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Joanne Richardson
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BY COURIER

July 7, 2016

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700,
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2016-0050 – Hydro One Inc's S86 (2)(b) Leave to Purchase Voting Securities of Great Lakes Power – Interrogatory Responses Update Filing

I am attaching two (2) paper copies of the Hydro One Inc's updated Interrogatory Responses that were filed with the Board on June 20, 2016.

The update is limited to including the second page of AMPCO Interrogatory 10 which was inadvertently missed, namely, Exhibit I, Tab 3, Schedule 10, Page 2.

An electronic copy of the complete interrogatory responses, including the attached updates, has been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

Attach

c. Intervenors

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BY COURIER

June 20, 2016

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700,
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2016-0050 – Hydro One Inc's S86 (2)(b) Leave to Purchase Voting Securities of Great Lakes Power Transmission Inc. – Hydro One Inc's Responses to Interrogatory Questions

Please find attached the responses provided by Hydro One Inc. to interrogatory questions.

Below are the Tab numbers for each intervenor:

Tab	Intervenor
1	Ontario Energy Board (Board Staff)
2	Energy Probe
3	Association of Major Power Consumers in Ontario (AMPCO)
4	School Energy Coalition (SEC)
5	Vulnerable Energy Consumers Coalition (VECC)

Hydro One is also providing a correction to Pages 8 and 9 of Exhibit A, Tab 2, Schedule 1. The update provides anticipated 2026 UTR impacts as a result of this transaction by holding all other 2016 UTR revenue requirements constant.

An electronic copy of the Interrogatories has been filed using the Board's Regulatory Electronic Submission System. Two hard copies will be sent to the Board shortly.

SINCERELY,

ORIGINAL SIGNED BY PASQUALE CATALANO ON BEHALF OF JOANNE RICHARSON

JOANNE RICHARDSON

cc Intervenors (electronic)

Ontario Energy Board (Board Staff) INTERROGATORY #1

Interrogatory

Ref: Exhibit A, Tab 1, Schedule 1, Page 6

The application states that 1937672 Ontario Inc., a wholly-owned subsidiary of Hydro One Inc. (Hydro One) will own the limited partnership units of Great Lakes Transmission Holdings II LP and also states that there is no contemplated transfer or change in the ownership of the limited partnership interests in GLPT or GLPTLP.

a) Please explain why Hydro One considers that no change of ownership will take place when the limited partnership units of Great Lakes Transmission Holdings II LP will now be owned by 1937672 Ontario Inc.

b) Please confirm whether the limited partnership units currently held by Great Lakes Holdings LP will be owned by 1937672 Ontario Inc. after the transaction. If not, please provide a detailed explanation of the ownership structure of the limited partnership units of Great Lakes Power Transmission Holdings LP and Great Lakes Power Transmission LP following the transaction.

c) Please comment on whether 1937172 Ontario Inc. will own the limited partnership units of Great Lakes Transmission Holdings II LP indefinitely or if, this is a temporary arrangement please comment on Hydro One's plans for the ownership of these limited partnership units going forward.

Response

a) For consistency and ease of reference, HOI uses the following terms for purposes of answering this interrogatory. These terms are defined at pages 2 and 3 of the Application (Exhibit A, Tab 1, Schedule 1):

   - Great Lakes Power Transmission LP ("GLPTLP")
   - Great Lakes Power Transmission Holdings L.P. ("Holdings LP")
   - Great Lakes Power Transmission Holdings II L.P. ("Holdings II LP")
   - Great Lakes Power Transmission Inc. ("GLPT")
   - Great Lakes Power Transmission Holdings Inc. ("GLPT Holdings")
   - Hydro One Inc. ("HOI"); and
   - Hydro One Networks Inc. ("Hydro One").

   The organizational chart found at Exhibit A, Tab 1, Schedule 1, Attachment 1 shows that the limited partnership units issued in GLPTLP are held by (1) Holdings LP (99.99%) and (2) GLPT (0.01%). Importantly, GLPT is the regulated transmitter in these circumstances and acts on behalf of GLPTLP. What is also important is that the ownership of GLPTLP limited partnership units will remain unchanged by the transaction and will continue to be held by Holdings LP and GLPT.

The organizational chart also shows the entities that own the limited partnership units of Holdings LP. These are (1) Holdings II LP (99.99%) and (2) GLPT Holdings (0.01%). Under the terms of the transaction, 1937672 Ontario Inc., a wholly owned subsidiary of HOI, will acquire all limited partnership units of Holdings II LP. HOI will acquire the voting securities of GLPT Holdings, the general partner of Holdings II LP and Holdings LP. HOI is also acquiring the voting securities of GLPT.

Neither Holdings II LP nor its general partner, GLPT Holdings, is regulated by the OEB because neither are licensed transmitters. Thus, the disposition of these interests from these entities to HOI and 1937672 Ontario Inc. are not matters that fall within section 86(2) of the Act.

On the acquisition side, HOI further notes that the OEB has previously determined that section 86(2) does not apply to the acquisition of limited partnership units. That is, limited partnership units are not voting securities for the purposes of section 86(2). In EB-2013-0078, EB-2013-0079 and EB-2013-0080 at Page 5 the OEB made the following finding:

> In principle, based on the information in the application, the Board has no objection to the proposed acquisition of a 34% interest in B2M LP by SON LP Co. However, it is clear that the wording of subsection 86(2)(a) of the Act does not cover the acquisition of an interest in a limited partnership. Accordingly leave from the Board under subsection 86(2)(a) is not required for the proposed acquisition of a 34% interest in B2M LP by SON LP Co. (emphasis added).

For these reasons, HOI maintains the view that there is no contemplated transfer or change in the ownership of the limited partnership interests in GLPTLP. The only transfer requiring leave from the OEB concerns the acquisition of the voting securities of the licensed transmitter GLPT by HOI in accordance with section 86(2)(b).

b) The limited partnership units of GLPTLP, currently held by Holdings LP, will remain owned by Holdings LP. 1937672 Ontario Inc. intends to acquire the limited partnership units of Holdings II LP. Please see (a) above.

c) HOI assumes the question is intended to refer to 1937672 Ontario Inc. At the present time, there is no further plan, post-closing, to restructure ownership of the limited partnership interests contemplated to be transferred to 1937672 Ontario Inc. As noted in response (a) above, limited partnership interests are not voting securities of a regulated transmitter and thus fall outside of the requirements found in section 86(2) of the Act. In any event, 1937672 Ontario Limited will hold the limited partnership units of Holdings II LP for the foreseeable future. Changes in circumstances arising in the future are always possible and could result in changes to the post-closing ownership structure.

Ontario Energy Board (Board Staff) INTERROGATORY #2

Interrogatory

Ref: Exhibit A, Tab 2, Schedule 1, Page 3

Hydro One states that the transaction is expected to result in downward pressure on the cost structures of Hydro One and GLPT as compared to the scenario where the transaction did not proceed. Hydro One states that this conclusion is supported by two comparative assessments: (1) Hydro One and GLPT's productivity improvements; and (2) savings opportunities relative to the status quo scenario.

a) Please comment on the particular aspects of the transaction that will result in the anticipated productivity improvements.

b) Please comment on any other productivity measures other than the OM&A per gross fixed asset that Hydro One could use in evaluating the impact on cost structures.

c) Please identify any factors that may affect the achievement of the expected efficiencies and the recovery of costs associated with the proposed transaction in the timelines projected.

Response

a) In 2017-2018, GLPT and Hydro One will continue to operate as stand-alone licensed transmitters. During this period, Hydro One will examine areas where operational efficiencies may be achieved through integration. The areas in which OM&A savings are expected to be realized following 2018 relate to scale and operational synergies. These include procurement, maintenance programs, planning, operations, project management, engineering, scheduling, back-office administration, corporate governance, etc. Additional savings opportunities may include information technology, insurance, and research and development and in later years savings are assumed to reflect the legal and financial amalgamation of the two entities which is expected to occur. Qualitative benefits associated with the transaction include coordinated regional planning, emergency response and ongoing outage management activities as well as opportunities for GLPT's management and staff to work within the Hydro One organization. These resources will help address expected retirements and other attrition within Hydro One.

   Additional synergy areas exist in capital expenditure reductions arising from some asset redundancy, the economic scale of Hydro One's operations, and potential savings from adopting Hydro One's asset management programs. The level of actual realized savings is uncertain and will depend on the experience gained by the parties in 2017 and 2018, circumstances prevailing when operational integration plans are implemented, and external factors affecting operations (e.g. storms). Cost reductions associated with the SCADA system, transport and work equipment, spare parts inventory, and asset replacement costs are expected in years 3 to 5, with savings in later years attributable to the ability to avoid the relocation of a backup control center given Hydro One's existing infrastructure. Additional cost savings are assumed due to GLPT's use of other Hydro One operational programs, such as its Asset Risk Assessment model, and avoidance of significant costs for improvements to redundant buildings and facilities, and strengthening purchasing economies of scale.

b) There are no widely-accepted measures of productivity used in the transmission sector. As has been described in previous benchmarking studies before the Board[1], strong correlations exist between spending and assets. These same studies found that other normalizing factors, such as the number of customers or circuit kilometers, are not appropriate, as the correlation between these variables and costs is weak. Gross fixed assets, instead of net assets, is used as a normalizing factor because depreciation methodologies vary amongst entities.[2]

With respect to the cost variable used in HOI's analysis in this Application, HOI proposed to use OM&A as the cost variable as that is the most controllable transmitter cost.

c) Based on its current assessment of GLPT's assets, Hydro One does not see any significant risks originating within the suite of stations, lines or system control / SCADA assets and facilities and therefore has not flagged any barriers to the integration of the GLPT assets. Hydro One's overall assessment of the suite of GLPT assets indicated they are in fair-to-good condition and they pose minimal risks to either integration or incorporation into the Hydro One suite of assets and supporting data systems. While there is always a possibility of discovering (through a more detailed analysis conducted closer to integration) that some assets or facilities may require additional remediation efforts to be undertaken, at this time, Hydro One does not see any asset risks that are of significant impact.

Land access and rights negotiations involving both First Nations and existing land owners occur from time to time and have associated risks. While this transaction is not expected to materially change these existing risks, the successful conclusion of such negotiations could affect the timing and level of achieved efficiencies. Other potential risks include unforeseen factors such as adverse weather (i.e. storms), labor contract negotiations (i.e. PWU union contract expiry and terms) and unexpected loss of supply or equipment failures.

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[1] EB-2014-0238 – Exhibit 4, Tab 2, Schedule 1 Appendix A 1QC Benchmarking Study and EB-2016-0160 – Exhibit B2, Tab 2, Schedule 1 Attachment 1 Navigant Transmission Total Cost Benchmarking Study
[2] EB-2016-0160 – Exhibit B2, Tab 2, Schedule 1 Attachment 1 Navigant Transmission Total Cost Benchmarking Study - Section 2.4

Ontario Energy Board (Board Staff) INTERROGATORY #3

Interrogatory

Ref: Exhibit A, Tab 2, Schedule 1, Page 7

Hydro One states that incremental transaction costs will be financed through productivity gains associated with the transaction and will not be included in either GLPT or Hydro One's revenue requirement and thus will not be funded by ratepayers.

a) Please provide the magnitude of the incremental transaction costs that will be incurred as a result of this transaction.

Response

Incremental transaction costs are described in Exhibit A, Tab 2, Schedule 1, Page 7. HOI expects to incur these types of costs in two phases.

Phase 1 (2016)

In phase 1, costs associated with negotiating the transaction and obtaining all required regulatory approvals as well as initial steps to integrate GLPT and Hydro One financial systems will be incurred. The major integration activity during this period is loading and validating GLPT's financial data into Hydro One's financial systems. This will provide functionality for monthly trial balance uploads, intercompany transactions and reporting. This phase is estimated to cost approximately $3,500,000.

Phase 2 (2018, and early 2019)

In this phase, in preparing for a seamless transition and full operational integration, Hydro One will be completing a number of discovery / collection activities, including:

- Collect data / drawings and prepare for data loading
- Assess data systems structural setup for integration and testing
- Implement nomenclature solutions (data systems, diagrams, prints, Operating / NMS)
- Prepare operations to be integrated into OGCC Control / NMS / SCADA environment
- Prepare for migration of all IT / Database management information into existing Hydro One tools

Full operational integration entails all finance tools, new equipment assets, database updates, customer conversions, settlements, supply chain, human resources, telecommunications, work management, and full SCADA integration. This process will commence in the latter half of 2018 (and into early 2019). The estimated cost of these activities is $3.9M.

Ontario Energy Board (Board Staff) INTERROGATORY #4

Interrogatory

Ref: Exhibit A, Tab 2, Schedule 1, Page 8

Hydro One states that the premium paid over book value on the transaction will not have a material impact on Hydro One's financial viability as the value of the transaction equates to approximately 2% of Hydro One's fixed assets. Hydro One also states that the premium will not be recovered through revenue requirement and no return will be earned on that premium.

a) Please confirm the amount of the premium that is being paid as well as the rate base portion of the price that is expected to be recovered from ratepayers.

Response

The amount of premium associated with the transaction is approximately $150 million. The final premium amount will be determined once all post-closing costs have been incurred. As noted in Exhibit A, Tab 1, Schedule 1, page 7, neither Hydro One nor GLPT will seek to increase future revenue requirements recovered from customers in order to recover transaction costs and premiums associated with this transaction.

The 2016 approved GLPT rate base is $218,654,000. The return on this amount is currently included in the GLPT approved revenue requirement and will therefore be recovered from ratepayers as will any OEB-approved changes to rate base in future years.

Ontario Energy Board (Board Staff) INTERROGATORY #5

Interrogatory

Ref: Exhibit A, Tab 1, Schedule 1, Page 8

Hydro One states that it has selected a 10 year rate rebasing deferral period commencing on the closing dat of the transaction. Should the transaction close before or during the first quarter of 2017, the rate rebasing deferral period would end December 31, 2016. Rates would then be rebased effective January 1, 2027. Hydro One also states that its understanding is that GLPT expects to file in 2016 a rate application for approval of its 2017 and 2018 revenue requirements in 2016.

a) Please clarify if Hydro One is requesting a deferred rate rebasing period for 10 years beginning in 2017 or is Hydro One requesting a deferred rate rebasing period for 8 years, commencing in 2019.

Response

HOI assumes that the second sentence in the preamble to this question is intended to read "Should the transaction close before or during the first quarter of 2017, the rate rebasing deferral period would **end** on December 31, 2026. Rates would then be rebased effective January 1, 2027".

HOI is requesting a 10 year deferred rebasing period commencing after the close of the transaction. This approach is intended to comply with the 2016 Handbook which states at Page 12:

> "The 2015 Report permits consolidating distributors to defer rebasing for up to 10 years from the closing of the transaction [emphasis added]"[1].

Given the timing uncertainty of when regulatory approval of this application may occur, and given that regulatory approval is a condition to closing, HOI has proposed having the deferred rebasing period commence on January 1, 2017 in the event transaction closing occurs before or during the first quarter of 2017. The deferred rebasing period would then end on December 31, 2026. The first two years of that deferral period would then correspond to the 2017 and 2018 revenue requirement application to be filed by GLPT. For the subsequent 8 years of the deferred rebasing period, GLPT's by then previously approved 2018 revenue requirement would be used and adjusted annually for inflation. Please refer to Exhibit A, Tab 3, Schedule 1, page 1.

[1] Handbook, page 12

Ontario Energy Board (Board Staff) INTERROGATORY #6

Interrogatory

Ref: Exhibit A, Tab 3, Schedule 1, Pages 1-2

Hydro One has requested the OEB's acceptance of the proposed methodology to calculate GLPT's revenue requirement for 2019 and for each subsequent year during the rate rebasing deferral period. In 2016, GLPT intends to file a rate application for approval of its 2017 and 2018 revenue requirements. For 2019 and each subsequent year of the rebasing deferral period, GLPT's annual revenue requirement will be calculated by using GLPT's prior year revenue requirement and adjusting this amount with an inflation factor.

a) Will GLPT be making a request under section 78 of the OEB Act in its 2017/2018 rate application for its proposed methodology to calculate the GLPT 2019 revenue requirement and for each subsequent year during the deferred rebasing period?

b) If Hydro One will not be making a request under section 78 of the OEB Act:

    a. Please explain what Hydro One is seeking from the OEB through the request made in this application

    b. Please provide the basis on which Hydro One is making this request, setting out in detail how this request is consistent with the OEB Handbook to Electricity Distributor and Transmitter Consolidations.

Response

a) HOI has been advised by GLPT that the cost of service application to be filed will be for 2017 and 2018 revenue requirements. GLPT will not be seeking an approval for any revenue requirement beyond this time period in that application.

b) HOI is seeking approval for the methodology by which revenue requirements will be determined during the entirety of the deferred rebasing period.

    HOI's application has been prepared to comply with the Board's new *Handbook to Electricity Distributor and Transmitter Consolidations* ("Handbook") dated January 19, 2016. In so doing, HOI was mindful of the language found at page 11 which notes that <u>rate-setting</u> 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.

By seeking confirmation of, or alternatively, non-objection to the proposed method of determining rates during the entirety of the deferred rebasing period, HOI is provided with regulatory certainty that the methodology will not be subject to change and that it has a reasonable opportunity to realize efficiencies and have these offset against transaction and premium amounts. If acceptance or non-objection to the proposed rate-making methodology was not obtained, then the objectives of the deferred rebasing period, namely to provide acquiring transmitters with the opportunity to recover transaction premiums through efficiencies, would remain uncertain. Based on HOI's review of the Handbook, Table 1 on page 15 demonstrates that certainty over the rate setting methodology over a deferral period is a necessary and integral part of the deferred rebasing period.

In seeking confirmation of, or non-objection to, the revenue setting methodology proposed for the post 2019 deferred rebasing period, HOI was also informed by the information found under the heading "Rate Setting During Deferred Rebasing Period" as found at pages 13 and 14. Table 1, referenced in this section, addresses six scenarios in terms of the rate methodologies that would apply to distributors during the entirety of a deferred rebasing period. The Handbook acknowledged that the six scenarios are not all inclusive and that unique circumstances may exist that would require the OEB to assess the rate-setting proposals on a case by case basis.

The fact that the Handbook expressly contemplates Board consideration of revenue-setting proposals for and during the deferred rebasing period and within the context of applications made pursuant to section 86(2)(a), is the primary reason why HOI has included information to this effect in its application and sought confirmation of its rate-setting proposal.

HOI's proposal does not explicitly fall into the rate-setting options during the deferred rebasing period as outlined in Table 1. As such, HOI has requested approval of the revenue-setting methodology to be utilized during the deferred rebasing period. The circumstances in the present transaction are unique when compared to the scenarios described in Table 1 are:

- Both GLPT and Hydro One are transmitters and as such neither has been required to adopt an IRM method of rate regulation. Both entities, however, intend to do so commencing in 2019, midway through the deferred rebasing period.
- This requirement, coupled with the fact that both GLPT and Hydro One will be seeking cost of service revenue requirement approvals during a two year period while the deferred rebasing period is in effect, are unique circumstances and unlike those found in Table 1.

- The 2017 and 2018 cost of service rate application to be filed by GLPT will effectively be the "starting point" revenue requirements for the first two years of the deferral rebasing period and the 2018 approved amount will become the base upon which the inflation adjustment will apply for the remaining years of the deferral period. Scrutiny and justification for the GLPT 2017 and 2018 revenue requirements is expected through the OEB's hearing process in that application.

- The inflation adjustment proposal is unique to transmission consolidation circumstances but akin to other rate setting proposals approved in other consolidation proceedings.

Based on the foregoing, HOI submits that unique circumstances exist allowing the OEB to assess the proposed rate-setting methodology for the post 2018 deferred rebasing period. The OEB's consideration and assessment of the rate-setting proposal for the entire deferral rebasing period are consistent with the Handbook.

In response to part (a) to this request, HOI is seeking either express approval of or non-objection to the rate-setting methodology. This pronouncement will then guide the manner by which GLPT will make rate applications for the period 2019 to 2026 in accordance with section 78 of the Act. Specifically, HOI would expect this form of application to be uncontentious and more of a compliance filing given the underlying expectation that the future revenue requirement will be based on the 2018 approved level and adjusted for inflation. HOI does not view the proposed methodology to cause any undue prejudice since it is based upon approval of a yet to be determined 2018 revenue requirement. In that respect, HOI is not opposed to having its proposal acknowledged to be conditional upon approval of the GLPT 2018 revenue requirement.

Ontario Energy Board (Board Staff) INTERROGATORY #7

Interrogatory

Ref: OEB Filing Requirements For Electricity Transmission Applications, Chapter 2, Page 1

The Filing Requirements set out two new transmission revenue plan options. One of these is an incentive-based revenue index plan of five years, comprising an initial application to establish a revenue requirement based on a single test year cost of service application, followed by incentive-based and indexed adjustments to revenue requirement for the balance of the term. Analogous to a Price Cap for distributors, this "Revenue Cap index" approach includes expectations for the development of an index, as well as productivity and stretch commitments. The OEB invites transmitters to propose and substantiate the appropriate method and commitments for these elements.

a) If Hydro One is seeking the OEB's approval for its proposed methodology for setting its revenue requirement for 2019:

   a. Please confirm whether Hydro One has completed analysis to substantiate its proposal.

   b. If this analysis has been undertaken, please advise whether this information is expected to be filed as part of GLPT's rate application for 2017/2018. If not, please indicate when Hydro One expects to provide this information.

b) Please comment on the impact to the transaction if the OEB does not accept Hydro One's proposed metholodology or indicates that it will not be dealt with as part of this application.

Response

a) HOI has not completed this analysis because HOI is not seeking approval of a revenue requirement amount under s.78 of the *OEB Act, 1998* in this Application. The relief sought is acceptance of the methodology used to determine the revenue requirement amount for GLPT in the deferred rebasing period proposed between 2019 and 2026. The Handbook permits consolidating entities to defer revenue requirement rebasing for a period up to ten years after the closing of the transaction. This deferred rebasing period is intended "to enable (consolidating entities) to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction"[1]. In years six through ten, the Handbook also requires implementation of an earnings sharing mechanism

[1] Handbook page 9

("ESM") in order to protect customers and ensure that they share in any benefits from consolidation during the deferred rebasing period[2] which HOI has proposed. Due to the implementation of an ESM during the extended deferred rebasing period, the productivity and stretch factors proposed by HOI are zero, for the following reasons:

- Per the Board's MAAD policy[3] the achieved savings realized in the deferred rebasing period are to the benefit of the consolidating shareholder.
- Currently the OEB does not have any established revenue adjustment mechanism for transmission

HOI has also proposed an annual inflation factor, similar to the rate proposed in Chapter 3 of the distribution filing requirements, and requested the use of an ICM, both consistent with OEB policy.

b) The purchase agreement for the proposed transaction is not contingent upon the OEB accepting the proposed methodology. However, one of the business and regulatory objectives that HOI is trying to achieve is certainty over the methodology used to determine revenue requirements during the deferred rebasing period. This would not be achieved if the methodology is not dealt with as part of this application. HOI sees these objectives as being beneficial not only to its interests, but also to the interests of ratepayers.

The proposed revenue requirement setting methodology is intended to provide an equivalent level of certainty to that which would arise in circumstances involving distribution consolidations. Based on Table 1 (found on page 15 of the Handbook), distributors would know the methodology by which their rates are determined during the entirety of the deferred rebasing period.

Implications arise if the Board decides not to approve or defer consideration of the proposed revenue requirement methodology. For instance, the level of certainty afforded to distribution consolidations would be greater than those involving transmission. Additionally, deferring assessment of the methodology would create confusion on the revenue setting methodologies to be used during the deferred rebasing period, which would benefit neither ratepayers nor HOI.

As noted in Exhibit I, Tab 1, Schedule 6, establishing a deferred rebasing period provides limited value absent knowledge of how revenue requirements within that period are to be determined. HOI interprets the discussion in the Handbook (in particular, with regard to Table 1) to mean that rate setting methodologies for the deferred rebasing period are expected to be known to applicants seeking

[2] Handbook page 16

[3] EB-2014-0138: Report of the Board on Rate-making Associated with Distributor Consolidation

consolidation authorizations. This information provides a consolidating applicant with a reasonable basis to assess and quantify cost efficiencies and synergies as they become known.

Ontario Energy Board (Board Staff) INTERROGATORY #8

Interrogatory

Ref: Exhibit A, Tab 3, Schedule 1, Pages 2-3

Hydro One has proposed an earnings sharing mechanism 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.

a) Please confirm whether it is Hydro One's intention to share potential excess earnings with customers of both Hydro One and GLPT or whether the shared earnings will accrue only to the benefit of the customers of GLPT.

b) Please confirm whether Hydro One has considered any other methods for the calculation of shared earnings, post-amalgamation. If so, please provide details on the alternative methods that Hydro One has considered.

Response

a) Assuming the Uniform Transmission Rate ("UTR") methodology remains in effect during 2022-2026 (i.e. the time period in which the ESM is in effect) HOI's intention is to have any excess earnings that are shared with consumers, to be reflected in deductions to future revenue requirements. The reduced revenue requirement will then form part of the revenue requirements used by the Board to determine the overall UTR (the combined total of all licensed electricity transmitters in Ontario that recover their revenues through Ontario's UTR). The impact of the reduction will then be reflected in the UTRs charged to all Ontario electricity customers. The UTR rate methodology does not differentiate transmission rates by user. This means that benefits from excess earnings will be shared equally amongst all Ontario ratepayers.

b) No, HOI only considered the method described in the Handbook.

Energy Probe INTERROGATORY #1

Interrogatory

Reference: Exhibit A, Tab 1, Schedule 1, Page 7

Preamble: Hydro One's assessment of the proposed transaction takes into account the Board's "No Harm" Test outlined in the Handbook.

a) Please provide the specific Handbook reference(s) and extract(s).

b) How does Hydro One interpret the "No Harm" test from a ratepayer perspective?

c) If GPLP's revenue requirement and rates were to increase at or below inflation (absent the merger), how would this affect the "No Harm" test?

Response

a) Please refer to pages 3-4 of the Handbook, Section 3, *The OEB Test*, and Section 4, *The OEB Assessment of the Application*, found on pages 6-10.

b) HOI's interpretation of the no harm test is informed by the Handbook and previous OEB decisions (EB-2013-0187/0196/0198, EB-2014-0213, EB-2014-0244) that concerned relief under section 86 of the *OEB Act*. In general terms, HOI understands that 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 *OEB Act, 1998*.

c) If GLPT's revenue requirement over the deferred rebasing period was to increase at an amount equal to inflation, then GLPT's resulting revenue requirement would be equal to the revenue requirement proposed in this application resulting in no harm. In the unlikely scenario where GLPT's revenue requirement was to increase at a rate less than inflation then HOI's proposal would produce a higher revenue requirement. However, HOI believes this is an unlikely outcome and will not reflect the ongoing operational needs of GLPT. For further information please refer to GLPT's draft capital expenditure plan provided in Exhibit I, Tab 2, Schedule 6.

   HOI also observes that in 2015, GLPT's approved revenue requirement increased by approximately 10% when compared to 2014. If this transaction did not proceed, GLPT could be expected to file two more revenue requirement applications in accordance with the OEB's proposed RRFE for transmitters in the period 2019-2026. HOI has no reason to expect those revenue requirements would increase at a rate less than inflation.

The transaction before the OEB provides revenue requirement certainty over a 10 year period, in that the revenue requirement over the last eight years of the deferral period will only increase by inflation. In the absence of this transaction, such certainty is not provided to ratepayers. Additionally, HOI's evidence is that this transaction will result in downward pressure on the overall cost structures of both entities, to the ultimate benefit of Ontario ratepayers.

Energy Probe INTERROGATORY #2

Interrogatory

Reference: Exhibit A, Tab 1, Schedule 1, Page 8

Preamble: While longer term synergy savings opportunities are reasonably expected, reductions to the GLPT cost structure over time are not expected to result in significant reductions to the level of the UTR relative to the UTR rate had the transaction not proceeded. This outcome is due to the relatively small size of the GLPT revenue requirement as compared to the overall revenue requirement recovered through the UTR.

Please explain why "size matters" in assessing the cost/benefit of the Transaction. In your response take into account the fact that GPLT's revenue requirement is now recovered in the pooled UTR rates now and Post-merger.

Response

HOI was referring to the relative size of the revenue requirements. GLPTs revenue requirement, expressed as a percentage of the overall total revenue requirement recovered by the UTRs is 2.7%. The point HOI makes is that regardless of the actual achieved synergy savings, ratepayers should not expect significant reductions to the overall level of the UTR because GLPT's revenue requirement is such a small component of the overall revenue requirements recovered by the UTR.

Energy Probe INTERROGATORY #3

Interrogatory

References: Exhibit A, Tab 3, Schedule 1. Page 2 and Distribution Filing Requirements Chapter 3 (RRFE)

a) With reference to the RRFE, specifically Chapter 3, Table 1, Page 2 of the Guidelines, please indicate which of the Option(s) Hydro One is attempting to mirror - 4th Generation IR, Custom IR or Annual IR Index.

b) Please demonstrate/discuss how the specific proposals in the Application and resulting Rates meet/do not meet the Structure and Options of the RFFE.

c) Please discuss why Hydro One is proposing to adopt certain parts of the RRFE framework in the 10 year period post-merger and not others e.g. X factor, Term.

Response

Please refer to Exhibit I, Tab 1, Schedule 7.

Energy Probe INTERROGATORY #4

Interrogatory

References: Exhibit A, Tab 2, Schedule 1, Page 3 and Exhibit A, Tab 3, Schedule 1, Page 1

a) Please confirm Hydro One Tx and GLPT rates recently have been set for a two year period based on a Revenue Requirement based on Cost of Service.

b) Please provide for each entity, the annual Revenue Requirement and the realized rate of return for the period 2010-2015.

c) Leaving aside relative size argument(s), please explain why a 10 year rebasing for GPLT is appropriate for Hydro One and for existing ratepayers?

d) Given the historic revenue requirements for Hydro One TX and GLPT, please explain why inflation is an appropriate escalator for GPLT revenue requirement post 2019?

Response

a) Confirmed. Hydro One's current transmission revenue requirement for 2015 and 2016 was set under cost of service application (EB-2014-0140). On May 31, 2016, Hydro One submitted a 2 year cost of service revenue requirement application for 2017 and 2018, EB-2016-0160.

GLPT's revenue requirement for 2015 and 2016 was also set under a cost of service application (EB-2014-0238). GLPT expects to file a cost of service revenue requirement application later in 2016 for 2017 and 2018.

b)

	2010	2011	2012	2013	2014	2015
Hydro One Revenue Requirement ($M)	1,217.7	1,299.5	1,385.1	1,390.8	1,446.4	1,477.3
Hydro One Realized Return on Equity (%)	10.49	10.95	12.41	13.22	13.12	10.93
GLPT Revenue Requirement ($M)	34.2	34.8	36.1	38.1	38.7	39.6
GLPT Realized Return on Equity (%)	11.03	10.94	11.86	11.51	11.42	9.66

c) HOI relied on the Handbook, in selecting a 10 year deferral period. Specifically, page 12 of the Handbook permits deferral of rebasing for up to 10 years and states that the extent of the deferred rebasing period is at the option of the applicant and no supporting evidence is required to justify the selection of the deferred rebasing period. In allowing this, the OEB requires the applicant to identify the specific number of years for which deferral is sought. HOI has provided this information.

d) GLPT's historical revenue requirement has increased on average at a rate of 3% per year over the 2010-2015 period. See part b) above. The GDP inflation rate over the same time period averages approximately 1.6%[1]. As a result, increasing GLPT revenue requirement by the rate of inflation is an appropriate escalator.

[1] From OEB distributors inflation factors (2011-1.3%; 2012-2.0%' 2013-1.6%; 2014-1.7%; 2015-1.6%)

Energy Probe INTERROGATORY #5

Interrogatory

Reference: Exhibit A, Tab 2, Schedule 1 Page 3 Table 1

a) Please explain why in Table 1 “OM&A per gross fixed assets” is an appropriate measure.

b) Has this measure been approved as a Productivity Measure for Transmitters, comparable to Total Factor Productivity used for Distributors? If so, please provide references.

c) Does Hydro One have TFP figures for GPLT and Hydro One? If so, please provide these.

Response

a) Please refer to Exhibit I, Tab 1, Schedule 2b.

b) To HOI’s knowledge, there are no formal approvals for performance measures. However the “OM&A per gross fixed assets” measure is used in the industry.

c) No, HOI does not have these TFP figures.

Energy Probe INTERROGATORY #6

Interrogatory

Reference: Exhibit A, Tab 2, Schedule 1 Tables 2 and 3

a) Please provide a draft of GPLT's Capital Plan as referenced in the evidence.

b) Comparing Tables 2 and 3, please provide the basis of the reductions in CAPEX i.e. which projects will be deferred or integrated with Hydro One plans. Please be as specific as possible with a listing of projects and capital costs before and after the merger.

Response

a) Please refer to Attachment 1 for the draft 5 year GLPT capital plan. GLPT also provided HOI with a year 6-10 capital plan. This extended capital plan is provided in Attachment 2.

b) Please refer to Attachment 3 for the reductions in CAPEX identified in Exhibit A, Tab 2, Schedule 1, Table 3.

Great Lakes Power Transmission LP
5 Year Capital Plan

C$ in thousands	2017	2018	2019	2020	2021	Total
Capital Expenditures - Detailed						
Transmission Line Upgrades						
Wood Structure Replacements	$ 6,002.2	$ 6,390.1	$ 1,929.6	$ 1,607.4	$ 1,766.5	$ 17,695.9
Sault #3 115kV Line Upgrade	-	1,022.7	6,162.9	5,238.4	8,549.1	20,973.1
Engineering - Transmission Lines	430.8	498.1	756.5	634.3	572.6	2,892.3
Total Transmission Line Upgrades	**6,433.0**	**7,910.9**	**8,849.0**	**7,480.1**	**10,888.2**	**41,561.2**
Station Upgrades						
Anjigami Transmission Station Upgrade	1,832.9	-	-	-	-	1,832.9
Mackay Transmission Station - T1 Transformer Replacement	1,377.0	-	-	-	-	1,377.0
Watson Transmission Station Protection Upgrades	1,382.1	-	-	-	-	1,382.1
New Generation Network	510.0	520.2	-	-	-	1,030.2
Echo River Transmission Station Upgrade	331.5	-	-	-	-	331.5
Third Line Transmission Station - T2 Transformer Replacement	3,040.6	2,630.3	-	-	-	5,671.0
Critical Spare Parts	-	520.2	530.6	541.2	-	1,592.0
Transformer Contingency Plan - Replacements & Spares	-	-	-	1,226.8	588.8	1,815.6
Hollingsworth Transmission Station Protection Upgrades	-	-	248.7	-	-	248.7
Mackay Transmission Station Relay Replacements	-	-	193.9	298.8	-	492.6
Steelton Transmission Station Upgrade	-	-	2,220.6	2,265.0	-	4,485.6
New Transmission Station - Replace Goulais & Batchawana	-	485.9	1,068.1	2,178.9	3,333.77	7,066.7
Security Camera Upgrades at Transmission Stations	-	-	-	541.2	-	541.2
Engineering - Transmission Stations	698.8	641.2	423.2	569.0	351.2	2,683.4
Transmission Line/Station Emergency Work	168.3	171.7	175.1	178.6	182.2	875.8
Total Station Upgrades	**9,341.3**	**4,969.5**	**4,860.2**	**7,799.5**	**4,456.0**	**31,426.4**
System Equipment						
Fibre Optic Network Upgrades	726.8	299.1	-	-	-	1,025.9
SCADA Hardware Refresh	-	-	-	-	1,104.1	1,104.1
SCADA Asset Management	-	-	596.9	1,826.6	-	2,423.5
Radio System Upgrade	765.0	780.3	-	-	-	1,545.3
General SCADA, Telecom, Communications Upgrades	153.0	156.1	159.2	162.4	165.6	796.2
Information Technology Refresh - Hardware & Software	255.0	260.1	265.3	270.6	276.0	1,327.0
Transportation and Work Equipment	204.0	208.1	1,485.7	649.5	220.8	2,768.0
Total System Equipment	**2,103.8**	**1,703.7**	**2,507.1**	**2,909.0**	**1,766.5**	**10,990.1**
Land and Property Rights						
Third Line Transmission Station Storage Facility Building	714.0	-	-	-	-	714.0
W23K Line ROW Expansion	153.0	156.1	-	-	-	309.1
Land Acquisitions	-	1,040.4	1,061.2	-	-	2,101.6
Minor Fixed Assets	234.6	129.0	130.2	194.8	198.7	887.4
General Building Upgrades	385.1	330.3	212.2	216.5	220.8	1,364.9
Total Land and Property Rights	**1,486.7**	**1,655.8**	**1,403.7**	**411.3**	**419.6**	**5,377.0**
Total Spend	**$ 19,364.7**	**$ 16,239.8**	**$ 17,619.9**	**$ 18,600.0**	**$ 17,530.3**	**$ 89,354.7**

GLTP 10-year Capital Expenditure Forecast

C$ in thousands

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
GLPT 10-Year Detailed Capex										
Transmission Line Upgrades	6,433	7,911	8,849	7,480	10,888	7,815	7,896	7,967	8,211	8,375
Stations Upgrade	9,341	4,969	4,860	7,800	4,456	7,682	5,010	7,348	5,308	5,414
System Equipment	2,104	1,704	2,507	2,909	1,767	3,514	5,342	2,510	3,432	3,500
Land and Property Rights	1,487	1,656	1,404	411	420	1,585	1,617	454	463	473
Total GLPT 10-Year Detailed Capex	**19,365**	**16,240**	**17,620**	**18,600**	**17,530**	**20,596**	**19,864**	**18,279**	**17,413**	**17,762**

Capital Expenditure Forecast - Base and High Case

C$ in thousands

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
GLPT 10-Year Detailed Capex										
Transmission Line Upgrades	6,433	7,911	8,849	7,480	10,888	7,815	7,896	7,967	8,211	8,375
Stations Upgrade	9,341	4,969	4,860	7,800	4,456	7,682	5,010	7,348	5,308	5,414
System Equipment	2,104	1,704	2,507	2,909	1,767	3,514	5,342	2,510	3,432	3,500
Land and Property Rights	1,487	1,656	1,404	411	420	1,585	1,617	454	463	473
Total GLPT 10-Year Detailed Capex -	**19,365**	**16,240**	**17,620**	**18,600**	**17,530**	**20,596**	**19,864**	**18,279**	**17,413**	**17,762**
Reductions for Base Case										
Station Upgrades										
Critical Spare Parts			(531)	(541)	-					
Transformer Contingency Plan - Replacements & Spares			-	(1,227)	(589)					
System Equipment										
SCADA Hardware Refresh					(1,104)					
SCADA Asset Management			(597)	(1,827)	-					
Transportation and Work Equipment			(1,486)	(649)						
Back Up Control Centre						(2,459)	(2,459)			
Costs savings from Operational programs			(300)	(300)	(500)	(500)	(500)	(500)	(500)	(500)
Adjusted **Base Case** CAPEX	**$ 19,365**	**$ 16,240**	**$ 14,707**	**$ 14,056**	**$ 15,337**	**$ 17,637**	**$ 16,905**	**$ 17,779**	**$ 16,913**	**$ 17,262**
HIGH CASE SCENARIO										
Additional 10% reductions	-	-	(1,471)	(1,406)	(1,534)	(1,764)	(1,691)	(1,778)	(1,691)	(1,726)
Adjusted HIGH CASE	**$ 19,365**	**$ 16,240**	**$ 13,236**	**$ 12,650**	**$ 13,804**	**$ 15,873**	**$ 15,215**	**$ 16,001**	**$ 15,222**	**$ 15,536**

Energy Probe INTERROGATORY #7

Interrogatory

Reference: Exhibit A, Tab 2, Schedule 1 Tables 4 and 5

Comparing Tables 4 and 5, please list the major areas and amounts of OM&A savings, e.g. Salaries and Wages and associated savings for Business as Usual/Base/High scenarios.

Response

Please refer to Exhibit I, Tab 1, Schedule 2, for a description of the anticipated productivity improvements. The expected savings shown in Table 5 was prepared by applying percentage reductions to the 'status quo" OM&A. The overall OM&A was reduced by 10% and 30% in the Base and High scenarios. An additional $500,000 savings was also assumed in each of years 8 to 10 to reflect the future legal and financial amalgamation of the two entities.

Energy Probe INTERROGATORY #8

Interrogatory

Reference: Exhibit A, Tab 2, Schedule 1 Table 6

a) Does Hydro One have Regional SAIFI and SAIDI figures that correspond geographically to GPLTs service area?

b) If so, please provide these data.

Response

a) Yes please refer to Exhibit A, Tab 2, Schedule 1, Table 6 on Page 9. This information shows the regional Hydro One SAIFI and SAIDI figures from Mississagi TS to Martindale TS. This segment is similar to GLPT's system in terms of location, asset types, line length, delivery points, and load.

b) See part a) above.

Energy Probe INTERROGATORY #9

Interrogatory

Reference: Exhibit A, Tab 3, Schedule 1, Page 2

a) Please explain why Hydro One is proposing one of the features of RRFE - a 300 basis point ESM/Off Ramp.

b) Confirm the proposed ESM is asymmetric.

c) Please indicate if Hydro One is linking the ESM and the rebasing period. If so, describe the relationship and examples of other rebasing periods and ESM thresholds Hydro One has considered.

d) If the Board was to require a productivity offset similar to Distribution, what would Hydro One propose? Please consider historic rate increases in your response.

e) If the Board decided to set the rebasing term at 5 years with/without an option to extend, what would Hydro One's position be?

Response

a) HOI's proposal is consistent with the OEB Handbook. Page 16 of the OEB Handbook states the following:

> "the OEB determined that under the ESM, excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE. Earnings will be assessed each year once audited financial results are available and excess earnings beyond 300 basis points will be shared with customers annually. No evidence is required in support of an ESM that follows the form set out in the 2015 Report"[1].

b) Confirmed.

c) The ESM and rebasing period were selected based on the content of the OEB Handbook. The Handbook states that for any extended deferred rebasing period beyond 5 years an ESM is required. HOI did not consider any other rebasing periods and ESM thresholds than what was described in the Handbook.

d) Please refer to Exhibit I, Tab 1, Schedule 7.

[1] Page 16 of the OEB Handbook

e) A rebasing term of 5 years would not provide HOI with an adequate duration to have cost efficiencies offset the transaction costs. The term of the deferral period is one that is selected by the applicant and does not require justification. Given this, HOI would not expect the OEB to impose a deferral period that is different from what has been applied for.

Energy Probe INTERROGATORY #10

Interrogatory

Reference: Exhibit A, Tab 3, Schedule 1, Page3, line 6

Preamble: In the absence of audited financial statements, GLPT's last available audited financial statement will serve as a proxy for the achieved ROE amount (excluding one-time extraordinary, unusual items and any OEB-approved adjustments) for purposes of calculating shared earnings.

a) Please provide the following Financial Pro-formas 2017-2026 for GLPT using the data in Tables 2-5.
   i) Business as usual (No Merger)
   ii) Base (Savings)
   iii) High (Savings)

   Please provide in Active XLS format.

b) Please illustrate using the pro-forma(s), with rates increasing at inflation, the annual revenue requirement for each case and the return to Hydro One assuming the $222 million Acquisition Costs are recovered in rates over a) 5 years and b) 10 years? Please provide all assumptions.

Response

a) Financial Pro-formas (Balance Sheet, Income Statement, Statement of Cash Flows) for the following scenarios are provided:
   i. For the Business as Usual (No Merger), refer to Attachment 1.
      Assumption: GLPT is a limited partnership and as such does not pay income taxes (the tax will be calculated on GLPT distributions made to owners at the ownership level). However, for purposes of illustrating after-tax earnings of the regulated utility, the income statement includes a corporate tax provision based on 26.5% of income before taxes. The pro-forma financial statements assume that the tax liability established by GLPT is paid in the year established using funds generated by GLPT.
   ii. For the Base (Savings) assuming HOI ownership, refer to Attachment 2.
   iii. For the High (Savings) assuming HOI ownership, refer to Attachment 3.

   For scenarios ii and iii, taxes are assumed to be calculated and paid in GLPT and are therefore presented consistently with the Pro-Forma's provided in Attachment 1.

   An active Excel.XLS model is provided as Attachment 4.

b) The attached Excel model includes a tab called ‘Assumptions’ which contains the modeling assumptions and enables the user to switch between the three scenarios requested in a) above.

Acquisition costs will be paid by HOI in year 0 (i.e., at the close of the transaction). These costs will not be recovered in rates or form part of GLPT’s future revenue requirements. HOI’s acquisition costs will therefore not be amortized and recovered in GLPT’s revenue requirement under either a 5 or 10 year period.

Great Lakes Power Transmission LP
Pro-Forma Financial Statements

Scenario 1 : Status Quo (No Merger)

For the Years Ending December 31, 2017 - December 31, 2026

Great Lakes Power Transmission LP

Balance Sheet - Annual

Scenario 1 : Status Quo (No Merger)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Assets										
Current assets										
Cash	$ 3,040,000	$ 3,190,000	$ 2,960,000	$ 2,200,000	$ 3,280,000	$ 2,290,000	$ 3,330,000	$ 3,460,000	$ 3,150,000	$ 2,890,000
Trade and other receivables	3,400,000	3,400,000	3,500,000	3,600,000	3,700,000	3,800,000	3,900,000	4,000,000	4,100,000	4,200,000
Prepaid expenses and other	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
	6,840,000	6,990,000	6,860,000	6,200,000	7,380,000	6,490,000	7,630,000	7,860,000	7,650,000	7,490,000
Property, plant and equipment										
Gross	283,300,000	299,500,000	317,100,000	335,700,000	353,200,000	373,800,000	393,700,000	412,000,000	429,400,000	447,200,000
CWIP	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000
Accum. deprec.	(54,100,000)	(63,700,000)	(73,900,000)	(84,200,000)	(94,900,000)	(106,100,000)	(117,600,000)	(129,400,000)	(141,500,000)	(153,850,000)
Property, plant and equipment, net	230,900,000	237,500,000	244,900,000	253,200,000	260,000,000	269,400,000	277,800,000	284,300,000	289,600,000	295,050,000
	$ 237,740,000	**$ 244,490,000**	**$ 251,760,000**	**$ 259,400,000**	**$ 267,380,000**	**$ 275,890,000**	**$ 285,430,000**	**$ 292,160,000**	**$ 297,250,000**	**$ 302,540,000**
Liabilities and Partners' equity										
Current liabilities										
Trade and other payables	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000
Current portion of Trans senior bonds	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000	94,700,000	-	-	-	-
Due to related parties	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
	5,800,000	6,000,000	6,200,000	6,400,000	6,600,000	97,900,000	3,200,000	3,200,000	3,200,000	3,200,000
Pension liability	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000
Trans senior bonds	106,000,000	103,400,000	100,600,000	97,600,000	94,400,000	-	-	-	-	-
New debt	-	-	-	-	-	-	161,100,000	161,300,000	161,500,000	161,700,000
	115,300,000	112,900,000	110,300,000	107,500,000	104,500,000	101,400,000	167,800,000	168,000,000	168,200,000	168,400,000
Partners' equity	122,440,000	131,590,000	141,460,000	151,900,000	162,880,000	174,490,000	117,630,000	124,160,000	129,050,000	134,140,000
	$ 237,740,000	**$ 244,490,000**	**$ 251,760,000**	**$ 259,400,000**	**$ 267,380,000**	**$ 275,890,000**	**$ 285,430,000**	**$ 292,160,000**	**$ 297,250,000**	**$ 302,540,000**

Great Lakes Power Transmission LP

Income Statement - Annual

Scenario 1 : Status Quo (No Merger)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Revenues										
Transmission revenues	$ 39,540,000	$ 40,750,000	$ 42,270,000	$ 43,240,000	$ 44,480,000	$ 46,010,000	$ 47,240,000	$ 48,430,000	$ 49,390,000	$ 50,340,000
Regulatory account collection	800,000	-	-	-	-	-	-	-	-	-
Total Revenues	**40,340,000**	**40,750,000**	**42,270,000**	**43,240,000**	**44,480,000**	**46,010,000**	**47,240,000**	**48,430,000**	**49,390,000**	**50,340,000**
Operating Expenses										
Operations and administration	9,300,000	9,500,000	9,600,000	9,900,000	10,000,000	10,300,000	10,400,000	10,700,000	10,800,000	11,100,000
Depreciation and amortization	9,300,000	9,600,000	10,200,000	10,300,000	10,700,000	11,200,000	11,500,000	11,800,000	12,100,000	12,350,000
Maintenance	2,100,000	2,100,000	2,200,000	2,200,000	2,300,000	2,300,000	2,400,000	2,400,000	2,500,000	2,500,000
Taxes, other than income taxes	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Total Operating Expenses	**20,800,000**	**21,300,000**	**22,100,000**	**22,500,000**	**23,100,000**	**23,900,000**	**24,400,000**	**25,000,000**	**25,500,000**	**26,050,000**
Net Operating Income	**19,540,000**	**19,450,000**	**20,170,000**	**20,740,000**	**21,380,000**	**22,110,000**	**22,840,000**	**23,430,000**	**23,890,000**	**24,290,000**
Finance costs	7,300,000	7,100,000	6,900,000	6,700,000	6,500,000	6,400,000	8,400,000	10,600,000	10,600,000	10,600,000
Other income	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Income before taxes	12,340,000	12,450,000	13,370,000	14,140,000	14,980,000	15,810,000	14,540,000	12,930,000	13,390,000	13,790,000
Corporate tax provision	3,300,000	3,300,000	3,500,000	3,700,000	4,000,000	4,200,000	3,900,000	3,400,000	3,500,000	3,700,000
Net Income	**$ 9,040,000**	**$ 9,150,000**	**$ 9,870,000**	**$ 10,440,000**	**$ 10,980,000**	**$ 11,610,000**	**$ 10,640,000**	**$ 9,530,000**	**$ 9,890,000**	**$ 10,090,000**

Great Lakes Power Transmission LP

Statement of Cash Flows - Annual

Scenario 1 : Status Quo (No Merger)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Operating Activities										
Net Income	$ 9,040,000	$ 9,150,000	$ 9,870,000	$ 10,440,000	$ 10,980,000	$ 11,610,000	$ 10,640,000	$ 9,530,000	$ 9,890,000	$ 10,090,000
Items not affecting cash;										
Depreciation and amortization	9,300,000	9,600,000	10,200,000	10,300,000	10,700,000	11,200,000	11,500,000	11,800,000	12,100,000	12,350,000
Finance costs	7,300,000	7,100,000	6,900,000	6,700,000	6,500,000	6,400,000	8,400,000	10,600,000	10,600,000	10,600,000
Net change in non-cash working capital & other	-	-	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Operating cash flows before interest	25,640,000	25,850,000	26,870,000	27,340,000	28,080,000	29,110,000	30,440,000	31,830,000	32,490,000	32,940,000
Cash interest paid	(7,400,000)	(7,200,000)	(7,000,000)	(6,800,000)	(6,600,000)	(6,400,000)	(8,500,000)	(10,700,000)	(10,700,000)	(10,700,000)
	18,240,000	18,650,000	19,870,000	20,540,000	21,480,000	22,710,000	21,940,000	21,130,000	21,790,000	22,240,000
Investing Activities										
Additions to property, plant and equipment	(19,100,000)	(15,900,000)	(17,300,000)	(18,300,000)	(17,200,000)	(20,300,000)	(19,600,000)	(18,000,000)	(17,100,000)	(17,500,000)
	(19,100,000)	(15,900,000)	(17,300,000)	(18,300,000)	(17,200,000)	(20,300,000)	(19,600,000)	(18,000,000)	(17,100,000)	(17,500,000)
Financing Activities										
Principal repayment - Trans senior bonds	(2,500,000)	(2,600,000)	(2,800,000)	(3,000,000)	(3,200,000)	(3,400,000)	(94,800,000)	-	-	-
New debt (repayment)	-	-	-	-	-	-	161,000,000	-	-	-
Distributions paid	(1,000,000)	-	-	-	-	-	(67,500,000)	(3,000,000)	(5,000,000)	(5,000,000) *
	(3,500,000)	(2,600,000)	(2,800,000)	(3,000,000)	(3,200,000)	(3,400,000)	(1,300,000)	(3,000,000)	(5,000,000)	(5,000,000)
(Decrease) increase in cash	(4,360,000)	150,000	(230,000)	(760,000)	1,080,000	(990,000)	1,040,000	130,000	(310,000)	(260,000)
Cash, beginning balance	7,400,000	3,040,000	3,190,000	2,960,000	2,200,000	3,280,000	2,290,000	3,330,000	3,460,000	3,150,000
Cash, ending balance	**$ 3,040,000**	**$ 3,190,000**	**$ 2,960,000**	**$ 2,200,000**	**$ 3,280,000**	**$ 2,290,000**	**$ 3,330,000**	**$ 3,460,000**	**$ 3,150,000**	**$ 2,890,000**

