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December 23, 2016

RESS, EMAIL & COURIER

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

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: Application by Great Lakes Power Transmission LP for 2017 Transmission Rates (EB-2016-0356)

We are counsel to Great Lakes Power Transmission LP ("GLPT"). Enclosed, please find GLPT's application and pre-filed evidence for 2017 transmission rates. The Board has assigned file no. EB-2016-0356 to this proceeding.

Should you have any questions, please do not hesitate to contact the undersigned.

Yours truly,

per Tyson Dyck

Charles Keizer

Tel 416.865.7512
Fax 416.865.7380
ckeizer@torys.com

cc: Duane Fecteau, GLPT
Tyson Dyck, Torys LLP

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2017 transmission rates and related matters.

EB-2016-0356

1. Great Lakes Power Transmission Inc. in its capacity as the General Partner of Great Lakes Power Transmission LP ("GLPT"), a limited partnership formed under the laws of Ontario, carries on the business of owning and operating electricity transmission facilities in the vicinity of Sault Ste. Marie, Ontario.

2. GLPT hereby applies to the Ontario Energy Board (the "Board") for an Order or Orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998*, as amended (the "OEB Act"), approving just and reasonable rates for the transmission of electricity in 2017.

3. The Applicant has materially followed the filing requirements applicable to a revenue cap index proposal, as set out in Chapter 2 of the Board's *Filing Requirements for Electricity Transmission Applications,* dated February 11, 2016.

4. GLPT is seeking Board approval for 2017 base revenue requirement of $40,533,904, which was calculated using GLPT's 2016 OEB approved revenue

requirement as the base revenue adjusted by an annual adjustment under the revenue cap index framework to be included in the Board's determination of the 2017 Uniform Transmission Rates for Ontario.

5. GLPT requests that the proposed revenue requirement be reflected in rates effective January 1, 2017. However, if implementation occurs after January 1, 2017, GLPT requests that the existing transmission rates be made interim to permit the implementation of the proposed revenue requirement effective as of January 1, 2017.

6. GLPT also requests an accounting order to establish a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2017 until GLPT's proposed 2017 rates are implemented, if necessary.

7. Furthermore, GLPT is requesting approval to disburse, through the use of account 1595, the balances in various deferral and various accounts in 2017 as described more particularly in Exhibit 5 of the pre-filed evidence.

8. GLPT is also requesting approval for continuation in the test period of account 1508 and sub-accounts Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs, Property Tax and Use and Occupation Permit Fees, IFRS Gains and Losses and OEB Cost Assessment.

9. Based upon the Accounting Procedures Handbook, GLPT will continue to maintain in the test period account 1592 for tax variances and account 1595 related to previously approved regulatory asset collections.

10. In the event GLPT encounters unforeseen events which meet the three defined eligibility criteria of Causation, Materiality and Prudence, GLPT would also seek to establish a new Z-factor deferral account in Account 1572.

11. This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

12. The Applicant requests that, pursuant to Section 34.01 of the Board's *Rules of Practice and Procedure,* this proceeding be conducted by way of written hearing.

13. The persons affected by this Application are the ratepayers of the Uniform Transmission Rate. It is impractical to set out their names and addresses because they are too numerous.

14. The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

Great Lakes Power Transmission Inc.
on behalf of Great Lakes Power Transmission LP
2 Sackville Road, Suite B
Sault Ste. Marie, Ontario
P6B 6J6

Attention: Mr. Duane Fecteau
General Manager
Telephone: (705) 256-3846
Fax: (705) 941-5600
Email: dfecteau@glp.ca

- and -

Mr. Kevin Lewis
Controller
Telephone: (705) 759-7605
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The Applicant's Counsel:

Torys LLP
79 Wellington Street West, Suite 3000
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M5K 1N2

Attention: Mr. Charles Keizer
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Fax: (416) 865-7380
Email: ckeizer@torys.com

- and -

Mr. Tyson Dyck
Telephone: (416) 865-8136
Fax: (416) 865-7380
Email: tdyck@torys.com

DATED at Toronto, Ontario, this ____ day of December, 2016.

GREAT LAKES POWER TRANSMISSION INC. ON BEHALF OF GREAT LAKES POWER TRANSMISSION LP

By its counsel,

per

Charles Keizer

SUMMARY OF THE APPLICATION

1.0 Introduction

Great Lakes Power Transmission LP is a limited partnership duly registered in the Province of Ontario, the partners of which are Great Lakes Power Transmission Inc., as general partner, and Great Lakes Power Transmission Holdings LP, as limited partner (collectively, "GLPT"). GLPT is a licensed transmitter under licence number ET-2007-0649.

On March 10, 2016 Hydro One Inc. ("HOI") filed a Section 86 (2) (b) Application for the Leave to Purchase Voting Securities of Great Lakes Power Transmission Inc. with the Ontario Energy Board ("OEB") (EB-2016-0050). In that application, HOI sought OEB acceptance of a proposed 10 year rate rebasing deferral period, an earnings sharing mechanism, and a methodology to calculate GLPT's revenue requirement during the deferral period. Along with approving the purchase of the securities, the OEB accepted HOI's proposal to defer the rebasing of rates for GLPT for a 10 year period as well as its proposed earnings sharing mechanism, but did not fully accept the proposed rate-setting framework for GLPT, namely, the resetting of rates at the beginning of a 10-year deferral period:

> *"…rate-setting policies associated with consolidation are predicated on the notion that the going-in rates are the rates intended to provide the revenues required as the starting point to achieve savings over the deferred rebasing period[1]".*

[1] EB-2016-0050 Decision and Order, page 17

The OEB determined that GLPT can continue with its existing 2016 revenue requirement and file a new rate application, proposing a revenue cap index framework for the deferral period. The Decision and Order from EB-2016-0050 ("MAAD Decision") is attached as **Appendix 'A'**.

As a result, this transmission rate application (the "Application"), filed by Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP, is based on a revenue cap index for 2017 which is modelled on the price cap incentive regulation framework ("Price Cap IR') used for distributors. As GLPT is seeking an adjustment to its OEB approved 2016 revenue requirement which was fully reviewed and approved by the Board in EB-2014-0238, this application is intended to represent year two of the five-year revenue cap adjustment and provides the information as requested in the MAAD Decision, specifically, "the annual adjustment (expected inflation, productivity, stretch factors) and proposed performance reporting and monitoring (draft scorecard, RRR filings, etc.)"[2].

Among other things, GLPT is seeking approval to recover its 2017 base revenue requirement in the amount of $40,533,904, to be included in Ontario's 2017 Uniform Transmission Rates. In calculating the 2017 revenue requirement in accordance with the revenue cap framework, GLPT applied a formula to its approved 2016 base revenue requirement of $39,778,120. The revenue requirement increase sought by GLPT is 1.90%. This figure is calculated in the same fashion as a Price Cap IR for distributors in accordance with the Report of the Board *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's*

[2] Ibid, page 19

Electricity Distributors (EB-2010-0379), where GLPT has utilized an inflation factor of 1.90%, less a productivity and stretch factors of zero percent.

The approval of GLPT's revenue requirement, plus the disbursal of certain deferral and variance accounts receivable from ratepayers, will result in a 0.060% increase in the overall revenue requirement used in the calculation of Uniform Transmission Rates of Ontario ("UTR") for 2017.

This change in the GLPT revenue requirement does not result in any change to the existing UTR. GLPT estimates that the revenue requirement increases arising in this application will result in a negligible impact to the typical residential and retail customer's total bill for 2017.

1.1 Effective Date of Rates

GLPT requests that the proposed revenue requirement be reflected in rates effective January 1, 2017. For the 2017 test year, if implementation of approved rates occurs after January 1, 2017, GLPT requests that the existing transmission rates be made interim to permit the implementation of the proposed revenue requirement effective January 1, 2017, and that an accounting order be approved to establish a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2017 until GLPT's proposed 2017 revenue requirement and rates are implemented.

In the summary that follows, GLPT has provided a general overview of the Application and identified key aspects of the Application for the Board to consider.

2.0 General Overview

2.1 Performance and Reporting

GLPT is aligning itself with the principles of the OEB's Renewed Regulatory Framework for Electricity ("RRFE") through the development and integration of a balanced scorecard. GLPT has historically developed annual key performance indicators ("KPIs") for business performance measurement and is committed to continuous improvement in performance to maximize value for the ratepayer. The evolution of a balanced scorecard as described in Exhibit 3, Tab 1, Schedule 2 will further enhance GLPT's performance management and ensure that the objectives and goals of the company are being managed to create additional value for the ratepayer.

Reliability is an important metric included in GLPT's proposed scorecard, and one which forms an integral part of GLPT's KPIs which tie directly to employee compensation. GLPT uses Customer Delivery Point Performance Standards ("CDPPS") and unsupplied energy data to monitor its service quality and reliability. GLPT's CDPPS statistics indicate that reliability is improving, and for the most part is being maintained at levels that are superior to the standard average of performance. In addition, GLPT's unsupplied energy performance is meeting or exceeding the threshold as set by the IESO.

GLPT is committed to compliance and has managed its operation in the same fashion as it manages its health, safety and environmental programs, with a focus on ensuring compliance with applicable laws and standards. This is supported by GLPT having regulatory compliance as another business objective forming an integral part of its KPIs which tie directly to employee compensation. The implementation of GLPT's internal compliance program has been completed. The program is operational and at this time there are no outstanding areas of non-compliance.

2.2 Revenue Requirement and Annual Adjustment

This is GLPT's first transmission rate application under the Board's revenue cap index framework. In accordance with the Decision and Order in EB-2016-0050, GLPT has calculated its proposed 2017 revenue requirement, by using an annual adjustment to its 2016 OEB approved revenue requirement. The annual adjustment is based on proposed inflation, productivity and stretch factors. As noted by the Board in their Decision and Order in EB 2016-0050, "The OEB also recognizes that the incentive regulatory framework for transmitters is not as well defined as it is distributors." Further information on GLPT's revenue requirement and annual adjustment are found at Exhibit 4, Tab 1, Schedule 1.

2.3 Deferral and Variance Accounts

GLPT is requesting approval for continuance of the following deferral/variance accounts:

- Other Regulatory Assets Account 1508 and sub-accounts Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs, Property Tax and Use and Occupation Permit Fee, IFRS Gains and Losses and OEB Cost Assessment;
- Based upon the Accounting Procedures Handbook, GLPT will continue to maintain in the test period account 1595 related to previously approved regulatory asset recovery; and

- As described in the OEB's 2008 report entitled *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, OEB policy prescribes a 50/50 sharing of impacts of legislated tax changes from a utility's tax rates embedded in its OEB approved base rate known at the time of application. GLPT is proposing to maintain in the test period a sub-account within account 1592 to capture these impacts.

As described in more detail in Section 1.5 of Exhibit 2, Tab 1, Schedule 1, in the event GLPT encounters unforeseen events which meet the three defined eligibility criteria of Causation, Materiality and Prudence, a new Z-factor deferral account would be established in Account 1572.

Furthermore, GLPT is requesting approval to disburse the balances in the following accounts:

- Four sub-accounts of account 1508:
    - Comstock Claim;
    - Property Tax and Use and Occupation Permit Fee Variance;
    - Bulk Energy System ("BES") definitional change; and
    - OEB Cost Assessment Variance; and
- Account 1595 related to previously approved regulatory asset collections.

Account 1595 is currently being disbursed over a three year period. The collection period began on January 1, 2015 with the implementation of UTR for the 2015 calendar year. Therefore, at December 31, 2016, there will be one year remaining in the collection period. Subject to the approval of the various account balances that GLPT is seeking to disburse as part of this

Application, it is GLPT's position that the most administratively efficient method to disburse the various account balances would be to aggregate the balance of all accounts, including the remaining balance in account 1595, and disburse the balance in 2017. The total amount GLPT is seeking to disburse is a debit balance of $975,219. This disbursal methodology is consistent with prior rate applications, and is described in more detail in Exhibit 5, Tab 2, Schedule 1.

3.0 Rate Design and Rates

Aspects related to rate design, including the calculation of the UTR, are set out in Exhibit 7. In calculating the 2017 UTR, GLPT has used the base revenue requirement sought in this Application of $40,533,904, plus the forecasted disbursal related to the net deferral and variance accounts of $975,219, for a total of $41,509,123. As shown in Exhibit 7, the proposed UTR arising from this Application are expected to remain unchanged, as follows:

- Network Rate: $3.66 per kW
- Line Connection Rate: $0.87 per kW
- Transformation Connection Rate: $2.02 per kW

Appendix A

Decision and Order – EB-2016-0050

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

DECISION AND ORDER

EB-2016-0050

HYDRO ONE INC.

Application for the acquisition of Great Lakes Power Transmission Inc. by Hydro One Inc.

BEFORE: Ken Quesnelle
Presiding Member and Vice-Chair

Christine Long
Vice-Chair

Cathy Spoel
Member

October 13, 2016

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1 INTRODUCTION AND SUMMARY

This is the Decision of the Ontario Energy Board (OEB) regarding an application filed by Hydro One Inc. (Hydro One) requesting:

- Approval to purchase all of the voting shares of Great Lakes Power Transmission Inc. (GLPT).
- Acceptance of a proposed 10 year rate rebasing deferral period, earnings sharing mechanism, and methodology to calculate GLPT's revenue requirement for 2019 and for each subsequent year during the rate rebasing deferral period.

Section 86 of the *Ontario Energy Board Act, 1998* (Act) requires that the OEB review applications for a merger, acquisition of shares, divestiture or amalgamation that results in a change of ownership or control of an electricity transmitter or distributor and approve applications which are in the public interest.

The OEB recently 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, 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.

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

In reaching the Decision, the OEB was aided by the participation of intervenors and OEB staff.

The OEB has determined that Hydro One’s proposed share purchase transaction meets the no harm test. The OEB approves this transaction.

The OEB does not fully accept the rate-setting framework for GLPT rates, as proposed by Hydro One for the reasons set out in the Decision. The OEB is prepared to accept Hydro One’s proposal to defer the rebasing of rates for GLPT for a 10 year period as well as the proposed earning sharing mechanism, but cannot simultaneously accept the proposal that rates for GLPT must be reset at the beginning of this ten year period. The OEB has determined that GLPT can continue with its existing revenue requirement and file a new rate application, proposing a revenue cap index framework for the deferral period. It should include the components set out in the updated Chapter 2 Filing Requirements for Electricity Transmission Applications (Transmission Filing Requirements).

2 THE APPLICATION

Hydro One filed an application with the OEB on March 18, 2016 seeking approval to purchase all of the issued and outstanding voting securities of GLPT under section 86(2)(b) of the Act. Hydro One is also requesting the OEB's acceptance of its proposal to defer the rate rebasing of GLPT for ten years from the date of closing of the proposed transaction, an earnings sharing mechanism proposal for years 6 to 10 of the deferred rebasing period and a proposed methodology to calculate GLPT's revenue requirement for 2019 and for each subsequent year during the rebasing deferral period.

The applicant also requested confidentiality of certain parts of the Share Purchase Agreement (SPA), which sets out the terms of the proposed transaction. The OEB accepts the confidentiality requests, addressed in detail later in the Decision.

GLPT is the general partner of Great Lakes Power Transmission LP (GLPTLP) and is licensed on behalf of GLPTLP to provide transmission services in accordance with the terms and conditions described in Electricity Transmission Licence ET-2007-0649.

The SPA enables Hydro One to acquire various entities that own and control GLPTLP. According to the terms of the SPA, Hydro One will purchase securities comprised of the voting securities of the general partners, Great Lakes Power Transmission Holdings Inc. (GLPT Holdings) and GLPT. These will be owned by Hydro One. The limited partnership units of Great Lakes Power Transmission Holdings II LP will be owned by 1937672 Ontario Inc., a wholly owned subsidiary of Hydro One. A cash payment of $222 million has been agreed to by the parties for this transaction.

Following the completion of the share purchase transaction, GLPT and Hydro One will continue to operate as stand-alone licensed transmitters. Hydro One states that the existing GLPTLP debt covenants prevent GLPT from being amalgamated absent consent of the debt holders. This may involve renegotiation of the terms of the GLPTLP debt instruments which could result in substantial additional costs. Therefore, Hydro

One intends to allow GLPT's outstanding debt obligations to continue until they reach maturity in mid-2023. Amalgamation steps will be considered after this time.

Process

The OEB issued a Notice of Application and Hearing on April 7, 2016, inviting intervention and comment. The OEB approved intervention requests by Algoma Coalition, Association of Major Power Consumers in Ontario (AMPCO), Energy Probe Research Foundation (Energy Probe), Power Workers' Union (PWU), School Energy Coalition (SEC) and Vulnerable Energy Consumers Coalition (VECC).

The OEB provided for interrogatories and submissions on the application and held two days of oral hearing.

3 REGULATORY PRINCIPLES

3.1 The No Harm Test

The OEB has confirmed in the Handbook that it will continue to apply the no harm test in its assessment of applications relating to consolidation transactions. The no harm test was first established by the OEB in 2005 in the Combined Decision, and has been considered in detail in several recent OEB decisions. [2]

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.

[2] Hydro One Inc./Norfolk Power Distribution Inc. Decision– OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Haldimand County Hydro Inc. Decision – OEB File No. EB-2014-0244
Hydro One Inc./Woodstock Hydro Services Inc. Decision– OEB File No. EB-2014-0213

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.

As set out in the Handbook, while the OEB has broad statutory objectives, in applying the no harm test, the OEB's review has primarily focused on the impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and the 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

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[3] (the 2007 Report) and a further report issued under the same name on March 26, 2015 (the 2015 Report). The Handbook consolidates information provided in these two reports and identifies the key rate-making considerations expected to arise in a

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

consolidation transaction. To encourage consolidations, the OEB has introduced policies that provide consolidating distributors with an opportunity to offset transaction costs with savings achieved as a result of the consolidation. 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 Handbook also clarified the rate-setting mechanisms during the deferred rebasing period. The OEB requires 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 any increased benefits from consolidation.

The Handbook confirmed that the Incremental Capital Module (ICM), an additional mechanism under the Price Cap IR rate-setting option to allow adjustment to rates for discrete capital projects is available for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. To encourage consolidation, the 2015 Report extended the availability of the ICM for consolidating distributors that are on Annual IR Index, thereby providing consolidating distributors with the ability to finance capital investments during the deferred rebasing period without being required to rebase earlier than planned.

The Handbook confirmed that 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

Hydro One asserted that this transaction is expected to result in downward pressure on the cost structure of Hydro One and GLPT, as a result of savings opportunities in capital and operating, maintenance and administrative (OM&A) expenditures.

Hydro One provided a ten year forecast of capital expenditures and OM&A costs, reflecting "with transaction" and "without transaction" assumptions. Hydro One submitted that capital expenditure reductions are expected to result from some asset redundancy, the economic scale of Hydro One's operations, and potential savings from adopting Hydro One's asset management programs. Hydro One noted that the level of actual realized savings is uncertain and will depend on the experience gained by the parties in 2017 and 2018. Hydro One has anticipated operational synergies and savings to be achieved from 2019 onwards in the areas of procurement, maintenance programs, planning, operations, project management, engineering, scheduling, back-office administration, corporate governance, information technology and insurance.

Hydro One identified qualitative benefits associated with the transaction including coordinated regional planning, emergency response and ongoing outage management activities, and opportunities for GLPT's management and staff to work within the Hydro One organization, which will help address expected retirements and other attrition.

Hydro One submitted that longer term synergy savings opportunities are reasonably expected to result in reductions to underlying cost structures which would not arise but for the transaction. The transaction therefore promotes economic efficiency and cost effectiveness, which benefits customers in the long term.

While SEC agreed that the application meets the no harm test, it argued that the OEB should not have a policy of providing incentives to encourage consolidation in the transmission sector, as there are fundamental differences between the transmission and distribution sectors.

There are only a few transmitters. Hydro One owns 94.2% of the transmission system. This percentage will rise to 96.8% if this transaction is approved. SEC submitted that the transmitter consolidation might not promote economic efficiency and cost effectiveness as the consolidation degrades competition in the sector by removing one transmitter.

OEB staff submitted while the actual cost savings may be lower than projected, operational and capital synergies can reasonably be expected following the implementation of operational integration post-2018. OEB staff submitted that Hydro One's forecast of capital and OM&A expenditures does reflect expected reductions as a result of the transaction in the deferred rebasing period, which in OEB staff's view, is likely to continue to provide ratepayers with ongoing benefits when rebasing occurs in 2027.

OEB staff submitted that much like with distributors, as part of the OEB's performance-based regulatory framework, transmitters are also expected to achieve certain outcomes and provide value for money for customers. One of these outcomes is operational effectiveness, which requires continuous improvement in productivity and cost performance and delivery on system reliability and quality objectives.

OEB Findings

The OEB finds that the proposed share acquisition transaction meets the no harm test. The OEB accepts Hydro One's evidence that the transaction is expected to result in downward pressure on the cost structures of Hydro One and GLPT.

With respect to SEC's submissions on incentives to encourage consolidation in the transmission sector, the OEB recognizes that there may not be the same drivers for consolidation in the transmission sector as there are in the distribution sector. However, the OEB finds that consolidations between transmitters can, and in the case of the proposed consolidation, does provide similar forms of benefits to ratepayers.

The OEB finds that with respect to the submissions of SEC regarding the impact of the transaction on competition in the transmission sector, there are no negative impacts to customers and given the regulated monopoly nature of the business, no ill effect on competition. The OEB considers the references made by SEC to OEB proceeding EB-2010-0059 and the OEB's Decision on the East-West Tie Transmission Line, EB-2011-0040 reflecting a desire for competition embedded in various frameworks and policy statements, to be aimed at the building of new transmission facilities, not the operation of existing assets. There is no competition between incumbent transmitters; there is not even a rate differential given the province wide uniform transmission rate.

Reliability and Quality of Electricity Service

Hydro One provided a comparison of Hydro One's regional reliability indices, both SAIDI and SAIFI, against that of GLPT for the past six years. The results show that Hydro One's measures in most years are better than GLPT's. Hydro One submitted that coordination of Hydro One and GLPT's existing staff is expected to improve regional system knowledge, which would lead to coordinated regional planning.

Hydro One submitted that it does not expect that the reliability of either transmission system will be materially impacted as a result of the transaction as both GLPT and Hydro One are both experienced licensed transmitters that are required to design and operate their respective systems in conformance with the IESO Market Rules and the Ontario Resource & Transmission Assessment Criteria (ORTAC), and that both systems must also comply with reliability standards established by the North American Electric Reliability Corporation (NERC).

Energy Probe submitted that the assurances provided by the applicants that the reliability of the GLPT system will not deteriorate and that costs will not increase more than under a business-as-usual scenario to be inadequate. Energy Probe submitted that more weight should be placed on evidence regarding positive and negative outcomes from the consolidation merger, given the goals of consolidation and the outcomes expected from the OEB's regulatory framework.

OEB staff submitted that based on the evidence, service quality and reliability can reasonably be expected to be maintained by these consolidating utilities. OEB staff also submitted that these utilities should continue to meet the customer delivery point performance standards as approved by the OEB.

OEB Findings

The OEB expects that both Hydro One and GLPT will continue to comply with rules set out for all transmitters and meet the reliability standards established by NERC and the OEB approved customer delivery point standards. In the OEB's view, the proposed transaction does not lead to any adverse impact with respect to the reliability and quality of service to be provided by these consolidating utilities and the OEB finds that the no harm test is met in this regard.

The OEB does not accept Energy Probe's argument that positive benefits are required in its assessment of the no harm test.

Financial Viability

Hydro One submitted that neither it nor GLPT will seek to increase future revenue requirements recovered from customers in order to recover transaction costs and premiums associated with this transaction. Hydro One also submitted that the amount paid by Hydro One will not have a material impact upon its financial position, as it is approximately 2% of Hydro One's fixed assets, and will be paid in cash.

OEB staff agreed that the premium paid will have no material impact on Hydro One's financial viability.

OEB Findings

The OEB accepts Hydro One's evidence that the premium to be paid will not impact Hydro One's financial viability and finds that the proposed transaction therefore meets the no harm test with respect to financial viability.

4.2 Rate-making Considerations

Hydro One requested that the OEB accept its proposed selection of a 10 year rate rebasing deferral period for GLPT commencing on the closing date of the transaction, currently anticipated before or during the first quarter of 2017. The rate rebasing deferral period would end on December 31, 2026.

Hydro One has proposed an ESM that will take effect during the last five years of the rebasing deferral period: GLPT's revenue requirement will be adjusted so that prior year excess earnings are shared with ratepayers on a 50:50 basis for all earnings that exceed 300 basis points above the ROE approved by the Board for 2018 in GLPT's 2017-18 rates application. GLPT's audited financial statements will be used to calculate any earning sharing amounts if amalgamation has not occurred during the rebasing deferral period. If amalgamation occurs during the rebasing deferral period, GLPT's last available audited financial statement will serve as a proxy for the achieved ROE amount for purposes of calculating shared earnings. The shared amount will be held constant and treated as an annual credit to each subsequent revenue requirement amount in the remaining rebasing deferral period.

Subsequent to the filing of this consolidation application, GLPT filed a rate application for approval of its 2017 and 2018 revenue requirement. As part of the consolidation application, for 2019 and each subsequent year of the rebasing deferral period, Hydro One has proposed to calculate GLPT's annual revenue requirement by using GLPT's prior year revenue requirement and adjusting this amount with an inflation factor. Hydro One argued that it has put forward this proposal on the basis that there are certain unique aspects of this transaction, including that both Hydro One and GLPT are transmitters and, therefore have not been required to adopt to an IRM method of rate regulation. Hydro One suggested that the inflation adjustment proposal is akin to rate-setting proposals approved in other consolidation proceedings.

Hydro One submitted that the proposed inflation factor used during the rebasing deferral period aligns with the calculation described in Chapter 3 of the *Distribution Filing Requirements*. Hydro One proposed having the productivity and stretch factor be set at 0%, given that the circumstances in this case concern transmission entities and that the OEB does not have any established revenue adjustment mechanisms in place for transmission.

SEC and Energy Probe opposed Hydro One's proposal. They argued that under the deferred rebasing period, a transmitter or distributor is not able to rebase rates through a cost of service or a similar basis, yet GLPT intends to reset 2017 and 2018 rates. SEC also argued that the OEB should not allow a 10-year deferral period but instead apply the five-year deferral period that was originally set out in 2007.

OEB staff did not make submissions on the proposed deferred rebasing period but submitted that the proposed ESM follows the requirements of the 2015 Report and the Handbook. OEB staff submitted that it is feasible to use the ESM as a means to reduce the Uniform Transmission Rates (UTRs) to all Ontario transmission customers, and that it could be done in a way that is fair to all Ontario electricity customers.

In its reply submissions, Hydro One asserted that the use of cost-of-service methodology at the outset is reasonable because that's what transmitters are expected to come in to the OEB with, absent a consolidation transaction. Therefore, that is what GLPT is doing. Hydro One noted that GLPT does not have a rate order for the 2017 and 2018 period and that the notion put forward by SEC that higher rates will ensue after a cost-of-service methodology is wrong. Hydro One submitted that it has committed, in this application, that transaction costs and premium recovery will not be included in revenue requirements of Hydro One or GLPT.

Hydro One noted that intervenors, with the exception of OEB staff, took the view that the duration of the deferral period was something that could be challenged. However, Hydro One disagreed that the OEB has or should interpret the Handbook as suggesting that it has the discretion to impose a shorter or a period other than the one that has been selected by the applicant. Hydro One also argued that if the OEB were to reduce the deferral period to five years, it would hurt the ratepayer as it does not provide the ratepayer with the opportunity to share through the ESM.

Proposed Rate-Setting Methodology

OEB staff and the intervenors argued that the OEB should not approve Hydro One's rate-setting methodology. They argued that the proposal concerns a revenue-setting methodology which should properly be applied for and assessed by the OEB through a rate application.

With respect to the specific components of that methodology, SEC disagreed with Hydro One's proposed methodology to have GLPT's revenue requirements set for each year during the deferred rebasing period on a revenue cap basis and every year adjusted to take into account the OEB's set inflation factor. SEC noted that Hydro One is proposing no productivity or stretch factor, which is not consistent with how incentive regulation rates are set under IRM. SEC submitted that there should be no incentive at all necessarily for transmission consolidation and there should not be an added incentive, by not requiring a stretch or productivity factor in the price cap or revenue cap IR model. Energy Probe submitted that Hydro One and GLPT should not receive prior approval of the form and nature of 2017-18 rates for GLPT arguing that parties affected by its rate application may have an opinion regarding an appropriate rate-setting approach within the scope allowed by the Filing Requirements for Transmitters.

VECC submitted that approving Hydro One's plan to change the rate-making process by applying generic policies that the OEB has formulated largely for consolidating distribution utilities is at the potential detriment and harm of ratepayers. In VECC's view, the harm arises in large part out of the fact that the OEB will not, after 2018, be able to ensure future efficiencies that it can within the revenue requirement approval process.

OEB staff stated that it does not agree with Hydro One's reason that the productivity and stretch factors be set at zero, as the OEB's policies set out that the achieved savings realized in the deferred rebasing period are to the benefit of the consolidating shareholder. OEB staff noted that it is the deferred rebasing period rather than the incentive rate-setting plan that is intended to enable distributors or, in this case, a transmitter to fully realize anticipated efficiency gains from the transaction and retain achieved savings for the period of time to help offset the costs of the transaction.

Hydro One submitted that the Handbook states that rate-setting methodologies during the deferral period are matters that can and should be decided in the consolidation application process.

Hydro One noted that parties involved in amalgamation transactions require time to create new cost structures and performance improvements, which is the purpose of the deferral period. Hydro One argued that it has paid a premium of $150 million which provides enormous incentive for cost savings, cost structure reductions and performance benefits to be achieved and therefore, there is no need for additional incentive in the form of a productivity factor.

Hydro One submitted that the model they are proposing is for the benefit of both ratepayers and shareholder and that they are prepared to accept risks outside the paradigm of a cost-of-service methodology. Hydro One argued that the OEB consider the unique circumstances of this transaction in requesting the relief sought – that these two transmitter entities operate under a cost of service method of regulation, which is presently at the end of the current rate approval, and are required to seek the OEB's approval for rates; that the size differential between Hydro One and GLPT should not be discounted; and that individual facts and circumstances that affect the transaction, for example, outstanding debt covenants, that preclude immediate amalgamation are relevant and need to be taken into account.

In support of the proposed rate-setting methodology, Hydro One argued that approval of this methodology provides certainty and clarity to Hydro One and generally to market participants wanting to enter into consolidation transactions. Hydro One has submitted that the OEB take into account the unique facts and circumstances of this transaction in its consideration of the proposed methodology. Hydro One also argued that there would be no better information in a separate section 78 application to look at the rate methodology than there is now.

OEB Findings

The OEB does not fully accept the proposed rate-setting framework.

Hydro One submitted that it modeled its proposal on the Handbook requesting the deferral of rate rebasing for GLPT for 10 years with an ESM in place for years 6 to 10 of this period. Hydro One has, however, also proposed that the rates for GLPT be reset at the initial stages of the 10 year period.

The OEB accepts that the applicant's proposals for a 10 year deferred rebasing period and ESM are aligned with the Handbook. However, Hydro One's proposal for a resetting of rates at the beginning of the 10 year deferred rebasing period is not contemplated by the Handbook and the OEB does not accept it. Rate-setting policies associated with consolidation are predicated on the notion that the going-in rates are the rates intended to provide the revenues required as the starting point to achieve savings over the deferred rebasing period.

Hydro One has submitted that the proposal to have rates reset and then have rebasing deferred for ten years enables it to recoup the premium (approximately $150 million) and incremental transaction costs ($7.4 million).

The OEB does not consider the premium unless it will affect the financial viability of the purchaser, which is not the case here. The purchaser should be able to determine how much it thinks it can earn based on the existing rate structure being continued for 10 years and bid accordingly. Presumably, a purchaser who thinks it can drive more savings will pay a higher premium. If Hydro One has based its projections on some higher, not yet approved, revenue requirement, that should not enter into it.

As set out by the OEB in the Decision on Hydro One's acquisition of Norfolk Power Distribution Inc. (EB-2013-0196):

> *The intent of the framework established by the 2007 Report is that the amount of a premium paid by a purchaser would be determined by the purchaser's ability to serve the acquired service area at a lower cost, over a given period. The difference between the actual cost of service and the revenues generated during the given rate deferral period is intended to provide the purchaser with the funds to cover the transaction costs of the acquisition, including any premium. This aspect of the framework acts as a positive economic factor in the consolidation marketplace by favoring the purchaser that is able to serve the acquired service area at the lowest cost. The Board's future rate setting (whether or not on a harmonized basis) will be based on forward costs, and a*

> *purchaser should not expect that the revenues from future rates will provide any funds to cover any purchase premium.*

In response to Hydro One's argument for predictability for the business community, the OEB finds that the setting of the price a purchaser is willing to pay should reasonably assume stable rates for 10 years - it does not assume that these rates will be adjusted either up or down immediately following the purchase. The OEB is not convinced that the approval of a proposed rate-setting methodology in the deferred rebasing period provides rate or revenue certainty. A purchaser will not know what the rates will be if they are to be reset. It is not clear why any purchaser would bid in the face of such an unknown. More importantly, the OEB's mandate is to make decisions in the public interest, not to set price signals for the market.

As the rates will not be reset, the OEB will not address the issues raised about inflation, productivity factors, and similar issues.

The OEB also finds that there is no basis for Hydro One's argument that approval of GLPT's revenue requirement must be sought at the end of its term in order to continue to collect revenue. The OEB notes that contrary to the submissions by Hydro One, the current rate/revenue requirement order does not expire but continues until a new rate/revenue requirement order is issued.

The OEB recognizes that the Handbook better defines the rate-setting framework for the deferred rebasing period for distributor consolidations. However, the deferral period is predicated on maintaining existing rates that are already in a rate order.

Consolidating distributors are permitted to move to an IRM rate-setting methodology once their existing rate terms expire. The OEB also recognizes that the incentive regulation framework for transmitters is not as well defined as it is for distributors, whose stretch factors are established through benchmarking by the OEB. Nevertheless, the OEB has put in place its expectations for revenue cap index frameworks, as defined in the Transmission Filing Requirements.

The OEB notes that a cost of service application was filed by GLPT on August 26, 2016. However, the OEB finds that GLPT can continue with its existing revenue requirement. and may bring forward a separate rate application to seek approval for the elements of a specific revenue cap index framework, for the deferral period. Such an application would be expected to encompass the following components as required by the Transmission Filing Requirements: the annual adjustment (expected inflation, productivity, stretch factors) and proposed performance reporting and monitoring (draft scorecard, RRR filings, etc).

Z-Factor and Capital Factor Events

Hydro One included in the application a request anticipating the recovery of Z-factor and capital factor events (i.e. material costs incurred due to unforeseen events beyond the control of transmitters). Hydro One has also put forward in the application its position that this should be allowed to be applied for in the normal course, notwithstanding approval of the deferred rebasing period and the methodology forecast establishing the GLPT revenue requirement in this period.

OEB staff submitted that the Handbook extended the availability of the ICM for consolidating distributors that are on an annual IR index, thereby providing those consolidating distributors with the ability to finance capital investments during the deferred rebasing period without being required to rebase earlier than planned.

Hydro One's expectations for the recovery of Z-factor and capital factor events are, in OEB's staff's submission, rate matters which lie outside the scope of this proceeding and which Hydro One can address through a rate application.

OEB Findings

The OEB finds that Hydro One will be granted recourse to file for recovery of Z-factor events, if required, through a separate rate application. The OEB expects in all cases that an applicant will have to demonstrate that failure to recover the sought-after amount would have significant impact on its operations.

4.3 Batchewana First Nations Correspondence

A letter was filed with the OEB by the Chief of Batchewana First Nation of Ojibways, dated July 7, 2016. In the letter, the Batchewana First Nations claimed that GLPT does not have a valid section 28.2 permit, which is a permit under the federal *Indian Act*, R.S.C.**,** 1985, c. I-5 granted by the Minister for the use of reserve lands for various purposes for a particular purported 200-foot easement over the First Nation, affecting a former north transmission A and transmission B corridors that run west to eat and are located on Rankin Reserve 15D, south of Old Garden River Road. The permits were issued by the predecessor of the Department of Indigenous and North Affairs Canada, which expired on December 31, 2008 and have not been renewed.

OEB staff submitted that the issues raised in the letter relate to the *Indian Act* which is outside the jurisdiction of the OEB and, as such, the matter of whether or not there is a permit and if there is an issue of trespass by GLPT with respect to the particular area of land referenced in the letter are matters that are outside the scope of this proceeding. OEB staff noted that this proceeding involves the purchase of voting securities and, as such, is not one which, even if the OEB did have jurisdiction, would be a matter that is relevant to this proceeding.

The Batchewana First Nation requested in its submission that the transaction be placed on hold until such time as the grievances outlined in the letter have been addressed.

OEB Findings

The OEB considers that the matters raised by the Batchewana First Nations group are outside of the OEB's jurisdiction and finds that these matters are not affected in any way by the proposed share acquisition transaction that the OEB is required to approve. The OEB also notes that the Decision on this transaction will not impact the rights or remedies of the Batchewana First Nation with respect to their existing ongoing grievance claims.

4.4 Confidentiality Requests

Hydro One made two requests for confidentiality.

In accordance with section 5.1.4 of the OEB's Practice Direction on Confidential Filings (Practice Direction), Hydro One filed a request for confidentiality relating to information in the SPA that it considers commercially sensitive. Hydro One also sought confirmation, in accordance with section 4.3.1 of the Practice Direction, that certain identified personal information also contained in the SPA would not be disclosed in this proceeding.

In Procedural Order No. 1, the OEB allowed, as an interim measure, parties to review the confidential information claimed as commercially sensitive after signing a copy of the OEB's Declaration and Undertaking, and filing it with the OEB. The OEB also stated that parties would not be allowed to review personal information filed in confidence until the OEB determined whether the disclosure of the personal information is permitted under the *Freedom of Information and Protection of Privacy Act.*

Procedural Order No. 1 provided for a process for parties to object to the requests for confidentiality and stated that subsequent to any and all submissions received, the OEB would make its findings with respect to Hydro One's claims for confidentiality. OEB staff made submissions questioning the need for confidential treatment of information contained in sections 6.3.2, 9.6.2 and Schedule 9.6 of the SPA. Hydro One responded to OEB staff's submissions regarding section 6.3.2, stating that Hydro One was prepared to publicly disclose the redacted content as Hydro One's bond rating and asset valuation is publicly disseminated information.

Hydro One submitted that Section 9.6.2 and Schedule 9.6 concern information regarding Brookfield Infrastructure Holdings (Canada) Inc. which is unregulated and not subject to OEB oversight. Furthermore, the information set out in Schedule 9.6 is financial information relating to a letter of credit that will expire and be replaced on the closing of the transaction by a letter of credit obtained by Hydro One Inc. and 1937672 Ontario Inc. pursuant to Section 9.6 of the Purchase Agreement. As such, it does not form part of GLPT's operations post-closing and therefore is not relevant or material to the OEB's prospective consideration of the impact of the acquisition.

In Procedural Order No. 2, the OEB asked for further explanation as to why Section 2.4.1 (ii), Schedule 1.1.2.6 and Schedule 9.6 should be granted confidential status. Hydro One responded stating that each of these proposed redactions concerns financial information relating to unregulated entities that are not parties to the aspect of the transaction for which approval is being sought. Hydro One advised that the transacting parties have, however, reconsidered their position and submitted that public disclosure of these three particular items is acceptable and therefore withdrew its request for confidential treatment of this information..

The OEB also asked Hydro One to provide justification for all instances in which it has requested confidential treatment for an entire section or an entire schedule. The sections and schedules for which Hydro One, on behalf of the transacting parties, requested confidential treatment in their entirety are Sections 1.1.92 and 9.6.2, as well as Schedules 1.1.7, 1.1.116, 5.6 and 5.21. Hydro One advised that most of these redactions were requested on the basis that these sections and schedules concern financial information relating to unregulated entities that are not parties to the aspect of the transaction for which approval is being sought. Hydro One advised that despite this, the transacting parties have reconsidered their position and Hydro One submitted that public disclosure of these particular items is acceptable and therefore withdrew its request for confidential treatment of this information. Moreover, in connection with the disclosure of Section 1.1.92, Hydro One confirmed that the disclosure of Section 1.1.76 is also acceptable.

The OEB asked whether, in respect of the information contained in Schedule 9.2, Item 2, the commercial negotiations are ongoing or anticipated. Hydro One advised that the commercial negotiations referenced at Items 2 (a), (b), (c), (h) and (k) are ongoing. The commercial negotiations referenced at Item 2 (m) is anticipated. The commercial negotiations referenced at Items (d), (e), (f), (g), (i), U) and (I) are now completed. Based on discussion with the transacting parties, Hydro One advised that public disclosure of the completed negotiations (subject to the continued redaction of the name of the individual contained in Item 2(i)) is acceptable.

Based on the foregoing, Hydro One's request for confidential treatment applies to:

- parts of Sections 1.1.32 and 9.13, as well as parts of Schedules 1.1.85, 3.2.1.2, 5.11, 5.13, 5.17 and 5.18 as identified in the original confidentiality request; and
- the descriptions of ongoing and anticipated commercial negotiations in Schedule 9.2, Items 2 (a), (b), (c), (h), (k) and (m), as well as the name of the individual contained in Item 2(i).

OEB Findings

The OEB accepts the applicant’s requests for the confidential treatment of information contained in the SPA, as amended by the applicant on June 21, 2016.

5 CONCLUSION

The OEB concludes that Hydro One’s proposed share purchase transaction meets the no harm test and approves this transaction.

The OEB is prepared to accept Hydro One’s proposal to defer the rebasing of rates for GLPT for a 10 year period as well as its proposed earning sharing mechanism, but does not accept the proposal that rates for GLPT must be reset at the beginning of this ten year period.

The OEB has determined that GLPT can continue with its existing revenue requirement and bring forward a separate rate application, proposing a revenue cap index for the deferral period, encompassing the components set out by the Transmission Filing Requirements, as described above.

6 ORDER

THE BOARD ORDERS THAT:

1. Hydro One Inc. is granted leave to purchase all of the issued and outstanding voting securities of Great Lakes Power Transmission Inc.

2. The applicant shall promptly notify the OEB of the completion of the transaction referred to in paragraph 1 above.

3. The leave granted in paragraph 1 above shall expire 18 months from the date of this Decision and Order.

4. 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.

5. The applicant 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.

6. 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.

