5m west of the center-line of Highway 50 in the City of Brampton.

6. City of Barrie Service Area:

   Within the municipal boundary of the City of Barrie as detailed firstly in Schedules A and B to the Barrie-Innisfil Annexation Act, 1981, secondly in the Schedule to the Barrie-Vespra Annexation Act, 1984 and thirdly as shown on Reference Map Document Number 4884 included on page 4 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board.

7. Community of Bradford West Gwillimbury Service Area:

   Within the Community of Bradford-West Gwillimbury as detailed firstly as the "Expansion Service Area" in Schedule 'B' and 'C' to the Corporation of the Town of Bradford-West Gwillimbury By-law 95-048 dated September 11, 1995, and shown in attached Reference Map, Document Number 4993, and further described in attached Map 1. The boundary is defined by Crooked Creek between Middletown Road (10th Sideroad) to the West and the concession line between lot 12 and lot 13 to the East, south of Holland Street West and north of 6th Line in the Town of Bradford-West Gwillimbury.

8. Community of Thornton Service Area:

   Within the Community of Thornton as detailed firstly in the Thornton Settlement Area in accordance with Schedule “A” of the Official Plan of the Township of Essa as approved by the County of Simcoe, April 22, 2003 and secondly as shown on Reference Map Document Number 5009 included on page 6 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board, excluding the following municipal addresses:

- #'s 6, 8, 10, 12, 19, 21, 23, 25, 27, 28, 29, 30, 31, 32, 33, 34 and 35 Earl's Court;
- # 4520 Robert Street (or County Road 21 Pt.16 Concession11);
- all residential lots fronting onto Jamieson Court from Thornton Ave to the cul-de-sac dead end;
- #'s 218, 219, 220, 221, 222, 223, 224, 225, 226, 227, 228, 229, 230, 231, and 232 Thornton Avenue;
- all residential lots fronting onto Lennox Court from Spence Avenue to the cul-de-sac dead end;
- all residential lots fronting onto Spencer Avenue except # 221 Spencer Avenue from Thornton Avenue to North Ridge Road;
- all residential lots fronting onto North Ridge Road except #'s 204 and 205 from Camilla Crescent to Spencer Avenue.

9. Community of Alliston Service Area:

Within the Community of Alliston as detailed firstly as the "Alliston Urban Area Expansion" in Schedule 'A' to the Corporation of the Town of the Amalgamated Municipalities of Alliston, Beeton, Tecumseth & Tottenham By-law 91-169 dated October 15, 1991 (entiltled "H.E.C. Service Area Expansion By-Law") and secondly as shown on Reference Map Document Number 5720 included on page 7 of "Schedule 1 Definition of Distribution Service Area" dated March 10, 2004, filed as supplementary material with the Board, excluding the consumer located at 4700 Tottenham Road. 2011 – to include lands as described in Proposed Draft Plan of Subdivision of Belterra Estates, to include Part of Lots 12 &13, Concession 14 and Parts of Lots 12 & 13, Concession 15, file number NT-T03002 under the Corporate Township of Tecumseh. In effect it will include lands east of the current border to include the new subdivision by Cable Bridge Enterprises Inc. (Belterra Estates).

10. Community of Beeton Service Area:

Within the Community of Beeton as detailed firstly as the "Beeton Urban Area Expansion" in Schedule 'A' to the Corporation of the Town of the Amalgamated Municipalities of Alliston, Beeton, Tecumseth & Tottenham By-law 91-169 dated October 15, 1991 (entiltled "H.E.C. Service Area Expansion By-Law") and secondly as shown on Reference Map Document Number 4982 included on page 8 of "Schedule 1 Definition of Distribution Service Area" dated March 10, 2004, filed as supplementary material with the Board.

11. Community of Tottenham Service Area:

Within the Community of Tottenham as detailed firstly as the "Tottenham Urban Area Expansion" in Schedule 'A' to the Corporation of the Town of the Amalgamated Municipalities of Alliston, Beeton, Tecumseth & Tottenham By-law 91-169 dated October 15, 1991 (entiltled "H.E.C. Service Area Expansion By-Law") and secondly as shown on Reference Map Document Number 5013 included on page 9 of "Schedule 1 Definition of Distribution Service Area" dated March 10, 2004, filed as supplementary material with the Board. It is noted that the "Beeton Creek" referenced in this schedule is technically a tributary to the actual Beeton Creek. The location of this tributary creek is shown on the Reference Map and it is to the east of the former Village of Tottenham.