* Adjust distributions paid to arrive at appropriate level of closing cash balance

Great Lakes Power Transmission LP
Pro-Forma Financial Statements

Scenario 2 : Base Savings (HOI Ownership)

For the Years Ending December 31, 2017 - December 31, 2026

Great Lakes Power Transmission LP

Balance Sheet - Annual

Scenario 2 : Base Savings (HOI Ownership)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Assets										
Current assets										
Cash	$ 3,040,000	$ 3,190,000	$ 6,150,000	$ 10,140,000	$ 13,380,000	$ 14,890,000	$ 10,580,000	$ 10,970,000	$ 10,780,000	$ 10,820,000
Trade and other receivables	3,400,000	3,400,000	3,500,000	3,500,000	3,600,000	3,700,000	3,700,000	3,800,000	3,900,000	4,000,000
Prepaid expenses and other	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
	6,840,000	6,990,000	10,050,000	14,040,000	17,380,000	18,990,000	14,680,000	15,170,000	15,080,000	15,220,000
Property, plant and equipment										
Gross	283,300,000	299,500,000	314,200,000	328,300,000	343,600,000	361,200,000	378,100,000	395,900,000	412,800,000	430,100,000
CWIP	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000
Accum. deprec.	(54,100,000)	(63,700,000)	(73,800,000)	(84,000,000)	(94,500,000)	(105,400,000)	(116,600,000)	(128,100,000)	(139,900,000)	(151,900,000)
Property, plant and equipment, net	230,900,000	237,500,000	242,100,000	246,000,000	250,800,000	257,500,000	263,200,000	269,500,000	274,600,000	279,900,000
	$ 237,740,000	**$ 244,490,000**	**$ 252,150,000**	**$ 260,040,000**	**$ 268,180,000**	**$ 276,490,000**	**$ 277,880,000**	**$ 284,670,000**	**$ 289,680,000**	**$ 295,120,000**
Liabilities and Partners' equity										
Current liabilities										
Trade and other payables	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000
Current portion of Trans senior bonds	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000	94,700,000	-	-	-	-
Due to related parties	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
	5,800,000	6,000,000	6,200,000	6,400,000	6,600,000	97,900,000	3,200,000	3,200,000	3,200,000	3,200,000
Pension liability	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000
Trans senior bonds	106,000,000	103,400,000	100,600,000	97,600,000	94,400,000	-	-	-	-	-
New debt	-	-	-	-	-	-	153,200,000	153,400,000	153,600,000	153,800,000
	115,300,000	112,900,000	110,300,000	107,500,000	104,500,000	101,400,000	159,900,000	160,100,000	160,300,000	160,500,000
Partners' equity	122,440,000	131,590,000	141,850,000	152,540,000	163,680,000	175,090,000	117,980,000	124,570,000	129,380,000	134,620,000
	$ 237,740,000	**$ 244,490,000**	**$ 252,150,000**	**$ 260,040,000**	**$ 268,180,000**	**$ 276,490,000**	**$ 277,880,000**	**$ 284,670,000**	**$ 289,680,000**	**$ 295,120,000**

Great Lakes Power Transmission LP

Income Statement - Annual

Scenario 2 : Base Savings (HOI Ownership)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Revenues										
Transmission revenues	$ 39,540,000	$ 40,750,000	$ 41,560,000	$ 42,390,000	$ 43,240,000	$ 44,110,000	$ 44,990,000	$ 45,890,000	$ 46,810,000	$ 47,740,000
Regulatory account collection	800,000	-	-	-	-	-	-	-	-	-
Total Revenues	**40,340,000**	**40,750,000**	**41,560,000**	**42,390,000**	**43,240,000**	**44,110,000**	**44,990,000**	**45,890,000**	**46,810,000**	**47,740,000**
Operating Expenses										
Operations and administration	9,300,000	9,500,000	8,400,000	8,700,000	8,800,000	9,000,000	9,100,000	8,900,000	9,000,000	9,200,000
Depreciation and amortization	9,300,000	9,600,000	10,100,000	10,200,000	10,500,000	10,900,000	11,200,000	11,500,000	11,800,000	12,000,000
Maintenance	2,100,000	2,100,000	2,200,000	2,200,000	2,300,000	2,300,000	2,400,000	2,400,000	2,500,000	2,500,000
Taxes, other than income taxes	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Total Operating Expenses	**20,800,000**	**21,300,000**	**20,800,000**	**21,200,000**	**21,700,000**	**22,300,000**	**22,800,000**	**22,900,000**	**23,400,000**	**23,800,000**
Net Operating Income	**19,540,000**	**19,450,000**	**20,760,000**	**21,190,000**	**21,540,000**	**21,810,000**	**22,190,000**	**22,990,000**	**23,410,000**	**23,940,000**
Finance costs	7,300,000	7,100,000	6,900,000	6,700,000	6,500,000	6,400,000	8,100,000	10,100,000	10,100,000	10,100,000
Other income	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Income before taxes	12,340,000	12,450,000	13,960,000	14,590,000	15,140,000	15,510,000	14,190,000	12,990,000	13,410,000	13,940,000
Corporate tax provision	3,300,000	3,300,000	3,700,000	3,900,000	4,000,000	4,100,000	3,800,000	3,400,000	3,600,000	3,700,000
Net Income	**$ 9,040,000**	**$ 9,150,000**	**$ 10,260,000**	**$ 10,690,000**	**$ 11,140,000**	**$ 11,410,000**	**$ 10,390,000**	**$ 9,590,000**	**$ 9,810,000**	**$ 10,240,000**

Great Lakes Power Transmission LP

Statement of Cash Flows - Annual

Scenario 2 : Base Savings (HOI Ownership)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Operating Activities										
Net Income	$ 9,040,000	$ 9,150,000	$ 10,260,000	$ 10,690,000	$ 11,140,000	$ 11,410,000	$ 10,390,000	$ 9,590,000	$ 9,810,000	$ 10,240,000
Items not affecting cash;										
Depreciation and amortization	9,300,000	9,600,000	10,100,000	10,200,000	10,500,000	10,900,000	11,200,000	11,500,000	11,800,000	12,000,000
Finance costs	7,300,000	7,100,000	6,900,000	6,700,000	6,500,000	6,400,000	8,100,000	10,100,000	10,100,000	10,100,000
Net change in non-cash working capital & other	-	-	(100,000)	-	(100,000)	(100,000)	-	(100,000)	(100,000)	(100,000)
Operating cash flows before interest	25,640,000	25,850,000	27,160,000	27,590,000	28,040,000	28,610,000	29,690,000	31,090,000	31,610,000	32,240,000
Cash interest paid	(7,400,000)	(7,200,000)	(7,000,000)	(6,800,000)	(6,600,000)	(6,400,000)	(8,200,000)	(10,200,000)	(10,200,000)	(10,200,000)
	18,240,000	18,650,000	20,160,000	20,790,000	21,440,000	22,210,000	21,490,000	20,890,000	21,410,000	22,040,000
Investing Activities										
Additions to property, plant and equipment	(19,100,000)	(15,900,000)	(14,400,000)	(13,800,000)	(15,000,000)	(17,300,000)	(16,600,000)	(17,500,000)	(16,600,000)	(17,000,000)
	(19,100,000)	(15,900,000)	(14,400,000)	(13,800,000)	(15,000,000)	(17,300,000)	(16,600,000)	(17,500,000)	(16,600,000)	(17,000,000)
Financing Activities										
Principal repayment - Trans senior bonds	(2,500,000)	(2,600,000)	(2,800,000)	(3,000,000)	(3,200,000)	(3,400,000)	(94,800,000)	-	-	-
New debt (repayment)	-	-	-	-	-	-	153,100,000	-	-	-
Distributions paid	(1,000,000)	-	-	-	-	-	(67,500,000)	(3,000,000)	(5,000,000)	(5,000,000) *
	(3,500,000)	(2,600,000)	(2,800,000)	(3,000,000)	(3,200,000)	(3,400,000)	(9,200,000)	(3,000,000)	(5,000,000)	(5,000,000)
(Decrease) increase in cash	(4,360,000)	150,000	2,960,000	3,990,000	3,240,000	1,510,000	(4,310,000)	390,000	(190,000)	40,000
Cash, beginning balance	7,400,000	3,040,000	3,190,000	6,150,000	10,140,000	13,380,000	14,890,000	10,580,000	10,970,000	10,780,000
Cash, ending balance	**$ 3,040,000**	**$ 3,190,000**	**$ 6,150,000**	**$ 10,140,000**	**$ 13,380,000**	**$ 14,890,000**	**$ 10,580,000**	**$ 10,970,000**	**$ 10,780,000**	**$ 10,820,000**

* Adjust distributions paid to arrive at appropriate level of closing cash balance

Great Lakes Power Transmission LP
Pro-Forma Financial Statements

Scenario 3 : High Savings (HOI Ownership)

For the Years Ending December 31, 2017 - December 31, 2026

Great Lakes Power Transmission LP

Balance Sheet - Annual

Scenario 3 : High Savings (HOI Ownership)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Assets										
Current assets										
Cash	$ 3,040,000	$ 3,190,000	$ 9,450,000	$ 16,740,000	$ 23,280,000	$ 28,390,000	$ 23,580,000	$ 27,870,000	$ 31,580,000	$ 35,520,000
Trade and other receivables	3,400,000	3,400,000	3,500,000	3,500,000	3,600,000	3,700,000	3,700,000	3,800,000	3,900,000	4,000,000
Prepaid expenses and other	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
	6,840,000	6,990,000	13,350,000	20,640,000	27,280,000	32,490,000	27,680,000	32,070,000	35,880,000	39,920,000
Property, plant and equipment										
Gross	283,300,000	299,500,000	312,700,000	325,400,000	339,200,000	355,000,000	370,200,000	386,200,000	401,400,000	417,000,000
CWIP	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000
Accum. deprec.	(54,100,000)	(63,700,000)	(73,800,000)	(84,000,000)	(94,500,000)	(105,400,000)	(116,500,000)	(127,900,000)	(139,600,000)	(151,500,000)
Property, plant and equipment, net	230,900,000	237,500,000	240,600,000	243,100,000	246,400,000	251,300,000	255,400,000	260,000,000	263,500,000	267,200,000
	$ 237,740,000	**$ 244,490,000**	**$ 253,950,000**	**$ 263,740,000**	**$ 273,680,000**	**$ 283,790,000**	**$ 283,080,000**	**$ 292,070,000**	**$ 299,380,000**	**$ 307,120,000**
Liabilities and Partners' equity										
Current liabilities										
Trade and other payables	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000
Current portion of Trans senior bonds	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000	94,700,000	-	-	-	-
Due to related parties	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
	5,800,000	6,000,000	6,200,000	6,400,000	6,600,000	97,900,000	3,200,000	3,200,000	3,200,000	3,200,000
Pension liability	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000
Trans senior bonds	106,000,000	103,400,000	100,600,000	97,600,000	94,400,000	-	-	-	-	-
New debt	-	-	-	-	-	-	149,000,000	149,200,000	149,400,000	149,600,000
	115,300,000	112,900,000	110,300,000	107,500,000	104,500,000	101,400,000	155,700,000	155,900,000	156,100,000	156,300,000
Partners' equity	122,440,000	131,590,000	143,650,000	156,240,000	169,180,000	182,390,000	127,380,000	136,170,000	143,280,000	150,820,000
	$ 237,740,000	**$ 244,490,000**	**$ 253,950,000**	**$ 263,740,000**	**$ 273,680,000**	**$ 283,790,000**	**$ 283,080,000**	**$ 292,070,000**	**$ 299,380,000**	**$ 307,120,000**

Great Lakes Power Transmission LP

Income Statement - Annual

Scenario 3 : High Savings (HOI Ownership)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Revenues										
Transmission revenues	$ 39,540,000	$ 40,750,000	$ 41,560,000	$ 42,390,000	$ 43,240,000	$ 44,110,000	$ 44,990,000	$ 45,890,000	$ 46,810,000	$ 47,740,000
Regulatory account collection	800,000	-	-	-	-	-	-	-	-	-
Total Revenues	**40,340,000**	**40,750,000**	**41,560,000**	**42,390,000**	**43,240,000**	**44,110,000**	**44,990,000**	**45,890,000**	**46,810,000**	**47,740,000**
Operating Expenses										
Operations and administration	9,300,000	9,500,000	6,000,000	6,200,000	6,300,000	6,500,000	6,500,000	6,200,000	6,300,000	6,500,000
Depreciation and amortization	9,300,000	9,600,000	10,100,000	10,200,000	10,500,000	10,900,000	11,100,000	11,400,000	11,700,000	11,900,000
Maintenance	2,100,000	2,100,000	2,200,000	2,200,000	2,300,000	2,300,000	2,400,000	2,400,000	2,500,000	2,500,000
Taxes, other than income taxes	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Total Operating Expenses	**20,800,000**	**21,300,000**	**18,400,000**	**18,700,000**	**19,200,000**	**19,800,000**	**20,100,000**	**20,100,000**	**20,600,000**	**21,000,000**
Net Operating Income	**19,540,000**	**19,450,000**	**23,160,000**	**23,690,000**	**24,040,000**	**24,310,000**	**24,890,000**	**25,790,000**	**26,210,000**	**26,740,000**
Finance costs	7,300,000	7,100,000	6,900,000	6,700,000	6,500,000	6,400,000	8,000,000	9,800,000	9,800,000	9,800,000
Other income	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Income before taxes	12,340,000	12,450,000	16,360,000	17,090,000	17,640,000	18,010,000	16,990,000	16,090,000	16,510,000	17,040,000
Corporate tax provision	3,300,000	3,300,000	4,300,000	4,500,000	4,700,000	4,800,000	4,500,000	4,300,000	4,400,000	4,500,000
Net Income	**$ 9,040,000**	**$ 9,150,000**	**$ 12,060,000**	**$ 12,590,000**	**$ 12,940,000**	**$ 13,210,000**	**$ 12,490,000**	**$ 11,790,000**	**$ 12,110,000**	**$ 12,540,000**

Great Lakes Power Transmission LP

Statement of Cash Flows - Annual

Scenario 3 : High Savings (HOI Ownership)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Operating Activities										
Net Income	$ 9,040,000	$ 9,150,000	$ 12,060,000	$ 12,590,000	$ 12,940,000	$ 13,210,000	$ 12,490,000	$ 11,790,000	$ 12,110,000	$ 12,540,000
Items not affecting cash;										
Depreciation and amortization	9,300,000	9,600,000	10,100,000	10,200,000	10,500,000	10,900,000	11,100,000	11,400,000	11,700,000	11,900,000
Finance costs	7,300,000	7,100,000	6,900,000	6,700,000	6,500,000	6,400,000	8,000,000	9,800,000	9,800,000	9,800,000
Net change in non-cash working capital & other	-	-	(100,000)	-	(100,000)	(100,000)	-	(100,000)	(100,000)	(100,000)
Operating cash flows before interest	25,640,000	25,850,000	28,960,000	29,490,000	29,840,000	30,410,000	31,590,000	32,890,000	33,510,000	34,140,000
Cash interest paid	(7,400,000)	(7,200,000)	(7,000,000)	(6,800,000)	(6,600,000)	(6,400,000)	(8,100,000)	(9,900,000)	(9,900,000)	(9,900,000)
	18,240,000	18,650,000	21,960,000	22,690,000	23,240,000	24,010,000	23,490,000	22,990,000	23,610,000	24,240,000
Investing Activities										
Additions to property, plant and equipment	(19,100,000)	(15,900,000)	(12,900,000)	(12,400,000)	(13,500,000)	(15,500,000)	(14,900,000)	(15,700,000)	(14,900,000)	(15,300,000)
	(19,100,000)	(15,900,000)	(12,900,000)	(12,400,000)	(13,500,000)	(15,500,000)	(14,900,000)	(15,700,000)	(14,900,000)	(15,300,000)
Financing Activities										
Principal repayment - Trans senior bonds	(2,500,000)	(2,600,000)	(2,800,000)	(3,000,000)	(3,200,000)	(3,400,000)	(94,800,000)	-	-	-
New debt (repayment)	-	-	-	-	-	-	148,900,000	-	-	-
Distributions paid	(1,000,000)	-	-	-	-	-	(67,500,000)	(3,000,000)	(5,000,000)	(5,000,000) *
	(3,500,000)	(2,600,000)	(2,800,000)	(3,000,000)	(3,200,000)	(3,400,000)	(13,400,000)	(3,000,000)	(5,000,000)	(5,000,000)
(Decrease) increase in cash	(4,360,000)	150,000	6,260,000	7,290,000	6,540,000	5,110,000	(4,810,000)	4,290,000	3,710,000	3,940,000
Cash, beginning balance	7,400,000	3,040,000	3,190,000	9,450,000	16,740,000	23,280,000	28,390,000	23,580,000	27,870,000	31,580,000
Cash, ending balance	**$ 3,040,000**	**$ 3,190,000**	**$ 9,450,000**	**$ 16,740,000**	**$ 23,280,000**	**$ 28,390,000**	**$ 23,580,000**	**$ 27,870,000**	**$ 31,580,000**	**$ 35,520,000**

* Adjust distributions paid to arrive at appropriate level of closing cash balance

Energy Probe INTERROGATORY #11

Interrogatory

Reference: Exhibit A, Tab 1, Schedule 1, Page 8

Preamble: The rate rebasing deferral period is intended to give HOI the opportunity to realize cost savings through operational integration and the eventual amalgamation with Hydro One. Savings realized during the deferral period will be used by HOI to offset transaction costs and premiums incurred in respect of the transaction. The resulting cost structure reductions following the deferral period will be reflected in rebased rates charged to transmission customers.

Please provide rebasing periods for previous purchases in the company's transmission and distribution businesses.

Response

Since the *2007 Report on Rate-making Associated with Distributor Consolidation*, HOI has acquired 3 LDCs and no transmission companies. Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc., were all negotiated prior to the release of the March 26, 2015 amended Report, which extended the deferred period for up to 10 years. Consequently, the OEB approved a 5 year deferral period for these applications.

Energy Probe INTERROGATORY #12

Interrogatory

Reference: Exhibit A, Tab 2, Schedule 1, Table 2 and Table 4

a) Please provide the capital expenditure data back to 2010.

b) Please provide the OM&A data back to 2010.

Response

	2010	2011	2012	2013	2014	2015	2016F
GLPT Capital Expenditure ($M)	7,339	20,509	14,454	4,334	3,845	8,899	9,388
GLPT OM&A ($M)	9,568	9,581	9,411	10,719	10,695	10,730	11,233

Figures retrieved from GLPTLP Financial Statements.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #1

Interrogatory

Ref: Exhibit A, Tab 1, Schedule 1, Attachment 5, Hydro One Annual Report 2015 Page 29

Preamble: Hydro One's Annual Report 2015 states the following:

> **Great Lakes Power Transmission Purchase Agreement**
>
> On January 28, 2016, Hydro One reached an agreement to acquire from Brookfield Infrastructure various entities that own and control Great Lakes Power Transmission LP, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario, for $222 million in cash, subject to customary adjustments, plus the assumption of approximately $151 million in outstanding indebtedness. The acquisition is pending a *Competition Act* approval as well as regulatory approval from the OEB.

a) Please explain and quantify all of the "customary adjustments".

b) Please provide the status of the Competition Act approval.

c) Please identify and discuss all of the risks to HOI and GLPT associated with the proposed transaction.

d) Please identify and discuss all of the risks to ratepayers of the proposed transaction.

Response

a) The purchase agreement is filed as Attachment 2 to Exhibit A, Tab 1, Schedule 1. Article 2, Section 2.2. outlines the details of the purchase price including adjustments for deferral accounts balances and working capital. These customary adjustments are subject to change between the signing and close of the agreement, and have not been quantified. Their actual amount will be determined at the closing of the transaction.

b) Competition Bureau approval is still pending.

c) Please refer to Exhibit I, Tab 1, Schedule 2c.

d) HOI does not believe there is any additional risk to ratepayers resulting from this transaction. Quality and reliable service will be maintained. Expected efficiencies will provide benefits to ratepayers both during the extended deferred rebasing period, through the ESM, and in the long term when rates are reset with lower cost structures.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #2

Interrogatory

Ref: Exhibit A, Tab 1, Schedule 1, Page 6

a) Please provide a copy of Hydro One's audited 2015 financial statements.

Response

Please refer to Attachment 1 for the Hydro One Inc. 2015 Consolidated Financial Statements and please refer to Attachment 2 for the 2015 Hydro One Networks Inc. Transmission Business Financial Statements.

HYDRO ONE INC.
MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 11, 2016.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, management has assessed the design and operating effectiveness of the Company's internal control over financial reporting in accordance with the criteria set forth in Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2015. The effectiveness of these internal controls is reported to the Audit Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the shareholder of the Company. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit findings.

The President and Chief Executive Officer and the Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting.

On behalf of Hydro One's management:

Mayo Schmidt President and Chief Executive Officer	Michael Vels Chief Financial Officer

HYDRO ONE INC.
INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying Consolidated Financial Statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014, the consolidated statements of operations and comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of Consolidated Financial Statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free from material misstatement.

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

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

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2015 and December 31, 2014, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
February 11, 2016

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2015 and 2014

Year ended December 31 *(millions of Canadian dollars, except per share amounts)*	**2015**	**2014**
Revenues		
Distribution (includes $159 related party revenues; 2014 – $159) *(Note 23)*	4,949	4,903
Transmission (includes $1,554 related party revenues; 2014 – $1,567) *(Note 23)*	1,536	1,588
Other	44	57
	6,529	6,548
Costs		
Purchased power (includes $2,335 related party costs; 2014 – $2,633) *(Note 23)*	3,450	3,419
Operation, maintenance and administration *(Note 23)*	1,130	1,192
Depreciation and amortization *(Note 5)*	757	722
	5,337	5,333
Income before financing charges and income taxes	1,192	1,215
Financing charges *(Note 6)*	376	379
Income before income taxes	816	836
Income taxes *(Notes 7, 23)*	114	89
Net income	**702**	**747**
Other comprehensive income	–	–
Comprehensive income	**702**	**747**
Net income and comprehensive income attributable to:		
Noncontrolling interest *(Note 22)*	10	(2)
Preferred shareholder	13	18
Common shareholder	679	731
	702	**747**
Earnings per common share *(Note 20)*		
Basic	$6,340	$7,319
Diluted	$6,340	$7,319
Dividends per common share declared *(Note 19)*	$8,750	$2,696

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS
At December 31, 2015 and 2014

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Assets		
Current assets:		
Cash and cash equivalents *(Note 13)*	89	100
Accounts receivable (net of allowance for doubtful accounts – $61; 2014 – $66) *(Note 8)*	772	1,016
Due from related parties *(Note 23)*	184	224
Regulatory assets *(Note 11)*	36	31
Materials and supplies	21	23
Deferred income tax assets *(Note 7)*	19	19
Derivative instruments *(Note 13)*	–	2
Prepaid expenses and other assets	24	35
	1,145	1,450
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	25,911	25,356
Less: accumulated depreciation	9,319	9,134
	16,592	16,222
Construction in progress	1,144	1,025
Future use land, components and spares	157	154
	17,893	17,401
Other long-term assets:		
Regulatory assets *(Note 11)*	3,015	3,200
Deferred income tax assets *(Note 7)*	1,610	7
Intangible assets (net of accumulated amortization – $274; 2014 – $305) *(Note 10)*	336	276
Goodwill *(Note 4)*	163	173
Deferred debt issuance costs	34	36
Derivative instruments *(Note 13)*	1	–
Other	6	7
	5,165	3,699
Total assets	**24,203**	**22,550**

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)
At December 31, 2015 and 2014

December 31 *(millions of Canadian dollars, except number of shares)*	**2015**	**2014**
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	–	2
Short-term notes payable *(Notes 12, 13)*	1,491	–
Accounts payable	152	173
Accrued liabilities *(Notes 15, 16)*	591	611
Due to related parties *(Note 23)*	132	227
Accrued interest	96	100
Regulatory liabilities *(Note 11)*	19	47
Derivative instruments *(Note 13)*	–	3
Long-term debt payable within one year (includes $nil measured at fair value; 2014 – $252) *(Notes 12, 13)*	500	552
	2,981	1,715
Long-term debt (includes $51 measured at fair value; 2014 – $nil) *(Notes 12, 13)*	8,224	8,373
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	1,541	1,533
Pension benefit liability *(Note 15)*	952	1,236
Regulatory liabilities *(Note 11)*	236	168
Deferred income tax liabilities *(Note 7)*	206	1,313
Environmental liabilities *(Note 16)*	185	221
Net unamortized debt premiums	17	18
Due to related parties *(Note 21, 23)*	10	–
Asset retirement obligations *(Note 17)*	9	9
Long-term accounts payable and other liabilities	17	17
	3,173	4,515
Total liabilities	**14,378**	**14,603**
Contingencies and Commitments (Notes 25, 26)		
Subsequent Events (Note 28)		
Preferred shares *(Notes 18, 19)*	–	323
Noncontrolling interest subject to redemption *(Note 22)*	23	21
Equity		
Common shares *(Notes 18, 19)*	6,000	3,314
Retained earnings	3,759	4,249
Accumulated other comprehensive loss	(9)	(9)
Total Hydro One shareholder's equity	9,750	7,554
Noncontrolling interest *(Note 22)*	52	49
Total equity	**9,802**	**7,603**
	24,203	**22,550**

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the years ended December 31, 2015 and 2014

Year ended December 31, 2015 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Hydro One Shareholder's Equity**	**Non-controlling Interest** *(Note 22)*	**Total Equity**
January 1, 2015	3,314	4,249	(9)	7,554	49	7,603
Net income	–	692	–	692	7	699
Other comprehensive income	–	–	–	–	–	–
Distributions to noncontrolling interest	–	–	–	–	(4)	(4)
Dividends on preferred shares	–	(13)	–	(13)	–	(13)
Dividends on common shares	–	(875)	–	(875)	–	(875)
Common shares issued *(Note 18)*	2,923	–	–	2,923	–	2,923
Hydro One Brampton spin-off *(Note 4)*	(196)	(258)	–	(454)	–	(454)
Hydro One Telecom and MBSI spin-offs *(Note 4)*	(41)	(36)	–	(77)	–	(77)
December 31, 2015	6,000	3,759	(9)	9,750	52	9,802

Year ended December 31, 2014 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Hydro One Shareholder's Equity**	**Non-controlling Interest** *(Note 22)*	**Total Equity**
January 1, 2014	3,314	3,787	(9)	7,092	–	7,092
Net income	–	749	–	749	(1)	748
Other comprehensive income	–	–	–	–	–	–
Amount contributed by noncontrolling interest	–	–	–	–	50	50
Dividends on preferred shares	–	(18)	–	(18)	–	(18)
Dividends on common shares	–	(269)	–	(269)	–	(269)
December 31, 2014	3,314	4,249	(9)	7,554	49	7,603

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2015 and 2014

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Operating activities		
Net income	702	747
Environmental expenditures	(19)	(18)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	667	641
Regulatory assets and liabilities	(3)	(69)
Deferred income taxes *(Note 7)*	(2,817)	10
Other	24	–
Changes in non-cash balances related to operations *(Note 24)*	187	(55)
Net cash from (used in) operating activities	(1,259)	1,256
Financing activities		
Long-term debt issued	350	628
Long-term debt retired	(585)	(776)
Short-term notes issued	1,491	–
Common shares issued	2,600	–
Dividends paid	(888)	(287)
Amount contributed by noncontrolling interest *(Note 22)*	–	72
Distributions paid to noncontrolling interest	(5)	–
Change in bank indebtedness	(2)	(29)
Other	(7)	(3)
Net cash from (used in) financing activities	2,954	(395)
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(1,594)	(1,481)
Intangible assets	(37)	(23)
Capital contributions received *(Note 24)*	62	–
Acquisition of Haldimand Hydro *(Note 4)*	(66)	–
Acquisition of Woodstock Hydro *(Note 4)*	(24)	–
Investment in Hydro One Brampton *(Note 4)*	(53)	–
Acquisition of Norfolk Power *(Note 4)*	–	(66)
Proceeds from investment	–	250
Other	6	(6)
Net cash used in investing activities	(1,706)	(1,326)
Net change in cash and cash equivalents	(11)	(465)
Cash and cash equivalents, beginning of year	100	565
Cash and cash equivalents, end of year	**89**	**100**

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by Hydro One Limited.

On October 31, 2015, Hydro One Limited, a subsidiary of the Province of Ontario (Province), acquired Hydro One. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

In November 2015, Hydro One Limited and the Province completed an initial public offering (IPO) on the Toronto Stock Exchange of 15% of Hydro One Limited's 595 million outstanding common shares. See Note 18 for reorganization of Hydro One.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries. Intercompany transactions and balances have been eliminated.

On August 31, 2015, Hydro One completed the spin-off of its subsidiary, Hydro One Brampton Networks Inc. (Hydro One Brampton) to the Province. See note 4 – Business Combinations. These Consolidated Financial Statements include the results of operations of Hydro One Brampton up to August 31, 2015.

On November 6, 2015, Hydro One completed the spin-off of its subsidiaries, Hydro One Telecom Inc. (Hydro One Telecom) and Municipal Billing Services Inc. (MBSI). See note 4 – Business Combinations. These Consolidated Financial Statements include the results of operations of Hydro One Telecom and MBSI up to November 6, 2015.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

Hydro One performed an evaluation of subsequent events through to February 11, 2016, the date these Consolidated Financial Statements were issued, to determine whether any events or transactions warranted recognition and disclosure in these Consolidated Financial Statements. See Note 28 – Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations, goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

The Company's Transmission Business consists of the transmission business of Hydro One Networks, as well as its 66% interest in B2M Limited Partnership (B2M LP). The Company's Distribution Business consists of the distribution businesses of Hydro One Networks, Haldimand County Utilities Inc. (Haldimand Hydro), Hydro One Remote Communities Inc. (Hydro One Remote Communities), and Woodstock Hydro Holdings Inc. (Woodstock Hydro).

The Ontario Energy Board (OEB) has approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' transmission and distribution businesses, as well as by Hydro One Remote Communities.

Transmission

On January 8, 2015, pursuant to an application filed with the OEB, the OEB approved the 2015 Hydro One transmission rates revenue requirement, excluding the B2M LP revenue requirement, of $1,477 million.

On June 30, 2015, B2M LP updated its application (originally filed March 30, 2015) with the OEB for 2015-2019 transmission rates, requesting approval of revenue requirement of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. On December 29, 2015, the OEB issued a Decision and Order approving the 2015-2019 rates revenue requirement, and on January 14, 2016, the OEB approved the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes.

Distribution

On March 12, 2015, the OEB issued a Decision and Rate Order approving a revenue requirement of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The revenue requirements for 2016 and 2017 are estimates that may change based on 2016 and 2017 Rate Orders. On April 23, 2015, the Final Rate Order for 2015 rates was approved by the OEB.

On September 24, 2014, Hydro One Remote Communities filed an Incentive Regulation Mechanism application with the OEB for 2015 rates, seeking approval for increased base rates for the distribution and generation of electricity of 1.7%. On March 19, 2015, the OEB approved an increase of approximately 1.6% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2015.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. Unbilled revenues are based on an estimate of electricity delivered determined by historical trends of consumption and are estimated at the end of each month. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The existing allowance for doubtful accounts will continue to be affected by changes in volume, prices and economic conditions.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to shareholders of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income (loss) and other comprehensive income (loss) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Income Taxes

By virtue of being wholly owned by the Province, Hydro One was exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (Federal Tax Regime). However, under the *Electricity Act*, Hydro One was required to make payments in lieu of tax (PILs) to the Ontario Electricity Financial Corporation (OEFC) (PILs Regime). The PILs were, in general, based on the amount of tax that Hydro One would otherwise be liable to pay under the Federal Tax Regime if it was not exempt from taxes under those statutes.

In connection with the IPO of Hydro One Limited, Hydro One's exemption from tax under the Federal Tax Regime ceased to apply. Upon exiting the PILs Regime, Hydro One is required to make corporate income tax payments to the Canada Revenue Agency (CRA) under the Federal Tax Regime.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2015. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Transmission	56 years	1% – 2%	2%
Distribution	46 years	1% – 7%	2%
Communication	16 years	1% – 15%	6%
Administration and service	18 years	1% – 20%	6%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rate for computer applications software and other intangible assets is 10%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

For the year ended December 31, 2015, based on the qualitative assessment performed as at September 30, 2015, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2015.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitored the assets of its unregulated Hydro One Telecom subsidiary prior to spin-off for indications of impairment. Management assessed the fair value of such long-lived assets using commonly accepted techniques, which included but were not limited to, the use of recent third party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset was generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2015 and 2014, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts as deferred debt issuance costs on the Consolidated Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 13 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. Additionally, the Company enters into derivative agreements that are economic hedges which either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2015 or 2014.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

Pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management’s best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year. Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan.

Post-retirement and post-employment benefits

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management’s best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period. Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded at each year end based on annual actuarial reports.

For post-retirement benefits, all actuarial gains or losses are deferred using the “corridor” approach. The amount calculated above the “corridor” is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the “corridor” approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Multiemployer Pension Plan

Former employees of Haldimand Hydro and Woodstock Hydro participate in the Ontario Municipal Employees Retirement System Fund (OMERS Plan), a multiemployer, contributory, defined benefit public sector pension fund. Former employees of Norfolk Power Inc. (Norfolk Power) ceased to contribute to the OMERS Plan upon integration of Norfolk Power into Hydro One Networks in September 2015. These employees are now included in Hydro One’s defined benefit pension plan. OMERS Plan provides retirement pension payments based on members’ length of service and salary. Both the participating employers and members are required to make plan contributions. The OMERS Plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated by member entity. The OMERS Plan is registered with the Financial Services Commission of Ontario under Registration #0345983.

The OMERS Plan is accounted for as a defined contribution plan by Hydro One because it is not practicable to determine the present value of the Company’s obligation, the fair value of plan assets or the related current service cost applicable to employees of Haldimand Hydro and Woodstock Hydro. Hydro One recognizes its contributions to the OMERS Plan as pension expense, with a portion being capitalized. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

Stock-Based Compensation

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period, as management considers it to be probable that such costs will be recovered in the future through the rate-setting process.

The Company also records the liabilities associated with its Directors' Deferred Share Unit (DSU) Plan at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on Hydro One Limited's common share closing price at the end of each reporting period.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with contaminated land assessment and remediation and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations currently exist for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Company's asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recent Accounting Guidance Not Yet Adopted

In January 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items. This ASU eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary and to show the item separately in the income statement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Company's consolidated financial statements.

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides guidance about the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. This ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The recognition and measurement guidance for debt issuance costs are not affected. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. Upon adoption of this ASU in the first quarter of 2016, the Company's deferred debt issuance costs that are currently presented under other long-term assets will be reclassified as a deduction from the carrying amount of long-term debt.

In April 2015, the FASB issued ASU 2015-04, Compensation – Retirement Benefits (Topic 715): Practical Expedient for the Measurement Date of an Employer's Defined Benefit Obligation and Plan Assets. This ASU permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure the defined benefit plan assets and obligations using the month-end that is closest to the entity's fiscal year-end. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-05, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement. This ASU provides guidance to customers about whether a cloud computing arrangement includes a software license, as well as the related accounting for the arrangement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The Company is currently assessing the impact of adoption of this ASU on its consolidated financial statements.

In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date. This ASU defers by one year the effective date of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) issued by the FASB in May 2014. ASU 2014-09 provides guidance on revenue recognition that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The guidance in ASU 2014-09 is now effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company is currently assessing the impact of adoption of ASU 2014-09 on its consolidated financial statements.

In September 2015, the FASB issued ASU 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments. The amendments in this ASU require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period of a business combination in the reporting period in which the adjustment amounts are determined. The amendments in this update require that the acquirer to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. Upon adoption of this ASU in the first quarter of 2016, the Company will apply the guidance in this ASU to future measurement adjustments related to business combinations, as applicable.

In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes. The amendments in this ASU require that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Upon adoption of this ASU in the first quarter of 2017, the current portions of the Company's deferred income tax assets and liabilities will be reclassified as noncurrent assets and liabilities on the consolidated Balance Sheets.

In January 2016, the FASB issued ASU 2016-01, Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities. This ASU requires equity investments to be measured at fair value with changes in fair value recognized in net income, and requires enhanced disclosures and presentation of financial assets and liabilities in the financial statements. This ASU also simplifies the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company is currently assessing the impact of adoption of this ASU on its consolidated financial statements.

4. BUSINESS COMBINATIONS

Acquisition of Woodstock Hydro

On October 31, 2015, Hydro One acquired 100% of the common shares of Woodstock Hydro, an electricity distribution company located in southwestern Ontario. The total purchase price for Woodstock Hydro was approximately $32 million.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Cash and cash equivalents	3
Working capital	4
Property, plant and equipment	28
Intangible assets	1
Deferred income tax assets	2
Goodwill	17
Long-term debt	(17)
Other long-term liabilities	(2)
Post-retirement and post-employment benefit liability	(1)
Derivative instruments	(3)
	32

The preliminary determination of the fair value of assets acquired and liabilities assumed has been based upon management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. Due to the timing of the transaction, the Company has not yet completed the final fair value measurements as at December 31, 2015. In addition, the purchase agreement provides for final purchase price adjustments based on agreed working capital and other balances at the acquisition date which have not yet been finalized. The Company will continue to review information and perform further analysis prior to finalizing the total purchase price and the fair values of the assets acquired and liabilities assumed. The actual total purchase price and the fair values of the assets acquired and liabilities assumed may differ from the amounts above.

Goodwill of approximately $17 million arising from the Woodstock Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Woodstock Hydro. All of the goodwill was assigned to Hydro One's Distribution Business segment. Woodstock Hydro contributed revenues of $12 million and net income of $2 million to the Company's consolidated financial results for the year ended December 31, 2015. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Woodstock Hydro's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2015 and therefore, has not been disclosed on a pro forma basis.

Hydro One Brampton Spin-off

On August 31, 2015, Hydro One completed the spin-off of its subsidiary, Hydro One Brampton. The spin-off was accounted as a non-monetary, nonreciprocal transfer with the Province, based on its carrying values at August 31, 2015. Transactions that immediately preceded the spin-off as well as the spin-off were as follows:

- Hydro One subscribed for 357 common shares of Hydro One Brampton for an aggregate subscription price of $53 million;
- Hydro One transferred to a company wholly owned by the Province all the issued and outstanding shares of Hydro One Brampton as a dividend-in-kind; and all of the long-term intercompany debt in aggregate principal amount of $193 million plus accrued interest of $3 million owed by Hydro One Brampton to Hydro One as a return of stated capital of $196 million on its common shares.

In connection with the Hydro One Brampton spin-off, the following assets and liabilities of Hydro One Brampton were transferred:

(millions of Canadian dollars)	
Working capital	33
Property, plant and equipment and intangibles (net)	360
Other long-term assets	6
Long-term liabilities	(205)

As a result of the spin-off, goodwill related to Hydro One Brampton of $60 million was eliminated from the Consolidated Balance Sheet.

Acquisition of Haldimand Hydro

On June 30, 2015, Hydro One acquired 100% of the common shares of Haldimand Hydro, an electricity distribution company located in southwestern Ontario. The final total purchase price for Haldimand Hydro was approximately $73 million.

The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Cash and cash equivalents	3
Working capital	5
Property, plant and equipment	52
Deferred income tax assets	1
Goodwill	33
Long-term debt	(18)
Regulatory liabilities	(3)
	73

The determination of the fair value of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed.

Goodwill of approximately $33 million arising from the Haldimand Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Haldimand Hydro. All of the goodwill was assigned to Hydro One's Distribution Business segment. Haldimand Hydro contributed revenues of $32 million and net income of $6 million to the Company's consolidated financial results for the year ended December 31, 2015. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Haldimand Hydro's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2015 and therefore, has not been disclosed on a pro forma basis.

Acquisition of Norfolk Power

On August 29, 2014, Hydro One acquired 100% of the common shares of Norfolk Power, an electricity distribution and telecom company located in southwestern Ontario. Norfolk Power was a holding company for two subsidiaries, Norfolk Power Distribution Inc. (NPDI) and Norfolk Energy Inc. The total purchase price for Norfolk Power, net of the long-term debt assumed, was approximately $68 million. The purchase price was finalized in 2015, with no adjustments to the preliminary purchase price allocation as disclosed at December 31, 2014.

The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Working capital	6
Property, plant and equipment	56
Deferred income tax assets	1
Goodwill	40
Bank indebtedness	(3)
Derivative instruments	(3)
Long-term debt	(26)
Post-retirement and post-employment benefit liability	(1)
Environmental liability	(1)
Long-term accounts payable and other liabilities	(1)
	68

The determination of the fair values of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed.

Goodwill of approximately $40 million arising from the Norfolk Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Norfolk Power. All of the goodwill was assigned to Hydro One's Distribution Business segment. Norfolk Power contributed revenues of $18 million and net income of less than $1 million to the Company's consolidated financial results for the year ended December 31, 2014. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Norfolk Power's financial information was not material to the Company's consolidated financial results for the year ended December 31, 2014 and therefore, has not been disclosed on a pro forma basis.

Other

On November 6, 2015, Hydro One completed the spin-off of its subsidiary, Hydro One Telecom. The spin-off was accounted as a non-monetary, nonreciprocal transfer with Hydro One Limited, based on its carrying values at November 6, 2015. Hydro One transferred to Hydro One Limited all the issued and outstanding shares of Hydro One Telecom totalling $17 million, and all of the intercompany debt receivable held by Hydro One due from Hydro One Telecom and Hydro One Telecom Link Limited totalling $21 million, as a return of stated capital of $38 million on its common shares.

On November 6, 2015, Hydro One completed the spin-off of its subsidiary, MBSI. The spin-off was accounted as a non-monetary, nonreciprocal transfer with Hydro One Limited, based on its carrying values at November 6, 2015. Hydro One transferred to Hydro One Limited all the issued and outstanding shares of MBSI and all of the intercompany debt receivable held by Hydro One due from MBSI, as a return of stated capital of $3 million on its common shares.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Depreciation of property, plant and equipment	594	565
Amortization of intangible assets	54	53
Asset removal costs	90	81
Amortization of regulatory assets	19	23
	757	722

6. FINANCING CHARGES

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Interest on long-term debt	417	432
Other	16	12
Less: Interest capitalized on construction and development in progress	(52)	(49)
Gain on interest-rate swap agreements	(2)	(10)
Interest earned on investments	(3)	(6)
	376	379

7. INCOME TAXES

Income taxes / provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Income taxes / provision for PILs at statutory rate	216	222
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(37)	(72)
Pension contributions in excess of pension expense	(25)	(24)
Overheads capitalized for accounting but deducted for tax purposes	(15)	(15)
Interest capitalized for accounting but deducted for tax purposes	(13)	(13)
Environmental expenditures	(5)	(5)
Non-refundable investment tax credits	(2)	(3)
Post-retirement and post-employment benefit expense in excess of cash payments	(1)	3
Prior year's adjustments	(1)	(4)
Other	(2)	(1)
Net temporary differences	(101)	(134)
Net tax benefit resulting from transition from PILs Regime to Federal Tax Regime	(9)	–
Hydro One Brampton spin-off	7	–
Net permanent differences	1	1
Total income taxes / provision for PILs	114	89

The major components of income tax expense are as follows:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Current income taxes / provision for PILs	2,931	79
Deferred income taxes / provision for (recovery of) PILs	(2,817)	10
Total income taxes / provision for PILs	114	89
Effective income tax rate	13.97%	10.63%

The provision for PILs / current income taxes is remitted to, or received from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime). At December 31, 2015, $12 million (2014 – $39 million) due from the OEFC was included in due from related parties and $1 million (2014 – $nil) due from the CRA was included in prepaid expenses and other assets on the Consolidated Balance Sheet.

In connection with the IPO, Hydro One's exemption from tax under the Federal Tax Regime ceased to apply. Under the PILs Regime, Hydro One was deemed to have disposed of its assets immediately before it lost its tax exempt status under the Federal Tax Regime, resulting in Hydro One making payments in lieu of tax (Departure Tax) totalling $2.6 billion. To enable Hydro One to make the Departure Tax payment, Hydro One Limited subscribed for 39,598 common shares of Hydro One for $2.6 billion. Hydro One used the proceeds of this share subscription to pay the Departure Tax.

At December 31, 2015, the total income taxes / provision for PILs includes deferred income taxes / recovery of PILs of $2,817 million (2014 – deferred provision of $10 million), including $2,798 million (2014 – $nil) resulting from transition from the PILs Regime to the Federal Tax Regime, that is not included in the rate-setting process, using the liability method of accounting. Deferred income taxes / PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax basis of the Company's assets and liabilities. At December 31, 2015 and 2014, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	918	(4)
Post-retirement and post-employment benefits expense in excess of cash payments	572	8
Environmental expenditures	75	4
Non-capital losses	62	–
Other	2	(1)
Total deferred income tax assets	1,629	7
Less: current portion	19	–
	1,610	7

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	(153)	(140)
Partnership interest	(41)	(38)
Goodwill	(10)	(21)
Capital cost allowance in excess of depreciation and amortization	(1)	(1,713)
Post-retirement and post-employment benefits expense in excess of cash payments	–	559
Environmental expenditures	–	59
Other	(1)	–
Total deferred income tax liabilities	(206)	(1,294)
Less: current portion	–	19
	(206)	(1,313)

During 2015 and 2014, there were no changes in the rate applicable to future taxes. The Company has recorded a valuation allowance in the amount of $278 million (2014 – $nil) in respect of non-depreciable capital property.

8. ACCOUNTS RECEIVABLE

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Accounts receivable – billed	374	496
Accounts receivable – unbilled	459	586
Accounts receivable, gross	833	1,082
Allowance for doubtful accounts	(61)	(66)
Accounts receivable, net	772	1,016

In 2015, the Company revised the method to estimate the unbilled accounts receivable by using new technology that improved the estimation process. This change has been accounted for on a prospective basis in the consolidated financial statements at December 31, 2015. At December 31, 2015, the change in estimation technology resulted in a reduction in unbilled accounts receivable of approximately $121 million, with a corresponding offset to various components of the retail settlement variance accounts (RSVA). The change in estimate had no significant impact on 2015 net income.

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2015 and 2014:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Allowance for doubtful accounts – January 1	(66)	(36)
Write-offs	37	24
Additions to allowance for doubtful accounts	(32)	(54)
Allowance for doubtful accounts – December 31	(61)	(66)

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2015 *(millions of Canadian dollars)*	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction in Progress**	**Total**
Transmission	13,803	4,625	853	10,031
Distribution	9,205	3,177	238	6,266
Communication	1,006	609	18	415
Administration and service	1,531	848	35	718
Easements	523	60	–	463
	26,068	9,319	1,144	17,893

December 31, 2014 *(millions of Canadian dollars)*	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction in Progress**	**Total**
Transmission	13,209	4,416	626	9,419
Distribution	9,076	3,225	320	6,171
Communication	1,100	615	56	541
Administration and service	1,502	793	23	732
Easements	623	85	–	538
	25,510	9,134	1,025	17,401

Financing charges capitalized on property, plant and equipment under construction were $50 million in 2015 (2014 – $48 million).

10. INTANGIBLE ASSETS

December 31, 2015 *(millions of Canadian dollars)*	**Intangible Assets**	**Accumulated Amortization**	**Development in Progress**	**Total**
Computer applications software	579	270	24	333
Other	7	4	–	3
	586	274	24	336

December 31, 2014 *(millions of Canadian dollars)*	**Intangible Assets**	**Accumulated Amortization**	**Development in Progress**	**Total**
Computer applications software	573	303	3	273
Other	5	2	–	3
	578	305	3	276

Financing charges capitalized to intangible assets under development were $1 million in 2015 (2014 – $1 million). The estimated annual amortization expense for intangible assets is as follows: 2016 – $57 million; 2017 – $57 million; 2018 – $57 million; 2019 – $47 million; and 2020 – $30 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Regulatory assets:		
Deferred income tax regulatory asset	1,445	1,327
Pension benefit regulatory asset	952	1,236
Post-retirement and post-employment benefits	240	273
Environmental	207	239
RSVA	110	11
Pension cost variance	37	90
2015-2017 rate rider	20	–
DSC exemption	10	16
Share-based compensation	10	–
B2M LP start-up costs	8	–
OEB cost assessment differential	–	12
Other	12	27
Total regulatory assets	3,051	3,231
Less: current portion	36	31
	3,015	3,200
Regulatory liabilities:		
External revenue variance	87	54
Green Energy expenditure variance	76	83
CDM deferral variance	53	25
Deferred income tax regulatory liability	23	21
PST savings deferral	4	19
Other	12	13
Total regulatory liabilities	255	215
Less: current portion	19	47
	236	168

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2015 income tax expense would have been higher by approximately $101 million (2014 – $132 million).

Pension Benefit Regulatory Asset

In accordance with OEB rate orders, pension costs are recorded on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2015 OCI would have been higher by $284 million (2014 – lower by $391 million).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2015 OCI would have been higher by $33 million (2014 – $35 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2015, the environmental regulatory asset decreased by $24 million (2014 – $33 million) to reflect related changes in the Company's PCB liability, and increased by $1 million (2014 – $13 million) due to changes in the land assessment and remediation liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2015 operation, maintenance and administration expenses would have been lower by $23 million (2014 – $20 million). In addition, 2015 amortization expense would have been lower by $19 million (2014 – $18 million), and 2015 financing charges would have been higher by $10 million (2014 – $11 million).

RSVA

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In March 2015, the OEB approved the disposition of the total RSVA balance accumulated from January 2012 to December 2013, including accrued interest, to be recovered through the 2015-2017 Rate Rider. In 2015, the Company revised its method to estimate the unbilled accounts receivable based on new technology implemented to improve the accuracy of the estimation process. At December 31, 2015, the change in estimate reduced unbilled accounts receivable by approximately $121 million, with a corresponding offset to various components of RSVA. The change in estimate had no significant impact on 2015 net income.

Pension Cost Variance

A pension cost variance account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In March 2015, the OEB approved the disposition of the distribution business portion of the total pension cost variance account at December

31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In the absence of rate-regulated accounting, 2015 revenue would have been lower by $6 million (2014 – $10 million).

2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' Distribution rate application for 2015-2019 the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account includes the balances approved for disposition by the OEB and will be disposed over a 32-month period in accordance with the OEB decision.

DSC Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the Distribution System Code (DSC), with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Network distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account, and there were no additions to this regulatory account in 2015.

Share-based Compensation

The Company recognizes costs associated with stock-based compensation in a regulatory asset as management considers it probable that stock-based compensation costs will be recovered in the future through the rate-setting process. At December 31, 2015 the stock-based compensation costs relate to the share grant plans, are measured at fair value estimated based on grant date Hydro One Limited share price and recognized using the graded-vesting attribution method. In the absence of rate-regulated accounting 2015 operation, maintenance and administration expenses would have been higher by $5 million (2014 – $nil).

B2M LP Start-up Costs

In December 2015, OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of $8 million of start-up costs relating to B2M LP. The costs will be recovered over a 4 year period beginning in 2016, in accordance with the OEB decision.

OEB Cost Assessment Differential

In April 2010, the OEB issued its Decision regarding Hydro One Networks' distribution rate application for 2010 and 2011. As part of this decision, the OEB also approved the distribution-related OEB Cost Assessment Differential Account to record the difference between the amounts approved in rates and actual expenditures with respect to the OEB's cost assessments. In March 2015, the OEB approved the disposition of the OEB Cost Assessment Differential Account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account, and there were no additions to this regulatory account in 2015.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

Green Energy Expenditure Variance

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. At December 31, 2014, the balance in the CDM deferral variance account relates to the actual 2013 CDM compared to the amounts included in 2013 revenue requirement. At December 31, 2015, the balance also includes the difference between the actual 2014 CDM compared to the amounts included in 2014 revenue requirement. The OEB rate order specifically states that the IESO (Ontario Power Authority (OPA) prior to January 1, 2015) data used to calculate the difference between forecasted and actual savings will be provided one year in arrears, and as a result, no amount should be recorded in advance of notification from the IESO of actual results.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administration expenses or capital expenditures for past revenue requirements approved during a full cost-of-service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administration expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable, and calculations for tracking and refund were requested by the OEB. For Hydro One Networks' transmission revenue requirement, PST was included between July 1, 2010 and December 31, 2010 and recorded in a deferral account, per direction from the OEB. For Hydro One Networks' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2015 and recorded in a deferral account, as directed by the OEB. In March 2015, the OEB approved the disposition of the PST Savings Deferral account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider.

12. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. The Commercial Paper Program is supported by the Company's committed revolving credit facilities totalling $2.3 billion. At December 31, 2015, Hydro One had $1,491 million in commercial paper borrowings outstanding (December 31, 2014 – $nil).