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

DATED at Toronto October 13, 2016

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Exhibit 1, Tab 1, Schedule 3

Revenue Requirement Work Form (2016 Approved)

Revenue Requirement Workform

Version 4.00

Utility Name	
Service Territory	*Great Lakes Power Transmission*
Assigned EB Number	EB-2014-0238
Name and Title	Scott Seabrook, Director of Administration
Phone Number	(705) 759-7624
Email Address	sseabrook@glp.ca

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)			(6)		Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$259,531,046		$ -	$ 259,531,046		$ -	$259,531,046	
	Accumulated Depreciation (average)	($41,366,782)	(5)	$ -	($41,366,782)		$ -	($41,366,782)	
	Allowance for Working Capital:								
	Controllable Expenses	$11,331,876		($210,000)	$ 11,121,876		$ -	$11,121,876	
	Cost of Power	$ -		$ -			$ -	$0	
	Working Capital Rate (%)	4.32%	(9)		4.40%	(9)		4.40%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$38,731,100		$0	$38,731,100		$0	$38,731,100	
	Distribution Revenue at Proposed Rates	$40,230,644		($452,525)	$39,778,120		$0	$39,778,120	
	Other Revenue:								
	Specific Service Charges	$ -		$0	$ -		$0	$ -	
	Late Payment Charges	$ -		$0	$ -		$0	$ -	
	Other Distribution Revenue	$ -		$0	$ -		$0	$ -	
	Other Income and Deductions	$89,900		$0	$89,900		$0	$89,900	
	Total Revenue Offsets	$ -	(7)	$0	$ -		$0	$ -	
	Operating Expenses:								
	OM+A Expenses	$11,331,876		($210,000)	$ 11,121,876		$ -	$11,121,876	
	Depreciation/Amortization	$9,771,327		$ -	$ 9,771,327		$ -	$9,771,327	
	Property taxes	$240,424		$ -	$ 240,424		$ -	$240,424	
	Other expenses	$ -		$ -	0		$ -	$0	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($2,115,011)	(3)		($2,115,011)			($2,115,011)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$1,608,920			$1,569,519			$1,569,519	
	Income taxes (grossed up)	$2,189,007			$2,135,400			$2,135,400	
	Federal tax (%)	15.00%			15.00%			15.00%	
	Provincial tax (%)	11.50%			11.50%			11.50%	
	Income Tax Credits	$ -			$ -			$ -	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	6.87%			6.87%			6.87%	
	Short-term debt Cost Rate (%)	2.11%			1.65%			1.65%	
	Common Equity Cost Rate (%)	9.36%			9.19%			9.19%	
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$259,531,046	$ -	$259,531,046	$ -	$259,531,046
2	Accumulated Depreciation (average)	(3)	($41,366,782)	$ -	($41,366,782)	$ -	($41,366,782)
3	Net Fixed Assets (average)	(3)	$218,164,264	$ -	$218,164,264	$ -	$218,164,264
4	Allowance for Working Capital	(1)	$489,809	($0)	$489,809	$ -	$489,809
5	**Total Rate Base**		$218,654,073	($0)	$218,654,073	$ -	$218,654,073

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$11,331,876	($210,000)	$11,121,876	$ -	$11,121,876
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$11,331,876	($210,000)	$11,121,876	$ -	$11,121,876
9	Working Capital Rate %	(2)	4.32%	0.08%	4.40%	0.00%	4.40%
10	Working Capital Allowance		$489,809	($0)	$489,809	$ -	$489,809

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$40,230,644	($452,525)	$39,778,120	$ -	$39,778,120
2	Other Revenue	(1)	$89,900	$ -	$89,900	$ -	$89,900
3	Total Operating Revenues		$40,320,544	($452,525)	$39,868,020	$ -	$39,868,020
	Operating Expenses:						
4	OM+A Expenses		$11,331,876	($210,000)	$11,121,876	$ -	$11,121,876
5	Depreciation/Amortization		$9,771,327	$ -	$9,771,327	$ -	$9,771,327
6	Property taxes		$240,424	$ -	$240,424	$ -	$240,424
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$21,343,627	($210,000)	$21,133,627	$ -	$21,133,627
10	Deemed Interest Expense		$8,601,501	($40,232)	$8,561,269	$ -	$8,561,269
11	Total Expenses (lines 9 to 10)		$29,945,128	($250,232)	$29,694,896	$ -	$29,694,896
12	**Utility income before income taxes**		$10,375,416	($202,292)	$10,173,124	$ -	$10,173,124
13	Income taxes (grossed-up)		$2,189,007	($53,607)	$2,135,400	$ -	$2,135,400
14	**Utility net income**		$8,186,408	($148,685)	$8,037,724	$ -	$8,037,724

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application				Per Board Decision
(1)	Specific Service Charges	$ -	$ -	$ -	$ -	$ -
	Late Payment Charges	$ -	$ -	$ -	$ -	$ -
	Other Distribution Revenue	$ -	$ -	$ -	$ -	$ -
	Other Income and Deductions	$89,900	$ -	$89,900	$ -	$89,900
	Total Revenue Offsets	$89,900	$ -	$89,900	$ -	$89,900

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$8,186,408	$8,037,724	$8,037,724
2	Adjustments required to arrive at taxable utility income	($2,115,011)	($2,115,011)	($2,115,011)
3	Taxable income	$6,071,397	$5,922,713	$5,922,713
	Calculation of Utility income Taxes			
4	Income taxes	$1,608,920	$1,569,519	$1,569,519
6	Total taxes	$1,608,920	$1,569,519	$1,569,519
7	Gross-up of Income Taxes	$580,087	$565,881	$565,881
8	Grossed-up Income Taxes	$2,189,007	$2,135,400	$2,135,400
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$2,189,007	$2,135,400	$2,135,400
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$122,446,281	6.87%	$8,416,957
2	Short-term Debt	4.00%	$8,746,163	2.11%	$184,544
3	**Total Debt**	60.00%	$131,192,444	6.56%	$8,601,501
	Equity				
4	Common Equity	40.00%	$87,461,629	9.36%	$8,186,408
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,461,629	9.36%	$8,186,408
7	**Total**	100.00%	$218,654,073	7.68%	$16,787,910

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$122,446,281	6.87%	$8,416,957
2	Short-term Debt	4.00%	$8,746,163	1.65%	$144,312
3	**Total Debt**	60.00%	$131,192,444	6.53%	$8,561,269
	Equity				
4	Common Equity	40.00%	$87,461,629	9.19%	$8,037,724
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,461,629	9.19%	$8,037,724
7	**Total**	100.00%	$218,654,073	7.59%	$16,598,993

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$122,446,281	6.87%	$8,416,957
9	Short-term Debt	4.00%	$8,746,163	1.65%	$144,312
10	**Total Debt**	60.00%	$131,192,444	6.53%	$8,561,269
	Equity				
11	Common Equity	40.00%	$87,461,629	9.19%	$8,037,724
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$87,461,629	9.19%	$8,037,724
14	**Total**	100.00%	$218,654,073	7.59%	$16,598,993

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,499,544		$1,047,020		$1,047,020
2	Distribution Revenue	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100
3	Other Operating Revenue Offsets - net	$89,900	$89,900	$89,900	$89,900	$89,900	$89,900
4	**Total Revenue**	$38,821,000	$40,320,544	$38,821,000	$39,868,020	$38,821,000	$39,868,020
5	Operating Expenses	$21,343,627	$21,343,627	$21,133,627	$21,133,627	$21,133,627	$21,133,627
6	Deemed Interest Expense	$8,601,501	$8,601,501	$8,561,269	$8,561,269	$8,561,269	$8,561,269
8	**Total Cost and Expenses**	$29,945,128	$29,945,128	$29,694,896	$29,694,896	$29,694,896	$29,694,896
9	**Utility Income Before Income Taxes**	$8,875,872	$10,375,416	$9,126,104	$10,173,124	$9,126,104	$10,173,124
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,115,011)	($2,115,011)	($2,115,011)	($2,115,011)	($2,115,011)	($2,115,011)
11	**Taxable Income**	$6,760,861	$8,260,405	$7,011,093	$8,058,113	$7,011,093	$8,058,113
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$1,791,628	$2,189,007	$1,857,940	$2,135,400	$1,857,940	$2,135,400
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$7,084,244	$8,186,408	$7,268,164	$8,037,724	$7,268,164	$8,037,724
16	**Utility Rate Base**	$218,654,073	$218,654,073	$218,654,073	$218,654,073	$218,654,073	$218,654,073
17	Deemed Equity Portion of Rate Base	$87,461,629	$87,461,629	$87,461,629	$87,461,629	$87,461,629	$87,461,629
18	Income/(Equity Portion of Rate Base)	8.10%	9.36%	8.31%	9.19%	8.31%	9.19%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.19%	9.19%	9.19%	9.19%
20	Deficiency/Sufficiency in Return on Equity	-1.26%	0.00%	-0.88%	0.00%	-0.88%	0.00%
21	Indicated Rate of Return	7.17%	7.68%	7.24%	7.59%	7.24%	7.59%
22	Requested Rate of Return on Rate Base	7.68%	7.68%	7.59%	7.59%	7.59%	7.59%
23	Deficiency/Sufficiency in Rate of Return	-0.50%	0.00%	-0.35%	0.00%	-0.35%	0.00%
24	Target Return on Equity	$8,186,408	$8,186,408	$8,037,724	$8,037,724	$8,037,724	$8,037,724
25	Revenue Deficiency/(Sufficiency)	$1,102,165	$ -	$769,559	$ -	$769,559	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,499,544 **(1)**		$1,047,020 **(1)**		$1,047,020 **(1)**	

Notes:

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

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$11,331,876		$11,121,876		$11,121,876	
2	Amortization/Depreciation	$9,771,327		$9,771,327		$9,771,327	
3	Property Taxes	$240,424		$240,424		$240,424	
5	Income Taxes (Grossed up)	$2,189,007		$2,135,400		$2,135,400	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$8,601,501		$8,561,269		$8,561,269	
	Return on Deemed Equity	$8,186,408		$8,037,724		$8,037,724	
8	**Service Revenue Requirement (before Revenues)**	$40,320,544		$39,868,020		$39,868,020	
9	Revenue Offsets	$ -		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$40,320,544		$39,868,020		$39,868,020	
11	Distribution revenue	$40,230,644		$39,778,120		$39,778,120	
12	Other revenue	$89,900		$89,900		$89,900	
13	**Total revenue**	$40,320,544		$39,868,020		$39,868,020	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$ -	(1)

Notes

(1) Line 11 - Line 8

CERTIFICATION STATEMENT

Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP: ET-2007-0649

Duane Fecteau, General Manager

Certifies that the evidence filed with the OEB in Great Lakes Power Transmission LP's 2017 transmission rate application (EB-2016-0356) is accurate, consistent and complete to the best of his knowledge.

Signature ______________________
Duane Fecteau

Date December 23, 2016

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PARTIES AFFECTED BY THE APPLICATION

GLPT's neighbouring utilities are:

- PUC Distribution Inc. (ED-2002-0546);
- Hydro One Networks Inc. (ED-2003-0043, ET-2003-0035); and
- Algoma Power Inc. (ED-2009-0072).

All ratepayers in Ontario are affected by this application, as they are all ultimately subject to the Uniform Transmission Rates, either directly as a market participant or indirectly through a distributor or embedded distributor.

INTERNET ADDRESS

GLPT's internet address is www.glp.ca. More specifically, this application and related documentation can be found at http://www.glp.ca/content/regulatory-3169.html.

CONTACT INFORMATION

Applicant:

Great Lakes Power Transmission Inc.
on behalf of Great Lakes Power Transmission LP
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P6B 6J6

Attention: Mr. Duane Fecteau
General Manager
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- and -

Mr. Kevin Lewis
Controller
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Applicant's Counsel:

Torys LLP
79 Wellington Street West, Suite 3000
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M5K 1N2

Attention: Mr. Charles Keizer
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- and -

Mr. Tyson Dyck
Telephone: (416) 865-8136
Fax: (416) 865-7380
Email: tdyck@torys.com

REQUESTED EFFECTIVE DATE

GLPT is requesting approval for its proposed 2017 revenue requirement to be included in the UTR to be effective January 1, 2017. In addition, GLPT is requesting approval for its current revenue requirement to be made interim as of January 1, 2017, if necessary.

Further, GLPT is requesting approval for an accounting order to establish a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2017 until GLPT's proposed 2017 revenue requirement is implemented, if necessary.

BILL IMPACTS

In Exhibit 7, Tab 1, Schedule 1, GLPT calculates the impact of this application on Ontario ratepayers. As demonstrated in that schedule, there is no forecasted change to any of the uniform transmission rates as a result of this application.

Overall, GLPT's 2017 revenue requirement request results in a 0.060% increase in Ontario's transmission revenue requirement pool for 2017 compared to the 2016 Ontario approved transmission revenue requirement, which would ultimately impact the Transmission Network Charge for residential and general service customers. The amount of this increase results in virtually no impact to a typical residential or retail customer's monthly electricity bill, as calculated in *Table 1-2-6 A* and *Table 1-2-6 B* below. For the purposes of this analysis, an average residential customer is one who consumes 750 kWh per month, and an average retail customer is a General Service <50 kW customer who consumes 2,000 kWh per month. The rates in the analysis are the rates for PUC Distribution Inc., effective May 1, 2016, and assume an average commodity rate equal to the current mid-peak time-of-use rate of 13.2 cents/kWh.

Table 1-2-6 A – Bill Impact on Typical Residential Customer - 2017

2017 Rate Impacts - Residential			**Per Unit**	**Per Month**
Monthly Consumption		750	kWh	
Electricity	per kWh		$0.132	$99.00
Monthly Service Charge	per month		13.23	13.23
Additional Rate Riders (Smart Metering)	per month		0.84	0.84
Distribution Charge	per kWh		0.0139	10.43
Transmission Network Charge	***per kWh***		***0.0061***	***4.58***
Standard Supply Service Admin	per month		0.25	0.25
Wholesale Market Services	per kWh		0.0060	4.50
Total Monthly Bill				**$132.82**
Amount of Bill Related to Transmission Rates				$4.58
Percentage Increase in Transmission Rates - 2016 to 2017				0.060%
Monthly $ Increase Resulting from Transmission Rate Change				**$0.00**
% Bill Increase Resulting from Transmission Rate Change				**0.00%**

Rates effective May 1, 2016

Table 1-2-6 B – Bill Impact on GS < 50kW customer - 2017

2017 Rate Impacts - GS <50kW		**Per Unit**	**Per Month**
Monthly Consumption	2,000	kWh	
Electricity	per kWh	$0.132	$264.00
Monthly Service Charge	per month	16.87	16.87
Additional Rate Riders (Smart Metering)	per month	0.79	0.79
Distribution Charge	per kWh	0.0205	41.00
Transmission Network Charge	***per kWh***	***0.0057***	***11.40***
Standard Supply Service Admin	per month	0.25	0.25
Wholesale Market Services	per kWh	0.0060	12.00
Total Monthly Bill			**$346.31**
Amount of Bill Related to Transmission Rates			$11.40
Percentage Increase in Transmission Rates - 2016 to 2017			0.060%
Monthly $ Increase Resulting from Transmission Rate Change			**$0.01**
% Bill Increase Resulting from Transmission Rate Change			**0.00%**

Rates effective May 1, 2016

FORM OF HEARING

GLPT has successfully settled its three most recent revenue requirement applications[1] through a written process. GLPT does not view the issues in this application to be material enough to warrant a change to this approach. As a result, GLPT is requesting that this application be resolved by way of written hearing.

[1] EB-2010-0291 for 2011 and 2012 rates, EB-2012-0300 for 2013 and 2014 rates, and EB-2014-0238 for 2015 and 2016 rates

SPECIFIC APPROVALS REQUESTED

GLPT applies for an Order or Orders of the Board granting:

(a) Approval of GLPT's 2017 base revenue requirement of $40,533,904 to be included in the UTR;

(b) Approval for GLPT's current revenue requirement and rates to be made interim as of January 1, 2017, if necessary;

(c) Approval for GLPT's proposed 2017 revenue requirement resulting from a revenue cap index annual adjustment and rates to be made effective as of January 1, 2017;

(d) An accounting order to establish a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2017 until GLPT's proposed 2017 revenue requirement and rates are implemented, if necessary;

(e) Approval to disburse, through the use of account 1595, balances in various deferral and variance accounts in 2017; and

(f) Approval for continuation in the test period of account 1508 and sub-accounts Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs, Property Tax and Use and Occupation Permit Fees, IFRS Gains and Losses and OEB Cost Assessment.

Based upon the Accounting Procedures Handbook, GLPT will also continue to maintain in the test period account 1592 for tax variances and account 1595 related to previously approved regulatory asset collections.

LENGTH OF TERM

The OEB's Decision and Order in Hydro One Inc.'s EB-2016-0050 application approved a 10 year deferral period for rebasing of GLPT's rates. In the same Decision and Order the OEB determined that GLPT can continue with its existing 2016 revenue requirement and bring forward a separate rate application, proposing a revenue cap index for the deferral period. This application represents GLPT's first application within the deferral period where GLPT is requesting a single-year incentive rate setting plan under the revenue cap index proposal as set out in *Filing Requirements for Electricity Transmission Applications, Chapter 2 (February 11, 2016).* It is GLPT's intent to continue to file applications of this nature on an annual basis throughout the deferral period.

BOARD DECISIONS AND ACCOUNTING ORDERS

On November 12, 2014 GLPT filed a proposed settlement agreement with the Board in its EB-2014-0238 application for 2015 and 2016 revenue requirement. The proposed settlement agreement, as filed with the Board, is attached as **Appendix "A"**. In a hearing dated November 19, 2014, the Board verbally approved the settlement agreement as filed. The transcript for this hearing is attached as **Appendix "B"**.

GLPT has attached as **Appendix "C"** the Board's written Decision and Order dated December 18, 2014 relating to GLPT's EB-2014-0238 application and 2015 transmission revenue requirement.

GLPT has attached as **Appendix "D"** the Board's January 14, 2016 Decision and Order in EB-2015-0337 which updates GLPT's Transmission Revenue Requirement for 2016 to reflect updated cost of capital parameters, published by the Board on October 15, 2015. The revised revenue requirement was used in the calculation of UTR for Ontario for 2016.

APPENDIX "A"

November 12, 2014 Proposed Settlement Agreement
EB-2014-0238

TORYS LLP

79 Wellington St. W., 30th Floor
Box 270, TD South Tower
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November 12, 2014

EMAIL, COURIER & RESS

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

Attention: Board Secretary

Dear Ms. Walli:

Re: Great Lakes Power Transmission LP - Application for 2015 & 2016 Transmission Rates (EB-2014-0238) - Settlement Proposal

We are counsel for the Applicant in respect of the above noted matter. Pursuant to Procedural Order No. 1, please find attached a proposed Settlement Proposal concluded between the parties noted therein. Each of the parties to the Settlement Proposal has reviewed and approved the proposed agreement as described therein.

Should you have any questions or concerns, please let me know.

Yours truly,

Tyson Dyck

Tel 416.865.8136
Fax 416.865.7380
tdyck@torys.com

cc: All Intervenors
R. Battista, Board Staff
D. Fecteau, GLPT LP
S. Seabrook, GLPT LP
C. Keizer, Torys LLP

SETTLEMENT PROPOSAL

November 12, 2014

GREAT LAKES POWER TRANSMISSION LP
2015 & 2016 RATES APPLICATION
(EB-2014-0238)

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PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board (the "**Board**") in connection with an application by Great Lakes Power Transmission ("**GLPT**") pursuant to section 78 of the *Ontario Energy Board Act, 1998* for an order or orders approving or fixing just and reasonable rates for the transmission of electricity (EB-2014-0238).

Pursuant to Procedural Orders No. 1 and 2 in this proceeding, a Settlement Conference was held on October 28, 2014 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the "**Rules**") and the Board's *Practice Direction on Settlement Conferences* (the "**Practice Direction**"). This Settlement Proposal arises from the Settlement Conference and is for the consideration of the Board in its determination of GLPT's 2015 and 2016 electricity transmission rates.

The Parties

GLPT and the following intervenors (collectively the "**Participating Intervenors**"), as well as Ontario Energy Board technical staff ("**Board Staff**"), participated in the Settlement Conference in respect of all issues contained in this proposal:

- Energy Probe Research Foundation ("**Energy Probe**")
- School Energy Coalition ("**SEC**")
- Vulnerable Energy Consumers Coalition ("**VECC**")

The following intervenors did not participate in the Settlement Conference:

- Independent Electricity System Operator ("**IESO**")
- Upper Canada Transmission, Inc. ("**UCT**")

The Applicant and the Participating Intervenors are collectively referred to herein as the "**Parties**". In accordance with pages 5-6 of the Practice Direction, Board Staff is neither a Party nor a signatory to this Settlement Proposal (unless the Board provides otherwise, which it did not in this proceeding). Although Board Staff is not a party to this Settlement Proposal, the Board Staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Guidelines. The parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal.

This document is called a "Settlement Proposal" because it is a proposal by the Parties to the Board to settle the issues in this proceeding. It is termed a proposal as between the Parties and the Board. However, as between the Parties, and subject only to the Board's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Preamble, this agreement is subject to a condition subsequent, that if it is not accepted by the Board in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering into this agreement, the Parties understand and agree that, pursuant to the Act, the Board has exclusive jurisdiction with respect to the interpretation or enforcement of the terms hereof.

The Settlement Proposal describes the agreements reached on the settled issues and identifies the parties who agree, or alternatively who take no position on each issue. The Settlement Proposal provides a direct link between each issue and the supporting evidence in the record to date. In this regard, the parties who agree with the individual settlements are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings on the settled issues.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format. For example, Exhibit 2, Tab 1, Schedule 1, Page 3 (commencing page) is referred to as 2-1-1-3. A concise description of the content of each exhibit is also provided. In this regard, GLPT's response to an interrogatory (IR) is described by citing the name of the Party and the number of the interrogatory (e.g., Board Staff IR #1 or SEC IR #2). The identification and listing of the evidence that relates to each issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

According to the Practice Direction (p. 4), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. GLPT and the other Parties who participated in the Settlement Conference agree that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

All of the issues contained in this proposal have been settled by the Parties as a package (the "**package**") and none of the provisions of these issues are severable. Compromises were made by the Parties with respect to various matters to arrive at this comprehensive Settlement Proposal. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal which may be unacceptable to one or more of the Parties. If the Board does not, prior to the commencement of the hearing of the evidence, accept the package in its entirety, then there is no settlement (unless the Parties agree that any portion of the package that the Board does accept may continue as part of a valid Settlement Proposal). None of the Parties can withdraw from this proposal except in accordance with Rule 32.05 of the Rules. Moreover, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not GLPT is a party to such proceeding.

The Parties agree that this Settlement Proposal and the Appendices form part of the record in EB-2014-0238. The Revenue Requirement Work Forms were prepared by the Applicant. The intervenors are relying on the accuracy and completeness of the Revenue Requirement Work Forms in entering into this Settlement Proposal. Summary of the Proposed Settlement

Summary of the Settlement Proposal

For the purposes of organizing this Settlement Proposal, and without prejudice to the positions of the Parties with respect to the issues that might otherwise be considered in this proceeding should a hearing be required, the Parties have followed, as applicable, the issues list set out at **'Appendix A'** to this Settlement Proposal, which was approved by the Board in its October 27, 2014 Decision.

We are pleased to inform the Board that the Parties have reached a comprehensive agreement on all issues.

Through this Settlement Proposal, GLPT agrees to certain changes from its initial application for 2015 and 2016 electricity transmission rates, as filed with the Board on July 14, 2014. The most significant matters arising from this Settlement Proposal are as follows:

- **Overall Revenue Requirements:** The Overall Base Revenue requirements as agreed by the parties are $39,582,100 and $40,020,600, for 2015 and 2016, respectively.

- **OM&A**: GLPT initially proposed operating costs that included OM&A costs of $11,021,100 for 2015 and $11,331,900 for 2016. As part of obtaining a complete settlement of all issues, the Parties have agreed that GLPT's OM&A expenses for the Test Years, as described herein, should be $10,821,100 for the 2015 test year and $11,121,900 for the 2016 test year, with the reduction from the proposed amounts reflecting the cost savings associated with additional efficiency and productivity measures that GLPT will undertake to implement during the test years.

- **Rate Base**: GLPT initially requested rate base amounts of $218,760,200 and $218,654,100 for 2015 and 2016, respectively. The Parties have agreed on the requested rate base amounts, with the expectation that a net cumulative asymmetrical variance account will be created for the test years to track the impact on revenue requirement of the cost of In-Service Additions during the test years.

- **Disbursal of Deferral and Variance Accounts**: In its application, GLPT proposed to disburse the various account balances by aggregating the balance of all accounts, including the remaining balance in Account 1595, and disbursing them over a three year period beginning in 2015. For the purpose of obtaining a complete settlement of all issues, the Parties have agreed that the various account balances being disbursed, and the proposed disbursal methodology, are appropriate

- **Closing, Creation and Continuation of Deferral and Variance Accounts**: Except as otherwise noted in this paragraph, the Parties accept GLPT's proposals in respect of the closing, creation and continuation of deferral and variance accounts. For the purpose of obtaining a complete settlement of all issues, the Parties have agreed that the sub-account within account 1508 related changes to existing IFRS standards or changes in the interpretation of such standards should be closed. In addition, as indicated above, the Parties also agree that a net cumulative asymmetrical variance account should be created for the test years to track the impact on revenue requirement of the cost of in-service additions during the test years. Finally, GLPT agrees at this time not to pursue a new deferral account for recording incremental expenditures related to new customer connection activities, but the Parties agree that GLPT may apply to the Board in the future to establish this account.

- **Rates**: The Parties have agreed that GLPT's rates are effective January 1 of each year with implementation on that date or according to a process established by the Board.

- **Other**: As part of the complete settlement of all issues, GLPT undertakes to submit to the Board: a more detailed and comprehensive asset management plan as part of GLPT's next rate application; agrees to participate in HONI's Total Cost Benchmarking Study (described in the proposed Settlement Proposal filed in EB-2014-0140) through the provision of relevant data, if GLPT is requested to do so; undertakes to complete a new lead lag study as part of GLPT's next rate application; and undertakes to prepare a new, bottom-up load forecast for submission to the Board with GLPT's next rate application.

Attached at **Appendix 'B'** is a copy of the Revenue Requirement Work Forms updated to reflect the impacts of the proposed settlement as herein described for the 2015 and 2016 Test Years.

ISSUES

1. General

1.1 Has GLPT responded appropriately to all relevant Board directions from previous proceedings?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a complete settlement of all issues, the Parties agree that GLPT has responded appropriately to all relevant Board directions from previous proceedings.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following: N/A

1.2 Is the overall increase in 2015 and 2016 revenue requirement reasonable?

Complete Settlement: Subject to the terms of this Settlement Proposal, including section 4, there is an agreement to settle this issue as follows:

In its application and evidence, GLPT forecasted its 2015 and 2016 base revenue requirement to be $39,782,100 and $40,230,600, respectively.

For the purpose of obtaining a complete settlement of all issues, the Parties accept that base revenue requirements for 2015 and 2016 of $39,582,100 and $40,020,600, respectively, are reasonable, and that these amounts should be adjusted to include future updates to the Board's Cost of Capital parameters for the rate year beginning January 1, 2015 and again for the rate year beginning January 1, 2016.

Approval:

Parties in Support:	SEC, VECC, Energy Probe
Parties Taking No Position:	N/A

Evidence: The evidence in relation to this issue includes the following:

1-1-1	Application
1-1-2	Summary of Application
1-1-3	Schedule of Overall Revenue Deficiency
1-1-4	Revenue Requirement Work Forms (2015 & 2016)
1-1-5	Sensitivity Analysis
9-2-1	2-Staff-8
9-2-1	2-Staff-20
9-4-1	3.0-VECC-9
9-5-1	2-Energy Probe-8
9-5-1	2-Energy Probe-13
9-5-1	2-Energy Probe-23
10-4-1	3.0-VECC-26
10-5-1	1-Energy Probe-24s
10-5-1	6-Energy Probe-27s

1.3 Are the productivity measures proposed and benchmarking performed by GLPT reasonable and appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

In its application and evidence, GLPT indicated that it had engaged First Quartile Consulting ("1QC") to provide a benchmarking study to compare the requested 2015 and 2016 OM&A expenditures against other transmission providers in North America. The 1QC benchmarking study indicates that GLPT falls below average on a cost per gross asset basis. GLPT also described its approach to asset management in the application and evidence, and indicated that it continues to improve its asset management approach with the development of tools and programs. GLPT also included evidence of productivity initiatives that it is has commenced and plans to undertake.

For the purpose of obtaining a complete settlement of all issues, the Parties agree that GLPT's productivity measures and benchmarking are reasonable and appropriate. As part of the complete settlement of all issues, GLPT also agrees to participate in HONI's Total Cost Benchmarking Study (described in the proposed Settlement Proposal filed in EB-2014-0140) through the provision of relevant data, if GLPT is requested to do so.

Approval:

Parties in Support:	SEC, VECC, Energy Probe
Parties Taking No Position:	N/A

Evidence: The evidence in relation to this issue includes the following:

1-1-2	Summary of Application
2-2-1	Asset Management and Capital Budgeting
4-1-1	Summary of Operating Costs
4-2-1	OM&A Overview
9-2-1	2-Staff-9
9-2-1	2-Staff-12
9-4-1	1.0-VECC-1
9-4-1	4.0-VECC-15
9-5-1	2-Energy Probe-9
10-2-1	2-Staff-36s

2. Rate Base

2.1 Is the proposed rate base for 2015 and 2016 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

In its application and evidence, GLPT forecasted its 2015 and 2016 rate base to be $218,760,200 and $218,654,100, respectively, as presented in Table 2-1-1A of the pre-filed evidence.

For the purpose of obtaining a complete settlement of all issues, the Parties agree that the Board should accept these amounts as GLPT's forecasted rate base for the 2015 and 2016 Test Years. GLPT also undertakes to submit to the Board a more detailed and comprehensive Asset Management plan as part of GLPT's next rate application

Further, since GLPT is forecasting to increase its capital additions in 2015 and 2016 Test Years, relative to 2013-2014, the Parties agree as part of the complete settlement of all issues, that a net cumulative asymmetrical variance account should be created for the test years to track the impact on revenue requirement of the cost of in-service additions during the test years compared to Board approved amounts, for disposition in a future rate application ("**In-service Addition Net Cumulative Asymmetrical Variance Account**"). The purpose of this account is to capture the revenue requirement amount which (i) would arise if the total in-service additions forecasted by GLPT for the test years 2015 and 2016 and agreed to in this Settlement Proposal are higher than the actual total in-service additions for 2015 and 2016, and (ii) reflects the net difference between the forecasted and in-service additions for 2015 and 2016 in the event that the circumstance set out in (i) occurs. For clarity, the account relates to variances in in-service additions and not variances in rate base generally. If the cumulative amount of in-service additions during 2015 and 2016 is less than the cumulative Board-approved amount, then the revenue requirement impact of the shortfall would be entered in the variance account, for disposition in a future rate application. If the cumulative amount of in-service additions exceeds the cumulative Board-approved amount for the test years, no entry would be made in the variance account. This approach ensures that ratepayers pay only for assets in service.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

1-1-2	Summary of Application
2-1-1	Rate Base Overview
2-1-2	Summary and Continuity Statements
9-2-1	2-Staff-2
9-2-1	2-Staff-3
9-2-1	2-Staff-4
9-2-1	2-Staff-7
9-2-1	2-Staff-8
9-2-1	2-Staff-10
9-2-1	2-Staff-11
9-3-1	2-SEC-3
9-3-1	2-SEC-5
9-3-1	2-SEC-6
9-4-1	2.0-VECC-2
9-4-1	2.0-VECC-3
9-4-1	2.0-VECC-4
9-4-1	2.0-VECC-5
9-4-1	2.0-VECC-6
9-5-1	2-Energy Probe-1
9-5-1	2-Energy Probe-2
9-5-1	2-Energy Probe-5
10-2-1	2-Staff-34s
10-2-1	2-Staff-35s
10-4-1	2.0-VECC-24
10-4-1	2.0-VECC-25
10-5-1	1-Energy Probe-24s

2.2 Is the working capital allowance for 2015 and 2016 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

The working cash allowance for the Test Years has been calculated by GLPT using the results of the working capital study completed in 2010 by Navigant Consulting Inc., plus a provision for inventory assets that are working capital for GLPT but that form no part of the working cash study.

For the purpose of obtaining a complete settlement of all issues, the Parties accept GLPT's working capital allowance calculation, and that the total working capital requirements of $474,000 for 2015 and $489,800 for 2016 are appropriate. As part of the complete settlement of all issues, GLPT also undertakes to complete a new lead lag study as part of GLPT's next rate application.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

1-1-4	Revenue Requirement Work Forms (2015 & 2016)
2-1-1	Rate Base Overview
2-1-3	Working Capital Allowance
9-2-1	2-Staff-2
9-4-1	2.0-VECC-6
9-5-1	2-Energy Probe-6

2.3 Is the capital expenditure forecast for 2015 and 2016 appropriate

2.3.1 **2015**

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a complete settlement of all issues, and subject to section 2.1, the Parties accept that GLPT's proposed capital addition of $9,460,000 for 2015 is appropriate.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

1-4-1	Materiality Threshold
2-1-1	Rate Base Overview
2-1-2	Summary and Continuity Statements
2-2-1	Asset Management and Capital Budgeting
9-2-1	2-Staff-3
9-5-1	4-Energy Probe-19

2.3.2 **2016**

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a complete settlement of all issues, and subject to section 2.1, the Parties accept that GLPT's proposed capital addition of $9,768,700 for 2016 is appropriate.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

1-4-1	Materiality Threshold
2-1-1	Rate Base Overview
2-1-2	Summary and Continuity Statements
2-2-1	Asset Management and Capital Budgeting
9-2-1	2-Staff-3
9-5-1	4-Energy Probe-19

2.4 Is the capitalization policy and allocation procedure appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a complete settlement of all issues, the Parties accept that GLPT's capitalization policy and allocation procedures, as set out in the application, are appropriate.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

2-1-1 Rate Base Overview

3. Load Forecast and Revenue Forecast

3.1 Is the load forecast and methodology appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a complete settlement of all issues, the Parties accept that GLPT's load forecast and revenue forecast is appropriate. Further, GLPT undertakes to prepare a new, bottom-up (Customer) load forecast for submission to the Board with GLPT's next rate application.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

3-1-1	Operating Revenue
3-1-2	Charge Determinant Forecast and Variance Analysis
9-2-1	3-Staff-13
9-4-1	3.0-VECC-9
9-4-1	3.0-VECC-10
9-4-1	3.0-VECC-11
9-5-1	2-Energy Probe-8
10-4-1	3.0-VECC-27
10-5-1	1-Energy Probe-24s

3.2 Is the impact of CDM appropriately reflected in the load forecast?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a complete settlement of all issues, the Parties accept that the impact of CDM is appropriately reflected in the load forecast. As indicated in section 3.1 above, as part of the complete settlement of all issues, GLPT undertakes to prepare a new, bottom-up (Customer) load forecast for submission to the Board with GLPT's next rate application.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

3-1-1 Operating Revenue
3-1-2 Charge Determinant Forecast and Variance Analysis

3.3 Are Other Revenues forecasts appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

In its application and evidence, GLPT forecasted its other income to be ($89,900) in each of 2015 and 2016, as presented in Table 3-1-3A of the pre-filed evidence.

For the purpose of obtaining a complete settlement of all issues, the Parties accept GLPT's forecasted other income for the 2015 and 2016 Test Years as appropriate.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

3-1-1 Operating Revenue

4. Operations, Maintenance and Administrative Costs

In its application, GLPT initially proposed total operating costs of $23,075,900 for 2015 and $23,532,600 for 2016. As shown in Table 4-1-1A, this was comprised of the following components:

- Operations, Maintenance and Administration ($11,021,100 for 2015 and $11,331,900 for 2016)
- Depreciation and Amortization ($9,701,200 for 2015 and $9,771,300 for 2016)
- Income Taxes ($2,115,400 for 2015 and $2,189,000 for 2016)
- Property Taxes ($238,200 for 2015 and $240,400 for 2016)

Operations, Maintenance & Administration expenses (OM&A), are considered in section 4.1, 4.2 and 4.4 of this Settlement Proposal, below.

Depreciation and Amortization expenses are considered in section 4.3 of this Settlement Proposal, below.

Income Taxes and Property Taxes are considered together in section 4.5, 4.6 and 4.7 of this Settlement Proposal.

4.1 Is the overall OM&A forecast in 2015 and 2016 appropriate?

4.2 Are the proposed spending levels for Shared Services and other costs in 2015 and 2016 appropriate?

4.4 Are the 2015 and 2016 compensation costs and employee levels appropriate?

Complete Settlement: There is an agreement to settle these issues 4.1, 4.2 and 4.4 as follows:

As indicated above, GLPT initially proposed operating costs that included OM&A costs of $11,021,100 for 2015 and $11,331,900 for 2016.

For the purpose of obtaining a complete settlement of all issues, the Parties have agreed that GLPT's OM&A expenses for the Test Years, as described herein, should be $10,821,100 for the 2015 test year and $11,121,900 for the 2016 test year. The Parties recognize that the reductions from GLPT's proposed OM&A costs for 2015 and 2016 reflect the cost savings associated with additional efficiency and productivity measures that GLPT will undertake to implement during the Test Years.

The Parties also note that the Pensions and Other Post- Employment Benefits (OPEB) costs included in the test period revenue requirement are based on actuarial calculations. In complying with IFRS accounting principles, the costs are recorded on an accrual basis for financial reporting as well. However, the actual payment for these costs is made by GLPT on a cash basis. In recent years, GLPT has paid out more in Pension costs than it recovered in rates while the opposite occurred for OPEB costs.

The table below sets out the actual cash amounts paid by GLPT over the 2010 to 2013 period and forecasted for 2014-2016 versus what was included in the applicable year's revenue requirement. Looking at Pension and OPEB on a combined basis it is apparent that, since 2010, GLPT has recovered less in rates than has been actually been paid out. Furthermore, there is no material difference between the cash and accrual accounting amounts reflected in GLPT's test period revenue requirement. Therefore, the Parties accept the Pension and OPEB costs included in GLPT's test period revenue requirement, without prejudice to the views they may hold as to the accounting practice that should apply for the calculation of Pension and OPEB costs to be recovered in rates and without prejudice to any position they may take in any other proceeding.

OPEB and Pension Costs

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year
OPEB							
Amount included in rates	$ 385,843	$ 359,614	$ 368,604	$ 490,000	$ 499,972	$ 480,984	$ 523,216
Amount actually paid	$ 199,208	$ 123,844	$ 131,136	$ 140,423	$ 150,000	$ 153,000	$ 156,060
Net Excess (less than) in rates	**$ 186,635**	**$ 235,770**	**$ 237,468**	**$ 349,577**	**$ 349,972**	**$ 327,984**	**$ 367,156**
Pension							
Amount included in rates	$ 229,405	$ 295,274	$ 302,656	$ 526,000	$ 536,704	$ 587,924	$ 644,561
Amount actually paid	$ 556,003	$ 1,536,782	$ 1,015,092	$ 680,650	$ 901,715	$ 913,149	$ 934,611
Net Excess (less than) in rates	**($326,598)**	**($1,241,508)**	**($712,436)**	**($154,650)**	**($365,011)**	**($325,225)**	**($290,050)**
Total Excess (less than) in rates	**($139,963)**	**($1,005,738)**	**($474,968)**	**$194,927**	**($15,039)**	**$2,759**	**$77,106**

Source: Response to Board staff interrogatory 4-Staff-22 (g) and Board staff interrogatory 4-Staff-23 (c)

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

4-1-1	Summary of Operating Costs
4-2-1	OM&A Overview
4-2-2	Employee Compensation Breakdown
4-2-3	Shared Services & Corporate Cost Allocation
4-2-4	Purchase of Non-Affiliate Services
9-2-1	2-Staff-8
9-2-1	3-Staff-14
9-2-1	4-Staff-15
9-2-1	4-Staff-17
9-2-1	4-Staff-18
9-2-1	4-Staff-20
9-2-1	4-Staff-21
9-2-1	4-Staff-22
9-2-1	4-Staff-23
9-2-1	4-Staff-24
9-2-1	4-Staff-25
9-2-1	6-Staff-29
9-2-1	6-Staff-33
9-3-1	4-SEC-10
9-3-1	4-SEC-12
9-3-1	4-SEC-13
9-4-1	2.0-VECC-7
9-4-1	3.0-VECC-13
9-4-1	4.0-VECC-15
9-4-1	4.0-VECC-16
9-4-1	6.0-VECC-20
9-5-1	2-Energy Probe-9
9-5-1	2-Energy Probe-10
9-5-1	2-Energy Probe-11
9-5-1	4-Energy Probe-14
9-5-1	4-Energy Probe-17
9-5-1	4-Energy Probe-18
9-5-1	4-Energy Probe-19
9-5-1	4-Energy Probe-20
9-5-1	4-Energy Probe-21
9-5-1	4-Energy Probe-23
10-3-1	4-SEC-20
10-4-1	4.0-VECC-28
10-5-1	6-Energy Probe-27s

4.3 Is the proposed level of depreciation/amortization expense for 2015 and 2016 appropriate?

Complete Settlement: There is an agreement to settle issue 4.3 as follows:

As indicated above, GLPT initially proposed operating costs that included depreciation and amortization costs of $9,701,200 for 2015 and $9,771,300 for 2016.

For the purpose of obtaining a complete settlement of all issues, the Parties have agreed that GLPT's proposed depreciation and amortization costs of $9,701,200 for 2015 and $9,771,300 for 2016 are appropriate.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

4-1-1	Summary of Operating Costs
4-2-3	Shared Services & Corporate Cost Allocation
4-3-1	Depreciation & Amortization
9-2-1	2-Staff-9
10-2-1	6-Staff-39s

4.5 Is the 2015 and 2016 forecast of property taxes appropriate?

4.6 Are the requested income tax allowance for the test years 2015 and 2016 reasonable considering that the ownership structure of GLPT has changed since the last application EB-2012-0300?

4.7 Is the 2015 and 2016 forecast of income tax appropriate?

Complete Settlement: There is an agreement to settle these issues 4.5, 4.6, and 4.7 as follows:

In its initial application, GLPT:

- Calculated its property tax expense as $238,200 for 2015 and $240,400 for 2016. The calculation of these amounts is described in 4-4-3; and

- Calculated its income tax expense as $2,115,400 for 2015 and $2,189,000 for 2016. The calculation of this amount is described in 4-4-2.

Property Tax

For the purpose of obtaining a complete settlement of all issues, the Parties accept that GLPT's calculations of property taxes described herein, which total $238,200 for 2015 and $240,400 for 2016 are appropriate.

Income Tax

For the purpose of obtaining a complete settlement of all issues, the Parties accept GLPT's calculations of income tax, totaling $2,115,400 for 2015 and $2,189,000 for 2016, are appropriate. As shown in the corporate chart in 1-5-11-B, and as described in the section 81 notice filed by GLPT with the Board on January 31, 2013, there was a change in GLPT's corporate structure since GLPT's previous rate application (EB-2012-0300) whereby Great Lakes Power Transmission Holdings LP became the new sole limited partner of GLPT. In particular, GLPT's current corporate structure chart[1] indicates that a non- taxable entity, Great Lakes Power Transmission Holdings LP, owns 99.99% of the partnership units of GLPT (as the sole limited partner), and that a taxable entity, Great Lakes Power Transmission Inc., owns 0.01% of the partnership units (as the general partner). The previous ownership structure[2] showed ownership by two taxable entities, Great Lakes Power Transmission Inc. with 0.01% GP interest and Brookfield Infrastructure Holdings (Canada) Inc. with 99.99% LP interest.

Regarding the provision of a tax allowance in GLPT's revenue requirement, the Board had previously found that the stand-alone principle applied to GLPT and that the tax allowance will be allowed in rates. The Board stated, "The two partners [i.e., the general partner and sole limited partner of GLPT] are taxable corporations in Canada. There is no need to look further up the Brookfield corporate structure for purposes of determining the tax position." While it is evident that GLPT is no longer directly held by two taxable entities, the Parties are of the view that the tax allowance should continue to be included in the revenue requirement for the test period. Underpinning this view is the fact that there is a taxable entity, Brookfield Infrastructure Holdings (Canada) Inc., further up the ownership chart. In effect, the change in corporate structure does not alter the tax liability or the corporate entities within the structure responsible for that liability.

[1] See EB-2014-0238/ Exhibit 1Tab5 Schedule 2 Appendix B p.5
[2] See EB-2012-0300/Exhibit 1 Tab1 Schedule 12 Appendix B p.5

Approval:

Parties in Support:	SEC, VECC, Energy Probe
Parties Taking No Position:	N/A

Evidence: The evidence in relation to this issue includes the following:

4-4-1	Tax Overview
4-4-2	Income Tax
4-4-3	Property Tax
4-4-4	Interest Expense
4-4-5	Capital Cost Allowance
9-4-1	4.0-VECC-19

5. Cost of Capital

5.1 Is the proposed capital structure, rate of return on equity and short term debt rate appropriate?

5.2 Is the proposed long term debt rate appropriate?

Capital Structure

Complete Settlement: There is an agreement to settle these issues 5.1 and 5.2 as follows:

In its application and evidence, GLPT proposed a capital structure for both the 2015 and 2016 Test Years that is 60% deemed debt (comprised of 4% short-term and 56% long-term) and 40% equity, as presented in Tables 5-1-1A and 5-1-1B of the pre-filed evidence.

For the purpose of obtaining a complete settlement of all issues, the Parties accept that GLPT's proposed capital structure for the 2015 and 2016 Test Years is appropriate.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

5-1-1 Cost of Capital & Rate of Return
9-2-1 5-Staff-26

Cost of Debt

Complete Settlement: There is an agreement to settle this issue as follows:

In its application, GLPT proposed a rate of interest on long term debt using its effective rate of interest on its actual debt. The rate proposed by GLPT was 6.87% in both 2015 and 2016, as presented in the Tables at 5-1-1A and 5-1-1B of the pre-filed evidence.

