ONTARIO ENERGY BOARD

EB-2016-0160

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

AND IN THE MATTER OF an application by Hydro One Networks Inc. (Hydro One) pursuant to section 78 of the *Ontario Energy Board Act*, 1998 for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018.

MOTION RECORD

(Environmental Defence Motion For Full and Adequate Interrogatory Responses)

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Note: The documents in tabs 2-4 and 10-13 are excerpts of the relevant document.

[1] https://www.ontario.ca/page/september-2016-mandate-letter-energy
[2] http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
[3] https://www.nyserda.ny.gov/-/media/Files/Publications/Research/Electic-Power-Delivery/epri-assessment-losses.pdf
[4] http://www.hme.ca/reports/CASA_Report_--_The_Efficiency_of_Alberta's_Electrical_ Supply_System_EEEC-02-04.pdf
[5] www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=43615
[6] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=36718.

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Hydro One Networks Inc. (Hydro One) pursuant to section 78 of the *Ontario Energy Board Act*, 1998 for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018.

NOTICE OF MOTION AND WRITTEN SUBMISSIONS

Environmental Defence will make a motion to the Ontario Energy Board ("Board") on a date fixed by the Board, at the offices of the Board, 2300 Yonge Street, 25th Floor, Toronto, Ontario.

PROPOSED METHOD OF HEARING: This motion is to be heard in writing or through any other method as directed by the Board.

THE MOTION IS FOR:

1. An order that Hydro One and/or the Independent Electricity System Operator (IESO) provide full and adequate responses to Environmental Defence interrogatories 1-5.

THE GROUNDS FOR THE MOTION ARE:

Overview and Relevance

2. Environmental Defence seeks full and adequate responses to interrogatories 1 to 5. These interrogatories relate to two important and highly relevant issues: (1) the constraints in Hydro One's system that limit's Ontario electricity import and export capacity and (2) potential measures to decrease Hydro One's transmission system energy losses. Environmental Defence wishes to examine whether Hydro One should be investing more in these two areas. It may be possible to make investments that

ultimately *reduce* customer bills by reducing costly energy losses or by increasing Ontario's capacity to import inexpensive clean power (e.g. from Quebec). These investments could also result in significant environmental and carbon-reduction benefits.

3. These topics are relevant and within scope. Hydro One has put forward a capital investment plan. Environmental Defence wishes to explore, among other things, whether changes should be made to increase certain kinds of investments. This proceeding also concerns performance measures and incentive mechanisms. Environmental Defence wishes to explore whether Hydro One should be required to measure and report on import/export constraints and transmission system energy losses and whether it should be incented to make improvements in these areas.

4. These kinds of investments are mandated by the Long-Term Energy Plan (LTEP). For example, the LTEP speaks of "operational constraints" that limit imports, and states that import contracts will be pursued "where cost effective and well matched to Ontario's electricity needs."[1] Furthermore, the September 2016 Mandate Letter to the Minister of Energy asks that he "explore an electricity trade agreement [with Quebec] that would provide value to Ontario ratepayers."[2] The LTEP also mandates pursuing conservation as "the preferred choice wherever cost-effective."[3] Environmental Defence believes that more should be done to examine transmission losses as an area for potential conservation, especially at the peak when both the losses and electricity prices are the highest.

5. Transmission system losses are not a minor issue. They merit significant attention and scrutiny. Environmental Defence's preliminary estimates suggest that the cost of these losses is more than $389,000,000 per year.[4] The actual figure is likely higher if one

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[1] Ontario Ministry of Energy, *Long-Term Energy Plan*, December, 2013, p. 45 [Motion Record, tab 2].
[2] September 2016 Mandate Letter to the Minister of Energy, p. 6 [Motion Record, tab 3].
[3] Ontario Ministry of Energy, *Long-Term Energy Plan*, December, 2013, p. 20 [Motion Record, tab 2].
[4] Ontario's generator output in 2015 was 153.7 TWh (*http://www.newswire.ca/news-releases/ieso-releases-2015-ontario-electricity-data-sector-wide-changes-continue-to-impact-supply-demand-price-564992261.html)*. Average transmission system line losses were approximately 2.5% (*http://www.ieso.ca/Documents/conservation/LDC-Toolkit/Guidelines-and-Tools/CDM-EE-Cost-Effectiveness-Test-Guide-v2-20150326.pdf, Appendix A*). Multiplying those figures provides approximate system losses for 2015 of 3,842,500 MWh. The weighted average Ontario wholesale market electricity price for 2015 was

accounts for the fact that losses are highest at the peak when generation is the most costly. The true cost of these losses is one of the interrogatory questions that Environmental Defence asked and is still outstanding.