At December 31, 2015, Hydro One's consolidated committed, unsecured and unused credit facilities totalling $2.3 billion consisted of the following:

(millions of Canadian dollars)	**Maturity**	**Amount**
Revolving standby credit facility	June 2020	1,500
Three-year senior, revolving term credit facility	October 2018	800
Total		2,300

The Company may use the credit facilities for working capital and general corporate purposes. If used, interest on the credit facilities would apply based on Canadian benchmark rates. The obligation of each lender to make any credit extension under its credit facility is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3.5 billion. At December 31, 2015, $3.5 billion remained available for issuance until January 2018.

The following table presents the outstanding long-term debt at December 31, 2015 and 2014:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
2.95% Series 21 notes due 2015[1]	–	500
Floating-rate Series 22 notes due 2015[2]	–	50
4.64% Series 10 notes due 2016	450	450
Floating-rate Series 27 notes due 2016[2]	50	50
5.18% Series 13 notes due 2017	600	600
2.78% Series 28 notes due 2018	750	750
Floating-rate Series 31 notes due 2019[2]	228	228
4.40% Series 20 notes due 2020	300	300
1.62% Series 33 notes due 2020[1]	350	–
3.20% Series 25 notes due 2022	600	600
7.35% Debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
4.59% Series 29 notes due 2043	435	435
4.17% Series 32 notes due 2044	350	350
5.00% Series 11 notes due 2046	325	325
4.00% Series 24 notes due 2051	225	225
3.79% Series 26 notes due 2062	310	310
4.29% Series 30 notes due 2064	50	50
	8,723	8,923
Add: Unrealized mark-to-market loss[1]	1	2
Less: Long-term debt payable within one year	(500)	(552)
Long-term debt	8,224	8,373

[1] The unrealized mark-to-market loss relates to $50 million of the Series 33 notes due 2020 (2014 – $250 million of the Series 21 notes due 2015). The unrealized mark-to-market loss is offset by a $1 million (2014 – $2 million) unrealized mark-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 13 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[2] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

In 2015, Hydro One issued $350 million (2014 – $628 million) of long-term debt under the MTN Program, and repaid $550 million of long-term debt MTN Program notes (2014 – $750 million).

Long-term debt totalling $35 million assumed by Hydro One as part of the Haldimand Hydro and Woodstock Hydro acquisitions was repaid in 2015.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 13 – Fair Value of Financial Instruments and Risk Management.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2015 and 2014, the Company's carrying amounts of accounts receivable, due from related parties, cash and cash equivalents, bank indebtedness, short-term notes payable, accounts payable, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2015 and 2014 are as follows:

December 31 *(millions of Canadian dollars)*	**2015 Carrying Value**	**2015 Fair Value**	**2014 Carrying Value**	**2014 Fair Value**
Long-term debt				
$250 million of MTN Series 21 notes[1]	–	–	252	252
$50 million of MTN Series 33 notes[1]	51	51	–	–
Other notes and debentures[2]	8,673	9,942	8,673	10,159
	8,724	9,993	8,925	10,411

[1] The fair value of the $50 million MTN Series 33 notes and $250 million of the MTN Series 21 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of other notes and debentures, and the portion of the MTN Series 21 notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

At December 31, 2015, Hydro One had an interest-rate swap in the amount of $50 million (2014 – $250 million) that was used to convert fixed-rate debt to floating-rate debt. This swap is classified as a fair value hedge. Hydro One's fair value hedge exposure was equal to about 1% (2014 – 3%) of its total long-term debt of $8,724 million (2014 – $8,925 million). At December 31, 2015, Hydro One's interest-rate swap designated as a fair value hedge was as follows:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt.

At December 31, 2015, the Company had no interest-rate swaps classified as undesignated contracts (2014 – $409 million).

As part of the Norfolk Power and Woodstock Hydro acquisitions, Hydro One assumed liabilities associated with unrealized losses on derivative instruments (interest-rate swaps) totalling $6 million. Hydro One extinguished the interest rate swaps and repaid these liabilities in 2015.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2015 and 2014 is as follows:

December 31, 2015 *(millions of Canadian dollars)*	**Carrying Value**	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Assets:					
Cash and cash equivalents	89	89	89	–	–
Derivative instruments					
Fair value hedge – interest-rate swap	1	1	1	–	–
	90	90	90	–	–
Liabilities:					
Short-term notes payable	1,491	1,491	1,491	–	–
Long-term debt	8,724	9,993	–	9,993	–
	10,215	11,484	1,491	9,993	

December 31, 2014 *(millions of Canadian dollars)*	**Carrying Value**	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Assets:					
Cash and cash equivalents	100	100	100	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	–	2	–
	102	102	100	2	–
Liabilities:					
Bank indebtedness	2	2	2	–	–
Derivative instruments					
Undesignated contracts – interest-rate swaps	3	3	–	3	–
Long-term debt	8,925	10,411	–	10,411	–
	8,930	10,416	2	10,414	–

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the fair value levels during the years ended December 31, 2015 and 2014.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The OEB-approved adjustment formula for calculating return on equity in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark rates of return for Government of Canada debt. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining its rate of return would reduce the Company's transmission business' 2015 net income by approximately $20 million (2014 – $20 million) and its distribution business' 2015 net income by approximately $13 million (2014 – $10 million). The Company's net income is adversely impacted by rising interest rates as Hydro One's maturing long-term debt is refinanced at market rates. Hydro One periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

Hydro One uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One also uses derivative financial instruments to manage interest-rate risk. Hydro One utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2015 or 2014.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2015 and 2014 are included in financing charges as follows:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Unrealized loss (gain) on hedged debt	(1)	(3)
Unrealized loss (gain) on fair value interest-rate swaps	1	3
Net unrealized loss (gain)	–	–

At December 31, 2015, Hydro One had $50 million (2014 – $250 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $1 million (2014 – $2 million). During the years ended December 31, 2015 and 2014, there was no significant impact on the results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2015 and 2014, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. At December 31, 2015 and 2014, there was no significant accounts receivable balance due from any single customer.

At December 31, 2015, the Company's provision for bad debts was $61 million (2014 – $66 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2015, approximately 6% (2014 – 6%) of the Company's net accounts receivable were aged more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Company's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. In addition to payment netting language in master agreements, the Company establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. The Company would offset the positive market values against negative values with the same counterparty only where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with the Company as specified in each agreement. The Company monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2015, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $1 million (2014 – $3 million). At December 31, 2015, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with one financial institution as the counterparty.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby facilities totaling $2.3 billion. The short-term liquidity under the Commercial Paper Program, and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2015, accounts payable and accrued liabilities in the amount of $743 million (2014 – $784 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2015, Hydro One had long-term debt in the principal amount of $8,723 million (2014 – $8,923 million). Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of Canadian dollars)*	Weighted Average Interest Rate *(%)*
1 year	500	4.3
2 years	600	5.2
3 years	750	2.8
4 years	228	1.2
5 years	650	2.9
	2,728	3.5
6 – 10 years	600	3.2
Over 10 years	5,395	5.4
	8,723	4.7

Interest payments on long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of Canadian dollars)*
2016	397
2017	386
2018	355
2019	332
2020	322
	1,792
2021-2025	1,496
2026 +	4,080
	7,368

14. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing access to capital, the Company targets to maintain strong credit quality. The Company considers its capital structure to consist of shareholder's equity, preferred shares, long-term debt, short-term notes payable, and cash and cash equivalents. At December 31, 2015 and 2014, the Company's capital structure was as follows:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Long-term debt payable within one year	500	552
Short-term notes payable	1,491	–
Less: cash and cash equivalents	89	100
	1,902	452
Long-term debt	8,224	8,373
Preferred shares	–	323
Common shares	6,000	3,314
Retained earnings	3,759	4,249
	9,759	7,563
Total capital	19,885	16,711

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of its total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2015 and 2014, Hydro One was in compliance with all of these covenants and limitations.

15. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except employees of Haldimand Hydro and Woodstock Hydro. Employees of Haldimand Hydro and Woodstock Hydro participate in the OMERS Plan. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

The OMERS Plan

Hydro One contributions to the OMERS Plan for the year ended December 31, 2015 were $2 million (2014 – $2 million). At December 31, 2015, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2014 – less than $1 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS Plan, as indicated in OMERS' most recently available annual report for the year ended December 31, 2014.

At December 31, 2014, the OMERS Plan was 90.8% funded, with an unfunded liability of $7.1 billion. This unfunded liability could result in future payments by participating employers and members. Hydro One future contributions could be increased substantially if other entities withdraw from the plan.

Pension Plan, Post-Retirement and Post-Employment Plans

The Pension Plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2015 of $177 million (2014 – $174 million) were based on an actuarial valuation effective December 31, 2013 and the expected level of pensionable earnings. Estimated annual Pension Plan contributions for 2016 are approximately $180 million, based on the actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**	**2015**	**2014**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	7,535	6,576	1,582	1,531
Current service cost	186	145	43	41
Interest cost	302	312	64	73
Benefits paid	(334)	(319)	(47)	(45)
Net actuarial loss (gain)	(6)	821	(27)	(18)
Change due to Hydro One Brampton spin-off	–	–	(5)	–
Change due to Hydro One Telecom spin-off	–	–	(19)	–
Projected benefit obligation, end of year	7,683	7,535	1,591	1,582
Change in plan assets				
Fair value of plan assets, beginning of year	6,299	5,731	–	–
Actual return on plan assets	582	703	–	–
Benefits paid	(334)	(319)	–	–
Employer contributions	177	174	–	–
Employee contributions	40	35	–	–
Administrative expenses	(33)	(25)	–	–
Fair value of plan assets, end of year	6,731	6,299	–	–
Unfunded status	952	1,236	1,591	1,582

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 *(millions of Canadian dollars)*	**2015**	**2014**	**2015**	**2014**
Accrued liabilities	–	–	50	49
Pension benefit liability	952	1,236	–	–
Post-retirement and post-employment benefit liability	–	–	1,541	1,533
Unfunded status	952	1,236	1,591	1,582

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
PBO	7,683	7,535
ABO	7,020	6,887
Fair value of plan assets	6,731	6,299

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2015 (2014 – 91%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2015 (2014 – 84%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2015 and 2014 for the Pension Plan:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Current service cost, net of employee contributions	146	110
Interest cost	302	312
Expected return on plan assets, net of expenses	(406)	(369)
Actuarial loss amortization	119	103
Prior service cost amortization	2	2
Net periodic benefit costs	163	158
Charged to results of operations[1]	81	81

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2015, pension costs of $177 million (2014 – $174 million) were attributed to labour, of which $81 million (2014 – $81 million) was charged to operations, and $96 million (2014 – $93 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2015 and 2014 for the post-retirement and post-employment benefit plans:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Current service cost, net of employee contributions	43	41
Interest cost	64	73
Actuarial loss amortization	14	18
Prior service cost amortization	–	2
Net periodic benefit costs	121	134
Charged to results of operations	55	62

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed-income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2015 and 2014:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2015**	**2014**	**2015**	**2014**
Significant assumptions:				
Weighted average discount rate	4.00%	4.00%	4.10%	4.00%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends[1]	–	–	4.36%	4.36%

[1] 6.38% per annum in 2016, grading down to 4.36% per annum in and after 2031 (2014 – 6.52% in 2015, grading down to 4.36% per annum in and after 2031)

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2015 and 2014. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	**2015**	**2014**
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.50%	6.50%
Weighted average discount rate	4.00%	4.75%
Rate of compensation scale escalation (without merit)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	13	11
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	4.00%	4.75%
Rate of compensation scale escalation (without merit)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	13.8	12
Rate of increase in health care cost trends[1]	4.36%	4.39%

[1] 6.52% per annum in 2015, grading down to 4.36% per annum in and after 2031 (2014 – 6.81% in 2014, grading down to 4.39% per annum in and after 2031)

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2015 and 2014 is as follows:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	252	248
Effect of a 1% decrease in health care cost trends	(196)	(193)

The effect of a 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2015 and 2014 is as follows:

Year ended December 31 (millions of Canadian dollars)	**2015**	**2014**
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	22	23
Effect of a 1% decrease in health care cost trends	(16)	(17)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2015 and 2014:

December 31, 2015				December 31, 2014			
Life expectancy at 65 for a member currently at				Life expectancy at 65 for a member currently at			
Age 65		Age 45		Age 65		Age 45	
Male	Female	Male	Female	Male	Female	Male	Female
23	25	24	26	23	25	24	26

Estimated Future Benefit Payments

At December 31, 2015, estimated future benefit payments to the participants of the Plans were:

(millions of Canadian dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2016	316	53
2017	328	55
2018	339	57
2019	350	59
2020	360	61
2021 through to 2025	1,928	342
Total estimated future benefit payments through to 2025	3,621	627

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Pension Benefits:		
Actuarial loss (gain) for the year	(181)	511
Actuarial loss amortization	(119)	(103)
Prior service cost amortization	(2)	(2)
	(302)	406
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	(27)	(18)
Actuarial loss amortization	(14)	(18)
Prior service cost amortization	–	(2)
	(41)	(38)

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2015 and 2014:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Pension Benefits:		
Prior service cost	–	2
Actuarial loss	952	1,234
	952	1,236
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	240	273
	240	273

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 *(millions of Canadian dollars)*	**2015**	**2014**	**2015**	**2014**
Prior service cost	–	2	–	–
Actuarial loss	96	119	8	10
	96	121	8	10

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension Plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Human Resource Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2015, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55.0	58.2
Debt securities	35.0	36.4
Other[1]	10.0	5.4
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2015, the Pension Plan held $9 million Hydro One corporate bonds (2014 – $nil) and $420 million of debt securities of the Province (2014 – $340 million).

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2015 and 2014. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2015 and 2014, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with financial institutions rated at least "A+" by Standard & Poor's Rating Services, DBRS Limited, and Fitch Ratings Inc., and "A1" by Moody's Investors Service, and also by utilizing exposure limits to each counterparty and ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following tables present the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2015 and 2014:

December 31, 2015 *(millions of Canadian dollars)*	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	–	23	299	322
Cash and cash equivalents	191	–	–	191
Short-term securities	–	80	–	80
Real estate	–	–	2	2
Corporate shares – Canadian	923	–	–	923
Corporate shares – Foreign	2,931	–	–	2,931
Bonds and debentures – Canadian	–	2,074	–	2,074
Bonds and debentures – Foreign	–	199	–	199
Total fair value of plan assets[1]	4,045	2,376	301	6,722

[1] At December 31, 2015, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, and $18 million relating to accruals for pension administration expense and foreign exchange contracts payable.

December 31, 2014 *(millions of Canadian dollars)*	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	–	18	142	160
Cash and cash equivalents	166	–	–	166
Short-term securities	–	176	–	176
Real estate	–	–	2	2
Corporate shares – Canadian	1,008	–	–	1,008
Corporate shares – Foreign	2,766	–	–	2,766
Bonds and debentures – Canadian	–	1,799	–	1,799
Bonds and debentures – Foreign	–	211	–	211
Total fair value of plan assets[1]	3,940	2,204	144	6,288

[1] At December 31, 2014, the total fair value of Pension Plan assets excludes $18 million of interest and dividends receivable, and $7 million relating to accruals for pension administration expense.

See Note 13 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2015 and 2014. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Fair value, beginning of year	144	119
Realized and unrealized gains	51	30
Purchases	106	23
Sales and disbursements	–	(28)
Fair value, end of year	301	144

There were no significant transfers between any of the fair value levels during the years ended December 31, 2015 and 2014.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. These sensitivity analyses resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled Funds

The pooled fund category mainly consists of private equity, real estate and infrastructure investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity, real estate and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity and infrastructure investments have been categorized as Level 3 within pooled funds.

Cash Equivalents

Demand cash deposits held with banks and cash held by the investment managers are considered cash equivalents and are included in the fair value measurements hierarchy as Level 1.

Short-Term Securities

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities have been categorized as Level 2.

Real Estate

Real estate investments represent investments in holding companies that invest in real estate properties. The investments in the holding companies are valued using net asset values reported by the fund manager. Real estate investments are categorized as Level 3.

Corporate Shares

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and Debentures

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

16. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2015 and 2014:

Year ended December 31, 2015 *(millions of Canadian dollars)*	**PCB**	**Land Assessment and Remediation**	**Total**
Environmental liabilities, January 1	172	67	239
Interest accretion	8	2	10
Expenditures	(8)	(11)	(19)
Revaluation adjustment	(24)	1	(23)
Environmental liabilities, December 31	148	59	207
Less: current portion	12	10	22
	136	49	185

Year ended December 31, 2014 *(millions of Canadian dollars)*	**PCB**	**Land Assessment and Remediation**	**Total**
Environmental liabilities, January 1	201	65	266
Interest accretion	9	2	11
Expenditures	(5)	(13)	(18)
Revaluation adjustment	(33)	13	(20)
Environmental liabilities, December 31	172	67	239
Less: current portion	8	10	18
	164	57	221

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2015 *(millions of Canadian dollars)*	**PCB**	**Land Assessment and Remediation**	**Total**
Undiscounted environmental liabilities	168	61	229
Less: discounting accumulated liabilities to present value	20	2	22
Discounted environmental liabilities	148	59	207

December 31, 2014 *(millions of Canadian dollars)*	**PCB**	**Land Assessment and Remediation**	**Total**
Undiscounted environmental liabilities	195	70	265
Less: discounting accumulated liabilities to present value	23	3	26
Discounted environmental liabilities	172	67	239

At December 31, 2015, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2016	22
2017	25
2018	26
2019	28
2020	30
Thereafter	98
	229

Hydro One records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act,* 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $168 million (2014 – $195 million). These expenditures are expected to be incurred over the period from 2016 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2015 to reduce the PCB environmental liability by $24 million (2014 – $33 million).

Land Assessment and Remediation

The Company's best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $61 million (2014 –$70 million). These expenditures are expected to be incurred over the period from 2016 to 2023. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2015 to increase the land assessment and remediation environmental liability by $1 million (2014 – $13 million).

17. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2015, Hydro One had recorded asset retirement obligations of $9 million (2014 – $9 million), consisting of $8 million (2014 – $8 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $1 million (2014 – $1 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal.

18. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2015, the Company had 142,239 common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2015, Hydro One had no issued and outstanding preferred shares.

On November 2, 2015, a special resolution of Hydro One Limited (as sole shareholder of Hydro One) was made to amend the articles of Hydro One to delete the share ownership restrictions and to amend the Hydro One preferred share terms to provide for basic redeemable preferred shares. When issued, the Class A preferred shares will be redeemable at the option of the Company. The holders of the Class A preferred shares will be entitled to receive, if and when declared by the Hydro One Board of Directors, non-cumulative preferred share dividends at a rate per year to be determined by the Hydro One Board of Directors. The holders of the Class A preferred shares will not be entitled to receive notice of, or to attend or to vote at, any meeting of the shareholders of Hydro One. The holders of the Class A preferred shares will be entitled to receive, before any distributions to the holders of common shares and any other shares ranking junior to the Class A preferred shares, an amount equal to the amount paid for the Class A preferred shares together with all dividends declared and unpaid up to the date of liquidation, dissolution or winding up of Hydro One, or the date of redemption.

Prior to October 31, 2015, the Company had 12,920,000 issued and outstanding 5.5% cumulative preferred shares held by the Province, with a redemption value of $25 per share or $323 million total value. These preferred shares were entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which was payable on a quarterly basis. These preferred shares had conditions for their redemption that were outside the control of the Company because the Province could exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. At December 31, 2014, these preferred shares were classified on the Consolidated Balance Sheet as temporary equity because the redemption feature was outside the control of the Company. On October 31, 2015, these preferred shares were purchased and cancelled by Hydro One. See "Reorganization" below for further details.

Reorganization

Prior to the completion of the IPO, Hydro One and Hydro One Limited completed a series of transactions (Pre-IPO Transactions) that resulted in, among other things, on October 31, 2015, Hydro One Limited acquiring all of the issued and outstanding shares of Hydro One from the Province.

The following table presents the common shares issued during the year ended December 31, 2015. There were no common shares issued during the year ended December 31, 2014.

Year ended December 31, 2015	*(millions of Canadian dollars)*	*(number of shares)*
Pre-Closing Transactions:		
Common shares issued – purchase and cancellation of preferred shares *(a)*	323	2,640
Common shares issued *(b)*	2,600	39,598
Common shares issued *(c)*	–	1
Total common shares issued	2,923	42,239

(a) As part of the Pre-Closing Transactions, on October 31, 2015, Hydro One purchased and cancelled its 12,920,000 preferred shares previously held by the Province for cancellation at a price equal to the redemption price of the preferred shares totaling $323 million, which was satisfied by the issuance to the Province of 2,640 common shares of Hydro One.

(b) On November 4, 2015, Hydro One issued 39,598 common shares to Hydro One Limited for proceeds of $2.6 billion.

(c) On November 3, 2015, Hydro One declared a stock dividend on its common shares, which due to the number of shares issued and the resulting effect on the price per share was treated as a stock split. On November 5, 2015, Hydro One effected a reverse split and issued as consideration one common share to Hydro One Limited. There was no impact to the capital structure of Hydro One as a net result of the stock dividend and the reverse split.

19. DIVIDENDS

In 2015, preferred share dividends in the amount of $13 million (2014 – $18 million) and common share dividends in the amount of $875 million (2014 – $269 million) were declared.

In August 2015, Hydro One declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton. See Note 4 – Business Combinations.

20. EARNINGS PER SHARE

Basic and diluted earnings per common share (EPS) is calculated by dividing net income attributable to common shareholder of Hydro One by the weighted average number of common shares outstanding. The weighted average number of shares outstanding at December 31, 2015 was 107,116 (2014 – 100,000). There were no dilutive securities during 2015 or 2014.

21. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One in current and future periods.

Share Grant Plans

At December 31, 2015, Hydro One Limited had two share grant plans, one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Power Workers' Union annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU share grant plan begins on July 3, 2015, which is the date the share grant plans were ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,952,212 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total share based compensation recognized by Hydro One.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of The Society of Energy Professionals annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan begins on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,367,158 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total share based compensation recognized by Hydro One.

The fair value of the Hydro One Limited share grants is estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. Total fair value of shares granted in 2015 is $111 million (2014 – $nil). Total share based compensation recognized during 2015 was $10 million (2014 – $nil) and was recorded as a regulatory asset. The historical turnover rate relating to members of the Power Workers' Union and The Society of Energy Professionals is not believed to be reflective of a future turnover rate due to benefits conferred by the share grant plans. At December 31, 2015 the Company expects all eligible employees to receive the share grants until such time that they no longer meet the eligibility criteria and therefore, a forfeiture rate of 0% is assumed in amounts recognized during 2015. The Company will reevaluate this assumption in subsequent periods based on actual experience.

A summary of share grant activity under the Plan as of December 31, 2015 is presented below:

Years ended December 31, 2015	Share Grants *(Number)*	Weighted-Average Price
Outstanding – beginning of year	–	–
Granted (non-vested)	5,319,370	$20.50
Outstanding – end of year	5,319,370	–

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited's Board of Directors.

(number of DSUs)	2015	2014
DSUs outstanding – January 1	–	–
DSUs granted	20,525	–
DSUs outstanding – December 31	20,525	–

For the year ended December 31, 2015, an expense of less than $1 million (2014 – $nil) was recognized in earnings with respect to the DSU Plan. At December 31, 2015, a liability of less than $1 million (December 31, 2014 – $nil) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $22.29 and is included in accrued liabilities on the Balance Sheet.

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One Limited established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company will match 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. No contributions were made under the ESOP during 2015.

Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted a Long-term Incentive Plan (LTIP). Under the LTIP, long-term incentives will be granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units, performance share units, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance. No long-term incentives were awarded during 2015.

22. NONCONTROLLING INTEREST

On December 16, 2014, the relevant Bruce to Milton Line transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation (SON) acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's initial investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), Hydro One purchase the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in noncontrolling interest for the years ended December 31, 2015 and December 31, 2014:

Year ended December 31, 2015 *(millions of Canadian dollars)*	**Temporary Equity**	**Equity**	**Total**
Noncontrolling interest – January 1, 2015	21	49	70
Distributions to noncontrolling interest	(1)	(4)	(5)
Net income attributable to noncontrolling interest	3	7	10
Noncontrolling interest – December 31, 2015	23	52	75

Year ended December 31, 2014 *(millions of Canadian dollars)*	**Temporary Equity**	**Equity**	**Total**
Noncontrolling interest – January 1, 2014	–	–	–
Amount contributed by noncontrolling interest	22	50	72
Net income (loss) attributable to noncontrolling interest	(1)	(1)	(2)
Noncontrolling interest – December 31, 2014	21	49	70

23. RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is the majority shareholder of Hydro One Limited. The OEFC, IESO, Ontario Power Generation Inc. (OPG), the OEB, Hydro One Brampton and Hydro One Telecom are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Effective January 1, 2015, the OPA and IESO have merged and are now operating as IESO.

The Province

- During 2015, Hydro One paid dividends to the Province totalling $888 million (2014 – $287 million). In addition, on August 31, 2015, Hydro One declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton. See Note 4 – Business Combinations.

IESO

- In 2015, Hydro One purchased power in the amount of $2,318 million (2014 – $2,601 million) from the IESO-administered electricity market.
- Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues for 2015 include $1,548 million (2014 – $1,556 million) related to these services.
- Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues for 2015 include $127 million (2014 – $127 million) related to this program.
- Hydro One also receives revenues related to the supply of electricity to remote northern communities from the IESO. Distribution revenues for 2015 include $32 million (2014 – $32 million) related to these services.
- The IESO (OPA prior to January 1, 2015) funds substantially all of the Company's CDM programs. The funding includes program costs, incentives, and management fees. During 2015, Hydro One received $70 million (2014 – $33 million) related to these programs.

OPG

- In 2015, Hydro One purchased power in the amount of $11 million (2014 – $23 million) from OPG.
- Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2015, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $7 million (2014 – $12 million), primarily for the Transmission Business. Operation, maintenance and administration costs in 2015 and 2014 related to the purchase of services with respect to these service level agreements were not significant.

OEFC

- In 2015, Hydro One made PILs to the OEFC totalling $2.9 billion (2014 – $86 million), including Departure Tax of $2.6 billion (2014 – $nil).
- In 2015, Hydro One purchased power in the amount of $6 million (2014 – $9 million) from power contracts administered by the OEFC.
- During 2015, Hydro One paid a $8 million (2014 – $5 million) fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999. Hydro One has not made any claims under the indemnity since it was put in place in 1999. Hydro One and the OEFC, with the consent of the Minister of Finance, terminated the indemnity fee effective October 31, 2015.
- PILs and payments in lieu of property taxes were paid to the OEFC.

OEB

- Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. In 2015, Hydro One incurred $12 million (2014 – $12 million) in OEB fees.

Hydro One Brampton

- Effective August 31, 2015, Hydro One Brampton is no longer a subsidiary of Hydro One, but is indirectly owned by the Province. For change in ownership of Hydro One Brampton, see Note 4 – Business Combinations.
- Subsequent to August 31, 2015, Hydro One continues to provide certain management, administrative and smart meter network services to Hydro One Brampton pursuant to certain service level agreements, which are provided at market rates. These agreements will continue until the end of 2016 (except in the case of smart meter network services, which will continue until the end of 2017). Hydro One Brampton has the right to renew these agreements (other than smart meter network services) for additional one-year terms to end no later than December 31, 2019. Additionally, on August 31, 2015, Hydro One and Hydro One Brampton entered into a license agreement which permits Hydro One Brampton to use the "Hydro One" name and related licensed marks. These agreements will terminate if the Province disposes of its interest in Hydro One Brampton, except in the case of the smart meter network services agreement, which is anticipated to continue for a transition period after the Province disposes of its interest in Hydro One Brampton. During 2015, revenues related to the provision of services with respect to these service level agreements were $1 million.

Hydro One Telecom

- Effective November 6, 2015, Hydro One Telecom is no longer a subsidiary of Hydro One, but is owned by Hydro One Limited. For change in ownership of Hydro One Telecom, see Note 4 – Business Combinations.
- Subsequent to November 6, 2015, Hydro One Telecom continues to provide certain network and carrier management, engineering, and Internet/LAN services to Hydro One. Costs relating to these services in 2015 were $6 million, of which $4 million was charged to OM&A, and $2 million was capitalized. In addition, Hydro One provides certain services to Hydro One Telecom, including management, corporate functions and services, supply management, network maintenance, customer support and asset construction. Revenues related to these services in 2015 were not significant.

Hydro One Limited

- During 2015, Hydro One incurred certain IPO related expenses totaling $7 million (2014 – $nil) which will be reimbursed to the Company by Hydro One Limited.
- On November 4, 2015, Hydro One issued 39,598 common shares to Hydro One Limited for proceeds of $2.6 billion.

- In 2015, Hydro One Limited established certain stock-based compensation plans, however they represent components of costs of Hydro One in current and future periods. Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with the share grant plans, and at December 31, 2015, Hydro One had a payable of $10 million (2014 – $nil) to Hydro One Limited associated with these plans. See Note 21 – Stock-based Compensation.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

(millions of Canadian dollars)	**December 31, 2015**	**December 31, 2014**
Due from related parties	184	224
Due to related parties[1]	(142)	(227)

[1] Included in due to related parties at December 31, 2015 are amounts owing to the IESO in respect of power purchases of $134 million (2014 – $214 million).

24. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Accounts receivable	244	(93)
Due from related parties	40	(27)
Materials and supplies	2	–
Prepaid expenses and other assets	12	(13)
Accounts payable	(26)	39
Accrued liabilities	(27)	(35)
Due to related parties	(95)	(3)
Accrued interest	(4)	–
Long-term accounts payable and other liabilities	–	(3)
Post-retirement and post-employment benefit liability	41	80
	187	(55)

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Capital investments in property, plant and equipment	(1,622)	(1,511)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	28	30
Capital expenditures – property, plant and equipment	(1,594)	(1,481)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Capital investments in intangible assets	(40)	(19)
Net change in accruals included in capital investments in intangible assets	3	(4)
Capital expenditures – intangible assets	(37)	(23)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2015, capital contributions from these reassessments totalled $62 million, which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments. No reassessments occurred in 2014.

Supplementary Information

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Net interest paid	416	412
Income taxes / PILs paid	2,928	86

25. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

In September 2015, Hydro One and three of its subsidiaries were served with a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. Hydro One intends to defend the action. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2015, the Company paid approximately $1 million (2014 – $1 million) in respect of consents obtained. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

26. COMMITMENTS

Outsourcing Agreements

Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., provides services to Hydro One, including settlements, source to pay services, pay operations services, information technology, finance and accounting services. The agreement with Inergi for these services expires in December 2019. In addition, Inergi provides customer service operations outsourcing services to Hydro One. The agreement for these services expires in February 2018.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The current agreement with Brookfield expires in December 2024.

At December 31, 2015, the annual commitments under the outsourcing agreements were as follows: 2016 – $167 million; 2017 – $138 million; 2018 – $106 million; 2019 – $99 million; 2020 – $2 million; and thereafter – $11 million.

Trilliant Agreement

In December 2015, Hydro One entered into an agreement with Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (Trilliant) for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licenses, as well as certain professional services. This agreement is for a term of ten years, from December 31, 2015 to December 31, 2025, with the option to renew for an additional term of five years at Hydro One's sole discretion. At December 31, 2015, the annual commitments under the agreement were as follows: 2016 – $17 million; 2017 – $17 million; 2018 – $17 million; 2019 – $17 million; 2020 – $16 million; and thereafter – $6 million.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2015, Hydro One provided prudential support to the IESO on behalf of its subsidiaries using parental guarantees of $329 million (2014 – $330 million), and on behalf of a distributor using guarantees of $1 million (2014 – $1 million). In addition, as at December 31, 2015, Hydro One has provided letters of credit in the amount of $15 million (2014 – $8 million) to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributor fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit. At December 31, 2015, Hydro One had letters of credit of $139 million (2014 – $126 million) outstanding relating to retirement compensation arrangements.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions. These leases have typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases.

During the year ended December 31, 2015, the Company made lease payments totaling $6 million (2014 – $11 million). At December 31, 2015, the future minimum lease payments under non-cancellable operating leases were as follows; 2016 – $10 million; 2017 – $9 million; 2018 – $7 million; 2019 – $2 million; 2020 – $7 million; and thereafter – $3 million.

27. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of transmitting high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering electricity to end customers and certain other municipal electricity distributors; and

- Other Business, which includes certain corporate activities, and the operations of the Company's telecommunications business up to November 6, 2015. See Note 4 – Business Combinations for details of Hydro One Telecom spin-off.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Year ended December 31, 2015 *(millions of Canadian dollars)*	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	1,536	4,949	44	6,529
Purchased power	–	3,450	–	3,450
Operation, maintenance and administration	426	633	71	1,130
Depreciation and amortization	374	380	3	757
Income (loss) before financing charges and income taxes	736	486	(30)	1,192
Capital investments	943	711	8	1,662

Year ended December 31, 2014 *(millions of Canadian dollars)*	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	1,588	4,903	57	6,548
Purchased power	–	3,419	–	3,419
Operation, maintenance and administration	394	742	56	1,192
Depreciation and amortization	346	367	9	722
Income (loss) before financing charges and income taxes	848	375	(8)	1,215
Capital investments	845	680	5	1,530

Total Assets by Segment:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Transmission	12,066	12,540
Distribution	9,213	9,805
Other	2,924	205
Total assets	24,203	22,550

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

28. SUBSEQUENT EVENTS

Dividends and Return of Stated Capital

On February 11, 2016, common share dividends in the amount of $2 million were declared, and a return of stated capital in the amount of $225 million was approved.

Great Lakes Power Transmission Purchase Agreement

On January 28, 2016, Hydro One reached an agreement to acquire from Brookfield Infrastructure various entities that own and control Great Lakes Power Transmission LP, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario, for $222 million in cash, subject to customary adjustments, plus the assumption of approximately $151 million in outstanding indebtedness. The acquisition is pending a *Competition Act* approval as well as regulatory approval from the OEB.

HYDRO ONE NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2015

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying carve-out financial statements of the Transmission Business (a business of Hydro One Networks Inc.), which comprise the carve-out balance sheet as at December 31, 2015, the carve-out statements of operations and comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The carve-out financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Management's Responsibility for the Carve-out Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these carve-out financial statements in accordance with the basis of accounting in Note 2 to the carve-out financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of carve-out financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these carve-out financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the carve-out financial statements are free from material misstatement.

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

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

Opinion

In our opinion, the carve-out financial statements as at and for the year ended December 31, 2015 are prepared, in all material respects, in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to the carve-out financial statements, which describes the basis of preparation used in these carve-out financial statements. In particular, in preparing the carve-out financial statements, long-term debt, shared functions and service costs, income taxes have been allocated to the Transmission Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to the carve-out financial statements. As a result, the carve-out financial statements may not necessarily be identical to the balance sheet, results of operations and cash flows that would have resulted had the Transmission Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. The carve-out financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, the carve-out financial statements may not be suitable for another purpose.

Our report is intended solely for the Directors of Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 26, 2016

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2015 and 2014

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Revenues		
Transmission tariff *(Note 18)*	1,456	1,549
Other	35	38
	1,491	1,587
Costs		
Operation, maintenance and administration *(Note 18)*	442	400
Depreciation and amortization *(Note 4)*	366	346
	808	746
Income before financing charges and income taxes	**683**	**841**
Financing charges *(Notes 5, 18)*	216	222
Income before income taxes	**467**	**619**
Income taxes *(Notes 6, 18)*	64	87
Net income	**403**	**532**
Other comprehensive income	–	–
Comprehensive income	**403**	**532**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS
At December 31, 2015 and 2014

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Assets		
Current assets:		
Inter-company demand facility *(Notes 11, 12, 18)*	–	234
Accounts receivable (net of allowance for doubtful accounts – $1; 2014 – $1) *(Notes 18)*	148	178
Materials and supplies	11	13
Regulatory assets *(Note 9)*	5	18
Deferred income tax assets *(Note 6)*	8	10
Derivative instruments *(Note 11)*	–	1
Other	9	8
	181	462
Property, plant and equipment *(Note 7)*:		
Property, plant and equipment in service	15,055	14,467
Less: accumulated depreciation	5,489	5,202
	9,566	9,265
Construction in progress	887	667
Future use land, components and spares	96	94
	10,549	10,026
Other long-term assets:		
Regulatory assets *(Note 9)*	1,174	1,106
Intangible assets (net of accumulated amortization – $132; 2014 – $123) *(Note 8)*	107	107
Deferred debt costs	20	22
Other	2	2
	1,303	1,237
Total assets	**12,033**	**11,725**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS (continued)
At December 31, 2015 and 2014

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Notes 11, 12, 18)*	749	–
Accounts payable	86	85
Accrued liabilities *(Notes 6, 13, 14, 18)*	196	166
Accrued interest *(Note 18)*	58	60
Regulatory liabilities *(Note 9)*	9	32
Long-term debt payable within one year *(Notes 10, 11, 12, 18)*	300	331
	1,398	674
Long-term debt *(Notes 10, 11, 12, 18)*	4,686	4,986
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 13)*	662	649
Deferred income tax liabilities *(Note 6)*	910	874
Regulatory liabilities *(Note 9)*	146	58
Environmental liabilities *(Note 14)*	77	86
Net unamortized debt premiums	8	9
Asset retirement obligations *(Note 15)*	4	4
Long-term accounts payable and other liabilities	17	13
	1,824	1,693
Total liabilities	**7,908**	**7,353**

Contingencies and commitments (Notes 20, 21)
Subsequent Events (Note 22)

Excess of assets over liabilities *(Notes 12, 16)*	4,125	4,372
Total liabilities and excess of assets over liabilities	**12,033**	**11,725**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

George L Cooke   Mayo Schmidt

George Cooke
Director

Mayo Schmidt
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2015 and 2014

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Operating activities		
Net income	403	532
Environmental expenditures	(7)	(6)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	336	319
Regulatory assets and liabilities	54	1
Deferred income taxes	(32)	1
Other	21	(2)
Changes in non-cash balances related to operations *(Note 19)*	63	26
Net cash from operating activities	838	871
Financing activities		
Long-term debt issued	–	365
Long-term debt retired	(330)	(325)
Payments to Hydro One Inc. to finance dividends	(625)	(685)
Other	–	(2)
Net cash used in financing activities	(955)	(647)
Investing activities		
Capital expenditures *(Note 19)*		
Property, plant and equipment	(925)	(834)
Intangible assets	(8)	(4)
Capital contributions received *(Note 19)*	69	–
Proceeds from transfer of assets	–	526
Other	(2)	(3)
Net cash used in investing activities	(866)	(315)
Net change in inter-company demand facility	(983)	(91)
Inter-company demand facility, beginning of year	234	325
Inter-company demand facility, end of year	**(749)**	**234**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and was wholly owned by the Province of Ontario (the Province) until October 31, 2015. On October 31, 2015, Hydro One Limited, a wholly owned subsidiary of the Province, acquired all issued and outstanding shares of Hydro One from the Province. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated transmission business (Transmission Business) operates a high-voltage electrical transmission network that represents almost all of the licensed transmission capacity in Ontario. The Transmission Business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP). These Financial Statements have been prepared for the specific use of the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2015 have been prepared and are publicly available.

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Transmission Business on a basis approved by the OEB. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company's Transmission Business. As a result of this basis of accounting, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Transmission Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Transmission Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Transmission Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Transmission Business was a separate taxpaying entity. However, income taxes paid and the deferred tax asset recognized by the Company in relation to the Company losing its exemption from tax under the Federal Tax Regime have been excluded as they represent transactions that are not included in the rate-setting process of the Transmission Business. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 26, 2016, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these financial statements. See Note 22 – Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset retirement obligations (AROs), asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB.

Rate Setting

The OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' Transmission Business.

On January 8, 2015, pursuant to an application filed with the OEB, the OEB approved the 2015 Hydro One transmission rates revenue requirement of $1,477 million.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Transmission Business' regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Transmission Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Transmission Business continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Transmission Business judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers. Revenues also include amounts related to sales of other services and equipment. Such revenues are recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Trade Accounts Receivable represents earned revenue for electricity transmitted and delivered to customers and receivable from the Independent Electricity System Operator (IESO). Trade accounts Receivable are recorded at the amount reported by the IESO. No allowance for doubtful accounts is recognized with respect to trade accounts receivable as there is no risk of loss associated with such amounts

Income Taxes

On October 31, 2015, Hydro One Networks ceased to be exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (Federal Tax Regime). Prior to that date, Hydro One Networks was required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the *Electricity Act*, 1998 (Ontario) (PILs Regime). These payments were calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998*, and related regulations. Upon exiting the PILs Regime, Hydro One is required to make corporate income tax payments to the Canada Revenue Agency (CRA) under the Federal Tax Regime.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Transmission Business records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Transmission Business uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Transmission Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Transmission Business' intangible assets primarily represent major administrative computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

Hydro One periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2015. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate (%)	
	Service Life	**Range**	**Average**
Transmission	55 years	1% – 2%	2%
Communication	17 years	1% – 7%	5%
Administration and service	19 years	1% – 20%	8%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rate for computer applications software assets is 10%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation and amortization, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no ARO has been recorded.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Transmission Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2015 and 2014, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI and net income are presented in a single continuous Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity investments; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. Hydro One Networks determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with its risk management policy disclosed in Note 11 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various derivative instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedge relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized in its Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Statement of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Statements of Operations and Comprehensive Income. Additionally, Hydro One enters into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2015 or 2014.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where Hydro One has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets of Hydro One for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

A detailed description of Hydro One pension benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2015.

Post-retirement and post-employment benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2015.

Stock-Based Compensation

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period, as management considers it to be probable that such costs will be recovered in the future through the rate-setting process.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Transmission Business' Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Transmission Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Transmission Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Transmission Business records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. The Company reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company’s transmission assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company’s easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Transmission Business expects to use the majority of its facilities in perpetuity, no asset retirement obligations currently exist for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such a case, an ARO would be recorded at that time.

The Transmission Business’ AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of certain assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recent Accounting Guidance Not Yet Adopted

In January 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items. This ASU eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary and to show the item separately in the income statement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Transmission Business' financial statements.

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. This ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The recognition and measurement guidance for debt issuance costs are not affected. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. Upon adoption of this ASU in the first quarter of 2016, the Transmission Business' deferred debt issuance costs that are currently presented under other long-term assets will be reclassified as a deduction from the carrying amount of long-term debt.

In April 2015, the FASB issued ASU 2015-05, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement. This ASU provides guidance to customers about whether a cloud computing arrangement includes a software license, as well as the related accounting for the arrangement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The Transmission Business is currently assessing the impact of adoption of this ASU on its financial statements.

In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date. This ASU defers by one year the effective date of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) issued by the FASB in May 2014. ASU 2014-09 provides guidance on revenue recognition that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The guidance in ASU 2014-09 is now effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Transmission Business is currently assessing the impact of adoption of ASU 2014-09 on its financial statements.

In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes. The amendments in this ASU require that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Upon adoption of this ASU in the first quarter of 2017, the current portions of the Transmission Business' deferred income tax assets and liabilities will be reclassified as noncurrent assets and liabilities on the Balance Sheets.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Depreciation of property, plant and equipment	309	289
Amortization of intangible assets	20	19
Asset removal costs	30	27
Amortization of regulatory assets	7	11
	366	346

5. FINANCING CHARGES

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Interest on long-term debt *(Note 18)*	248	255
Other	8	6
Less: Interest capitalized on construction and development in progress	(37)	(31)
Gain on interest-rate swap agreements	(1)	(3)
Interest earned on inter-company demand facility *(Note 18)*	(2)	(5)
	216	222

6. INCOME TAXES

Income taxes / provision for PILs differ from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Income taxes / provision for PILs at statutory rate	124	164
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(28)	(38)
Pension contributions in excess of pension expense	(12)	(12)
Interest capitalized for accounting but deducted for tax purposes	(9)	(9)
Overheads capitalized for accounting but deducted for tax purposes	(9)	(9)
Environmental expenditures	(2)	(2)
Non-refundable ITCs	(1)	(1)
Prior year's adjustments	1	(2)
Other	(1)	(5)
Net temporary differences	(61)	(78)
Net permanent differences	1	1
Total income taxes / provision for PILs	64	87
Current income taxes / provision for PILs	96	86
Deferred income taxes / provision for PILs	(32)	1
Total income taxes / provision for PILs	64	87
Effective income tax rate	13.7%	14.0%

The provision for PILs / current income taxes is remitted to, or received from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime). At December 31, 2015, $55 million (2014 – $17 million due from OEFC was included in accounts receivable) due to the OEFC and $17 million (2014 – $nil) due to the CRA were included in accrued liabilities.

At December 31, 2015, the total income taxes / provision for PILs includes deferred income taxes / recovery of PILs of $32 million (2014 – provision of $1 million) that is not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax basis of the Company's assets and liabilities. At December 31, 2015 and 2014, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,142)	(1,080)
Regulatory amounts not recognized for tax	(31)	(48)
Post-retirement and post-employment benefits expense in excess of cash payments	247	242
Environmental expenditures	29	24
Other	(5)	(2)
Total deferred income tax liabilities	(902)	(864)
Less: current portion	8	10
	(910)	(874)

During 2015 and 2014, there were no changes in the rate applicable to future taxes.

7. PROPERTY, PLANT AND EQUIPMENT

December 31, 2015 *(millions of Canadian dollars)*	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction in Progress**	**Total**
Transmission	13,748	4,673	851	9,926
Communication	882	545	18	355
Administration and Service	521	271	18	268
	15,151	5,489	887	10,549

December 31, 2014 *(millions of Canadian dollars)*	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction in Progress**	**Total**
Transmission	13,243	4,471	607	9,379
Communication	837	490	47	394
Administration and Service	481	241	13	253
	14,561	5,202	667	10,026

Financing charges capitalized on property, plant and equipment under construction were $37 million (2014 – $31 million).

8. INTANGIBLE ASSETS

December 31, 2015 *(millions of Canadian dollars)*	**Intangible Assets**	**Accumulated Amortization**	**Development in Progress**	**Total**
Computer applications software	227	129	8	106
Other	4	3	–	1
	231	132	8	107

December 31, 2014 *(millions of Canadian dollars)*	**Intangible Assets**	**Accumulated Amortization**	**Development in Progress**	**Total**
Computer applications software	224	120	2	106
Other	4	3	–	1
	228	123	2	107

Financing charges capitalized on intangible assets under development were immaterial in 2015 and 2014. The estimated annual amortization expense for intangible assets is as follows: 2016 – $20 million; 2017 – $20 million; 2018 – $20 million; 2019 – $15 million; and 2020 – $6 million

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. The Transmission Business has recorded the following regulatory assets and liabilities:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Regulatory assets:		
Deferred income tax regulatory asset	973	903
Post-retirement and post-employment benefits	104	119
Environmental	82	91
Pension cost variance	14	11
Share-based compensation	5	–
Other	1	–
Total regulatory assets	1,179	1,124
Less: current portion	5	18
	1,174	1,106
Regulatory liabilities:		
External revenue variance	87	54
CDM deferral variance	53	25
Deferred income tax regulatory liability	9	8
Other	6	3
Total regulatory liabilities	155	90
Less: current portion	9	32
	146	58

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Transmission Business has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Transmission Business' income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2015 income tax expense would have been higher by approximately $61 million (2014 – $78 million).

Post-Retirement and Post-Employment Benefits

The Transmission Business recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2015 OCI would have been higher by $15 million (2014 – $14 million).

Environmental

The Transmission Business records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, an equivalent amount was recorded as a regulatory asset. In 2015, the environmental regulatory asset decreased by $7 million (2014 – $8 million) to reflect related changes in the PCB liability, and did not change (2014 – increased by $1 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Transmission Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2015 operation, maintenance and administration expenses would have been lower by $7 million (2014 – $7 million). In addition, 2015 amortization expense would have been lower by $6 million (2014 – $6 million), and 2015 financing charges would have been higher by $4 million (2014 – $4 million).

Pension Cost Variance

A pension cost variance account was established for the Transmission Business to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In the absence of rate-regulated accounting, 2015 revenue would have been lower by $3 million (2014 – higher by $10 million).

Share-based Compensation

The Transmission Business recognizes costs associated with stock-based compensation in a regulatory asset as management considers it probable that stock-based compensation costs will be recovered in the future through the rate-setting process. At December 31, 2015, the stock-based compensation costs related to the share grant plans are measured at fair value estimated based on grant date Hydro One Limited share price and recognized using the graded-vesting attribution method. In the absence of rate-regulated accounting, 2015 operation, maintenance and administration expenses would have been higher by $2 million (2014 – $nil).

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, the Company agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. At December 31, 2014, the balance in the CDM deferral variance account relates to the actual 2013 CDM compared to the amounts included in 2013 revenue requirement. At December 31, 2015, the balance also includes the difference between the actual 2014 CDM compared to the amounts included in 2014 revenue requirement. The OEB rate order specifically states that the IESO data used to calculate the difference between forecasted and actual savings will be provided one year in arrears, and as a result, no amount should be recorded in advance of notification from the IESO of actual results.

10. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, which is then allocated between the Company's transmission and distribution businesses.

The following table presents the outstanding long-term debt of the Transmission Business as at December 31, 2015 and 2014:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Long-term debt	4,986	5,316
Add: Unrealized marked-to-market loss[1]	–	1
Less: Long-term debt payable within one year	(300)	(331)
Long-term debt	4,686	4,986

[1] At December 31, 2014, the unrealized marked-to-market loss related to $150 million of Transmission Business' $300 million note due 2015. This loss was offset by $1 million unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 11 – Fair Value of Financial Instruments and Risk Management.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Company classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occurs with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non−Derivative Financial Assets and Liabilities

At December 31, 2015 and 2014, the carrying amounts of accounts receivable, inter-company demand facility, and accounts payable are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Transmission Business's long-term debt at December 31, 2015 and 2014 are as follows:

December 31 *(millions of Canadian dollars)*	**2015 Carrying Value**	**2015 Fair Value**	**2014 Carrying Value**	**2014 Fair Value**
Long-term debt				
$150 million of $300 million notes due 2015[1]	–	–	151	151
Other notes and debentures[2]	4,986	5,729	5,166	6,040
	4,986	5,729	5,317	6,191

[1] The fair value of $150 million of Transmission Business' $300 million notes due 2015 subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk). Transmission Business did not hedge its debt during 2015.

[2] The fair value of other notes and debentures, and the portion of Transmission Business' notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

At December 31, 2015, the Transmission Business' share of the Company's derivative instruments include $nil (2014 – $150 million) of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These interest-rate swaps are classified as fair value hedges. At December 31, 2015, the Transmission Business had no fair value hedge exposure (2014 – 3% of its long-term debt).

Fair Value Hierarchy

Fair value hierarchy information for financial assets and liabilities at December 31, 2015 and 2014 was as follows:

December 31, 2015 *(millions of Canadian dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	749	749	749	–	–
Long-term debt	4,986	5,729	–	5,729	–
	5,735	6,478	749	5,729	–

December 31, 2014 *(millions of Canadian dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	234	234	234	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	1	1	–	1	–
	235	235	234	1	–
Liabilities:					
Long-term debt	5,317	6,191	–	6,191	–
	5,317	6,191	–	6,191	–

The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the un-hedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2015 and 2014.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The OEB-approved adjustment formula for calculating return on equity in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark rates of return for Government of Canada debt. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining the Transmission Business' rate of return would reduce the Transmission Business' 2015 net income by approximately $20 million (2014 – $20 million).

Hydro One uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One also uses derivative financial instruments to manage interest-rate risk. Hydro One utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2015 or 2014.

Fair Value Hedges
For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instruments as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Transmission Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2015 and 2014 are included in financing charges as follows:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Unrealized loss (gain) on hedged debt	–	(2)
Unrealized loss (gain) on fair value interest-rate swaps	–	2
Net unrealized loss (gain)	–	–

At December 31, 2015, the amount of the Transmission Business' fair value hedges outstanding related to interest-rate swaps was $nil (2014 – $150 million), with assets at fair value of $nil (2014 – $1 million). During the years ended December 31, 2015 and 2014, there was no significant impact on the Transmission Business' results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2015 and 2014, there were no significant concentrations of credit risk with respect to any class of financial assets. The Transmission Business did not earn a significant amount of revenue from any individual customer. At December 31, 2015 and 2014, there was no significant accounts receivable balance due from any single customer.