In its application, GLPT acknowledged that the Board has determined that the deemed amount of short term debt that should be factored into rate setting be fixed at 4% of rate base. For rates effective January 1, 2015 and January 1, 2016, to be consistent with GLPT's approach to Return on Equity ("ROE"), GLPT indicated its deemed short term debt rate to be 2.11% for each of 2015 and 2016. The deemed short term debt rate for 2015 and 2016 will be updated when the Board issues its approved cost of capital parameters for the rate year beginning January 1, 2015 and then again for the rate year beginning January 1, 2016.

For the purpose of obtaining a complete settlement of all issues, the Parties accept, as appropriate, GLPT's proposed rate of interest on long term debt of 6.87% and the Board-prescribed rate of interest on short term debt for the purpose of determining the cost of debt component of GLPT's revenue requirements for the 2015 and 2016 Test Years.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

5-1-1 Cost of Capital & Rate of Return

Cost of Equity

Complete Settlement: There is an agreement to settle this issue as follows:

In its application, GLPT initially proposed a ROE of 9.36% for each of the 2015 and 2016 test years. GLPT stated that it would update the ROE for each test year with the Board-approved figure, in accordance with the Board's Cost of Capital Report.

For the purpose of obtaining a complete settlement of all issues, the Parties accept GLPT's proposed ROE for the 2015 and 2016 test years, as updated when the Board issues its approved cost of capital parameters for the rate year beginning January 1, 2015 and again for the rate year beginning January 1, 2016.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

5-1-1 Cost of Capital & Rate of Return

6. Deferral and Variance Accounts

6.1 Are the proposed amounts, disposition and continuances of GLPT's existing Deferral and Variance Account appropriate?

6.1.1 Continuances

Complete Settlement: There is an agreement to settle this issue as follows:

In its application, GLPT proposed the following:

- the continuation in the test period of the sub-account for costs related to a legal claim made by Comstock Canada Inc., within account 1508;
- the continuation in the test period of the sub-account for Property Tax and Use and Occupation Permit Fee variances, within account 1508;
- the continuation in the test period of the sub-account to track and record impacts on test year revenue requirements resulting from any changes to existing IFRS standards or changes in the interpretation of such standards, within account 1508;
- the continuation in the test period of the sub-account to record costs in respect of IFRS gains and losses resulting from premature asset component retirements, within account 1508; and
- the continuation in the test period of the sub-account to record expenditures related to addressing an upcoming change to the definition of the Bulk Electric System ("BES"), within account 1508.

In addition, based upon the Board's Decision in EB-2009-0409, GLPT proposed to continue to maintain in the test period sub-accounts for Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs, within account 1508. Based upon the Accounting Procedures Handbook, GLPT proposed to continue to maintain in the test period account 1592 for tax variances and account 1595 related to previously approved regulatory liability repayments and account 1575 related to IFRS-CGAAP Transitional PP&E Amounts (for disbursement only).

<u>Account 1508 - Other Regulatory Assets</u>

As at the date of the Application, GLPT had six active sub-accounts of Account 1508: (i) Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs; (ii)

Comstock Claim; (iii) Property Tax and Use and Occupation Permit Fee Variances; (iv) Changes in IFRS; (v) IFRS Gains and Losses; and (vi) Changes to the definition of BES.

Account 1592 - Changes in Tax Legislation

The Board created this account to deal with changes in tax legislation and tax rules with respect to PILs and taxes.

Account 1575 - IFRS-CGAAP Transitional PP&E Amounts

The Board created this account to record differences arising as a result of accounting policy changes caused by the transition from previous CGAAP to modified IFRS.

Account 1595 - Five Year Liability Repayment

This account was established to refund the amount of $3,063,900 to ratepayers over a five year period beginning in 2011.

For the purpose of obtaining a complete settlement of all issues, the Parties accept GLPT's proposal that the Board should authorize GLPT to continue to establish and record costs in these existing accounts, as described in the evidence filed by GLPT in support of these requests (including the continuance of the account 1575 related to IFRS-CGAAP Transitional PP&E Amounts for disbursal only), with one exception: the Parties agree that the sub-account within account 1508 related changes to existing IFRS standards or changes in the interpretation of such standards should be closed.

The Parties also acknowledge that GLPT's loss on disposal of assets amounts in 2013 and 2014 were approximately $450,000 and $210,000, respectively, and GLPT anticipates the loss amounts related to planned projects will be in excess of $500,000 and $300,000 in each of 2015 and 2016, respectively. These amounts are therefore expected to exceed GLPT's materiality thresholds set out in 1-4-1 of the pre-filed evidence of $199,400 and $201, 600 for 2015 and 2016, respectively.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

6-1-1 Deferral and Variance Accounts Overview

6-1-2	Account 1508 - Other Regulatory Assets
6-1-3	Account 1575 - IFRS-CGAAP Transitional PP&E Amounts
6-4-1	Continuity of Deferral and Variance Accounts
9-2-1	6-Staff-27
9-2-1	6-Staff-28
9-2-1	6-Staff-29
9-2-1	6-Staff-30
9-2-1	6-Staff-31
9-2-1	6-Staff-32
9-2-1	6-Staff-33
9-3-1	4-SEC-14
9-5-1	6-Energy Probe-22
10-2-1	6-Staff-37s
10-2-1	6-Staff-39s
10-2-1	6-Staff-40s

6.1.2 **Amounts and Dispositions**

Complete Settlement: There is an agreement to settle this issue as follows:

In its application, GLPT proposed to disburse the various account balances by aggregating the balance of all accounts, including the remaining balance in Account 1595, and disbursing them over a three year period beginning in 2015.

For the purpose of obtaining a complete settlement of all issues, the Parties have agreed that the various account balances being disbursed, and the proposed disbursal methodology, are appropriate.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

6-1-1	Deferral and Variance Accounts Overview
6-1-4	Account 1595 – Three Year Liability Repayment
6-3-1	Disbursal of Existing Deferral and Variance Accounts
6-4-1	Continuity of Deferral and Variance Accounts

9-4-1 6.0-VECC-21

6.2 Are the proposed new Deferral and Variance Account appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

In its application, GLPT requested approval to establish the following in the test years:

- a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2015 until GLPT's proposed 2015 rates are implemented, if necessary;
- a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2016 until GLPT's proposed 2016 rates are implemented, if necessary;
- a new deferral account for recording incremental expenditures related to new customer connection activities.

For the purpose of obtaining a complete settlement of all issues, the Parties agree that an accounting order establishing the requested sub-accounts within deferral account 1574 is appropriate. In addition, as part of the complete settlement of all issues, the Parties accept that, at the appropriate time, the requested account may be established for GLPT to record costs related to new customer connection activities; however, the Parties agree that, at the present time, there is not sufficient certainty regarding the new customer connection activities to warrant establishing this account. The Parties agree that GLPT may apply to the Board in the future to establish this account as further details about the new customer connections become available. Upon such an application, the Participating Intervenors may take any position they feel appropriate.

As indicated in section 2.1 above, as part of a complete settlement of all the issues, the Parties agree that a In-Service Additions Net Cumulative Asymmetrical Variance Account should be created.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

6-1-1 Deferral and Variance Accounts Overview

6-2-1	Proposed Deferral and Variance Accounts
9-2-1	6-Staff-33
9-2-1	6-Energy Probe-23
10-2-1	6-Staff-40s
10-5-1	6-Energy Probe-27s
Pages 4-6	Board’s Decision and Order dated July 12, 2012 for proceeding EB-2012-0180 under the heading “Support Costs for OEB Designation Process”

7. Cost Allocation

7.1 Is the cost allocation proposed by GLPT appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

GLPT proposes to allocate its incremental revenue requirement to the Uniform Transmission Rate pools by applying the same proportions as set out in Hydro One's most recent cost allocation methodology, which remains unchanged from what was approved by the Board in the Decision and Rate Order in EB-2010-0002.

For the purpose of obtaining a complete settlement of all issues, the Parties agree that the Board should adopt GLPT's allocation of its incremental revenue requirement to the Uniform Transmission Rate pools in accordance with Hydro One's latest cost allocation methodology.

Approval:

Parties in Support:	SEC, VECC, Energy Probe
Parties Taking No Position:	N/A

Evidence: The evidence in relation to this issue includes the following:

8-1-1	Calculation of Uniform Transmission Rates
8-1-2	Uniform Transmission Rate Reconciliation
8-1-3	2014 Ontario Transmission Rate Schedules
9-4-1	7.0-VECC-23

8. Rate Design

8.1 Is the proposed charge determinate forecast appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

As described in 3-1-2 of its application, GLPT employed a methodology for developing a charge determinant forecast for its directly connected customers. As described in 8-1-1, this forecasting methodology was then combined with the approved charge determinants for Ontario's other three electricity transmitters in order to derive the Uniform Transmission Rate in Ontario (the "**UTR**").

	Proposed Annual Charge Determinants (MW)		
	Network	**Line Connection**	**Transformation Connection**
GLPT	3,445.341	2,461.434	455.652
All Transmitters	238,851.173	231,224.393	197,995.764

The Parties accept that the proposed charge determinants presented in the above table are appropriate. Note that the "All Transmitters" figure does not incorporate any update for HONI or other transmitters' 2015-2016 volume forecasts.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

3-1-2	Charge Determinant Forecast & Variance Analysis
8-1-1	Calculation of Uniform Transmission Rates
9-2-1	3-Staff-13
9-4-1	3.0-VECC-10
9-4-1	3.0-VECC-11
9-5-1	2-Energy Probe-8
10-4-1	3.0-VECC-27

8.2 Is the proposed calculation of the Uniform Transmission Rates appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

The Parties accept that GLPT's calculation of the Uniform Transmission Rates is appropriate, subject to the changes agreed to in this Settlement Proposal.

Approval:

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

8-1-1 Calculation of Uniform Transmission Rates
8-1-2 Uniform Transmission Rate Reconciliation
8-1-3 2014 Ontario Transmission Rate Schedules

9. Rate Implementation

9.1 Is the rate effective and implementation date appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

In its application, GLPT requested that its existing rates be made interim effective January 1, 2015, if necessary. GLPT also requested that its proposed rates for 2015 and 2016 test years be made effective as of January 1, 2015 and January 1, 2016, respectively.

The Parties accept that GLPT's existing rates should be made interim effective January 1, 2015, if necessary, and that GLPT's revised 2015 and 2016 rates should be made effective as of January 1, 2015 and January 1, 2016, respectively.

Approval*:*

Parties in Support: SEC, VECC, Energy Probe

Parties Taking No Position: N/A

Evidence: The evidence in relation to this issue includes the following:

1-1-1 Application
1-1-2 Summary of Application

<u>APPENDIX ‘A’</u>

ISSUES LIST

BOARD APPROVED ISSUES LIST

1. General

1.1 Has GLPT responded appropriately to all relevant Board directions from previous proceedings?

1.2 Is the overall increase in 2015 and 2016 revenue requirement reasonable?

1.3 Are the productivity measures proposed and benchmarking performed by GLPT reasonable and appropriate?

2. Rate Base

2.1 Is the proposed rate base for 2015 and 2016 appropriate?

2.2 Is the working capital allowance for 2015 and 2016 appropriate?

2.3 Is the capital expenditure forecast for 2015 and 2016 appropriate?

2.4 Is the capitalization policy and allocation procedure appropriate?

3. Load Forecast and Revenue Forecast

3.1 Is the load forecast and methodology appropriate?

3.2 Is the impact of CDM appropriately reflected in the load forecast?

3.3 Are Other Revenues forecasts appropriate?

4. Operations, Maintenance & Administration Costs

4.1 Is the overall OM&A forecast in 2015 and 2016 appropriate?

4.2 Are the proposed spending levels for Share Services and other costs in 2015 and 2016 appropriate?

4.3 Is the proposed level of depreciation/amortization expense for 2015 and 2016 appropriate?

4.4 Are the 2015 and 2016 compensation costs and employee levels appropriate?

4.5 Is the 2015 and 2016 forecast of property taxes appropriate?

4.6 Are the requested income tax allowances for the test years 2015 and 2016 reasonable considering that the ownership structure of GLPT has changed since the last application EB-2012-0300?

4.7 Is the 2015 and 2016 forecast of income taxes appropriate?

5. Cost of Capital

5.1 Is the proposed capital structure, rate of return on equity and short term debt rate appropriate?

5.2 Is the proposed long term debt rate appropriate?

6. Deferral/Variance Accounts

6.1 Are the proposed amounts, disposition and continuances of GLPT's existing Deferral and Variance Account appropriate?

6.2 Are the proposed new Deferral and Variance Account appropriate?

7. Cost Allocation

7.1 Is the cost allocation proposed by GLPT appropriate?

8. Rate Design

8.1 Is the proposed charge determinate forecast appropriate?

8.2 Is the proposed calculation of the Uniform Transmission Rates appropriate?

9. Rate Implementation

9.1 Is the rate effective and implementation date appropriate?

<u>APPENDIX 'B'</u>

REVENUE REQUIREMENT WORK FORMS - REVISED TO REFLECT SETTLEMENT AGREEMENT

Revenue Requirement Workform

Version 4.00

Utility Name	
Service Territory	*Great Lakes Power Transmission*
Assigned EB Number	EB-2014-0238
Name and Title	Scott Seabrook, Director of Administration
Phone Number	(705) 759-7624
Email Address	sseabrook@glp.ca

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)		(6)			Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$249,916,705		$ -	$ 249,916,705		$ -	$249,916,705	
	Accumulated Depreciation (average)	($31,630,529)	(5)	$ -	($31,630,529)		$ -	($31,630,529)	
	Allowance for Working Capital:								
	Controllable Expenses	$11,021,095		($200,000)	$ 10,821,095		$ -	$10,821,095	
	Cost of Power	$ -		$ -			$ -	$0	
	Working Capital Rate (%)	4.30%	(9)		4.38%	(9)		4.38%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$38,731,100		$0	$38,731,100		$0	$38,731,100	
	Distribution Revenue at Proposed Rates	$39,782,072		($200,000)	$39,582,072		$0	$39,582,072	
	Other Revenue:								
	Specific Service Charges	$ -		$0	$ -		$0	$ -	
	Late Payment Charges	$ -		$0	$ -		$0	$ -	
	Other Distribution Revenue	$ -		$0	$ -		$0	$ -	
	Other Income and Deductions	$89,900		$0	$89,900		$0	$89,900	
	Total Revenue Offsets	$ -	(7)	$0	$ -		$0	$ -	
	Operating Expenses:								
	OM+A Expenses	$11,021,095		($200,000)	$ 10,821,095		$ -	$10,821,095	
	Depreciation/Amortization	$9,701,179		$ -	$ 9,701,179		$ -	$9,701,179	
	Property taxes	$238,241		$ -	$ 238,241		$ -	$238,241	
	Other expenses	$ -		$ -	0		$ -	$0	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($2,323,145)	(3)		($2,323,145)			($2,323,145)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$1,554,818			$1,554,818			$1,554,818	
	Income taxes (grossed up)	$2,115,398			$2,115,398			$2,115,398	
	Federal tax (%)	15.00%			15.00%			15.00%	
	Provincial tax (%)	11.50%			11.50%			11.50%	
	Income Tax Credits	$ -			$ -			$ -	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	6.87%			6.87%			6.87%	
	Short-term debt Cost Rate (%)	2.11%			2.11%			2.11%	
	Common Equity Cost Rate (%)	9.36%			9.36%			9.36%	
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$249,916,705	$ -	$249,916,705	$ -	$249,916,705
2	Accumulated Depreciation (average)	(3)	($31,630,529)	$ -	($31,630,529)	$ -	($31,630,529)
3	Net Fixed Assets (average)	(3)	$218,286,176	$ -	$218,286,176	$ -	$218,286,176
4	Allowance for Working Capital	(1)	$474,028	($1)	$474,028	$ -	$474,028
5	**Total Rate Base**		$218,760,204	($1)	$218,760,204	$ -	$218,760,204

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$11,021,095	($200,000)	$10,821,095	$ -	$10,821,095
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$11,021,095	($200,000)	$10,821,095	$ -	$10,821,095
9	Working Capital Rate %	(2)	4.30%	0.08%	4.38%	0.00%	4.38%
10	Working Capital Allowance		$474,028	($1)	$474,028	$ -	$474,028

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$39,782,072	($200,000)	$39,582,072	$ -	$39,582,072
2	Other Revenue	(1)	$89,900	$ -	$89,900	$ -	$89,900
3	Total Operating Revenues		$39,871,972	($200,000)	$39,671,972	$ -	$39,671,972
	Operating Expenses:						
4	OM+A Expenses		$11,021,095	($200,000)	$10,821,095	$ -	$10,821,095
5	Depreciation/Amortization		$9,701,179	$ -	$9,701,179	$ -	$9,701,179
6	Property taxes		$238,241	$ -	$238,241	$ -	$238,241
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$20,960,515	($200,000)	$20,760,515	$ -	$20,760,515
10	Deemed Interest Expense		$8,605,676	($0)	$8,605,676	$ -	$8,605,676
11	Total Expenses (lines 9 to 10)		$29,566,191	($200,000)	$29,366,191	$ -	$29,366,191
12	**Utility income before income taxes**		$10,305,780	($0)	$10,305,780	$ -	$10,305,780
13	Income taxes (grossed-up)		$2,115,398	$ -	$2,115,398	$ -	$2,115,398
14	**Utility net income**		$8,190,382	($0)	$8,190,382	$ -	$8,190,382

<u>Notes</u>

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application				Per Board Decision
(1)	Specific Service Charges	$ -	$ -	$ -	$ -	$ -
	Late Payment Charges	$ -	$ -	$ -	$ -	$ -
	Other Distribution Revenue	$ -	$ -	$ -	$ -	$ -
	Other Income and Deductions	$89,900	$ -	$89,900	$ -	$89,900
	Total Revenue Offsets	$89,900	$ -	$89,900	$ -	$89,900

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$8,190,382	$8,190,382	$8,190,382
2	Adjustments required to arrive at taxable utility income	($2,323,145)	($2,323,145)	($2,323,145)
3	Taxable income	$5,867,237	$5,867,237	$5,867,237
	Calculation of Utility income Taxes			
4	Income taxes	$1,554,818	$1,554,818	$1,554,818
6	Total taxes	$1,554,818	$1,554,818	$1,554,818
7	Gross-up of Income Taxes	$560,581	$560,581	$560,581
8	Grossed-up Income Taxes	$2,115,398	$2,115,398	$2,115,398
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$2,115,398	$2,115,398	$2,115,398
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$122,505,714	6.87%	$8,421,043
2	Short-term Debt	4.00%	$8,750,408	2.11%	$184,634
3	**Total Debt**	60.00%	$131,256,123	6.56%	$8,605,676
	Equity				
4	Common Equity	40.00%	$87,504,082	9.36%	$8,190,382
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,504,082	9.36%	$8,190,382
7	**Total**	100.00%	$218,760,204	7.68%	$16,796,058

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$122,505,714	6.87%	$8,421,043
2	Short-term Debt	4.00%	$8,750,408	2.11%	$184,634
3	**Total Debt**	60.00%	$131,256,122	6.56%	$8,605,676
	Equity				
4	Common Equity	40.00%	$87,504,082	9.36%	$8,190,382
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,504,082	9.36%	$8,190,382
7	**Total**	100.00%	$218,760,204	7.68%	$16,796,058

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$122,505,714	6.87%	$8,421,043
9	Short-term Debt	4.00%	$8,750,408	2.11%	$184,634
10	**Total Debt**	60.00%	$131,256,122	6.56%	$8,605,676
	Equity				
11	Common Equity	40.00%	$87,504,082	9.36%	$8,190,382
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$87,504,082	9.36%	$8,190,382
14	**Total**	100.00%	$218,760,204	7.68%	$16,796,058

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,050,972		$850,972		$850,972
2	Distribution Revenue	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100
3	Other Operating Revenue Offsets - net	$89,900	$89,900	$89,900	$89,900	$89,900	$89,900
4	**Total Revenue**	$38,821,000	$39,871,972	$38,821,000	$39,671,972	$38,821,000	$39,671,972
5	Operating Expenses	$20,960,515	$20,960,515	$20,760,515	$20,760,515	$20,760,515	$20,760,515
6	Deemed Interest Expense	$8,605,676	$8,605,676	$8,605,676	$8,605,676	$8,605,676	$8,605,676
8	**Total Cost and Expenses**	$29,566,191	$29,566,191	$29,366,191	$29,366,191	$29,366,191	$29,366,191
9	**Utility Income Before Income Taxes**	$9,254,809	$10,305,780	$9,454,809	$10,305,780	$9,454,809	$10,305,780
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,323,145)	($2,323,145)	($2,323,145)	($2,323,145)	($2,323,145)	($2,323,145)
11	**Taxable Income**	$6,931,664	$7,982,635	$7,131,664	$7,982,635	$7,131,664	$7,982,635
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$1,836,891	$2,115,398	$1,889,891	$2,115,398	$1,889,891	$2,115,398
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$7,417,918	$8,190,382	$7,564,918	$8,190,382	$7,564,918	$8,190,382
16	**Utility Rate Base**	$218,760,204	$218,760,204	$218,760,204	$218,760,204	$218,760,204	$218,760,204
17	Deemed Equity Portion of Rate Base	$87,504,082	$87,504,082	$87,504,082	$87,504,082	$87,504,082	$87,504,082
18	Income/(Equity Portion of Rate Base)	8.48%	9.36%	8.65%	9.36%	8.65%	9.36%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-0.88%	0.00%	-0.71%	0.00%	-0.71%	0.00%
21	Indicated Rate of Return	7.32%	7.68%	7.39%	7.68%	7.39%	7.68%
22	Requested Rate of Return on Rate Base	7.68%	7.68%	7.68%	7.68%	7.68%	7.68%
23	Deficiency/Sufficiency in Rate of Return	-0.35%	0.00%	-0.29%	0.00%	-0.29%	0.00%
24	Target Return on Equity	$8,190,382	$8,190,382	$8,190,382	$8,190,382	$8,190,382	$8,190,382
25	Revenue Deficiency/(Sufficiency)	$772,464	$ -	$625,464	$ -	$625,464	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,050,972 **(1)**		$850,972 **(1)**		$850,972 **(1)**	

Notes:

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

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$11,021,095		$10,821,095		$10,821,095	
2	Amortization/Depreciation	$9,701,179		$9,701,179		$9,701,179	
3	Property Taxes	$238,241		$238,241		$238,241	
5	Income Taxes (Grossed up)	$2,115,398		$2,115,398		$2,115,398	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$8,605,676		$8,605,676		$8,605,676	
	Return on Deemed Equity	$8,190,382		$8,190,382		$8,190,382	
8	**Service Revenue Requirement (before Revenues)**	$39,871,972		$39,671,972		$39,671,972	
9	Revenue Offsets	$ -		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$39,871,972		$39,671,972		$39,671,972	
11	Distribution revenue	$39,782,072		$39,582,072		$39,582,072	
12	Other revenue	$89,900		$89,900		$89,900	
13	**Total revenue**	$39,871,972		$39,671,972		$39,671,972	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$ -	(1)

Notes

(1) Line 11 - Line 8

Revenue Requirement Workform

Version 4.00

Utility Name	
Service Territory	*Great Lakes Power Transmission*
Assigned EB Number	EB-2014-0238
Name and Title	Scott Seabrook, Director of Administration
Phone Number	(705) 759-7624
Email Address	sseabrook@glp.ca

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Revenue Requirement Workform

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [(1)]

		Initial Application	(2)			(6)		Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$259,531,046		$ -	$ 259,531,046		$ -	$259,531,046	
	Accumulated Depreciation (average)	($41,366,782)	(5)	$ -	($41,366,782)		$ -	($41,366,782)	
	Allowance for Working Capital:								
	Controllable Expenses	$11,331,876		($210,000)	$ 11,121,876		$ -	$11,121,876	
	Cost of Power	$ -		$ -			$ -	$0	
	Working Capital Rate (%)	4.32%	(9)		4.40%	(9)		4.40%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$38,731,100		$0	$38,731,100		$0	$38,731,100	
	Distribution Revenue at Proposed Rates	$40,230,644		($210,000)	$40,020,644		$0	$40,020,644	
	Other Revenue:								
	Specific Service Charges	$ -		$0	$ -		$0	$ -	
	Late Payment Charges	$ -		$0	$ -		$0	$ -	
	Other Distribution Revenue	$ -		$0	$ -		$0	$ -	
	Other Income and Deductions	$89,900		$0	$89,900		$0	$89,900	
	Total Revenue Offsets	$ -	(7)	$0	$ -		$0	$ -	
	Operating Expenses:								
	OM+A Expenses	$11,331,876		($210,000)	$ 11,121,876		$ -	$11,121,876	
	Depreciation/Amortization	$9,771,327		$ -	$ 9,771,327		$ -	$9,771,327	
	Property taxes	$240,424		$ -	$ 240,424		$ -	$240,424	
	Other expenses	$ -		$ -	0		$ -	$0	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($2,115,011)	(3)		($2,115,011)			($2,115,011)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$1,608,920			$1,608,920			$1,608,920	
	Income taxes (grossed up)	$2,189,007			$2,189,007			$2,189,007	
	Federal tax (%)	15.00%			15.00%			15.00%	
	Provincial tax (%)	11.50%			11.50%			11.50%	
	Income Tax Credits	$ -			$ -			$ -	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	6.87%			6.87%			6.87%	
	Short-term debt Cost Rate (%)	2.11%			2.11%			2.11%	
	Common Equity Cost Rate (%)	9.36%			9.36%			9.36%	
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$259,531,046	$ -	$259,531,046	$ -	$259,531,046
2	Accumulated Depreciation (average)	(3)	($41,366,782)	$ -	($41,366,782)	$ -	($41,366,782)
3	Net Fixed Assets (average)	(3)	$218,164,264	$ -	$218,164,264	$ -	$218,164,264
4	Allowance for Working Capital	(1)	$489,809	($0)	$489,809	$ -	$489,809
5	**Total Rate Base**		$218,654,073	($0)	$218,654,073	$ -	$218,654,073

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$11,331,876	($210,000)	$11,121,876	$ -	$11,121,876
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$11,331,876	($210,000)	$11,121,876	$ -	$11,121,876
9	Working Capital Rate %	(2)	4.32%	0.08%	4.40%	0.00%	4.40%
10	Working Capital Allowance		$489,809	($0)	$489,809	$ -	$489,809

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$40,230,644	($210,000)	$40,020,644	$ -	$40,020,644
2	Other Revenue	(1)	$89,900	$ -	$89,900	$ -	$89,900
3	Total Operating Revenues		$40,320,544	($210,000)	$40,110,544	$ -	$40,110,544
	Operating Expenses:						
4	OM+A Expenses		$11,331,876	($210,000)	$11,121,876	$ -	$11,121,876
5	Depreciation/Amortization		$9,771,327	$ -	$9,771,327	$ -	$9,771,327
6	Property taxes		$240,424	$ -	$240,424	$ -	$240,424
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$21,343,627	($210,000)	$21,133,627	$ -	$21,133,627
10	Deemed Interest Expense		$8,601,501	($0)	$8,601,501	$ -	$8,601,501
11	Total Expenses (lines 9 to 10)		$29,945,128	($210,000)	$29,735,128	$ -	$29,735,128
12	**Utility income before income taxes**		$10,375,416	($0)	$10,375,416	$ -	$10,375,416
13	Income taxes (grossed-up)		$2,189,007	$ -	$2,189,007	$ -	$2,189,007
14	**Utility net income**		$8,186,408	($0)	$8,186,408	$ -	$8,186,408

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$ -	$ -	$ -	$ -	$ -
	Late Payment Charges	$ -	$ -	$ -	$ -	$ -
	Other Distribution Revenue	$ -	$ -	$ -	$ -	$ -
	Other Income and Deductions	$89,900	$ -	$89,900	$ -	$89,900
	Total Revenue Offsets	$89,900	$ -	$89,900	$ -	$89,900

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$8,186,408	$8,186,408	$8,186,408
2	Adjustments required to arrive at taxable utility income	($2,115,011)	($2,115,011)	($2,115,011)
3	Taxable income	$6,071,397	$6,071,397	$6,071,397
	Calculation of Utility income Taxes			
4	Income taxes	$1,608,920	$1,608,920	$1,608,920
6	Total taxes	$1,608,920	$1,608,920	$1,608,920
7	Gross-up of Income Taxes	$580,087	$580,087	$580,087
8	Grossed-up Income Taxes	$2,189,007	$2,189,007	$2,189,007
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$2,189,007	$2,189,007	$2,189,007
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$122,446,281	6.87%	$8,416,957
2	Short-term Debt	4.00%	$8,746,163	2.11%	$184,544
3	**Total Debt**	60.00%	$131,192,444	6.56%	$8,601,501
	Equity				
4	Common Equity	40.00%	$87,461,629	9.36%	$8,186,408
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,461,629	9.36%	$8,186,408
7	**Total**	100.00%	$218,654,073	7.68%	$16,787,910

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$122,446,281	6.87%	$8,416,957
2	Short-term Debt	4.00%	$8,746,163	2.11%	$184,544
3	**Total Debt**	60.00%	$131,192,444	6.56%	$8,601,501
	Equity				
4	Common Equity	40.00%	$87,461,629	9.36%	$8,186,408
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,461,629	9.36%	$8,186,408
7	**Total**	100.00%	$218,654,073	7.68%	$16,787,910

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$122,446,281	6.87%	$8,416,957
9	Short-term Debt	4.00%	$8,746,163	2.11%	$184,544
10	**Total Debt**	60.00%	$131,192,444	6.56%	$8,601,501
	Equity				
11	Common Equity	40.00%	$87,461,629	9.36%	$8,186,408
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$87,461,629	9.36%	$8,186,408
14	**Total**	100.00%	$218,654,073	7.68%	$16,787,910

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,499,544		$1,289,544		$1,289,544
2	Distribution Revenue	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100
3	Other Operating Revenue Offsets - net	$89,900	$89,900	$89,900	$89,900	$89,900	$89,900
4	**Total Revenue**	$38,821,000	$40,320,544	$38,821,000	$40,110,544	$38,821,000	$40,110,544
5	Operating Expenses	$21,343,627	$21,343,627	$21,133,627	$21,133,627	$21,133,627	$21,133,627
6	Deemed Interest Expense	$8,601,501	$8,601,501	$8,601,501	$8,601,501	$8,601,501	$8,601,501
8	**Total Cost and Expenses**	$29,945,128	$29,945,128	$29,735,128	$29,735,128	$29,735,128	$29,735,128
9	**Utility Income Before Income Taxes**	$8,875,872	$10,375,416	$9,085,872	$10,375,416	$9,085,872	$10,375,416
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,115,011)	($2,115,011)	($2,115,011)	($2,115,011)	($2,115,011)	($2,115,011)
11	**Taxable Income**	$6,760,861	$8,260,405	$6,970,861	$8,260,405	$6,970,861	$8,260,405
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$1,791,628	$2,189,007	$1,847,278	$2,189,007	$1,847,278	$2,189,007
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$7,084,244	$8,186,408	$7,238,594	$8,186,408	$7,238,594	$8,186,408
16	**Utility Rate Base**	$218,654,073	$218,654,073	$218,654,073	$218,654,073	$218,654,073	$218,654,073
17	Deemed Equity Portion of Rate Base	$87,461,629	$87,461,629	$87,461,629	$87,461,629	$87,461,629	$87,461,629
18	Income/(Equity Portion of Rate Base)	8.10%	9.36%	8.28%	9.36%	8.28%	9.36%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-1.26%	0.00%	-1.08%	0.00%	-1.08%	0.00%
21	Indicated Rate of Return	7.17%	7.68%	7.24%	7.68%	7.24%	7.68%
22	Requested Rate of Return on Rate Base	7.68%	7.68%	7.68%	7.68%	7.68%	7.68%
23	Deficiency/Sufficiency in Rate of Return	-0.50%	0.00%	-0.43%	0.00%	-0.43%	0.00%
24	Target Return on Equity	$8,186,408	$8,186,408	$8,186,408	$8,186,408	$8,186,408	$8,186,408
25	Revenue Deficiency/(Sufficiency)	$1,102,165	$ -	$947,815	$ -	$947,815	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,499,544 **(1)**		$1,289,544 **(1)**		$1,289,544 **(1)**	

Notes:

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

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$11,331,876		$11,121,876		$11,121,876	
2	Amortization/Depreciation	$9,771,327		$9,771,327		$9,771,327	
3	Property Taxes	$240,424		$240,424		$240,424	
5	Income Taxes (Grossed up)	$2,189,007		$2,189,007		$2,189,007	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$8,601,501		$8,601,501		$8,601,501	
	Return on Deemed Equity	$8,186,408		$8,186,408		$8,186,408	
8	**Service Revenue Requirement (before Revenues)**	$40,320,544		$40,110,544		$40,110,544	
9	Revenue Offsets	$ -		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$40,320,544		$40,110,544		$40,110,544	
11	Distribution revenue	$40,230,644		$40,020,644		$40,020,644	
12	Other revenue	$89,900		$89,900		$89,900	
13	**Total revenue**	$40,320,544		$40,110,544		$40,110,544	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$ -	(1)

Notes

(1) Line 11 - Line 8

<u>APPENDIX "B"</u>

November 19, 2014 Hearing Transcript including Decision on EB-2014-0238 Proposed Settlement Agreement

Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2014-0238**

VOLUME:	**1**	
DATE:	**November 19, 2014**	
BEFORE:	**Ellen Fry**	**Presiding Member**
	Marika Hare	**Member**

EB-2014-0238

THE ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP seeking changes to its electricity transmission revenue requirement for 2015 and 2016 to be effective January 1, 2015 and January 1, 2016.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Wednesday, November 19th, 2014,
commencing at 10:33 a.m.

VOLUME 1

BEFORE:

ELLEN FRY	PRESIDING MEMBER
MARIKA HARE	MEMBER

A P P E A R A N C E S

MICHAEL MILLAR	Board Counsel
RICHARD BATTISTA KIERAN BISHOP	Board Staff
CHARLES KEIZER	Great Lakes Power Transmission LP (GLPT)
ROGER HIGGIN	Energy Probe Research Foundation
MARK RUBENSTEIN	School Energy Coalition (SEC)
MICHAEL JANIGAN	Vulnerable Energy Consumers' Coalition (VECC)

ALSO PRESENT:

DUANE FECTEAU	Great Lakes Power Transmission LP

I N D E X   O F   P R O C E E D I N G S

E X H I B I T S

U N D E R T A K I N G S

Description	Page No.

NO UNDERTAKINGS WERE FILED IN THIS PROCEEDING.

Wednesday, November 19, 2014

--- On commencing at 10:33 a.m.

MS. FRY: Good morning. Please be seated.

This is a hearing concerning an application by Great Lakes Power Transmission for approval of electricity transmission rates for 2015 and 2016. The Board's file number for this proceeding is EB-2014-0238.

Great Lakes filed a complete application on July 14th, 2014. A settlement conference was held on October 28, 2014. A settlement proposal for a complete settlement was filed on November 12th, 2014.

This proposal was agreed to by all parties who participated in the settlement conference. Board Staff filed a submission on the settlement proposal on November 13th, 2014.

This hearing is limited to the issue raised in the Board Staff submission concerning the IFRS gains and losses of account within deferral account 1508.

My name is Ellen Fry. I will be presiding in today's hearing. Along with me is my colleague, Marika Hare.

May I have appearances, for the record.

APPEARANCES:

MR. KEIZER: Good morning, Madam Chair. My name is Charles Keizer. I'm here as counsel for the applicant, Great Lakes Power Transmission LP. With me is Mr. Duane Fecteau, who is vice-president, operations for Great Lakes Power Transmission.

MS. FRY: Thank you.

MR. RUBENSTEIN: Good morning, Ms. Fry, Ms. Hare. Mark Rubenstein, counsel for the School Energy Coalition. I've been asked to put in an appearance for Mr. Janigan on behalf of the Vulnerable Energy Consumers Coalition and Dr. Higgin on behalf of Energy Probe.

MS. FRY: Yes. So just to be clear, what is the scope of your ability to speak for those other parties, given that you're putting in an appearance for them?

MR. RUBENSTEIN: We've had -- the parties, as well -- the intervenors, as well as GLPT, had a -- spoken at a discussion yesterday. They're generally supportive of the submissions that GLPT is going to make, or at least that we've agreed to, so I'm -- to ensure that Mr. Keizer stays on sort of the discussions that we had yesterday. But any comments that I'll be making, I'll be making on behalf of myself, not on behalf of VECC or Energy Probe. If there are questions that you're --

MS. FRY: Okay. So what I'm hearing is you have some ability to speak on behalf of those parties, but it's limited, and you'll tell us of the limitations.

MR. RUBENSTEIN: Yes.

MS. FRY: Okay.

MR. MILLAR: Good morning, Madam Chair, Ms. Hare. Michael Millar, counsel for Board Staff. I'm joined by Richard Battista and Kieran Bishop.

MS. FRY: Thanks very much.

Are there any preliminary issues?

MR. KEIZER: We have none.

MS. FRY: Mr. Rubenstein? Mr. Millar?

Okay. So the way I'm proposing to proceed is starting with you, Mr. Keizer, to make submissions on the issue that we're hearing today. Mr. Rubenstein, you'd go next, and Mr. Millar last, and then after that we'll take a recess while the panel considers its decision, and we'll take things from there depending on how things go.

Okay. So the floor is yours, Mr. Keizer.

GREAT LAKES POWER TRANSMISSION LP

PRESENTATION OF THE SETTLEMENT AGREEMENT BY MR. KEIZER:

MR. KEIZER: Thank you, Madam Chair. Good morning.

As you noted, I'm here today to speak on behalf of Great Lakes Power Transmission LP in respect of the settlement reached between the parties. As you noted, the settlement is dated November 12th, 2014. It's a settlement on all issues. And it's a package which it's been agreed that none of the issues are severable.

The parties have worked hard, I think, to -- and I think it would generally be supported, this view by the other parties, that they have worked hard to create a settlement that's fair for both the ratepayer and the applicant, and I think would, if adopted, the Board, lead to just and reasonable rates.

The settlement proposal's for the 2015/2016 test years and arise from GLPT's application of July 14th. The overview of the settlement is at page 5 and 6 of the proposal, but based on procedural order 4 I'm going to limit my submissions related to the deferral account, referred to as the IFRS gains and losses account, which is sub-account 21508.

So unless you want me to do otherwise, I'll focus only on that issue.

MS. FRY: That was what the procedural order said.

MR. KEIZER: I've read it closely, thank you, Madam Chair.

So let me just provide an outline of where we're going to go with respect to these submissions. I first want to, for you, which would be helpful, is to set a bit of a context, both about aspects related to Great Lakes Power Transmission, and also the history of this account that has appeared in the settlement proposal. And then I would also like to talk about the mechanics of the account in particular and how that provides for a fair and beneficial result for ratepayers.

So let me first note, it's important to note, I think, here that, although we're here to hear submissions with respect to the matter, all of the parties and Board Staff at the end of the day, I believe, are supportive of the continuation of the account on the basis of the settlement.

Second, I think, is that with respect to GLPT, as Great Lakes Power Transmission, it's a transmitter, which is different than what you may typically see within rates proceedings on the electricity side versus transmitter versus distributor, and I'll elaborate on why that distinction is important.

But in addition, I think it's also important to note that it's not subject to incentive rate-making. It's not an IRM utility, it's not subject to IRM at this stage, and the application that it made is a two-year cost-of-service application.

In addition, I think it's important to note that as a transmitter Great Lakes Power obviously is by no means the bulk of the transmission system. It is a small transmitter, $40 million total revenue requirement, compared to a provincial revenue requirement somewhere in the range of 1.5-billion, but because of its smaller size it does carry the characteristics of a transmitter, which is oftentimes large, significant assets that form its systems.

So, for example, large transformer stations and other things that make it part of the bulk system in Ontario and that form part of the $218 million of its rate base.

So because of that it does have significant financial exposure to unplanned retirements during the test years, so if we lose a transformer station it could be a significant expense, which would occur during that test year, and if it's an unplanned event, it's not something that would not otherwise be able to be contemplated or forecasted.

So although there may be assets that are planned as part of its capital program to come out of service, any one unplanned loss of a major asset during the test year could have a significant financial impact on Great Lakes Power. And in the absence of that, this account would not have the ability to recover that loss.

The third thing, I think, is with respect to the context of this account that I would like to draw your attention to, is that I think it's helpful for you to understand a little bit of -- and I'm not going to go into great detail about this, but just the chronology of how this account came about. It's not the first time that this has been before the Board, and I think in terms of Great Lakes Power and the approval of this account, and I think it would just be helpful to have that as a context to distinguish it from some of the circumstances that have arisen for distribution utilities, in particular the utility referenced in the Board Staff submissions, being Hydro Ottawa.

So with your indulgence, I provided to Mr. Millar this morning a document that was entitled "chronology of Board approval of the deferral account". And I provided copies to Mr. Millar, and I believe he may have made that available to you on the dais as well.

MS. FRY: Yes, we have that.

Should that have an exhibit number?

MR. MILLAR: Yes, Madam Chair. We'll call that Exhibit K1.1.

EXHIBIT NO. K1.1: DOCUMENT ENTITLED "CHRONOLOGY OF BOARD APPROVAL OF THE DEFERRAL ACCOUNT".

MR. KEIZER: I'm not going to get into the details of this, other than to kind of give you a sense of where Great Lakes Power Transmission has been from a chronology perspective.

So in 2009 there was the Board report on the transition for IFRS reporting standards. In the -- in late 2010 the Board did approve the account for Hydro One Networks and its implementation, for reasons related to Hydro One.

And then in February of 2011 Great Lakes, for the test years '11 and '12, sought this account and this account was approved for use by Great Lakes Power for the year 2012, because that was the year it was adopting IFRS.

In June of 2011, later in that year, the Board then issued the addendum to the report, which is the aspect that came into play in the Hydro Ottawa case subsequent to that year, where Hydro Ottawa filed in 2011 and then in December of 2011 Hydro Ottawa's request to establish the account was denied.

However, subsequent to that, Great Lakes came back in with a rate application for the years '13 and '14, sought the continuation of this account, and in December of 2012 the Board granted the approval for the continuation of this account on a second time.

So the request made by Great Lakes in its application of this year, July 2014, for the test years '15 and '16 are consistent with the two prior approvals that the Board has given, both before and after the addendum for the reporting IFRS to put in place this account. So it was consistent with prior approvals and on a go-forward basis.

So given that context, what conclusions could be drawn? And I think there's a couple.

One is that the addendum itself relates particularly to IRM utilities, and that is its focus within the context of the addendum for reporting.

GLPT is subject to -- is a cost of service -- in a cost of service circumstance. It's not an IRM utility.

One, it is a transmission entity and so its asset profile is different, I think, than what we would see from a distribution utility, given the relative size of and financial significance of its assets relative to its overall revenue requirement, and the ability, potential, for losing large, significant assets that a transmitter holds.

And the other is that GLPT's approach with respect to this account has been consistent with past approvals with respect to the Board.

So I wanted to provide that as a context for why the account formed an element of the application, and why GLPT made and included it within the context of the application. But I think that's not the end of the story; I think you also have to see the other part of this, which is the mechanics of the account and how this -- what implications it has for the ratepayer.

So let me take a moment to talk about that at a high level, with respect to the approach that is included in this proposal.

So unlike a situation where you would apply the IFRS approach or addendum, where you would forecast retirements, so the revenue requirement impact of capital retirements or a loss, what this approach does it is effectively doesn't deal with it in the test year and it doesn't have it forecast. The impact and the revenue requirement impact of the loss is, in effect, deferred until such time as the account is dispersed. So in other words, if there is a loss that occurs, it gets recorded in the account and the ratepayer doesn't feel the impact of that recovery until such time as the account gets dispersed at a later date. Whereas under the IFRS methodology, the impact of that loss would get felt in the test year, right away, so the ratepayer does get the benefit of a deferral.

The other element of it is that the ratepayer is also credited back for any depreciation that GLPT would have incurred with respect to that loss. The depreciation expense gets credited back to the ratepayer from the time of the loss to the time that the account is dealt with on a subsequent application.

As well, there is no risk of over- or under-forecasting the potential loss amount during the course of the test year. And also there's minimal exposure to the rate effect for the ratepayer, partly for a couple of reasons.