6. These issues fit squarely within the Board's statutory objectives relating to electricity. Increasing the capacity to import inexpensive electricity and reducing costly energy losses would lower bills and improve efficiency and cost effectiveness, key objectives under the *Ontario Energy Board Act*.[5] Reducing losses would also "promote electricity conservation."[6] Enabling increased imports of inexpensive renewable hydro-electric imports from Quebec would also promote "the timely expansion or reinforcement of transmission systems … to accommodate the connection of renewable energy generation facilities."[7]

7. Environmental Defence did not receive full and adequate responses to its interrogatories regarding the above important topics, including even the most basic questions asking for the current import/export capacity with neighboring jurisdictions and the annual energy losses of Hydro One's transmission system. Environmental Defence attempted to resolve this issue in correspondence and subsequent discussions but was unable to obtain a commitment to provide further information.

Role of the IESO

8. Hydro One states that the information sought by Environmental Defence is "within the control of" or "resides with" the IESO.[8] This appears to potentially be the case with respect to much of the information at issue. Environmental Defence therefore has

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$101.38/MWh (*http://www.ieso.ca/imoweb/pubs/marketReports/monthly/2015dec.pdf, p. 22*). Multiplying the losses by the price provides an approximate total cost of $389,552,650.

[5] *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 s. 1. (1) 1 & 2 ("The Board … shall be guided by the following objectives: 1. To protect the interests of consumers with respect to prices… 2. To promote economic efficiency and cost effectiveness in the … transmission … of electricity").

[6] *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 s. 1. (1) 3 ("The Board … shall be guided by the following objectives: … 3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario").

[7] *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 s. 1. (1) 5 (The Board … shall be guided by the following objectives: … 5. "To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.").

[8] Letter from Counsel for Hydro One to Counsel for Environmental Defence, September 15, 2016 [Motion Record, tab 8]; Response to Environmental Defence Interrogatory # 1 [Motion Record, tab 5].

requested an order that the interrogatories be answered by the IESO *and/or* Hydro One.

9. Environmental Defence has not sought this information solely from the IESO as it may be that some information or input is needed from Hydro One to answer some of the interrogatories.[9] Furthermore, the fact that certain information resides with the IESO does not mean that Hydro One cannot obtain the information or calculate the relevant figures. If the Board orders that the requested information be provided, we anticipate that Hydro One and the IESO can coordinate and decide together which party would file the response.

10. We do not anticipate that the IESO will challenge the Board's jurisdiction to order that the IESO file information relevant to this proceeding on the grounds that it is not the applicant. Indeed, it is not uncommon for the IESO to provide evidence in proceedings in which it is not the applicant. If the IESO objects to the Board's jurisdiction to order that it provide evidence in this proceeding, Environmental Defence will provide a response at that time.

Specific Interrogatories

Interrogatory #1

11. This interrogatory requested, among other things, the actual maximum amount of electricity (MWhs) that can be imported and exported to and from Ontario's five adjoining jurisdictions.[10] The IESO pointed Environmental Defence to the Ontario Transmission System reports.[11] However, these reports show the installed capacity in MW (i.e. the theoretical capacity), *not* the actual capacity in MWhs after considering

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[9] For example, Hydro One's input may be helpful to estimate the losses arising in Hydro One's system based on the total transmission system loss figures from the IESO. Whether this is the case is not known to Environmental Defence at the current time.

[10] Although this interrogatory requested data for each of the 26 interconnections, we understand that this level of granularity would be difficult to provide and therefore Environmental Defence will accept a response that provides the data at the level of each of the 5 adjoining jurisdictions.

[11] Letter from the IESO dated September 16, 2016 [Motion Record, tab 9].

operational constraints in the Hydro One system.[12] Environmental Defence is seeking the latter figures (i.e. the actual capacity after considering operational constraints).