At December 31, 2015, the Transmission Business' allowance for doubtful accounts was $1 million (2014 – $1 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2015, approximately 2% of the Transmission Business' net accounts receivable were aged more than 60 days (2014 – 1%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Hydro One's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. In addition to payment netting language in master agreements, Hydro One establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. Hydro One would only offset the positive market values against negative values with the same counterparty where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Hydro One as specified in each agreement. Hydro One monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk policy is consistent with Hydro One. The Transmission Business' credit risk for accounts receivable is limited to the carrying amounts on its Balance Sheets.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. The Company meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

At December 31, 2015, accounts payable and accrued liabilities in the amount of $282 million (2014 – $251 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2015, the principal amount of the Transmission Business' long-term debt was $4,986 million (2014 – $5,316 million). Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of Canadian dollars)*	Weighted Average Interest Rate *(%)*
1 year	300	4.3
2 years	405	5.2
3 years	412	2.8
4 years	137	1.2
5 years	180	4.4
	1,434	3.8
6 – 10 years	319	3.2
Over 10 years	3,233	5.4
	4,986	4.8

Interest payments on long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of Canadian dollars)*
2016	234
2017	228
2018	207
2019	194
2020	189
	1,052
2021-2025	902
2026 +	2,466
	4,420

12. CAPITAL MANAGEMENT

The Transmission Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB.

The Transmission Business considers its capital structure to consist of excess of assets over liabilities, long-term debt, and the inter-company demand facility. The following table summarizes this capital structure:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Long-term debt payable within one year	300	331
Inter-company demand facility	749	(234)
	1,049	97
Long-term debt	4,686	4,986
Excess of assets over liabilities	4,125	4,372
Total capital	9,860	9,455

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2015 and 2014:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Excess of assets over liabilities, January 1	4,372	4,525
Net income	403	532
Payments to Hydro One to finance dividends	(650)	(685)
Excess of assets over liabilities, December 31	4,125	4,372

13. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers most regular employees of Hydro One and its subsidiaries. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Balance Sheets.

Pension Benefits

The Pension Plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Hydro One's annual Pension Plan contributions for 2015 of $177 million (2014 – $174 million) were based on an actuarial valuation effective December 31, 2013 and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2016 are approximately $180 million, based on the actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

At December 31, 2015, based on the December 31, 2013 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,683 million (2014 – $7,535 million). The fair value of pension plan assets available for these benefits was $6,731 million (2014 – $6,299 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2015, the Transmission Business charged $20 million (2014 – $20 million) of post-retirement and post-employment benefit costs to operations, and capitalized $29 million (2014 – $30 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2015 were $20 million (2014 – $19 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $15 million (2014 – $14 million).

The Transmission Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets within the following line items:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Accrued liabilities	25	24
Post-retirement and post-employment benefit liability	662	649
	687	673

14. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2015 and 2014:

Year ended December 31, 2015 *(millions of Canadian dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	77	14	91
Interest accretion	4	–	4
Expenditures	(3)	(3)	(6)
Revaluation adjustment	(7)	–	(7)
Environmental liabilities, December 31	71	11	82
Less: current portion	2	3	5
	69	8	77

Year ended December 31, 2014 *(millions of Canadian dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	84	16	100
Interest accretion	4	–	4
Expenditures	(3)	(3)	(6)
Revaluation adjustment	(8)	1	(7)
Environmental liabilities, December 31	77	14	91
Less: current portion	2	3	5
	75	11	86

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheets after factoring in the discount rate:

December 31, 2015 *(millions of Canadian dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	81	11	92
Less: discounting accumulated liabilities to present value	10	–	10
Discounted environmental liabilities	71	11	82

December 31, 2014 *(millions of Canadian dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	87	15	102
Less: discounting accumulated liabilities to present value	10	1	11
Discounted environmental liabilities	77	14	91

At December 31, 2015, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2016	5
2017	8
2018	8
2019	9
2020	9
Thereafter	53
	92

The Transmission Business records a liability for the estimated future expenditures for the contaminated LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures.

Future expenditures have been discounted using factors ranging from approximately 3.8% to 5.1%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission Business' environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act,* 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, the Company's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Transmission Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $81 million. These expenditures are expected to be incurred over the period from 2016 to 2024. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2015 to reduce the PCB environmental liability by $7 million (2014 – $8 million).

LAR

The Transmission Business' best estimate of the total estimated future expenditures to complete its LAR program is $11 million. These expenditures are expected to be incurred over the period from 2016 to 2022. As a result of its annual review of environmental liabilities, the 2015 LAR revaluation adjustment was $nil (2014 – increase of $1 million).

15. ASSET RETIREMENT OBLIGATIONS

The Company records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission Business' AROs represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. AROs are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2015, the Company had recorded AROs of $4 million (2014 – $4 million), related to its Transmission Business, consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

16. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2015, Hydro One Networks had 207,577,181 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2015, Hydro One Networks declared preferred share dividends in the amount of $16 million (2014 – $20 million) and common share dividends in the amount of $875 million (2014 – $724 million) to Hydro One. The amount allocated to the Transmission Business to finance these dividends was $650 million (2014 – $685 million), of which $625 million was paid in 2015 (2014 – $685 million paid in 2014).

17. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

At December 31, 2015, Hydro One Limited had two share grant plans, one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan). These plans are part of the Company's overall compensation strategy. Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Power Workers' Union annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU share grant plan begins on July 3, 2015, which is the date the share grant plans were ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 1,761,152 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total share based compensation recognized by the Transmission Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of The Society of Energy Professionals annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan begins on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 608,626 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total share based compensation recognized by the Transmission Business.

The fair value of the Hydro One Limited share grants is estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. Total fair value of shares granted in 2015 is $49 million (2014 – $nil). Total share based compensation recognized during 2015 by Hydro One Networks' Transmission Business was $5 million (2014 – $nil) and was recorded as a regulatory asset. The historical turnover rate relating to members of the Power Workers' Union and The Society of Energy Professionals is not believed to be reflective of a future turnover rate due to benefits conferred by the share grant plans. At December 31, 2015, the Company expects all eligible employees to receive the share grants until such time that they no longer meet the eligibility criteria and therefore, a forfeiture rate of 0% is assumed in amounts recognized during 2015. The Company will reevaluate this assumption in subsequent periods based on actual experience.

A summary of the Transmission Business' share grant activity under the Share Grant Plans as of December 31, 2015 is presented below:

Years ended December 31, 2015	Share Grants *(Number)*	Weighted-Average Price
Outstanding – beginning of year	–	–
Granted (non-vested)	2,369,152	$20.50
Outstanding – end of year	2,369,152	–

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One Limited established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. Hydro One Networks will match 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. No contributions were made under the ESOP during 2015.

Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted a Long-term Incentive Plan (LTIP). Under the LTIP, long-term incentives will be granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units, performance share units, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance. No long-term incentives were awarded during 2015.

18. RELATED PARTY TRANSACTIONS

The Transmission Business is a separately regulated business of Hydro One Networks which is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited, and the Province is the majority shareholder of Hydro One Limited. The OEFC, IESO, Ontario Power Generation Inc. (OPG), the OEB, and Hydro One Brampton are related parties to Hydro One Networks because they are controlled or significantly influenced by the Province. Transactions between these parties and the Transmission Business are described below.

IESO

- The Transmission Business receives amounts for transmission services from the IESO, based on OEB-approved uniform transmission rates. Amounts received for the year ended December 31, 2015 were $1,508 million (2014 – $1,555 million). Consistent with the Company's revenue recognition policy, the Transmission Business recognized $1,456 million (2014 – $1,549 million) related to these services.

OPG

- The Company has service level agreements with OPG. These services include field and engineering, logistics and telecommunications services. In 2015, revenues of the Transmission Business related to the provision of construction and equipment maintenance services with respect to these service level agreements were $6 million (2014 – $11 million). Operation, maintenance and administration costs in 2015 and 2014 related to the purchase of services with respect to these service level agreements were not significant.

OEFC

- During 2015, Hydro One paid a $8 million (2014 – $5 million) fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999. Hydro One has not made any claims under the indemnity since it was put in place in 1999. Hydro One and the OEFC, with the consent of the Minister of Finance, terminated the indemnity fee effective October 31, 2015. The Transmission Business' allocation of this fee was $7 million.
- PILs and payments in lieu of property taxes were paid to the OEFC.

OEB

- Under the *Ontario Energy Board Act*, 1998, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. In 2015, the Transmission Business incurred $5 million (2014 – $5 million) in OEB fees.

Hydro One Brampton

- In August 2015, the Transmission Business received capital contributions totalling $8 million (2014 – $nil) from Hydro One Brampton.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Accounts receivable	119	135
Accrued liabilities	(59)	(25)

Hydro One Limited and Subsidiaries

- The Transmission Business provides services to, and receives services from, Hydro One Limited and its subsidiaries. Amounts due to and from Hydro One Limited and its subsidiaries are settled through the inter-company demand facility.

  The Company has entered into various agreements with Hydro One Limited and its other subsidiaries related to the provision of shared corporate functions and services, including legal, financial and human resources services, and operational services, including environmental, forestry, and line services. Revenues in 2015 of the Transmission Business include $3 million (2014 – $3 million) related to the provision of services to Hydro One and its subsidiaries. In 2015, the Transmission Business purchased services from Hydro One Limited and its other subsidiaries totalling $31 million (2014 – $31 million), of which $20 million (2014 – $20 million) was expensed, and 11 million (2014 – $11 million) was capitalized.
- The Transmission Business' long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or due from Hydro One. Financing charges include interest expense on the long-term debt in the amount of $248 million (2014 – $255 million), and interest income on the inter-company demand facility in the amount of $2 million (2014 –$5 million). At December 31, 2015, the Transmission Business had accrued interest payable to Hydro One totalling $58 million (2014 – $60 million).
- On December 16, 2014, transmission assets totalling $526 million were transferred from Hydro One Networks' Transmission Business to B2M LP, a limited partnership between Hydro One and the Saugeen Ojibway Nation, for proceeds of $526 million. These assets are associated with an electricity transmission line (Bruce to Milton Line) in southwestern Ontario, from the Bruce Power facility in Kincardine to our Milton Switching Station in the Town of Milton. The Transmission Business of Hydro One Networks will maintain and operate the Bruce to Milton Line in accordance with an operation and management services agreement. No gain or loss was recognized due to the transfer of Bruce to Milton Line transmission assets being a common control transaction as Hydro One controlled these assets before and after the transfer.

- During 2015, Hydro One Networks declared preferred share dividends in the amount of $16 million (2014 – $20 million) and common share dividends in the amount of $875 million (2014 – $724 million) to Hydro One. The amount allocated to the Transmission Business to finance these dividends was $650 million (2014 – $685 million), of which $625 million was paid in 2015 (2014 – $685 million paid in 2014), and $25 million (2014 – $nil) was included in accrued liabilities at December 31, 2015 and paid in 2016 (2014 – $nil paid in 2015).
- In 2015, Hydro One Limited established certain stock-based compensation plans, however they represent components of costs of Hydro One and its subsidiaries, including Hydro One Networks in current and future periods. Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with the share grant plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans. At December 31, 2015, Hydro One Networks' Transmission Business had a payable of $5 million (2014 – $nil) to Hydro One associated with these plans. See Note 17 – Stock-based Compensation.

19. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Accounts receivable	30	14
Materials and supplies	2	–
Other assets	(1)	(2)
Accounts payable	–	28
Accrued liabilities	2	(45)
Accrued interest	(2)	(1)
Long-term accounts payable and other liabilities	4	5
Post-retirement and post-employment benefit liability	28	27
	63	26

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Statements of Cash Flows after factoring in capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Capital investments in property, plant and equipment	(934)	(845)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	9	11
Capital expenditures – property, plant and equipment	(925)	(834)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Capital investments in intangible assets	(9)	–
Net change in accruals included in capital investments in intangible assets	1	(4)
Capital expenditures – intangible assets	(8)	(4)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2015, capital contributions to the Transmission Business from these reassessments totalled $69 million, which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments. No reassessments occurred in 2014.

Supplementary Information

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Net interest paid	250	251
Income taxes / PILs paid	38	62

20. CONTINGENCIES

In September 2015, Hydro One and three of its subsidiaries, including Hydro One Networks, were served with a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. Hydro One intends to defend the action. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Transmission Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

21. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Transmission Business. However, the assets of the Transmission Business are available to satisfy the commitments of both the Company and Hydro One.

22. SUBSEQUENT EVENTS

Long-term Debt

On February 24, 2016, Hydro One issued the following notes under its MTN Program:

- $500 million notes with a maturity date of February 24, 2021 and a coupon rate of 1.84%. This issuance was mirrored down to Hydro One Networks through the issuance of intercompany debt with a coupon rate of 1.86%, of which $250 million was allocated to the Company's Transmission Business;
- $500 million notes with a maturity date of February 24, 2026 and a coupon rate of 2.77%. $490 million of this issuance was mirrored down to Hydro One Networks through the issuance of intercompany debt with a coupon rate of 2.79%, of which $245 million was allocated to the Company's Transmission Business; and
- $350 million notes with a maturity date of February 23, 2046 and a coupon rate of 3.91%. This issuance was mirrored down to Hydro One Networks through the issuance of intercompany debt with a coupon rate of 3.93%, of which $175 million was allocated to the Company's Transmission Business.

On March 3, 2016, Hydro One repaid $450 million of maturing long-term debt notes under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $450 million to Hydro One, of which $270 million was allocated to the Company's Transmission Business.

Payments to Finance Dividends

On February 11, 2016, the Hydro One Networks paid $25 million of common share dividends to Hydro One. These dividends were declared in August 2015 and the entire amount was allocated to the Transmission Business to finance this payment.

On February 11, 2016, Hydro One Networks declared common share dividends in the amount of $2 million, and a return of stated capital in the amount of $225 million was approved. The amount allocated to the Transmission Business to finance these payments was $114 million, of which $12 million was paid on February 22, 2016.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #3

Interrogatory

Ref: Exhibit A, Tab 1, Schedule 1, Page 8

Preamble: The evidence indicates savings realized during the deferral period will be used by HOI to offset transaction costs and premiums incurred in respect of the transaction.

a) Please provide a breakdown and estimate of the transactions costs and indicate the year the costs will be incurred.

b) Please provide the amount of the premiums to be paid through savings realized during the deferral period.

Response

a) Please refer to Exhibit I, Tab 1, Schedule 3.

b) The transaction premium is approximately $150 million. Please refer to Exhibit I, Tab 1, Schedule 4. Cost savings during the deferred rebasing period for each scenario are provided in Tables 3 and 5 of Exhibit A, Tab 2, Schedule 1. The savings achieved during the deferral period will be used to offset transaction costs including the premium paid.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #4

Interrogatory

Ref: Exhibit A, Tab 1, Schedule 1, Page 9

Preamble: HOI proposes to calculate GLPT's revenue requirement by applying an annual inflation adjustment. HOI proposes having the productivity and stretch factor set at 0%.

a) Please provide the source of the annual inflation factor to be used.

Response

The inflation rate used will be consistent with the RRFE for distribution. The current distribution inflation factor is based upon the Gross Domestic Product Implicit Price Index. If a different inflation rate methodology is established for transmission by the Board during the 2019-2026 timeframe, HOI proposes to use that rate.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #5

Interrogatory

Ref: Exhibit A, Tab 1, Schedule 1, Page 9

Ref: OEB Handbook for Electricity Distributor and Transmitter Consolidations Page 5

Preamble: The Handbook states:

"As part of the regulatory framework, distributors are expected to achieve certain outcomes that provide value for money for customers. One of these outcomes is operational effectiveness, which requires continuous improvement in productivity and cost performance by distributors and that utilities deliver on system reliability and quality objectives. The OEB uses processes to hold all utilities to a high standard of efficiency and effectiveness." …..All of these measures are in place to ensure that distributors meet expectations regardless of their corporate structure or ownership. The OEB assesses applications for consolidation within the context of this regulatory framework."

a) Given that the OEB will assess consolidation applications in the context of the RRFE and improvements in productivity and cost performance, please explain why it is appropriate for HOI to exclude a productivity factor in the calculation of GLPT's annual revenue requirement.

Response

The exclusion of a productivity factor from the proposed methodology to calculate GLPT's 2019-2026 revenue requirement is consistent with the Handbook policy objectives associated with the deferred rate rebasing period. As noted at pages 8 and 9 of the Handbook, the deferred rebasing period is intended to enable consolidating entities to fully realize efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction. Implementation of a productivity factor in the revenue requirement methodology would conflict with this stated objective as it would reduce the amount of the realized efficiencies that could otherwise offset the costs of a transaction. This aspect of the policy is balanced by the fact that long-term productivity improvements achieved during the deferral period will be passed on to ratepayers at rebasing and through the implementation of an earnings sharing mechanism during the deferred rebasing period.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #6

Interrogatory

Ref: OEB Handbook for Electricity Distributor and Transmitter Consolidations Page

Preamble: The Handbook provides the opportunity to defer rebasing for a period up to ten years from the closing of the transaction. HOI has selected a ten year rate rebasing deferral period.

a) Please provide the underlying analysis that supports the specific ten year rebasing deferral period selected instead of a 5 year, 6 year, 7 year, 8 year or 9 year deferral period.

b) Please discuss how in the selection of a 10 year rebasing deferral period, HOI arrived at the appropriate balance between the incentives provided to utilities and the protection provided to customers.

Response

a) Please refer to Exhibit I, Tab 2, Schedule 4c.

b) Please refer to Exhibit I, Tab 2, Schedule 4c.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #7

Interrogatory

Ref: OEB Handbook for Electricity Distributor and Transmitter Consolidations Page 8

Preamble: The Handbook states "Specifically, the OEB will test the financial ratios and borrowing capacity of the resulting entity, as the improvement in financial strength is one of the expected underlying benefits of consolidation.

a) Please provide HOI's response to this expectation in terms of improvements to financial ratios and borrowing capacity.

Response

a) As discussed on lines 8 to 13 on page 8 of Exhibit A, Tab 2, Schedule 1, the value of the Transaction equates to approximately 2% of HOI's fixed assets. Hence, the Transaction will not have a material impact on HOI's consolidated financial ratios or borrowing capacity. GLPT will benefit from HOI's financial strength as a result of this Transaction.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #8

Interrogatory

Ref: OEB Handbook for Electricity Distributor and Transmitter Consolidations Page 1

Preamble: The Handbook states "Consolidation permits a larger scale of operation with the result that customers can be served at a lower per customer cost."

a) Please provide the cost per customer for HONI and GLPT for the years 2011 to 2015 and the forecast cost per customer under the base and high potential scenarios.

Response

Transmission is an integrated system that serves all Ontario customers. GLPT and Hydro One effectively have the same transmission rate-paying customers. If assessing strictly directly-connected load customers of the utilities, Hydro One serves 47 LDCs and 90 large industrial customers and GLPT serves 2 LDCs and 20 large industrial customers (including generators). The cost per customer would be in the millions for each utility, as illustrated in the table below.

	2011	**2012**	**2013**	**2014**	**2015**
Hydro One Transmission					
Revenue Requirement	$1,299.5	$1,385.1	$1,390.8	$1,446.4	$1,477.3
# customers	137	137	137	137	137
Cost/Customer	$9.5M	$10.1M	$10.2	$10.6	$10.8
GLPT					
Revenue Requirement	$34.8	$36.1	$38.1	$38.7	$39.6
# customers	22	22	22	22	22
Cost/Customer	$1.6M	$1.6M	$1.7M	$1.8M	$1.8M

Consequently, the requested ratio does not provide a meaningful comparison of productivity for transmission unlike the case in distribution. For instance, this analysis assumes the same weighting for all LDCs and their downstream customers, throughput, etc.

HOI believes a more transmission appropriate ratio is OM&A/GFA as provided in HOI's prefiled evidence at Table 1, in Exhibit A, Tab 2, Schedule 1 and as further described in Exhibit I, Tab 1, Schedule 2b.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #9

Interrogatory

Ref: Exhibit A, Tab 2, Schedule 1, Page 9, Table 3

Preamble: The evidence states that the productivity of transmitters is generally measured by "OM&A per gross fixed assets."

a) Please provide more information on the background of this measure and its acceptance by the OEB.

b) Table 1: Please provide the Actual OM&A and GFA amounts used in the calculation for the years 2011 to 2015 for HONI and GLPT.

c) Please provide the same table based on Total Cost per gross fixed assets.

d) Please provide other metrics used in the industry to measure the productivity of transmitters.

Response

a) Please refer to Exhibit I, Tab 1, Schedule 2b.

b) The actual OM&A and GFA amounts for both Hydro One and GLPT are provided below.

Actual OM&A/ GFA	2011	2012	2013	2014	2015
HONI[1]	3.5%	3.1%	2.7%	2.8%	2.9%
GLPT[2]	3.1%	2.8%	3.1%	3.0%	3.0%
Hydro One ($/million)					
OM&A	434	414	388	400	442
GFA (less Future Use Land and Spares)	12,410	13,522	14,140	14,467	15,055
GLPT ($/million)					
OM&A	9.3	9.3	10.2	10.3	10.5
GFA	298.9	328.6	334.1	338.1	344.8

c) Total Cost/GFA analysis for both utilities is provided below.

Hydro One ($/M)	2011	2012	2013	2014	2015
OM&A ($M)	434	414	388	400	442
CapEx ($M)	792	759	706	845	934
Total Cost ($M)	1,226	1,173	1,094	1,245	1,376
GFA ($M)	12,410	13,522	14,140	14,467	15,055
Total Cost/GFA	9.88%	8.67%	7.74%	8.61%	9.14%

GLPT ($/M)	2011	2012	2013	2014	2015
OM&A ($M)	9.3	9.3	10.2	10.3	10.5
CapEx ($M)	21	14	4	4	9
Total Cost ($M)	30.3	23.3	14.2	14.3	19.5
GFA ($M)	298.9	328.6	334.1	338.1	344.8
GLPT Total Cost/GFA	10.1%	7.1%	4.3%	4.2%	5.7%

HOI used OM&A in its productivity analysis as it is considered a more controllable transmitter costs as compared to total costs. Total cost comparisons amongst transmitters have limited value as the statistic does not account for the significant operational

[1] Source: Hydro One Transmission 2011-2015 Financial Statements
[2] Source: GLPT 2011-2015 Financial Statements, EB-2012-0300, EB-2014-0238, and actual OM&A values provided by GLPT.

differences (e.g. transmission assets, service territory, line length, electricity throughput) between GLPT and Hydro One. GLPT was not included in Hydro One's recent 16 utility peer group Total Cost Benchmarking Study.

When comparing Hydro One against the peers outlined in the Navigant Total Cost Benchmarking Study, the following results were provided by Navigant:

- "…Hydro One's total transmission expenditure (OM&A and CAPEX) was below the median of the peer group…
- …Hydro One's direct transmission expenditure (O&M and CAPEX) was among the lowest in the peer group…
- Hydro One's direct transmission O&M was at the median of the peer group…
- Hydro One's CAPEX was among the lowest in the peer group…" [3]

d) Please refer to Exhibit I, Tab 1, Schedule 2b.

[3] EB-2016-0160 – Exhibit B2, Tab 2, Schedule 1, Attachment 1 - Executive Summary

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #10

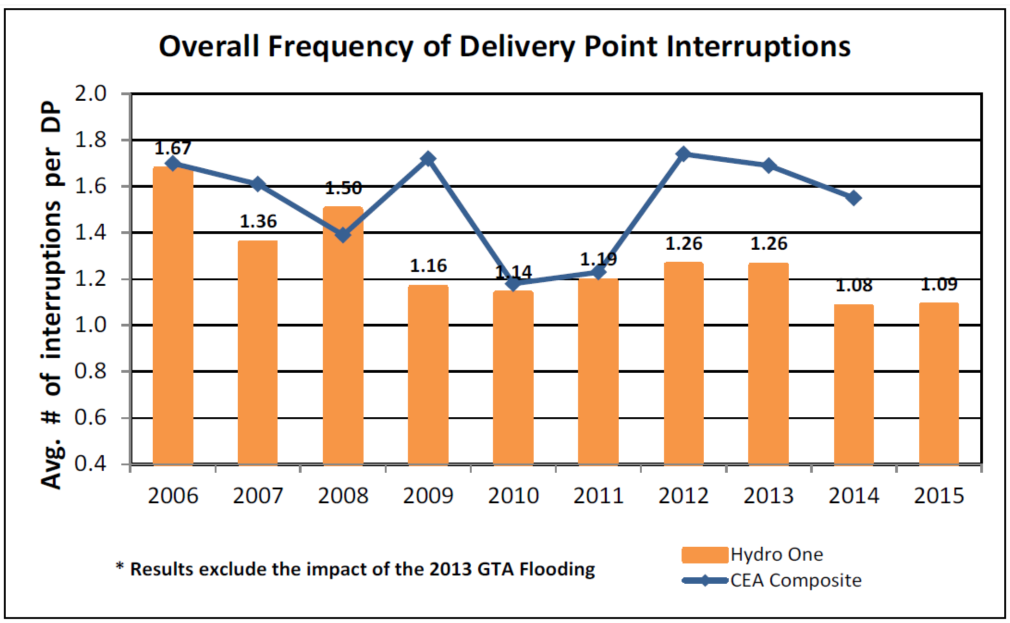
Interrogatory

Ref: Exhibit A, Tab 2, Schedule 1, Page 9, Table 6

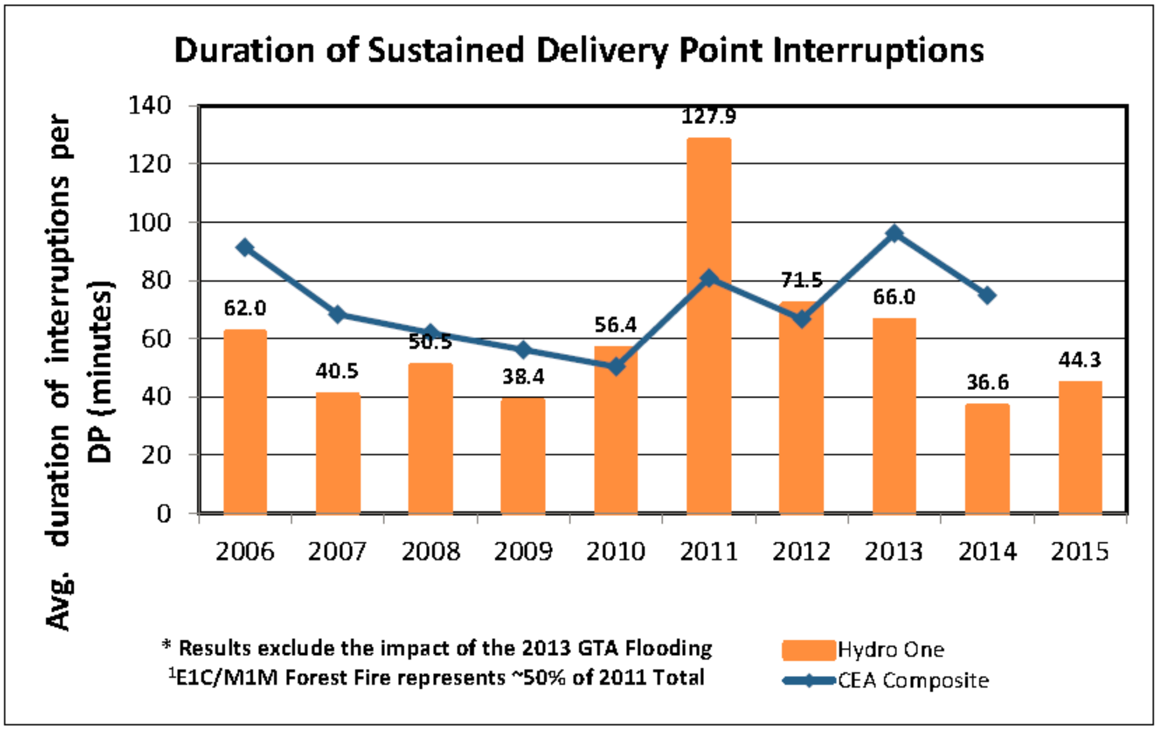
a) Please provide the SAIDI and SAIFI results for HONI and GLPT excluding Major Event Days and Scheduled Outages for the years 2010 to 2015.

Response

a) Hydro One's SAIFI and SAIDI results from 2011 to 2015 are provided below and similar results to GLPT are provided in Attachment 1. These statistics are only for sustained forced outages and do not include planned outages. Please note that the GLPT statistics are consistent with previous GLPT rate applications. Although they include significant events to GLPT, there are no events included in the statistics that could be classified as major.



1


Duration of Sustained Delivery Point Interruptions
Avg. duration of interruptions per DP (minutes)
140
120
100
80
60
40
20
0
62.0
40.5
50.5
38.4
56.4
127.9
71.5
66.0
36.6
44.3
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
* Results exclude the impact of the 2013 GTA Flooding
1E1C/M1M Forest Fire represents ~50% of 2011 Total
Hydro One
CEA Composite

GLPT SAIFI AND SAIDI (2010-2015)

System Average Interruption Frequency Index - SAIFI (Forced Sustrained)

	Customer Delivery Point	2015	2014	2013	2012	2011	2010
Load Blk 4	**(>80 MW)**	0	0	0	1	1	0
Load Blk 3	**(40-80 MW)**	0	0	2	0	1	0
Load Blk 2	**(15-40MW)**	0	0	0	3	4	0
Load Blk 1	**(0-15 MW)**	12	9	24	43	39	28
	A - Total Outages	12	9	26	47	45	28
	B - Delivery Points Served	**19**	**19**	**19**	**21**	**21**	**21**
	SAIFI (A/B)	**0.6**	**0.5**	**1.4**	**2.2**	**2.1**	**1.3**

System Average Interruption Duration Index - SAIDI (Forced Sustained)

	Customer Delivery Point	2015	2014	2013	2012	2011	2010
Load Blk 4	**(>80 MW)**	0	0	0	16	356	0
Load Blk 3	**(40-80 MW)**	0	0	23	0	345	0
Load Blk 2	**(15-40MW)**	0	0	0	44	1442	0
Load Blk 1	**(0-15 MW)**	1516	482	16338	3652	4088	3165
	A - Total Outages	1516	482	16361	3712	6231	3165
	B - Delivery Points Served	**19**	**19**	**19**	**21**	**21**	**21**
	SAIDI (A/B)	**79.8**	**25.4**	**861.1**	**176.8**	**296.7**	**150.7**

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #11

Interrogatory

Ref: Exhibit A, Tab 2, Schedule 1, Page 10

Preamble: Hydro One does not believe that this transaction will have any negative impact on reliability or its trend, and believes that, once best practices of both organizations are amalgamated, these metrics could improve further.

a) Please confirm this improved reliability performance is expected to occur without an increase in costs.

Response

Confirmed, this improved reliability performance is expected to occur without an increase in costs to ratepayers.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORY #12

Interrogatory

Ref: Exhibit A, Tab 2, Schedule 1, Page 1

Preamble: Hydro One indicates that existing GLPTLP debt covenants prevent GLPT from bring amalgamated absent consent of the debt holders and potential renegotiation of the fundamental terms of the GLPTLP debt instruments. Renegotiation of these terms is expected to result in the occurrence of substantial costs.

a) Please provide an estimate of these costs.

Response

An estimate cannot be provided as HOI has not had any discussion with the bondholders concerning renegotiation of fundamental terms.

The GLPT debt has a high coupon rate of 6.6%. The current market value of this debt is well in excess of its face value. Based on the current Bloomberg Canadian 'A' rated utility 7-year yield of approximately 2.10%, the current $115 million face value of the debt would have a market value of approximately $145 million, about a $30 million premium.

Absent consent of the debt holders, GLPT could unilaterally terminate the debt by exercising the early redemption provisions in the bond indenture. However, the redemption cost would be even higher than the current market value.

School Energy Coalition (SEC) INTERROGATORY #1

Interrogatory

[A-1-1, p.1] Does Great Lakes Power Transmission ("GLPT"), or any of its affiliates, require approval from the Board pursuant to section 86(1)(a) of the Ontario Energy Board Act? If so, is this application seeking such approval?

Response

No. HOI interprets section 86(1)(a) of the *OEB Act* to relate to asset sale transactions involving the entirety or substantially the entirety of a transmission system. This interpretation is consistent with the views expressed in the Handbook dated January 19, 2016 at page 3 which reads "Section 86(1)(a) and (c) of the *OEB Act* relate to asset sales and amalgamations. Section 86(2) of the *OEB Act* relates to voting securities".

As described in Exhibit A, Tab 1, Schedule 1, pages 1 through 3, the transaction before the Board involves HOI's acquisition of all outstanding voting securities of the licensed transmitter, GLPT. It is not a transaction involving the acquisition or disposition of assets comprising the entirety or substantially the entirety of a transmission system. For these reasons, relief pursuant to section 86(2), and not section 86(1), is sought.

School Energy Coalition (SEC) INTERROGATORY #2

Interrogatory

[A-1-1] Please provide a copy of all material provided to the Applicant's Board of Directors, related to the approval of the transaction.

Response

HOI declines to provide the requested information as it is information not relevant to the relief sought in the application. In support of this position, HOI relies on the Handbook. One of the objectives of the Handbook is stated at Page 1:

> "The OEB has a statutory obligation to review and approve consolidation transactions where they are in the public interest. In discharging its mandate, the OEB is committed to reducing regulatory barriers to consolidation. In order to facilitate both a thorough and timely review of requests for approval of transactions, in this Handbook the OEB provides guidance on the process for review of an application, the information the OEB expects to receive in support, and the approach it will take in assessing the merits of the consolidation in meeting the public interest.
>
> Recent OEB policies and decisions on consolidation applications have already established a number of principles to create a more predictable regulatory environment for applications. This Handbook will provide further clarity to applicants, investors, shareholders and other stakeholders."

Regulatory efficiencies in consolidation proceedings cannot be achieved if the evidentiary record is allowed to include information that pertains to matters outside of the OEB's stated considerations.

At page 3 of the Handbook, the OEB states that the Filing Requirements found in Schedule 2 set out the information needed for inclusion in an application.

The scope of review to be carried out during a consolidation proceeding is discussed at page 9 of the Handbook. Confirmation is provided that deliberations, activities, and documents leading up to the final transaction agreement are not matters relevant for consideration when an application made pursuant to section 86(2) of the *OEB Act*.

The requested information concerns deliberations, activities and documents leading up to the final transaction agreement and this application. As such, and based on the above reasons, HOI respectfully submits the information is not relevant to this proceeding and therefore declines to produce these materials.

School Energy Coalition (SEC) INTERROGATORY #3

Interrogatory

[A-1-1, p.3] Please provide the premium paid by Hydro One. Please provide the derivation of the calculation.

Response

Please refer Exhibit I, Tab 1, Schedule 4.

School Energy Coalition (SEC) INTERROGATORY #4

Interrogatory

[A-1-1, p.3] Please provide the forecasted transaction costs incurred by Hydro One, by year. Please provide a breakdown of those costs.

Response

Please refer to Exhibit I, Tab 1, Schedule 3.

School Energy Coalition (SEC) INTERROGATORY #5

Interrogatory

[A-1-1, p.8-9] The Applicant states that the rate rebasing deferral period will be 10 years for GLPT. Please reconcile that with the statement that GLPT is expected to file a rate application for its revenue requirement in 2017 and 2018, and then in 2019, its revenue requirement will be set by way of inflationary adjustment through to 2026, which would be 8, not 10 years.

Response

Please refer to Exhibit I, Tab 1, Schedule 5.

School Energy Coalition (SEC) INTERROGATORY #6

Interrogatory

[A-1-1, p.8] Please explain why, given this application and the proposed rebasing deferral period, it is appropriate for GLPT to bring an application for approval for 2017 and 2018 rates on a cost of service basis and have the deferral period begin in 2019.

Response

The proposed deferred rebasing period commences at the close of the transaction and not in 2019. GLPT's revenue requirement for the first two years of the deferred rebasing period is intended to be established through its cost of service application for 2017 and 2018.

The 2017 and 2018 GLPT cost of service application will ensure the revenue requirement for these years allows GLPT to continue to provide safe and reliable transmission service. GLPT will continue to operate on a stand-alone basis during this period.

While HOI does not expect to undertake any significant operational integration steps with GLPT in 2017 and 2018, commencement of the deferred rebasing period at the close of the transaction is necessary given the requirements set out in the OEB's Handbook. The initial two year period will be used to assess, identify and plan where operational savings and synergies may be achieved in the remainder of the deferral rebasing period and beyond without impacting quality of service.

School Energy Coalition (SEC) INTERROGATORY #7

Interrogatory

[A-1-1, p.8] Please justify why a rate rebasing deferral period of 10 years is appropriate.

Response

Please refer to Exhibit I, Tab 2, Schedule 4c.

School Energy Coalition (SEC) INTERROGATORY #8

Interrogatory

[A-1-1-Attach, section 1.1.16] Please provide a copy of the ‘memorandum of agreement between GLPT and Power Workers’ Union C.U.P.E. Local 1000 dated November 23, 2015.

Response

Please refer to Attachment 1.

AGREEMENT entered into this 23rd day of November, 2015 (to take effect January 1, 2016)

Between

GREAT LAKES POWER TRANSMISSION LP (GLPT)

(hereinafter called the "Company")

- and -

POWER WORKERS' UNION
CUPE LOCAL 1000

(hereinafter called the "Union")

Article 1 RECOGNITION

1.1 The Company recognizes the Power Workers' Union – CUPE Local 1000 as the bargaining agent for all office, clerical, and technical employees of Great Lakes Power Transmission LP employed in or out of the City of Sault Ste. Marie save and except supervisors and persons above the rank of supervisor, engineers, engineers-in-training, the right of way coordinator, and persons for whom any trade union holds bargaining rights. The Company shall bargain with the regular committees as established by this agreement.

Article 2 RELATIONSHIP

2.1 It is recognized that the business of the Company is continuous and that the employees must be prepared to assist in maintaining service at all hours of the day or night, if available.

2.2 No employee shall be discriminated against by the Company or by the Union because he/she is or is not a member of the Union, because of Union activities or because of exercising his/her right provided by law or by this agreement.

2.3 The Company recognizes the need to keep employees informed of planned technological changes that would impact significantly on jobs. The Company also recognizes the need to consider re-deployment and retraining as preferred alternatives when introducing new technology.

2.4 Senior employees are expected to give assistance in training junior employees.

2.5 The Company and the employees covenant that they will co-operate to the fullest extent in carrying out the terms of this agreement. This will be accomplished by the process outlined in Article 17.

Article 3 MANAGEMENT RIGHTS

3.1 The Company has and shall retain the exclusive right and power to manage its business and direct its working force including, but without limiting the generality of the foregoing, the right to hire, suspend, discharge for just cause, promote, demote and discipline any employee, subject to the terms of this agreement.

Article 4 UNION SECURITY

4.1 All employees, as a condition of employment, who have completed thirty (30) days employment, will be required to authorize deductions from pay in an amount equal to the current monthly union dues as determined by the Union.

4.2 During the term of this agreement, the Company agrees to deduct regular union dues from the wages of each employee in the bargaining unit. The current monthly dues will be deducted in equal amounts from each pay received in the calendar month, and shall be remitted to the Financial Officer of the Union within ten (10) working days of the final monthly deduction.

4.3 Notwithstanding Clause 4.2, in consideration of deductions of dues by the Company, the Union agrees to indemnify and save harmless the Company against any claim or liability arising out of or resulting from the collection of these dues.

4.4 Employees excluded from the bargaining unit, with the exceptions of students, shall not perform work normally done by employees within the bargaining unit unless; (i) in an emergency situation and regular employees are not at work. In an emergency situation after hours regular employees will be offered the opportunity to do the work. (ii) for training and instruction purposes. For clarity, students may perform bargaining unit work provided it does not directly result in the lay-off of a bargaining unit employee.

4.5 When the Company schedules a meeting with an employee to discuss work performance, the employee has the right to request a Union representative to attend.

4.6 Annually, the supervisor will review the employee file for letters of reprimand that have been in the file for more than three (3) years and the supervisor will determine whether the current behaviour warrants removal of the letter. If the removal of the letter is not warranted, a meeting will be arranged where the employee may have a Union representative in attendance and a plan shall be established with the employee's co-operation which, if followed, will ultimately result in removal of the letter.

Article 5 EMPLOYEE CATEGORIES

5.1 Definition of Employees

Temporary Employee: is an employee who is hired for a specific purpose and for a limited duration (up to twelve (12) months). An extension of a maximum of an additional six (6) months will be by mutual consent of the Company and the Union. The Company may terminate his/her employment at any time by giving at least two (2) weeks' notice.

It is understood and agreed that only Article 4, Article 7, Article 8 and Article 21 and those benefits required by law shall apply to temporary employees.

Temporary employees will be hired at a job class which reflects the job to be done and the required skills/knowledge of the individual hired. A temporary employee may, at the Company's discretion, be put into a job class category up to Class B in any Power Workers' Union – CUPE Local 1000 job class as outlined in this Collective Agreement.

At twelve (12) months when a temporary job is to continue as per Article 5.1 or the Company's decision in other cases, the following will occur:

(a) The incumbent of a temporary position will be offered health benefit coverage equivalent to Blue Choice Hospital Health Plan. The Company will pay ninety per cent (90%) of the premium.

(b) Seniority will be established and will accumulate as from the date of hire i.e. in the event a temporary employee is hired into a regular job in the Company, he/she will bring seniority equivalent to the number of months of continuous service as a temporary employee prior to accepting the regular posting.

The Principal Steward will be notified prior to temporary employees being hired detailing the work they will be performing and the duration of the assignment.

5.1.1 Temporary - Part-time Employee: is an employee who normally works between 1 and 24 hours per week and is employed on a temporary bases. It is understood and agreed that only Article 4, Article 7, Article 8, and Article 21 and those benefits required by law shall apply to temporary - part-time employees.

- Temporary part-time employees must be hired into an existing job classification.
- There shall be no more than one (1) part-time employee per job classification.
- At no time can a regular job classification be split into two (2) part time positions.

5.1.2 Probationary Employee: is an employee who is hired to determine his/her suitability for employment. An employee shall be considered probationary for six (6) continuous calendar months. If the employee is retained, his/her seniority shall commence from his/her original date of employment.

5.1.3 Regular Employee: is an employee of the Company who has successfully completed the probationary period.

5.1.4 Regular - Part-time Employee: is an employee who normally works between 1 and 24 hours per week.

- Regular part-time employees must be hired into an existing job classification.
- There shall be no more than one (1) part-time employee per job classification.
- At no time can a job classification be split into two (2) part time positions.
- All benefits associated with regular employees will be pro-rated for regular part-time employees.
- The Company will only classify employees in the regular - part time employees' classifications when it is mutually agree by the PWU and the Company.

5.2 Seniority shall be defined as the length of service a regular employee has established with the Company from the day the employee last entered the employ of the Company. An employee shall lose seniority rating under any of the following conditions:

(1) the employee resigns and is not rehired within ten (10) working days;

(2) the employee is discharged and not reinstated;

(3) the employee is laid off for a period exceeding eighteen (18) calendar months;

(4) The employee fails to return to work after layoff within fourteen (14) calendar days after being notified by registered mail to do so. If such failure to return is caused by sickness certified by a duly qualified medical practitioner, the time for return while prevented by illness shall be extended for a further period not to exceed a maximum of six (6) calendar months;

(5) The employee retires.

5.3 When an employee is placed on LTD his/her vacation and recognized holiday pay shall be prorated on the basis of time worked thereafter.

An employee, receiving benefits from the Workers' Safety and Insurance Board for illness or injury arising out of the duties of their job, shall also receive an additional payment from the Company which will be the lesser of ten per cent (10%) of the employee's normal wage or the amount necessary that, when combined with the pre-tax equivalent of the compensation payments, will bring the total equivalent gross payments from the two sources to one hundred per cent (100%) of the employee's normal wage. The Union will work with the Company and the injured worker to achieve the earliest reasonable return to work for the injured worker.

When an employee is receiving WSIB benefits for a period greater than one (1) year, his/her vacation and recognized holiday pay shall be prorated on the basis of time worked thereafter.

Article 6 STRIKES AND LOCKOUTS

6.1 There shall be no lockout by the Company and no interruption, work stoppage, strike, sit-down, or picketing of the operation of the Company's system by an employee or employees during the life of this agreement.

6.2 The Company agrees that hourly rated employees will not be required to cross picket lines except to perform duties required for the operation of the Company's system and the maintenance of machinery and equipment within the Company's system and under no circumstances will an individual employee or group of employees be required to use force in the crossing of a picket line.

Article 7 GRIEVANCE AND ARBITRATION PROCEDURE

7.1 Disagreements relating to the interpretation, application, administration or alleged violations of this agreement shall be considered fit matter for grievance and shall be promptly dealt with in the following manner:

All grievances and replies to grievances must be set out in writing in all steps and shall be addressed through normal line management.

Step 1

The alleged grievance must be submitted in writing to the supervisor responsible for his/her area and department within fifteen (15) working days of the event which gave rise to the grievance or, in the case of a monetary item, within fifteen (15) working days of receipt of the employee's pay. Within five (5) working days of submitting the alleged grievance, the employee, assisted by a steward, shall take up the matter with the supervisor responsible for his/her area. Failing settlement within five (5) working days of Step 1, the grievance may be processed within the next ten (10) working days to Step 2. Step 1 may be eliminated with reference to any grievance for discharge or suspension.

Step 2

Within ten (10) working days of notifying the Vice-President/Operations of the Company or his/her alternate of invoking Step 2, the grievance committee of the Union shall meet with the Vice- President/ Operations or his/her alternate. The reply of the Company to the grievance at Step 2 will be made to the grievor and the Principle Steward or his/her alternate within ten (10) working days of the meeting. Failing settlement at Step 2, within thirty (30) calendar days from the date of the reply of the Vice-President/ Operations, or his/her alternate, the grievance may be processed to arbitration as defined in the current Labour Relations Act of Ontario.

7.2 Permission will be granted to stewards to deal with grievances arising in their own work areas. Time spent by the steward investigating and settling such grievances will be without loss of normal earnings. A steward will not absent himself/herself from his/her normal work area without permission of the supervisor in charge.

7.3 The Company shall grant leave without loss of normal earnings to employees who are members of a grievance committee acting under Step 2 of the grievance procedure and to employees when attending a meeting called by the Company. When a steward who is working away from his/her normal work area attends a meeting called by the Company or attends a meeting under this procedure, the Company will provide transportation, if available, or will pay mileage in order for the said steward to attend such meetings.

7.4 Grievances affecting more than one employee, or any grievance brought forward by the Company, or where differences arise between the Company and the Union concerning the interpretation or general application of this agreement which may be considered as policy matters, shall be submitted in writing by either party within seven (7) working days of the alleged occurrence and shall be dealt with in the manner provided in the grievance procedure commencing at Step 2. It is the intention of the parties that the filing of policy grievances by an employee or employees shall not be used to bypass the regular grievance procedure.

7.5 Local Union officers, stewards, and committee members who are employees of the Company, shall have the right to originate a grievance for an employee on behalf of employees concerned, in the manner prescribed in the grievance procedure. The grievors involved shall be listed on the grievance form.

7.6 The parties agree that all grievances shall be submitted to single panel arbitration. The arbitrator shall be selected from a pool of arbitrators that are mutually agreed to by the parties. It is agreed by the parties that the arbitrator shall not have the power to alter or to change any of the provisions of this agreement, or to substitute any new provisions for any existing provisions or to provide a decision which is inconsistent with the terms of this agreement, providing that they are not in conflict with any legislation affecting the parties.

7.7 The Union shall have the right at any time to have the assistance of representatives of the Power Workers' Union – CUPE Local 1000 when dealing or negotiating with the Company.

Article 8 — WORK SCHEDULES AND WAGE PROVISIONS RELATING THERETO

8.1 Hours of Work

(a) Normal Hours of Work

To work seven and a half (7.5) hours per day, five (5) days per week, Monday through Friday, so as to work thirty seven and a half (37.5) hours per week, 0800 to 1630 hours, with one (1) hour allowance for lunch between 1200 hours and 1300 hours but can be adjusted through department consensus and Company approval. When an adjustment is in effect, the Company reserves the right to return to normal hours, providing they give seven (7) calendar days' notice. Failure to give the appropriate notice to the employee's will require the applicable premium rate to be paid for all regular hours worked until such seven (7) days has elapsed after the original notice has been given.

Exceptions to Normal Hours of Work for Information Technology (IT) Employee

(b) Monday to Friday change to normal hours of work; upon mutual agreement, the hours of work for IT employees may change to start no earlier than 0700 and end no later than 1800. The change would remain in effect for five (5) day increments.

(c) Monday to Saturday afternoon shift; upon 30 days' notice, the Company may change the hours of work for five (5) consecutive days for an individual IT employee to start at 1300 hours and end at 2100 hours, for a total of forty (40) regular hours of work for the week. Each IT employee can only be put on the afternoon shift three (3) times per calendar year. The Company reserves the right to return to normal hours, providing they give seven (7) calendar days' notice. Failure to give the appropriate notice to the employee will require the appropriate premium rate of pay for all regular hours worked until seven (7) calendar days have elapsed since the original notice has been given.

Employees will be entitled to two (2) fifteen (15) minute breaks per shift. The first break will be taken between the hours of 1400 hours to 1500 hours. The second break will be taken between 1830 hours to 1930 hours. A paid meal period will be taken in a minimum amount of time between 1600 hours to 1700 hours.

8.1.1 Employees will be entitled to two (2) fifteen (15) minute paid breaks per day. The morning break is to be taken between 0930 and 1030 hours and the afternoon break is to be taken between 1430 and 1530 hours. Employees are to utilize their break periods when scheduled: breaks shall not be worked through and taken at alternate times.

8.2 Overtime

All Company approved overtime will be paid as follows. The first four (4) hours after normal quitting time or preceding normal start time Monday to Friday will be paid at one and a half (1.5) times their hourly rate. No more than four (4) hours a day, from Monday to Friday, can be paid at time and a half (1.5). All overtime performed outside of the first four (4) hours Monday to Friday will be paid at two (2) times the employee's hourly rate.

All overtime performed on Saturday, Sundays and Statutory holidays will be paid at two (2) times the employees regular hourly rate.

Overtime will be offered to Regular Employees before Temporary Employees, Temporary Part-Time Employees, Regular Part-Time Employees or contract workers unless the work is a continuation of the original assignment and the Regular Employees are qualified to do the work.

8.2.1 Rest Time

Employees should come to work adequately rested so they can perform their duties effectively and safely.

Day workers who work more than four (4) hours during the period between 2300 hours and the next regular scheduled shift shall be allowed a rest period of five (5) hours with compensation at the basic hourly rate. Double time rates will apply until a rest period is taken.

An employee who is required to work continuously for more than sixteen (16) hours, or an employee who accumulates sixteen (16) hours of working time in any twenty-four (24) hour period without a minimum five (5) hour continuous break between 2300 hours and 0700 hours, shall be entitled to an eight (8) hour rest period.

Employees may use vacation, or unpaid leave for the remainder of the regular scheduled shift subject to supervisory approval.

8.3 Minimum Call-Out

Employees called out to work other than their normal hours shall be paid at the applicable premium rate with a minimum of three (3) hours pay.

Article 9 **RECOGNIZED HOLIDAYS**

9.1 Statutory holidays for Temporary/Temporary Part-Time Employees, Regular Part-Time Employees and employees serving a probationary period will be prorated based on regular hours worked in the four (4) weeks preceding the statutory holiday. After the completion of a three (3) months' probationary period employees will be paid for the following holidays, or if the day falls on a Sunday, for the day observed as the holiday, unless off on an approved leave of absence: New Year's Day, Good Friday, Victoria Day, Canada Day, Civic Holiday, Labour Day, Thanksgiving Day, Remembrance Day, Christmas Day, Boxing Day, Easter Monday and Family Day.

9.2 All time worked on any of the above named holidays will be paid at the rate of double-time in addition to the normal day's pay for all employees.

9.3 When a statutory holiday falls on a scheduled day off, with mutual agreement the employee may take the scheduled day of work prior or after the statutory holiday without pay.

9.4 The Company reserves the right to determine and schedule employees necessary to work any statutory holidays. Forty-eight (48) hours' notice will be given to the employees that are scheduled to work statutory holidays.

Article 10 **VACATIONS**

10.1 The reference year for vacation purposes is January 1 to December 31. Vacation entitlement is accrued monthly and is pro-rated for an employee who is hired or who leaves the Company during the year. An employee may use their vacation days once they are earned. An employee may make a request in writing, for approval, to their supervisor to use vacation days that have not yet been earned. However, the total vacation entitlement used in the current year must not exceed the employee's entitlement for that year.

Employees who achieve the number of years of service required to move to the next level of vacation entitlement during a given year will be granted vacations on a prorated basis based on their anniversary date.