Assuming here that -- a two-year test year, the earliest that Great Lakes Power would be able to come back to seek recovery for anything in the account would be at the end of those two test years. So because there is a deferral of the revenue requirement impact until such time as the account is dispersed, the ratepayer has at least two years before it would see it in rates.

And as well, Great Lakes has had the history of usually dispersing its accounts on a three-year basis or seeking the recovery of the amounts in those accounts on a three-year basis.

So potentially the ratepayer may actually see the rate impact of this spread out over a five-year basis. So the overall impact on the ratepayer is lessened by virtue of this approach.

So coupling that, that, one, we have a settlement agreement which everybody has worked very hard to create -- I think it's created a fair package overall -- with the advantage of the fact that this works within the context of Great Lakes as a transmitter from a cost of service perspective, and that it's consistent with previous approvals from the Board, and also the fact that it also provides a benefit for the ratepayer, for the purposes of this settlement proposal, Great Lakes -- as well, I believe, would be echoed by the intervenors -- are supportive of continuation of this account as part of this proposal and the adoption of the settlement proposal overall by the Board.

MS. FRY: Mr. Rubenstein?

SUBMISSIONS BY MR. RUBENSTEIN:

MR. RUBENSTEIN: This part I can say on behalf of my friends. As the Board can understand, there are gives and takes in the settlement process between the parties between the various issues that come to leading to just and reasonable rates.

Parties are supportive of the settlement agreement. I think Mr. Keizer provided the -- and explained the uniqueness of a transmitter, specifically of GLPT, and in the context of the past Board approvals why we believe that the approval of this account in the context of this settlement is a reasonable result.

MS. FRY: Mr. Millar?

SUBMISSIONS BY MR. MILLAR:

MR. MILLAR: Thank you, Madam Chair. I know that you've read all the prefiled submissions, so I don't intend to go over our comments in any detail.

But just to give you the 30-second overview, I think the bottom line from Staff's submission is that we do support the settlement agreement as filed.

The deferral account that's at issue right now that we're discussing, as Mr. Keizer has already gone through, it already exists. It's not a new deferral account that they're proposing. So it's something the Board had considered and approved in the past.

That being said, Board Staff did want to draw the Ottawa Hydro decision to the Panel's attention. That was an instance, as you've seen, where the Board denied a request for a similar account, though as Mr. Keizer says, there may be some relevant differences there. And in that case, the Board preferred that a forecast actually go into rates.

So we felt we had to at least bring that to the Panel's attention, but even knowing that, Staff still does support the agreement as filed.

And those are my comments.

MS. FRY: Thank you, Mr. Millar.

QUESTIONS BY THE BOARD:

MS. HARE: I do have a few questions.

First, I'd like to ask: What amounts have been booked to that account in '12, '13 and '14?

MR. KEIZER: If you give me a moment, I can clarify with Mr. Fecteau.

MS. HARE: Thank you.

MR. MILLAR: Madam Chair, if it assists, at page 2 of the Staff's submission -- I don't know if you have it -- the amounts for 2013 and 2014 are $450,000 and $210,000 respectively.

MS. HARE: Do you know if anything was booked in '12?

MR. MILLAR: I don't have that information here.

MR. KEIZER: Nothing in '12.

MS. HARE: Okay. Thank you.

I would like you to explain a little bit more to me why you think deferring a cost for two years-plus is a benefit to ratepayers. Is it not a matter of "pay now or pay later"?

MR. KEIZER: I guess it is an element of that. I mean, it's partly, I guess -- you think about it from a -- often from an applicant's perspective, is that it is a deferral, so it means it's one less aspect that ultimately, although it may be small, gets layered into the provincial revenue requirement and ultimately gets passed on to rates.

So to the extent that you can smooth any of that, I think, is advantageous to the ratepayer. Not that I think that, given the relative size of GLPT to the provincial revenue requirement, its overall impact is not really reasonably felt within the context of the rate, and I think we would have to acknowledge that fact, but I think there is an element that, from a ratepayer's perspective of having to pay, to the extent you can smooth that cost out over time, that may not necessarily be a bad thing.

I think the other issue that we present is -- and I think it goes to the issue of a forecast. I mean, there's two elements to any forecast expense. There's those in which you can actually plan and contemplate for, and there are those which are unplanned, which catch you completely by surprise, and you had no understanding or appearance that it would happen.

So I think to this extent that in this circumstance, you know, the deferral, I think, also removes that issue of inconsistencies or concerns with respect to forecast ability. That's the other element.

MS. HARE: How is that difficulty in forecasting any different than any of the other elements that make up the revenue requirement?

MR. KEIZER: You know, I think that goes to the issue of the nature of the system itself. You know, in the context of an in-service -- or a capital program that a party may undertake, there certainly would be well aware that I'm going to carry out this nature of this work, and there may be elements of assets that you may take out of service, and therefore that loss is understood, and you may be able to reasonably forecast that.

The element, I think, of the asset, specific aspect (sic) for Great Lakes as a transmitter, given its relative size to some of the values of the assets, if you, for example, are faced with, you know, a significant loss of an asset in an unplanned way, so there's a catastrophic event that you could not have planned -- and for example, I think there was one in 2013 that Great Lakes experienced in one of its transformer stations. Would not have been able to plan for it, not been able to forecast it, but it is a significant cost relative to its overall revenue requirement. And so it's that element, I think, as well that forecasting does not necessarily capture.

MS. HARE: But in your example you just gave me, I fail to understand how that's related to IFRS. Can you clarify that?

MR. KEIZER: Well, it's related to IFRS to the extent that the IFRS requires you, upon the occurrence of the loss or the loss of service of that asset, to the extent it comes out of service and no longer has -- has to be written off, requires you to recognize the expense, and recognize the expense in the period in which it's incurred.

So if you incur it in the test year, and your forecast doesn't otherwise contemplate that, then that is an expense that you will have to deal with but have no means by which to actually have contemplated it in rates or to recover it without the advantage of an account.

MS. HARE: You said one other thing that I didn't quite understand. You said that a deferral account then provides no risk of over-forecasting the potential loss.

MR. KEIZER: Right.

MS. HARE: And whereas that's true, is that not also true of a variance account, because if it's overforecast in the variance account it's adjusted when you come to clear that account in any event; is that not right?

MR. KEIZER: That is the nature of any account, and the fact that the difference between the deferral and the variance account is, you know, effectively when you're starting to build it up, the other is you're varying around a certain number, and obviously the fact that you're able to capture something in the variance account does take into account the forecasting for error.

MS. HARE: Thank you.

MS. FRY: Okay. Thank you very much, counsel. So we'll take a break until 11:30, and then we'll reconvene.

--- Recess taken at 10:57 a.m.

--- On resuming at 11:54 a.m.

MS. FRY: Please be seated.

DECISION:

MS. FRY: Concerning the issue that is the subject of today's hearing, Great Lakes is correct that the statement of Board policy in the addendum to the report on implementing IFRS in an incentive rate mechanism environment does address IRM situations.

However, the addendum does state that the Board will have regard to the policy rationale for the policy in the addendum when considering similar issues. The Board considers that the policy and the rationale in the addendum indicate that a variance account is likely preferable to the deferral account. The Board expects Great Lakes to address this in its next rates application.

The Board recognizes that the settlement proposal in this proceeding is a complete settlement, and does consider that, as a whole, it is in the public interest.

Accordingly, the Board approves the settlement proposal as filed and declares the current rates interim as of January 1, 2015.

And I would also like to establish at this point, since we're all in one room, the timelines for getting a draft rate order through to finalization.

So, Mr. Keizer, when do you think you could have a draft rate order to us?

MR. KEIZER: Allow me to confer with Mr. Fecteau.

MS. FRY: Sure.

MR. KEIZER: I actually don't have my calendar in front of me, but the sense is that we would be able to circulate the draft order to parties by this Friday.

MS. FRY: How about you file it with the Board by this Friday? And then we'll have a comment period.

MR. KEIZER: That's fine.

MR. MILLAR: Madam Chair, if I could just mention, I think part of the settlement agreement contemplates using the new ROE figures, which have not yet been released by the Board. That is coming out imminently, as we understand it; it's the November update. But I don't know if they'll be out by Friday, so I don't know if that would be left open as a placeholder or if it makes more sense to wait a couple more days and file a complete rate order that includes the new ROE figures.

MS. FRY: So, Mr. Millar, obviously you don't have a crystal ball either, but you're thinking, say, if we say the 26th, which is Wednesday, would that -- you think that would allow --

MR. MILLAR: My guess is that that --

MS. FRY: That would be your guess?

MR. MILLAR: That it will be out before that.

MS. FRY: Could you live with a few more days, Mr. Keizer?

MR. KEIZER: We can always live with a few more days.

MS. FRY: So you'll file a draft rate order by November the 26th.

Mr. Rubenstein, how long do you think intervenors will require to comment?

MR. RUBENSTEIN: Not very long; a few days.

MS. FRY: Not very long? Give me a...

MR. RUBENSTEIN: The 26th is a...

MS. FRY: Is a Wednesday.

MR. RUBENSTEIN: So to the Monday?

MS. FRY: Monday, December the 1st? That works for you?
Does that work for you, Mr. Millar?
MR. MILLAR: Yes.
MS. FRY: Okay. And, Mr. Keizer, any reply argument?
MR. KEIZER: I would imagine we would only be a couple of days following that. And -- in terms of any reply on the comments made. So that's the 1st, is the Monday?
MS. FRY: 1st is the Monday.
MR. KEIZER: So I would assume that we would be able to -- at the latest, the Thursday.
MS. FRY: Okay. That's Thursday, December the 4th.
So we have draft rate order filed by November 26th, intervenor and Board Staff comments by December the 1st, reply by Great Lakes December the 4th.
Okay. No further comment on that? Okay. So that completes today's hearing. Thank you very much, counsel.
MR. KEIZER: Thank you very much.
--- Whereupon the hearing concluded at 11:58 a.m.

APPENDIX "C"

December 18, 2014 Decision and Order of the Board
2015 Transmission Revenue Requirement
EB-2014-0238

EB-2014-0238

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

AND IN THE MATTER OF an application by Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP seeking changes to the electricity transmission revenue requirement for 2015 and 2016 to be effective January 1, 2015 and January 1, 2016.

BEFORE: Ellen Fry
Presiding Member

Marika Hare
Member

DECISION AND ORDER

December 18, 2014

Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP (GLPT) filed a complete cost of service application with the Ontario Energy Board (the "Board") on July 14, 2014 under section 78 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its electricity transmission revenue requirements for 2015 and 2016 to be effective January 1, 2015 and January 1, 2016. GLPT recovers its Board-approved revenue requirement through Ontario's Uniform Transmission Rates.

GLPT, the Vulnerable Energy Consumers Coalition (VECC), the School Energy Coalition (SEC), and Energy Probe Research Foundation (Energy Probe) agreed on a complete Settlement Proposal, which was filed on November 12, 2014. On November 19, 2014 the Board heard submissions on an issue regarding the continuation of Sub-account IFRS Gains and Losses within deferral account 1508.

At this hearing the Board among other things approved the Settlement Proposal, directed GLPT to file a draft Rate Order and set timelines for submissions by intervenors and Board staff and GLPT reply submissions.

On November 25, 2014 GLPT filed a draft Rate Order. The Board received submissions from Board staff on the draft Rate Order. SEC and Energy Probe agreed with the Board staff submission and on December 3, 2014 GLPT filed a revised draft Rate Order that addressed the submissions by Board staff.

The Board notes that in its submission Board staff identified a discrepancy between the charge determinants shown in the Settlement Proposal[1] and those contained in the initial draft Rate Order. GLPT responded that the Settlement Proposal had inadvertently shown the charge determinants for 2014 rather than those proposed for 2015 and 2016.

The Board finds that the revised draft Rate Order is in keeping with the terms of the Settlement Proposal as approved by the Board. The Board notes that its approval of the Settlement Proposal is subject to the correction of the error concerning charge determinants discussed above.

Accordingly, the Board approves revenue requirements for GLPT in the amount of $40,302,831 for 2015 and in the amount of $40,990,460 for 2016 for the purposes of calculating the Uniform Transmission Rates. The amount for 2015 reflects the cost of capital parameters that have been approved by the Board for 2015.The amount for 2016 will be adjusted to reflect the cost of capital parameters for 2016 when they are approved by the Board.

For 2015, the Board also approves the allocation of the revenue requirement of $40,302,831 among the three Uniform Transmission Rate pools that are currently approved for Hydro One Networks Inc. (Hydro One). In accordance with Appendix C, the allocations for GLPT for 2015 using these percentages are:

[1] at page 36

- $24,611,934 (61.1%) to Network;
- $5,106,199 (12.7%) to Line Connection; and
- 10,584,698 (26.2%) to Transformation Connection

The Board notes that currently there is an application before the Board to set, among other things, Hydro One's Uniform Transmission Rates pool allocations for 2015. When these allocations have been set for Hydro One, the 2015 pool allocations for GLPT will be adjusted to reflect the same allocations. Similarly, the 2016 pool allocations for GLPT will be set to reflect the same allocations as the Hydro One allocations for 2016, when these have been approved.

IT IS ORDERED THAT:

1. The revenue requirement for GLPT to be included in the calculation of Uniform Transmission Rates effective January 1, 2015 is $40,302,831, calculated in accordance with Appendix A. The revenue requirement for GLPT effective January 1, 2016 is $40,990,460 calculated in accordance with Appendix A-1 subject to adjustment to reflect the cost of capital parameters approved by the Board for 2016 when these are available.

2. The GLPT revenue requirement allocations to the transmission pools for the calculation of the Uniform Transmission Rates for 2015 will be based on the allocations currently utilized for Hydro One, in accordance with Appendix C. When the Board has approved the 2015 pool allocations for Hydro One, the 2015 allocations for GLPT will be adjusted to be the same.

3. The GLPT charge determinants for the calculation of the Uniform Transmission Rates for 2015 are as shown in Appendix C.

4. GLPT shall establish the following variance accounts in accordance with Appendix D, effective January 1, 2015:
    - Sub-account "In-service Addition Net Cumulative Asymmetrical Variance Account" within Account 1508 – Other Regulatory Assets
    - Sub-account "2015 Revenue Deficiencies" within Account 1574
    - Sub-account "2016 Revenue Deficiencies" within Account 1574

5. GLPT shall close effective immediately the variance account referred to as "Sub-account within account 1508 to track and record impacts on test year revenue requirements resulting from any changes to existing IFRS standards or changes in the interpretation of such standards".
6. GLPT shall recover $787,816 in each of 2015, 2016 and 2017 to clear deferral and variance account balances totalling $2,363,488 to the end of 2014, in accordance with Appendix B.

Cost Awards

The Board may grant cost awards to eligible parties pursuant to its power under section 30 of the Ontario Energy Board Act, 1998. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's Practice Direction on Cost Awards. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

1. Intervenors shall file with the Board and forward to GLPT their respective cost claims within 7 days from the date of issuance of this Decision and Order.

2. GLPT shall file with the Board and forward to intervenors any objections to the claimed costs within 17 days from the date of issuance of this Decision and Order.

3. Intervenors shall file with the Board and forward to GLPT any responses to any objections for cost claims within 24 days of the date of issuance of this Decision and Order.

4. GLPT shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote the file number, EB-2014-0238, be made electronically through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, in searchable / unrestricted PDF format. Two paper copies must also be filed at the Board's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

ADDRESS

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

E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, December 18, 2015

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

TO DECISION AND ORDER

EB-2014-0238

Great Lakes Power Transmission LP

DATED: December 18, 2014

Revenue Requirement Workform

Version 4.00

Utility Name	
Service Territory	*Great Lakes Power Transmission*
Assigned EB Number	EB-2014-0238
Name and Title	Scott Seabrook, Director of Administration
Phone Number	(705) 759-7624
Email Address	sseabrook@glp.ca

Revenue Requirement Workform

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

#	Item	Initial Application	(2)			(6)		Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$249,916,705		$ -	$ 249,916,705		$ -	$249,916,705	
	Accumulated Depreciation (average)	($31,630,529)	(5)	$ -	($31,630,529)		$ -	($31,630,529)	
	Allowance for Working Capital:								
	Controllable Expenses	$11,021,095		($200,000)	$ 10,821,095		$ -	$10,821,095	
	Cost of Power	$ -		$ -			$ -	$0	
	Working Capital Rate (%)	4.30%	(9)		4.38%	(9)		4.38%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$38,731,100		$0	$38,731,100		$0	$38,731,100	
	Distribution Revenue at Proposed Rates	$39,782,072		($200,000)	$39,582,072		($67,057)	$39,515,015	
	Other Revenue:								
	Specific Service Charges	$ -		$0	$ -		$0	$ -	
	Late Payment Charges	$ -		$0	$ -		$0	$ -	
	Other Distribution Revenue	$ -		$0	$ -		$0	$ -	
	Other Income and Deductions	$89,900		$0	$89,900		$0	$89,900	
	Total Revenue Offsets	$ -	(7)	$0	$ -		$0	$ -	
	Operating Expenses:								
	OM+A Expenses	$11,021,095		($200,000)	$ 10,821,095		$ -	$10,821,095	
	Depreciation/Amortization	$9,701,179		$ -	$ 9,701,179		$ -	$9,701,179	
	Property taxes	$238,241		$ -	$ 238,241		$ -	$238,241	
	Other expenses	$ -		$ -	0		$ -	$0	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($2,323,145)	(3)		($2,323,145)			($2,323,145)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$1,554,818			$1,554,818			$1,540,905	
	Income taxes (grossed up)	$2,115,398			$2,115,398			$2,096,469	
	Federal tax (%)	15.00%			15.00%			15.00%	
	Provincial tax (%)	11.50%			11.50%			11.50%	
	Income Tax Credits	$ -			$ -			$ -	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	6.87%			6.87%			6.87%	
	Short-term debt Cost Rate (%)	2.11%			2.11%			2.16%	
	Common Equity Cost Rate (%)	9.36%			9.36%			9.30%	
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$249,916,705	$ -	$249,916,705	$ -	$249,916,705
2	Accumulated Depreciation (average)	(3)	($31,630,529)	$ -	($31,630,529)	$ -	($31,630,529)
3	Net Fixed Assets (average)	(3)	$218,286,176	$ -	$218,286,176	$ -	$218,286,176
4	Allowance for Working Capital	(1)	$474,028	($1)	$474,028	$ -	$474,028
5	**Total Rate Base**		$218,760,204	($1)	$218,760,204	$ -	$218,760,204

(1) **Allowance for Working Capital - Derivation**

6	Controllable Expenses		$11,021,095	($200,000)	$10,821,095	$ -	$10,821,095
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$11,021,095	($200,000)	$10,821,095	$ -	$10,821,095
9	Working Capital Rate %	(2)	4.30%	0.08%	4.38%	0.00%	4.38%
10	Working Capital Allowance		$474,028	($1)	$474,028	$ -	$474,028

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$39,782,072	($200,000)	$39,582,072	($67,057)	$39,515,015
2	Other Revenue	(1)	$89,900	$ -	$89,900	$ -	$89,900
3	Total Operating Revenues		$39,871,972	($200,000)	$39,671,972	($67,057)	$39,604,915
	Operating Expenses:						
4	OM+A Expenses		$11,021,095	($200,000)	$10,821,095	$ -	$10,821,095
5	Depreciation/Amortization		$9,701,179	$ -	$9,701,179	$ -	$9,701,179
6	Property taxes		$238,241	$ -	$238,241	$ -	$238,241
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$20,960,515	($200,000)	$20,760,515	$ -	$20,760,515
10	Deemed Interest Expense		$8,605,676	($0)	$8,605,676	$4,375	$8,610,052
11	Total Expenses (lines 9 to 10)		$29,566,191	($200,000)	$29,366,191	$4,375	$29,370,567
12	**Utility income before income taxes**		$10,305,780	($0)	$10,305,780	($71,432)	$10,234,349
13	Income taxes (grossed-up)		$2,115,398	($0)	$2,115,398	($18,929)	$2,096,469
14	**Utility net income**		$8,190,382	($0)	$8,190,382	($52,502)	$8,137,880

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$ -	$ -	$ -	$ -	$ -
	Late Payment Charges	$ -	$ -	$ -	$ -	$ -
	Other Distribution Revenue	$ -	$ -	$ -	$ -	$ -
	Other Income and Deductions	$89,900	$ -	$89,900	$ -	$89,900
	Total Revenue Offsets	$89,900	$ -	$89,900	$ -	$89,900

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$8,190,382	$8,190,382	$8,137,880
2	Adjustments required to arrive at taxable utility income	($2,323,145)	($2,323,145)	($2,323,145)
3	Taxable income	$5,867,237	$5,867,237	$5,814,735
	Calculation of Utility income Taxes			
4	Income taxes	$1,554,818	$1,554,818	$1,540,905
6	Total taxes	$1,554,818	$1,554,818	$1,540,905
7	Gross-up of Income Taxes	$560,581	$560,581	$555,564
8	Grossed-up Income Taxes	$2,115,398	$2,115,398	$2,096,469
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$2,115,398	$2,115,398	$2,096,469
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$122,505,714	6.87%	$8,421,043
2	Short-term Debt	4.00%	$8,750,408	2.11%	$184,634
3	**Total Debt**	60.00%	$131,256,123	6.56%	$8,605,676
	Equity				
4	Common Equity	40.00%	$87,504,082	9.36%	$8,190,382
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,504,082	9.36%	$8,190,382
7	**Total**	100.00%	$218,760,204	7.68%	$16,796,058

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$122,505,714	6.87%	$8,421,043
2	Short-term Debt	4.00%	$8,750,408	2.11%	$184,634
3	**Total Debt**	60.00%	$131,256,122	6.56%	$8,605,676
	Equity				
4	Common Equity	40.00%	$87,504,082	9.36%	$8,190,382
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,504,082	9.36%	$8,190,382
7	**Total**	100.00%	$218,760,204	7.68%	$16,796,058

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$122,505,714	6.87%	$8,421,043
9	Short-term Debt	4.00%	$8,750,408	2.16%	$189,009
10	**Total Debt**	60.00%	$131,256,122	6.56%	$8,610,052
	Equity				
11	Common Equity	40.00%	$87,504,082	9.30%	$8,137,880
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$87,504,082	9.30%	$8,137,880
14	**Total**	100.00%	$218,760,204	7.66%	$16,747,931

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,050,972		$850,972		$783,915
2	Distribution Revenue	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100
3	Other Operating Revenue Offsets - net	$89,900	$89,900	$89,900	$89,900	$89,900	$89,900
4	**Total Revenue**	$38,821,000	$39,871,972	$38,821,000	$39,671,972	$38,821,000	$39,604,915
5	Operating Expenses	$20,960,515	$20,960,515	$20,760,515	$20,760,515	$20,760,515	$20,760,515
6	Deemed Interest Expense	$8,605,676	$8,605,676	$8,605,676	$8,605,676	$8,610,052	$8,610,052
8	**Total Cost and Expenses**	$29,566,191	$29,566,191	$29,366,191	$29,366,191	$29,370,567	$29,370,567
9	**Utility Income Before Income Taxes**	$9,254,809	$10,305,780	$9,454,809	$10,305,780	$9,450,433	$10,234,349
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,323,145)	($2,323,145)	($2,323,145)	($2,323,145)	($2,323,145)	($2,323,145)
11	**Taxable Income**	$6,931,664	$7,982,635	$7,131,664	$7,982,635	$7,127,288	$7,911,204
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$1,836,891	$2,115,398	$1,889,891	$2,115,398	$1,888,731	$2,096,469
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$7,417,918	$8,190,382	$7,564,918	$8,190,382	$7,561,702	$8,137,880
16	**Utility Rate Base**	$218,760,204	$218,760,204	$218,760,204	$218,760,204	$218,760,204	$218,760,204
17	Deemed Equity Portion of Rate Base	$87,504,082	$87,504,082	$87,504,082	$87,504,082	$87,504,082	$87,504,082
18	Income/(Equity Portion of Rate Base)	8.48%	9.36%	8.65%	9.36%	8.64%	9.30%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.30%	9.30%
20	Deficiency/Sufficiency in Return on Equity	-0.88%	0.00%	-0.71%	0.00%	-0.66%	0.00%
21	Indicated Rate of Return	7.32%	7.68%	7.39%	7.68%	7.39%	7.66%
22	Requested Rate of Return on Rate Base	7.68%	7.68%	7.68%	7.68%	7.66%	7.66%
23	Deficiency/Sufficiency in Rate of Return	-0.35%	0.00%	-0.29%	0.00%	-0.26%	0.00%
24	Target Return on Equity	$8,190,382	$8,190,382	$8,190,382	$8,190,382	$8,137,880	$8,137,880
25	Revenue Deficiency/(Sufficiency)	$772,464	$ -	$625,464	$ -	$576,178	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,050,972 **(1)**		$850,972 **(1)**		$783,915 **(1)**	

Notes:

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

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$11,021,095		$10,821,095		$10,821,095	
2	Amortization/Depreciation	$9,701,179		$9,701,179		$9,701,179	
3	Property Taxes	$238,241		$238,241		$238,241	
5	Income Taxes (Grossed up)	$2,115,398		$2,115,398		$2,096,469	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$8,605,676		$8,605,676		$8,610,052	
	Return on Deemed Equity	$8,190,382		$8,190,382		$8,137,880	
8	**Service Revenue Requirement (before Revenues)**	$39,871,972		$39,671,972		$39,604,915	
9	Revenue Offsets	$ -		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$39,871,972		$39,671,972		$39,604,915	
11	Distribution revenue	$39,782,072		$39,582,072		$39,515,015	
12	Other revenue	$89,900		$89,900		$89,900	
13	**Total revenue**	$39,871,972		$39,671,972		$39,604,915	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	**(1)**	$ -	**(1)**	$ -	**(1)**

Notes

(1) Line 11 - Line 8

APPENDIX A-1

TO DECISION AND ORDER

EB-2014-0238

Great Lakes Power Transmission LP

DATED: December 18, 2014

Revenue Requirement Workform

Version 4.00

Utility Name	
Service Territory	*Great Lakes Power Transmission*
Assigned EB Number	EB-2014-0238
Name and Title	Scott Seabrook, Director of Administration
Phone Number	(705) 759-7624
Email Address	sseabrook@glp.ca

Revenue Requirement Workform

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)			(6)		Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$259,531,046		$ -	$ 259,531,046		$ -	$259,531,046	
	Accumulated Depreciation (average)	($41,366,782)	(5)	$ -	($41,366,782)		$ -	($41,366,782)	
	Allowance for Working Capital:								
	Controllable Expenses	$11,331,876		($210,000)	$ 11,121,876		$ -	$11,121,876	
	Cost of Power	$ -		$ -			$ -	$0	
	Working Capital Rate (%)	4.32%	(9)		4.40%	(9)		4.40%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$38,731,100		$0	$38,731,100		$0	$38,731,100	
	Distribution Revenue at Proposed Rates	$40,230,644		($210,000)	$40,020,644		$0	$40,020,644	
	Other Revenue:								
	Specific Service Charges	$ -		$0	$ -		$0	$ -	
	Late Payment Charges	$ -		$0	$ -		$0	$ -	
	Other Distribution Revenue	$ -		$0	$ -		$0	$ -	
	Other Income and Deductions	$89,900		$0	$89,900		$0	$89,900	
	Total Revenue Offsets	$ -	(7)	$0	$ -		$0	$ -	
	Operating Expenses:								
	OM+A Expenses	$11,331,876		($210,000)	$ 11,121,876		$ -	$11,121,876	
	Depreciation/Amortization	$9,771,327		$ -	$ 9,771,327		$ -	$9,771,327	
	Property taxes	$240,424		$ -	$ 240,424		$ -	$240,424	
	Other expenses	$ -		$ -	0		$ -	$0	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($2,115,011)	(3)		($2,115,011)			($2,115,011)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$1,608,920			$1,608,920			$1,608,920	
	Income taxes (grossed up)	$2,189,007			$2,189,007			$2,189,007	
	Federal tax (%)	15.00%			15.00%			15.00%	
	Provincial tax (%)	11.50%			11.50%			11.50%	
	Income Tax Credits	$ -			$ -			$ -	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	6.87%			6.87%			6.87%	
	Short-term debt Cost Rate (%)	2.11%			2.11%			2.11%	
	Common Equity Cost Rate (%)	9.36%			9.36%			9.36%	
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$259,531,046	$ -	$259,531,046	$ -	$259,531,046
2	Accumulated Depreciation (average)	(3)	($41,366,782)	$ -	($41,366,782)	$ -	($41,366,782)
3	Net Fixed Assets (average)	(3)	$218,164,264	$ -	$218,164,264	$ -	$218,164,264
4	Allowance for Working Capital	(1)	$489,809	($0)	$489,809	$ -	$489,809
5	**Total Rate Base**		$218,654,073	($0)	$218,654,073	$ -	$218,654,073

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$11,331,876	($210,000)	$11,121,876	$ -	$11,121,876
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$11,331,876	($210,000)	$11,121,876	$ -	$11,121,876
9	Working Capital Rate %	(2)	4.32%	0.08%	4.40%	0.00%	4.40%
10	Working Capital Allowance		$489,809	($0)	$489,809	$ -	$489,809

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$40,230,644	($210,000)	$40,020,644	$ -	$40,020,644
2	Other Revenue	(1)	$89,900	$ -	$89,900	$ -	$89,900
3	Total Operating Revenues		$40,320,544	($210,000)	$40,110,544	$ -	$40,110,544
	Operating Expenses:						
4	OM+A Expenses		$11,331,876	($210,000)	$11,121,876	$ -	$11,121,876
5	Depreciation/Amortization		$9,771,327	$ -	$9,771,327	$ -	$9,771,327
6	Property taxes		$240,424	$ -	$240,424	$ -	$240,424
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$21,343,627	($210,000)	$21,133,627	$ -	$21,133,627
10	Deemed Interest Expense		$8,601,501	($0)	$8,601,501	$ -	$8,601,501
11	Total Expenses (lines 9 to 10)		$29,945,128	($210,000)	$29,735,128	$ -	$29,735,128
12	**Utility income before income taxes**		$10,375,416	($0)	$10,375,416	$ -	$10,375,416
13	Income taxes (grossed-up)		$2,189,007	$ -	$2,189,007	$ -	$2,189,007
14	**Utility net income**		$8,186,408	($0)	$8,186,408	$ -	$8,186,408

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$ -	$ -	$ -	$ -	$ -
	Late Payment Charges	$ -	$ -	$ -	$ -	$ -
	Other Distribution Revenue	$ -	$ -	$ -	$ -	$ -
	Other Income and Deductions	$89,900	$ -	$89,900	$ -	$89,900
	Total Revenue Offsets	$89,900	$ -	$89,900	$ -	$89,900

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$8,186,408	$8,186,408	$8,186,408
2	Adjustments required to arrive at taxable utility income	($2,115,011)	($2,115,011)	($2,115,011)
3	Taxable income	$6,071,397	$6,071,397	$6,071,397
	Calculation of Utility income Taxes			
4	Income taxes	$1,608,920	$1,608,920	$1,608,920
6	Total taxes	$1,608,920	$1,608,920	$1,608,920
7	Gross-up of Income Taxes	$580,087	$580,087	$580,087
8	Grossed-up Income Taxes	$2,189,007	$2,189,007	$2,189,007
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$2,189,007	$2,189,007	$2,189,007
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$122,446,281	6.87%	$8,416,957
2	Short-term Debt	4.00%	$8,746,163	2.11%	$184,544
3	**Total Debt**	60.00%	$131,192,444	6.56%	$8,601,501
	Equity				
4	Common Equity	40.00%	$87,461,629	9.36%	$8,186,408
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,461,629	9.36%	$8,186,408
7	**Total**	100.00%	$218,654,073	7.68%	$16,787,910

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$122,446,281	6.87%	$8,416,957
2	Short-term Debt	4.00%	$8,746,163	2.11%	$184,544
3	**Total Debt**	60.00%	$131,192,444	6.56%	$8,601,501
	Equity				
4	Common Equity	40.00%	$87,461,629	9.36%	$8,186,408
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$87,461,629	9.36%	$8,186,408
7	**Total**	100.00%	$218,654,073	7.68%	$16,787,910

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	56.00%	$122,446,281	6.87%	$8,416,957
9	Short-term Debt	4.00%	$8,746,163	2.11%	$184,544
10	**Total Debt**	60.00%	$131,192,444	6.56%	$8,601,501
	Equity				
11	Common Equity	40.00%	$87,461,629	9.36%	$8,186,408
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$87,461,629	9.36%	$8,186,408
14	**Total**	100.00%	$218,654,073	7.68%	$16,787,910

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,499,544		$1,289,544		$1,289,544
2	Distribution Revenue	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100	$38,731,100
3	Other Operating Revenue Offsets - net	$89,900	$89,900	$89,900	$89,900	$89,900	$89,900
4	**Total Revenue**	$38,821,000	$40,320,544	$38,821,000	$40,110,544	$38,821,000	$40,110,544
5	Operating Expenses	$21,343,627	$21,343,627	$21,133,627	$21,133,627	$21,133,627	$21,133,627
6	Deemed Interest Expense	$8,601,501	$8,601,501	$8,601,501	$8,601,501	$8,601,501	$8,601,501
8	**Total Cost and Expenses**	$29,945,128	$29,945,128	$29,735,128	$29,735,128	$29,735,128	$29,735,128
9	**Utility Income Before Income Taxes**	$8,875,872	$10,375,416	$9,085,872	$10,375,416	$9,085,872	$10,375,416
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,115,011)	($2,115,011)	($2,115,011)	($2,115,011)	($2,115,011)	($2,115,011)
11	**Taxable Income**	$6,760,861	$8,260,405	$6,970,861	$8,260,405	$6,970,861	$8,260,405
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$1,791,628	$2,189,007	$1,847,278	$2,189,007	$1,847,278	$2,189,007
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$7,084,244	$8,186,408	$7,238,594	$8,186,408	$7,238,594	$8,186,408
16	**Utility Rate Base**	$218,654,073	$218,654,073	$218,654,073	$218,654,073	$218,654,073	$218,654,073
17	Deemed Equity Portion of Rate Base	$87,461,629	$87,461,629	$87,461,629	$87,461,629	$87,461,629	$87,461,629
18	Income/(Equity Portion of Rate Base)	8.10%	9.36%	8.28%	9.36%	8.28%	9.36%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-1.26%	0.00%	-1.08%	0.00%	-1.08%	0.00%
21	Indicated Rate of Return	7.17%	7.68%	7.24%	7.68%	7.24%	7.68%
22	Requested Rate of Return on Rate Base	7.68%	7.68%	7.68%	7.68%	7.68%	7.68%
23	Deficiency/Sufficiency in Rate of Return	-0.50%	0.00%	-0.43%	0.00%	-0.43%	0.00%
24	Target Return on Equity	$8,186,408	$8,186,408	$8,186,408	$8,186,408	$8,186,408	$8,186,408
25	Revenue Deficiency/(Sufficiency)	$1,102,165	$ -	$947,815	$ -	$947,815	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,499,544 **(1)**		$1,289,544 **(1)**		$1,289,544 **(1)**	

Notes:

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

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$11,331,876		$11,121,876		$11,121,876	
2	Amortization/Depreciation	$9,771,327		$9,771,327		$9,771,327	
3	Property Taxes	$240,424		$240,424		$240,424	
5	Income Taxes (Grossed up)	$2,189,007		$2,189,007		$2,189,007	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$8,601,501		$8,601,501		$8,601,501	
	Return on Deemed Equity	$8,186,408		$8,186,408		$8,186,408	
8	**Service Revenue Requirement (before Revenues)**	$40,320,544		$40,110,544		$40,110,544	
9	Revenue Offsets	$ -		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$40,320,544		$40,110,544		$40,110,544	
11	Distribution revenue	$40,230,644		$40,020,644		$40,020,644	
12	Other revenue	$89,900		$89,900		$89,900	
13	**Total revenue**	$40,320,544		$40,110,544		$40,110,544	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$ -	(1)

Notes

(1) Line 11 - Line 8

APPENDIX B

TO DECISION AND ORDER

EB-2014-0238

Great Lakes Power Transmission LP

DATED: December 18, 2014

Appendix B

Deferral and Variance Account balances for the year ending December 31, 2014

($'s) Account Number	Account Description	Balance for Disbursal
1595	Three Year Liability Amount (1 Yr Remaining)	($699,363)
1508	Legal Claim (Comstock)	2,354,305
1508	IFRS Gains and Losses (2013-2014)	634,138
1508	EWT Variance	451,345
1508	EWT Support Costs	56,967
1575	IFRS-CGAAP Transitional PP&E Amounts	(433,945)
	Total Deferral Accounts	**$2,363,448**

Account Number	Account Description	Total Disbursal	Annual Disbursal
1595	Three Year Asset Disbursement	$2,797,393	$932,464
1575	Three Year Transitional PP&E Disbursement	(433,945)	(144,648)
	Total Disbursement	**$2,363,448**	**$787,816**

APPENDIX C

TO DECISION AND ORDER

EB-2014-0238

Great Lakes Power Transmission LP

DATED: December 18, 2014

Appendix C

Revenue Requirement and Charge Determinant Volumes

Rates- Revenue Requirement for UTR effective Jan 1 2015		
Approved 2015 revenue requirement	A	$39,515,015
Add D&VA annual disposition	B	$787,816
2015 Rates- Revenue Requirement	C = A+B	**$40,302,831**

2015 Rates- Revenue Requirement allocated to transmission pools				
	Network	Line Connection	Transformation Connection	Total
2015	$24,611,934	$5,106,199	$10,584,698	$40,302,831

Approved Charge Determinant (MW)			
	Network	Line Connection	Transformation Connection
2015	3,489.236	2,725.624	626.252
2016	3,498.236	2,734.624	635.252

APPENDIX D

TO DECISION AND ORDER

EB-2014-0238

Great Lakes Power Transmission LP

DATED: December 18, 2014

Appendix D

ACCOUNTING ORDER

Great Lakes Power Transmission LP ("GLPT") shall establish the following variance accounts effective as of January 1, 2015:

1 - Sub-account "In-service Addition Net Cumulative Asymmetrical Variance Account" within Account 1508 – Other Regulatory Assets

Purpose: To record the revenue requirement impact associated with the net difference between the forecasted and in-service additions for 2015 and 2016, in the event that total cumulative actual in-service additions are lower than total cumulative approved in-service additions for the 2015 and 2016 test years.

2 - Sub-account "2015 Revenue Deficiencies" within Account 1574

Purpose: To record revenue deficiencies incurred from January 1, 2015 until GLPT's proposed 2015 rates are implemented, if necessary.

3 - Sub-account "2016 Revenue Deficiencies" within Account 1574

Purpose: To record revenue deficiencies incurred from January 1, 2016 until GLPT's proposed 2016 rates are implemented, if necessary.

Attachment A provides details on the proposed accounting entries for the above accounts.

Attachment A - Accounting Entries:

1 - Sub-account "In-service Addition Net Cumulative Asymmetrical Variance Account" within Account 1508 – Other Regulatory Assets

Dr:	4110	Transmission Services Revenue
Cr:	1508	Other Regulatory Assets – Sub account "In-service Addition Net Cumulative Asymmetrical Variance Account"

To record the revenue requirement impact associated with the net difference between the forecasted and in-service additions for 2015 and 2016, in the event that total cumulative actual in-service additions are lower than total cumulative approved in-service additions for the 2015 and 2016 test years.

Dr:	6035	Other Interest Expense
Cr:	1508	Other Regulatory Assets – Sub account "In-service Addition Net Cumulative Asymmetrical Variance Account"

To record interest on the principal balance of the "In-service Addition Net Cumulative Asymmetrical Variance Account".

2 - Sub-account "2015 Revenue Deficiencies" within Account 1574

Dr:	1574	Sub-account "2015 Revenue Deficiencies"
Cr:	4110	Transmission Services Revenue

To record revenue deficiencies incurred from January 1, 2015 until GLPT's proposed 2015 rates are implemented.

Dr:	1574	Sub-account "2015 Revenue Deficiencies"
Cr:	6035	Other Interest Expense

To record interest on the principal balance of the "2015 Revenue Deficiencies" account.

3 - Sub-account "2016 Revenue Deficiencies" within Account 1574

Dr:	1574	Sub-account "2016 Revenue Deficiencies"
Cr:	4110	Transmission Services Revenue

To record revenue deficiencies incurred from January 1, 2016 until GLPT's proposed 2016 rates are implemented.

Dr:	1574	Sub-account "2016 Revenue Deficiencies"
Cr:	6035	Other Interest Expense

To record interest on the principal balance of the "2016 Revenue Deficiencies" account.

APPENDIX "D"

January 14, 2016 Decision and Order of the Board
2016 Transmission Revenue Requirement
EB-2015-0337

Ontario

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

DECISION AND ORDER

EB-2015-0337

GREAT LAKES POWER TRANSMISSION INC.

2016 Revenue Requirement

BEFORE: Ken Quesnelle
Presiding Member

January 14, 2016

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

Great Lakes Power Transmission Inc. (GLPT) is one of five licensed electricity transmitters in Ontario that recover their revenues through Ontario's uniform transmission rates (UTR). The Ontario Energy Board (OEB) approves the revenue requirements and charge determinants of the individual transmitters and uses them to calculate the UTR.

GLPT filed an application with the OEB on July 14, 2014 seeking approval for changes to its electricity transmission revenue requirements for 2015 and 2016. In its December 18, 2014 decision, the OEB approved a 2016 revenue requirement for GLPT of $40,990,460, subject to adjustment to reflect the cost of capital parameters approved by the OEB for 2016 when these became available. The OEB also approved GLPT's recovery of $787,816 in each of 2015, 2016 and 2017 to clear deferral and variance account balances and charge determinants for 2015 and 2016.

On November 20, 2015, GLPT filed an application to revise its 2016 revenue requirement to reflect the 2016 cost of capital parameters approved by the OEB on October 15, 2015. GLPT requested a total revenue requirement, including deferral and variance account recovery, of $40,565,936.

2 THE PROCESS

The total amount to be recovered for GLPT in 2016 is derived from the OEB's EB-2014-0238 Decision. The findings in this Decision involve only the implementation of findings in that previous decision. The OEB has therefore determined that no person will be adversely affected in a material way by the outcome of this proceeding. In accordance with section 21 (4) (b) of the Act, this matter has been determined without a hearing.

3 2016 REVENUE REQUIREMENT AND CHARGE DETERMINANTS

GLPT requested approval of a 2016 revenue requirement to recover the amount as approved in EB-2014-0238, updated to reflect the OEB's approved 2016 cost of capital parameters, as well as the OEB-approved annual disposition of deferral and variance account balances of a debit amount of $787,816. GLPT requested no change to the 2016 charge determinants as approved by the OEB in EB-2014-0238.

In support of its application, GLPT provided a revised Revenue Requirement Work Form incorporating a long-term debt rate of 6.87%. Consistent with the OEB's Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), an OEB-approved debt rate shall remain in place over the life of the instrument, unless it is renegotiated. GLPT's long-term debt rate of 6.87% was approved by the OEB in EB-2009-0408 for its existing third party debt, which has not been renegotiated. GLPT's application also contained a short-term debt rate of 1.65% and return on equity of 9.19% as approved by the OEB for 2016 in accordance with the Cost of Capital report[1]. On the basis of the 2016 parameters, the revised 2016 Cost of Capital for GLPT is reduced from $16,787,910 to $16,598,993. This revision results in a 2016 base revenue requirement of $39,778,120.

The total proposed 2016 revenue requirement is as follows:

Table 1: Revenue Requirement

Particulars	Amount
2016 BASE REVENUE REQUIREMENT	$39,778,120
DEFERRAL AND VARIANCE ACCOUNT DISPOSITION	$787,816
2016 TOTAL REVENUE REQUIREMENT	$40,565,936

[1] *Ontario Energy Board Letter, October 15, 2015 Re: Cost of Capital Parameter Updates for 2016 Applications*

GLPT's approved charge determinants to be incorporated into the calculation of UTRs are as follows:

Table 2: Charge Determinants (MW)

	Network	Line Connection	Transformation Connection
2016	3,498.236	2,734.624	635.252

Findings

The OEB approves GLPT's revised 2016 base revenue requirement as proposed.

4 ORDER

THE BOARD ORDERS THAT:

1. The total revenue requirement for GLPT to be included in the calculation of Uniform Transmission Rates effective January 1, 2016 is $40,565,936, inclusive of the previously approved deferral and variance account recovery of $787,816.