12. Community of Penetanguishene Service Area:

    Within the Community of Penetanguishene as detailed firstly as the “Boundary Expansion Agreement” or “Annexation Transfer Agreement” dated December 31, 1998 between the former Ontario Hydro and the Penetanguishene Hydro-Electric Commission and secondly as shown on Reference Map Document Number 5001 included on page 10 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

1. The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

With respect to the Enersource Rate Zone:

1. The Licensee is exempt from the requirement of section 2.6.1A of the Distribution System Code to issue a bill to each non-seasonal residential customer and each General Service <50kW customer in the Enersource Rate Zone on a monthly basis. This monthly billing exemption expires on December 31, 2018

With respect to the Horizon Rate Zone:

1. The Licensee is exempt from the requirement of section 2.6.1A of the Distribution System Code to issue a bill to each non-seasonal residential customer and each General Service <50kW customer in the Horizon Utilities Rate Zone on a monthly basis. This monthly billing exemption expires on June 30, 2017.

APPENDIX A MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

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

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

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

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

2. Information Given to IESO

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the

IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

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

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

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

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

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

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

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

2. Information Given to IESO

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

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

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

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

APPENDIX B LAND DESCRIPTIONS

No.	Area	Legal Description	No.	Area	Legal Description
1	Vaughan	PT LOT 2, CON 7, PTS 6 & 8, 65R24532; KING ; T/W R216549; S/T EASE OVER PT 6, 65R24532 AS IN A24558A AND RENEWED BY R610943.	17	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING
2	Vaughan	PT E 1/2 LT 2 CON 7 KING; PT LT 3 CON 7 KING AS IN R707971; S/T & T/W B35507B ; S/T A24558A KING	18	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING
3	Vaughan	PT LT 2 CON 6 KING AS IN A55205A EXCEPT PTS 1 & 2 65R18259 ; KING	19	Richmond Hill	PT LT 2 CON 2 KING; PT LT 3 CON 2 KING AS IN B16975B, B19261B & A29730A EXCEPT PTS 4 & 5 65R14738 & PTS 8 & 9 65R531 ; KING
4	Vaughan	PT LT 2 CON 6 KING AS IN A55205A EXCEPT PTS 1 & 2 65R18259 ; KING	20	Richmond Hill	LOT 5, CONCESSION 2, KING
5	Vaughan	PT E 1/2 LT 2 CON 7 KING; PT LT 3 CON 7 KING AS IN R707971; S/T & T/W B35507B ; S/T A24558A KING	21	Richmond Hill	PT LT 3 CON 2 KING PT 2 65R5820 ; KING
6	Vaughan	PT E 1/2 LT 2 CON 7 KING; PT LT 3 CON 7 KING AS IN R707971; S/T & T/W B35507B ; S/T A24558A KING	22	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING
7	Vaughan	PT LT 3 CON 6 KING AS IN R184760 ; KING	23	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING
8	Vaughan	PT LT 3 CON 6 KING AS IN R184760 ; KING	24	Vaughan	LOT 2, CONCESSION 2, KING TWNSHP
9	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING	25	Vaughan	PT LT 5 CON 2 KING PT 2 65R599 ; KING
10	Richmond Hill	PT LT 3 CON 2 KING PT 2 65R5820 ; KING	26	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING
11	Richmond Hill	LOT 7, CONCESSION 2, KING	27	Vaughan	PT LT 5 CON 2 KING PT 2 65R599 ; KING
12	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING	28	Aurora	PT LT 14 CON 2 KING AS IN R180958 EXCEPT PT 13 EXPROP PL R233113 ; KING ; SUBJECT TO EXECUTION 95-05877, IF ENFORCEABLE. ; SUBJECT TO EXECUTION 95-06771, IF ENFORCEABLE. ; SUBJECT TO EXECUTION 96-02878, IF ENFORCEABLE. ;
13	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING	29	Aurora	PT LT 14 CON 2 KING AS IN KI25920 EXCEPT PT 11 EXPROP PL R233113 ; KING ; SUBJECT TO EXECUTION 96-06008, IF ENFORCEABLE. ;
14	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING	30	Aurora	PT LT 14 CON 2 KING PT 1 65R2712 ; KING
15	Richmond Hill	PT LT 2 CON 2 KING; PT LT 3 CON 2 KING AS IN B16975B, B19261B & A29730A EXCEPT PTS 4 & 5 65R14738 & PTS 8 & 9 65R531 ; KING	31	Aurora	PT LT 14 CON 2 KING PT 1 65R2712 ; KING
16	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING	32	Aurora	PT LT 15 CON 2 KING PT 2 65R8504 ; KING