All employees will receive vacation with pay on the following schedule;

After one (1) years' employment	– 3 weeks
After seven (7) years' employment	– 4 weeks
After eleven (11) years' employment	– 4 weeks plus one day
After twelve (12) years' employment	– 4 weeks plus two days
After thirteen (13) years' employment	– 4 weeks plus three days
After fourteen (14) years' employment	– 4 weeks plus four days
After fifteen (15) years' employment	– 5 weeks

10.2 Vacations are not to be taken in periods of more than two (2) weeks at one time unless special arrangements are made. When booking vacation, vacation is to be booked in a minimum of one (1) day intervals. With Company approval and subject to changes to a posted vacation schedule, vacation may be taken in one-half (1/2) day increments.

10.3 Employees will have the month of January in each year to submit suggested vacations. Within two (2) weeks, the Company will post a vacation schedule for those employees covered by this agreement. Every effort will be made to allow employees to have at least two (2) weeks' vacation between June 1st and September 1st. The Company will attempt to grant preference of remaining vacation time as requested by the employees but the final decision regarding vacation schedules rests with the Company.

10.4 It is recognized that employees will not carry over vacations from one calendar year to the next. However, employees who are entitled to three (3) or more weeks' vacation, may be allowed to carry over one or two weeks' vacation respectively, when a special excursion is planned and approved by the Company. This privilege will not be extended to any employee more frequently than once every five (5) years.

10.5 An employee who becomes ill while on vacation shall not be placed on sick leave until after termination of the vacation. Under exceptional circumstances in case of very serious illness, accident, or injury; sick leave may be granted if the employee submits with his/her application for sick benefit a certificate of a qualified doctor certifying to his/her illness and approved by insurance carrier. The employee would then be entitled to the unused portion of his/her vacation after recovery from illness.

Article 11 SICK LEAVE

11.1 The Company agrees to pay eighty five percent (85%) of an employee's normal earnings for the first three (3) days of sick leave providing, if requested by his/her immediate supervisor, the employee submits with his/her application for sick benefit a certificate of a qualified doctor certifying to his/her illness.

Absences related to illness that extend beyond three (3) days, or absences related to injury shall be paid as outlined in the existing Group Insurance benefits as set out in the GLPT Group Plan 162565 with the Great-West Life Assurance Company and in the GLPT Group Plan 0048956-001 with RBC Insurance Company.

11.2 If an employee is absent and requires a Doctor's certificate the Company will reimburse the employee for the cost of the Doctor's certificate upon proof of payment.

Article 12 PENSION AND INSURANCE

12.1 The existing Defined Contribution Pension Plan for Salaried Employees of Great Lakes Power Transmission LP (GLPT Pension Registration No. 1240423), revised in accordance with changes negotiated for this agreement, shall continue in effect.

12.2 The existing Group Insurance benefits as set out in the GLPT Group Plan 162565 with the Great-West Life Assurance Company and in the GLPT Group Plan 0048956-001 with RBC Insurance Company revised in accordance with changes negotiated for this agreement, shall continue in effect.

12.2.1 Under the above noted insurance plan or similar plan (equivalent or better), the following basic benefits will be provided:

(1) Life Insurance

(2) Weekly Indemnity

(3) Long Term Disability

(4) Vision Care

(5) Dental Plan

(6) Extended Health Care and Drug Plan

LTD eligibility is as defined in the Group Plan with the RBC Insurance Company.

12.3 The Company agrees to pay one hundred per cent (100%) of the premium costs of the benefits plans listed in 12.2.1 above and one hundred per cent (100%) of the Employer Health Tax.

12.4 After thirty-six (36) months on long term disability, if the employee is unable to return to work he/she shall lose seniority and be removed from the payroll. At this time, continuation of healthguard coverage shall be made available at the Company's expense.

12.5 It is acknowledged and agreed that additional benefits granted by the Company in this agreement satisfy the requirements of the refund provisions of the rebate section of the Employment Insurance Premium Reduction Program.

12.6 The Company agrees to top up the employees maternity leave benefits from EI to the difference of 80% of the employee's base rate for 26 weeks.

Article 13 JOB POSTING AND SELECTION

13.1 In the event that the Company must select between more than one (1) employee in making reductions, additions, or replacements to the work force, or in making promotions or demotions, seniority, ability and proficiency will be the governing factors, but where ability and proficiency are relatively equal, seniority with the Company from the last date of hire will govern. All such vacancies or additions, except for vacation relief, casual work or emergency work, or approved leaves shall be posted on the bulletin boards within fifteen (15) working days of becoming vacant for at least ten (10) working days, with such vacancies being posted in all areas on the same day. No applications for the positions posted will be accepted after the ten (10) day posting. If there are no successful applicants within the Company, the Company may fill the vacancy externally.

An employee may decline promotion at any time without affecting his/her seniority or promotional rights.

13.1.1 Subject to all the provisions of this article, any employee who will be absent for more than seven (7) calendar days on an approved leave of absence of thirty (30) days or less may lodge in writing with his/her immediate Company supervisor a request to be considered for specified vacancies that arise during his/her period of absence. This request will constitute sufficient reason for him/her to be considered as any other applicant.

13.1.2 The names of the successful applicants shall be posted on the bulletin board for at least five (5) calendar days within fifteen (15) working days following the last day of posting on the bulletin board.

13.2 The Company shall notify the Union of all persons so promoted or transferred.

13.3 Where an applicant does not receive a position applied for, he/she shall, upon request to his/her supervisor, be counselled in writing as to what steps should be taken to be more likely to succeed in future applications.

Article 14 LAYOFF AND RECALL

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14.1 In the event of a layoff, employees in the bargaining unit shall be laid off in the reverse order of their seniority, provided the Company can retain a staff qualified to perform the work available. Employees shall be recalled on the basis of their seniority, provided they are qualified to do the work available.

14.2 Notice Period

The Company will notify the Union at least sixty (60) days prior to the effective date of layoff of designated employees. The Company and the Union will meet and discuss alternatives.

The Company will give the employees who are to be laid off as much advance notice as possible and in no case less than six (6) weeks.

Article 15 LEAVE OF ABSENCE

15.1 General

15.1.1 All employees are required to give as much notice as possible to their immediate supervisor when, due to illness or otherwise, they are unable to report for work. Any employee absenting himself/herself from work without providing reasonable cause shall be subject to disciplinary action.

Any employee absenting himself/herself from work without providing reasonable cause, for more than two (2) consecutive work days, may be subject to dismissal.

15.1.2 If the Union requires a Union representative to be released from their normal duties to perform Union business, the Union will compensate the Company in the following manner:

(i) absences less than or equal to five (5) days - the employee's normal rate of pay;

(ii) all absences after five (5) days - normal rate of pay plus benefits totaling forty-two per cent (42%) will be reimbursed.

On giving sixteen (16) days' notice to the Company such absences will be accommodated insofar as the regular operation of the department in which he/she is employed will permit.

Normally absences for the Principal Steward will not exceed fifteen (15) days' per year and eight (8) days per year to the Stewards.

Where delegates have incurred expenses in order to attend a Union Convention and, because of a Company emergency, are unable to attend the Convention, the Company shall reimburse the two (2) delegates for non-recoverable expenses.

15.1.3 An employee of the Company who is elected or selected for a position with the Union or anybody with which the Union is affiliated or who is elected to public office, must make application for a leave of absence in writing at least three (3) weeks in advance of such leave. Approval will not be unjustly withheld; however, only one employee at any one time will be granted a leave of absence under this paragraph.

15.1.4 With the mutual consent of the employee and his/her supervisor, employees will be allowed thirty seven and a half (37.5) hours leave of absence annually at their request for additional time off. It is understood that such requests for leave of absence will normally be granted. Such time off will be without pay and may be used at the employee's discretion with a minimum of one-half (1/2) of a shift off.

15.1.5 Employees called to Her Majesty's service or enlisting during a period when Canada is at war, shall be reinstated upon their return with all privileges and seniority ratings they had when leaving the service of the Company.

15.1.6 When in the Company's judgment the circumstances warrant such action a leave of absence with pay will be granted to a maximum of three (3) days per calendar year.

This leave is based upon reasons of personal emergency, such as severe illness in the immediate family which would necessitate remaining away from work until adequate arrangements could be made for outside help or in cases where an employee is faced with the effects of a severe storm, fire or flood.

15.2 Bereavement Leave

15.2.1 Whenever a death occurs to a member of the immediate family of an employee, the Company will compensate the employee for any time lost from work up to a maximum of four (4) consecutive work days which include the day of the funeral. The Company agrees to consider the granting of up to two (2) additional days with pay for traveling time, provided cause is shown for the need of this time. Compensation shall be at the regular hourly rate of the employee for a normal work day. The term "immediate family", for the purpose of this paragraph, to be considered to include only the following:

(i) the spouse, parents, sister, brother, child, grandchildren, mother-in-law or father-in-law, son-in-law, daughter-in-law or grandparents of the employee; and

(ii) a relative or foster children residing in the household of the employee.

15.2.2 Whenever a death occurs to a member of the family who is not considered as immediate family, the Company will compensate the employee for one (1) day of lost time in order to attend the funeral. The Company agrees to consider the granting of up to two (2) additional days with pay for traveling time, provided cause is shown for the need of this time. For purposes of this clause, family other than immediate shall be interpreted to mean: brother-in-law, sister-in-law, spouses' grandparents, aunt or uncle, niece or nephew.

15.3 Jury and/or Witness Duty

The difference in wages between an employee's straight time wage, excluding premium pay, and the fee allowed will be paid by the Company to any employee required to serve on a jury or to be a court witness in the District of Algoma. Exceptions to this case shall be taken to the Company for consideration.

Article 16 ALLOWANCES

16.1 Travel

16.1.1 The Company will supply transportation, at its own discretion either in Company vehicles or by public transportation, for employees carrying out their normal duties when travelling between work centres. Time spent in travelling will be paid for at the applicable rate when an employee is required to travel between work centres. Employees will travel from their work centres to and from the job on the Company's time. The words "work centre" shall, for the purpose of this clause, be where the employee is normally reporting for work.

16.1.2 Employees working away from their regular work centre during the week will be allowed to return to that centre on Company time for the weekend, unless they are required for weekend work.

16.1.3 Except in the case of an emergency, when employees are required to be away from home overnight, every effort will be made to give at least forty-eight (48) hours' notice of such requirement.

16.1.4 Any employee covered by this agreement whose work requires him/her to be away overnight from where he/she normally resides, will be provided with a room, reimbursement at the appropriate kilometer rate as per the Company policy if the employee utilizes their personal vehicle and reimbursement of meal expenses subject to the limits outlined in 16.1.5. At all times the use of a personal vehicle for business purposes is to be preapproved by the Company.

16.1.5 Employees will be reimbursed for actual meal expenses, not including alcoholic beverages, upon provision of an itemized receipt. The maximum reimbursable expenses, including tip, are as follows:

(i) a breakfast allowance of twenty dollars ($20.00)
(ii) a lunch allowance of twenty five dollars ($25.00), and
(iii) a dinner allowance of forty dollars ($40.00)

On the first day away from their normal work center the meal expense will be prorated to include lunch and dinner and on the day the employee returns home to include breakfast and lunch unless the employee works past 1800 hours, in which case the dinner allowance would apply.

16.1.6 In all cases, where the Company requires the employee to travel for training, the Company will pay for the course, course materials, meals and accommodations.

16.1.7 Travel time, for the purpose of training, which is conducted outside of an employee's scheduled working time, will not be compensated.

16.2 Employees forced to transfer within the Company will be reimbursed for their moving expenses to a maximum of five thousand dollars ($5,000).

Article 17 WORKING RELATIONS COMMITTEES

The Company and the Power Workers' Union – CUPE Local 1000 have agreed to work together to improve relationships and organizational effectiveness through co-operation and a commitment to excellence. In this way employees can influence the decision making process in matters concerning our future. In working together we will demonstrate fair and equitable treatment to all employees.

We will adhere to the following Guiding Principles:

- Foster an open, honest forum of information exchange
- Encourage and respect differing opinions
- Actively promote decisions formed by consensus
- Respect rights and privileges of all parties
- Focus on decisions that are good for people and good for business
- Focus on our future rather than our past

17.1 Stewards: The Company will recognize two (2) stewards.

17.2 Grievance Committee: The Company will recognize a Committee of not more than two (2) employees.

17.3 Negotiating Committee: The Company will recognize a Negotiating Committee of not more than two (2) employees as well as a representative(s) of the Power Workers' Union and an executive member of the Union.

The two (2) employees on the Negotiating Committee will be paid their regular hourly rate for time spent in negotiating a collective agreement during normal working hours up to a maximum of thirty seven and a half (37.5) hours per employee.

It is understood that negotiation means time up to but not including conciliation and mediation.

17.4 The Working Relation Committee shall be kept informed of the names and addresses of all officers, stewards and committee members of the Union. The Company will advise the Principal Steward of the Union of the names of the Company personnel to be notified with reference to the grievance procedure.

17.5 Senior Company representatives (2) and utility representatives (2) will constitute a working group which will meet regularly so that issues that do occur are resolved quickly and a positive relationship is established to minimize future issues. The working group will act as a sounding board for Company policies which might affect Union members. This will not circumvent the normal supervisory role in solving day-to-day issues.

Article 18 SAFETY RELATED CLAUSES

The parties are committed to the health and safety of all employees as demonstrated in the Company Joint Health and Safety Policies and Safety Work Management Systems.

18.1 Time will be scheduled during regular working hours for all employees to maintain their Company mandated safety training. Those employees not on duty will be paid applicable premium rates when instructed by the Company to attend such training sessions.

18.2 The Union and the Company agree to observe the provincial health and safety regulations and the safety regulations prescribed and published by the Company from time-to-time. The Union will co-operate with the Company in encouraging employees to observe the safety regulations, and to work in a safe manner. The Company agrees to discuss and review safety concerns as they occur with the union safety representatives. The union safety representatives shall assist, make recommendations to and co-operate with the Company to ensure the Safety Procedures and Programs are implemented. The Company will involve union health and safety representatives and/or other union members as required in System Safety Accident Investigations.

18.3 The Company will consult with the Union and supply safety clothing when, in the opinion of the Company, such is needed.

Article 19 CONTRACTING OUT

19.1 The Company agrees that during the term of the current agreement with Power Workers' Union-CUPE Local 1000 no regular employee of the Company shall be laid off or demoted as a result of the contracting out of work by the Company.

Article 20 GENERAL

20.1 Certification/Training

The Company in recognizing the need for updating employee qualifications will provide the opportunity at their discretion for employees to attend training courses. An employee on a training course shall be paid on the basis of their normal day's pay while at the course. No compensation shall be given for time outside of normal working hours.

20.2 Payment of Professional Fees

Where an employee is required by the Company to maintain a professional accreditation to establish a particular level of competency, and there is a professional fee associated with doing so, the Company will reimburse each such individual so required the amount of the fee upon presentation of appropriate proof of payment to his/her department head.

Article 21 WAGES AND CLASSIFICATIONS

21.1 Wage rates shall be paid as they appear in the following sections of the agreement and shall be for pay purposes only.

21.2 EMPLOYEE CLASSIFICATIONS

Job Classes

	Accounting Clerk	Admin. Assistant	Service Desk Technician	Operations/ Engineering Technician	Contract Specialist	Technical Analyst	Management Accountant	System Analyst
2016								
Class D (80%)	19.77	19.56	18.98	23.15	26.00	28.73	30.98	35.24
Class C (85%)	21.00	20.78	20.17	24.60	27.63	30.52	32.91	37.44
Class B (90%)	22.24	22.01	21.36	26.05	29.25	32.32	34.85	39.65
Class A (100%)	24.71	24.45	23.73	28.94	32.50	35.91	38.72	44.05
2017 2.6%								
Class D (80%)	20.28	20.07	19.48	23.75	26.68	29.47	31.78	36.16
Class C (85%)	21.55	21.33	20.70	25.24	28.35	31.31	33.77	38.42
Class B (90%)	22.82	22.58	21.92	26.72	30.02	33.16	35.76	40.68
Class A (100%)	25.35	25.09	24.35	29.69	33.35	36.84	39.73	45.20
2018 2.65%								
Class D (80%)	20.82	20.60	20.00	24.38	27.38	30.26	32.62	37.12
Class C (85%)	22.12	21.89	21.25	25.91	29.10	32.15	34.66	39.44
Class B (90%)	23.42	23.18	22.50	27.43	30.81	34.04	36.70	41.76
Class A (100%)	26.02	25.75	25.00	30.48	34.23	37.82	40.78	46.40

21.3 <u>Cost of Living Adjustment</u>

If the average monthly CPI for Ontario for the twelve (12) months ending December 31, 2017 is greater than the average monthly CPI for Ontario for the twelve (12) months ending December 31, 2016, a onetime lump sum payment will be made prior to March 31, 2018 based on the following table:

PERCENTAGE CHANGE IN CPI	PAYMENT AS A PER CENT OF GROSS EARNINGS
<3.00	0.00
>=3.00<3.50	0.50
>=3.50<4.00	1.00
>=4.00<4.50	1.50
>=4.50	2.00

Similarly, if the average monthly CPI for Ontario for the twelve (12) months ending December 31, 2018 is greater than the average monthly CPI for Ontario for the twelve (12) months ending December 31, 2017, a onetime lump sum payment will be made prior to March 31, 2019 based on the following table:

PERCENTAGE CHANGE IN CPI	PAYMENT AS A PER CENT OF GROSS EARNINGS
<3.00	0.00
>=3.00<3.50	0.50
>=3.50<4.00	1.00
>=4.00<4.50	1.50
>=4.50	2.00

21.4 All employees covered by this agreement will be paid every second Thursday by 1500 hours by direct deposit to a bank account, but in the event the Thursday on which payday falls is a holiday, employees shall receive their pay the previous day. Cheque stubs will be forwarded to the employee's Work Centre.

21.5 When major changes are proposed to be made in any classification, or new classifications are requested by the Company, during the term of this agreement, wage rates and hours of work for the change shall be subject to negotiation.

Article 22 CLASSIFICATION CHANGES AND PROGRESSIONS

22.1 The wage rates, progression schedules, classifications and categories of employees covered by this agreement shall be those shown in Article 21.

22.1.1 All employees moving through an annual progression grid will have their performance monitored on an ongoing basis and documented at least annually by the employee's supervisor. Where an employee's performance is not satisfactory he/she shall be informed of the areas of work that are deficient. Progression will be based on the recommendation of the employee's supervisor. When progression is withheld, the Company shall meet with the employee, who may request the presence of his/her steward, or another Union representative, and shall give the employee the reason for withholding progression. Two (2) months thereafter his/her general performance will be reviewed and if found satisfactory, the employee shall be granted the progression.

22.1.2 If his/her progress and general performance are still unsatisfactory, the employee shall:

(1) in the case of a new employee in the step in the classification in which they started , be terminated;

(2) in the case of an employee above the starting classification in any category, remain in such class for at least one (1) year and then may again request a reclassification and recommendation from his/her supervisor;

(3) in the case of an employee who was previously transferred from another category, revert to his/her former job if it is available. If it is not available, he/she may be transferred to other available work, providing he/she is qualified. Failing this, his/her employment may be terminated.

Article 23 DURATION OF AGREEMENT

23.1 This agreement shall remain in effect from January 1, 2016 to December 31, 2018 and from year to year thereafter unless either party gives notice in writing to the other party not more than ninety (90) days and not less than thirty (30) days prior to December 31st in any year of their desire to alter same.

23.2 Working conditions during the term of this Agreement shall be outlined in this Agreement and any Mid-Term Agreement.

A Mid-Term is a modification of the Collective Agreement executed by the parties in the following format during the term of the Collective Agreement.

Mid-Term Agreement

Title ____________________

Number ____________________

Date ____________________

It is jointly agreed that the following Mid-Term shall form part of the Collective Agreement between the parties.

SIGNED ON BEHALF OF:

GREAT LAKES POWER TRANSMISSION LP

____
Vice-President, Operations

POWER WORKERS' UNION, CUPE LOCAL 1000

____
Vice-President, Power Workers' Union

____
Principal Steward

____
Steward

School Energy Coalition (SEC) INTERROGATORY #9

Interrogatory

[A-1-1-Attach, section 6.3.2] Please explain the rationale for section 6.3.2.

Response

Great Lakes Power Transmission Holdings LP and Great Lakes Power Transmission LP are indebted under various debt instruments. Section 6.3.2 repeats the terms on which control of the borrowers can change without triggering a default resulting in the outstanding debt falling due. The Vendor included section 6.3.2 in its form of Purchase and Sale Agreement to ensure that the debt could remain in place on sale of the Purchased Securities.

School Energy Coalition (SEC) INTERROGATORY #10

Interrogatory

[A-2-1, p.4] Please provide a copy of GLPT's "draft capital expenditure plan".

Response

Please refer to Exhibit I, Tab 2, Schedule 6a.

School Energy Coalition (SEC) INTERROGATORY #11

Interrogatory

[A-2-1, p4] With respect to the capital expenditure cost saving scenarios:

a. Please provide a breakdown of Table 3, to show the specific areas of the potential cost savings per year.

b. Please provide details of all assumptions used in the calculations.

Response

Please refer Exhibit I, Tab 2, Schedule 6b.

School Energy Coalition (SEC) INTERROGATORY #12

Interrogatory

[A-2-1, p.5] With respect to the capital expenditure cost saving scenarios:

a. Please provide the basis, including all underlying documentation, that the Applicant used to derive the GLPT "OM&A Cost Forecast Without Transaction" forecast (Table 4).

b. Please provide a breakdown of Table 7, to show the specific areas of the potential cost savings per year.

c. Please provide details of all assumptions used in the calculations.

Response

a) GLPT provided HOI with information shown in Table 4 relating to 2017 and 2018 costs. The 2017 and 2018 costs are reflective of the OM&A expenses, expected at the time, to be included in GLPT's 2017 and 2018 revenue requirement application. OM&A expenses beyond 2018 were inflated annually by 2%.

b) HOI understands the request to be a breakdown of Table 4. This information is provided below.

HOI completed an envelope reduction to the total OM&A and not a line by line savings analysis. As outlined in the application, detailed cost savings analysis will be undertaken in 2017 and 2018. Potential areas of productivity savings related to OM&A are discussed in Exhibit I, Tab 1, Schedule 2.

GLPT Operating Expense

$/M	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Escalation (%)	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Operating & Administration	8.67	8.84	9.02	9.20	9.38	9.57	9.76	9.96	10.15	10.36
Maintenance	2.06	2.10	2.14	2.18	2.23	2.27	2.32	2.36	2.41	2.48
Insurance	0.34	0.35	0.36	0.36	0.37	0.38	0.39	0.39	0.40	0.41
Cost Allocations	0.41	0.42	0.42	0.43	0.44	0.45	0.46	0.47	0.48	0.49
TOTAL	11.48	11.71	11.94	12.17	12.42	12.67	12.93	13.18	13.44	13.74

c) Please refer to b)

School Energy Coalition (SEC) INTERROGATORY #13

Interrogatory

[A-2-1, p.8-9] Please provide all calculations and assumptions made with respect to the forecast of the UTR with and without the transactions for both, the base and high case scenarios.

Response

Hydro One estimated the UTR revenue requirement for GLPT based upon the assumptions in Tables 2-5 of Exhibit A, Tab 1, Schedule 1. The requested analysis is broken down into two parts, the calculation of the 2026 projected GLPT revenue requirement and then the derivation of the UTR.

2026 Projected Revenue Requirement

$/million	Status Quo	Base Case	High Case
OM&A	13.7	11.8	9.1
Depreciation	12.3	11.9	11.8
Return on Debt	11.3	10.8	10.3
Return on Equity	10.7	10.1	9.7
Income Tax	2.4	2.1	1.9
Less Other Income	-0.1	-0.1	-0.1
Revenue Requirement	50.3	46.6	42.7
Rate Base	289.9	274.8	262.9
LT Debt Rate	6.87%	4.62%	4.62%
ST Debt Rate	1.65%	1.65%	1.65%
ROE	9.19%	9.19%	9.19%

Calculations showing the potential impact of the above revenue requirements on the UTR are found in Attachments 1-3. In order to isolate the UTR impact of the GLPT revenue requirement all other transmitter's revenue requirements were held constant at 2016 levels.

The UTR impact of the transaction at the end of the 10 year rate rebasing deferral period (relative to current 2016 UTR rates) based upon the scenarios described in Exhibit A, Tab 2, Scheulde 1 is to be an increase of approximately $0.02 to the Network Service Rate and $0.01 to the Transformation Connection rate under the Base Case scenarios (i.e. capital and OM&A). Under the High Case scenarios, the Network Service Rate is to increase by approximately $0.01 from current 2016 rates.

Uniform Transmission Rates and Revenue Disbursement Allocators
assuming GLPT Base Case Revenue at Year 10 of Rebasing Period

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
GLPT	$27,273,727	$6,474,466	$12,869,807	$46,618,000
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	$932,693,850	$213,585,139	$424,560,029	$1,570,839,018

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	241,956	207,936	
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)	**3.68**	**0.87**	**2.03**	
	↓	↓	↓	
FNEI Allocation Factor	**0.00397**	**0.00411**	**0.00411**	
CNPI Allocation Factor	**0.00280**	**0.00290**	**0.00290**	
GLPT Allocation Factor	**0.02924**	**0.03031**	**0.03031**	
H1N Allocation Factor	**0.92865**	**0.96268**	**0.96268**	
B2MLP Allocation Factor	**0.03534**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Uniform Transmission Rates and Revenue Disbursement Allocators
Assuming GLPT High Case Revenue at Year 10 of Rebasing Period

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
GLPT	$24,993,799	$5,933,237	$11,793,964	$42,721,000
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	$930,413,921	$213,043,911	$423,484,187	$1,566,942,018

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	241,956	207,936	
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)	**3.67**	**0.87**	**2.02**	
	↓	↓	↓	
FNEI Allocation Factor	**0.00398**	**0.00412**	**0.00412**	
CNPI Allocation Factor	**0.00280**	**0.00291**	**0.00291**	
GLPT Allocation Factor	**0.02686**	**0.02785**	**0.02785**	
H1N Allocation Factor	**0.93093**	**0.96512**	**0.96512**	
B2MLP Allocation Factor	**0.03543**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Uniform Transmission Rates and Revenue Disbursement Allocators
Assuming GLPT Status Quo Revenue at Year 10 of Rebasing Period

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
GLPT	$29,450,103	$6,991,112	$13,896,785	$50,338,000
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	$934,870,225	$214,101,785	$425,587,008	$1,574,559,018

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	241,956	207,936	
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)	**3.68**	**0.87**	**2.03**	
	↓	↓	↓	
FNEI Allocation Factor	**0.00396**	**0.00410**	**0.00410**	
CNPI Allocation Factor	**0.00279**	**0.00289**	**0.00289**	
GLPT Allocation Factor	**0.03150**	**0.03265**	**0.03265**	
H1N Allocation Factor	**0.92649**	**0.96036**	**0.96036**	
B2MLP Allocation Factor	**0.03526**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

School Energy Coalition (SEC) INTERROGATORY #14

Interrogatory

[A-2-1, p.4-9] Based on the forecasted capital and OM&A cost savings, forecasted under both the base and high case scenarios, please provide an estimated actual ROE for GLPT for each year between 2017 and 2026.

Response

The estimated ROEs for GLPT under both the base and high case scenarios for the periods 2017-2026 can be sourced from the model provided in Exhibit I, Tab 2, Schedule 10, Attachment 4. The results can be found by setting the scenario 'modes' in the excel model tab labeled "ROE" and will be calculated on row 13. The model scenarios can be changed (to Base and High) in the Excel model, by going to the 'Assumptions' tab by entering the correct scenario number in cell D11.

ROE%	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Base Scenario	11.26%	10.63%	11.27%	11.28%	11.29%	11.11%	10.95%	11.22%	11.08%	11.16%
High Scenario	11.26%	10.63%	13.24%	13.42%	13.40%	13.29%	13.41%	13.71%	13.72%	13.87%

School Energy Coalition (SEC) INTERROGATORY #15

Interrogatory

[A-2-1, p.4-9] Please explain why there are no forecasted capital and OM&A cost savings under both the base and high case scenarios for 2017 and 2018.

Response

Please refer to Exhibit I, Tab 4, Schedule 6.

School Energy Coalition (SEC) INTERROGATORY #16

Interrogatory

[A-2-1, p.9] Please advise whether Applicant would consider it appropriate for the Board to make commitments to maintain or improve reliability as a condition of its transmission license. If the Applicant does not consider that appropriate, please explain why.

Response

The type of condition proposed is not appropriate. Licensed transmitters are required to meet all applicable safety and reliability standards as required under the applicable legislation and regulations. HOI expects that Hydro One and GLPT will continue to meet these requirements, should this application be approved.

<u>School Energy Coalition (SEC) INTERROGATORY #17</u>

<u>Interrogatory</u>

[A-2-1-p.8-9] What harm, if any, does the Applicant believe that increasing its share of the transmission system in Ontario from 94.6% to 96.8% will have on ratepayers. Please provide a copy of all submissions, information and materials provided to the Competition Commissioner related to the transaction.

<u>Response</u>

No harm to ratepayers is expected to result from this transaction.

HOI declines to provide the requested information as it is not relevant to the application before the OEB. The Competition Bureau is an independent law enforcement agency responsible for administering and enforcing (among other legislation) the federal *Competition Act*. The Competition Bureau's review of the transaction concerns requirements found under the *Competition Act*; its process is distinct from the jurisdiction of the OEB and the approvals sought in this Application.

School Energy Coalition (SEC) INTERROGATORY #18

Interrogatory

[A-3-1, p.1] Please provide any analysis or evidence to justify why a 0% productivity factor for transmission is appropriate.

Response

Please refer to Exhibit I, Tab 3, Schedule 5.

School Energy Coalition (SEC) INTERROGATORY #19

Interrogatory

[A-3-1, p.1] Please explain what the Applicant means by the "… given that the circumstances in this case concern transmission entities..."

Response

The quoted phrase concerns HOI's proposal to set a productivity and stretch factor at 0%. The rationale for this is found in Exhibit I, Tab 1, Schedule 7 and Exhibit I, Tab 3, Schedule 5.

School Energy Coalition (SEC) INTERROGATORY #20

Interrogatory

[A-3-1, p.1] Please explain why the Applicant believes a stretch factor of 0% is appropriate.

Response

Please refer to Exhibit I, Tab 1, Schedule 7 and Exhibit I, Tab 3, Schedule 5.

School Energy Coalition (SEC) INTERROGATORY #21

Interrogatory

[A-3-1, p.1] Please provide a copy of all benchmarking studies or analysis undertaken by GLPT, or by the Applicant which includes GLPT in it, in the last 5 years.

Response

Benchmarking studies undertaken by Hydro One in the last 5 years have not included GLPT. Hydro One's peer group has included comparable larger-sized transmitters.

For benchmarking studies completed by GLPT over the last 5 years, please refer to Attachments 1, 2 and 3.

Attachment 1

Great Lakes Power Transmission operation Cost Analysis

Prepared by:
First Quartile Consulting, LLC

September 9, 2010

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Introduction

Great Lakes Power Transmission LP (GLPT) is a transmission owner and operator serving a portion of northern Ontario, Canada. GLPT was established as part of a series of reorganizations of Great Lakes Power Limited (GLPL) in which GLPT became the owner and operator of GLPL's transmission business. Prior to these reorganizations GLPL ran the transmission business financially separate from its generation and distribution businesses and operationally in conjunction with the distribution business. Previously the transmission business of GLPL has been through a full cost of service review. This is the second application of GLPT as a stand-alone transmitter, i.e., both financially and operationally.

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. There are very few true "peers" for comparison, since GLPT is somewhat unique in terms of its size, rural geographic location, and dense vegetation. Nevertheless, 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 company. 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.

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 and distribution benchmark study. That study doesn't collect A&G costs as part of the standard comparisons.

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 (some of whom are included in the comparison panel) typically capture the A&G costs together with the O&M costs, and report them as OM&A. The experience from the annual 1QC benchmark studies is that the Canadian utilities are able to separate out the A&G costs effectively, by following the definitions provided in the uniform system of accounts, so their results are directly comparable,

To address the need to include A&G costs in the comparison, we gathered three years of A&G expenses from available FERC reports. These A&G expenses as reported to FERC are for the whole generation, transmission and distribution operation. Therefore, it was necessary to make an allocation of A&G expenses for just transmission lines & substations. A rudimentary calculation was used to allocate A&G to transmission: (transmission O&M expense / (transmission + generation + distribution O&M expense)) * total A&G expense = transmission portion of A&G expense. While this is a very simple approach to allocating the costs, it has been tested in previous years through annual benchmark studies, and has proven accurate in determining allocations that are very close to the actual allocations for each company.

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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.

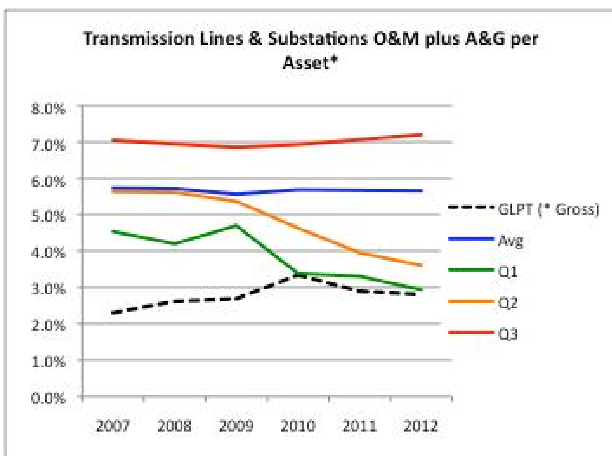
Results and Conclusions

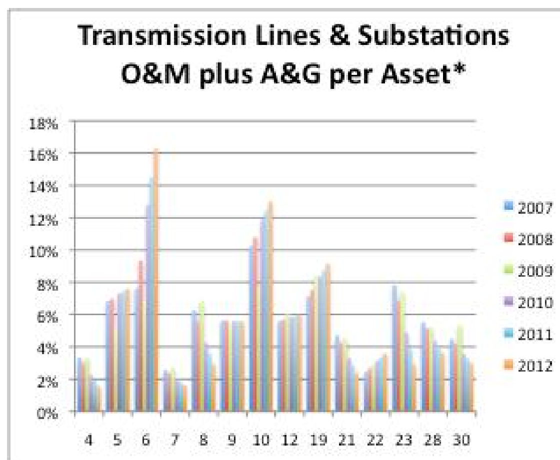
Based upon our primary comparison, GLPT generally falls below average on a cost per asset basis. In the graphs below, the mean and quartiles are calculated without GLPT's data. They are based solely on our panel of companies, so that GLPT is being compared against a data set without influencing it.

Note that in graphs years 2010 to 2012 are projected based upon 2007 to 2009 actual data for all companies other than GLPT.

For all of the graphs only companies for which A&G data was available were used. GLPT compares favorably against this panel. Graph 2 shows just the A&G per asset. Clearly, while GLPT shows slightly increasing A&G costs, the result is still well below the median cost within the panel

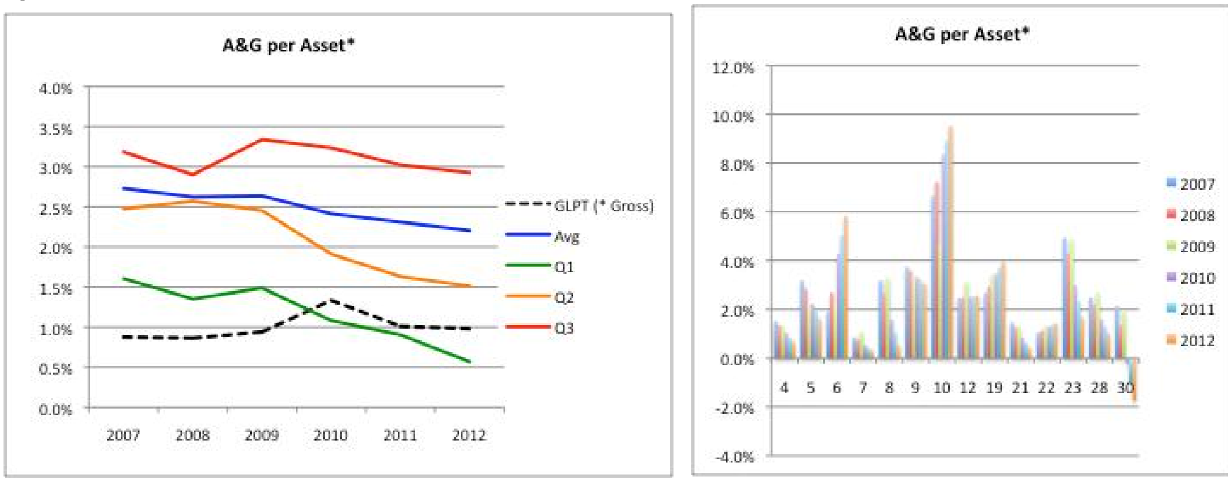
Graph 1





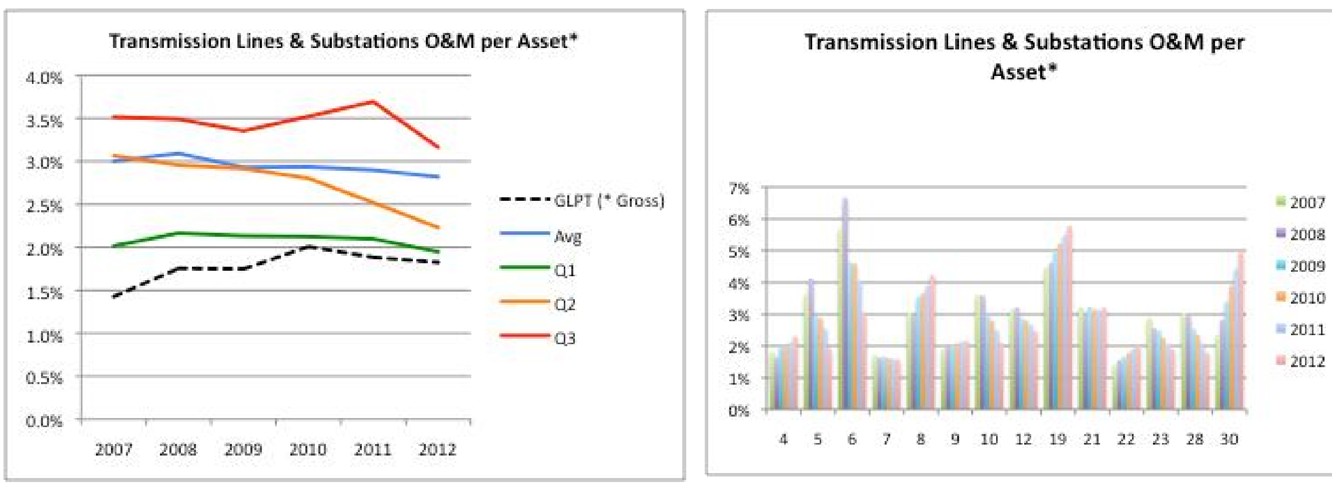
A comparison of this report with a similar report prepared during 2009 will show different values for the cost-per-asset figures for Great Lakes Power. In particular, during the 2009 study, the net assets were used for Great Lakes Power, rather than the gross assets, as was done for all other companies in the comparison. This was corrected during this year's study. The conclusions of the study don't change on the basis of the revised computation, so there is no need to go back and re-issue the previous study.

Graph 2



Graph 3 below shows the O&M costs without the A&G costs. GLPT, even with increases in the past two years, is and expects to remain in the first quartile for the comparison panel.

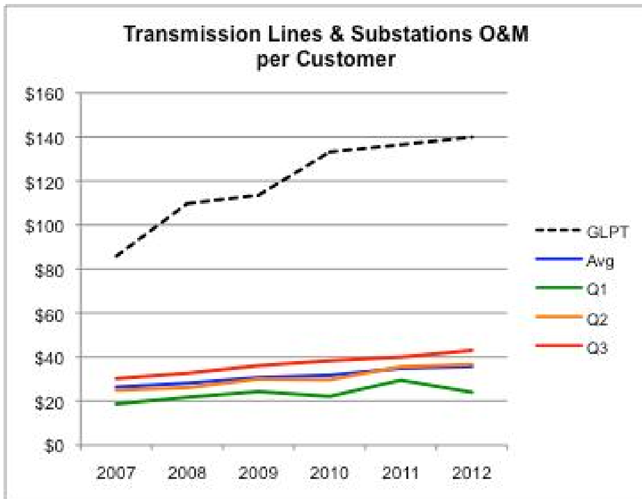
Graph 3



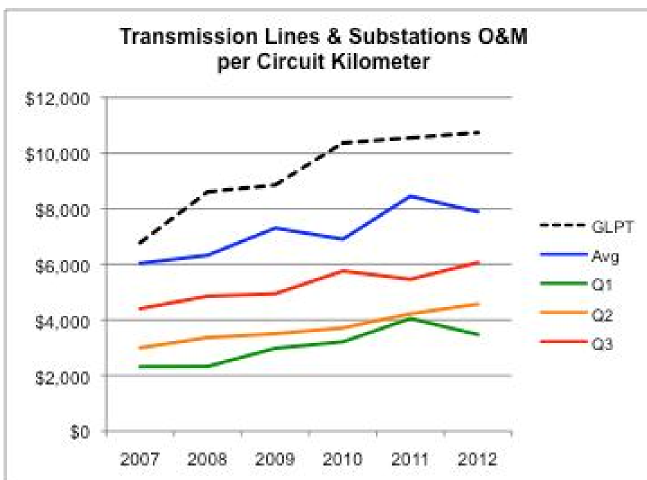
An important point about the GLPT costs for 2009 and 2010 should be noted. GLPT is in the midst of a multi-year construction program, so the asset base will be growing. These expenditures won't be reflected in the denominator of the ratio charted until 2011, because a large portion of the expenditures will be in CWIP for the forecast period, rather than in the in-service asset base. At the same time, the new assets (primarily substation assets) will require less maintenance than the assets they are replacing. The implication is that once the new assets are placed in service after 2010, there will be a dampening effect on the increasing cost/asset shown in graph 1 above.

For other comparisons, we also normalized spending based upon customers and circuit kilometers. Neither of these comparisons is recommended (see appendix) and the results are about as expected for GLPT, which is a small transmission operator.

Graph 4



Graph 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. 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 are generally the same direction.
In order to re-validate the results from previous years, the project team performed an analysis of the data from the most recently completed annual benchmark dataset. The results of that analysis are presented below.

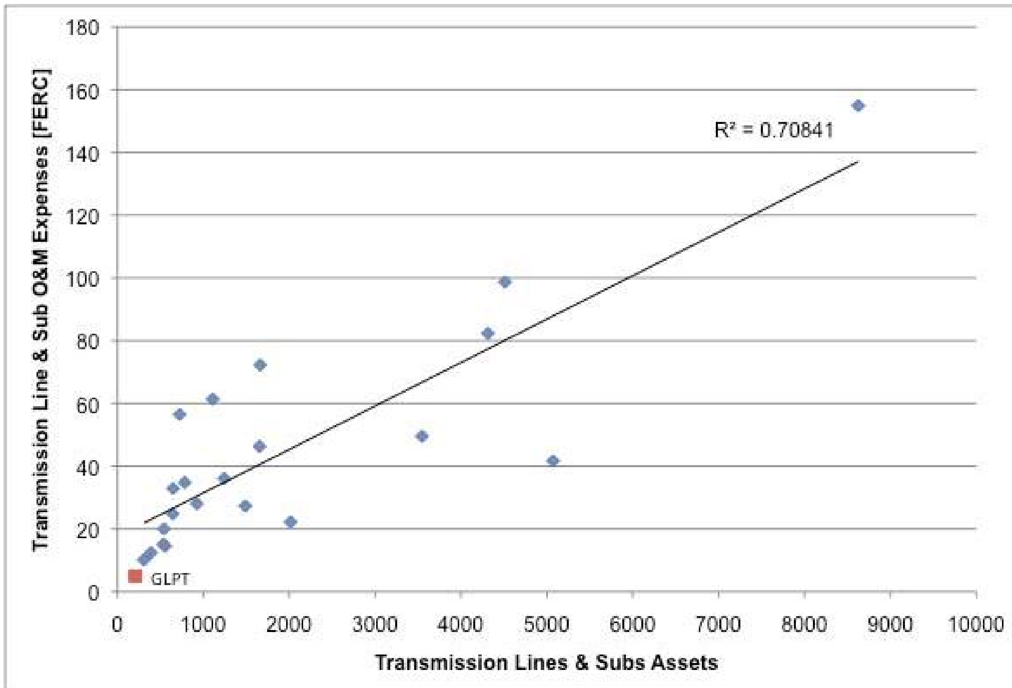
To determine the appropriate denominators (normalizing factors) to use for analysis, we compare the dependent variable, in this case O&M spending, to various independent variables: customers, circuit kilometers, and assets. We look for a strong correlation between the two variables. For transmission lines and substations O&M spending, the strongest correlation exists between spending and assets. The relationship between spending and customers or circuit km is much weaker. 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. It was necessary to determine the correct normalizing factor from our most current valid data set.

	Transmission Lines & Subs Assets	Transmission Circuit Kilometers	Customers
Transmission Line & Sub O&M Expenses (FERC)	0.708	0.502	0.257

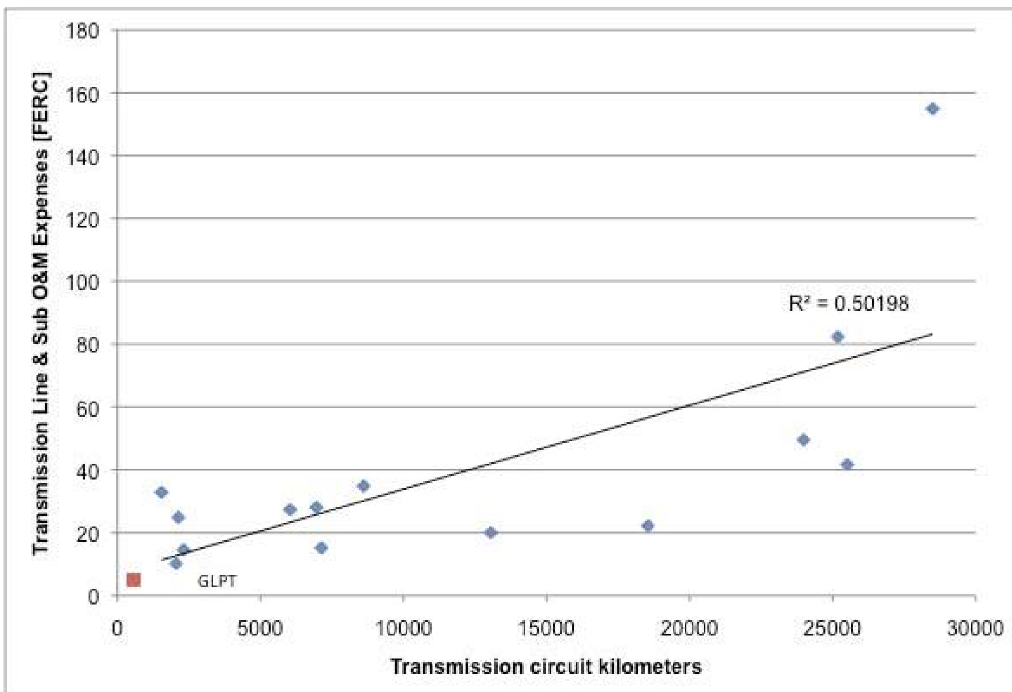
In summary, we have found assets to be the appropriate denominator because it appears to have a higher predictive value when there are big differences in customer density among the panel.

Transmission operators do not really have end-use customers, which is one reason customers is such a weak normalizing factor. Kilometers is also weak because the costs of operating substations are included in the dependent variable and substations are not accounted for when kilometers is used as a normalizing factor.

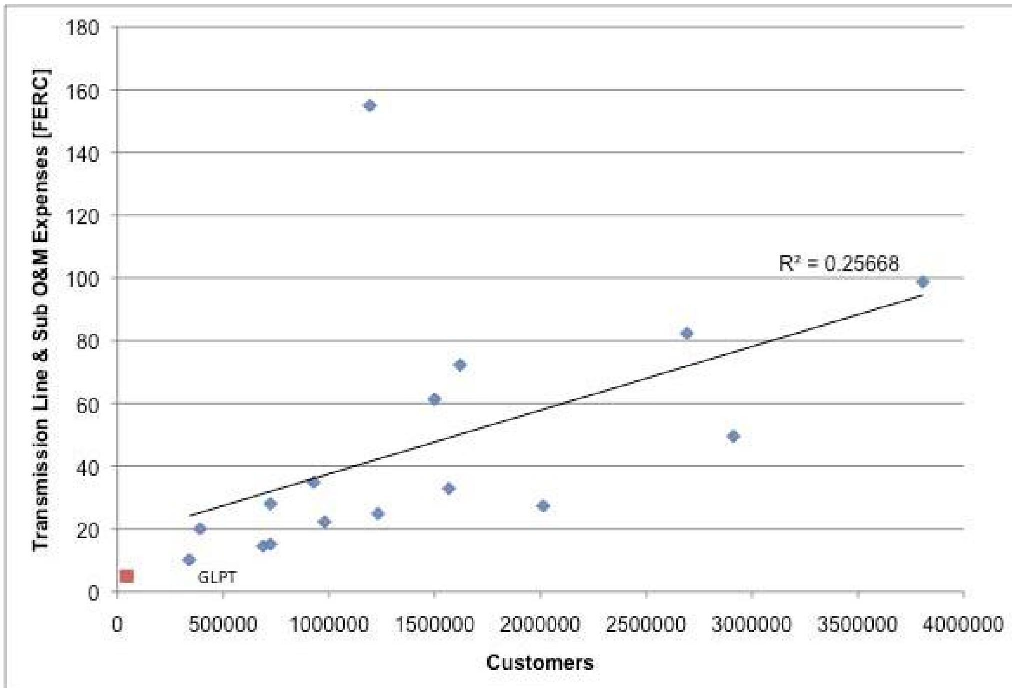
Shown below are the individual graphs from which the R^2 values are derived. In each graph, GLPT has been added to the graph to show where they fall compared to the other companies, but they are not included in the calculation of the correlation coefficient. 1QC decided that it was appropriate to determine the correlation coefficients independently of GLPT's data. By performing the analysis this way, GLPT's data isn't influencing the findings.



Other correlation charts between expenses and normalizing factors:



Note that the outlier on the circuit kilometers graph is on the regression line when assets are used. This is particularly noteworthy because this company has some of the same characteristics of GLPT, namely low customer density. The density issue is also illustrated on the graph below.