2. The GLPT charge determinants for the calculation of the Uniform Transmission Rates for 2016 shall be those approved in EB-2014-0238 and as shown in Table 2 of this decision.

DATED at Toronto January 14, 2016

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

ACCOUNTING STANDARD

GLPT adopted International Financial Reporting Standards ("IFRS") for reporting purposes with a changeover date of January 1, 2013, and with a transition date of January 1, 2012. In EB-2012-0300, GLPT sought and received approval of its revenue requirement for 2013 and 2014 based on Modified IFRS ("MIFRS"). This application continues the use of MIFRS.

COMPLIANCE WITH FILING REQUIREMENTS

GLPT has materially followed the filing requirements applicable to a revenue cap index proposal, as set out in Chapter 2 of the Board's *Filing Requirements for Electricity Transmission Applications, Chapter 2: Revenue Requirement Applications* dated February 11, 2016.

METHODOLOGY AND CHANGES TO METHODOLOGY

GLPT is requesting a single-year incentive revenue requirement setting plan under the revenue cap index to establish its 2017 revenue requirement. The OEB determined that GLPT can continue with its existing 2016 revenue requirement and bring forward a separate rate application, proposing a revenue cap index for the deferral period using incentive regulation framework defined for distributors as a guideline.

On March 10, 2016 Hydro One Inc. ("HOI") filed a Section 86 (2) (b) Application for the Leave to Purchase Voting Securities of Great Lakes Power Transmission Inc. with the Ontario Energy Board ("OEB") (EB-2016-0050). In that application, HOI sought OEB acceptance of a proposed 10 year rate rebasing deferral period, an earnings sharing mechanism, and a methodology to calculate GLPT's revenue requirement during the deferral period. Along with approving the purchase of the securities, the OEB accepted HOI's proposal to defer the rebasing of rates for GLPT for a 10 year period as well as its proposed earnings sharing mechanism. The rate setting methodology utilized throughout this application follows the direction provided by the Board in its Decision and Order in EB-2016-0050.

This is GLPT's first transmission rate application under the Board's revenue cap index framework set out in *Filing Requirements for Electricity Transmission Applications, Chapter 2 (February 11, 2016).* GLPT is requesting a single-year incentive rate setting plan under the revenue cap index for the 2017 test year. This methodology is a change from GLPT's historical filing of forward test year cost-of-service rate applications.

NON-UTILITY OPERATIONS

GLPT's core business is the operation of a regulated transmission utility in Ontario. However, from time to time GLPT may encounter matters that may be considered to be non-utility business. To the extent these matters arise, the impacts are segregated from GLPT's rate-regulated activities.

STATUS OF BOARD DIRECTIVES

1.0 Board Decisions

As detailed in the Board's oral decision in EB-2014-0238[1], dated November 19, 2014, the Board's policy is that a variance account is likely preferable to a deferral account for purposes of capturing gains and losses on asset disposals, and the Board expects GLPT to address this in this application. However, as described in Exhibit 1, Tab 1, Schedule 2, the Board's Decision and Order in EB-2016-0050 approved a ten year deferral period for rebasing of rates. Therefore, any asset disposals that trigger gains or losses in 2015 or 2016 will not be embedded within a rebased rate base, where these amounts will instead remain in GLPT's rate base for the duration of the ten year deferral period approved in EB-2016-0050.

2.0 EB-2014-0238 Settlement Agreement Undertakings

In the Board-approved settlement agreement arising from GLPT's EB-2014-0238 application, GLPT undertook to satisfy a number of conditions which are described in more detail below.

[1] Please refer to **Appendix 'B'** of Exhibit 1, Tab 2, Schedule 10 for the transcript of the November 19, 2014 hearing.

2.1 Asset Management Plan

GLPT committed to filing a more detailed and comprehensive asset management plan as part of its next rate application. However, given the October 31, 2016 acquisition of GLPT's voting securities by Hydro One Inc. ("Hydro One"), GLPT, with assistance from Hydro One, is in the midst of assessing and revising its approach to asset management. GLPT and Hydro One are working together to develop a transmission system plan that will maximize value to ratepayer while maintaining GLPT's service quality and reliability performance. Therefore, GLPT is not currently in a position to provide a detailed and comprehensive asset management plan or a transmission system plan that will accurately convey how GLPT's assets will be managed in the long term.

2.2 Benchmarking Study

GLPT agreed to participate in HONI's Total Cost Benchmarking Study (described in the Settlement Proposal filed in Hydro One Inc.'s 2015-2016 transmission rate application, EB-2014-0140), through the provision of relevant data, if GLPT was requested to do so. GLPT participated in the stakeholder consultation process related to HONI's study, and was prepared to provide the relevant data. However, GLPT was not selected as a comparator and as a result no request was received to provide data or participate further in the Study.

2.3 Lead Lag Study

GLPT undertook to complete a new lead lag study as part of its next rate application. However, as described in Exhibit 2, Tab 1, Schedule 1, the Board's Decision and Order in EB-2016-0050 approved a ten year deferral period for rebasing of rates. Consequently, this application is not a cost-of-service application and thus does not contain a component related to working capital, and therefore GLPT has not filed an updated lead lag study.

2.4 Load Forecast

GLPT undertook to prepare a new, bottom-up (Customer) load forecast for submission to the Board with its next rate application. GLPT engaged an independent consultant and the load forecast was completed in 2016. However, as described in Exhibit 2, Tab 1, Schedule 1, the Board's Decision and Order in EB-2016-0050 approved a ten year deferral period for rebasing of rates. Consequently, this application is not a cost-of-service application and thus does not contain a component related to a customer load forecast, and therefore GLPT has not filed an updated forecast.

2.5 Efficiency and Productivity Measures

GLPT undertook to implement additional efficiency and productivity measures during the Test Years in order to achieve the agreed upon reductions from GLPT's proposed OM&A costs for 2015 and 2016. GLPT has successfully managed its overall OM&A expenses within the Board-approved envelopes for the 2015 and 2016 Test Years. Further, GLPT is continuing to manage efficiency and productivity to mitigate future cost increases.

Exhibit 1, Tab 2, Schedule 16

GLPT Transmission Licence

Electricity Transmission Licence

ET-2007-0649

Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP

Valid Until

March 11, 2028

Original signed by

Kirsten Walli
Board Secretary
Ontario Energy Board
Date of Issuance: December 24, 2007
Effective Date: March 12, 2008
Date of Sch.1 Correction: March 13, 2008
Date of Amendment: November 19, 2008
Date of Amendment: May 5, 2009

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

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1 Definitions

In this Licence:

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

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

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

"**Board**" means the Ontario Energy Board;

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

"**Licensee**" means Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP

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

"**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;

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

"**transmission services**" means services related to the transmission of electricity and the services the Board has required transmitters to carry out for which a charge or rate has been established in the Rate Order;

"**Transmission System Code**" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes the obligations of a transmitter with respect to the services and terms of service to be offered to customers and provides minimum technical operating standards of transmission systems;

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

2 Interpretation

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

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence to own and operate a transmission system consisting of the facilities described in Schedule 1 of this Licence, including all associated transmission equipment.

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 2 of this Licence. The following Codes apply to this Licence:

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

b) the Transmission System 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 Requirement to Enter into an Operating Agreement

6.1 The Licensee shall enter into an agreement ("Operating Agreement") with the IESO providing for the direction by the IESO of the operation of the Licensee's transmission system. Following a request made by the IESO, the Licensee and the IESO shall enter into an Operating Agreement within a period of 90 business days, unless extended with leave of the Board. The Operating Agreement shall be filed with the Board within ten (10) business days of its completion.

6.2 Where there is a dispute that cannot be resolved between the parties with respect to any of the terms and conditions of the Operating Agreement, the IESO or the Licensee may apply to the Board to determine the matter.

7 Obligation to Provide Non-discriminatory Access

7.1 The Licensee shall, upon the request of a consumer, generator, distributor or retailer, provide such consumer, generator, distributor or retailer, as the case may be, with access to the Licensee's transmission system and shall convey electricity on behalf of such consumer, generator, distributor or retailer in accordance with the terms of this Licence, the Transmission System Code and the Market Rules.

8 Obligation to Connect

8.1 If a request is made for connection to the Licensee's transmission system or for a change in the capacity of an existing connection, the Licensee shall respond to the request within 30 business days.

8.2 The Licensee shall process connection requests in accordance with published connection procedures and participate with the customer in the IESO's Connection Assessment and approval process in accordance with the Market Rules, its Rate Order(s) and the Transmission System Code.

8.3 An offer of connection shall be consistent with the terms of this Licence, the Market Rules, the Rate Order, and the Transmission System Code.

8.4 The terms of such offer to connect shall be fair and reasonable.

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

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its transmission system to the standards established in the Transmission System Code and Market Rules, and have regard to any other recognized industry operating or planning standards required by the Board.

10 Transmission Rates and Charges

10.1 The Licensee shall not charge for the connection of customers or the transmission of electricity except in accordance with the Licensee's Rate Order(s) as approved by the Board and the Transmission System Code

11 Separation of Business Activities

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

12 Expansion of Transmission System

12.1 The Licensee shall not construct, expand or reinforce an electricity transmission system or make an interconnection except in accordance with the Act and Regulations, the Transmission System Code and the Market Rules.

13 Provision of Information to the Board

13.1 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.

13.2 Without limiting the generality of paragraph 13.1, 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) business days past the date upon which such change occurs.

14 Restrictions on Provision of Information

14.1 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.

14.2 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.

14.3 Information regarding consumers, retailers, wholesalers or generators may be disclosed where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

14.4 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.

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

15 Term of Licence

15.1 The effective date of this Licence is March 12, 2008, and the Licence will expire on March 11, 2028. The term of this Licence may be extended by the Board.

16 Transfer of Licence

16.1 In accordance with subsection 18(2) of the Act, this Licence is not transferable or assignable without leave of the Board.

17 Amendment of Licence

17.1 The Board may amend this Licence in accordance with section 74 of the Act or section 38 of the Electricity Act.

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.

SCHEDULE 1 SPECIFICATION OF TRANSMISSION FACILITIES

This Schedule specifies the facilities over which the Licensee is authorized to transmit electricity in accordance with paragraph 3 of this Licence.

1. Great Lakes Power Inc. on behalf of Great Lakes Power Transmission LP's transmission facilities consist of:

   - 318.25 circuit km of 230 kV line and associated equipment;
   - 232.37 circuit km of 115 kV line and associated equipment; and
   - 11 circuit km of 44 kV line and associated equipment which was deemed by the Board as serving a transmission function under section 84 of the Act.

   .

SCHEDULE 2 LIST OF CODE EXEMPTIONS

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

MANAGER'S SUMMARY

1.0 Management Summary Overview

On March 10, 2016, Hydro One Inc. ("HOI") filed a Section 86(2)(b) application for leave to purchase voting securities of Great Lakes Power Transmission Inc. with the Ontario Energy Board ("OEB") (EB-2016-0050). In that application, HOI sought OEB acceptance of a proposed 10 year rate rebasing deferral period, an earnings sharing mechanism, and a methodology to calculate GLPT's revenue requirement during the deferral period. Along with approving the purchase of the securities, the OEB accepted HOI's proposal to defer the rebasing of rates for GLPT for a 10 year period as well as its proposed earnings sharing mechanism, but did not fully accept the proposed rate-setting framework for GLPT, namely, the resetting of rates at the beginning of a 10-year deferral period:

> *"…rate-setting policies associated with consolidation are predicated on the notion that the going-in rates are the rates intended to provide the revenues required as the starting point to achieve savings over the deferred rebasing period".* [1]

The OEB determined that GLPT can continue with its existing 2016 revenue requirement and file a new rate application, proposing a revenue cap index framework for the deferral period. The rate setting methodology utilized throughout this application follows the direction provided by the OEB in its Decision and Order in EB-2016-0050.

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[1] EB-2016-0050 Decision and Order, page 17

This is GLPT's first transmission rate application under the OEB's revenue cap index as set out in the *Filing Requirements for Electricity Transmission Applications, Chapter 2 (February 11, 2016).* As outlined in Section 1.1 below, GLPT is requesting a single-year incentive rate setting plan ("IR Plan") under the revenue cap index for the 2017 test year.

The evidence filed by HOI in EB-2016-0050, combined with the OEB's Decision and Order issued on October 13, 2016, provides direction that influences this application as it relates to the form of the application, going-in rates, annual adjustments, earning sharing mechanism ("ESM"), and Z-factor.

1.1 Form of Application

As per the OEB Decision and Order in EB-2016-0050, this transmission rate application, filed by GLPT, is based on a revenue cap index for 2017. GLPT is requesting a single-year incentive rate setting plan under the revenue cap index framework as set out by the relevant sections of Chapter 2 of the February 11, 2016 *Filing Requirements for Electricity Transmission Applications*.

1.2 Going-In Rates

In the OEB's Decision and Order in EB-2016-0050, the OEB found that GLPT can continue with its existing 2016 revenue requirement and may bring forward a separate rate application to seek approval for elements of a specific revenue cap index framework. As such, GLPT's going in rates are based on its OEB approved 2016 revenue requirement (EB-2014-0238) of

$39,778,120, in accordance with the approved 2016 revenue requirement work form filed at Exhibit 1, Tab 1, Schedule 3.

1.3 Annual Adjustment

In accordance with the Decision and Order in EB-2016-0050, GLPT has calculated its proposed 2017 revenue requirement, by using an annual adjustment to its 2016 OEB approved revenue requirement. The annual adjustment is based on expected inflation taking into account productivity and stretch factors. In 2017, GLPT will continue to operate as a stand-alone licensed transmitter. During 2017 and 2018, Hydro One and GLPT will be undertaking a significant review of GLPT's operations prior to the operational integration of GLPT into Hydro One which is anticipated to begin in 2019. This review is expected to result in longer term operational synergies and savings post operational integration. GLPT does not expect any significant operational integration steps, or savings, to occur during 2017 or 2018 and submits that under this premise the annual adjustment is appropriate.

1.4 Earnings Sharing Mechanism

An ESM will not be applicable to any excess earnings in 2017. The OEB Decision and Order in EB-2016-0050 granted a 10 year deferral period (2017-2026) and approved HOI's proposed ESM. In the Section 86(2)(b) application, HOI proposed to establish an ESM for years 6-10 (2022-2026) of the deferral period consistent with the OEB's recently issued *Handbook to Electricity Distributor and Transmitter Consolidations* (January 2016).

1.5 Z-Factor Events

As per the OEB's Decision and Order in EB-2016-0050, GLPT will be granted recourse to file for recovery of Z-factor events, if required, through a separate application. Consistent with the OEB decision, GLPT's proposed IR Plan would permit GLPT to bring, for OEB approval, costs for unforeseen events outside of management's control, provided that such claims meet the three eligibility criteria of Causation, Materiality and Prudence.

GLPT proposes to record such amounts for unforeseen events into a separate Z-factor deferral account. GLPT would establish a Z-factor deferral account in Account 1572 as contemplated in Section 2.8.12 of Chapter 2 of the OEB's February 11, 2016 *Filing Requirements for Electricity Transmission Applications*. Any amount recorded into the Z-factor deferral account would accrue carrying charges at the OEB approved rates. GLPT would notify the OEB and interveners in this application of any amounts recorded in the Z-factor deferral account within six months of the unforeseen event. GLPT would apply to the OEB for recovery of amounts recorded in the Z-factor deferral account, and such application will include evidence from GLPT demonstrating that the costs incurred meet the three eligibility criteria outlined above. There are no Z-factor events being sought in this application.

While the EB-2016-0050 Decision and Order did not directly provide OEB findings on capital factor events, it is GLPT's position that capital events can be addressed through a separate application. However for 2017, GLPT does not anticipate the need to request a capital module, other than for circumstances that would be covered by the OEB's Z-factor.

SERVICE QUALITY AND RELIABILITY PERFORMANCE AND REPORTING OVERVIEW

1.1 Service Quality and Reliability Performance and Reporting Overview

As described in Exhibit 1, Tab 1, Schedule 2, this is GLPT's first transmission rate application under the Board's revenue cap index framework. In accordance with the *Filing Requirements for Electricity Transmission Applications, Chapter 2 (February 11, 2016)*, GLPT has incorporated two primary elements of the RRFE policy: a proposed scorecard to measure performance and enhanced reporting on customer engagement.

GLPT has provided its proposed scorecard along with a description of how it has evolved in Exhibit 3, Tab 1, Schedule 2. In order to achieve the desired business results as identified in the proposed scorecard GLPT actively manages the following performance measures:

- Reliability Performance (Exhibit 3, Tab 1, Schedule 3);
- Cost control through Benchmarking (Exhibit 3, Tab 1, Schedule 4);
- Compliance (Exhibit 3, Tab 1, Schedule 5) and
- Customer Engagement (Exhibit 3, Tab 1, Schedule 6).

PROPOSED SCORECARD

1.1 Introduction

GLPT has historically developed annual key performance indicators ("KPIs") for business performance measurement and is committed to continuous improvement in performance to maximize value for the ratepayer. The evolution of a balanced scorecard as described in this schedule will aid in determining new key factors to enhance the effectiveness of GLPT's KPI program.

This schedule describes GLPT's alignment with the principles of the OEB's Renewed Regulatory Framework for Electricity ("RRFE") through the development and integration of a balanced scorecard. The introduction of the scorecard will further enhance GLPT's performance management and ensure that the objectives and goals of the company are being managed to create additional value for the rate payer.

Through this schedule, GLPT will detail (i) how its existing KPIs are utilized to manage and monitor performance, and (ii) the development of an initial scorecard and how GLPT intends to expand future KPIs to reflect the scorecard.

1.2 Key Performance Indicators

GLPT manages a safe, reliable, cost efficient and environmentally responsible transmission system and has been committed to continuous improvement of critical areas of the business through the establishment of annual KPIs to measure and manage performance. GLPT establishes the annual KPIs through the budgeting process which occurs in October of each year to allow the approval and communication of the strategies and objectives to the appropriate work groups and individuals. GLPT's KPIs have traditionally been separated into four main categories; Excellence in Health, Safety, Security and Environment, Continued Value Creation, Risk Management, and Investment in our People. GLPT's operational performance objectives are based against specific goals that are relevant to each working group. Working groups are determined based on duties and functions within the organization and the duties and functions of the organization as a whole. The common working group performance objectives include:

Excellence in Health, Safety, Security and Environment ("HSSE")

- Zero high-risk HSSE incidents and zero lost time injuries;
- Maintain effective HSSE management systems; and
- Continue to reinforce and promote safe work practices and management team commitment to HSSE within the organization and the public.

In addition to the intrinsic, self-evident value of HSSE, this is to the benefit of the ratepayer as incidents affect productivity and work completion and also can be costly in respect of work stoppage, investigation, legal review and rehabilitation.

Continued Value Creation

- All planned work accomplished within established OM&A budget;

- Ensure capital projects are managed and completed on scope, schedule and budget; and
- Ensure that all capital projects are completed as per plan with respect to budget and scope. Project actual spending not to exceed + or – 10% variance to budget.

This benefits ratepayers by increasing the reliability and performance of the transmission system within prudent budget constraints.

Risk Management

- Zero high risk regulatory compliance and operational incidents; and
- Maintain reliability standards and ensure compliance program is in place.

Management of key reliability, operational and compliance risk increases quality of service and mitigates risk of penalties associated with non-compliance.

Investment in our People

- Establish individual development plan structure and promote leadership development.

People development is important for GLPT to promote individual development and provide appropriate tools and resources to enable managers to build effective teams. This will help increase competence, efficiency, productivity and succession planning opportunities both at GLPT and Hydro One, with the benefits ultimately received by the ratepayer.

A number of the KPIs tracked and measured by GLPT are consistent with the metrics that GLPT has introduced in its proposed scorecard.

1.3 Development of Scorecard

As a step in achieving the integration of the core concepts of the RRFE to manage and measure performance GLPT has developed an initial scorecard. Metrics have been drawn from internal and external sources that include GLPT's current KPIs, scorecards and metrics of other utilities and the OEB's *Performance Measurement for Electricity Distributors: A Scorecard Approach* report. GLPT's proposed scorecard is attached at **Appendix 'A'** to this schedule.

1.4 Evolution of KPIs and the GLPT Scorecard

GLPT is committed to identifying new key factors which are aligned with the RRFE and incorporating them into the current performance management system as KPIs. GLPT believes that it can draw very direct links between major corporate drivers (HSSE, Value Creation and Risk Management) and measurable objectives that will translate into tangible performance measures. GLPT believes these will also align with the requirements of the balanced scorecard and further drive value for the rate payer. GLPT will further support these objectives by connecting them with direct work groups, individual employee goals and the compensation program. In *Table 3-1-2 A* below, GLPT has identified improvement initiatives to improve measurement of GLPT's performance and improve the ability to record the achieved results into the evolving scorecard. Also, as mentioned in EB-2016-0050, "commencing in 2017 and 2018, GLPT and Hydro One will begin to identify areas where longer-term operational synergies and savings may be achieved"[1] as a result of consolidation.

Table 3-1-2 A – Improvement Initiatives

Performance Outcomes	Performance Categories	Improvement initiatives	GLPT Business Drivers
Customer Focus **Services are provided in a manner that responds to identified customer preferences.**	**Service Quality**		**Continued Value Creation**
	Customer Satisfaction	Improvements in documenting and formally requesting feedback from customers on the outage process and overall % of satisfaction	
Operational Effectiveness **Continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives.**	**Safety**	Improvements in tracking of additional health and safety statistics for more granular reporting	**HSSE, Continued Value Creation & Risk Management**
	System Reliability	Development of a process and collecting operational data utilizing the SCADA system with respect to equipment and system unavailability	
	Asset Management	Continuous improvement in the development of tangible goals and objectives in growing asset management capabilities	
	Cost Control		
Public Policy Responsiveness **Transmitters deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).**	**Connection of Renewable Generation**		**Risk Management**
	Market Regulatory Compliance	Required collection of results from self assessment of the GLPT internal Compliance program and audit findings to illustrate achieved performance (i.e., number and type of violations)	
	Regional Infrastructure	Ongoing strategic objectives to ensure that the regional planning process continues as required	
Financial Performance **Financial viability is maintained; and savings from operational effectiveness are sustainable.**	**Financial Ratios**		**Continued Value Creation**

[1] EB-2016-0050 - Exhibit A, Tab 2, Schedule 1, Page 1

APPENDIX "A"

Proposed Scorecard

Performance Outcomes	Performance Categories	Measures	Historical Years 2011	2012	2013	2014	2015	Trend
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	Satisfaction with Outage Planning Procedures (% Satisfied)	N/A	N/A	N/A	N/A	N/A	-
		Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	33%	24%	25%	20%	16%	▲
	Customer Satisfaction	Overall % Customer Satisfaction in Corporate Survey	N/A	N/A	N/A	N/A	N/A	-
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	High Risk Incidents (determined per GLPT's Managed System)	0.00	0.00	0.00	0.00	0.00	-
	System Reliability	T-SAIFI (Ave. # Power Interruptions per per Delivery Point)	2.14	2.24	1.37	0.47	0.89	▲
		T-SAIDI (Ave. # Minutes of Power Interruptions per Delivery Point)	296.71	176.76	861.11	25.37	82.32	▲
		System Unavailability (%)	N/A	N/A	N/A	N/A	N/A	▲
		Unsupplied Energy (minutes)	111.97	20.38	24.73	6.79	60.35	▲
	Asset Management	In-Service Additions (% of OEB approved plan)	120%	111%	99%	99%	92%	-
		CapEx as % of Budget	97%	113%	95%	95%	100%	-
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	10.69%	6.87%	4.38%	4.33%	5.76%	▲
		Sustainment Capital per Gross Fixed Asset Value (%)	7.55%	4.03%	1.29%	1.25%	2.70%	▲
		OM&A per Gross Fixed Asset Value (%)	3.15%	2.84%	3.09%	3.08%	3.06%	-

Legend:
▲ Performance Improving
▼ Performance deteriorating
\- No change

Performance Outcomes	Performance Categories	Measures		Historical Years 2011	2012	2013	2014	2015	Trend
Public Policy Responsiveness **Transmitters deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).**	**Connection of Renewable Generation**	% on time completion of renewables connection impact assessments		100%	100%	100%	100%	100%	-
	Market Regulatory Compliance	NERC/NPCC Reliability Standards Compliance							
		- Number of High Impact Violations		N/A	N/A	N/A	N/A	N/A	
		- Number of Medium/Low Impact Violations		N/A	N/A	N/A	N/A	N/A	
	Regional Infrastructure	Regional Infrastructure Planning progress - % Deliverables met		N/A	N/A	N/A	100%	100%	-
Financial Performance **Financial viability is maintained; and savings from operational effectiveness are sustainable.**	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.21	1.34	1.69	1.67	1.62	▲
		Leverage: Total Debt (includes short-term & long-term debt) to Equity Ratio		1.13	1.10	1.09	1.12	1.04	-
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.42%	8.93%	9.36%	9.30%	-
			Achieved	10.94%	11.86%	11.51%	11.42%	9.66%	-

Legend:
▲ Performance Improving
▼ Performance deteriorating
- No change

GLPT has provided the following descriptions of the various measures used in the scorecard to provide additional context.

Performance Category	Metric	Description
Service Quality	1. Satisfaction with Outage Planning Procedures (% Satisfied)	*GLPT traditionally monitors and manages customer satisfaction in this category through day to day communication via GLPT's System Control and through stakeholder engagements. Based on feedback received through these lines of communication, GLPT believes that customer satification related to outage planning procedures is maintained at a medium to high level. GLPT's outage scheduling and coordination ensures the impact to connected customers is reduced to minimize the impact on connected customers. In 2017, GLPT intends to develop and implement a process to measure and produce quantitative customer satisfaction results for purposes of tracking this metric.*
	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	*The percentage of customer delivery points deemed as either group or individual outliers. The Customer Delivery Point Performance Standard (CDPPS) data is described at Exhibit 3, Tab 1, Schedule 3 of this application.*
Customer Satisfaction	Overall % Customer Satisfaction in Corporate Survey	*GLPT traditionally manages overall customer satisfaction by means of annual stakeholder meetings which allows GLPT to meet with all directly connected transmission customers (LDCs, Large industrial and Generation). In these meetings GLPT facilitates open discussions around transmitter and customer market requirements, operational impacts and future planning. Recent stakeholder engagement meetings have been positively received and provided no indication of negative trends with customer satisfcation related to overall transmission services. Additionally, GLPT is available to meet with customers on an ad hoc basis with respect to planning or to address issues as they arise. While GLPT does not conduct a formal survey with customers, customer satisfaction is typically influenced by measures that are included directly in GLPT's KPIs such as reliability and cost management measures, among others. GLPT plans to develop and implement a process in 2017 to measure and produce quantitative results for the purpose of tracking performance of this metric.*
Safety	High Risk Incidents (determined per GLPT's Managed System)	*GLPT's overall safety objective is to incur zero high-risk incidents and zero lost time injuries. The measure applies to GLPT employees and contractors.*
System Reliability	T-SAIFI (Ave. # Power Interruptions per per Delivery Point)	*Average Frequency of Delivery Point Interruptions is an indicator of the average number of unplanned interruptions per delivery point per year. Both momentary outages (those lasting less than 1 minute) and sustained outages (those lasting 1 minute or more) contribute to this measure.*
	T-SAIDI (Ave. # Minutes of Power Interruptions per Delivery Point)	*Average Duration of Delivery Point Interruptions is an indicator of the average minutes of unplanned interruptions per delivery point per year. Both momentary outages (those lasting less than 1 minute) and sustained outages (those lasting 1 minute or more) contribute to this measure.*
	System Unavailability (%)	*GLPT plans to implement a process in 2017 to measure and produce quantitative results for the purpose of tracking performance of this metric.*
	Unsupplied Energy (minutes)	*Unsupplied Energy is an indicator of total energy not supplied to customers due to unplanned delivery point interruptions. In order to make it comparable among different sizes of utilities, the unsupplied energy is normalized by the system peak. The unit of the measure of normalized unsupplied energy is expressed in "system minutes".*
Asset Management	In-Service Additions (% of OEB approved plan)	*Measurement of the % capital place in-service compared to plan.*
	CapEx as % of Budget	*Progress is measured as the ratio of actual total capital expenditure to the total amount of planned capital expenditures.*

Performance Category	Metric	Description
Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	*Demonstrate cost effectiveness by comparing the ratio of Total Capital and OM&A to Gross Fixed Asset value.*
	Sustainment Capital per Gross Fixed Asset Value (%)	*Demonstrate cost effectiveness by comparing the ratio of Sustainment Capital to Gross Fixed Asset value.*
	OM&A per Gross Fixed Asset Value (%)	*Demonstrate cost effectiveness by comparing the ratio OM&A to Gross Fixed Asset value. This metric was benchmarked for GLPT by First Quartile Consulting; the report can be found at Exhibit 3, Tab 1, Schedule 4.*
Regulatory Compliance	NERC/NPCC Reliability Standards Compliance - Number of High Impact Violations - Number of Medium/Low Impact Violations	*Measure tracks GLPT's transmission compliance to NERC reliability Standards by measuring the number of "High Impact Violations" and "Medium/Low Impact Violations" over a calendar year.* *Violations are assessed as "High Impact Violations" when the potential or actual impact of a breach is severe based on the level of risk as assessed by the IESO. Violations are assessed as "Medium/Low Impact Violations" when the potential or actual impact of a breach is material (for "medium") or negligible or no impact (for "low") and are weighted the same.*
Regional Infrastructure Planning	Regional infrastructure Planning Progress - % Deliverables met	*Deliverables include meeting the Transmission System Code (TSC) prescribed timelines and delivering the required products. The number of deliverables will vary as they are identified in a given year. Deliverables includes Plans, Reports and LDC Status Update letters.*
Financial Ratios	1. Liquidity: Current Ratio (Current Assets/Current Liabilities)	*The company measures current ratio as the ratio of its current assets to its current liabilities. Current assets are defined as cash or other assets to be converted to cash within the year and which can be used to fund daily operations and pay ongoing expenses. Current liabilities are defined as short term debts or financial obligations that become due within the year.*
	Leverage: Total Debt (includes short-term & long-term debt) to Equity Ratio	*The debt-to-equity ratio is a measure of the company's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors.*
	Profitability: Regulatory Return on Equity - Deemed (includes in rates)	*The Board-approved return on Equity that is embedded in the transmitter's base rates. Return on Equity is the rate of return that the utility is allowed to earn through its transmission rates, as approved by the OEB.*
	Profitability: Regulatory Return on Equity - Achieved	*The transmitter's achieved regulated return on equity earned in the preceding fiscal year. The reported return is calculated on the same basis as was used in establishing GLPT's base rates. This shows the utility's actual return on equity earned each year.*

RELIABILITY PERFORMANCE

1.1 Introduction

This schedule has been prepared to highlight GLPT's reliability performance and provide explanations of notable historical events and circumstances that have affected reliability performance. GLPT has provided supporting information to illustrate the current level of system performance and demonstrate how GLPT is proactively identifying trends that may require remedial action. Reliability is an important metric included in GLPT's proposed scorecard, and one which forms an integral part of GLPT's Key Performance Indicators.

GLPT has employed Customer Delivery Point Performance Standards ("CDPPS") and unsupplied energy to monitor its service quality and reliability. Through continuous improvement objectives and initiatives in the area of reliability performance management GLPT will investigate the inclusion and benchmarking of system unavailability as an ongoing reliability measure.

1.2 Customer Delivery Point Performance Standard

As part of the OEB Transmission System Code requirement 4.5 GLPT has developed CDPPS, which relates the reliability of supply to the size of load being served at the delivery point. The standard includes measures for both frequency and duration of interruption. GLPT's CDPPS are defined in four load categories, which are made up of delivery points as follows: 0-15 MW, 15-40 MW, 40-80 MW and >80 MW. GLPT's CDPPS are attached as **Appendix 'A'**.

The standard generally considers two concepts for identifying concerns; these are the "outlier" concept and the "inlier" concept.

Performance triggers have been established to identify delivery point performance "outliers" utilizing Hydro One Networks Inc.'s historical (1991-2000) statistics, as illustrated in *Table 3-1-3 A* below. GLPT adopted these standards as performance triggers to identify "outliers" and to initiate technical and financial discussions and evaluations with impacted customers. An "outlier" is defined when the three year rolling average of delivery point performance falls below the minimum standard of performance as illustrated below for frequency and/or duration of interruptions.

Table 3-1-3 A - Delivery Performance Standards Based on Load Size

Performance Measures	**Delivery Point Performance Standards** (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		**>15 to 40MW**		**>40 to 80MW**		**>80MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

As noted above, the standard also includes an "inlier" concept, which is a provision to establish a performance standard to maintain the historical reliability performance levels at each customer delivery point and avoid deteriorating trends, notwithstanding the fact that they may have satisfactory performance. Baseline triggers were set once 10 years of GLPT customers' individual historical delivery point performance data was available (2004-2013). Delivery point performance that is worse than either baseline trigger (frequency or duration) in two consecutive years will be a candidate for remedial action. GLPT will respond by initiating technical and financial evaluations with affected customers to determine the root cause of the unreliability and to identify remedial measures that may be required to restore the historical reliability of performance.

Relevant statistics are reviewed with each customer on an annual basis to discuss details of past service interruption, to provide an opportunity to discuss any potential remedial actions and to ensure GLPT is aware of the customer satisfaction level.

Below are GLPT's aggregated CDPPS statistics for each load block category for both frequency (total interruptions / load block) and duration (total minutes / load block). The Standard Average and Minimum Standard of performance for the purpose of the illustrations below are calculated by using the Hydro One standards and multiplying by the number of delivery points in the respective load block category. *Table 3-1-3 B* and *Table 3-1-3 C* below illustrate GLPT's actual frequency and duration of outages from 2012-2015 in comparison to the Hydro One standards.

Table 3-1-3 B - 2012-2015 Frequency of Interruptions

Customer Delivery Point	# DP's	Interruption Frequency (Outages) 2012	2013	2014	2015
>80 MW					
GLPT	***1***	***1.0***	***-***	***-***	***-***
Minimum Standard	1	1.0	1.0	1.0	1.0
Standard Average	1	0.3	0.3	0.3	0.3
40-80 MW					
GLPT	***1***	***-***	***2.0***	***-***	***-***
Minimum Standard	1	1.5	1.5	1.5	1.5
Standard Average	1	0.5	0.5	0.5	0.5
15-40 MW					
GLPT	***4***	***3.0***	***-***	***-***	***-***
Minimum Standard	4	14.0	14.0	14.0	14.0
Standard Average	4	4.4	4.4	4.4	4.4
0-15 MW					
GLPT	***15***	***43.0***	***24.0***	***9.0***	***17.0***
Minimum Standard	15	135.0	135.0	135.0	135.0
Standard Average	15	61.5	61.5	61.5	61.5

Table 3-1-3 C - 2012-2015 Duration of Interruptions

Customer Delivery Point	# DP's	Interruption Duration (minutes) 2012	2013	2014	2015
>80 MW					
GLPT	***1***	***16***	***-***	***-***	***-***
Minimum Standard	1	25	25	25	25
Standard Average	1	5	5	5	5
40-80 MW					
GLPT	***1***	***-***	***23***	***-***	***-***
Minimum Standard	1	55	55	55	55
Standard Average	1	11	11	11	11
15-40 MW					
GLPT	***4***	***44***	***-***	***-***	***-***
Minimum Standard	4	560	560	560	560
Standard Average	4	88	88	88	88
0-15 MW					
GLPT	***15***	***3,652***	***16,338***	***482***	***1,564***
Minimum Standard	15	5,400	5,400	5,400	5,400
Standard Average	15	1,335	1,335	1,335	1,335

1.3 SAIFI and SAIDI

GLPT also uses CDPPS statistics to aid in reporting Canadian Electricity Association's System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). GLPT currently utilizes this industry standard measure for internal benchmarking to identify local system reliability trends year over year and determine if the asset management strategies and objectives are improving overall system reliability. Below are the combined system statistics and associated calculation of GLPT's SAIFI (*Table 3-1-3 D*) and SAIDI (*Table 3-1-3 E*).

Table 3-1-3 D – T-SAIFI Data for 2012-2015

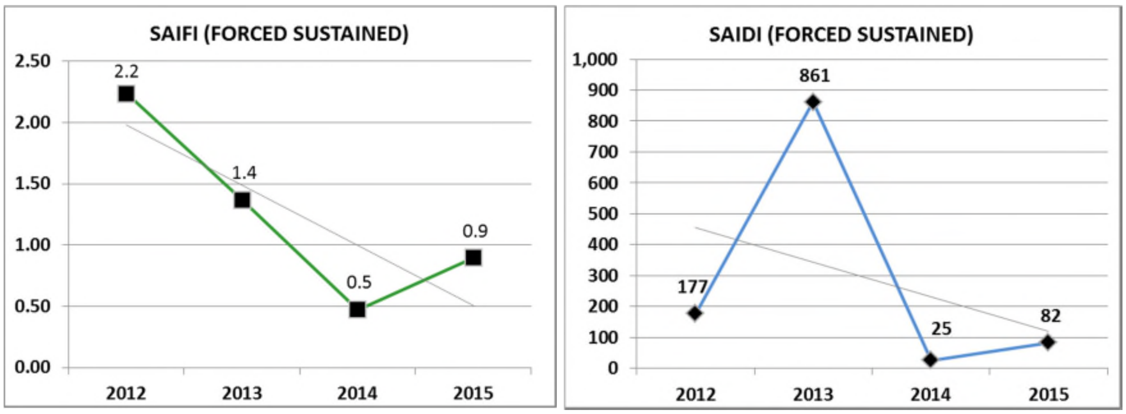
	Interruption Frequency (outages)			
Delivery Point Load Block Category	**2012**	**2013**	**2014**	**2015**
(>80 MW)	1	-	-	-
(40-80 MW)	-	2	-	-
(15-40 MW)	3	-	-	-
(0-15 MW)	43	24	9	17
A -Total Interruption Frequency (outages)	**47**	**26**	**9**	**17**
B - Customers Served	21	19	19	19
SAIFI (A/B)	**2.2**	**1.4**	**0.5**	**0.9**

Table 3-1-3 E – T-SAIDI Data for 2012-2015

	Interruption Duration (minutes)			
Delivery Point Load Block Category	**2012**	**2013**	**2014**	**2015**
(>80 MW)	16	-	-	-
(40-80 MW)	-	23	-	-
(15-40 MW)	44	-	-	-
(0-15 MW)	3,652	16,338	482	1,564
A -Total Interruption Duration (minutes)	**3,712**	**16,361**	**482**	**1,564**
B - Customers Served	21	19	19	19
SAIDI (A/B)	**177**	**861**	**25**	**82**

GLPT has also provided the SAIFI and SAIDI data in *Figure 3-1-3 A* and *Figure 3-1-3 B* to visually highlight the trend of the statistics from 2012-2015.

Figure 3-1-3 A & 3-1-3 B – SAIFI and SAIDI Data for 2012-2015

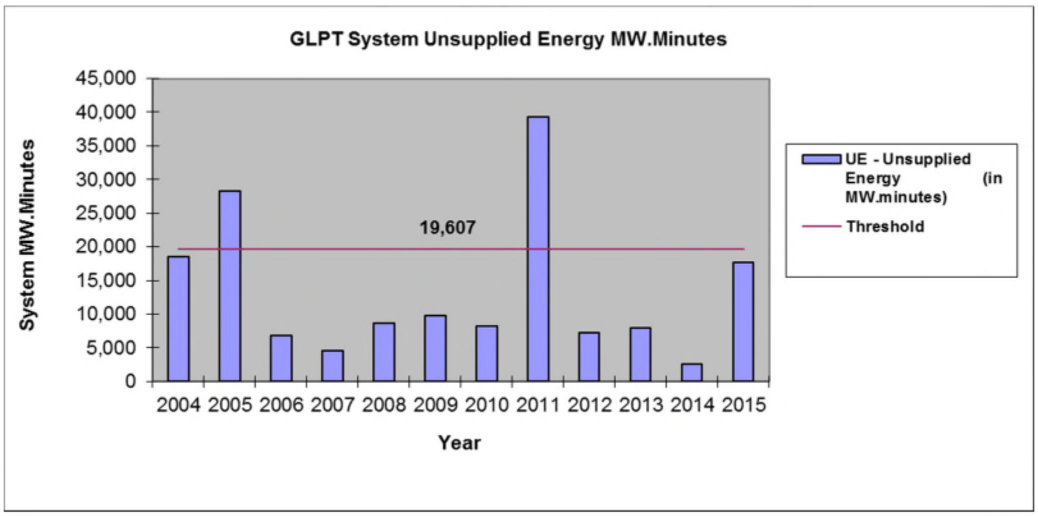


The GLPT SAIFI statistics indicate that the system average is improving and is being maintained below one outage over the last 2 years. The GLPT SAIDI statistics indicate that the system average is improving and is being maintained below 100 minutes over the last 2 years. The trend indicates overall improvement in frequency and duration of interruptions.

1.4 Unsupplied Energy

One industry standard indicator of power system unreliability is the amount of load that is interrupted ("Unsupplied Energy") each year due to planned or unplanned outages. Unsupplied Energy is a performance measure which GLPT reports to the IESO on a monthly basis. The IESO has developed a process and defined specific criteria for the assessment of the GLPT local area performance. Through this process and based on the assessment results of performance, GLPT will be assigned a category reflecting its overall level of performance. At this time based on the assessment criteria GLPT is in good standing with respect to this performance measure. The supporting data in *Figure 3-1-3 C* below illustrates that the local area performance is meeting or exceeding the threshold of Unsupplied Energy as set by the IESO.

Figure 3-1-3 C – Unsupplied Energy data for 2004-2015 (MW Minutes)



1.5 Reliability Trends and Remedies

Overall the performance trends of the GLPT system have been moving in a positive direction and are being maintained at an acceptable level of performance. As illustrated by the CDPPS and Unsupplied Energy reliability statistics GLPT has performed extremely well in the upper 3 load categories; >80MW, 40-80MW, 15-40MW and has had zero service interruptions and no loss of load in the last 2 years. Although the overall reliability of the 0-15MW load block category performance is acceptable as compared to the standards there are a few delivery point customers which still require some additional improvements, particularly as it relates to outage durations.

1.5.1 Reliability Trends

Outliers

As defined in the CDPPS, an outlier is identified when the three year rolling average of a delivery point performance falls below the minimum standard. *Table 3-1-3 F* and *Table 3-1-3 G* represent identified outliers in each category and the numbers of outliers as a percentage of total system delivery points.

Table 3-1-3 F – Frequency of Interruption performance outliers as a percentage of total delivery points

	Frequency of Interruption Outliers			
Delivery Point Load Block Category	**2012**	**2013**	**2014**	**2015**
(>80 MW)	-	-	-	-
(40-80 MW)	-	-	-	-
(15-40MW)	-	-	-	-
(0-15 MW)	-	-	-	-
# of DP's considered Outliers	-	-	-	-
Average # of DP's During 3 Year Period	21	20	20	19
CDPPS Outliers as a % of Total DP	0%	0%	0%	0%

Table 3-1-3 G – Duration of Interruption performance outliers as a percentage of total delivery points

	Duration of Interruption Outliers			
Delivery Point Load Block Category	**2012**	**2013**	**2014**	**2015**
(>80 MW)	1	1	-	-
(40-80 MW)	1	1	-	-
(15-40MW)	-	-	-	-
(0-15 MW)	5	7	4	3
# of DP's considered Outliers	**7**	**9**	**4**	**3**
Average # of DP's During 3 Year Period	21	20	20	19
CDPPS Outliers as a % of Total DP	**33%**	**44%**	**20%**	**16%**

As illustrated in *Table 3-1-3 G*, duration of interruptions has been the primary concern for GLPT, particularly as it relates to the 0-15 MW load block. GLPT continues to focus its capital program on projects and programs that aid in the timely restoration of forced outages. For example, GLPT has undertaken protection upgrade projects in more remote areas such as Anjigami TS and Watson TS which will help reduce response time and reduce overall outage durations. As a part of its customer engagement activities, GLPT regularly communicates with its connected customers to discuss reliability concerns as well as future capital plans, including how it intends to address issues that are of concern to customers.