No.	Area	Legal Description	No.	Area	Legal Description
33	Aurora	PT LT 15 CON 2 KING PT 1 65R8504 ; KING	51	Aurora	PT LT 22 CON 2 KING; PT LT 23 CON 2 KING PT 1, 65R6742 ; KING
34	Aurora	PT LT 15 CON 2 KING AS IN B47985B EXCEPT PT 8 EXPROP PL R233113 ; KING	52	Aurora	PT LT 22 CON 2 KING; PT LT 23 CON 2 KING PT 1, 65R6742 ; KING
35	Aurora	PT SE1/4 LT 16 CON 2 KING PTS 2 & 3 65R10629; T/W R439940 ; KING	53	Aurora	PT LT 24 CON 2 KING AS IN R629682 T/W R137178 ; KING
36	Aurora	PT SE1/4 LT 16 CON 2 KING PTS 2 & 3 65R10629; T/W R439940 ; KING	54	Aurora	PT LT 24 CON 2 KING AS IN R629682 T/W R137178 ; KING
37	Aurora	PT NE1/4 LT 16 CON 2 KING PT 2 65R15552 ; KING	55	Aurora	PT LT 24, CON 2, (KING) IN R662420 EXCEPT PTS 1 & 2, PL 65R29165, KING
38	Aurora	PT NE1/4 LT 16 CON 2 KING; PT LT 17 CON 2 KING; PT LT 18 CON 2 KING PTS 1, 3 65R15552 ; KING	56	Aurora	LOT 16, CONCESSION 2, KING
39	Aurora	PT NE1/4 LT 16 CON 2 KING; PT LT 17 CON 2 KING; PT LT 18 CON 2 KING PTS 1, 3 65R15552 ; KING	57	Aurora	PT LT 15 CON 2 KING AS IN R166067 EXCEPT R242869 ; KING
40	Aurora	PT LT 18 CON 2 KING PT 1 65R5395 ; KING	58	Aurora	PT LT 15 CON 2 KING AS IN R400615 ; KING
41	Aurora	PT LT 18 CON 2 KING AS IN R602840 ; KING	59	Aurora	PT SE1/4 LT 16 CON 2 KING PT 1 65R3379; T/W R145038 ; KING
42	Aurora	LOT 18, CONCESION 2, KING TWSHP	60	Aurora	PT LT 14 CON 2 KING AS IN B50839B EXCEPT PTS 10 & 12 EXPROP PL R233113; PT LT 15 CON 2 KING AS IN B27240B EXCEPT PT 2 65R9307; T/W R406638 ; KING
43	Aurora	PT LT 18 CON 2 KING PT 1 65R13476 ; KING	61	Aurora	PT LT 14 CON 2 KING AS IN B50839B EXCEPT PTS 10 & 12 EXPROP PL R233113; PT LT 15 CON 2 KING AS IN B27240B EXCEPT PT 2 65R9307; T/W R406638 ; KING
44	Aurora	PT LT 18 CON 2 KING PT 1 65R13476 ; KING	62	Aurora	PT LT 15 CON 2 KING PTS 2, 3 & 4 65R17617; S/T R660937; T/W R660070. ; KING
45	Aurora	PT LT 18 CON 2 KING PT 1 65R609 EXCEPT PT 8 EXPROP PL R233114 ; KING	63	Aurora	PT LT 15 CON 2 KING PT 5 65R17617; T/W R660938 ; KING
46	Aurora	LOT 19, KING TWSHP	64	Aurora	NE1/4 LT 16 CON 2 KING PTS 1,2 65R3343; SE1/4 LT 16 CON 2 KING PTS 3,4 65R3343 ; KING
47	Aurora	LOT 19, KING TWSHP	65	Aurora	PT LT 13 CON 2 KING AS IN R306307 S/T INTEREST IN KI22671, S/T DEBTS IN R306307 ; KING
48	Aurora	PT LT 20 CON 2 KING PT 1 65R1245 EXCEPT PT 11, EXPROP PL R233114 ; KING	66	Aurora	PT SE1/4 LT 16 CON 2 KING PT 1, 65R20034; KING
49	Aurora	PT LT 21 CON 2 KING; PT LT 22 CON 2 KING AS IN B2661B EXCEPT PT 4 B33711B; DESCRIPTION MAY NOT BE ACCEPTABLE IN THE FUTURE AS IN B2661B ; KING	67	Aurora	PT SE1/4 LT 16 CON 2 KING PT 3, 65R20034; T/W R720871 ; KING ; SUBJECT TO EXECUTION 96-00974, IF ENFORCEABLE
50	Aurora	PT LT 22 CON 2 KING; PT LT 23 CON 2 KING PT 1, 65R6742 ; KING	68	Aurora	LOT 21, CONCESSION 2, KING TWNSHP