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Appendix B: Demographics of Comparison panel

ID	CHARACTERISTICS	GEOGRAPHIC LOCATIONS	VOLTAGES/KM	TERRAIN	NUMBER OF CUSTOMERS	INDUSTRIAL CUSTOMERS	% Ind'l
4	Combined D&T	Southeast US	69kV : 684km, 100kV class : 3398km, 300kV Class and above : 1956km,	flat, dense trees	2,011,174	6,951	0.346%
5	Combined D&T	MidAtlantic US		flat, dense trees	1,225,305	389	0.032%
6	Combined D&T	MidAtlantic US	69kV : 177km, 100kV class : 211km, 200kV Class : 853km, 400kV Class and above : 302	flat, dense trees	1,555,343	3,081	0.198%
7	Combined D&T	Southwest US	69kV : 4740km, 100kV class : 11128km, 300kV Class and above : 8116km,	flat, few trees	3,077,913	182,018	5.914%
8	Combined D&T	Southeast US	69kV : 4435km, 100kV class : 3242km, 300kV Class and above : 838km, 400kV Class and above : 92	flat, dense trees	934,215	1,981	0.212%
9	Combined D&T	Southeast US	<69kV : 166km, 69kV : 2541km, 100kV class : 15395km, 200kV Class : 3640km, 300kV Class and above : 156km, 400kV Class and above : 3282	flat, dense trees	2,656,120	44,373	1.671%
10		MidWest US	69kV : 1131km, 100kV class : 2428km, 300kV Class and above : 748km	flat, some trees	510,296	2,342	0.459%
12	Combined D&T	MidWest US	<69kV : 2257km, 69kV : 2656km, 100kV class : 5701km, 200kV Class : 1562km, 300kV Class and above : 79km, 400kV Class and above : 796	flat, few trees	385,467	71	0.018%
19	Combined D&T	Northeast US	<69kV : 2257km, 69kV : 2656km, 100kV class : 5701km, 200kV Class : 1562km, 300kV Class and above : 79km, 400kV Class and above : 796	flat, dense trees	1,614,884	1,695	0.105%
21	Combined D&T	MidAtlantic US		flat, dense trees	3,800,000		0.000%
22	Combined D&T	Southwest US	<69kV : 15km, 69kV : 4258km, 100kV class : 265km, 200kV Class : 1161km, 300kV Class and above : 963km, 400kV Class and above : 2126km	flat, few trees	1,212,625	108,781	8.971%
23	Combined D&T	MidWest US	69kV : 1857km, 100kV class : 3481km, 200kV Class : 668km, 300kV Class and above : 1736km	flat, some trees	683,615	4,842	0.708%
28	Combined D&T	Southwest US	<69kV : 735km, 100kV class : 606km, 300kV Class and above : 1830km, 400kV Class and above : 853km	flat, few trees	401,263	631	0.157%
30	Combined D&T	Northwest US	<69kV : 203km, 100kV class :2755km, 200kV Class : 506km, 400kV Class and above : 825km	flat, dense trees	1,072,828	3,710	0.346%

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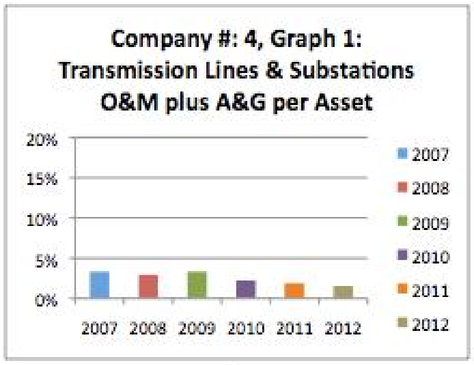
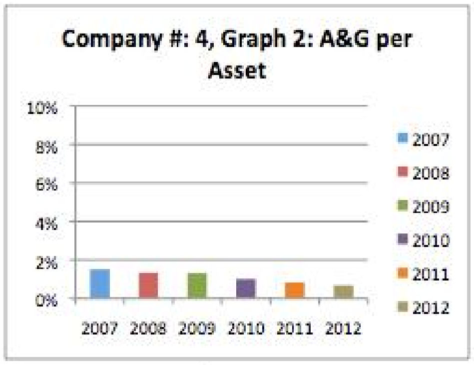
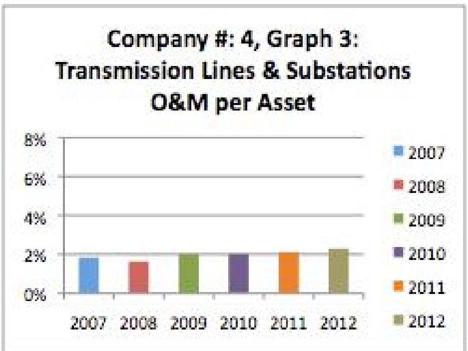
Appendix C: Individual Bar charts for comparison panel

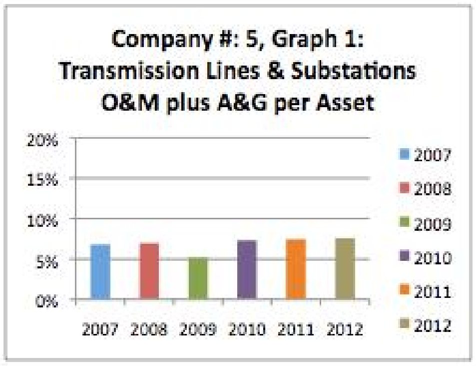
Company #4

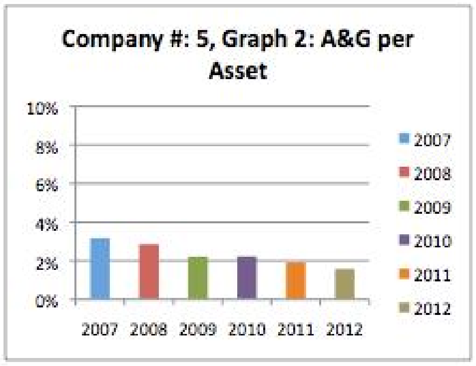


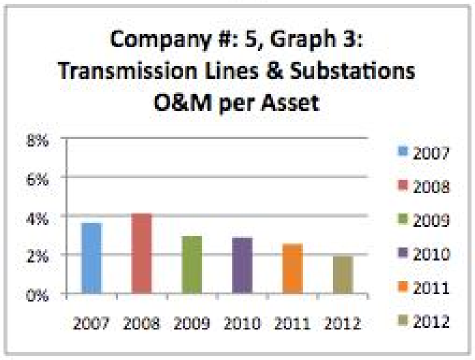




Company #5







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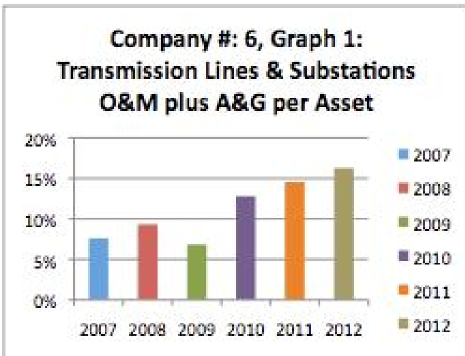
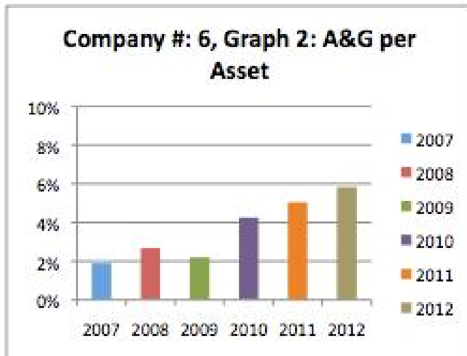
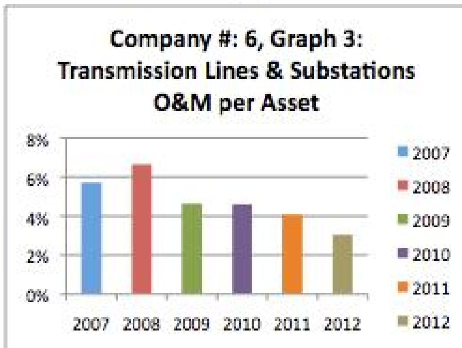
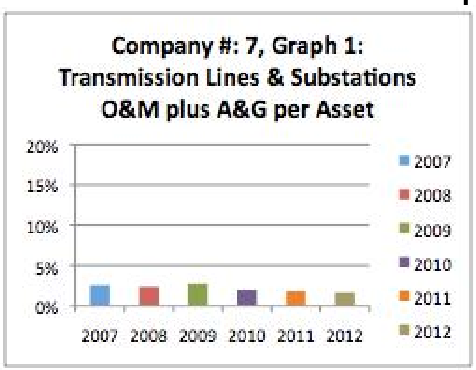
Company #6

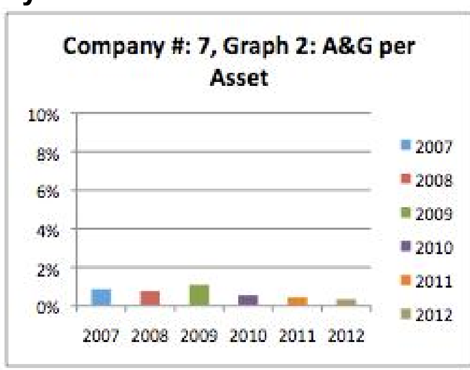


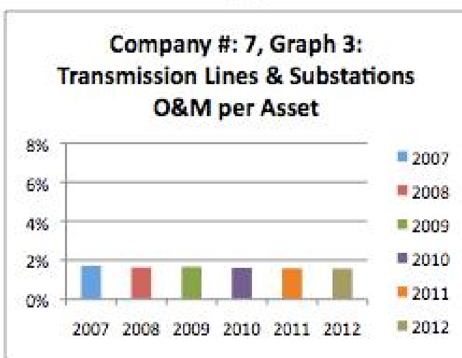




Company #7







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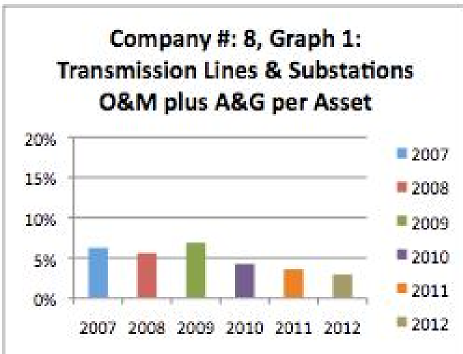
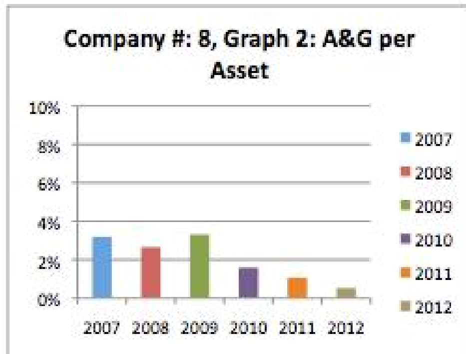
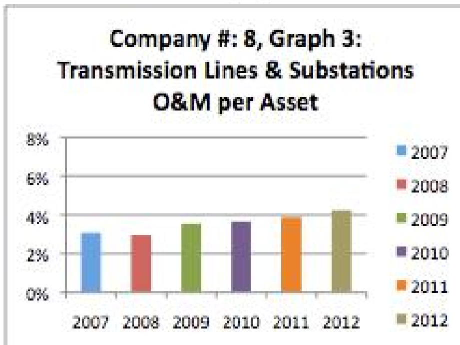
Company #8







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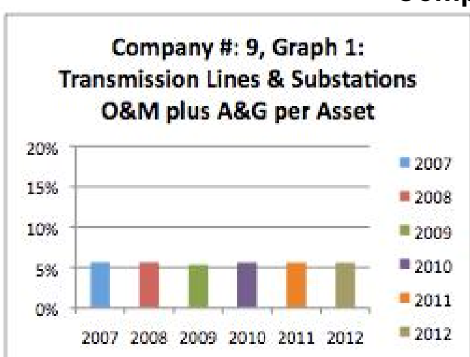

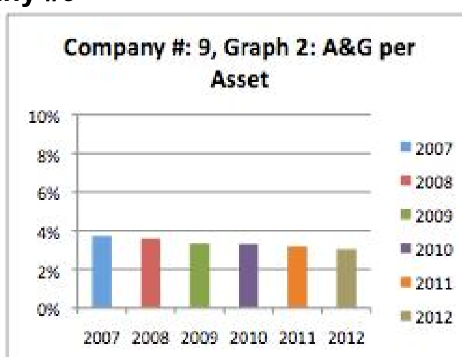

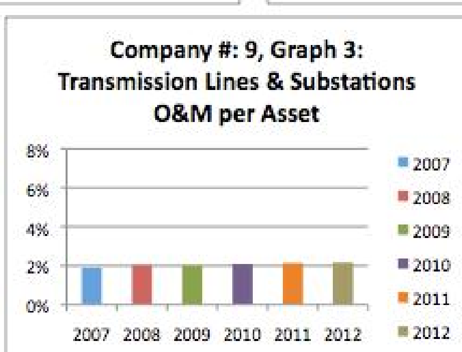

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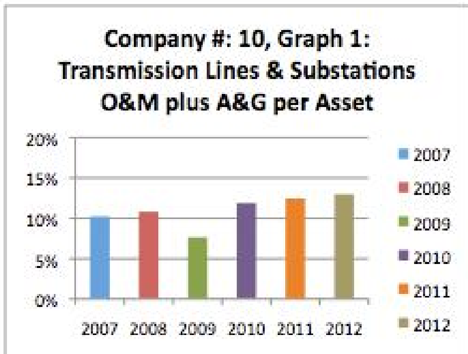

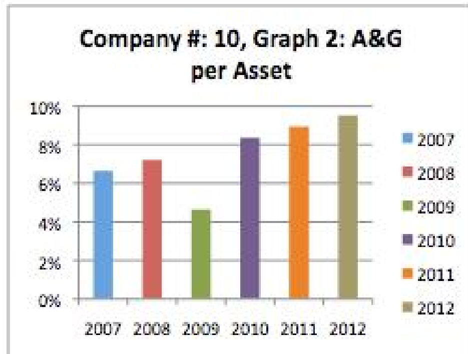

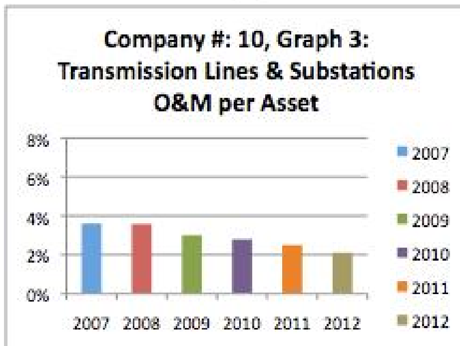

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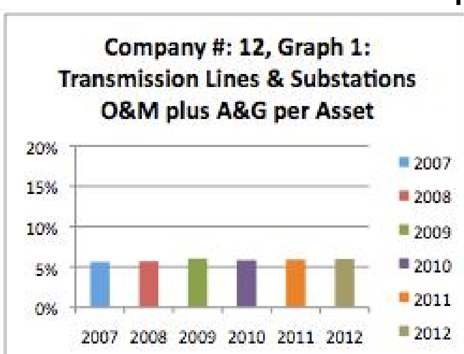

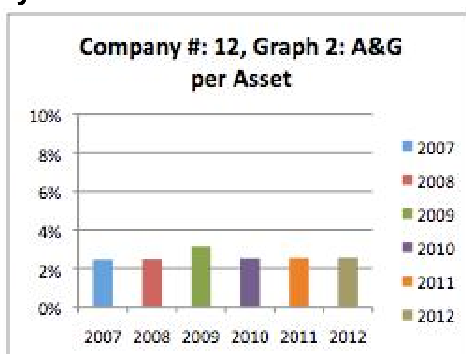

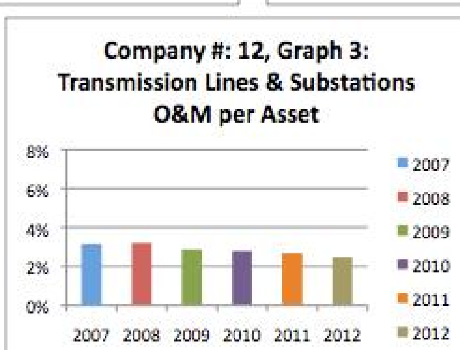

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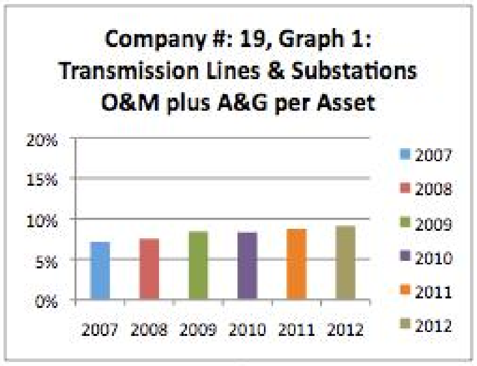

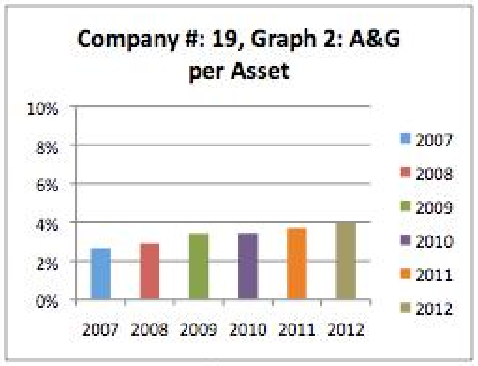

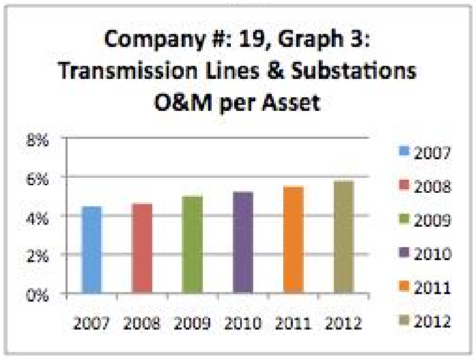

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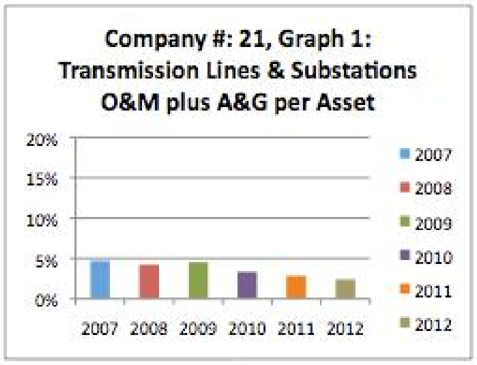

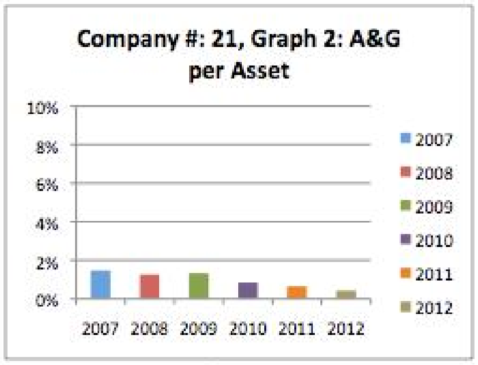

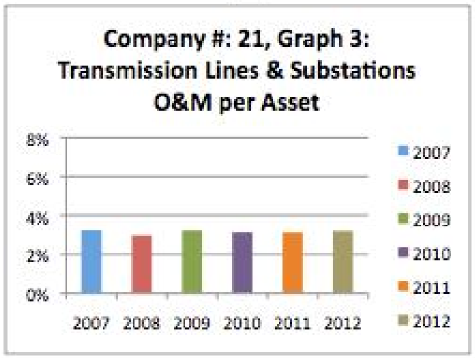

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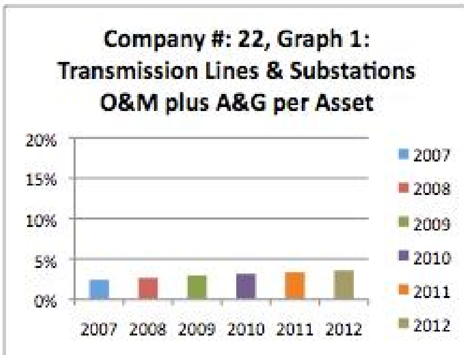

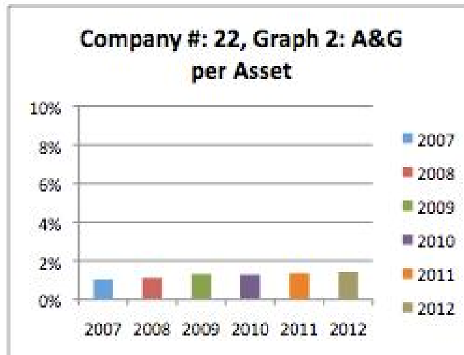

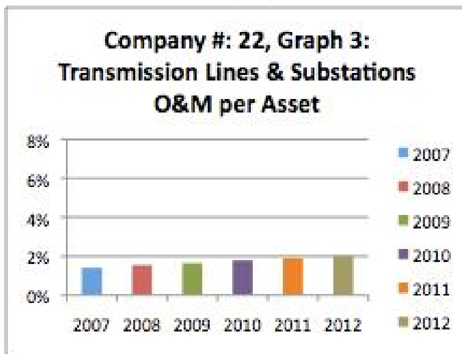

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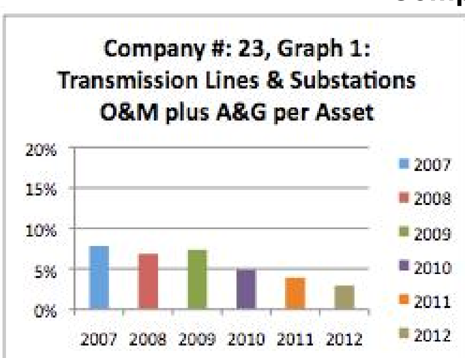

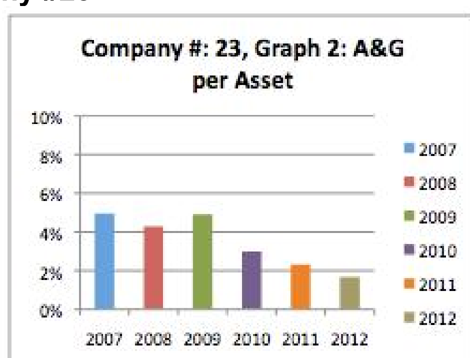

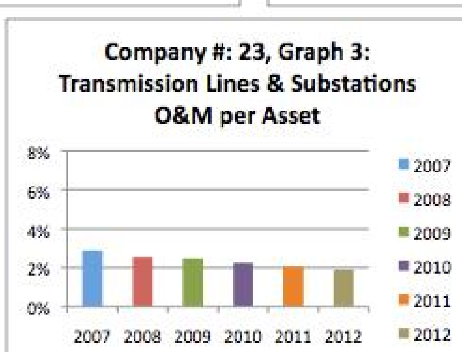

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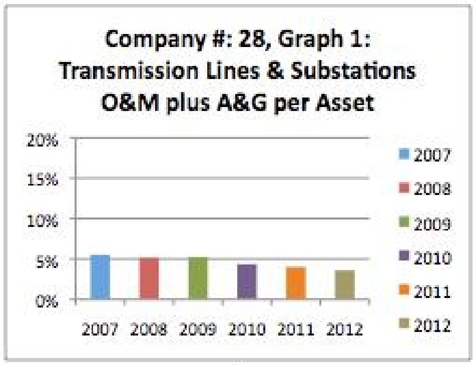

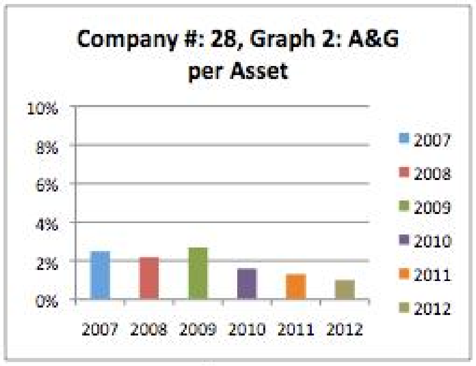

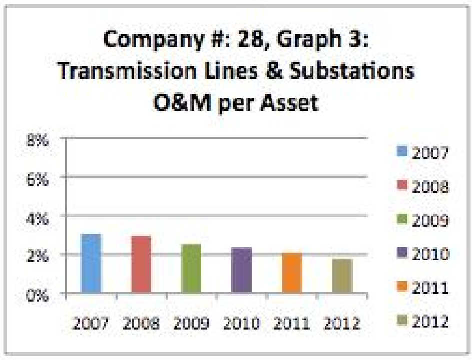

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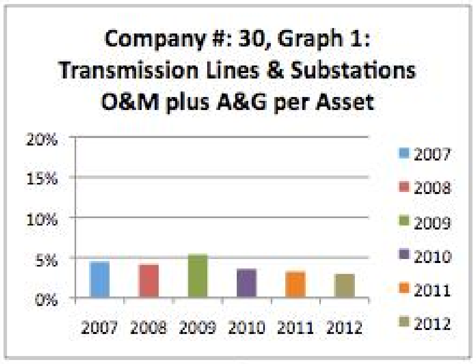

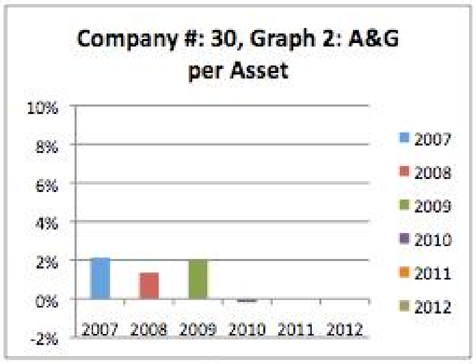

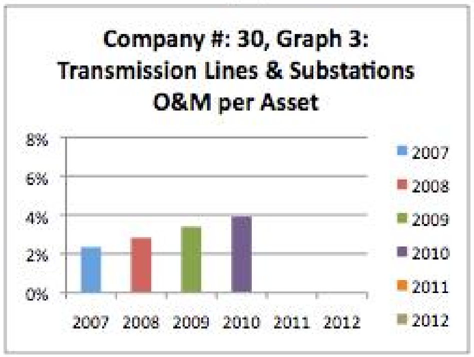

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Attachment 2

GREAT LAKES POWER TRANSMISSION OPERATION COST ANALYSIS

PREPARED BY:
FIRST QUARTILE CONSULTING, LLC

JUNE 21, 2012

FIRST QUARTILE CONSULTING

INTRODUCTION

Great Lakes Power Transmission LP (GLPT) is a transmission owner and operator serving a portion of northern Ontario, Canada. GLPT was established as part of a series of reorganizations of Great Lakes Power Limited (GLPL) in which GLPT became the owner and operator of GLPL's transmission business. Prior to these reorganizations GLPL ran the transmission business financially separate from its generation and distribution businesses and operationally in conjunction with the distribution business. This is the third application of GLPT as a stand-alone transmitter, i.e., both financially and operationally.

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. There are very few true "peers" for comparison, since GLPT is somewhat unique in terms of its size, rural geographic location, and dense vegetation. Nevertheless, 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 company. 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.

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.

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 2007 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 / (transmission + distribution + customer service expense)) * total A&G expense = transmission portion of A&G expense.

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.

Beginning in 2013, a change in Canadian accounting rules has required GLPT to adopt the International Financial Reporting Standards (IFRS), which caused GLPT to adjust the value of its asset base, effectively writing down the value of its gross assets by the amount of the accumulated depreciation at the end of 2012. Because we use gross assets for the normalizing factor in the analysis, this change makes a significant difference in the outcome of the analysis. For the purposes of the analysis, we have adjusted the figures for GLPT to include the value of the accumulated depreciation as of the end of 2012 as part of the asset value figures for 2013 and 2014. This has the effect of making the comparisons between GLPT and the other members of the comparison panel essentially "fair".

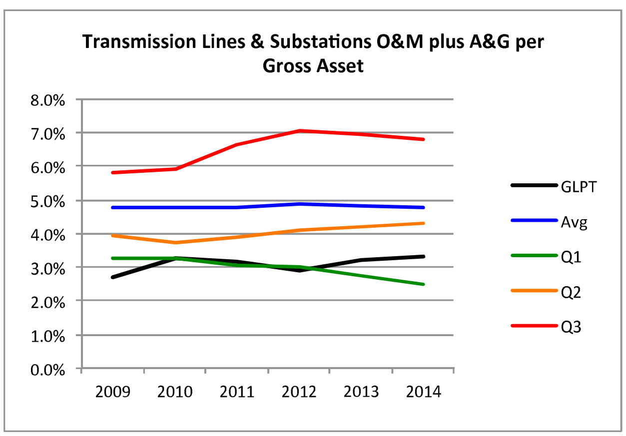
RESULTS AND CONCLUSIONS

Based upon our primary comparisons, GLPT falls significantly 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 2012 to 2014 are projected based upon 2007 to 2011 actual data for all companies other than GLPT. 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 very close to the first quartile of the panel, well below the median.

Figure 1



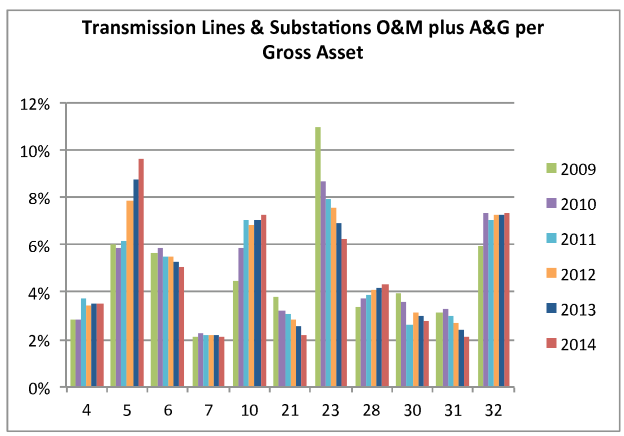


Figure 2 shows just the A&G cost per asset. GLPT's A&G costs fluctuate in a band around the lowest-cost quartile of the group, and remain well below the median for all years.

Figure 2

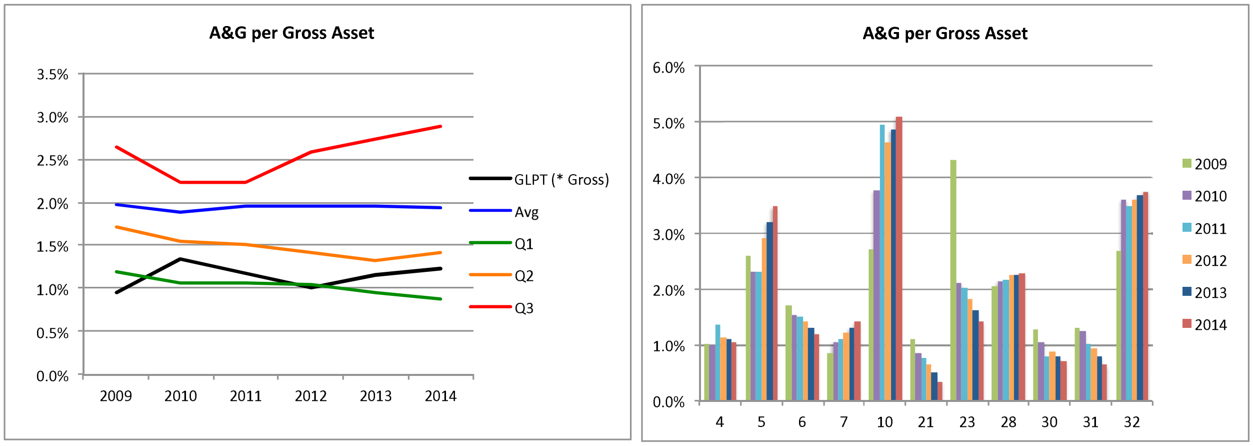
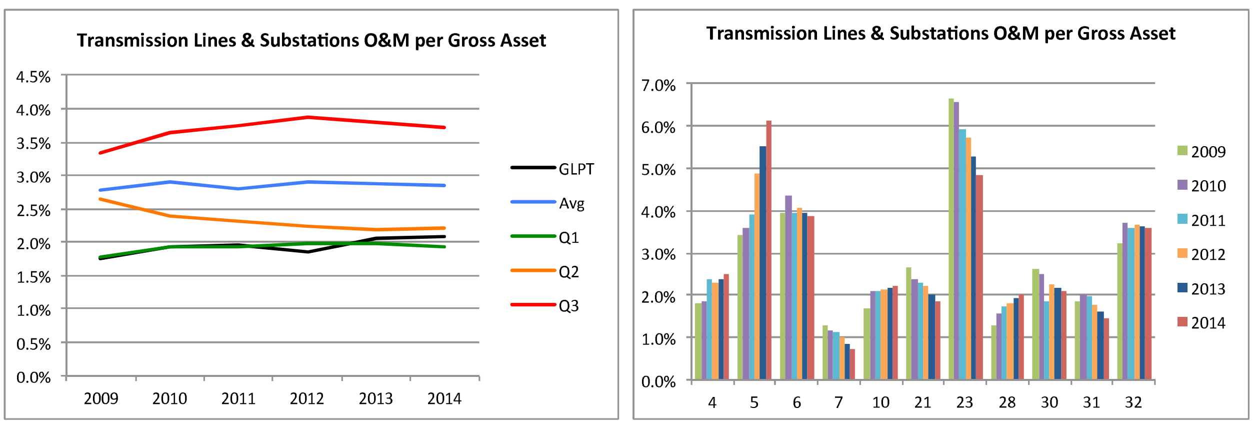


Figure 3 below shows the O&M costs without the A&G costs. GLPT is among the lowest cost providers in the group, within the first quartile for all years but one in the comparison.

Figure 3



For other comparisons, we also normalized spending based upon customers and circuit kilometers. Neither of these comparisons is recommended and the results are about as expected for GLPT, which is a small transmission operator. 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. The r^2 value for assets is .71, for circuit kilometers is .50, and for customers is .26. Appendix A provides a more complete description of this analysis.

Figure 4

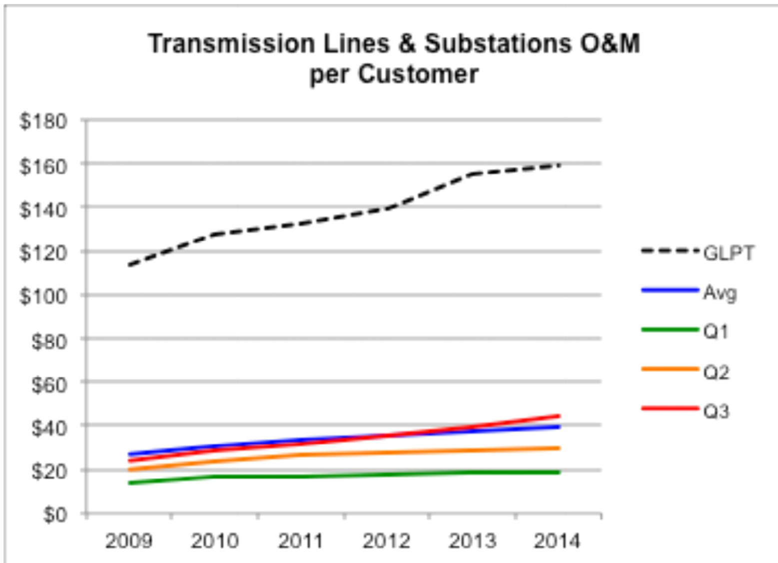
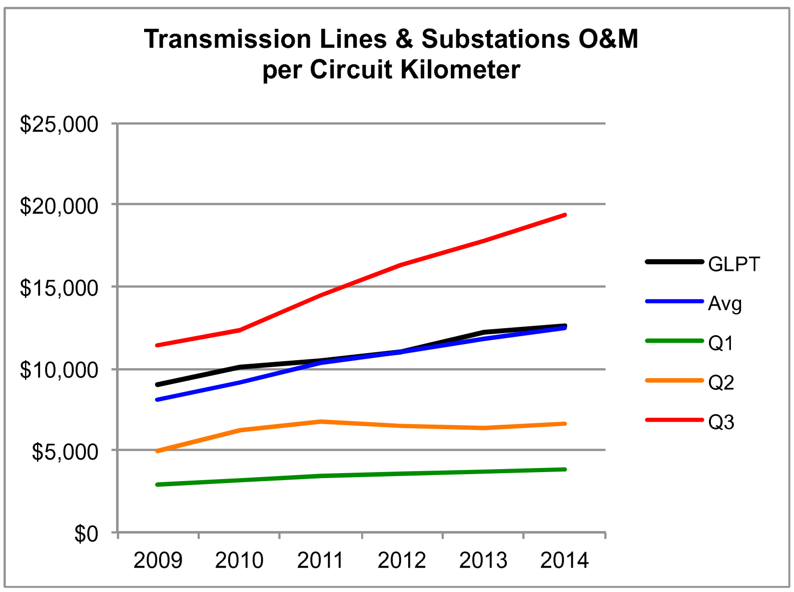


Figure 5



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.

During 2010, 1QC re-ran the analysis to verify that the basic conclusions hadn't changed. The results of that analysis are presented below.

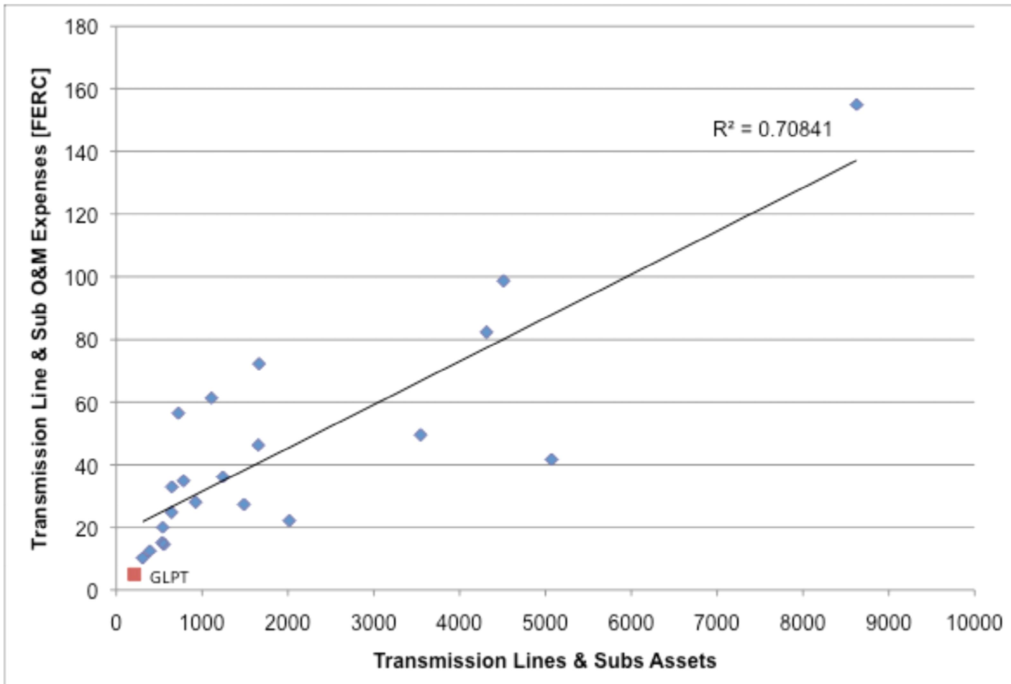
To determine the appropriate denominators (normalizing factors) to use for analysis, we compare the dependent variable, in this case O&M spending, to various independent variables: customers, circuit kilometers, and assets. We look for a strong correlation between the two variables. For transmission lines and substations O&M spending, the strongest correlation exists between spending and assets. The relationship between spending and customers or circuit km is much weaker. 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. It was necessary to determine the correct normalizing factor from our most current valid data set.

	Transmission Lines & Subs Assets	Transmission Circuit Kilometers	Customers
Transmission Line & Sub O&M Expenses (FERC)	0.708	0.502	0.257

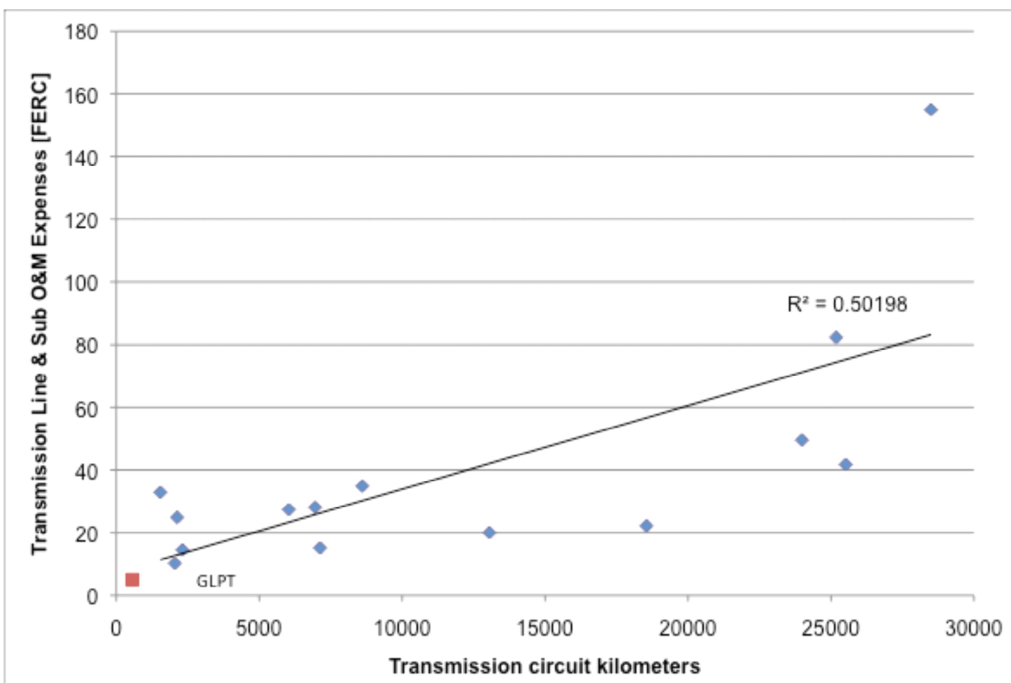
In summary, we have found assets to be the appropriate denominator because it appears to have a higher predictive value when there are big differences in customer density among companies in the comparison panel.

Transmission operators do not really have end-use customers, which is one reason customers is such a weak normalizing factor. Kilometers is also weak because the costs of operating substations are included in the dependent variable and substations are not accounted for when kilometers is used as a normalizing factor.

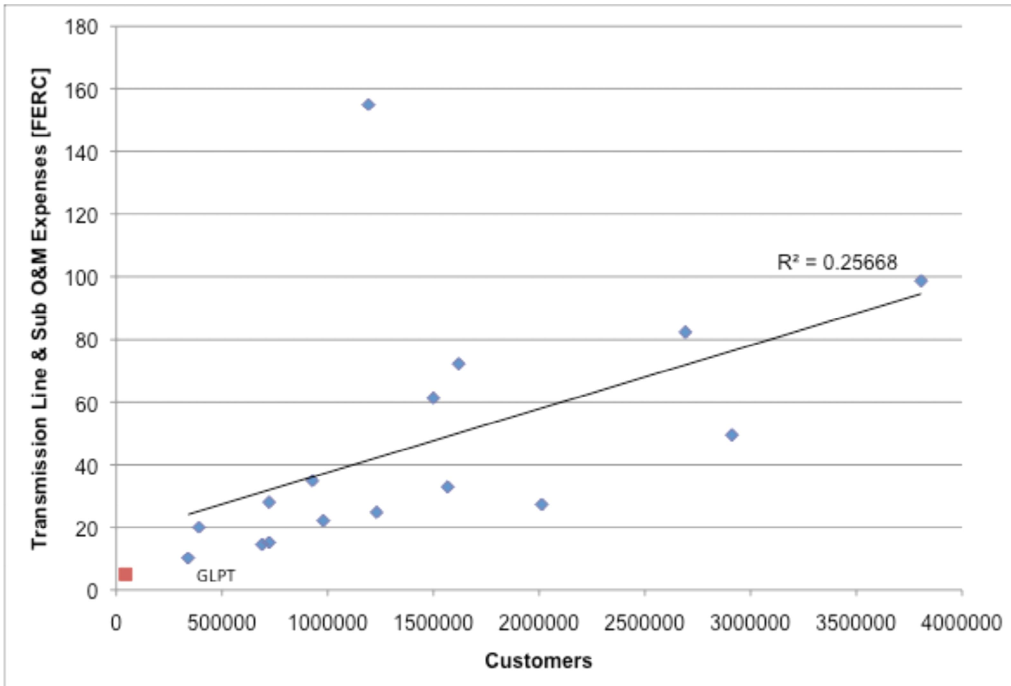
Shown below are the individual graphs from which the R^2 values are derived. In each graph, GLPT has been added to the graph to show where they fall compared to the other companies, but they are not included in the calculation of the correlation coefficient. It was appropriate to determine the correlation coefficients independently of GLPT's data, since by performing the analysis this way, GLPT's data isn't influencing the findings.



Other correlation charts between expenses and normalizing factors:



Note that the outlier on the circuit kilometers graph is on the regression line when assets are used. This is particularly noteworthy because this company has some of the same characteristics of GLPT, namely low customer density. The density issue is also illustrated on the graph below.

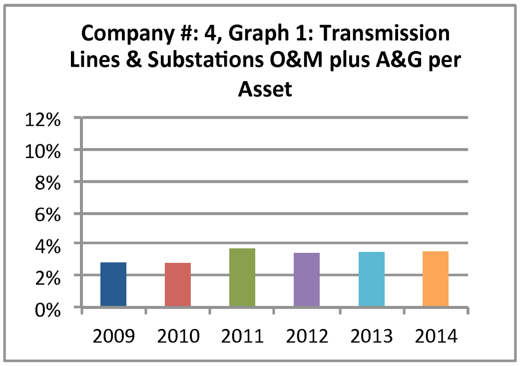


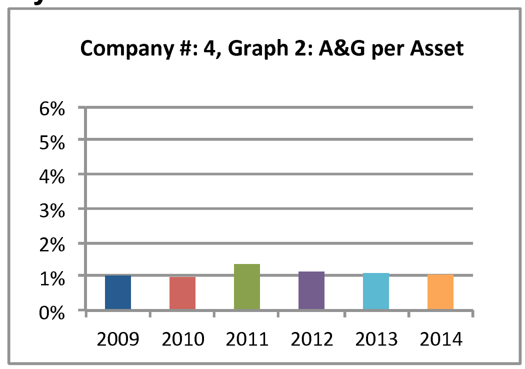
APPENDIX B: DEMOGRAPHICS OF THE COMPARISON PANEL

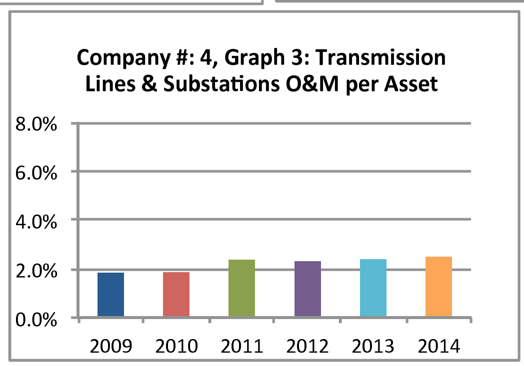
ID	CHARACTERISTICS	GEOGRAPHIC LOCATIONS	VOLTAGES/KM	TERRAIN	NUMBER OF CUSTOMERS	INDUSTRIAL CUSTOMERS	% Ind'l
4	Combined D&T	Southeast US	69kV : 684km, 100kV class : 3398km, 300kV Class and above : 1956km,	flat, dense trees	2,011,174	6,951	0.346%
5	Combined D&T	MidAtlantic US		flat, dense trees	1,225,305	389	0.032%
6	Combined D&T	MidAtlantic US	69kV : 177km, 100kV class : 211km, 200kV Class : 853km, 400kV Class and above : 302	flat, dense trees	1,555,343	3,081	0.198%
7	Combined D&T	Southwest US	69kV : 4740km, 100kV class : 11128km, 300kV Class and above : 8116km,	flat, few trees	3,077,913	182,018	5.914%
10	Combined D&T	MidWest US	69kV : 1131km, 100kV class : 2428km, 300kV Class and above : 748km	flat, some trees	510,296	2,342	0.459%
21	Combined D&T	MidAtlantic US		flat, dense trees	3,800,000	9,324	0.245%
23	Combined D&T	MidWest US	69kV : 1857km, 100kV class : 3481km, 200kV Class : 668km, 300kV Class and above : 1736km	flat, some trees	683,615	4,842	0.708%
28	Combined D&T	Southwest US	<69kV : 735km, 100kV class : 606km, 300kV Class and above : 1830km, 400kV Class and above : 853km	flat, few trees	401,263	631	0.157%
30	Combined D&T	Northwest US	<69kV : 203km, 100kV class :2755km, 200kV Class : 506km, 400kV Class and above : 825km	flat, dense trees	1,072,828	3,710	0.346%
31	Combined D&T	MidWest US	100kV class :248km, 200kV Class : 4816km, 400kV Class and above : 4390km	flat, dense trees	3,818,690	1,988	0.052%
32	Combined D&T	Northwest US	100kV class :808km, 200kV Class : 900km, 300kV Class : 612, 400kV Class and above : 353km	flat, dense trees	820,266	265	0.032%

APPENDIX C: INDIVIDUAL BAR CHARTS FOR COMPARISON PANEL

Company #4







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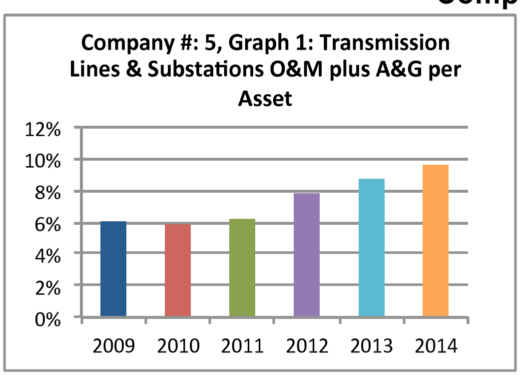

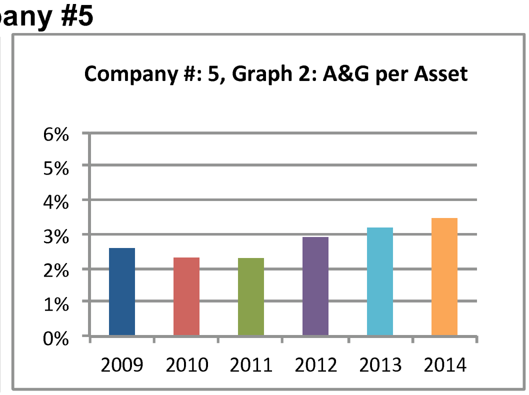

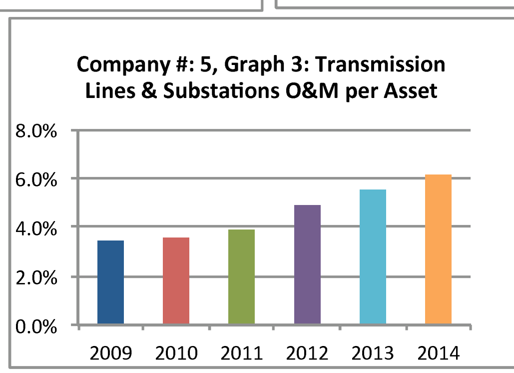

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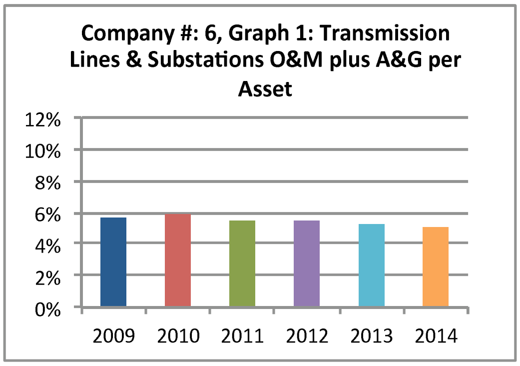

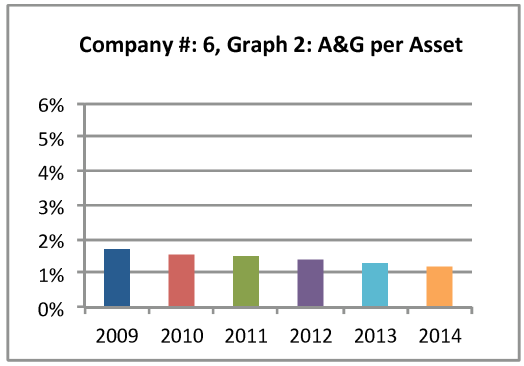

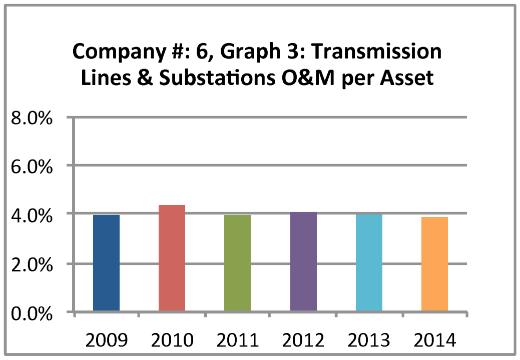

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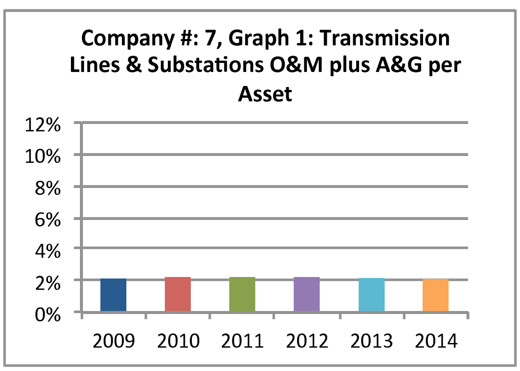

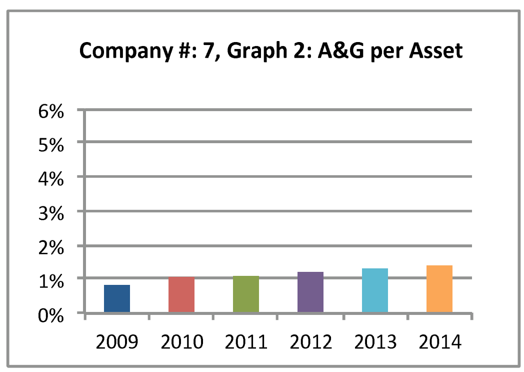

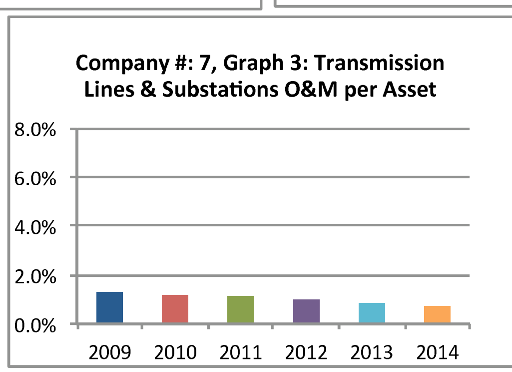

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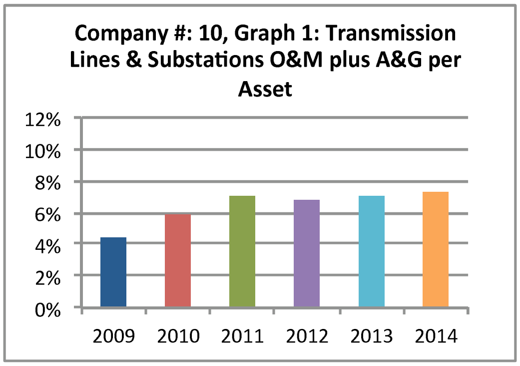