The percentage of delivery points considered performance outliers was reduced from 33% in 2012 to 16% in 2015 which shows a year over year improvement in line with GLPT's objectives and commitment to continuous improvement.

Inliers

A delivery point's performance that is worse than either baseline trigger (frequency or duration) in two consecutive years will be a candidate for remedial action. Currently GLPT does not have any performance inliers and since this is a relatively new reliability measure GLPT will continue to evaluate and investigate the baseline data to ensure that each delivery point continues to show improvements where required and at minimum is maintained at a level that has been provided year over year.

1.5.2 Causes & Remedies

>80 MW, 40-80 MW, 15-40 MW Load Block Categories

No significant issues are affecting reliability at this delivery point at this time. Regularly scheduled asset maintenance and sustainment capital investments will be required to maintain the appropriate level of reliability required by the standards for these load blocks.

0-15 MW Load Block Category

In 2013 both duration and frequency of interruption peaked primarily as a result of a rare outage at Northern Ave TS. The station suffered equipment failure causing extended outages to the local distribution loads. The loads are connected directly to and depend exclusively upon a single supply point. The transformer failure at Northern Ave. TS required GLPT to undertake a capital project to replace the transformer. This transformer replacement project was reviewed and approved in EB-2014-0238.

In 2015 duration of interruptions increased slightly in the 0-15 MW load block from the previous year primarily as a result of an equipment failure on the No. 3 Sault 115kV line. The No. 3 Sault circuit is the main connection element for two GLPT stations which supply local distribution. GLPT repaired a section of line to resolve the issue at the time to return service quality to a level expected by the connected customers.

Additionally in the 0-15 MW load block GLPT continues to experience outages related to the 44 kV supply points in the Wawa area. Although GLPT has experienced a positive trend in performance, GLPT will continue with plans to improve reliability in the area. In

2015 GLPT completed a capital project to upgrade Highway 101 TS and is planning to continue with projects at Anjigami TS to further bolster reliability in this area of GLPT's system. These Transmission sites are critical to the 44kV system and therefore completion of these upgrades are imperative to further improved reliability through the realization of improved fault isolation, fault sensing equipment and improved protection coordination.

1.6 Reliability and Key Performance Indicators

In order to ensure that reliability is a key part of the GLPT culture and to aid in performance management of the transmission system, reliability forms an integral part of GLPT's Key Performance Indicators. In addition, GLPT has included a number of reliability metrics in its proposed scorecard found at Exhibit 3, Tab 1, Schedule 2.

<u>APPENDIX "A"</u>

GLPT Customer Delivery Point Performance Standards (CDPPS)

Great Lakes Power

Great Lakes Power Limited – Transmission

Customer Delivery Point Performance Standards (CDPPS)

December 2007

1. Introduction

A transmitter shall develop performance standards that apply at the customer delivery point level and that: (Code section 4.5)

(a) reflect typical transmission system configurations that take into account the historical development of the transmitter's transmission system at the customer delivery point level;

(b) reflect historical performance at the customer delivery point level;

(c) are, where applicable, consistent with the comparable performance standards applicable to all delivery points throughout the transmitter's transmission system;

(d) establish acceptable bands of performance at the customer delivery point level for transmission system configurations, geographic area, load, and capacity levels;

(e) establish appropriate triggering events to be used to initiate technical and economic evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;

(f) establish the steps to be taken based on the results of any evaluation that has been so triggered, as well as the circumstances in which such steps need not be taken; and

(g) establish any circumstances in which the performance standards will not apply.

GLPL CDPP Standards will include two components:

1) Relate the reliability of supply to the size of load being served at the delivery point where the triggers are taken from Hydro One Networks Inc. (Hydro One) CDPPS document using Hydro One's statistics (refer to section 2) to identify GLPL Delivery Point (DP) performance "outliers".

2) Once data is available, maintain a customer's individual historical delivery point performance based on a minimum of five years of DP data to establish baseline triggers to identify GLPL DP performance "inliers".

The performance standards and triggers for identifying "outliers" are provided in section 3 and for identifying "inliers" are provided in section 4.

GLPL shall report to the Ontario Energy Board (the "Board") no later than the end of the first quarter of 2010 on the results of its assessment of its minimum performance standards and on whether it intends to propose any material changes for review and approval by the Board.[1]

2. Performance Standards Based on Size of Load Being Served

GLPL will use Hydro One's Customer Delivery Point Performance Standards and triggers based on the size of load being served (as measured in megawatts by a delivery point's total average station load[2]) are provided in Table 1 below.

Table 1: Delivery Point Performance Standards Based on Load Size

Performance Measures	**Delivery Point Performance Standards** (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		**>15 to 40MW**		**>40 to 80MW**		**>80MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

The above Hydro One DP performance standards are based on historical (1991-2000) performance, as measured by the frequency and duration of outages of all momentary and sustained interruptions[3] caused by forced outages, excluding outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical performance. Included in this category of excluded events are the 1998 Ice Storm, 2003 Blackout, tornadoes, earthquakes, other acts of God and any other significant event having "excessive" impact on performance that is beyond the reasonable control of, and not a result of the fault or negligence of Hydro One.

[1] Board Decision and Order EB-2006-0201 dated June 6, 2007 section 4 page 8

[2] The load size groups are to be based on the total station gross load, where Average Gross Load (MW) = (Total Energy Delivered in the Station (MWh) + Total Energy Generated at the Station Site (MWh))/8760 hours.

[3] Momentary interruption is any forced interruption to a delivery point lasting less than 1 minute and a sustained interruption is any interruption to a delivery point lasting 1 minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more Networks' components causing load loss. Interruptions caused by GLPL's customers are recorded but not charged against GLPL reliability performance for the customer initiating the interruption, but are charged against GLPL reliability performance for other interrupted customers.

3. Performance Standards to Identify Performance "Outliers"

The Hydro One minimum standard of performance will be used as triggers by GLPL to initiate technical and financial evaluations with affected customers. GLPL is committed to compare GLPL delivery point performance against the Hydro One delivery point performance standards in 2009, when GLPL has five (5) years of data. Further to the Board's direction referenced in section 1 above, GLPL will review its decision to commit to the Hydro One standards.

At least until that time, the Hydro One minimum standard of performance will apply to all existing GLPL transmission load customers. For new or expanding customer loads, the delivery point performance requirements will be specified and paid for by the customer based on their connection needs and negotiated as part of the connection cost recovery agreement (CCRA).

When the three year rolling average of delivery point performance falls below the minimum standard of performance (i.e. performance "outlier") or when delivery point customers indicate that analysis is required, GLPL will initiate technical and financial evaluations to determine the root cause of unreliability and if any remedial action is required to improve reliability.

4. Performance Standards to Identify Performance "Inliers"

The performance standard to maintain the historical reliability performance levels at each customer DP will identify customer delivery points with deteriorating trends in reliability performance (i.e. performance "inliers") notwithstanding the fact that they are satisfactory performers as outlined in section 3. Specifically, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is to be set at each delivery point, based on that delivery point's fixed 10 year 2004 to 2013 average performance, plus one standard deviation (1σ). The performance baseline triggers are to include forced outages resulting from force majéure events, but exclude events which have excessive impact on the transmission system that in GLPL's assessment, strongly skew the historical trend of the measure e.g. tornadoes, earthquakes, other acts of God and any other significant event having "excessive" impact on performance that is beyond the reasonable control of, and not a result of the fault or negligence of GLPL.

Until GLPL has 10 years of data, GLPL will treat existing customers and new/modified customers by excluding them from identification as an "inlier" until a minimum of 5 years of data is available to establish the baseline triggers. The baseline triggers for these delivery points will be updated each year until 10 years of performance data is available. DP performance that is worse than either baseline trigger (frequency or duration) in two consecutive years will be a candidate for remedial action. GLPL will respond by initiating technical and financial evaluations with affected customers to determine the root cause of the unreliability and remedial measures required to restore the historical reliability of DP performance.

Further to the Board's direction referenced in section 1 above, GLPL will analyze the data after 5 years of data is available for existing customers and will review its decision to commit to the "inlier" standard.

As a result of insufficient statistical data during the 2007 to 2009 period, deteriorating performance will be monitored but no delivery point will be classified as an "inlier". During this period, GLPL shall meet annually with each existing customer to review DP performance and to initiate remedial action when the root cause is within GLPL's control[4].

5. Remedial Costs to Address Performance "Outliers and Inliers"

As specified by the Code, GLPL will not attribute the costs associated with network investment to any customer. Any variance from that approach requires a determination of the Board further to a request by any party, including GLPL.[5]

GLPL does not charge customers for the cost of the initial technical and financial evaluation. The cost to prepare the final estimate is the only portion of the technical and financial evaluation that is included as part of the cost of the remedial work.[6]

GLPL will cover the remedial costs, including appropriate asset maintenance costs which include on-going maintenance and asset replacement to restore/sustain the inherent reliability performance of the existing assets to what was designed originally. These expenditures are made on an ongoing basis consistent with "good utility practices", irrespective of actual delivery point performance or of whether a delivery point is a performance "outlier or inlier". No customer financial/capital contribution is required for these normal maintenance expenditures.[7]

To encourage proceeding with only those reliability performance improvements that are technically and economically practical and to limit the subsidization of reliability improvement costs by other pool customers, GLPL's level of incremental investment for improving the performance of an "outlier or inlier", beyond what was the original design, will be limited to the present value of three years worth of transformation and/or transmission line connection revenue[8] associated with that delivery point. Any funding shortfalls for improving delivery point reliability performance, beyond what was the original design, will be made up by affected delivery point customers in the form of a financial/capital contribution. Cost responsibility for these investments is to be consistent with the new Market Rules and the Transmission System Code. Affected delivery point

[4] Board Decision and Order EB-2006-0201 dated June 6, 2007 section 4 page 7
[5] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.9 page 19
[6] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.9 page 19
[7] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.9 page 20
[8] In the special case where a delivery point pays only network tariffs, transmission line connection tariffs are to be used as proxy in the revenue calculation.

customers will be responsible for all the costs associated with any new/modified facilities required on facilities (lines and stations) they own. The financial/capital contribution requirement is to be detailed in a Connection Cost Recovery Agreement (CCRA) to be signed with the affected customers, before any work to improve delivery point "outlier or inlier" performance begins.

Where specific GLPL transmission facilities are serving two or more customers in common with performance "outlier or inlier" performance, GLPL will approach all affected customers to determine their willingness to contribute jointly.[9]

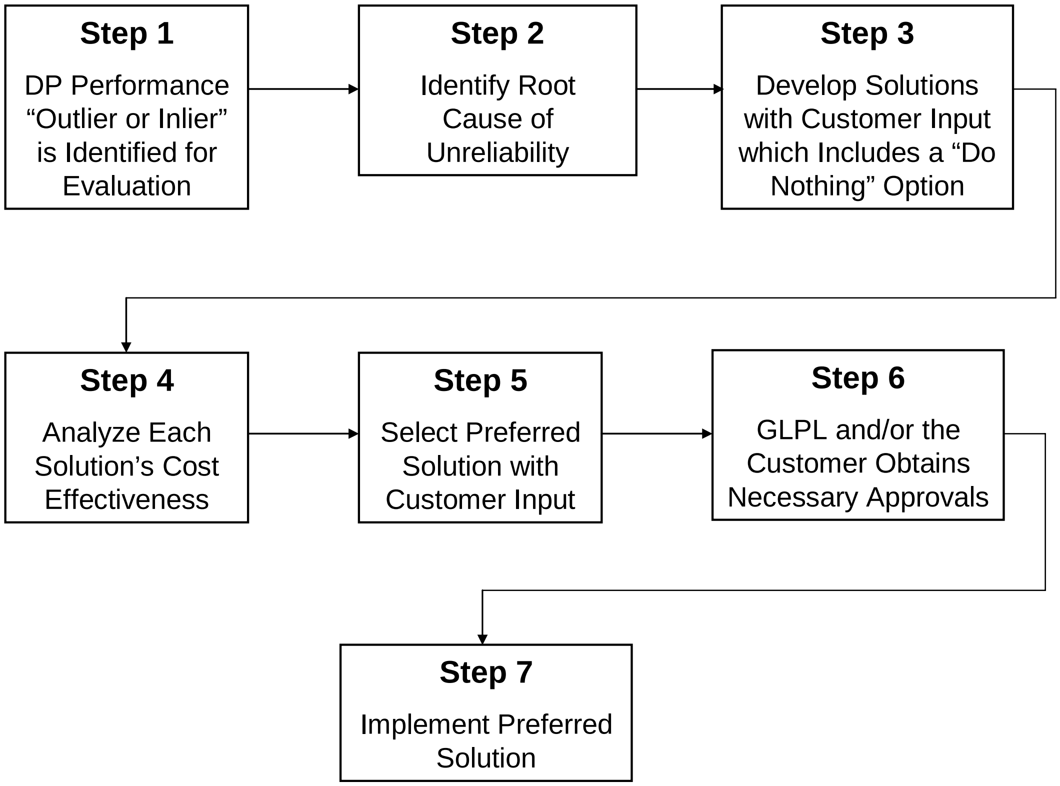
Where a customer contribution is required to improve or expand the transmission system to correct performance "outlier or inlier" performance, the customer will be given the right to undertake contestable work consistent with those applicable to new customer connections in the Code.[10]

When GLPL completes work to restore delivery point performance to standard, it will continue to monitor the delivery point the year after the work is completed. If future performance suggests that the standard has not been met, then GLPL will review the work that has taken place and will identify corrective action, possibly with the financial participation of the customer. GLPL will not as a practice wait another 3 years and start a new technical and financial evaluation. GLPL will review and identify customer delivery point performance annually, regardless of the investment history.[11]

6. Implementation Process to Address Performance "Outliers and Inliers"

The Customer Delivery Point Performance Standards define triggers for GLPL to initiate technical and financial evaluations with affected customers. Each year GLPL reviews reliability performance with its customers based on forced outage statistics which are compiled in January of each year once the previous year's data has been reviewed. For customer delivery points that are identified as performance "outliers or inliers" identified as per section 3 or 4 above, GLPL will negotiate timing, solution, cost sharing arrangement, and any other related matters with each customer wanting to proceed with the delivery point reliability performance improvements based on the process outlined below.

[9] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.12 page 22
[10] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.13 page 23
[11] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.19 page 19



Step 1 - DP Performance "Outlier or Inlier" is Identified for Evaluation

GLPL compiles the DP data for each year by the end of January including identifying any "outliers or inliers" that may require a technical and financial evaluation. GLPL will inform each customer of the results where it's DP is an "outlier and/or inlier" and determines with the customer if GLPL will proceed with a technical and financial evaluation. The timing of starting the process for each customer will be discussed with the customer and will be base on prioritizing the "outliers and inliers".

Step 2 - Identify Root Cause of Unreliability
(Timeline: 1 to 2 months)

GLPL will analyze the available data and obtain additional data as necessary to determine if there is a root cause for the unreliability or whether there are several factors.

Step 3 – Develop Solutions with Customer Input which includes a "Do Nothing" Option (Timeline: 1 month)

The data from Step 2 will be discussed with the customer and possible options (including a "do nothing" option) will be developed focused on improving the reliability of the delivery point.

Step 4 - Analyze Each Solution's Cost Effectiveness
(Timeline: 1 month)

Estimated costs of implementing each option are prepared and cost/benefit analysis is undertaken to determine the most cost effective solution. Any cost sharing with the customer is identified for each option.

Step 5 - Select Preferred Solution with Customer Input
(Timeline: 1 to 2 months)

Based on the results of Step 4, the selection of the preferred solution will be discussed with the customer. With respect to any cost sharing the customer will have to agree to pay its share if GLPL proceeds to implement that option as the selected option.

Step 6 – GLPL and/or the Customer Obtain Necessary Approvals
(Timeline: 2 months)

GLPL will then obtain internal approval to proceed with the preferred solution. For "outliers or inliers", where the customer must make a financial/capital contribution, the customer will obtain internal approval to pay the required contribution.

Step 7 – Implement Preferred Solution
(Timeline: To be Determined)

The timing/schedule for the preferred solution will consider customer impacts, nature of the remedial measures, equipment deliveries, GLPL resource capabilities, other investment priorities, and outage/resource availability. Where a customer has the obligation to pay a financial/capital contribution the customer and GLPL will execute a Connection Cost Recovery Agreement (CCRA) prior to commencement of work on the preferred solution.

Note: Timelines are based on dealing with one customer regarding one "outlier or inlier". If more than one customer is involved in dealing with a DP performance issue then the timelines will likely be longer because of the increased complexity of dealing with more than one customer.

BENCHMARKING

1.0 Introduction

This is GLPT's first transmission rate application under the Board's revenue cap index framework. As outlined in the *Filing Requirements for Electricity Transmission Applications, Chapter 2 (February 11, 2016),* the OEB recognizes that a transition period may better accommodate the gradual entrenchment of RRFE objectives and principles in transmission rate-setting over time. It is stated that where a transmitter is filing based on cost of service or the revenue cap index, if benchmarking evidence is not currently available, the transmitter must file in its application a strategy to acquire such evidence for its subsequent application.

GLPT has provided benchmarking information for 2017 and 2018 as part of the evidence supporting this application, consistent with previous benchmarking exercises undertaken by GLPT.

1.1 Benchmarking

In EB-2009-0408, EB-2010-0291, EB-2012-0300 and in EB-2014-0238, GLPT provided the Board with a benchmarking report prepared by First Quartile Consulting, LLC ("1QC"). GLPT engaged 1QC to update the benchmarking report for 2017 and 2018, the results of which can be found at **Appendix "A"** to this schedule. 1QC was engaged to analyze the costs of operation of the GLPT transmission system, in comparison with those of other transmission providers in North America. There are very few true “peers” for comparison, since GLPT is somewhat unique in terms of its size, rural geographic location, and dense vegetation. 1QC used the data from a panel of companies who have provided that data during detailed annual benchmark studies of North American transmission utilities as a basis for comparison against GLPT, augmented by information filed by the companies with FERC. The peer group used in the current study is the same as the peer group used in the study prepared for GLPT’s revenue requirement application (EB-2014-0238). 1QC’s overall conclusion, based on the primary comparison, is that GLPT falls below average on a cost per asset basis in this group. 1QC's specific conclusion is that GLPT compares favourably against the panel of companies on the total of Operations and Maintenance (“O&M”) and Administrative and General (“A&G”) expenses, ranking well below the median for the panel.

As confirmed by the independent benchmarking report prepared by 1QC, GLPT continues to operate a cost-efficient transmission system that is safe, secure, reliable and environmentally responsible.

APPENDIX “A”

First Quartile Consulting Benchmarking Report

GREAT LAKES POWER TRANSMISSION OPERATION COST ANALYSIS

PREPARED BY:
FIRST QUARTILE CONSULTING, LLC

JUNE 21, 2016

FIRST QUARTILE CONSULTING

INTRODUCTION

Great Lakes Power Transmission LP (GLPT) is a transmission owner and operator serving a portion of northern Ontario, Canada. In January of 2016, Hydro One Inc. agreed to purchase the voting securities of GLPT.

First Quartile Consulting (1QC) was engaged to analyze the costs of operation of the GLPT transmission system, in comparison with those of other transmission providers in North America. Because of its unique size, rural geographic location, and dense vegetation, there are very few true "peers" for comparison to GLPT. Even so, it is important to gain some understanding of the relative costs of operation of the system in comparison to other transmission providers, in order to determine reasonable rates for operating the system.

ANALYSIS APPROACH

1QC performed a set of analyses to determine how GLPT compared against a panel of companies with regard to Transmission Line, Transmission Substation and related Administrative and General (A&G) expenses. The primary basis for the comparison was a data set of Transmission Lines & Substations O&M expenses which is gathered during the annual 1QC transmission & distribution benchmark study. That study doesn't collect A&G costs as part of the standard comparisons, so the dataset was augmented by information filed by the companies with FERC.

The definitions used for separation of direct O&M costs versus A&G costs in the 1QC study are those used in the FERC uniform system of accounts. Canadian utilities typically capture the A&G costs together with the O&M costs, and report them as OM&A.

To address the need to include A&G costs in the comparison, we gathered A&G expense data back to 2010 from available FERC reports. These A&G expenses as reported are for the whole utility operation. Therefore, it was necessary to make an allocation of A&G expenses for just transmission lines & substations. A very straightforward calculation was used to allocate A&G to transmission: (transmission O&M expense / (generation + transmission + distribution + customer service)) * total A&G expense = transmission portion of A&G expense.

Normalization

GLPT's Transmission lines & substations O&M expenses and its O&M + A&G expenses were compared against the 1QC panel. To perform a valid comparison, it was necessary to normalize the data to account for the different sizes of the companies. For the primary normalizing factor we chose total transmission lines & substations assets. Through analysis over the years, we have determined that total assets is the appropriate normalization factor for transmission spending and that it is possible to accurately predict a company's O&M expenses based upon the value of the assets they have. See **Appendix A** for a more complete explanation of the selection of normalizing factor.

Forecasting

As a part of the analysis, it was necessary to forecast costs into the future, as well as forecasting the exchange rates between U.S. and Canadian currency. For the cost elements, forecasts were generated using the Excel function for a straight-line forecast. For the exchange rates, 1QC reviewed the forecasts from several financial institutions, and eventually selected one shown at the following site: http://longforecast.com/fx/canadian-dollar-to-us-dollar-forecast-for-2015-2016-and-2017.html. For the exchange rates in previous years, the rates were drawn from the official figures published by the U.S. Federal Reserve, at http://www.federalreserve.gov/releases/g5a/current/.

Results and Conclusions

Based upon our primary comparisons, GLPT falls below average on a cost per asset basis. In Figures 1 to 3 below, the mean and quartiles are calculated without GLPT's data. They are based solely on our panel of companies, so that GLPT is being compared against a data set without influencing it. In the bar charts to the right of the line charts, the companies in our comparison panel are shown individually. GLPT is not included on those charts.

Note that the values for years 2016 to 2018 are projected based upon 2007 to 2015 actual data. For all of the graphs, only companies for which A&G data was available were used.

In Figure 1 below, showing GLPT compared against the panel of companies on the total of O&M and A&G, GLPT compares favorably against the panel, ranking well below the median for the panel.

Figure 1

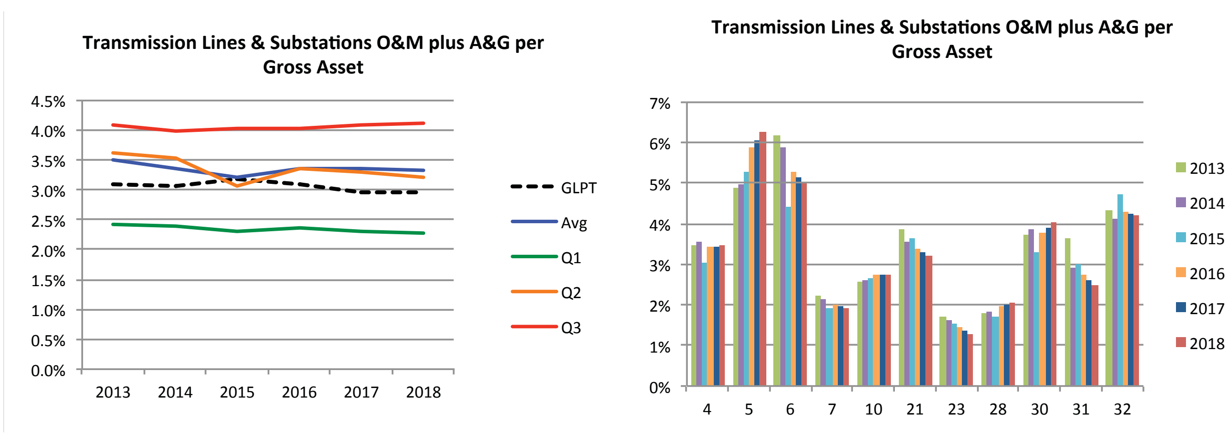


Figure 2 shows just the A&G cost per asset. GLPT's A&G costs have been relatively flat and are projected to remain around 3rd quartile.

Figure 2

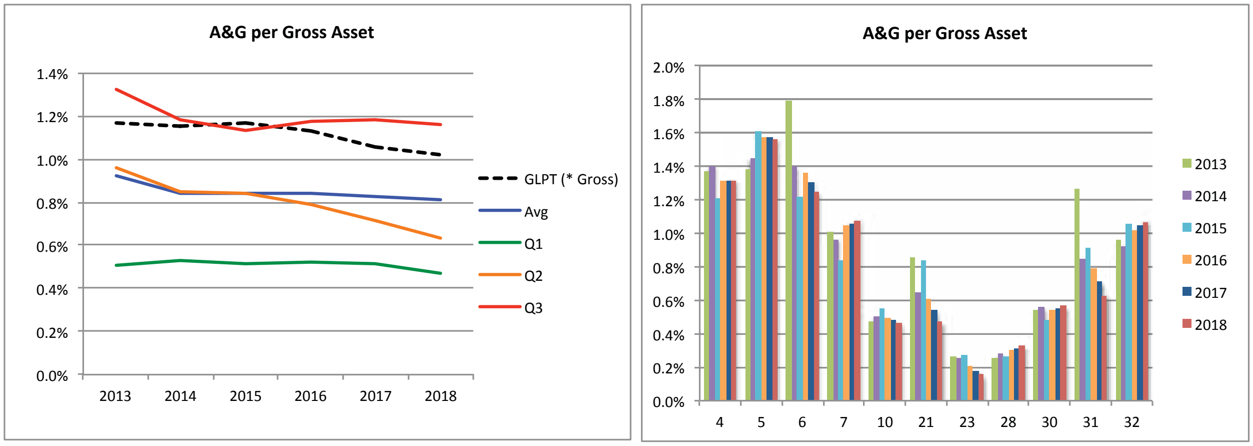
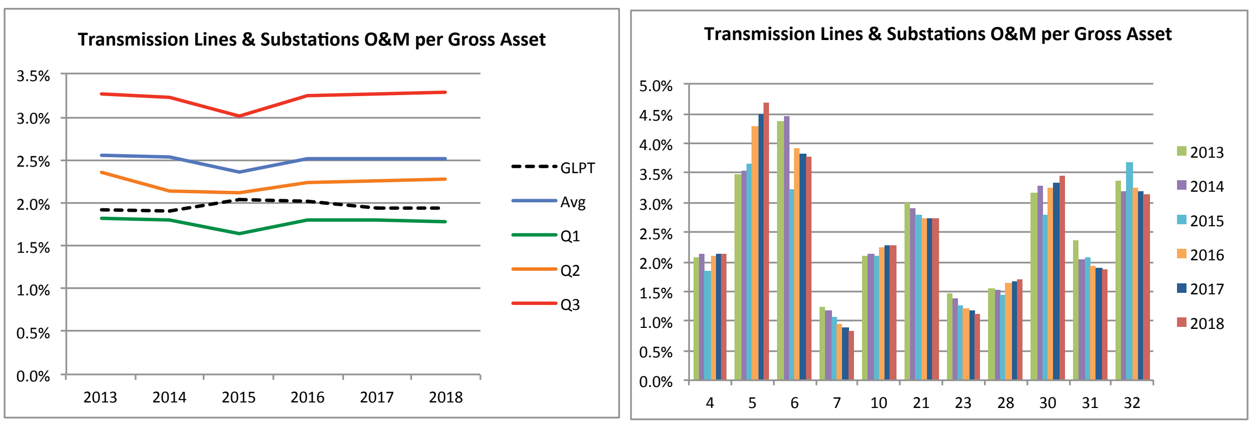


Figure 3 shows the O&M costs without the A&G costs. GLPT's costs are slightly above the first quartile value.

Figure 3



For other comparisons, we also normalized spending based upon customers and circuit kilometers, as shown in Figures 4 and 5 below. As explained in Appendix A, neither of these comparisons is recommended, based on the relative predictive accuracy of those factors. Even so, we present the results below, and they are about as expected for GLPT, which is a small transmission operator with a small customer base and comparatively long transmission lines. In studying the relationship between O&M spending and various normalizing variables, we have conducted regression analyses in which the r^2 value for the relationship is calculated. A value of 1.0 represents a perfect correlation. Based on 2015 YE cost data, the r^2 value for assets is 0.77, for circuit kilometers is 0.49, and for customers is 0.65. Appendix A provides a more complete description of this analysis.

First Quartile Consulting

Figure 4

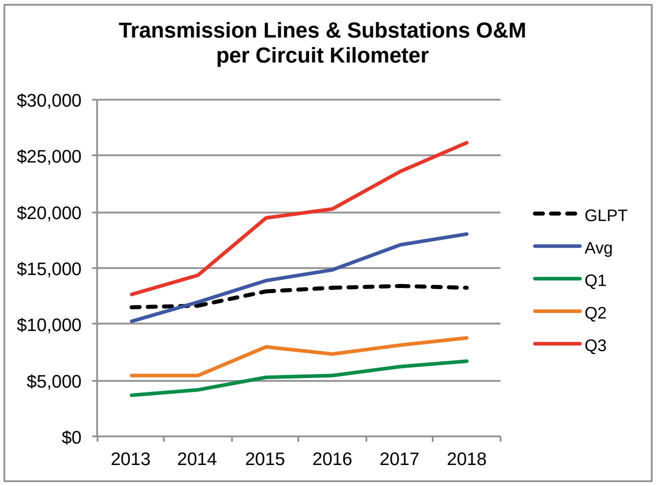
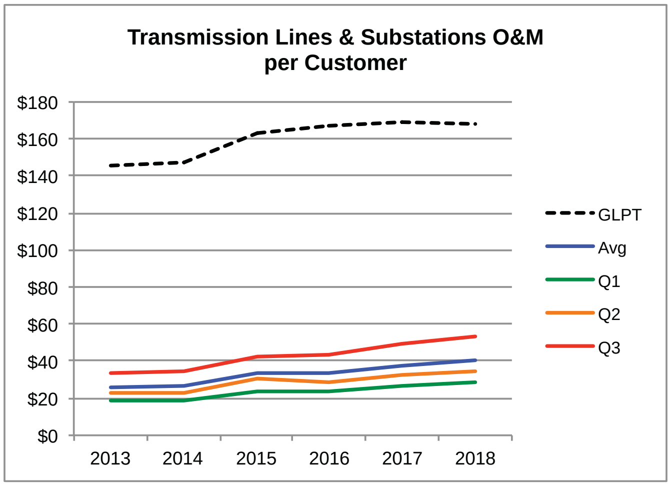


Figure 5



Two other possible normalizing factors (denominators) (kWh transmitted and megawatt miles) were excluded because of lack of data, but neither has been demonstrated to be better than assets at predicting transmission & substation O&M spending.

APPENDIX A: WHY "ASSETS" IS THE APPROPRIATE DENOMINATOR.

Over a span of more than 20 years of executing benchmark studies of electric transmission and distribution operations in North American utilities, the consultants at 1QC have performed a variety of analyses of the resulting data. One question of enduring interest is how to normalize the data from different companies in order to make both fair and understandable comparisons. Through a number of different analyses and reporting efforts, it has become clear that with an appropriate normalizing factor, it is possible to make fair comparisons, and that it is also possible to explain the results in ways that make them useful to regulators and companies.

For many years, the studies have been consistent in terms of identifying the normalizing factor that produces the best predictor of operating costs in transmission and distribution. Using simple and more complex linear regressions, our consultants have tested the relationship between the normalizing factor and the resulting O&M costs. Given the difference in the functions of transmission and distribution, separate studies have been performed for transmission and distribution (and indeed for substation operations). The exact regression results change from year to year, but the basic conclusions have been consistent.

To determine the appropriate denominators (normalizing factors) to use for analysis, we compare the dependent variable, in this case O&M spending, to various independent variables: customers, circuit kilometers, and assets. We look for a strong correlation between the two variables. For transmission lines and substations O&M spending, the strongest correlation exists between spending and assets. The relationship between spending and customers or circuit km is weaker.

For this study, 1QC updated the comparison. The table below shows R^2 correlation coefficient values for the dependent and independent variables. The table was generated without A&G expenses because of the method used for estimating A&G expenses. We used five years worth of data in order to determine the correct normalizing factor (2011-2015).

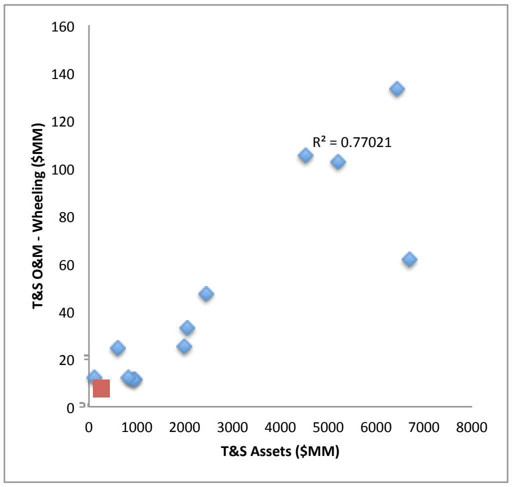
		Including All Companies		
		Transmission Lines & Subs Assets	Customers	Transmission OH and UG Circuit KM
2011YE	Transmission Lines & Subs O&M Expenses	0.8532	0.1513	0.6635
2012YE	Transmission Lines & Subs O&M Expenses	0.5058	0.2567	0.5270
2013YE	Transmission Lines & Subs O&M Expenses	0.4549	0.3619	0.5038
2014YE	Transmission Lines & Subs O&M Expenses	0.7426	0.6002	0.6658
2015YE	Transmission Lines & Subs O&M Expenses	0.7702	0.4957	0.6528

In most years, we have found assets to be the best normalizing factor because it has a higher predictive value when there are big differences in customer density among companies in the comparison panel. Though we have included all companies in the comparison for this analysis, in other years when we have removed significant outliers from the dataset, the conclusions have remained the same.

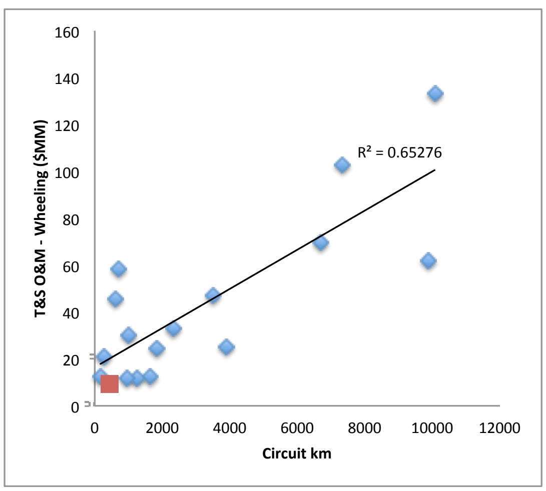
A side benefit of using the asset base as the primary normalizing factor in the analysis is that it removes the issue of the exchange rate from the analysis. For each individual company in the comparison, their costs versus their asset base are all in the same currency, so the resulting ratio is independent of the exchange rate between the U.S. and Canada.

Shown below are the individual graphs from which the R^2 values are derived. In each graph, GLPT has been added to the graph to show where they fall compared to the other companies, but they are not included in the calculation of the correlation coefficient. It is appropriate to determine the correlation coefficients independently of GLPT's data, since by performing the analysis this way GLPT's data isn't influencing the findings.

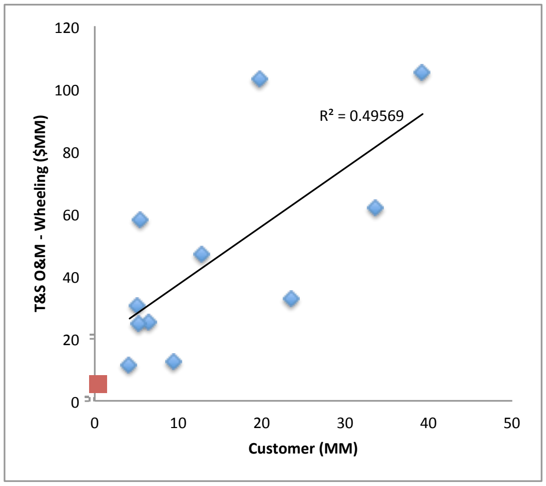
2015YE – Per Assets



2015YE – Per Circuit kilometer



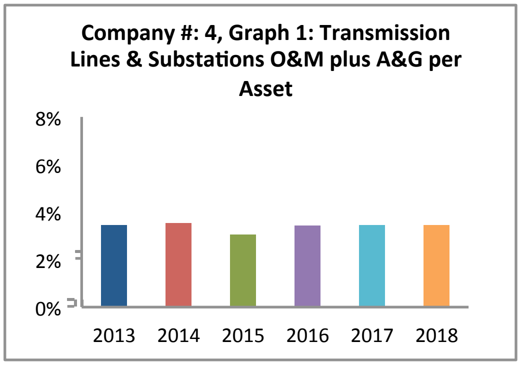
2015YE – Per Customer

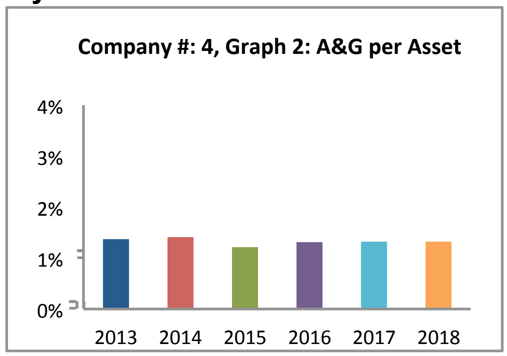


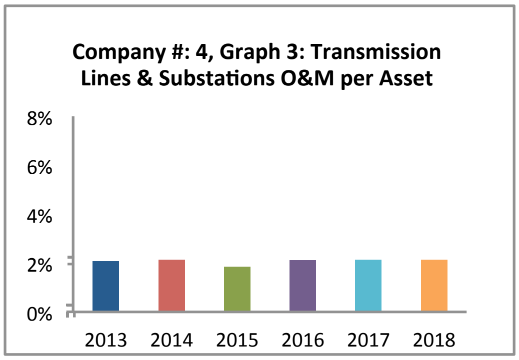
ID	CHARACTERISTICS	GEOGRAPHIC LOCATIONS	VOLTAGES/KM	TERRAIN	NUMBER OF CUSTOMERS	INDUSTRIAL CUSTOMERS	% Ind'l
4	Combined D&T	Southeast US	<69kV:0; 69kV:344; 100kV Class:2185; 200kV Class:0; 300kV Class:1216; 400kV & Above Class:0	flat, dense trees	2,299,248	1,921	0.084%
5	Combined D&T	MidAtlantic US	<69kV:0; 69kV:0; 100kV Class:854; 200kV Class:332; 300kV Class:0; 400kV & Above Class:218	flat, dense trees	1,351,891	5,990	0.443%
6	Combined D&T	MidAtlantic US	100kV class: 307km, 200kV Class: 251km, 300kV Class: 881, 400kV Class and above: 302	flat, dense trees	1,590,478	3,112	0.196%
7	Combined D&T	Southwest US	<69kV:0; 69kV:2788.45; 100kV Class:6903.77; 200kV Class:0; 300kV Class:6448.58; 400kV & Above Class:0	flat, few trees	3,310,530	6,471	0.195%
10	Combined D&T	MidWest US	<69kV:0; 69kV:692; 100kV Class:1497.5; 200kV Class:0; 300kV Class:478.1; 400kV & Above Class:0	flat, some trees	903,776	4,636	0.513%
21	Combined D&T	MidAtlantic US	69kV class : 194km, 100kV class: 619, 200kV Class: 950km, 300kV class: 43, 400kV class: 654km	flat, dense trees	2,256,964	9,219	0.408%
23	Combined D&T	MidWest US	<69kV:1634.85; 69kV:1098.84; 100kV Class:2022.04; 200kV Class:336.19; 300kV Class:1148.55; 400kV & Above Class:0	flat, some trees	695,972	5,128	0.737%
28	Combined D&T	Southwest US	<69kV:474.46; 69kV:0; 100kV Class:408.41; 200kV Class:0; 300kV Class:966.88; 400kV & Above Class:95.17	flat, few trees	414,748	631	0.152%
30	Combined D&T	Northwest US	<69kV : 203km, 100kV class :2755km, 200kV Class : 506km, 400kV Class and above : 825km	flat, dense trees	1,099,696	3,710	0.337%
31	Combined D&T	MidWest US	<69kV:0; 69kV:149; 100kV Class:2904; 200kV Class:0; 300kV Class:2656; 400kV & Above Class:90	flat, dense trees	3,842,198	1,956	0.051%
32	Combined D&T	Northwest US	100kV class :808km, 200kV Class : 900km, 300kV Class : 612, 400kV Class and above : 353km	flat, dense trees	840,993	265	0.032%

APPENDIX C: INDIVIDUAL BAR CHARTS FOR COMPARISON PANEL

Company #4







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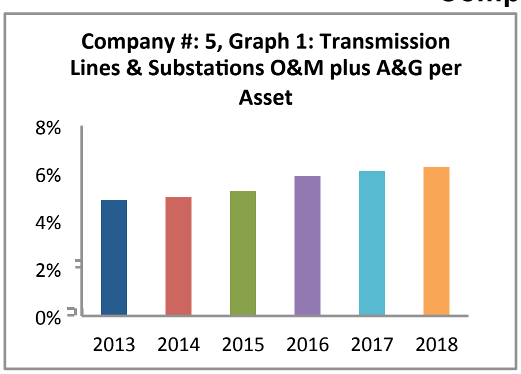

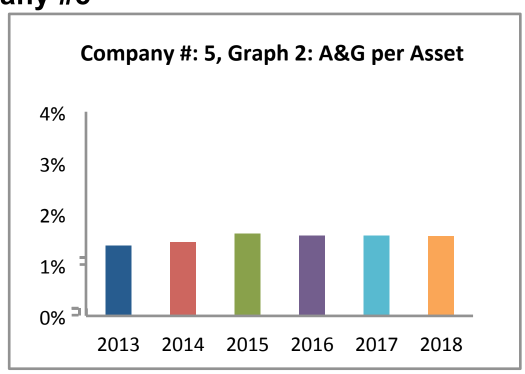

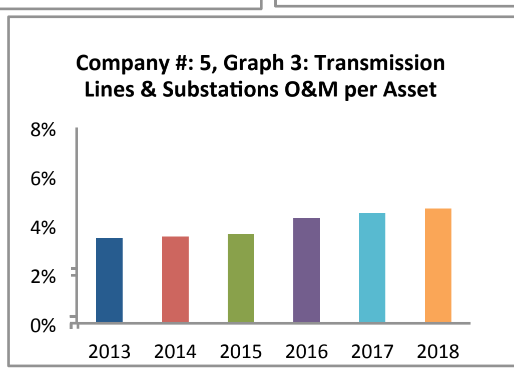

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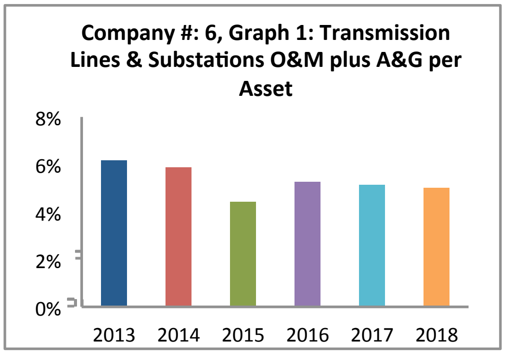

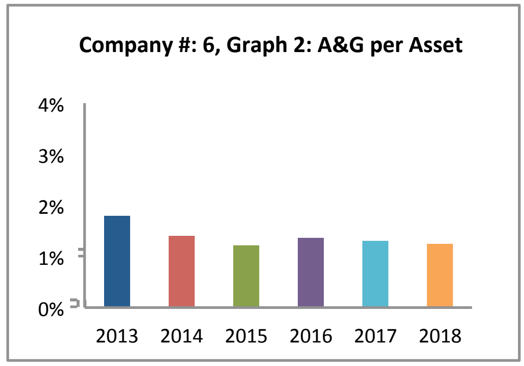

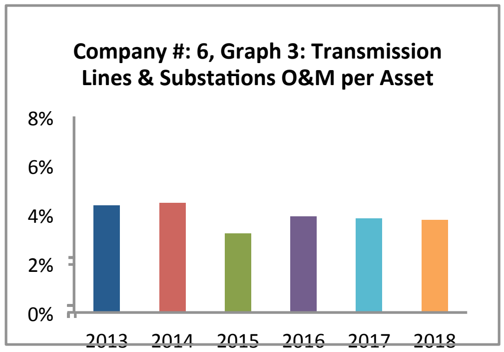

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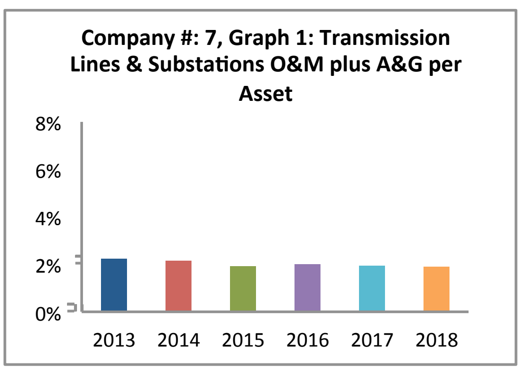