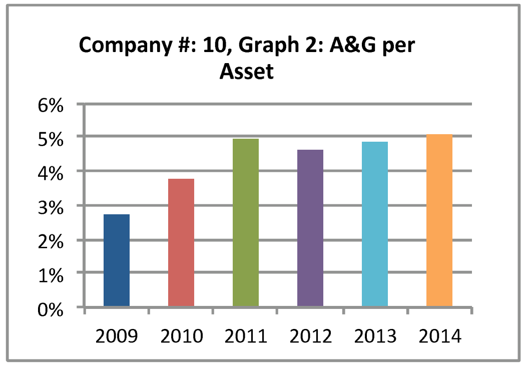

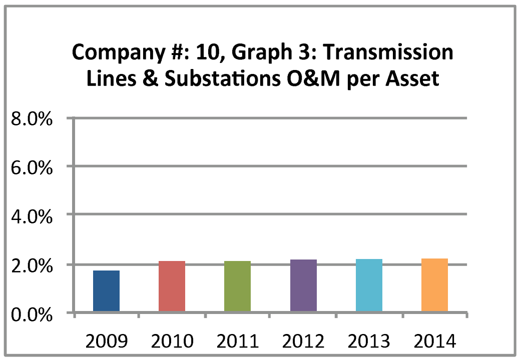

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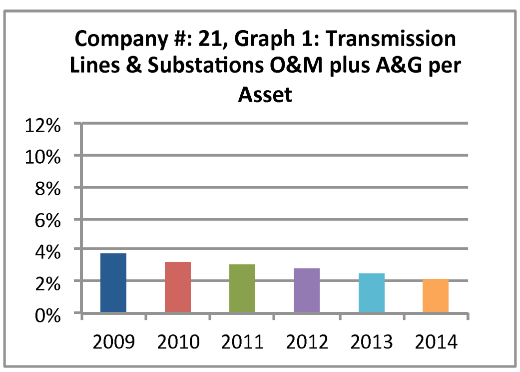

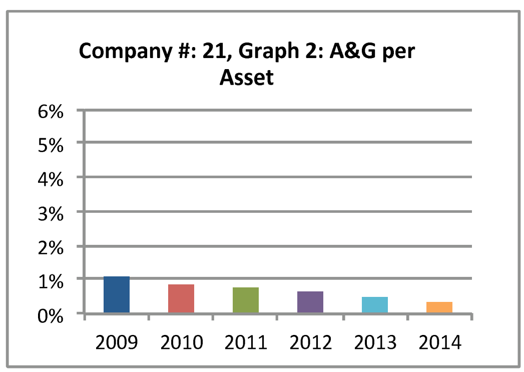

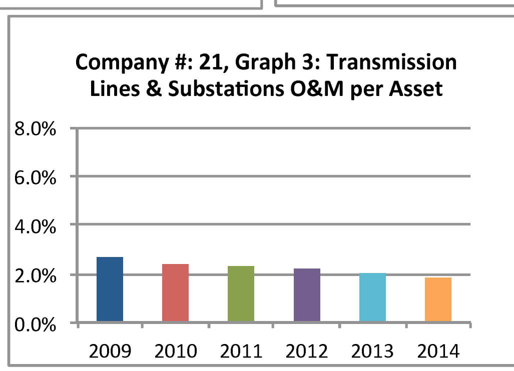

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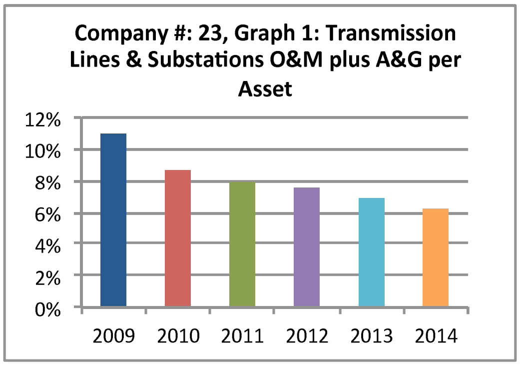

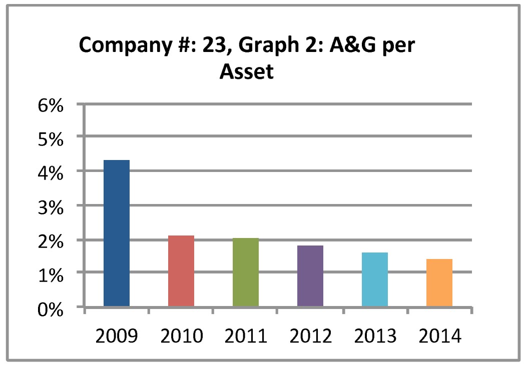

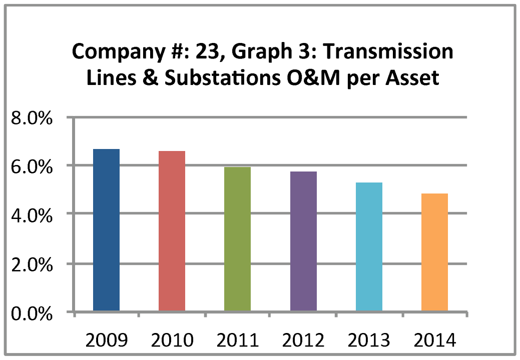

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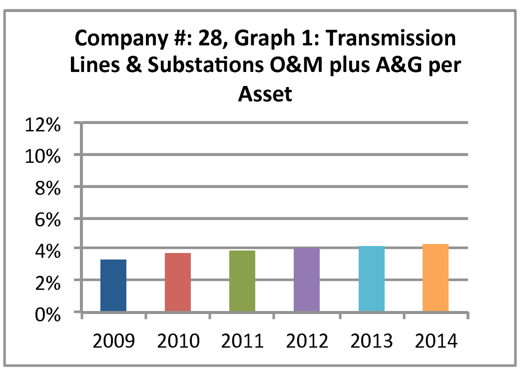

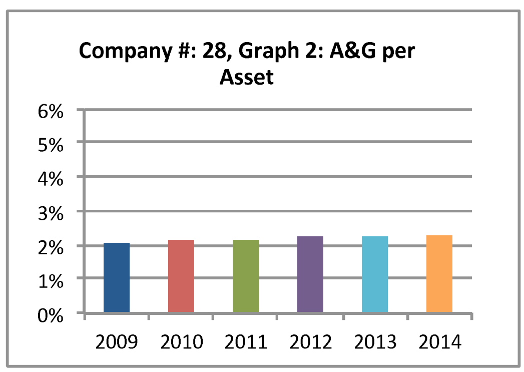

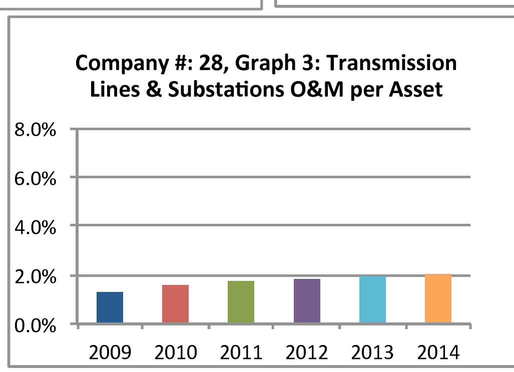

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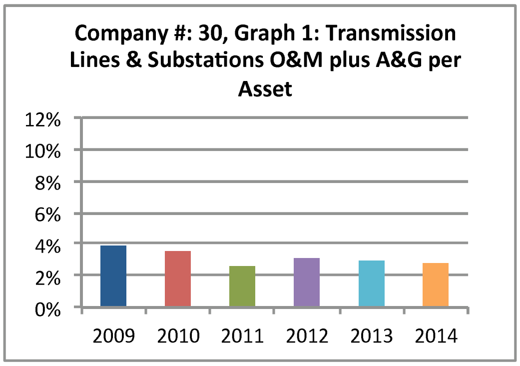

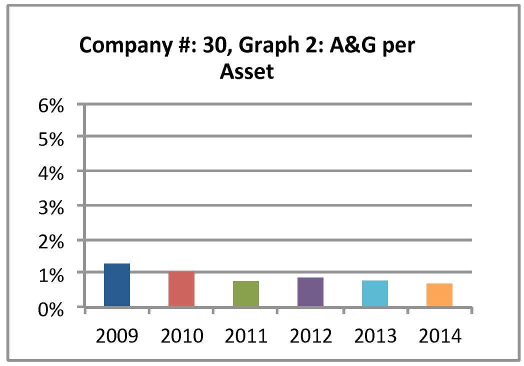

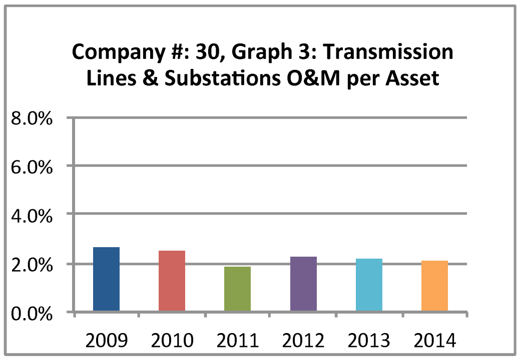

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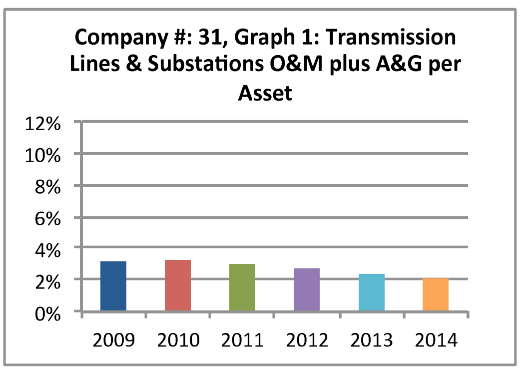

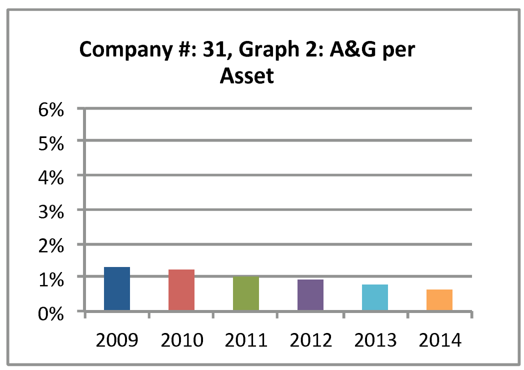

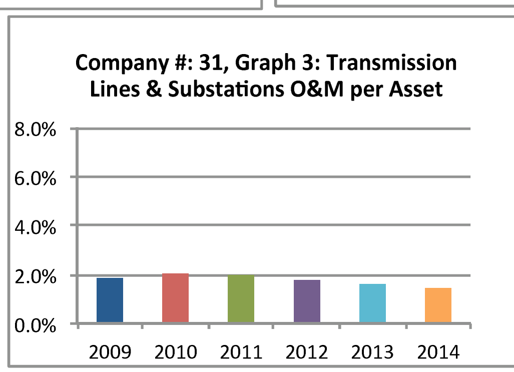

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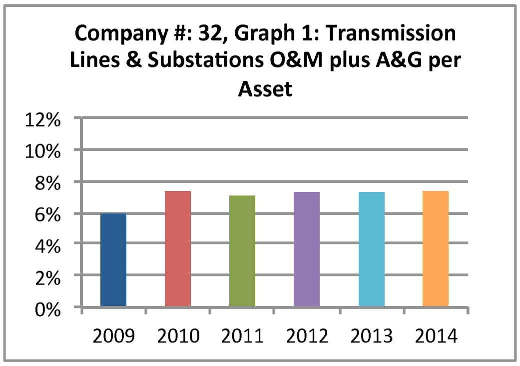

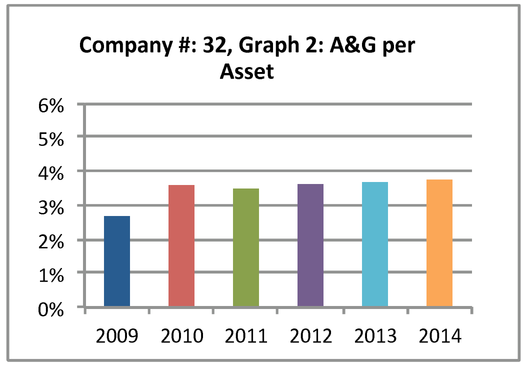

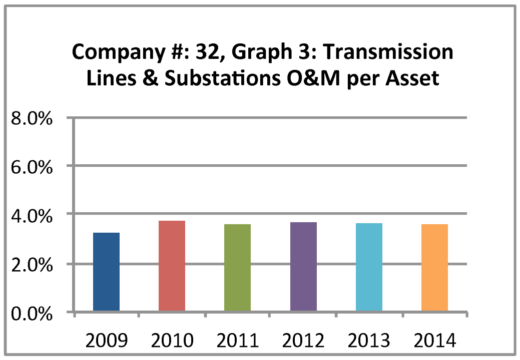

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Attachment 3

GREAT LAKES POWER TRANSMISSION OPERATION COST ANALYSIS

PREPARED BY:
FIRST QUARTILE CONSULTING, LLC

JULY 7, 2014

FIRST QUARTILE CONSULTING

INTRODUCTION

Great Lakes Power Transmission LP (GLPT) is a transmission owner and operator serving a portion of northern Ontario, Canada. 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. There are very few true "peers" for comparison, since GLPT is somewhat unique in terms of its size, rural geographic location, and dense vegetation. Nevertheless, 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 company. 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.

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.

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 / (transmission + distribution + customer service)) * total A&G expense = transmission portion of A&G expense.

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.

Beginning in 2013, a change in Canadian accounting rules required GLPT to adopt the International Financial Reporting Standards (IFRS), which caused GLPT to adjust the value of its asset base, effectively writing down the value of its gross assets by the amount of the accumulated depreciation at the end of 2012. Because we use gross assets for the normalizing factor in the analysis, this change makes a significant difference in the outcome of the analysis. For the purposes of the analysis, we have adjusted the figures for GLPT to include the value of the accumulated depreciation as of the end of 2012 as part of the asset value figures for later years. This has the effect of making the comparisons between GLPT and the other members of the comparison panel essentially “fair”.

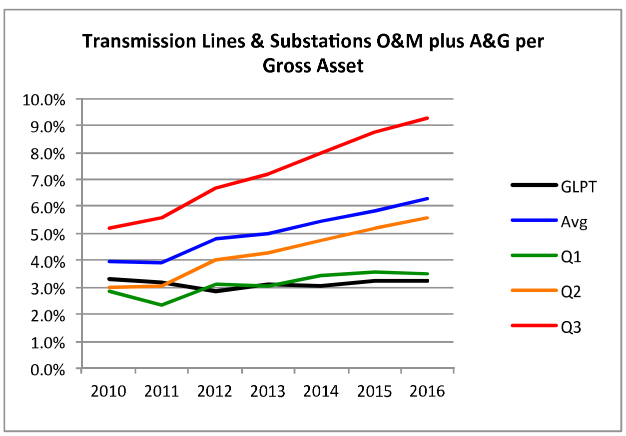
RESULTS AND CONCLUSIONS

Based upon our primary comparisons, GLPT falls significantly 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 2014 to 2016 are projected based upon 2010 to 2013 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 within the first quartile of the panel.

Figure 1



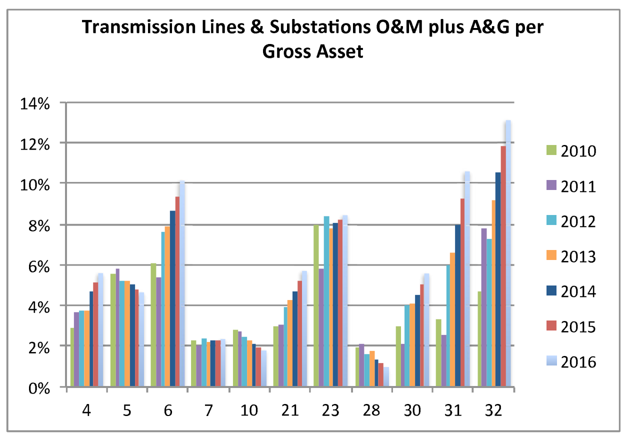


Figure 2 shows just the A&G cost per asset. GLPT’s A&G costs have been relatively flat, thus remaining below the median of the panel.

Figure 2

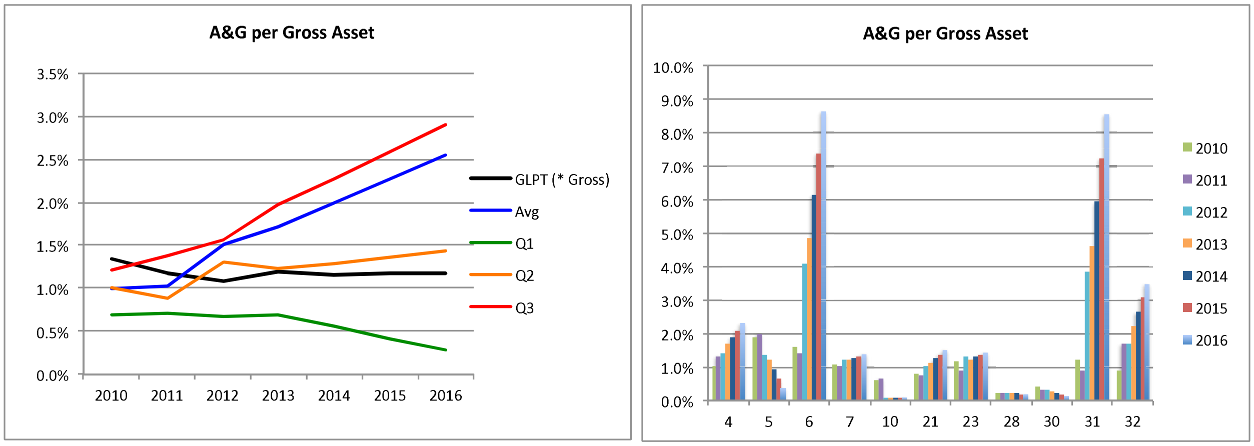
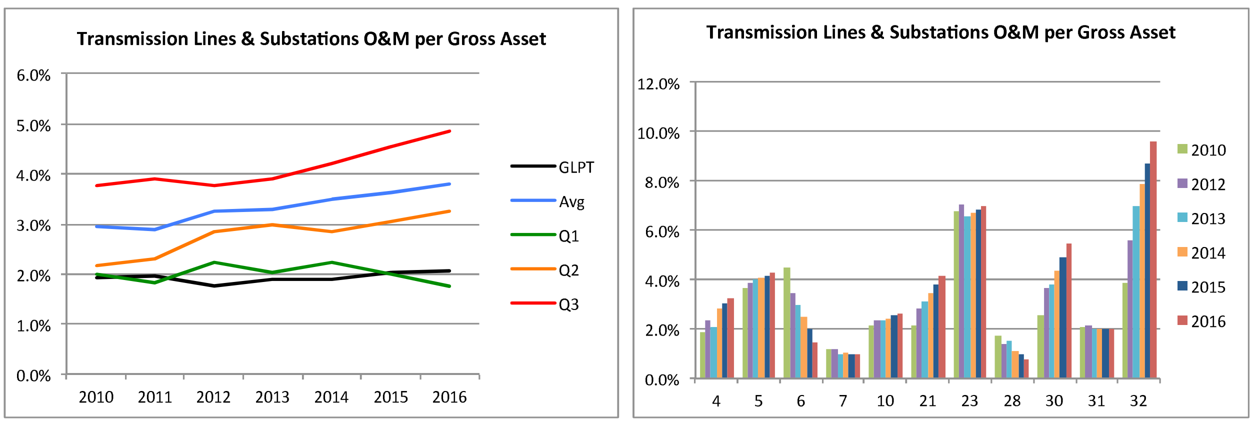


Figure 3 below shows the O&M costs without the A&G costs. GLPT's costs are below the first quartile value for most years. The projection for 2016 shows GLPT moving into the 2nd quartile, with a very slight growth combined with an anticipated reduction in O&M at the first quartile level for the panel.

Figure 3



For other comparisons, we also normalized spending based upon customers and circuit kilometers, as shown in Figures 4 and 5 below. Neither of these comparisons is recommended and the results are about as expected for GLPT, which is a small transmission operator. 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. The r^2 value for assets is .81, for circuit kilometers is .25, and for customers is .56. Appendix A provides a more complete description of this analysis.

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Figure 4

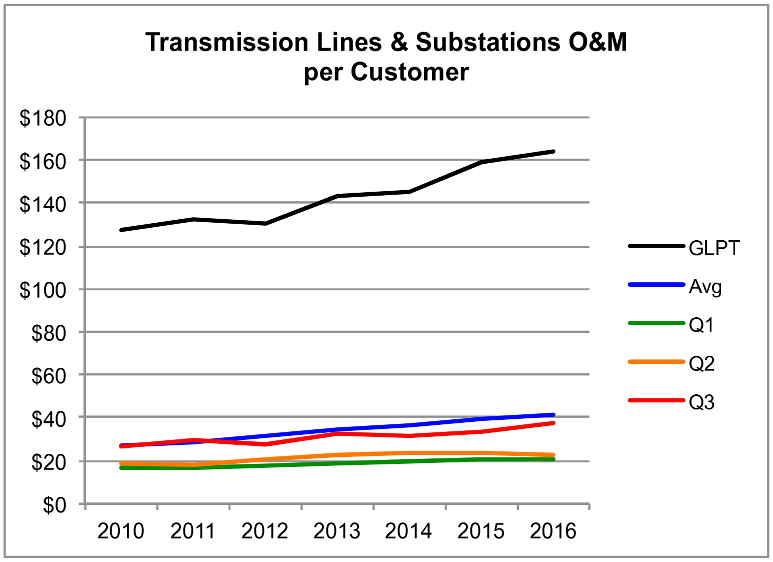
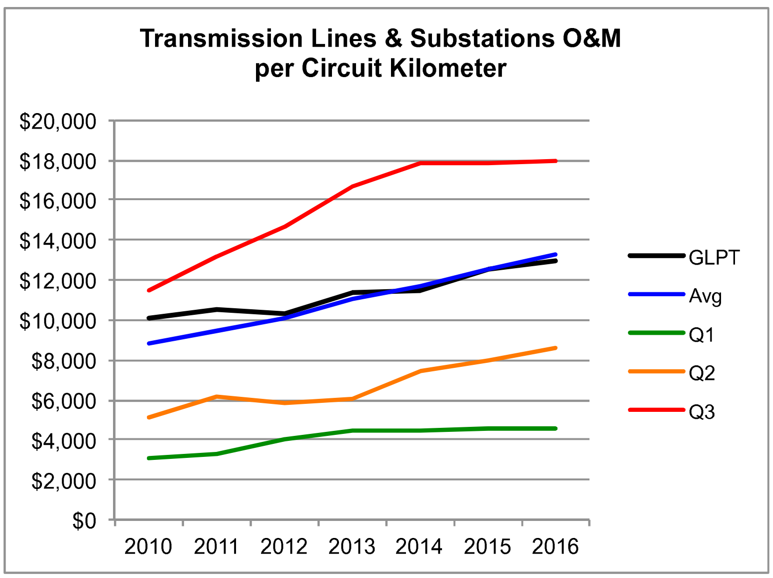


Figure 5



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.

For this study, 1QC re-ran the comparison to verify that the basic conclusions haven't changed. The results of that analysis are presented below.

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. Typically, there are companies included in the analysis that drive the regression to be stronger or weaker, so we ran the analysis both including and excluding those companies.

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 3 years worth of data in order to determine the correct normalizing factor -- 2011YE, 2012YE and available data from 2013YE (data collection is not yet complete).

Including All Companies

	Transmission Lines & Subs Assets	Customers	Transmission Circuit Kilometers	
Transmission Lines & Subs O&M Expenses	0.8532	0.15133	0.6635	2011YE
Transmission Lines & Subs O&M Expenses	0.50577	0.25666	0.52704	2012YE
Transmission Lines & Subs O&M Expenses	0.45488	0.36188	0.50383	2013YE

Excluding Extreme Outliers

	Transmission Lines & Subs Assets	Customers	Transmission Circuit Kilometers	
Transmission Lines & Subs O&M Expenses	0.75569	0.5874	0.11178	2011YE
Transmission Lines & Subs O&M Expenses	0.81275	0.55962	0.2553	2012YE
Transmission Lines & Subs O&M Expenses	0.6618	0.45467	0.52044	2013YE

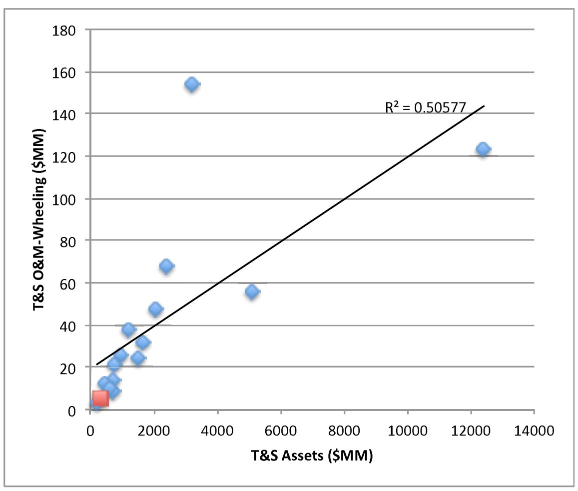
As before, we have found assets to be the appropriate normalizing factor because it appears to have a higher predictive value (whether extreme companies are included or excluded) when there are big differences in customer density among companies in the comparison panel.

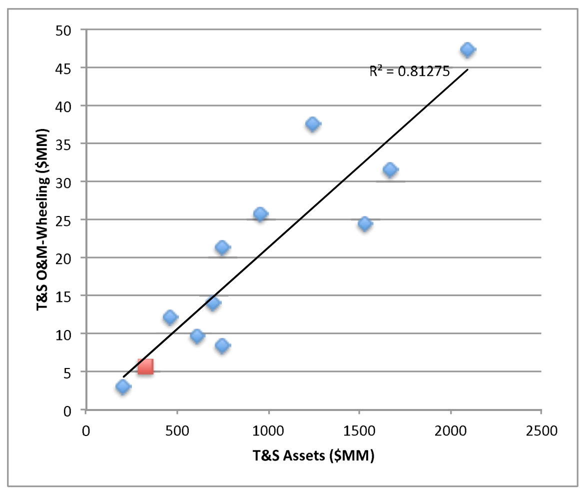
Transmission operators do not all have end-use customers, which is one reason customers is such a weak normalizing factor. Kilometers is also weak because the costs of operating substations are included in the dependent variable and substations are not accounted for very effectively when kilometers is used as a normalizing factor.

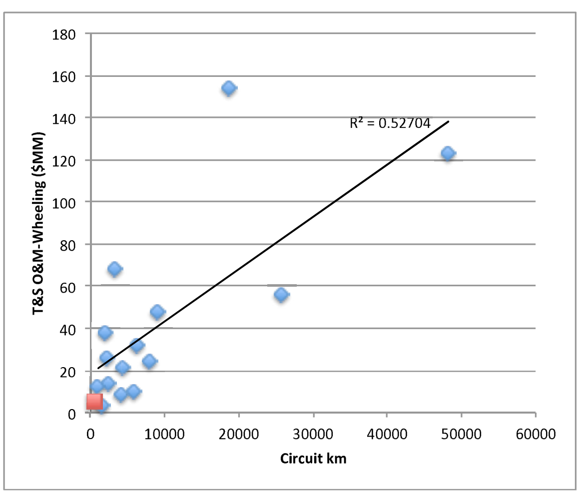
Shown below are the individual graphs from which the R^2 values are derived. In each graph, GLPT has been added to the graph to show where they fall compared to the other companies, but they are not included in the calculation of the correlation coefficient. It is appropriate to determine the correlation coefficients independently of GLPT's data, since by performing the analysis this way GLPT's data isn't influencing the findings. We present graphs for 2012YE since that relates to the data used for the rest of the analysis discussed in the body of the report.

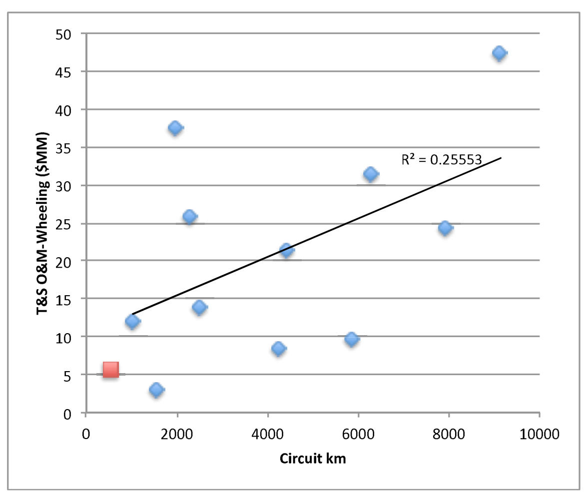
Including all Companies

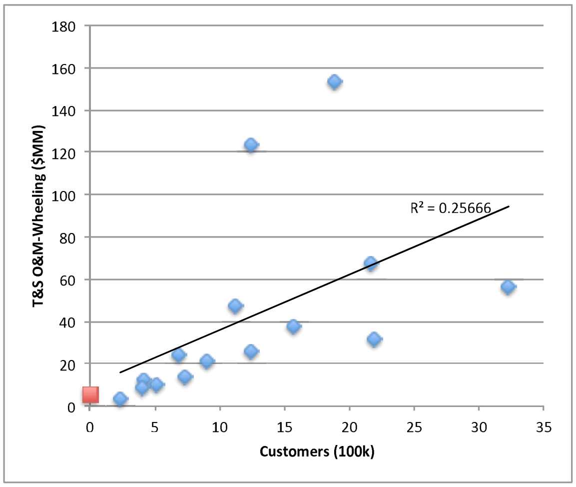
Excluding Extreme Outliers



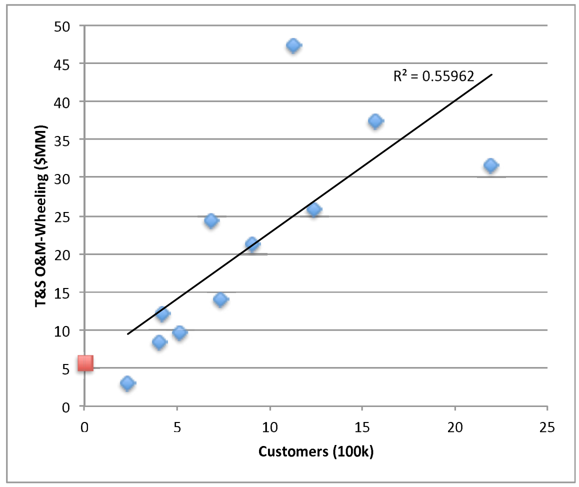








T&S O&M-Wheeling ($MM)
180
160
140
120
100
80
60
40
20
0
0
5
10
15
20
25
30
35
Customers (100k)
R² = 0.25666



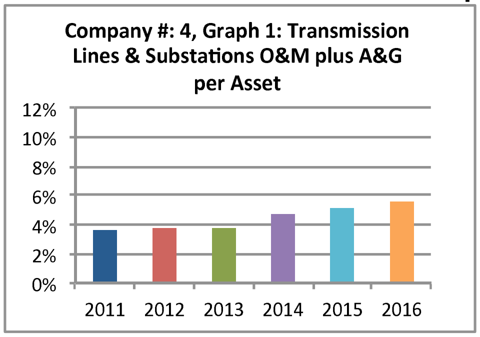
T&S O&M-Wheeling ($MM)
50
45
40
35
30
25
20
15
10
5
0
0
5
10
15
20
25
Customers (100k)
R² = 0.55962

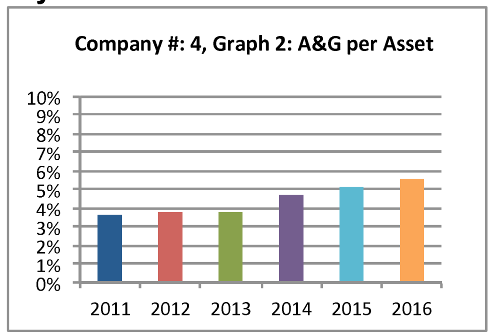
APPENDIX B: DEMOGRAPHICS OF THE COMPARISON PANEL

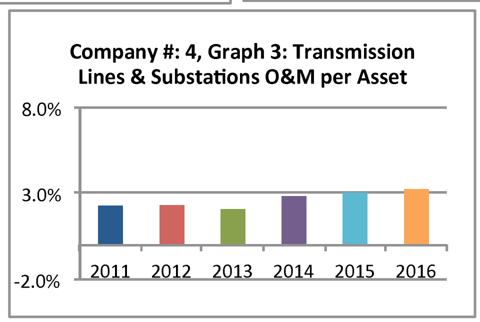
ID	CHARACTERISTICS	GEOGRAPHIC LOCATIONS	VOLTAGES/KM	TERRAIN	NUMBER OF CUSTOMERS	INDUSTRIAL CUSTOMERS	% Ind'l
4	Combined D&T	Southeast US	69kV : 603km, 100kV class : 3456km, 300kV Class: 1956km	flat, dense trees	2,244,289	1962	0.087%
5	Combined D&T	MidAtlantic US	69kV : 35km, 200kV class: 1120km, 300kV Class: 519km; 400kV Class and Above: 350	flat, dense trees	1,240,986	5559	0.448%
6	Combined D&T	MidAtlantic US	100kV class: 307km, 200kV Class: 251km, 300kV Class: 881, 400kV Class and above: 302	flat, dense trees	1,578,200	3,111	0.197%
7	Combined D&T	Southwest US	69kV : 4548km, 100kV class : 10986km, 300kV Class: 9267km	flat, few trees	3,266,126	6,564	0.201%
10	Combined D&T	MidWest US	69kV : 1131km, 100kV class : 2390km, 300kV Class: 768km	flat, some trees	893,122	4,862	0.544%
21	Combined D&T	MidAtlantic US	69kV class : 194km, 100kV class: 619, 200kV Class: 950km, 300kV class: 43, 400kV class: 654km	flat, dense trees	2,164,582	9,219	0.426%
23	Combined D&T	MidWest US	69kV : 1796km, 100kV class : 3464km, 200kV Class : 541km, 300kV Class : 1852km	flat, some trees	690,080	4,822	0.699%
28	Combined D&T	Southwest US	<69kV : 735km, 100kV class : 667km, 300kV Class : 1786km, 400kV Class and above : 907km	flat, few trees	405,153	635	0.157%
30	Combined D&T	Northwest US	<69kV : 203km, 100kV class :2755km, 200kV Class : 506km, 400kV Class and above : 825km	flat, dense trees	1,083,395	3,710	0.342%
31	Combined D&T	MidWest US	100kV class :239km, 200kV Class : 4643km, 300kV Class : 4250km, 400kV class: 144	flat, dense trees	3,828,849	1,999	0.052%
32	Combined D&T	Northwest US	100kV class :808km, 200kV Class : 900km, 300kV Class : 612, 400kV Class and above : 353km	flat, dense trees	823,215	265	0.032%

APPENDIX C: INDIVIDUAL BAR CHARTS FOR COMPARISON PANEL

Company #4







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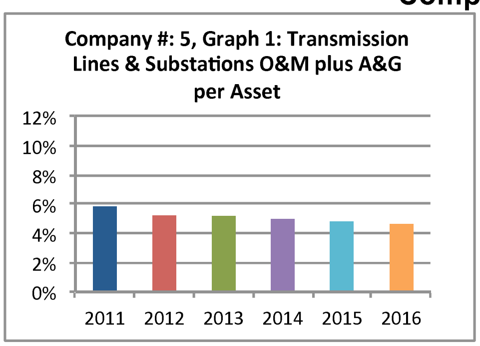

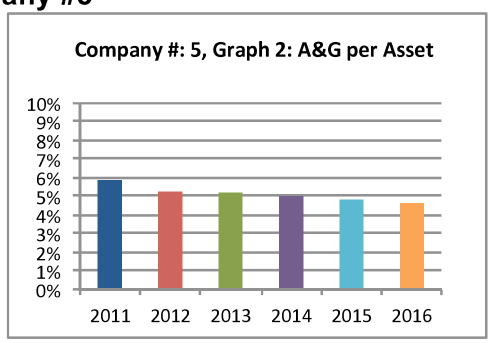

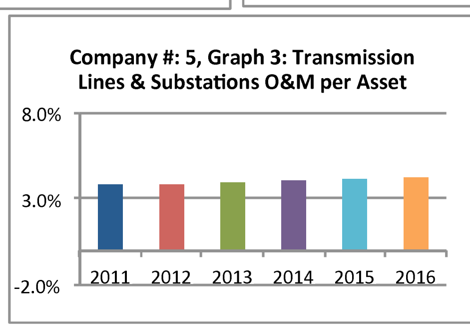

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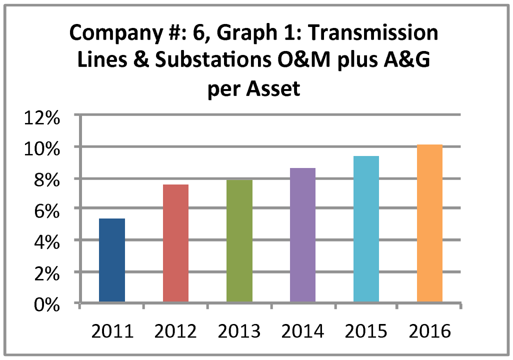

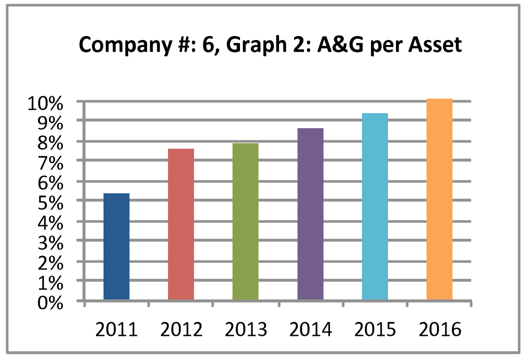

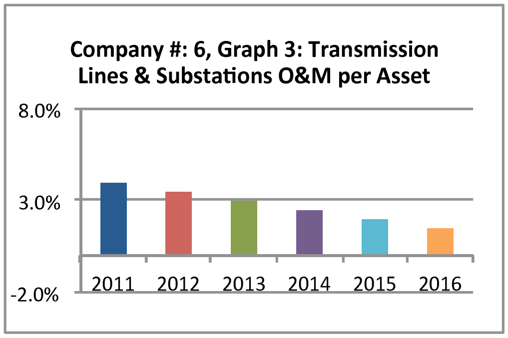

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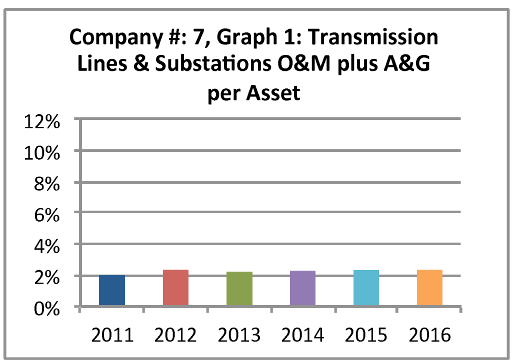

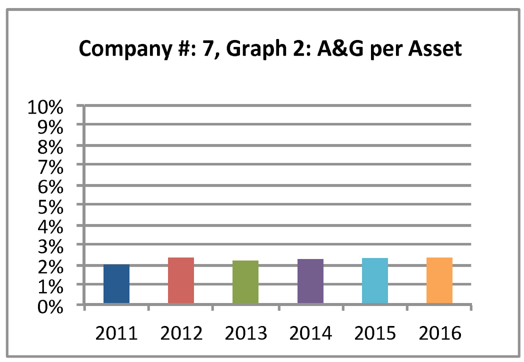

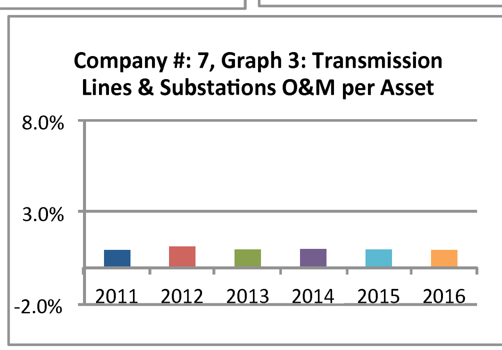

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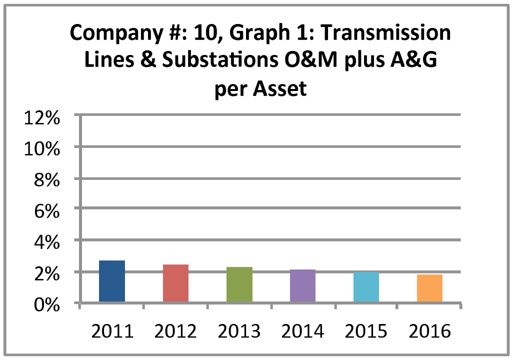

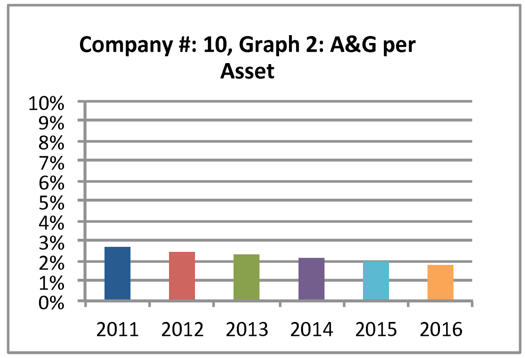

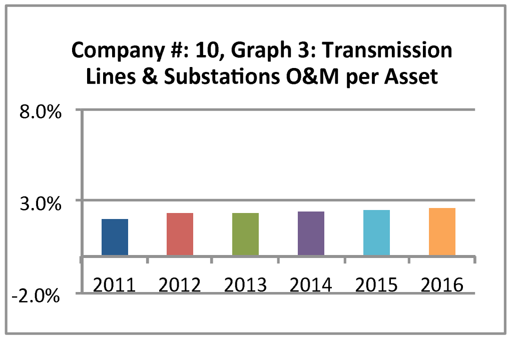

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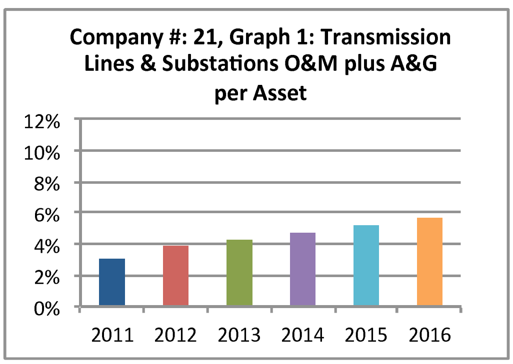

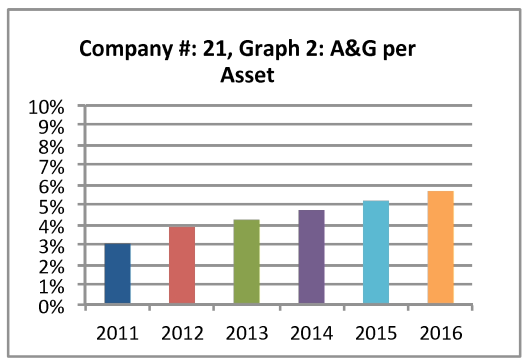

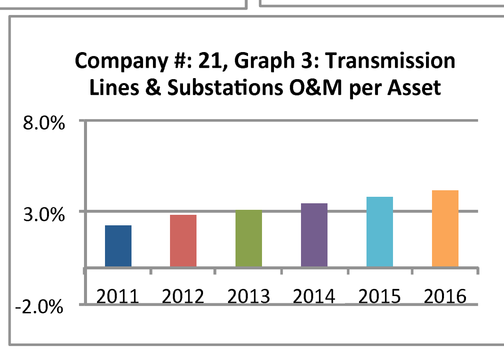

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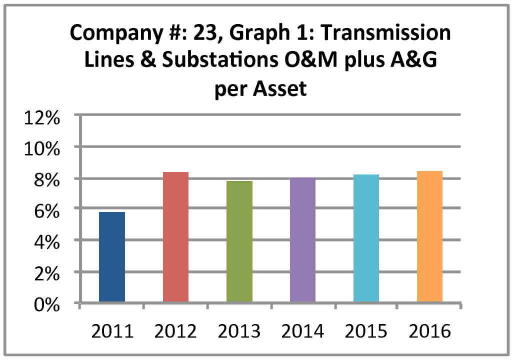

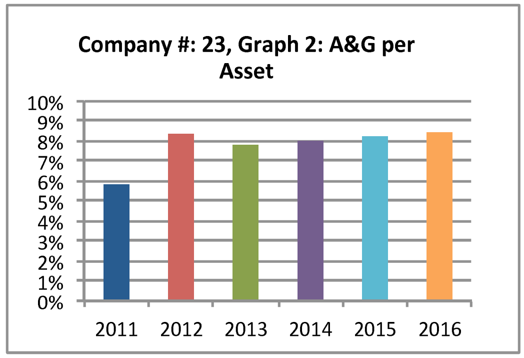

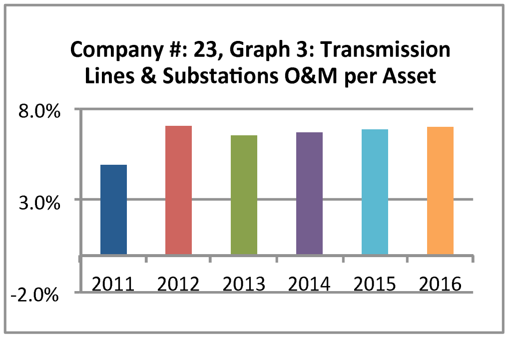

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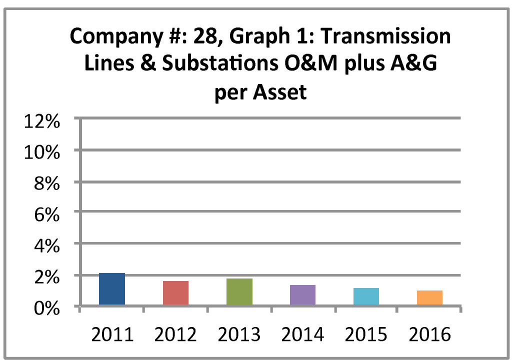

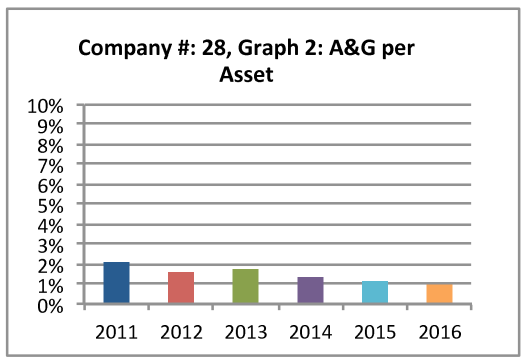

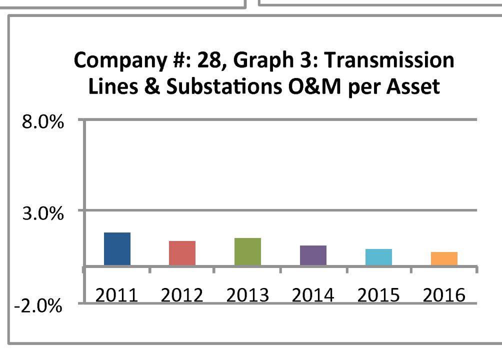

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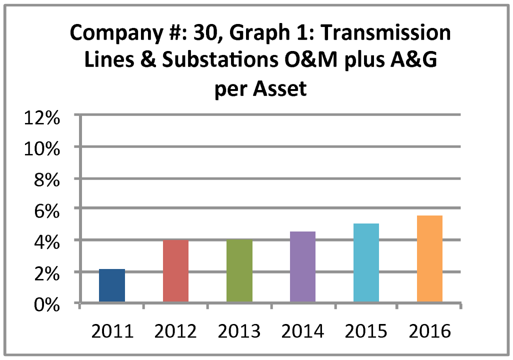

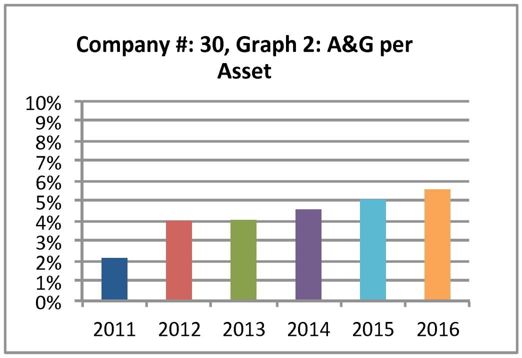

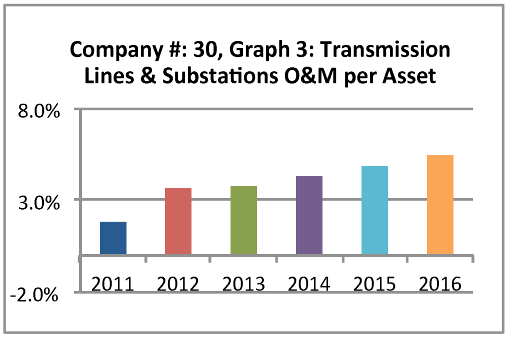

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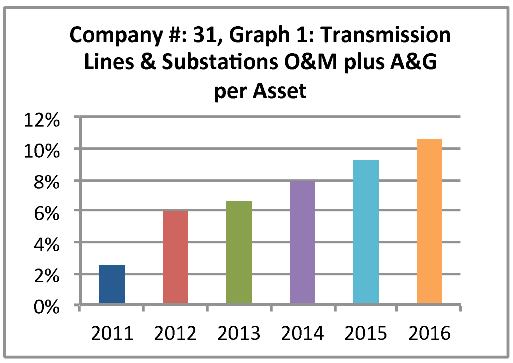

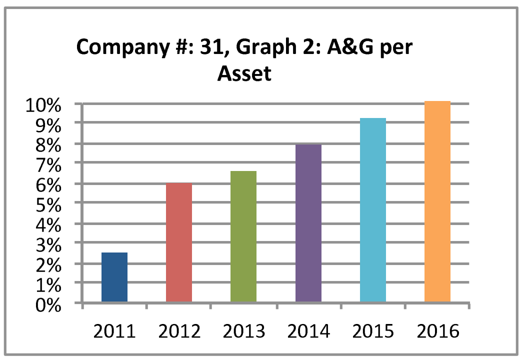

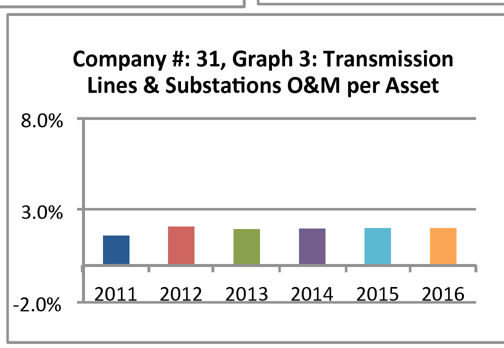

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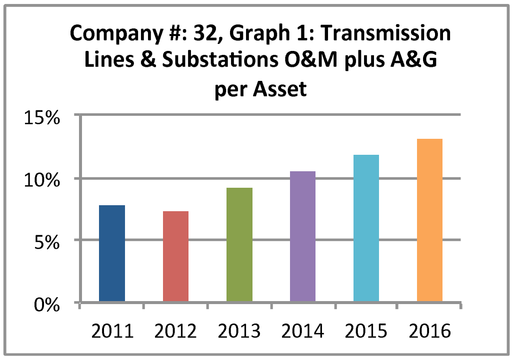
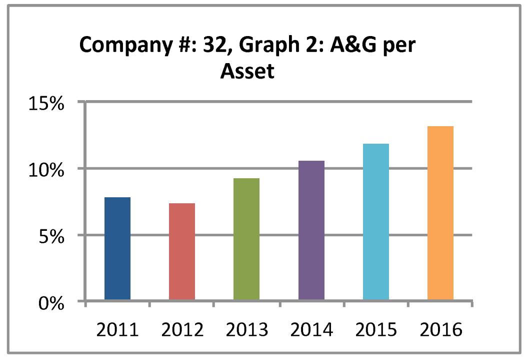
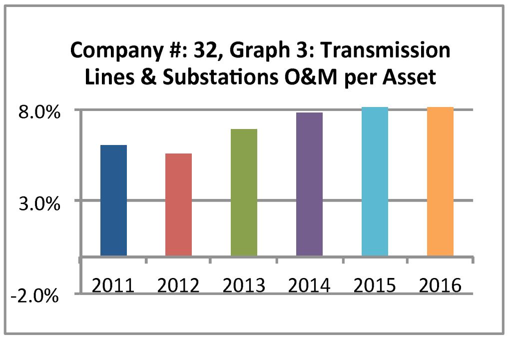

Company #: 32, Graph 1: Transmission Lines & Substations O&M plus A&G per Asset
15%
10%
5%
0%
2011
2012
2013
2014
2015
2016


Company #: 32, Graph 2: A&G per Asset
15%
10%
5%
0%
2011
2012
2013
2014
2015
2016


Company #: 32, Graph 3: Transmission Lines & Substations O&M per Asset
8.0%
3.0%
-2.0%
2011
2012
2013
2014
2015
2016

School Energy Coalition (SEC) INTERROGATORY #22

Interrogatory

[A-3-1, p.1] Please provide the actual regulated ROE for GLPT for the last 5 years.

Response

Please refer to Exhibit I, Tab 2, Schedule 4b.

School Energy Coalition (SEC) INTERROGATORY #23

Interrogatory

[A-3-1, p.1] Based on the forecasted capital and OM&A cost savings forecasted under both the base and high case scenarios, please provide an estimated actual ROE for GLPT for each year between 2017 and 2026.

Response

Please refer to Exhibit I, Tab 4, Schedule 14.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #1

Interrogatory

Reference: A/T1/S1/pg.4

a) Please provide an update on the status of the approval sought from the Commissioner of Competition.

Response

Please refer to Exhibit I, Tab 3, Schedule 1.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #2

Interrogatory

Reference: A/T1/S1/pg.5

a) HOI explains that the Distribution Business operations will not be affected by this transaction. Is this because GLPT is proposed to be operated as a separate entity until 2023?

b) Will there be any common or shared costs as between GLPT and Hydro One Transmission if this application is approved?

Response

a) No. As described in Exhibit A, Tab 1, Schedule 1 Hydro One's distribution business is separate from and excludes transmission and is separately regulated by the OEB under distribution licence ED-2003-0043. Even after GLPT will be integrated into Hydro One's transmission business, Hydro One's distribution business operations will not be impacted by this transaction.

b) Yes, standard form affiliate agreements that address the allocation of shared costs will be used in accordance with the Affiliate Relationships Code.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #3

Interrogatory

Reference: A-1-1/Attachment 2/Purchase Agreement/PDF pg.76

a) Please explain what type of loses might be contemplated for "OEB loss recovery" under the provisions of section 10.6 of the Purchase Agreement.

Response

Section 10.6 is intended to cause the transmitter to seek recovery of certain losses from ratepayers before being entitled to rely on the indemnity. The type of recoverable losses would be ones which the OEB would approve had the transaction not taken place. In other words, there are no special or unique losses contemplated for recovery from ratepayers under this section.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #4

Interrogatory

Reference: A-1-1-/Attachment 7

a) Please provide the 2015 Financial Statements of Great Lakes Power Transmission Limited Partnership. If it is currently not available please explain why and when it is anticipated.

Response

Please refer to Attachment 1.

Financial Statements

GREAT LAKES POWER TRANSMISSION LIMITED PARTNERSHIP

December 31, 2015

Deloitte LLP
Bay Adelaide East
22 Adelaide Street West
Suite 200
Toronto ON M5H 0A9
Canada

Tel: (416) 601-6150
Fax: (416) 601-6151
www.deloitte.ca

Independent Auditor's Report

To the Partners of
Great Lakes Power Transmission Limited Partnership

We have audited the accompanying financial statements of Great Lakes Power Transmission Limited Partnership, which comprise the statement of financial position as at December 31, 2015 and the statement of comprehensive income, statement of changes in partners' equity and statement of cash flows for the year then ended and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

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

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Great Lakes Power Transmission Limited Partnership as at December 31, 2015, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
April 5, 2016

Great Lakes Power Transmission Limited Partnership
Statement of Financial Position
Expressed in thousands of Canadian dollars

	Note		**December 31, 2015**		December 31, 2014
Assets					
Current Assets					
Cash		**$**	**3,340**	$	5,201
Trade and other receivables			**3,086**		3,422
Due from related parties	*20*		**95**		89
Prepaid expenses and other			**661**		696
			7,182		9,408
Property, plant and equipment, net	*5*		**218,843**		219,941
Intangible assets, net	*6*		**2,886**		2,742
		$	**228,911**	$	232,091
Liabilities					
Current liabilities					
Trade and other payables	*7*	**$**	**1,922**	$	3,223
Due to related parties	*20*		**198**		218
Current portion of Trans senior bonds	*9*		**2,327**		2,180
			4,447		5,621
Pension liability	*8*		**3,457**		7,677
Trans senior bonds	*9*		**110,627**		112,743
			118,531		126,041
Partners' equity			**110,380**		106,050
		$	**228,911**	$	232,091

Great Lakes Power Transmission Limited Partnership
Statement of Changes in Partners' Equity
Expressed in thousands of Canadian dollars

	Capital: Great Lakes Power Transmission Holdings LP	Capital: Great Lakes Power Transmission Inc.	Accumulated other comprehensive income (loss)	Retained earnings (deficit)	Total partners' equity
Balance at January 1, 2015	**$ 112,405**	**$ 11**	**$ (2,423)**	**$ (3,943)**	**$ 106,050**
Net income	-	-	-	11,449	11,449
Distributions paid	-	-	-	(11,338)	(11,338)
Other comprehensive income	-	-	4,219	-	4,219
Balance at December 31, 2015	**$ 112,405**	**$ 11**	**$ 1,796**	**$ (3,832)**	**$ 110,380**

	Capital: Great Lakes Power Transmission Holdings LP	Capital: Great Lakes Power Transmission Inc.	Accumulated other comprehensive income (loss)	Retained earnings (deficit)	Total partners' equity
Balance at January 1, 2014	$ 112,405	$ 11	$ (1,298)	$ (768)	$ 110,350
Net income	-	-	-	11,663	11,663
Distributions paid	-	-	-	(14,838)	(14,838)
Other comprehensive loss	-	-	(1,125)	-	(1,125)
Balance at December 31, 2014	$ 112,405	$ 11	$ (2,423)	$ (3,943)	$ 106,050

Great Lakes Power Transmission Limited Partnership

Statement of Comprehensive Income

Expressed in thousands of Canadian dollars

Years ended December 31,	*Note*		**2015**		2014
Revenue		**$**	**39,887**	$	39,805
Operating expenses					
Operating and administration	*12*		**9,473**		9,122
Depreciation and amortization	*15*		**9,645**		9,302
Maintenance	*13*		**1,257**		1,573
Taxes, other than income taxes			**111**		107
			20,486		20,104
Net operating income			**19,401**		19,701
Finance income			**(48)**		(66)
Finance costs	*14*		**7,651**		7,901
Loss on disposal of property, plant & equipment	*5*		**406**		215
Other income			**(57)**		(12)
Income for the period			**11,449**		11,663
Other comprehensive loss					
Items that will not be reclassified subsequently to profit or loss:					
Remeasurement of pension liability	*8*		**4,219**		(1,125)
Total comprehensive income		**$**	**15,668**	$	10,538

Great Lakes Power Transmission Limited Partnership

Statement of Cash Flows

Expressed in thousands of Canadian dollars

Years ended December 31,	*Note*	**2015**	2014
Operating Activities			
Net income		$ **11,449**	$ 11,663
Items not affecting cash;			
Depreciation and amortization	*15*	**9,645**	9,302
Finance costs	*14*	**7,651**	7,901
Loss on disposal of property, plant & equipment	*5*	**406**	215
Net change in non-cash working capital and other	*17*	**(957)**	(942)
Operating cash flows before interest		**28,194**	28,139
Cash interest paid		**(7,686)**	(7,823)
		20,508	20,316
Investing activities			
Proceeds on disposition of property, plant and equipment	*5*	**48**	18
Additions to property, plant and equipment and intangible assets		**(8,899)**	(3,845)
		(8,851)	(3,827)
Financing activities			
Principal repayments on Trans senior bonds		**(2,180)**	(2,043)
Distributions paid		**(11,338)**	(14,838)
		(13,518)	(16,881)
Decrease in cash		**(1,861)**	(392)
Cash, beginning balance		**5,201**	5,593
Cash, ending balance		$ **3,340**	$ 5,201

1. GENERAL INFORMATION

Ontario-based Great Lakes Power Transmission Limited Partnership (the "Partnership") was formed on May 17, 2007 for the purpose of acquiring the assets and liabilities of the transmission division of Great Lakes Power Limited ("GLPL"), a related party due to common ownership. The address of the Partnership's registered office is 2 Sackville Road, Suite B, Sault Ste. Marie, Ontario, Canada, P6B 6J6.

Great Lakes Power Transmission Holdings LP is the Limited Partner and holds a 99.99% interest in the Partnership. Great Lakes Power Transmission Inc., the General Partner, holds a 0.01% limited interest in the Partnership and is responsible for management of the Partnership. Both the General and Limited Partners are wholly owned subsidiaries of Brookfield Infrastructure Partners LP ("BIP"), the ultimate parent company and controlling party of the group.

The Partnership is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board ("OEB").

2. BASIS OF PRESENTATION

Statement of compliance

These financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Accounting policies are consistently applied to both years presented, unless otherwise stated.

The financial statements were approved and authorized for issue by those charged with governance of the Partnership on April 5, 2016.

Basis of measurement

The financial statements have been prepared on a going concern assumption using the historical cost basis except where otherwise noted. Historical cost is generally based on the fair value of the consideration given in exchange for assets or settlement of liabilities as at the date the transaction occurs.

Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Partnership's functional currency. All amounts have been rounded to the nearest thousand, unless otherwise indicated.

Critical judgments and estimation uncertainties

In the preparation of these financial statements in conformity with IFRS, management makes judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of revenues, expenses, assets and liabilities. Facts and circumstances may change and actual results could differ from those estimates.

Estimates and Judgments

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods

2. BASIS OF PRESENTATION (continued)

affected. Information about critical judgments and estimates in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are included in the following notes:

Impairment

Assets, including property, plant and equipment and intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. Intangible assets with indefinite useful lives are tested for impairment annually and whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. The assessment of fair value often requires estimates and assumptions on items such as approved uniform transmission rates, discount rates, rehabilitation and restoration costs, future capital requirements and future operating performance. Changes in such estimates could impact recoverable values of these assets. Estimates are reviewed annually by management.

Judgment is involved in assessing whether there is any indication that an asset or cash generating unit ("CGU") may be impaired. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets. This assessment is made based on the analysis of changes in the market or business environment, and events that have transpired that have impacted the asset or CGU.

Depreciation of property, plant and equipment and intangible assets

Each property, plant and equipment and intangible asset is assessed annually for both its physical life limitations and its economic recoverability. Those assets with a finite life are depreciated on a straight-line basis over a useful life estimated by management. Asset useful lives and residual values are re-evaluated annually. At December 31, 2015 the carrying value of property plant and equipment and intangible assets is $218,843 (2014 - $219,941) and $2,886 (2014 - $2,742) respectively.

Fair value disclosures of Trans senior bonds

The Partnership has estimated the fair value of its Trans senior bonds for disclosure purposes, as they are not separately traded. The fair value is based on future cash flows and the timing of settlement, along with assumptions about the discount rate, credit risk and by incorporating other assumptions made by market participants. At December 31, 2015 the carrying value of Trans senior bonds is $112,954 (2014 - $114,923).

Pension

Significant estimates and assumptions are made in determining pension and employee future benefits as there are numerous factors that will affect the pension obligation. The actuarial determination of the accrued benefit obligation for pensions and post-employment benefits uses the projected unit credit method prorated on service which incorporates management's best estimate of future salary levels, other cost escalation, mortality rates, retirement ages of employees and other actuarial factors. In addition, actuarial determinations used in estimating obligations relating to the defined benefit plans incorporate assumptions using management's best estimates of factors including plan performance, salary escalation, retirement dates of employees

2. BASIS OF PRESENTATION (continued)

and drug cost escalation rates. At December 31, 2015 the carrying value of pension liabilities is $3,457 (2014 - $7,677).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Partnership has consistently applied the following accounting policies to both periods presented in these financial statements:

Financial Instruments

The Partnership recognizes all financial instruments at fair value upon initial recognition and subsequently classifies them into one of the following categories: Financial assets and financial liabilities at fair value through profit or loss, held-to-maturity, loans and receivables, available-for-sale and other liabilities. As at December 31, 2015, the Partnership only holds the following financial instruments: Trade and other payables, Trans Senior Bonds (which are classified as other financial liabilities) and trade and other receivables (which are classified as loans and receivables).

The Partnership initially recognizes other financial liabilities and loans and receivables on the trade date. The Partnership derecognizes a financial liability when its contractual obligations are discharged, cancelled, or expired.

Other financial liabilities including borrowings are initially measured at fair value net of transaction costs, and subsequently measured at amortized cost using the effective interest method. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Property, plant and equipment

Recognition and measurement

Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. The cost of major inspections or overhauls is capitalized and costs relating to the replacement of a major part of property, plant and equipment are recognized in the carrying amount of the asset to which that part relates, if it is probable that the inspection, overhaul or replacement part will generate future economic benefits and its cost can be measured reliably. The carrying amount of previous inspections and overhauls, or the part being replaced is derecognized and any gain or loss is recognized against income. The cost of the day-to-day servicing of property, plant and equipment is recognized in operating and administration or maintenance expense as incurred.

Costs included in the carrying amount of property, plant and equipment include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads.

Borrowing costs associated with major projects are capitalized during the construction period, if those projects meet the definition of a qualifying asset, meaning those projects that are under construction for a substantial period of time. Capitalization of borrowing costs is suspended during

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

extended periods in which construction development is interrupted. Assets under construction are recorded as work-in-progress until they become available for use.

When property, plant and equipment is disposed of or retired, the related cost, accumulated depreciation and any accumulated impairment losses are eliminated. Any resulting gains or losses are reflected against income in the period the asset is disposed of or retired.

Depreciation

The cost, net of estimated residual values, of an asset classified as property, plant and equipment is amortized over the estimated useful life of the asset using a straight-line method. Land is not depreciated.

The estimated useful lives of property, plant and equipment are as follows:

	Method	Rate
Transmission assets	Straight-line	5 to 60 years
Equipment and other assets	Straight-line	5 to 30 years

The estimated useful lives, residual values and method of depreciation are based on depreciation studies and are reviewed annually for reasonableness.

Construction work-in-progress assets are not depreciated until the assets become available for their intended use.

Impairment

At each reporting date, the Partnership reviews the carrying amount of its non-financial assets to determine whether there is any indication of impairment. Impairment assessments are conducted at the CGU level. If any such indication exists, the recoverable amount of the CGU is estimated.

The recoverable amount of the CGU is the greater of its value in use and its fair value less costs to sell. Value in use is based on the estimated future cash flows, discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized against income if the carrying amount of a CGU exceeds its recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If such indications exist, the Partnership estimates the recoverable amount of that CGU. A reversal of an impairment loss is recognized up to the lesser of the recoverable amount or the carrying amount that would have been determined (net of depreciation charges) had no impairment loss been recognized on the CGU.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Intangible assets

Acquired intangible assets having finite useful lives are measured at cost less accumulated amortization and any accumulated impairment losses. Intangible assets are capitalized if: (i) It is probable that the asset acquired or developed will generate future economic benefits, (ii) the intangible asset is identifiable, and (iii) the Partnership exerts control over the economic benefit to be derived from the asset. The costs incurred to establish technological feasibility or to maintain existing levels of performance are recognized in operating or maintenance expense as incurred.

The carrying costs of intangible assets include expenditures that are directly attributable to the acquisition or development of the asset. The cost of self-developed assets includes materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects (qualifying assets) are capitalized during the development period. Qualifying assets are those projects that are under development for a substantial period of time. Assets under development are recorded as in progress until they become available for use.

Subsequent expenditures are capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. All other expenditures are recognized against income as incurred.

Amortization is based on the cost of the asset less its residual value and is calculated using the straight-line method over the estimated useful life of the asset from the date the asset is available for use, and is generally recognized against income. The useful lives of intangible assets range from 5 to 15 years. Land rights with indefinite lives are not amortized.

The estimated useful lives, residual values and method of amortization are reviewed annually for reasonableness.

Intangible assets with an indefinite life are tested for impairment on an annual basis.

Employee benefits

Short-term employee benefits

Short-term employee benefits are expensed as the related service is provided by the employee. A liability is recognized for the amount expected to be paid if the Partnership has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

Defined contribution plans

Obligations for contributions to defined contribution plans are expensed as the related service is provided by the employee. Prepaid contributions are recognized as an asset to the extent that a cash refund or a reduction in future payments is available.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Defined benefit plans

The Partnership's net obligation in respect to defined benefit plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in the current and prior periods, discounting that amount and deducting the fair value of any plan assets.

The calculation of defined benefit obligations is performed annually by a qualified actuary using the projected unit credit method. When the calculation results in a potential asset for the Partnership, the recognized asset is limited to the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. To calculate the present value of economic benefits, consideration is given to any applicable minimum funding requirements.

Remeasurements of the net defined benefit liability, which comprise actuarial gains and losses, the return on plan assets (excluding interest) and the effect of the asset ceiling (if any, excluding interest), are recognized immediately in other comprehensive income. The Partnership determines the net interest expense (income) on the net defined benefit liability (asset) for the period by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the then-net defined benefit liability (asset), taking into account any changes in the net defined benefit liability (asset) during the period as a result of contributions and benefit payments. Net interest expense and other expenses related to defined benefit plans are recognized against income.

When the benefits of a plan are changed or when a plan is curtailed, the resulting change in benefit that relates to past service or the gain or loss on curtailment is recognized immediately against income. The Partnership recognizes gains and losses on the settlement of a defined benefit plan when the settlement occurs. The gain or loss on curtailment or settlement comprises any resulting change in the fair value of plan assets, any change in the present value of the defined benefit obligation, and any relating actuarial gains or losses and past service costs that had not been previously been recognized.

Other long-term employee benefits

The Partnership's net obligation in respect of long-term employee benefits is the amount of future benefit that employees have earned in return for their service in the current and prior periods. That benefit is discounted to determine its present value. Remeasurements are recognized against income in the period in which they arise.

Revenue

Revenue is measured at the fair value of the consideration received or receivable. Revenue is recognized by the Partnership when a sales arrangement exists, delivery of goods or services has occurred, the amount of revenue and costs incurred or to be incurred in respect of the transaction can be measured reliably and it is probable that future economic benefits will flow to the Partnership.

The Partnership recognizes revenue on an accrual basis, when electricity is wheeled, at the regulated rate established by the OEB.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Foreign currency

Transactions in foreign currencies are translated to the functional currency of the Partnership at exchange rates at the dates of the transactions.

Borrowing costs

Borrowing costs that are directly attributable to the acquisition, construction or development of a qualifying asset are added to the cost of that asset, until it is available for use. Qualifying assets are those that take a substantial period of time to get ready for their intended use. The Partnership capitalizes borrowing costs by applying its cost of debt. All other borrowing costs are recognized in finance expense in the period in which they are incurred.

Changes in accounting policies

In 2015, there have been no new or amended accounting pronouncements that have had a material impact on the Partnership's financial statements.

4. FUTURE CHANGES IN ACCOUNTING POLICIES

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning after December 31, 2015 and have not been applied in preparing these financial statements. Those which may be relevant to the Partnership are set out below. The Partnership does not plan to early adopt any of these standards.

Depreciation

On May 12, 2014, the IASB issued amendments to IAS 16, Property, Plant and Equipment ("IAS 16"), and IAS 38, Intangible Assets ("IAS 38"). In issuing the amendments, the IASB has clarified that the use of revenue-based methods to calculate the depreciation of a tangible asset is not appropriate because revenue generated by an activity that includes the use of a tangible asset generally reflects factors other than the consumption of the economic benefits embodied in the asset. The IASB has also clarified that revenue is generally presumed to be an inappropriate basis for measuring the consumption of the economic benefits embodied in an intangible asset. This presumption for an intangible asset, however, can be rebutted in certain limited circumstances. The standard is to be applied prospectively for reporting periods beginning on or after January 1, 2016 with early application permitted. The adoption of these amendments is not expected to have an impact on the Partnership's financial statements.

Revenue

On May 28, 2014 the IASB issued IFRS 15, Revenue from Contracts with Customers ("IFRS 15"). This standard outlines a single comprehensive model with prescriptive guidance for entities to use in accounting for revenue arising from contracts with its customers. IFRS 15 uses a control based approach to recognize revenue which is a change from the risk and reward approach under the current standard. This standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. The effective date is for reporting periods beginning on or after January 1, 2018 with early application permitted. The Partnership has not yet determined the effect of adoption of IFRS 15 on its financial statements.

4. FUTURE CHANGES IN ACCOUNTING POLICIES (continued)

Financial instruments

On July 24, 2014 the IASB issued IFRS 9, Financial Instruments ("IFRS 9") as a complete standard. This standard replaces the guidance in IAS 39 Financial Instruments: Recognition and Measurement on the classification and measurement of financial assets and financial liabilities. IFRS 9 utilizes a single approach to determine whether a financial asset is measured at amortized cost or fair value and a new mixed measurement model for debt instruments having only two categories: amortized cost and fair value. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. Final amendments released on July 24, 2014 also introduce a new expected loss impairment model and limited changes to the classification and measurement requirements for financial assets. The IASB has tentatively decided to require an entity to apply IFRS 9 for annual periods beginning on or after January 1, 2018. The Partnership has not yet determined the effect of adoption of IFRS 9 on its financial statements.

Presentation of Financial Statements

On December 18, 2014 the IASB amended IAS 1, Presentation of Financial Statements ("IAS 1"). The amendments to existing IAS 1 requirements relate to materiality; order of the notes; subtotals; accounting policies; and disaggregation. The amendments are effective for annual periods beginning on or after January 1, 2016. The adoption of these amendments is not expected to have a significant impact on the Partnership's financial statements.

Employee Benefits

IAS 19, Employee Benefits ("IAS 19") was amended on July 30, 2014. These amendments clarify the application of the requirements of IAS 19 on determination of the discount rate to a regional market consisting of multiple countries sharing the same currency. These amendments are effective for annual periods beginning on or after January 1, 2016. The adoption of these amendments is not expected to have an impact on the Partnership's financial statements.

Leases

IFRS 16, Leases ("IFRS 16") was issued by the IASB on January 13, 2016, and will replace IAS 17, Leases. IFRS 16 will bring most leases onto the balance sheet for lessees under a single model, eliminating the distinction between operating and financing leases. Lessor accounting remains largely unchanged. The new standard is effective for annual periods beginning on or after January 1, 2019. The Partnership has not yet determined the effect of adoption of IFRS 16 on its financial statements.

Joint Arrangements

IFRS 11, Joint Arrangements ("IFRS 11") was amended by the IASB on May 6, 2014. The amendments add new guidance on how to account for the acquisition of an interest in a joint operation that constitutes a business. The amendments are effective for annual periods beginning on or after January 1, 2016. The adoption of these amendments is not expected to have an impact on the Partnership's financial statements.

(expressed in thousands of Canadian dollars)

5. PROPERTY, PLANT AND EQUIPMENT, NET

	Land	Equipment and other assets	Transmission assets	Work-in-progress	Total
Cost					
Balance, December 31, 2013	$ 236	$ 9,460	$ 230,145	$ 1,941	$ 241,782
Additions	-	-	-	4,044	4,044
Transfers	-	540	3,726	(4,266)	-
Disposals	-	(6)	(322)	(102)	(430)
Balance, December 31, 2014	$ 236	$ 9,994	$ 233,549	$ 1,617	$ 245,396
Additions	-	-	-	8,597	8,597
Transfers	-	808	7,352	(8,160)	-
Disposals	-	(163)	(1,935)	-	(2,098)
Balance, December 31, 2015	$ 236	$ 10,639	$ 238,966	$ 2,054	$ 251,895
Accumulated Depreciation					
Balance, December 31, 2013	$ -	$ 1,414	$ 15,283	$ -	$ 16,697
Additions (Depreciation)	-	920	7,933	-	8,853
Disposals	-	(6)	(89)	-	(95)
Balance, December 31, 2014	$ -	$ 2,328	$ 23,127	$ -	$ 25,455
Additions (Depreciation)	-	952	8,289	-	9,241
Disposals	-	(161)	(1,483)	-	(1,644)
Balance, December 31, 2015	$ -	$ 3,119	$ 29,933	$ -	$ 33,052
Carrying amounts					
Balance, December 31, 2014	$ 236	$ 7,666	$ 210,422	$ 1,617	$ 219,941
Balance, December 31, 2015	$ 236	$ 7,520	$ 209,033	$ 2,054	$ 218,843

During the year, the Partnership disposed of assets with a total net book value of $454 (2014 - $233) for net proceeds of $48 (2014 - $18). A resultant loss on disposal of property, plant and equipment of $406 (2014 - $215) was recorded to the statement of comprehensive income.

(expressed in thousands of Canadian dollars)

6. INTANGIBLE ASSETS, NET

	Land rights	Computer software	Work-in-progress	Total
Cost				
Balance, December 31, 2013	$ 1,102	$ 2,839	$ 271	$ 4,212
Additions	-	-	139	139
Transfers	-	46	(46)	-
Disposals	-	-	(110)	(110)
Balance, December 31, 2014	1,102	2,885	254	4,241
Additions	-	-	623	623
Transfers	124	459	(583)	-
Disposals	-	(3)	(75)	(78)
Balance, December 31, 2015	$ 1,226	$ 3,341	$ 219	$ 4,786
Accumulated Depreciation				
Balance, December 31, 2013	$ -	$ 1,050	$ -	$ 1,050
Additions (Amortization)	-	449	-	449
Disposals		-	-	-
Balance, December 31, 2014	-	1,499	-	1,499
Additions (Amortization)	-	404	-	404
Disposals	-	(3)	-	(3)
Balance, December 31, 2015	$ -	$ 1,900	$ -	$ 1,900
Carrying amounts				
Balance, December 31, 2014	$ 1,102	$ 1,386	$ 254	$ 2,742
Balance, December 31, 2015	$ 1,226	$ 1,441	$ 219	$ 2,886

During the year, the Partnership wrote off $75 (2014 - $110) in work-in-progress assets, which was recorded to the statement of comprehensive income under operating and administration expense.

The Partnership owns land rights and other land easements that are needed as part of the normal business operations. Land rights have been obtained through contractual rights where the transferor has transferred land rights and land easements to specific parcels of land. The Partnership has identified land rights as intangible assets with an indefinite useful life since contractual rights give access to specific land parcels in perpetuity. The Partnership accounts for land rights at cost less cumulative impairment losses, if any. At December 31, 2015 the carrying amounts of land rights is $1,226 (2014 - $1,102).

The Partnership has not identified events or changes in circumstances that indicate that the land rights' carrying amounts exceed their recoverable amounts. The Partnership has tested land rights for impairment in accordance with annual impairment tests.

(expressed in thousands of Canadian dollars)

6. INTANGIBLE ASSETS, NET (continued)

The Partnership has identified the recoverable amount of land rights to be their fair values less cost of disposal. In arriving at the fair value less cost of disposal, the Partnership has used a recent sale proposal which it believes is indicative of the fair value less cost of disposal of the land rights owned. The Partnership has determined that as at December 31, 2015 the fair value less cost of disposal is greater than the carrying amount and hence no impairment loss has been recorded.

The Partnership uses fair value less cost of disposal to determine the recoverable amount as it believes that this will generally result in a value greater than or equal to the value in use. For the purpose of the intangible impairment test, the Partnership used a non-binding sale agreement. The inputs used in the fair value measurement constitute Level 2 inputs under the fair value hierarchy. Level 2 inputs are quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets, inputs other than quoted prices that are observable for the asset or liability (for example, interest rate and yield curves observable at commonly quoted intervals, forward pricing curves used to value currency and commodity contracts), or inputs that are derived principally from or corroborated by observable market data or other means.

7. TRADE AND OTHER PAYABLES

	Dec 31, 2015	Dec 31, 2014
Trade payables and accruals	$ 404	$ 955
Payroll liabilities	426	527
Accrued interest	311	322
Connection deposits	593	1,076
Other payables	188	343
	$ 1,922	$ 3,223

The Partnership retains connection deposits for power generating entities as reimbursement to the Partnership for costs to be incurred in connecting those power generating entities to the Partnership's power transmission property assets. Any unused connection deposit balance will be refunded to the appropriate power generating entity.

8. PENSION AND EMPLOYEE FUTURE BENEFITS

The Partnership is part of a registered defined benefit, final pay pension plan and other post-employment benefit plan (the "Plans").

The other post-employment benefit plan includes benefits such as health and dental care, and life insurance. The obligation under these plans is determined periodically through the preparation of actuarial valuations. The Partnership contributions for the benefit plans for 2015 was $1,142 (2014 - $1,193).

The Partnership also participates in a defined contribution pension plan provided to certain employees. The Partnership contributes based on the level of employee contributions for this plan. In 2015, the total employer expense for the Partnership's defined contribution pension plan was $138 (2014 - $140). The minimum employer's contribution for 2016 is estimated to be $82.

The Partnership's pension plan information is provided in the following tables:

(expressed in thousands of Canadian dollars)

8. PENSION AND EMPLOYEE FUTURE BENEFITS (continued)

	December 31, 2015			December 31, 2014		
	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total
Change in the present value of the accrued benefit obligation						
Balance, beginning of year	22,645	6,869	29,514	20,415	5,708	26,123
Current service cost	415	259	674	376	195	571
Past service cost	-	-	-	-	(315)	(315)
Interest expense	888	278	1,166	989	269	1,258
Benefit payments from plan	(922)	(95)	(1,017)	(892)	(142)	(1,034)
Employee contributions	115	-	115	117	-	117
Increases (decreases) due to other significant events	-	-	-	(25)	-	(25)
Remeasurements:						
Effect of changes in demographic assumptions	-	(1,775)	(1,775)	200	102	302
Effect of changes in financial assumptions	(499)	(11)	(510)	1,966	1,052	3,018
Effect of experience adjustments	22	(648)	(626)	(501)	-	(501)
Balance, end of year	**22,664**	**4,877**	**27,541**	**22,645**	**6,869**	**29,514**
Change in fair value of the plan assets						
Fair value, beginning of year	21,837	-	21,837	19,070	-	19,070
Return on plan assets	1,213	-	1,213	1,763	-	1,763
Contributions:						
Employer	1,047	95	1,142	1,051	142	1,193
Employee	115	-	115	117	-	117
Benefit payments from plan	(922)	(95)	(1,017)	(892)	(142)	(1,034)
Administrative expenses paid from plan assets	(81)	-	(81)	(208)	-	(208)
Interest income	875	-	875	956	-	956
Decreases due to other significant events	-	-	-	(20)	-	(20)
Fair value, end of year	**24,084**	**-**	**24,084**	**21,837**	**-**	**21,837**
Net Defined Benefit Liability						
Accrued benefit obligation	(22,664)	(4,877)	(27,541)	(22,645)	(6,869)	(29,514)
Fair value of plan assets	24,084	-	24,084	21,837	-	21,837
Net Defined Benefit Liability	1,420	(4,877)	(3,457)	(808)	(6,869)	(7,677)
Total expense recognized in profit and loss						
Current service cost	415	259	674	376	195	571
Past service cost	-	-	-	-	(315)	(315)
Net interest expense	13	278	291	32	266	298
Administrative expenses and taxes	175	-	175	140	-	140
Total expense recognized in profit and loss	**603**	**537**	**1,140**	**548**	**146**	**694**
Actuarial losses/(gains) recognized in statement of comprehensive income						
Effect of changes in demographic assumptions	-	(1,775)	(1,775)	200	102	302
Effect of changes in financial assumptions	(499)	(11)	(510)	1,966	1,052	3,018
Effect of experience adjustments	22	(648)	(626)	(501)	-	(501)
Return on plan assets	(1,308)	-	(1,308)	(1,694)	-	(1,694)
Total actuarial losses/(gains) recognized in statement of comprehensive income	**(1,785)**	**(2,434)**	**(4,219)**	**(29)**	**1,154**	**1,125**

Effects of changes in assumptions

	Revalued pension obligation	Revalued pension obligation	Total
Discount Rate			
Increase by 100 basis points	18,875	832	19,707
Decrease by 100 basis points	25,443	968	26,411
Inflation Rate			
Increase by 100 basis points	23,778	895	24,673
Decrease by 100 basis points	19,840	895	20,735

Significant Actuarial Assumptions	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Defined Benefit Pension Plan	Non-Pension Benefit Plans
	December 31, 2015		December 31, 2014	
Weighted-Average actuarial assumptions used:				
Discount rate	4.15%	4.20%	4.00%	4.10%
Rate of compensation increases	3.00%	3.00%	3.00%	3.00%
Inflation Rate	2.00%	2.00%	2.00%	2.00%

Plan Assets by asset class allocation (%)	31-Dec-15	31-Dec-14
Fixed income	37%	33%
Equities	63%	67%
Other	0%	0%
Total	100%	100%

(expressed in thousands of Canadian dollars)

9. TRANS SENIOR BONDS

The Trans Senior Bonds (the "Bonds") have a principal amount of $120,000 and are secured by a charge on the Partnership's transmission real property assets, both present and future. On behalf of the Partnership, a company related through common control, BIP, continues to maintain a letter of credit in the amount of $3,960 to cover six months of interest payments on the Bonds.

The fair market value of the Bonds as at December 31, 2015 is $143,002 based on current market prices for debt with similar terms (2014 - $144,112). Amortization of deferred financing fees for the year related to the Partnership's Bonds are included in finance costs and totaled $211 (2014 - $203).

The Bonds bear interest at the rate of 6.6% per annum. Semi-annual payments of interest only were due and payable on June and December 16 each year up until and including June 16, 2013. Equal blended semi-annual payments of principal and interest on the Bonds commenced on December 16, 2013 and will continue until and including June 16, 2023. The Bonds will not be fully amortized by their maturity date. The remaining principal balance of the Bonds will be fully due on June 16, 2023.

	Dec 31, 2015	Dec 31, 2014
Trans senior bonds	$ 114,803	$ 116,984
Less: unamortized deferred financing fees	(1,849)	(2,061)
Less: current portion	(2,327)	(2,180)
	$ 110,627	$ 112,743

As at December 31, 2015, principal repayments due in each of the next five years were as follows:

	2016	2017	2018	2019	2020
Principal repayments	$ 2,327	$ 2,483	$ 2,649	$ 2,827	$ 3,017

During the year, the Partnership identified a number of projects which were considered to be qualifying assets for purposes of capitalizing borrowing costs. For the year ended December 31, 2015, the Partnership capitalized borrowing costs of $235 (2014 - $125). The capitalization rate on funds borrowed amounted to 6.6% (2014 - 6.6%).

10. PARTNERSHIP UNITS

The Partnership is authorized to issue an unlimited number of Class A and Class B partnership units, of which 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2015. 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2014.

(expressed in thousands of Canadian dollars)

11. COMMITMENTS AND CONTINGENCIES

Letters of credit

On behalf of the Partnership, BIP continues to maintain a letter of credit totaling $3,960 to cover six months of interest payments on the Bonds. No amount has been drawn against this letter of credit.

Commitments

As at December 31, 2015 future minimum lease payments for operating leases entered into by the Partnership, as lessee, were as follows:

	2016	2017-2020	Thereafter
Minimum lease payments	$336	$1,009	$nil

Contingencies

The Partnership may, from time to time, be involved in legal proceedings, claims and litigation that arises in the ordinary course of business which the Partnership believes would not reasonably be expected to have a material adverse effect on the financial condition of the Partnership.

There are no specified decommissioning costs relating to the Partnership's assets. The Partnership has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to industry standards. Replacement of the assets occurs in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which the Partnership would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

12. OPERATING AND ADMINISTRATION EXPENSES

	2015	2014
Compensation expenses	$ 6,025	$ 5,989
Contract expenses	1,635	1,780
Materials	771	801
Other	1,042	552
	$ 9,473	$ 9,122

(expressed in thousands of Canadian dollars)

13. MAINTENANCE EXPENSES

	2015	2014
Compensation expenses	$ 328	$ 393
Contract expenses	463	545
Materials	107	146
Other	359	489
	$ 1,257	$ 1,573

14. FINANCE COSTS

	2015	2014
Interest expense on Trans senior bonds	$ 7,675	$ 7,823
Amortization of deferred financing fees on Trans senior bonds	211	203
Less: capitalized interest	(235)	(125)
	$ 7,651	$ 7,901

15. DEPRECIATION AND AMORTIZATION

	2015	2014
Depreciation on property, plant and equipment	$ 9,241	$ 8,853
Amortization of intangible assets	404	449
	$ 9,645	$ 9,302

16. INCOME TAXES

The Partnership does not record income tax expenses as it is not subject to income taxation as a result of its formation as a limited partnership.

17. STATEMENT OF CASH FLOWS

Net change in non-cash working capital related to operations

	2015	2014
Trade and other receivables	$ 336	$ 54
Prepaid expenses and other	35	(326)
Due from related parties	(6)	(53)
Trade and other payables	(1,301)	250
Due to related parties	(20)	(367)
Pension liability	(1)	(500)
	$ (957)	$ (942)

(expressed in thousands of Canadian dollars)

18. CAPITAL RISK MANAGEMENT

The Partnership's primary capital management objective is to ensure the sustainability of its capital to support continuing operations, meet its financial obligations, allow for growth opportunities and provide stable distributions to its partners. The Partnership manages its capital to maintain an investment grade credit rating while prudently making use of leverage in order to provide its ultimate parent with enhanced returns. In addition, the Partnership manages its capital to ensure access to incremental borrowings needed to fund new growth initiatives.

The Partnership manages its capital structure in accordance with changes in economic conditions. Generally, capital expenditures are funded with external borrowings. In order to adjust the capital structure, the Partnership may elect to adjust the distribution amount paid to its partners, increase or reduce the equity participation in new and existing operations, adjust the level of capital spending or issue new partnership units.

The Partnership manages its capital in order to maintain a debt to capitalization ratio below 75%. As at December 31, 2015, the ratio was 52% (2014 – 52%). The table below presents the detail of the Partnership's capitalization and the calculation of the ratio:

	Dec 31, 2015	Dec 31, 2014
Trans senior bonds	$ 114,803	$ 116,984
	114,803	116,984
Partners' equity	110,380	106,050
Total capitalization	$ 225,183	$ 223,034
Debt to capitalization	51%	52%

There has been no change in the Partnership's approach to managing capital in the year.

(expressed in thousands of Canadian dollars)

19. FINANCIAL INSTRUMENTS

Fair value measurement

The Partnership defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The Partnership classifies its financial assets and liabilities as outlined below:

		Dec 31, 2015		Dec 31, 2014	
	Class	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets					
Cash	LAR	$ 3,340	$ 3,340	$ 5,201	$ 5,201
Trade and other receivables	LAR	3,086	3,086	3,422	3,422
Financial liabilities					
Trade and other payables	OL	1,922	1,922	3,223	3,223
Trans senior bonds	OL	112,954	143,002	114,923	144,112

Classification details:
FVTPL – fair value through profit or loss
LAR – loans and receivables
OL – other liabilities

The statements of financial position carrying amounts for cash, trade and other receivables, trade and other payables, and due to and from related parties approximate fair value due to their short-term nature. Due to the use of subjective judgments and uncertainties in the determination of fair values, these values should not be interpreted as being realizable in an immediate settlement of the financial instruments.

Fair value hierarchy

The following provides a description of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable:

(a) Level 1 fair value measurements are those derived from quoted market prices (unadjusted) in active markets for identical assets or liabilities;
(b) Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
(c) Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

No financial instruments have been ranked level 2 or 3, except for the Bonds which are ranked as level 2.

19. FINANCIAL INSTRUMENTS (continued)

There were no transfers between Level 1, 2 and 3 during the reporting periods. The fair values of financial assets and liabilities carried at amortized cost are approximated by their carrying values, except for the Bonds whose fair market value is presented in note 9.

Financial risk management

The Partnership has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk.

The Partnership's management has overall responsibility for the establishment and oversight of the Partnership's risk management framework. Risk management policies are established to identify and analyze the risks faced by the Partnership, to set appropriate risk limits and controls and to monitor risks and ensure adherence to these limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Partnership's activities. The Partnership, through its training and management standards and procedures, aims to maintain a disciplined and constructive control environment in which all employees understand their roles and obligations. The objectives, policies and processes for managing risk were consistent with those in the prior year.

Market Risk

Market risk is the risk that changes in market prices (interest rates) will affect the Partnership's income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Partnership's Bonds are subject to a fixed interest rate of 6.6% per annum, payable semi-annually on June 16 and December 16. As a result of having fixed rate debt, fluctuations in market interest rates are not expected to materially affect the Partnership's cash flows.

Credit Risk

Credit risk is the risk of financial loss to the Partnership if a counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Partnership's receivables from counterparties. The carrying amount of financial assets represents the maximum credit exposure.

The Partnership actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

The majority of trade receivable transactions entered by the Partnership are with the Independent Electricity System Operator ("IESO"). The IESO operates the provincial transmission system, and is a reliable counterparty. The quality of the Partnership's counterparties mitigates the Partnership's exposure to credit risk.

(expressed in thousands of Canadian dollars)

19. FINANCIAL INSTRUMENTS (continued)

The Partnership's maximum exposure to credit risk as at December 31 is as follows:

	Dec 31, 2015	Dec 31, 2014
Trade and other receivables	$ 3,086	$ 3,422

The Partnership is also exposed to credit risk on cash. Credit risk is mitigated by ensuring the majority of the financial assets are placed with a major Canadian financial institution with strong investment-grade ratings by a primary ratings agency. The credit risk of cash has been assessed as low.

Liquidity Risk

Liquidity risk is the risk that the Partnership will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset. The Partnership manages liquidity risk by forecasting cash flows required by operations and anticipating investing and financing activities to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they are due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Partnership's reputation.

The table below analyzes the Partnership's financial liabilities into relevant maturity groupings based on the remaining period at the date of the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows:

		Contractual Maturities				
	Carrying Amount	Less Than 1 Year	1-2 Years	3-5 Years	More Than 5 Years	Total
Trade and other payables	$ 1,922	$ 1,922	$ -	$ -	$ -	$ 1,922
Trans senior bonds	112,954	9,866	9,866	29,598	117,709	167,039
	$114,876	$11,788	$9,866	$29,598	$117,709	$168,961

At year end, the Partnership's relatively stable operating cash flows provide sufficient liquidity to fund these contractual obligations.

20. RELATED PARTY TRANSACTIONS AND BALANCES

Through the normal course of business, the Partnership enters into transactions with parties that meet the definition of a related party. Throughout the year ended December 31, 2015 the Partnership entered into the following transactions with entities considered to be related:

(a) In the normal course of operations, Riskcorp Inc., an insurance broker related through common control, entered into transactions with the Partnership to provide insurance. The total cost allocated to the Partnership in 2015 was $323 (2014 - $373) and no amount remains outstanding at year end.

(b) The Partnership has provided services to and received services from entities under common control in the normal course of operations. The balances payable and receivable for these services are non-interest bearing and unsecured. The balances payable to and receivable from related parties will come due during the following year.

Office Complex

The office complex in which the Partnership conducts its operations is owned by GLPL, and leased by the Partnership. Lease payments are made to GLPL on a monthly basis, with the annual lease cost for 2015 equal to $340 (2014 - $334).

Communication Equipment

The Partnership uses a fiber optic network that is owned by GLPL and is licensed by the Partnership. License fee payments are made to GLPL on a quarterly basis, with the annual lease cost for 2015 equal to $166 (2014 – $166).

The Partnership owns Radio Systems Assets and issues licenses for the use of these assets to GLPL. License fee payments are received from GLPL on a quarterly basis, with the annual lease payments for 2015 equal to $41 (2014 - $37).

Pole Rental

The Partnership owns transmission poles and receives license fee payments in accordance with a Licensed Attachment Agreement between the Partnership and GLPL. This agreement allows GLPL to affix and maintain its apparatus and equipment to the transmission poles owned by the Partnership. Payments are received by the Partnership annually. Total payments received by the Partnership in 2015 are equal to $33 (2014 - $33).

Road Maintenance

The Partnership shares a remote roadway in the northern portion of its service territory with GLPL. The roadway is used for access to various generating stations and transmission stations. The road maintenance costs are shared between the Partnership and GLPL, with GLPL incurring the initial cost and passing a predetermined portion on to the Partnership. Payments for this road maintenance are made to GLPL as the costs are incurred by GLPL, with the total portion borne by the Partnership in 2015 being equal to $135 (2014 - $136).

(expressed in thousands of Canadian dollars)

20. RELATED PARTY TRANSACTIONS AND BALANCES (continued)

Corporate Costs

In accordance with the Services Agreement between Brookfield Infrastructure Holdings (Canada) Inc. and the Partnership in effect January 1, 2012 until January 1, 2017, the Partnership records a corporate cost allocation for services received. The Partnership may request such services as but not limited to information technology management, human resource administration, and financial administration. The total corporate cost allocation recorded as an expense in 2015 was $412 (2014 - $400).

(c) As a result, the following balances are receivable (payable) as at:

	Dec 31, 2015	Dec 31, 2014
Due from related parties		
Services provided to entities under common control	$ 95	$ 89
Due to related parties		
Services received from entities under common control	$ 198	$ 218

(d) Transactions with key management personnel

A summary of key management and director compensation for the year ended December 31 is as follows:

	2015	2014
Salaries, management bonus and fees	$ 916	$ 881
Other benefits	124	129
Director fees	15	15
	$ 1,055	$ 1,025

21. SUBSEQUENT EVENT

On January 29th, 2016, Hydro One Inc. entered into a purchase agreement to acquire all of the issued and outstanding voting securities of the Partnership.

The transaction is conditional upon the satisfaction of customary closing conditions, including receipt of *Competition Act (Canada)* approval and approval of the OEB.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #5

Interrogatory

Reference: A/T2/S1/pg.1

a) Since no **consolidation** of GLPT is expected until the termination of pre-acquisition debt obligations please explain how this application qualifies for any of the policies articulated by the Board in the Handbook to Electricity Distributor and Transmitter **Consolidations**.

Response

HOI has applied in accordance with section 86 (2)(b) because it is seeking to acquire all voting securities of GLPT. This transaction is expected to close within 5 business days from the release of the OEB's approval decision of this application. Consequently, there is no delay in the commencement of acquisition activities. Consolidation of GLPT and Hydro One will occur within the deferred rebasing period.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #6

Interrogatory

Reference: A/T2/S1/pg.9

a) What, if any, reliability **improvements** to GLPT transmission system might be gained by approval of this application.

Response

GLPT's transmission system reliability may benefit from this transaction by improving the co-ordinated planning efforts to review and identify long term transmission needs for the entire East Lake Superior regional planning area; assessing future investment needs in the area; and from efficiently planning expenditures to realize savings while maintaining all requisite safety and reliability requirements for the system. Having coordination and integration of Hydro One and GLPT's staff is expected to improve regional system knowledge and allow for the implementation of best in class programs.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #7

Interrogatory

Reference: A/T1/S1/pg.23

a) What is the expected date (month) for the filing of the GLPT revenue requirement application?

b) Given that GLPT will be filing a rate application what is the basis for seeking approval of revenue requirement matters related to this utility in this application.

c) What would be the implication to this transaction if the Board deferred consideration of the revenue requirement issues proposed in this application until the time of the GLPT revenue requirement application?

Response

a.) GLPT has advised HOI that the expected filing date has not yet been determined.

b.) Please refer to Exhibit I, Tab 1, Schedule 6.

c.) Please refer to Exhibit I, Tab 1, Schedule 7

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #8

Interrogatory

Reference: A/T1/S1/pg8 & A/T3/S1/pg.1

a) When does Hydro One expect to file its next transmission revenue requirement application?

b) Does the proposed earning sharing mechanism apply equally to Hydro One Transmission? If not, please explain why not?

Response

a.) Hydro One Transmission filed a revenue requirement application on May 31, 2016 for approval of 2017 and 2018 revenue requirements. Hydro One's next transmission revenue requirement application is expected to be filed in 2018 for rates commencing in 2019.

b.) Please refer to Exhibit I, Tab 1, Schedule 8a.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #9

Interrogatory

Reference: A/T2/S1/pg.7

a) Will the employees of GLPT become employees of Hydro One upon close of this transaction? Will the transaction impact compensation and benefits (including pension benefits) of GLPT employees?

Response

Upon close of this transaction, employees of GLPT will not become employees of Hydro One. The acquired employees will retain their current GLPT compensation and benefits until they are integrated with Hydro One.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #10

Interrogatory

Reference: All

a) Does Hydro One expect this transaction, if approved, to impact any of the Settlement Agreements in the last revenue requirements applications of either GLPT (EB-2014-0238) or Hydro One (EB-2014-0140)?

Response

No.

Share Valuation and Financing of the Proposed Transaction

Valuation of the Transaction was the result of a multiple party competitive bid process undertaken by BIH and BIP.

HOI is not financing the Transaction with new debt sources. Instead, the purchase price will be paid in cash through use of existing credit facilities and the assumption of GLPL's existing debt.

The premium paid over the book value on the transaction will not have a material impact on Hydro One's or HOI's financial viability. As indicated in **Exhibit A, Tab 1, Schedule 1**, the value of the Transaction equates to approximately 2% of HOI's fixed assets. In alignment with Board practice and as referred to in the Handbook, the premium paid over the net book value of the assets will not be recovered through revenue requirement and no return will be earned on that premium.

Protection of Consumers with Respect to Prices and the Adequacy, Reliability and Quality of Electricity Services

Price of Electricity Service

The OEB approves the revenue requirements of transmitters in Ontario. GLPT currently accounts for approximately 2.6% of the uniform rates and revenue allocators. Hydro One represents approximately 94.6% of these rates and allocators. The OEB also approves the charge determinants of individual transmitters and uses these to calculate the UTR. The current approved UTRs for 2016 are: Network Service Rate $3.66/kW, Line Connection Service Rate $0.87/kW, Transformation Connection Service Rate $2.02/kW.

The UTR impact of the transaction at the end of the 10 year rate rebasing deferral period (relative to current 2016 UTR rates) is forecast to be an increase of approximately $0.02 to the Network Service Rate and $0.01 to the Transformation Connection rate under the Base Case scenarios (i.e. capital and OM&A). Under the High Case scenarios, the Network Service Rate is forecast to increase by approximately $0.01 from current 2016 rates.

Adequacy, Reliability and Quality of Electricity Service

Hydro One does not expect that the reliability of either transmission system will be materially impacted as a result of the transaction. Hydro One and GLPT are both experienced licensed transmitters. All licensed transmitters in the province are required to meet standardized performance expectations and public policy objectives relating to reliability. Both Hydro One and GLPT must design and operate their respective systems in conformance with the IESO Market Rules and the Ontario Resource & Transmission Assessment Criteria ("ORTAC"). Both systems must also comply with reliability standards established by NERC. Given that the system topology of Hydro One and GLPT will not be changing and both utilities adhere to the same design and operating standards required by all transmitters in the IESO-controlled grid, Hydro One and GLPT are confident that reliability will not be impacted.

Please see **Table 6** below for a comparison of Hydro One's regional reliability indices against those of GLPT.

TABLE 6 – RELIABILITY INDICES REGIONALLY OF HYDRO ONE AND GLPT

	2010	2011	2012	2013	2014	2015
HONI - SAIDI[3]	28.1	39.6	75.9	184.3	40.7	66.1
GLPT - SAIDI	150.7	296.7	176.8	861.1	25.4	79.8
HONI - SAIFI	0.76	0.50	0.86	0.97	2.23	0.81
GLPT - SAIFI	1.33	2.14	2.24	1.37	0.47	0.89

[3] Hydro One's SAIDI and SAIFI results in Table 7 are premised on the results of the Mississagi TS to Martindale TS subsystem. This segment of Hydro One's transmission system is similarly situated, sized (in terms of asset types, line length, and delivery points) and carries a comparable load to that of GLPT.