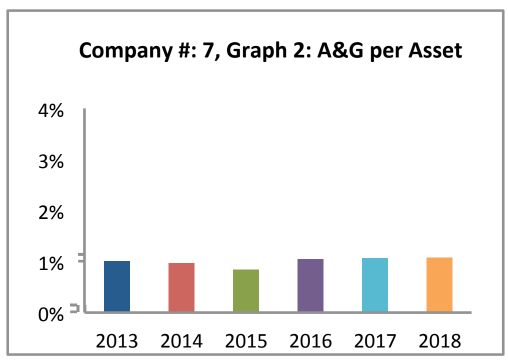

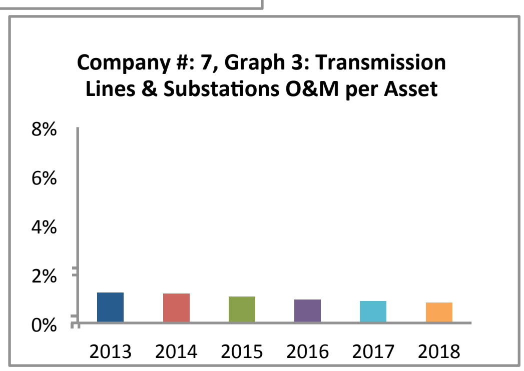

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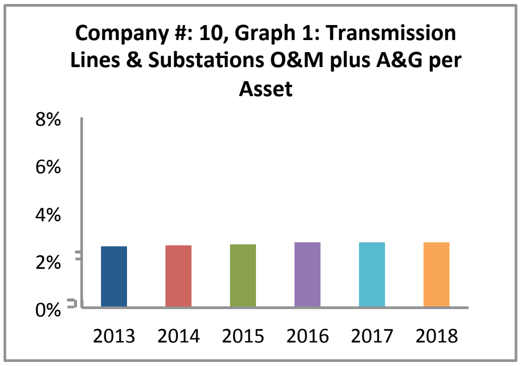

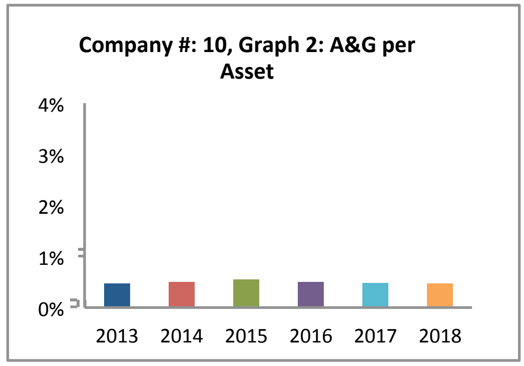

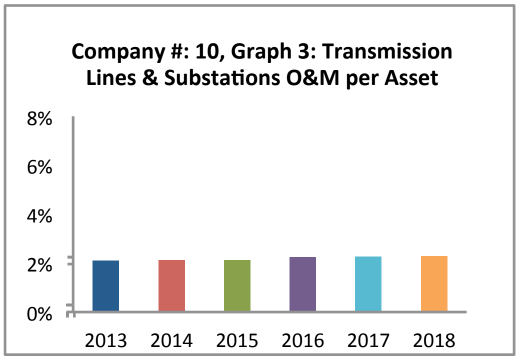

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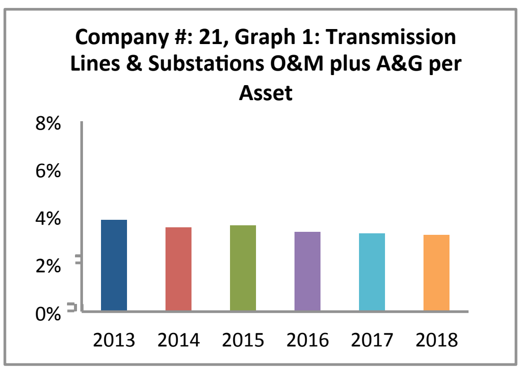

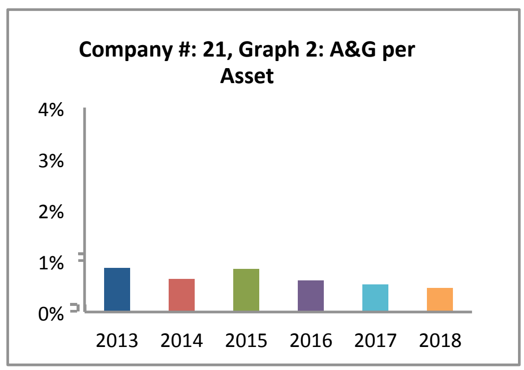

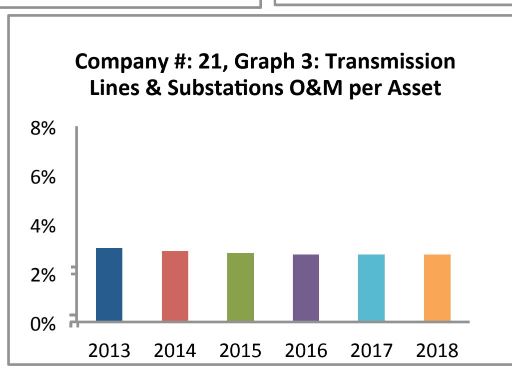

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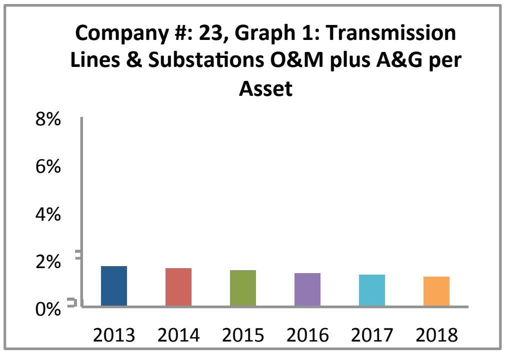

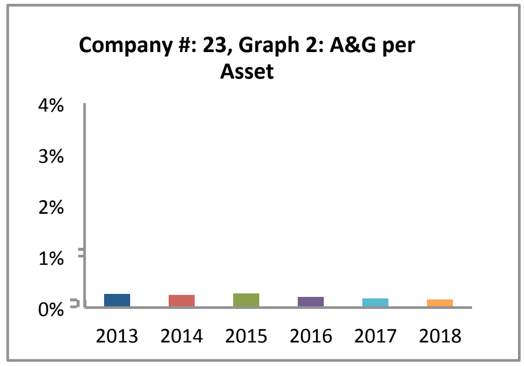

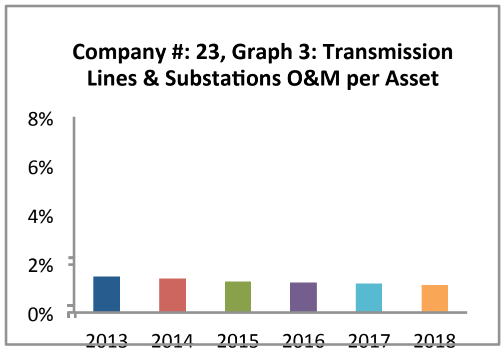

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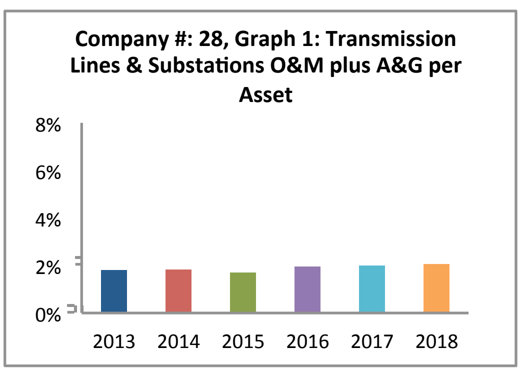

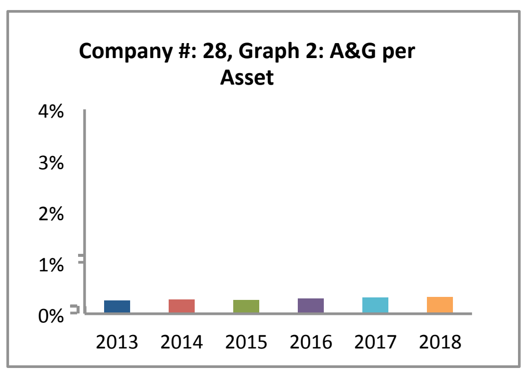

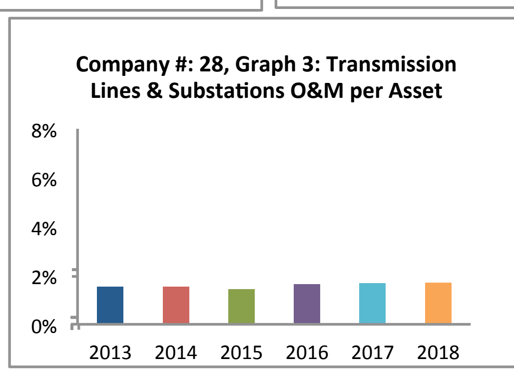

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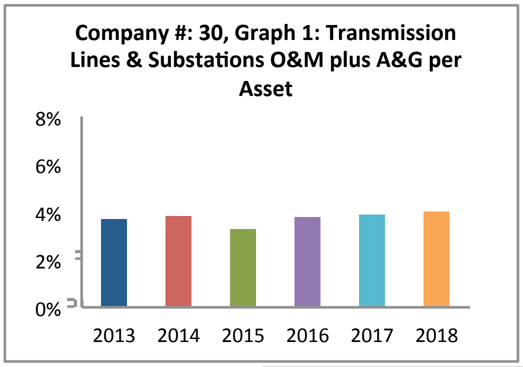

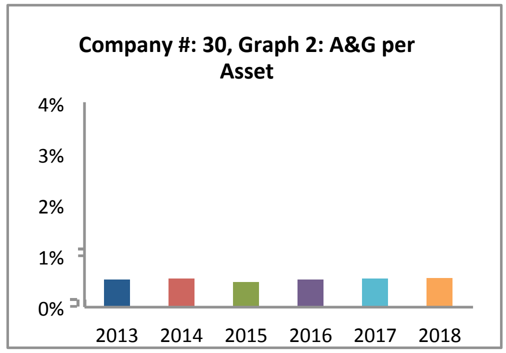

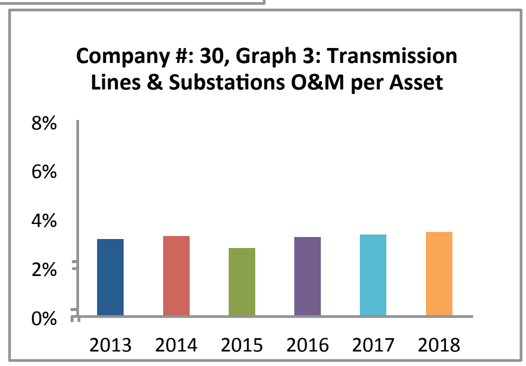

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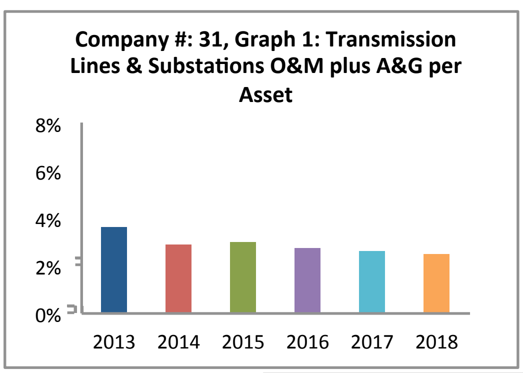

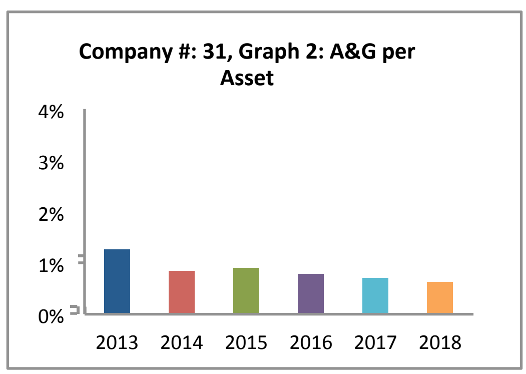

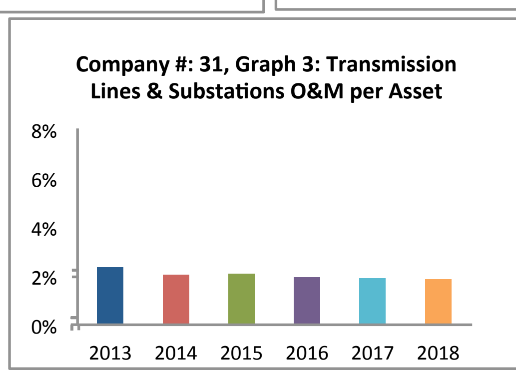

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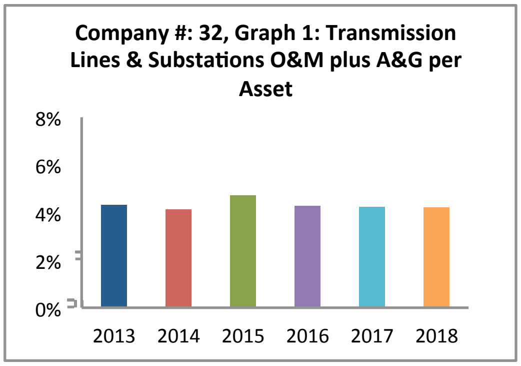

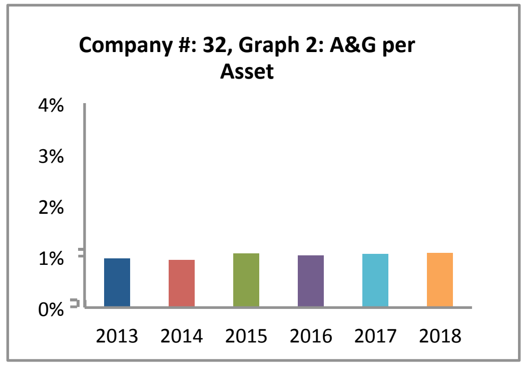

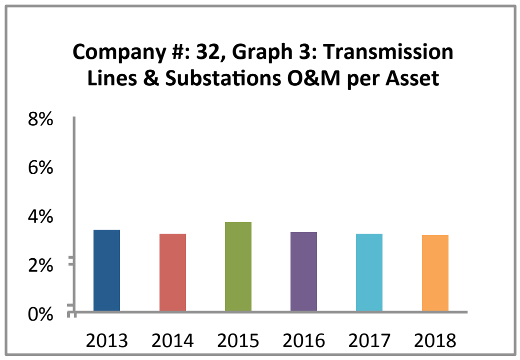

FIRST QUARTILE CONSULTING

COMPLIANCE MATTERS

1.0 Introduction

GLPT is committed to compliance and has managed its operation in the same fashion as it manages its health, safety and environmental programs, with a focus on ensuring compliance with applicable laws and standards. This is supported by GLPT having regulatory compliance as a business objective forming an integral part of its Key Performance Indicators. Utilities in Ontario are subject to Critical Infrastructure Protection ("CIP") standards, as well as non-CIP reliability standards. Prior to the changes in the regulatory environment described below, GLPT was compliant with version 3 of the CIP standards, and was not subject to any of the non-CIP reliability standards. In preparation for the changes, GLPT developed and implemented a regulatory compliance program which is now in place, ensuring compliance with all applicable standards. This Schedule describes (i) the major changes in the compliance environment, (ii) how GLPT identified its requirements and developed a compliance program, and (iii) how compliance will be managed into the future.

1.1 Changes in the Compliance Environment

For many years GLPT's transmission system has been significant to the bulk power system and the IESO-controlled grid. In EB-2014-0238, GLPT identified an upcoming change in the regulatory environment associated with the North American Electric Reliability ("NERC") Bulk Electric System ("BES") definition, where the revised BES definition now includes transmission assets equal to or greater than 100 kV. This change, effective July 1, 2016, resulted in certain GLPT assets being defined as NERC BES assets, which required compliance with various non-CIP reliability standards, and also required compliance with CIP version 5. Therefore, in that application, GLPT sought relief to address the change through the development and implementation of a regulatory compliance program; and since 2015 GLPT has been actively developing its regulatory compliance program. While GLPT was not subject to the same level of NERC standards prior to July 1, 2016, its operating practices under good utility practice were such that significant operational changes would not be required to ensure compliance with the newly applicable standards.

1.2 Defining Compliance Requirements and Program Development

By definition, GLPT is classified as a Transmission Operator ("TOP") and a Transmission Owner ("TO"). In Ontario, the IESO is responsible for defining the matrix of TOP reliability standards applicable to GLPT. However, GLPT is solely responsible to identify any additional standards that are applicable as a TO. In identifying the TO standards that apply, GLPT engaged a third party consulting firm that specializes in regulatory compliance to conduct a comprehensive review in conjunction with GLPT staff to ensure all required TO standards were identified and addressed in GLPT's compliance program. With its current asset profile, GLPT is responsible for 10 NERC standards pertaining to CIP version 5, and 36 NERC non-CIP reliability standards.

Once these standards were identified, GLPT continued to work with its third party consulting firm to establish the foundation for implementing a sustainable compliance program for both TOP and TO standards. The firm worked with GLPT staff to develop working documents that define the policies and procedures used by GLPT as they relate to all of the applicable NERC standards. To facilitate this process, a gap analysis was done for each standard to identify areas where GLPT required additional resources to meet the compliance requirements. In most cases it was evident that the day to day operations and the technical requirements of the facilities at GLPT were well within the boundaries of required compliance, with only minor adjustments required in regards to the documentation obligations of the program. In areas such as operator training, where new compliance efforts were required, GLPT developed the appropriate procedures and supporting work practices to ensure compliance.

1.3 Ongoing Management of Compliance

With the compliance program and the supporting procedures fully developed to comply with the 10 NERC CIP and 36 NERC Non-CIP reliability standards, GLPT has set up a transparent process to ensure the business is in a state of compliance at all times. For each NERC standard GLPT maintains a directory of evidence which will be updated on an annual basis and which represents the hard data that will be required as evidence during a compliance audit. A role and responsibility matrix has been established to ensure that all compliance related tasks are reviewed, updated and implemented by the task owner within the allowable timeframe set out in the appropriate GLPT procedure.

At GLPT, responsibility for reliability compliance tasks is divided between department managers, subject matter experts and the reliability compliance department.

Enforcement of the NERC standards in Ontario is the responsibility of the Market Assessment and Compliance Department (“MACD”), a division of the IESO. GLPT’s compliance program has been developed to meet MACD’s requirements, which include Self-Certification, Self-Reporting and periodic Compliance Audits.

GLPT’s internal compliance program has been completed, is operational and at this time there are no outstanding areas of non-compliance.

CUSTOMER ENGAGEMENT

1.0 Introduction

GLPT is committed to continuous improvements in managing its transmission system and an integral part of this objective involves ensuring proactive customer engagement takes place on a regular basis. Given the size and remote nature of GLPT's transmission service territory, there are relatively few connected customers. This allows GLPT to develop a strong one-on-one relationship with each connected customer; ensuring lines of communication are open on a regular basis.

GLPT's most formal means of communication is its annual stakeholder meetings where GLPT representatives meet with each customer to discuss system performance, capital and maintenance plans, and outage plans, among other things. GLPT also recently completed its regional planning exercise as lead transmitter in the East-Lake Superior ("ELS") region. While GLPT's next regional planning cycle will take place in 2019, the recent discussions opened up a collaborative communication channel that has enabled GLPT to identify areas of concern and to continue working with the affected parties to resolve such areas of concern.

On a less formal basis, GLPT engages in regular communications leading up to and during planned outages, and communicates in real time during forced outages to ensure issues identified by all parties are managed appropriately.

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As it relates to new connections, GLPT has a Customer Connection Process which was developed to meet the requirements of the Transmission System Code (the "TSC"). In 2015, GLPT successfully connected two new renewable generation customers and one new load customer to its transmission system.

GLPT's ultimate objective is to ensure it continues to take an active role in customer engagement, as contemplated by the RRFE. To further enhance its customer engagement activities, GLPT is investigating the addition of customer satisfaction surveys which will form a part of its scorecard as proposed in Exhibit 3, Tab 1, Schedule 2 of this Application. While GLPT does not currently conduct an official survey on customer satisfaction, many of the key aspects that impact customer satisfaction, such as reliability and cost control, are those that are currently included in GLPT's Key Performance Indicators ("KPIs").

1.1 Stakeholder Environment

The TSC defines a customer as a generator, consumer, distributor or unlicensed transmitter whose facilities are connected to or are intended to be connected to the transmission system. As noted above, GLPT has a small customer base, which is made up of the following:

- Two Local Distribution Companies ("LDCs")
- Four major load customers

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- Three generating companies with numerous connection points throughout GLPT's system
- Two IESO Controlled Grid ("ICG") connection points with the adjacent transmitter, Hydro One Networks Inc. ("HONI").

2.0 Customer Engagement Activities

GLPT undertakes various types of customer engagement activities with connected customers, including annual meetings, volume forecasting, regional planning and regular day to day communications. As a transmitter, GLPT must ensure prudent management of reasonable customer expectations as a component of good utility practice, and consider long term benefits for the customer, the rate payer and for GLPT as the system owner. GLPT must ensure that conflicting customer priorities are managed to a level of sensitivity that not only meets the needs of customer operational requirements, but also the needs of the broader transmission system, ensuring they fall within the prescribed regulations (i.e., Market Rules). In addition, through the course of customer engagement activities GLPT ensures that it has an awareness of the operational sensitivities of each connected customer with respect to power quality needs, future planning and the scheduling of outages. The significant customer engagement activities undertaken by GLPT are described in greater detail below, and are also summarized in **Appendix 'A'**.

2.1 Annual Meetings

Customer stakeholder meetings are held annually with each connected customer to provide information on system performance and reliability statistics, educate and verify

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information contained within Transmission Connection Agreements and communicate GLPT's capital and maintenance plans regarding upcoming projects and areas which may be of concern for each customer. The annual meeting agenda includes, among other things, a Transmission Connection Agreement discussion, a Customer Delivery Point Performance discussion, and a Transmission System Planning update. A sample annual meeting agenda is attached as **Appendix 'B'**. Information gathered through these annual meetings has influenced the development of GLPT's capital program.

2.2 Volume Forecasting

GLPT engages in communication with connected LDCs and load customers with respect to anticipated load changes to support its charge determinant forecasts for rate application purposes. The primary purpose of this communication is to understand if the connected customers anticipate material changes in loads during the test period, and it can also facilitate meaningful discussions regarding future needs of customers and how they may influence GLPT's capital plans.

2.3 Regional Planning

GLPT is the lead Transmitter in the ELS region for regional planning purposes. The ELS team was composed of participants representing GLPT, the IESO, HONI, Algoma Power Inc., PUC Distribution Inc. and Chapleau Public Utilities Corporation. GLPT completed the regional planning process on December 12, 2014 with the issuing of a final Needs

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Assessment Report. All report documents can be viewed under the regulatory tab of GLPT's website at www.glp.ca.

The Needs Assessment Report did not recommend any further Regional Planning, and therefore there will not be any need for an IESO scoping process for the ELS region. The report did address three issues where it stated that further regional coordination was required, and "localized" wire only solutions were to be developed by GLPT and the impacted distributor or customer. GLPT has accomplished this by continuing to work with one of the local LDCs to plan prudent projects that reduce the impact of events, particularly in locations where single supply points have the potential to create extended outages to customers.

This process provides a benefit to all stakeholders as they ultimately identify and address customer concerns, improve contingency planning, and provide the best value option for the rate payer.

GLPT will undertake the next Regional Planning process in 2019, as outlined by the TSC unless, before that date, there is sufficient load growth or a trigger event that requires the initiating of the Regional Planning process. However, in the meantime GLPT will continue to leverage information gathered and relationships that were forged through the regional planning process to improve its annual stakeholder meetings and improve its customer engagement initiatives overall.

2.4 Day to Day Operations

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Regarding day to day operations, with the appropriate amount of notice GLPT provides regular communications leading up to and during planned outages. GLPT's outage schedules take into consideration any relevant feedback gathered during this communication. Further, where customers are directly impacted, GLPT has established internal requirements for the provision of information on a real time basis during forced outages. GLPT's *Communication Procedure Between Great Lakes Power System Control and Connected Market Participants* is attached as **Appendix 'C'**.

3.0 New Customer Connections

As noted above, GLPT has a Customer Connection Process which was developed to meet the requirements of the Transmission System Code (the "TSC"). The connection process is a highly involved process that requires a customer application, system and customer impact assessments, estimates and potential cost recovery arrangements, and design, build and commissioning work. When new or modified customer connections are planned that may impact the reliability of other customers, the results of any customer impact assessments are shared with all customers. Details of GLPT's customer connection process are available on GLPT's website at http://www.glp.ca/content/regulatory/customer_connection_process-44189.html.

In 2015, following its customer connection process, GLPT commissioned the connection of two wind generators to its transmission system. GLPT also commissioned the connection of a new load customer at an existing connection point. The new load connection did not require any capital upgrades to facilitate the connection, and therefore while a connection cost recovery agreement was entered into, no contributions were made by the customer.

As noted above, GLPT regularly communicates with its connected customers regarding future plans and growth potential, which includes discussions around potential connection upgrades. GLPT's objective is to work with customers to facilitate any connection upgrades, ensuring their needs are met and ensuring upgrades and expenditures meet GLPT's standards. Where possible, GLPT will also consider broader solutions that may satisfy immediate needs, but also have the potential to provide additional value to other customers in the area and to the ratepayer overall.

4.0 Customer Satisfaction

While GLPT has and will continue to use evolving KPIs to monitor and manage business performance, the implementation of the proposed scorecard as described in Exhibit 3, Tab 1, Schedule 2, will facilitate the integration of additional concepts of the RRFE policy of the OEB, particularly those related to the customer engagement process. One significant improvement GLPT will investigate during the test period is developing a better understanding of customer satisfaction. GLPT intends to develop and implement a customer survey during the test period to measure overall customer satisfaction including satisfaction with GLPT's outage planning process.

While GLPT does not have a formal customer satisfaction survey in place at this time, it does actively manage aspects of the business that it believes directly impact customer

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satisfaction. Metrics such as system reliability (through CDPPS measurement), cost control (through measurement of capital and OM&A expenditures), and operational incident measurement form an integral part of GLPT's KPIs. GLPT believes that appropriately managing its KPIs provides value to connected customers and thus would have a positive impact on customer satisfaction.

5.0 Conclusion

As described above, given the relatively few connected customers GLPT has been able to develop strong one-on-one relationships with each connected customer; ensuring a number of different lines of communication are open on a regular basis. GLPT is committed to continuously improve its customer engagement processes and will continue to report to the Board on such activities through transmission rate filings under the revenue cap framework.

Appendix A

Coordinated Planning with Third Parties

Type of Consultation	Purpose of Consultation	Initiated or Invited	Participants	Timing of Deliverables	Impact on Transmitter's Plan
Annual Stakeholder Meetings	Provide information on system performance and reliability statistics, educate and verify information in Transmission Connection Agreements, and communicate capital and maintenance plans	Initiated	All directly connected market participants	Meetings conducted annually. To the extent action items arise, they are addressed within a reasonable timeframe	Formal communication sheds light on concerns of connected market participants. For example, discussions surrounding emergency response times and forced outages where there is a single point of supply provided further justification for the planned replacement of the T1 transformer at MacKay TS in 2017
Volume Forecasting	Collect information on charge determinant forecasts to inform forecast used for calculation of Uniform Transmission Rates	Initiated	All directly connected market participants	Typically ~3 months prior to filing of rate application	No direct impact to operational and capital plans, however provides a means to facilitate further discussion regarding potential load growth
Regional Planning	To ensure that regional issues and requirements are effectively integrated into utility planning processes, and to ensure that the development and implementation of the smart grid in Ontario is carried out on a coordinated basis	Initiated	- GLPT - Ontario Power Authority (OPA) - Independent Electricity System Operator (IESO) - Hydro One Networks	East Lake Superior Region - Needs Assessment Report was filed with OEB in December 2014. GLPT will undertake the next	The report did address three issues where it stated that further regional coordination was required, and "localized" wire only solutions were to be developed by GLPT

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	and that smart grid investments are made at the system level (distribution or transmission) that will best serve the interests of the region. Also a requirement under the Transmission System Code		Inc. (transmitter), - PUC Distribution Inc, - Algoma Power Inc, - Chapleau Public Utility Corporation.	Regional Planning process in five years (2019).	and the impacted distributor or customer. Examples of some of these solutions are described in Exhibit 2 of this Application, and include the replacement of T1 at Mackay TS, and a solution that sees the replacement of T2 at Third Line TS which specifically address contingency concerns that have been raised by an LDC connected to GLPT's system.
New Customer Connections	Discuss needs of new customer	Invited	New customers or connected customers projecting load growth	As needed	New customer connections and connection upgrades may trigger capital investments (subject to credits associated with customer contributions). Capital investments in this application are not impacted by new customer connections or customer load growth

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Appendix B

Sample Stakeholder Meeting Agenda

Great Lakes Power Transmission (GLPT) & Market Participant
Stakeholder Meeting Agenda

Date:
Time:
Location:

Attendees

Great Lakes Power Transmission LP	(Customer)

1. Introductions
2. Review and approval of meeting agenda
3. Organizational Overview and exchange of org charts
4. Approval of last Meeting Minutes (If applicable)
5. Review Action Items closed since the previous meeting (If applicable)
6. Transmission Connection Agreement
    a) TCA – Current as of •, does not expire
    b) Connection Status
        i. Confirm highest monthly peak of •W vs projected •kW
        ii. Confirm timing to reach project load of •kW
    c) Customer Connection Process (General Discussion)
        i. Step 1 Joint GLPT\IESO connection application
        ii. Step 2 CIA\SIA studies
        iii. Step 3 Connection Estimates & Financial Evaluation
        iv. Step 4 CCRA – Connection Cost Recovery Agreement
        v. Step 5 Design & Build
        vi. Step 6 Commissioning

vii. Total Normal Supply Capacity (ie. (n-1) x lowest NSC = TNSC)

viii. Available Capacity – First-come first serve basis. The need for assignment of available capacity must be demonstrated by customer

ix. Assigned Capacity – highest rolling three-month average peak.

d) Equipment Demarcation

e) Review Schedules

i. Schedule ‘A’ Operations Contacts

ii. Schedule ‘D’ – Fault levels

7. Other Agreements – N/A

8. Customer Delivery Point Performance\Forced Outages

A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more of GLPT components causing load loss. Interruptions caused by GLPT's customers are recorded but not charged against the reliability performance for the customer initiating the interruption, but are charged against the reliability performance for other interrupted customers.

Outlier Triggers

Performance Measures	Delivery Point Performance Standards (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		**>15 to 40MW**		**>40 to 80MW**		**>80MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

When the three year rolling average of DP performance falls below the minimum standard of performance ("Outlier"), GLPT will initiate technical and financial evaluations to determine root cause and if any remedial action is required. The customer at any time can also initiate a root cause analysis.

2013-2015 (3 year rolling average) reliability performance

Overall Frequency of Interruptions = •/yr (2015 = •)

Overall Duration of Interruptions = • min/yr (2015 = •min)

a) Transmission Caused Outages

b) Market Participants Caused Outages

9. Planned Outages

   a) Transmission Plans

      i. GLPT Station Schedule

         - Anjigami TS – Maintenance, May
         - Anjigami TS – Capital Work, July
         - Watson TS – Maintenance, June
         - Watson TS – Capital Work, July

      ii. GLPT Lines\Forestry Schedule

         - Hollingsworth 115kV Circuit – Capital Structure Replacement work, June thru September.

   b) Market Participant Plans

      i. Schedule down days

      ii. General production schedule

10. System planning

   a) 2017 - 2018 Details

      i. 2017 Anjigami & Watson Protection Upgrades

      ii. 2017 Watson TS 115kV Ring Bus

   b) 5 Year Planned items of impact to other customers

      i. 2017-2020 Protection upgrades – Hollingsworth TS

      ii. 2017-2019 Third Line TS T2 Replacement

11. Additional Items
    a) Provide copy of System Operating Diagram

12. Review Action Items

Action No	Agenda Item	Subject	Action	Assigned To	Due Date

13. Schedule next meeting

14. Adjourn Meeting

Time:

Appendix C

Communication Procedure Between Great Lakes Power System Control and Connected Market Participants

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Document Number:	Revision Date:	Revision Number:	Reviewed Date:
SC-043	**January 07, 2014**	**R5**	**January 07, 2014**
Prepared By: **W. Hammerstedt**	Authorized By: **Jason Drenth**	Effective Date: **January 01, 2010**	

Communication Procedure Between Great Lakes Power System Control And Connected Market Participants

Instruction:

Planned or Short Notice Outage Communications:

Should **Great Lakes Power** wish to isolate equipment that involves the operation of devices **owned by a Market Participant**, the following communication protocol will be followed:
Note: All steps must be recorded in the Operator's Daily Log.

1. The GLP System Outage Coordinator will complete and either fax or send electronically, a PC1 form requesting a Supporting Guarantee to the designated contact person for the Market Participant's equipment. The Operator will follow up with a phone call to make sure the document was received.
2. The GLP System Outage Coordinator will complete and send an outage slip to the IESO and any other party that he/she believes may require the information.
3. Two business days before the outage, the IESO will contact the GLP System Outage Coordinator, or the GLPSC Operator to either cancel the outage or give advanced approval.
4. On the day of the outage, the GLPSC Operator will contact the IESO one hour prior to the outage start to get final approval to proceed. He/She will also contact the Market Participant to ensure they are in position and ready to perform the desired switching.
5. Immediately before the outage starts, the GLPSC Operator will contact the IESO and get permission to begin the outage.
6. Upon completion of the switching, the Market Participant shall provide the Supporting Guarantee to the GLPSC Operator for inclusion in the Work Permit as per the EU&SA Work Protection Code (WPC).
7. Once the equipment is no longer required, the GLPSC Operator shall surrender the Supporting Guarantee to the Market Participant and in accordance with the EU&SA WPC, switching can begin to restore the equipment to service.
8. **Before the Equipment is re-energized,** the GLPSC Operator shall contact the IESO for permission to proceed and will ensure that everyone is in the clear, and if necessary, the Electrical Safety Authority (ESA) has given permission to re-energize.

Should a **Market Participant** wish to isolate equipment that involves the operation of devices **owned by Great Lakes Power**, the following communication protocol will be followed:

Note: All steps must be recorded in the Operator's Daily Log.

1. The Market Participant will complete and either fax or send electronically, a PC1 form or equivalent, requesting a supporting guarantee on the required Great Lakes Power equipment. The Market Participant will follow up with a phone call to make sure the document was received.
2. The GLP System Outage Coordinator will complete and send an outage slip to the IESO and any other party that he/she believes may require the information.
3. Two business days before the outage, the IESO will contact the GLP System Outage Coordinator, or the GLPSC Operator to either cancel the outage or give advanced approval. The GLP System Outage Coordinator or GLPSC Operator shall inform the Market Participant of the outage status.
4. On the day of the outage, the GLPSC Operator will contact the IESO one hour prior to the outage start to get final approval to proceed. He/She will also contact the Market Participant to ensure they are in position and ready to perform the desired switching.
5. Immediately before the outage starts, the GLPSC Operator will contact the IESO and get permission to begin the outage.
6. Upon completion of the switching, the GLP System Operator shall provide the Supporting Guarantee to the Market Participant per the EU&SA Work Protection Code (WPC).
7. Once the equipment is no longer required, the Market Participant shall surrender the Supporting Guarantee to the GLPSC Operator and in accordance with the EU&SA WPC, switching can begin to restore the equipment to service.
8. **Before the Equipment is re-energized,** the GLPSC Operator shall contact the IESO for permission to proceed and will ensure that everyone is in the clear, and if necessary, the Electrical Safety Authority (ESA) has given permission to re-energize.

Forced Outage Communications:

In the event of a Forced outage between Great Lakes Power and any of the market participants, which are directly connected to Great Lakes Power facilities, the following communication protocol will be followed: **Note: All steps must be recorded in the Operator's Daily Log.**

1. The GLPSC Operator will immediately contact the IESO and inform them of the outage and obtain permission to attempt to restore the equipment with the Market Participant's approval.
2. The GLPSC Operator will then contact the Market Participant and make an attempt to restore the equipment to service.
3. Should the equipment remain energized, the GLPSC Operator will contact the IESO and inform them of the status. Should the equipment trip free, the GLPSC Operator shall inform the IESO of the status and provide an approximate in-service time.
4. The GLPSC Operator will complete the online outage form and also email the System Outage Coordinator, the appropriate Forced Outage group, and any other party that he/she believes may require the information.

5. The Market Participant shall provide status updates to the GLPSC Operator in order that they may keep the IESO informed of the condition of the equipment.

Outage Types:

Planned outages are defined as outages submitted to the Great Lakes Power System Control (GLPSC) greater than 5 business days in advance of the planned outage start date. These outages go through the normal outage process and **should** be submitted greater than 33 days in advance of the outage but if less than 33 days, as early as possible to ensure the Independent Electrical System Operator (IESO) has recorded a priority timestamp.

Short Notice outages are outages submitted to the GLPSC outage office with less than 5 business days notice. These will be handled on a best effort basis depending on the nature of the outage.

The IESO reserves the right to cancel, defer, or recall any outage if they deem it necessary for system stability or continuity of supply.

Forced outages are outages that occur without notice due to circumstances beyond anyone's control, or outages that are initiated by people in the field who discover problems that could lead to equipment failure or environmental/safety concerns.

All of these outages are handled in a similar manner with the most important aspect being the communications between GLPSC, the IESO, and the connected market participant

Background:

The new electricity market in Ontario ushered in a whole new set of rules regarding the application and processing of transmission outages and with it came the necessity to review how we interact with the connected customers in our service area. For the purposes of this instruction, connected customers are considered to be all of those that have connection agreements with Great Lakes Power Limited.

Great Lakes Power Contacts:

GLP System Outage Coordinator
(Monday to Friday 08:00 16:00)
705-941-5654

GLP Senior Operator
(5 Days/Week 07:00 – 17:00)

705-941-5654

GLP System Operator
(24 Hours/Day)
705-254-1651 or 705-941-5654

Market Participant Contacts and their contact information can be found in their respective connection agreements.

REVENUE REQUIREMENT AND ANNUAL ADJUSTMENT

1.0 Introduction

The following are GLPT's proposed annual adjustments including inflation, productivity and stretch factors.

1.1 Inflation

GLPT proposes to use an inflation factor of 1.90% as calculated and released by the OEB on October 27, 2016 for Ontario distributor incentive rate setting under the Price Cap IR and Annual Index plans for rates effective in 2017. GLPT proposes that in the absence of a specific inflation factor established by the OEB for transmitters, it is appropriate for Ontario's transmitters to use the same inflation factor as distributors, recognizing they will share many of the same inputs.

1.2 Industry Productivity Factor

GLPT proposes to use the OEB-approved productivity factor of zero, as established for Ontario distributors in the 2017 test year. As no productivity factor has been determined for transmitters on an industry-wide basis, GLPT proposes that the productivity factor used by distributors in Ontario is the most applicable rate to use at this time because until there is more supporting information available, the general assumption is that transmitters' opportunities to realize productivity improvements are not greater than those of distributors.

1.3 Stretch Factor

Similar to productivity factors, the OEB has not approved stretch factors for Ontario transmitters. As has been noted, GLPT is in a unique situation as it was recently acquired by Hydro One and received approval for a 10 year rate rebasing deferral period. During the first two years of the deferral period, Hydro One and GLPT will be undertaking a significant review of GLPT's operations prior to the operational integration of GLPT into Hydro One. In 2018, Hydro One Transmission intends to file a Custom IR application (for 2019 rates and beyond) which would propose an annual productivity factor and stretch factor. It is anticipated that GLPT's revenue cap adjustment in those future years would adopt the same rate given that GLPT would be operationally integrated with Hydro One at that time. Consequently, GLPT submits that it would not be cost effective or timely to conduct a GLPT-specific stretch factor study for establishing 2017 and 2018 revenue requirements.

GLPT recognizes that a stretch factor is required in accordance with Chapter 2 of the OEB's February 11, 2016 *Filing Requirements for Electricity Transmission Applications*. GLPT has filed the 1QC Report at Exhibit 3, Tab 1, Schedule 4, Appendix "A", which outlines that GLPT's total O&M and A&G costs are lower than its peers, "GLPT falls below average on a cost per asset basis" and "compared against the panel of companies on the total of O&M and A&G, GLPT compares favorably, ranking well below the median for the panel".[1]

[1] Page 2 of the referenced exhibit.

Additionally, it is important to note that a stretch factor is utility-specific. GLPT is currently under a deferred rebasing period consistent with the Filing Requirements for Consolidation Applications. In accordance with those filing guidelines, achieved savings realized in the deferred rebasing period are intended for the acquiring utility's shareholder to offset transaction costs and premiums. Inclusion of a stretch factor would reduce GLPT's annual revenue requirement, and thereby reduce the amounts of achieved cost savings available to the acquiring utility. This would, in GLPT's opinion, be inconsistent with the OEB's guidelines.

GLPT submits that a 0% stretch factor is appropriate as its operating costs fall below the majority of its comparable peers. In addition, GLPT is currently undergoing significant changes to its business processes and planning activities, due to its consolidation with Hydro One, which is expected to result in longer term operational synergies and savings post operational integration. GLPT does not expect any significant operational integration steps to occur during 2017 or 2018.

1.4 2017 Revenue Forecast

GLPT has forecasted its 2017 base revenue requirement to be $40,533,904. The 2017 base revenue requirement was calculated using GLPT's 2016 OEB-approved revenue requirement ($39,778,120) as the base revenue adjusted by an annual adjustment of $755,784. The annual adjustment calculation is outlined in *Table 4-1-1 A* below:

Table 4-1-1 A – Proposed 2017 Revenue Requirement

GLPT 2016 OEB Approved Revenue Requirement	$ 39,778,120	(a)
Adjustment Factor (Inflation - Productivity - Stretch (1.9%-0%-0.0%)	1.90%	(b)
Proposed Annual Adjustment	$ 755,784	(c) = (a x b)
GLPT 2017 Proposed Revenue Requirement	$ 40,533,904	(d) = (a + c)

DEFERRAL AND VARIANCE ACCOUNTS OVERVIEW

1.0 Deferral and Variance Accounts Overview

GLPT is requesting approval for continuance of the following deferral/variance accounts:

- Other Regulatory Asset Account 1508
    - Sub-Accounts: Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs; Property Tax and Use and Occupation Permit Fee Variance; IFRS Gains and Losses; and OEB Cost Assessments;
- Based upon the Accounting Procedures Handbook, GLPT will continue to maintain in the test period account 1595 related to previously approved regulatory asset recovery; and
- As outlined in the OEB policy, as described in the OEB's 2008 report entitled *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, prescribes a 50/50 sharing of impacts of legislated tax changes from a utility's tax rates embedded in its OEB approved base rate known at the time of application. GLPT is proposing to maintain in the test period a sub-account within account 1592 to capture these impacts.

As described in more detail in Section 1.5 of Exhibit 2, Tab 1, Schedule 1, in the event GLPT encounters unforeseen events which meet the three defined eligibility criteria of Causation, Materiality and Prudence, a new Z-factor deferral account would be established in Account 1572.

2.0 Disbursal of Deferral Accounts

GLPT is requesting approval to disburse the balances in the following accounts:

- Four sub-accounts of account 1508:
  - Comstock claim;
  - Property tax and use and occupation permit fee variances;
  - Bulk Energy System ("BES") definitional change; and
  - OEB cost assessment variances; and
- Account 1595 related to previously approved regulatory asset recovery.

GLPT has provided additional details in:

- Exhibit 5, Tab 1, Schedule 2 - Account 1508; and
- Exhibit 5, Tab 1, Schedule 3 - Account 1595.

2.1 Proposed Disbursal Methodology

Account 1595 is currently a debit balance being disbursed over a 3 year period. The repayment period began on January 1, 2015 with the implementation of UTR for the 2015 calendar year. Therefore, at December 31, 2016, there will be one year remaining in the disbursement period. Subject to the approval of the various account balances that GLPT is seeking to disburse as part of this Application, it is GLPT's position that the most administratively efficient method to disburse the various account balances would be to aggregate the balance of all accounts, including the remaining balance in account 1595, and disburse the balance in 2017. The total amount GLPT is seeking to disburse is a debit balance of $975,219, which is similar in magnitude to amounts added to or subtracted from GLPT's revenue requirement in previous years, as approved by the Board. This includes all of the balances sought for approval for the accounts listed in section 2.0 above, as well as forecasted carrying charges for 2017. All account balances GLPT is seeking to disburse, inclusive of all carrying charges, would be cleared in 2017 under this proposal. This aggregation approach is consistent with prior rate applications, and is described in more detail in Exhibit 5, Tab 2, Schedule 1.

GLPT has provided a continuity schedule of deferral and variance accounts at Exhibit 5, Tab 3, Schedule 1.

ACCOUNT 1508 – OTHER REGULATORY ASSETS

1.0 Summary

As at December 31, 2015, GLPT has seven active sub-accounts of Account 1508 – Other Regulatory Assets. The seven sub-accounts are related to:

i) Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs[1];

ii) Comstock Claim;

iii) Property Tax and Use and Occupation Permit Fee Variances;

iv) IFRS Gains and Losses;

v) Incremental costs related to addressing an upcoming change to the definition of the Bulk Electric System ("BES");

vi) OEB Cost Assessment Variances; and

vii) In-service Addition Net Cumulative Asymmetrical Variance Account.

2.0 Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs

As described in EB-2014-0238, GLPT is using this sub-account to capture OM&A expenses and capital expenses related to renewable generation connection, system planning, and infrastructure investment arising from the *Green Energy and Green Economy Act, 2009* ("GEA"). GLPT has not had a requirement to use this account since EB-2014-0238, and therefore the account balance remains at $0.

[1] This account was approved by the OEB in its decision on EB-2009-0409, which was an application by GLPT to establish a deferral account to record expenses related to renewable generation connection, system planning, and infrastructure investment arising from the *Green Energy and Green Economy Act, 2009*.

GLPT is requesting to maintain this variance account for future use, as required.

3.0 Comstock Claim

In the EB-2014-0238 settlement agreement approved by the Board on November 19, 2014, the parties agreed that GLPT would disburse the December 31, 2013 balance in this account, plus 2014 carrying charges for a total of $2,354,305. The parties also agreed that GLPT would continue use of the account to capture costs incurred after December 31, 2013, until the matter was resolved. GLPT incurred additional costs in 2014 and 2015 to resolve the Comstock claim, and is forecasting no further costs to be incurred. The costs incurred were primarily legal costs related to negotiating and executing a full and final mutual release with Comstock and its Receiver, which was signed in February 2015.

Table 5-1-2 A below demonstrates the evolution of this account up to December 31, 2016.

Table 5-1-2 A – Comstock Costs

Year	Opening Balance	Costs Incurred	Transfers	Cumulative Costs	Carrying Charges	Transfers	Cumulative Carrying Charges	Closing Account Balance
2010	$0	$1,660,623	$0	$1,660,623	$0	$0	$0	$1,660,623
2011	1,660,623	106,634	-	1,767,257	24,920	-	24,920	1,792,177
2012	1,792,177	375,800	-	2,143,057	27,855	-	52,775	2,195,833
2013	2,195,833	93,664	-	2,236,721	31,928	-	84,704	2,321,425
2014	2,321,425	80,404	-	2,317,126	33,055	-	117,759	2,434,884
2015	2,434,884	15,075	(2,261,466)	70,735	789	(92,839)	25,709	96,444
2016	96,444	-	-	70,735	778	-	26,487	97,222
				$70,735			**$26,487**	**$97,222**

GLPT is seeking to disburse the forecast December 31, 2016 debit balance of $97,222, inclusive of carrying charges, as described in Exhibit 5, Tab 2, Schedule 1. As the matter has now been resolved, GLPT is not seeking continuation of this sub-account.

4.0 Property Tax and Use and Occupation Permit Fee Variances

As described in previous rate applications, GLPT is using this sub-account to capture variances in payments in lieu of taxes paid to First Nations as compared to the base cost embedded in revenue requirement for each year.

In 2015, GLPT negotiated an amendment to an existing agreement with one of its First Nation partners, establishing a 25 year agreement with an option for a 25 year renewal upon expiry. The amendment came into effect January 1, 2016 and resulted in a marginal increase in the annual fee. As a result, GLPT is forecasting to pay $146,167 in payments in lieu of taxes paid to First Nations compared to the $128,800 which is the base cost embedded in revenue requirement for 2016. GLPT has recorded the incremental fee in this sub-account for disbursal. *Table 5-1-2 B* below demonstrates the amounts recorded in this account, inclusive of carrying charges.

Table 5-1-2 B – Use and Occupation Permit Fee Variances

Year	Opening Balance	Costs Incurred	Cumulative Costs	Carrying Charges	Cumulative Carrying Charges	Closing Account Balance
2016	$0	$17,367	$17,367	$88	$88	$17,454
			$17,367		**$88**	**$17,454**

GLPT is seeking to disburse the forecast December 31, 2016 debit balance of $17,454, inclusive of carrying charges, as described in Exhibit 5, Tab 2, Schedule 1. However, GLPT is proposing to cease recording amounts in this account to the extent they are directly associated with the January 1, 2016 amendment variance described above.

GLPT is still negotiating with at least one First Nation group in respect of payments in lieu of taxes; and, as such GLPT is requesting to maintain this variance account for future use, as required.

5.0 IFRS Gains and Losses

As part of the EB-2014-0238 settlement agreement approved by the Board on November 19, 2014, the Board authorized GLPT to continue to maintain a deferral account to record costs in respect of gains and losses resulting from premature asset component retirements.

GLPT incurred a loss on disposal in 2015 and is forecasting a loss on disposal for 2016, net of proceeds from disposition. However, GLPT is not seeking to disburse the balance of this account at this time as rate base will not be rebased as a part of this application, therefore the amounts disposed will remain in GLPT's rate base for the life of the rebasing deferral period (10 years) consistent with the rate making methodology applied in this application.

6.0 Incremental costs related to addressing the change to the definition of the Bulk Electric System ("BES")

As part of the EB-2014-0238 settlement agreement approved by the Board on November 19, 2014, the Board approved continuation of GLPT's deferral account which was established to capture incremental costs relating to addressing an upcoming change to the definition of the BES. It was agreed that GLPT should establish two sub-accounts under this deferral account; one for OM&A expenses and one for capital expenses. GLPT has only recorded costs in the OM&A sub-account. *Table 5-1-2 C* below outlines the amounts recorded in this account to date.

Table 5-1-2 C - BES Variance Account Costs – OM&A

Year	Opening Balance	Costs Incurred	Cumulative Costs	Carrying Charges	Cumulative Carrying Charges	Closing Account Balance
2013	$0	$6,928	$6,928	$33	$33	$6,961
2014	6,961	12,627	19,555	133	166	19,721
2015	19,721	-	19,555	233	399	19,955
2016	19,955	-	19,555	215	615	20,170
			$19,555		**$615**	**$20,170**

This sub-account was established to track and record prudently incurred costs related to addressing changes to the BES definition which were effective July 1, 2016. As described in Exhibit 3, Tab 1, Schedule 5, GLPT is compliant with all applicable NERC standards, including those associated with the updated BES definition, and therefore GLPT no longer requires continuation of this sub-account. In light of this, GLPT is seeking to disburse the forecast December 31, 2016 debit balance of $20,170, inclusive of carrying charges, as described in Exhibit 5, Tab 2, Schedule 1. Given the work completion, GLPT is not seeking continuation of this sub-account.

7.0 OEB Cost Assessment Variances

As described in the Board’s letter dated February 9, 2016 addressed to all Regulated Entities subject to the OEB’s Cost Assessment, the OEB established a variance account for electricity distributors and transmitters to record any material differences between

OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment model effective April 1, 2016.

The base cost included in GLPT's approved 2016 revenue requirement is $107,095, while the forecast cost to be incurred for 2016 is $74,319. GLPT will record the variance of $32,776 in this sub-account in 2016, and is forecasting a balance owing to ratepayers of $32,896 in this sub-account at December 31, 2016, inclusive of carrying charges. *Table 5-1-2 D* below outlines the amounts recorded in this account to date.

Table 5-1-2 D – OEB Cost Assessment Variances

Year	Opening Balance	Costs Incurred	Cumulative Costs	Carrying Charges	Cumulative Carrying Charges	Closing Account Balance
2016	$0	($32,776)	($32,776)	($120)	($120)	($32,896)
			($32,776)		**($120)**	**($32,896)**

GLPT is seeking to disburse the forecast December 31, 2016 credit balance of $32,896, inclusive of carrying charges, as described in Exhibit 5, Tab 2, Schedule 1.

GLPT will continue to record variance amounts and their associated carrying charges in this account on a go-forward basis.

8.0 In-service Addition Net Cumulative Asymmetrical Variance Account

In the EB-2014-0238 settlement agreement approved by the Board on November 19, 2014, the parties agreed that GLPT would establish a net cumulative asymmetrical variance account for the test years to track the impact on revenue requirement of the cost of in-service capital additions during the test years compared to Board approved amounts, for disposition in a future rate application. The purpose of the account is to capture the revenue requirement amount which (i) would arise if the total capital in-service additions forecasted by GLPT for the test years 2015 and 2016 are higher than the actual total capital in-service additions for 2015 and 2016, and (ii) reflects the net difference between the forecasted in-service additions for 2015 and 2016 in the event that the circumstance set out in (i) occurs. If the cumulative amount of in-service additions during 2015 and 2016 is less than the cumulative Board-approved amount, then the revenue requirement impact of the shortfall would be entered in the variance account.

GLPT's forecast cumulative in-service additions are equal to the Board-approved amount of in-service additions for 2015 and 2016, which is $19,228,700. Therefore, GLPT has not recorded any amounts in this account at this time. As this application is not a cost of service application and given that this application will not result in the Board approving a specific 2017 annual Capital In-service amount, GLPT proposes to close this account.

<u>ACCOUNT 1595 –AGGREGATE BALANCE</u>

1.0 Aggregate Balance for 2015-2017 Recovery

In the EB-2014-0238 settlement agreement approved by the Board on December 18, 2014, the parties agreed that GLPT would recover $2,363,488 (including a credit balance of $433,945 arising from account 1575) [1] to clear deferral and variance account balances over a three year period beginning in 2015. At December 31, 2015 the balance of this account was $1,652,824 (including a credit balance of $318,788 arising from account 1575). In 2016, GLPT increased its revenue requirement for UTR purposes by $787,816, reflecting the recovery of funds from ratepayers for the year. As a result of the repayments from 2015 and 2016, GLPT is forecasting a balance of $871,990 (including a credit balance of $192,579 arising from account 1575) at December 31, 2016 inclusive of carrying charges. The EB-2014-0238 settlement agreement indicated that the funds would be recovered over a three year period, being 2015 through 2017. As described in Exhibit 5, Tab 2, Schedule 1, and consistent with prior applications, GLPT is proposing to aggregate this balance with other regulatory balances, and disburse the aggregate balance in 2017.

As indicated in Exhibit 5, Tab 2, Schedule 1, GLPT is seeking to continue use of this account for the purpose of tracking the approved disbursal of the aggregate balance of

[1] Included within the approved balance was a credit amount of $433,945 which arose from account 1575 – IFRS-CGAAP Transitional PP&E Amounts. This balance attracts carrying charges at the Board-approved cost of capital for GLPT as opposed to the deemed interest rate for deferral and variance accounts.

deferral and variance accounts. At this time GLPT does not intend to further true up the balance of the aggregate disbursal beyond 2017.

DISBURSAL OF EXISTING DEFERRAL AND VARIANCE ACCOUNTS

1.0 Proposed Methodology for Disbursal

In this application GLPT is proposing to aggregate all of the deferral and variance account balances that GLPT is seeking approval for, and disburse the total amount in 2017. This aggregation is consistent with the approach applied in previous applications, and most recently in the Board-Approved Settlement Agreement related to EB-2014-0238. GLPT is seeking approval to disburse a total debit balance of $975,219 by increasing its annual revenue requirement for UTR in 2017. GLPT does not intend to seek a true-up to this amount once collection in 2017 is complete.

2.0 Existing Deferral and Variance Account Recovery

GLPT is currently collecting a deferral account balance from ratepayers over a three year period (account 1595). At December 31, 2016, there will be one year remaining in the scheduled 3-year payback. The forecasted December 31, 2016 debit balance of this account is $871,990. This is made up of a debit balance of $1,064,569 related to the aggregate asset amounts, offset in part by a credit balance of $192,579 related to the IFRS-CGAAP Transitional PP&E account which draws carrying charges at a different rate and thus is accounted for separately. GLPT is seeking approval to disburse this balance as a part of this application.

3.0 New Deferral Account Disbursals

The subsections below deal with the individual accounts and sub-accounts that GLPT is proposing to disburse in this application. Section 4.0 below deals with the aggregation of the accounts, the treatment of carrying charges, and the proposed disbursal methodology.

3.1 Account 1508 – Sub-account Comstock Claim

As illustrated in *Table 5-1-2 A*, GLPT is forecasting a debit balance of $97,222 in this sub-account at December 31, 2016, inclusive of carrying charges. GLPT is seeking approval to disburse this balance as a part of this application.

3.2 Account 1508 – Sub-account Property Tax and Use and Occupation Permit Fee Variances

As illustrated in *Table 5-1-2 B*, GLPT is forecasting a debit balance of $17,454 in this sub-account at December 31, 2016, inclusive of carrying charges. GLPT is seeking approval to disburse this balance as a part of this application.

3.4 Account 1508 – Sub-account BES Definitional Change

As illustrated in *Table 5-1-2 C*, GLPT is forecasting a debit balance of $20,170 in this sub-account at December 31, 2016, inclusive of carrying charges. GLPT is seeking approval to disburse this balance as a part of this application.

3.5 Account 1508 – Sub-account OEB Cost Assessment Variances

As illustrated in *Table 5-1-2 D*, GLPT is forecasting a credit balance of $32,896 in this sub-account at December 31, 2016, inclusive of carrying charges. GLPT is seeking approval to disburse this balance as a part of this application.

4.0 Aggregation of Accounts

Table 5-2-1 A below demonstrates the balances of the deferral and variance accounts that GLPT is seeking to disburse over a one-year period beginning in 2017. Positive amounts in the table are debit amounts that are recoverable by GLPT, while negative amounts in the table are credit amounts that are payable by GLPT.

Table 5-2-1 A – Deferral and Variance Account Balances

($'s) Account Number	Account Description	Dec 31, 2016 Balance Sought for Disbursal
1595	Three Year Asset Amount (1 Yr Remaining)	$1,064,569
1595	IFRS-CGAAP Transitional PP&E Amount (1 Yr Remaining)	(192,579)
1508	Legal Claim (Comstock)	97,222
1508	Property Tax & Permit Fees	17,454
1508	BES	20,170
1508	OEB Cost Assessments	(32,896)
1595	Forecast Carrying Charges - 2017	1,279
	Total Deferral Accounts	**$975,219**

For the purposes of disbursing the entirety of the balances in the test years, GLPT is seeking to include forecasted carrying charges for 2017 in the amounts recovered. The carrying charges on the portion of the account balance associated with account 1575 are calculated using GLPT's return on rate base (currently 7.59%). All other carrying charges are calculated using the OEB's deemed rate for deferral and variance accounts (currently 1.10%).

Subject to the approval of the various account balances that GLPT is seeking to disburse as part of this Application, GLPT is seeking to disburse the aggregate debit balance of $975,219 by increasing its 2017 revenue requirement to be used in the calculation of UTR.

<u>CONTINUITY OF DEFERRAL AND VARIANCE ACCOUNTS</u>

The tables below demonstrate the continuity of GLPT's deferral and variance accounts for 2014 and 2015 actual, as well as 2016 and 2017 forecast. GLPT has reflected the proposed disbursal of its accounts, as described in Exhibit 5, Tab 2, Schedule 1. The continuity schedules do not include any amounts accrued or forecasted to be accrued in the IFRS Gains and Losses deferral account, as any amounts accrued for 2015 and 2016 will not be disbursed during the 10 year deferral period.

Table 5-3-1 A – Continuity of Deferral and Variance Accounts

Account Number	Description	2014 Opening Principle as of Jan 1, 2014	Transactions in 2014	Dispositions in 2014	Transfers in 2014	Closing Principle as of Dec 31, 2014	Opening Interest as of Jan 1, 2014	Interest for 2014	Dispositions in 2014	Transfers in 2014	Closing Interest as of Dec 31, 2014	Account Balance at Dec 31, 2014
Regulatory Assets:												
1508	Green Energy Deferral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	EWT Support Costs	54,972	-	-	-	54,972	1,187	808	-	-	1,995	56,967
1508	Legal Claim (Comstock)	2,236,721	80,404	-	-	2,317,126	84,704	33,055	-	-	117,759	2,434,884
1508	Property Tax Variances	-	-	-	-	-	-	-	-	-	-	-
1508	EWT Variance	274,963	169,235	-	-	444,198	1,091	5,868	-	-	6,959	451,157
1508	BES	6,928	12,627	-	-	19,555	33	133	-	-	166	19,721
1508	IFRS Gains and Losses	452,924	214,964	-	-	667,888	966	(966)	-	-	-	667,888
1592	Changes in Tax Legislation	-	-	-	-	-	-	-	-	-	-	-
1575	IFRS-CGAAP Transitional PP&E Amounts	-	(433,945)	-	-	(433,945)	-	-	-	-	-	(433,945)
1595	Aggregate Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-
	Subtotal Regulatory Assets	**$3,026,509**	**$43,286**	**$0**	**$0**	**$3,069,794**	**$87,981**	**$38,898**	**$0**	**$0**	**$126,879**	**$3,196,673**
Regulatory Liabilities:												
1595	Three Year Liability Amount	(1,115,343)	-	784,511	-	(330,832)	(321,735)	(11,086)	-	-	(332,821)	(663,653)
	Subtotal Regulatory Liabilities	**($1,115,343)**	**$0**	**$784,511**	**$0**	**($330,832)**	**($321,735)**	**($11,086)**	**$0**	**$0**	**($332,821)**	**($663,653)**
	Net Regulatory Asset (Liability) Balance	**$1,911,166**	**$43,286**	**$784,511**	**$0**	**$2,738,962**	**($233,754)**	**$27,812**	**$0**	**$0**	**($205,942)**	**$2,533,021**

Table 5-3-1 A – Continuity of Deferral and Variance Accounts (cont'd)

		2015										
Account Number	**Description**	**Opening Principle as of Jan 1, 2015**	**Transactions in 2015**	**Dispositions in 2015**	**Transfers in 2015**	**Closing Principle as of Dec 31, 2015**	**Opening Interest as of Jan 1, 2015**	**Interest for 2015**	**Dispositions in 2015**	**Transfers in 2015**	**Closing Interest as of Dec 31, 2015**	**Account Balance at Dec 31, 2015**
Regulatory Assets:												
1508	Green Energy Deferral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	EWT Support Costs	54,972	-	-	(54,972)	-	1,995	-	-	(1,995)	-	-
1508	Legal Claim (Comstock)	2,317,126	15,075	-	(2,261,466)	70,735	117,759	789	-	(92,839)	25,709	96,444
1508	Property Tax Variances	-	-	-	-	-	-	-	-	-	-	-
1508	EWT Variance	444,198	-	-	(444,198)	-	6,959	-	-	(6,959)	-	-
1508	BES	19,555	-	-	-	19,555	166	233	-	-	399	19,955
1508	IFRS Gains and Losses	667,888	-	-	(667,888)	-	-	-	-	-	-	-
1592	Changes in Tax Legislation	-	-	-	-	-	-	-	-	-	-	-
1595	IFRS-CGAAP Transitional PP&E Amounts	(433,945)	-	143,298	-	(290,647)	-	(28,141)			(28,141)	(318,788)
1595	Aggregate Regulatory Asset - 2015	-	-	(924,545)	3,097,693	2,173,148	-	29,492	-	(231,028)	(201,536)	1,971,612
	Subtotal Regulatory Assets	**$3,069,794**	**$15,075**	**($781,247)**	**($330,832)**	**$1,972,791**	**$126,879**	**$2,374**	**$0**	**($332,821)**	**($203,568)**	**$1,769,223**
Regulatory Liabilities:												
1595	Three Year Liability Amount	(330,832)	-	-	330,832	-	(332,821)	-	-	332,821	-	-
	Subtotal Regulatory Liabilities	**($330,832)**	**$0**	**$0**	**$330,832**	**$0**	**($332,821)**	**$0**	**$0**	**$332,821**	**$0**	**$0**
	Net Regulatory Asset (Liability) Balance	**$2,738,962**	**$15,075**	**($781,247)**	**$0**	**$1,972,791**	**($205,942)**	**$2,374**	**$0**	**$0**	**($203,568)**	**$1,769,223**

Table 5-3-1 A – Continuity of Deferral and Variance Accounts (cont'd)

2016												
Account Number	Description	Opening Principle as of Jan 1, 2016	Forecast Transactions in 2016	Forecast Dispositions in 2016	Forecast Transfers in 2016	Forecast Closing Principle as of Dec 31, 2016	Opening Interest as of Jan 1, 2016	Forecast Interest for 2016	Forecast Dispositions in 2016	Forecast Transfers in 2016	Forecast Closing Interest as of Dec 31, 2016	Forecast Account Balance at Dec 31, 2016
Regulatory Assets:												
1508	Green Energy Deferral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	Cumulative Asymmetrical Variance	-	-	-	-	-	-	-	-	-	-	-
1508	OEB Cost Assessment Variances	-	(32,776)	-	-	(32,776)	-	(120)	-	-	(120)	(32,896)
1508	EWT Support Costs	-	-	-	-	-	-	-	-	-	-	-
1508	Legal Claim (Comstock)	70,735	-	-	-	70,735	25,709	778	-	-	26,488	97,222
1508	Property Tax Variances	-	17,367	-	-	17,367	-	88	-	-	88	17,454
1508	EWT Variance	-	-	-	-	-	-	-	-	-	-	-
1508	BES	19,555	-	-	-	19,555	399	215	-	-	615	20,170
1592	Changes in Tax Legislation	-	-	-	-	-	-	-	-	-	-	-
1595	IFRS-CGAAP Transitional PP&E Amounts	(290,647)	-	143,317	-	(147,330)	(28,141)	(17,107)	-	-	(45,248)	(192,579)
1595	Aggregate Regulatory Asset - 2016	2,173,148	-	(923,881)	-	1,249,266	(201,536)	16,838	-	-	(184,697)	1,064,569
	Subtotal Regulatory Assets	**$1,972,791**	**($15,409)**	**($780,565)**	**$0**	**$1,176,817**	**($203,568)**	**$692**	**$0**	**$0**	**($202,876)**	**$973,940**
	Net Regulatory Asset (Liability) Balance	**$1,972,791**	**($15,409)**	**($780,565)**	**$0**	**$1,176,817**	**($203,568)**	**$692**	**$0**	**$0**	**($202,876)**	**$973,940**

Table 5-3-1 A – Continuity of Deferral and Variance Accounts (cont'd)

2017												
Account Number	**Description**	**Opening Principle as of Jan 1, 2017**	**Forecast Transactions in 2017**	**Forecast Dispositions in 2017**	**Forecast Transfers in 2017**	**Forecast Closing Principle as of Dec 31, 2017**	**Opening Interest as of Jan 1, 2017**	**Forecast Interest for 2017**	**Forecast Dispositions in 2017**	**Forecast Transfers in 2017**	**Forecast Closing Interest as of Dec 31, 2017**	**Forecast Account Balance at Dec 31, 2017**
Regulatory Assets:												
1508	Green Energy Deferral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	OEB Cost Assessment Variances	(32,776)	-	-	32,776	-	(120)	-	-	120	-	-
1508	Legal Claim (Comstock)	70,735	-	-	(70,735)	-	26,488	-	-	(26,488)	-	-
1508	Property Tax Variances	17,367	-	-	(17,367)	-	88	-	-	(88)	-	-
1508	BES	19,555	-	-	(19,555)	-	615	-	-	(615)	-	-
1592	Changes in Tax Legislation	-	-	-	-	-	-	-	-	-	-	-
1595	IFRS-CGAAP Transitional PP&E Amounts	(147,330)	-	147,330	-	-	(45,248)	(5,592)	50,841	-	-	-
1595	Aggregate Regulatory Asset - 2017	1,249,266	-	(1,324,147)	74,881	-	(184,697)	6,871	150,757	27,069	-	-
	Subtotal Regulatory Assets	**$1,176,817**	**$0**	**($1,176,817)**	**$0**	**$0**	**($202,876)**	**$1,279**	**$201,598**	**$0**	**$0**	**$0**
	Net Regulatory Asset (Liability) Balance	**$1,176,817**	**$0**	**($1,176,817)**	**$0**	**$0**	**($202,876)**	**$1,279**	**$201,598**	**$0**	**$0**	**$0**

COST ALLOCATION TO RATE POOLS

1.0 Background

In accordance with the Board's January 15, 2016 decision in EB-2015-0311, GLPT's 2016 revenue requirement was allocated to the transmission pools for the calculation of the UTR for 2016 based on the approved Revenue Requirement of Ontario Transmitters. As a result, effective January 1, 2016, GLPT's approved revenue requirement was allocated as follows:

Table 6-1-1 A – EB-2015-0311 Approved Figures

EB-2015-0311 Rate Order Approved Figures	Network	Line Connection	Transformation Connection	Total
Revenue Requirement	$23,732,985	$5,633,935	$11,199,017	$40,565,937

2.0 Test Year Revenue Requirement Allocation

As described in Exhibit 5, Tab 2, Schedule 1, GLPT is requesting disbursal of several deferral and variance account balances. The collective impact of this disbursal is expected to increase GLPT's 2016 revenue requirement by an additional $975,219 for the 2017 test year. As a result, GLPT's revenue required from UTR in 2017 is the total base revenue requirement plus $975,219, as shown in *Table 6-1-1 B* below.

Table 6-1-1 B – Calculation of Revenue Requirement for Uniform Transmission Rates

($'s)	2017
2017 Revenue Requirement (per Ex. 4, Tab 1, Sch. 1)	$40,533,904
Add: Annual Regulatory Account Disbursement	975,219
Revenue Requirement for Uniform Transmission Rates	**$41,509,123**

For illustrative purposes in Table 6-1-1-C below, GLPT has allocated its incremental revenue requirement to the transmission cost pools by applying the same proportions as were used for the 2016 UTR in EB-2015-0311. The actual 2017 allocations will be determined by the Board when its decision on 2017 UTR rates and allocations are made.

Table 6-1-1 C – 2017 Revenue Requirement by Transmission Pool

2017 Test Year	Network	Line Connection	Transformation Connection	Total
Revenue Requirement	$24,284,793	$5,764,928	$11,459,402	$41,509,123

CALCULATION OF UNIFORM TRANSMISSION RATES

1.0 Overview

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002 as per RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044. The current Ontario Uniform Transmission Rates ("UTR") Schedules, effective January 1, 2016 and approved as part of the Board's EB-2015-0311 Decision and Order issued January 14, 2016, are filed at Exhibit 7, Tab 1, Schedule 2.

Since rates are established on a uniform basis for the province, the revenue requirement of the five transmitters in the province, HONI, Canadian Niagara Power Inc., Five Nations Energy Inc., B2M Limited Partnership and GLPT, must be aggregated in order to determine the total transmission revenue requirement for the province. Therefore, any annual changes to the revenue requirement or charge determinant of any transmitter will contribute to an annual change in the overall provincial transmission tariffs.

The overall revenue requirement must be allocated to the UTR Pools in order for uniform rates by pool to be established.[1] The revenue requirement by Rate Pool for all transmitters is based on the shares established by the Board. Once the revenue requirement by rate pool has been established, rates are determined by applying the provincial charge determinants for each pool to the associated total revenue requirement

[1] GLPT's revenue is allocated to the Rate Pools in Exhibit 6, Tab 1, Schedule 1.

for each pool. The provincial charge determinants are the sum of all charge determinants for the transmitters, by Rate Pool.

2.0 Current Uniform Transmission Rates

Table 7-1-1 A below demonstrates the calculation of the UTR that are in effect in 2016, with GLPT's information highlighted within the table. As noted above, the complete 2016 rate schedule can be found at Exhibit 7, Tab 1, Schedule 2.

Table 7-1-1 A – 2016 Uniform Transmission Rate Calculation

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$3,701,645	$878,728	$1,746,716	$6,327,089
CNPI	$2,608,113	$619,136	$1,230,705	$4,457,954
GLPT	$23,732,985	$5,633,935	$11,199,017	$40,565,937
H1N	$866,145,218	$205,612,810	$408,712,802	$1,480,470,830
B2MLP	$32,965,146			$32,965,146
All Transmitters	$929,153,107	$212,744,609	$422,889,240	$1,564,786,956

Transmitter	Total Annual Charge Determinants (MW)		
	Network	Line Connection	Transformation Connection
FNEI	187.120	213.460	76.190
CNPI	522.894	549.258	549.258
GLPT	3,498.236	2,734.624	635.252
H1N	249,552.000	241,956.000	207,936.000
B2MLP	-	-	-
All Transmitters	253,760.250	245,453.342	209,196.700

Transmitter	Uniform Rates and Revenue Allocators		
	Network	Line Connection	Transformation Connection
Uniform Transmission Rates ($/kW-Month)	**3.66**	**0.87**	**2.02**
	↓	↓	↓
FNEI	0.00398	0.00413	0.00413
CNPI	0.00281	0.00291	0.00291
GLPT	0.02554	0.02648	0.02648
H1N	0.93219	0.96648	0.96648
B2MLP	0.03548	0.00000	0.00000
All Transmitters	1.00000	1.00000	1.00000

3.0 Proposed Uniform Transmission Rates

GLPT's proposed 2017 UTR incorporates GLPT's revenue requirement and charge determinants proposed in this application, and assumes the revenue requirement and charge determinant values approved for the other transmitters in the Board's most recent Rate Order (EB-2015-0311) remain the same.[2]

Table 7-1-1 B demonstrates the calculation of GLPT's proposed UTR for 2017, holding all other 2016 transmitter revenue requirements constant. As indicated above, the changes in the 2017 rates proposed in *Table 7-1-1 B* are driven only by GLPT's updated revenue requirement.

[2] GLPT notes that HONI is before the Board with a 2017-2018 rate application; however in order to isolate this application's impact to the proposed UTR in 2017 and 2018, GLPT has not incorporated HONI's proposed revenue requirement or proposed charge determinants in the calculation of 2017-2018 proposed UTR.

Table 7-1-1 B – Proposed 2017 Uniform Transmission Rates

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$3,701,645	$878,728	$1,746,716	$6,327,089
CNPI	$2,608,113	$619,136	$1,230,705	$4,457,954
GLPT	$24,284,793	$5,764,928	$11,459,402	$41,509,123
H1N	$866,145,218	$205,612,810	$408,712,802	$1,480,470,830
B2MLP	$32,965,146			$32,965,146
All Transmitters	$929,704,915	$212,875,602	$423,149,625	$1,565,730,142

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI	187.120	213.460	76.190	
CNPI	522.894	549.258	549.258	
GLPT	3,498.236	2,734.624	635.252	
H1N	249,552.000	241,956.000	207,936.000	
B2MLP	-	-	-	
All Transmitters	253,760.250	245,453.342	209,196.700	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.66**	**0.87**	**2.02**	
	↓	↓	↓	
FNEI	0.00398	0.00413	0.00413	
CNPI	0.00281	0.00291	0.00291	
GLPT	0.02612	0.02708	0.02708	
H1N	0.93163	0.96587	0.96587	
B2MLP	0.03546	0.00000	0.00000	
All Transmitters	1.00000	0.99999	0.99999	

GLPT has also prepared *Table 7-1-1 C* which is a replica of *Table 7-1-1 B*, but shows only the variances created by GLPT's revenue requirement and charge determinant forecast changes. *Table 7-1-1 C* shows the change from the currently approved rates to the 2017 proposed rates, holding all other 2016 transmitter revenue requirements constant. This assumption results in GLPT having a greater share of the overall Ontario revenue requirement and lowering the share of the other Ontario transmitters

Table 7-1-1 C – 2016-2017 Variance in Uniform Transmission Rates Driven By GLPT

Transmitter	**Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$0	$0	$0	$0
CNPI	$0	$0	$0	$0
GLPT	$551,808	$130,993	$260,385	$943,186
H1N	$0	$0	$0	$0
B2MLP				
All Transmitters	$551,808	$130,993	$260,385	$943,186

Transmitter	**Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	-	-	-	
CNPI	-	-	-	
GLPT	-	-	-	
H1N	-	-	-	
B2MLP	-	-	-	
All Transmitters	-	-	-	

Transmitter	**Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**0.00**	**0.00**	**0.00**	
	↓	↓	↓	
FNEI	0.00000	0.00000	0.00000	
CNPI	0.00000	0.00000	0.00000	
GLPT	0.00058	0.00060	0.00060	
H1N	-0.00056	-0.00061	-0.00061	
B2MLP	-0.00002	0.00000	0.00000	
All Transmitters	0.00000	-0.00001	-0.00001	

3.0 Rate Impacts

Overall, GLPT's request results in a 0.060% increase in Ontario's transmission revenue requirement pool for 2017 holding all other 2016 Ontario transmitter revenue requirements constant.

Exhibit 7, Tab 1, Schedule 2

2016 Ontario Uniform Transmission Rate Schedules – EB-2015-0311

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

DECISION AND RATE ORDER

EB-2015-0311

2016 UNIFORM TRANSMISSION RATES

BEFORE: Ken Quesnelle
Presiding Member

January 14, 2016

1. INTRODUCTION AND SUMMARY

The Ontario Energy Board (OEB) established the EB-2015-0311 proceeding on its own motion to issue the 2016 Uniform Transmission Rates (UTR).

There are five licensed electricity transmitters in Ontario that recover their revenues through Ontario's uniform transmission rates (UTR): Canadian Niagara Power Inc., Great Lakes Power Transmission Inc., Five Nations Energy Inc., Hydro One Networks Inc. and B2M Limited Partnership. The Ontario Energy Board (OEB) approves the revenue requirements and charge determinants of the individual transmitters and uses them to calculate the UTR.

The revenue requirements of the five transmitters are allocated to three transmission pools, Network, Line Connection and Transformation Connection on the basis of a cost allocation study conducted annually by Hydro One Networks. The costs are then divided by forecast consumption (charge determinants) to establish the UTR. The Independent Electricity System Operator (IESO) charges these rates to all wholesale market participants, including electricity distributors.

The combined UTR for 2016 is $6.55/kw, a $0.09 or 1.4% decrease relative to the 2015 UTR. The primary driver behind this decrease is the lower cost of capital for 2016. This change will be implemented effective January 1, 2016.

The impact of this decrease may take some time to materialize, and will vary depending on the customer mix and load characteristics in the different service areas and the proportion of power withdrawn by individual distributors from the bulk transmission system. Electricity distributors directly connected to the transmission system recover transmission costs from their customers through Retail Transmission Rates, which are established for each rate class annually. The majority of distributors adjust their rates in May 1 every year. These lower UTRs will be taken into account when establishing new retail transmission rates effective later this year. For any distributor whose rates for 2016 have already been established, the use of variance accounts will track differences between a distributor’s transmission costs and the associated revenues it receives from its customers, in order to ensure that its customers pay the true cost of transmission service over time.

2. THE PROCESS

The total revenue to be recovered for transmission services in 2016 is derived from the OEB's Decisions for the revenue requirements and charge determinants for all of the transmitters in Ontario. The findings in this Decision involve only the implementation of findings in these previous decisions. The OEB has therefore determined that no person will be adversely affected in a material way by the outcome of this proceeding. In accordance with section 21 (4) (b) of the Act, this matter has been determined without a hearing.

3. 2016 UNIFORM TRANSMISSION RATES

Hydro One Networks Inc. submitted its EB-2014-0140/EB-2015-0313 Draft Rate Order (DRO), on November 10, 2015, which included consolidated information from the other four Ontario transmitters and a calculation of the 2016 UTR. OEB staff reviewed the UTR documents and incorporated any 2016 updates for the remaining Ontario transmitters to calculate the 2016 UTRs.

This Order incorporates the OEB's findings in the most recent approved revenue requirements and pool load forecasts (charge determinants) for each of the other Ontario transmitters: Five Nations Energy Inc., Canadian Niagara Power Inc., Great Lakes Power Transmission Inc., Hydro One Networks Inc. and B2M Limited Partnership as shown below:

- Five Nations Energy Inc. (EB-2009-0387) issued December 9, 2010; and set as interim (EB-2015-0368) on December 29, 2015.

- Canadian Niagara Power Inc. (EB-2014-0204) issued June 25, 2015 with approved 2016 order under EB-2015-0354, issued January 14, 2016.

- Great Lakes Power Transmission Inc. (EB-2014-0238) issued December 18, 2014 with approved 2016 order under EB-2015-0337, issued January 14, 2016.

- Hydro One Networks Inc. (EB-2014-0140) issued December 2, 2014 with approved 2016 order under EB-2015-0313, issued on January 14, 2016; and

- B2M Limited Partnership (EB-2015-0026) 2016 final order issued on January 14, 2016.

The individual 2016 revenue requirement and charge determinant amounts for each of the five Ontario transmitters in the Ontario transmission rate pool were consolidated to arrive at the 2016 uniform transmission rates and revenue allocators as shown in Appendix A.

Findings

The OEB finds that the UTR calculations attached as Exhibit A to this Order, appropriately reflect the OEB's Decisions for all of the Ontario Transmitters in the 2016 transmission rate pool.

ORDER

THE BOARD ORDERS THAT:

1. The final revenue requirements by rate pool and the uniform electricity transmission rate and revenue allocators for rate effective January 1, 2016 as shown in Appendix A are approved.
2. The Ontario Uniform Transmission Rate Schedules, attached as Appendix B, are approved.

DATED at Toronto January 14, 2016

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

2016 Uniform Transmission Rates

and

Revenue Disbursement Allocators

EB-2015-0311

Decision and Rate Order

January 14, 2016

2016 Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2016 to December 31, 2016)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$3,701,645	$878,727	$1,746,716	$6,327,088
CNPI	$2,660,767	$631,635	$1,255,551	$4,547,953
GLPT	$23,732,985	$5,633,935	$11,199,017	$40,565,936
H1N	$866,145,218	$205,612,810	$408,712,802	$1,480,470,830
B2MLP	$32,965,146	$0	$0	$32,965,146
All Transmitters	$929,205,761	$212,757,107	$422,914,086	$1,564,876,953

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	187.120	213.460	76.190	
CNPI	522.894	549.258	549.258	
GLPT	3,498.236	2,734.624	635.252	
H1N	249,552.000	241,956.000	207,936.000	
B2MLP	0.000	0.000	0.000	
All Transmitters	253,760.250	245,453.342	209,196.700	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.66**	**0.87**	**2.02**	
FNEI Allocation Factor	**0.00398**	**0.00413**	**0.00413**	
CNPI Allocation Factor	**0.00286**	**0.00297**	**0.00297**	
GLPT Allocation Factor	**0.02554**	**0.02648**	**0.02648**	
H1N Allocation Factor	**0.93214**	**0.96642**	**0.96642**	
B2MLP Allocation Factor	**0.03548**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

** The sum of 12 monthly charge determinants for the year.*

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010. Set as Interim on December 29, 2015 under EB-2015-0368.
Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015 and 2016 order under EB-2015-0354, issued January 14, 2016.
Note 3: GLPT Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0238, issued December 18, 2014 and 2016 order under EB-2015-0337, issued January 14, 2016.
Note 4: Hydro One Rates Revenue Requirement per Board Decision on Settlement Agreement for EB-2014-0140 dated December 4, 2014 and 2016 order issued January 14, 2016.

Note 5: B2M LP 2016 Revenue Requirement per Board Decision and Order EB-2015-0026 dated December 29, 2015. 2016 Rate Order approved on January 14, 2016.

Appendix B

2016 Uniform Transmission Rate Schedules

EB-2015-0311

Decision and Rate Order

January 14, 2016

2016 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2015-0311

The rate schedules contained herein shall be effective January 1, 2016.

Issued: January 14, 2016
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS.

The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers that utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS-L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with the Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including

Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO-administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand[1,2]	**3.66**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.87**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**2.02**

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:
1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a “Per Transmission Delivery Point” basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: ETS	EXPORT TRANSMISSION SERVICE

APPLICABILITY:
The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:
The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

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

Ontario

BY E-MAIL

January 15, 2015

To: All registered intervenors in EB-2009-0387, EB-2014-0204, EB-2014-0238, EB-2014-0140 and EB-2015-0026

Re: 2016 Uniform Transmission Rate Decision and Rate Order
Board File Number: EB-2015-0311

In its Decision and Rate Order dated January 14, 2016 the OEB approved the uniform transmission rates and revenue allocators effective January 1, 2016.

In the table entitled "2016 Uniform Transmission Rates and Revenue Disbursement Allocators" in Appendix A, the total transmission revenue requirement for Canadian Niagara Power Inc. (CNPI) contained a transposition error.

Pursuant to its powers under Rule 41.02 of the OEB's Rules of Practice and Procedure, the OEB may at any time, without notice or a hearing of any kind, correct a typographical error, error of calculation or similar error made in its orders or decisions.

The OEB has amended the table in Appendix A so that the total revenue requirement for CNPI is correct. The uniform rates have not changed, but there is a corresponding correction to the revenue allocators.

The revised Appendix A is attached. This revised appendix supersedes and replaces any previously approved 2016 uniform transmission rates and revenue allocators.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

Attachment

Corrected, January 15, 2016
2016 Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2016 to December 31, 2016)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$3,701,645	$878,728	$1,746,716	$6,327,089
CNPI	$2,608,113	$619,136	$1,230,705	$4,457,953
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H1N	$866,145,218	$205,612,810	$408,712,802	$1,480,470,830
B2MLP	$32,965,146	$0	$0	$32,965,146
All Transmitters	$929,153,107	$212,744,608	$422,889,239	$1,564,786,954

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	187.120	213.460	76.190	
CNPI	522.894	549.258	549.258	
GLPT	3,498.236	2,734.624	635.252	
H1N	249,552.000	241,956.000	207,936.000	
B2MLP	0.000	0.000	0.000	
All Transmitters	253,760.250	245,453.342	209,196.700	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.66**	**0.87**	**2.02**	
FNEI Allocation Factor	**0.00398**	**0.00413**	**0.00413**	
CNPI Allocation Factor	**0.00281**	**0.00291**	**0.00291**	
GLPT Allocation Factor	**0.02554**	**0.02648**	**0.02648**	
H1N Allocation Factor	**0.93219**	**0.96648**	**0.96648**	
B2MLP Allocation Factor	**0.03548**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

** The sum of 12 monthly charge determinants for the year.*

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010. Set as Interim on December 29, 2015 under EB-2015-0368.
Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015 and 2016 order under EB-2015-0354, issued January 14, 2016.
Note 3: GLPT Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0238, issued December 18, 2014 and 2016 order under EB-2015-0337, issued January 14, 2016.
Note 4: Hydro One Rates Revenue Requirement per Board Decision on Settlement Agreement for EB-2014-0140 dated December 4, 2014 and 2016 order issued January 14, 2016.

Note 5: B2M LP 2016 Revenue Requirement per Board Decision and Order EB-2015-0026 dated December 29, 2015. 2016 Rate Order approved on January 14, 2016.