12. It is clear that constraints in Hydro One's system are limiting Ontario's import capacity. For example, the IESO's September 1, 2016 *Ontario Planning Outlook* states as follows:

> To facilitate any potential large firm import capacity arrangement from Quebec/ Newfoundland, major system reinforcements in eastern Ontario would be required – a new high-voltage direct current (HVDC) intertie to Lennox would be an example. The incorporation of new resources in Southwestern Ontario would require reinforcement of the transmission system, such as in the West of London area, as well as additional enabling facilities. Similarly, investments in new resources in the Greater Toronto Area might also trigger the need to reinforce the bulk transmission system.[13] Kent: I don't see how London's and the GTA's problems are related to imports from Quebec or the U.S.

13. Environmental Defence seeks to determine both the nameplate import/export capacity and the actual import/export capacity. The difference between these two figures will show the amount of capacity that can be "unlocked" if Hydro One were to undertake the kinds of system reinforcements discussed in the *Ontario Planning Outlook.*

<u>*Interrogatory #2*</u>

14. Interrogatory #2 reads as follows:

> a) Please provide, for each of the last 10 years, Hydro One's annual transmission energy losses as a percent of its total annual transmission throughput volumes; and
>
> b) Please provide, for each of the last 10 years, Hydro One's transmission energy losses during the annual peak demand hour as a percent of the total demand of its customers during the peak hour.

15. Rather than provide the requested annual figures, the IESO provided a link to website directory containing over 700 individual files, one for each hour of the past month, showing the total system transmission losses at 5-minute intervals. This raw data is not the information that was requested. The data is at 5-minute intervals, not the requested annual figures; covers only 1 month, not the requested 10 year period; is incomplete; is not specific to Hydro One; and is in a completely unmanageable format (a separate

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[12] Ontario Ministry of Energy, *Long-Term Energy Plan*, December, 2013, p. 45 ("Ontario has approximately 4,500 to 5,200 MW of import-export capacity. However, actual power flows do not reach these levels because of operational constraints in and outside Ontario.") [Motion Record, tab 2].

[13] IESO, *Ontario Planning Outlook*, September 1, 2016 [Motion Record, tab 4].

spreadsheet file for each hour). Environmental Defence is still seeking the specific figures it requested in its interrogatory.

16. The IESO also states that it "does not calculate transmitter-specific transmission losses." Although the IESO may not do this as part of its regular business, there is no reason that a value specific to Hydro One cannot be estimated. In other words, although it may be that the IESO "does not" calculate the losses specific to Hydro One, it has not shown that it *cannot* do so or that this would be overly onerous. For the purposes of this interrogatory, the IESO need only make a best efforts attempt to calculate this figure and can of course include any provisos that are necessary.

17. For example, it may be possible to estimate Hydro One's transmission losses by multiplying the total system transmission losses by the percentage of the total system transmission volumes that are transmitted Hydro One.[14] Alternatively, it may be possible to determine Hydro One's transmission losses by subtracting the MWhs provided to its customers (i.e. LDCs and transmission-connected customers) from the MWhs that generators transmit to Hydro One's system (Hydro One has confirmed that all of these figures are metered).[15] Regardless of how it is done, no technical constraint has been identified that would make an estimate of Hydro One's transmission losses impossible or overly onerous to generate on a best efforts basis.

18. Furthermore, the fact that transmission loss figures are available for other utilities shows that these figures can be determined for Hydro One as well. For example, transmission loss figures are available for numerous transmission companies in Canada, New York, and the United Kingdom.[16] Publicly available information for New York's transmission utilities includes a breakdown between peak and annual

[14] The IESO has noted that its data relates to total market demand (i.e. Ontario demand plus exports). Environmental Defence does not object to the response to this and other interrogatories including the losses associated with imports and exports (i.e. market demand, not only Ontario demand). Indeed, the interrogatory requested a calculation of Hydro One's losses as a percentage of total throughput, which would presumably include volumes that are imported or exported.

[15] Technical Conference Transcript, Day 2, September 23, 2016, p. 94, lns 5-11.

[16] *Assessment of Transmission and Distribution Losses in New York*, EPRI, Palo Alto, CA: 2012. PID071178 (NYSERDA 15464), Appendix A [Motion Record, tab 10]; JEM Energy & Associates, *A Study on the Efficiency of Alberta's Electrical Supply System*, October 2004, p. 39 [Motion Record, tab 11]; National Grid Electricity Plc, S*pecial Condition 2K.4 – Transmission Losses Report Reporting Period 1 April 2014 to 31 March 2015* [Motion Record, tab 12].

losses as well as details on each utility's loss mitigation strategies.[17] If company-specific transmission losses can be calculated in other jurisdictions, why couldn't that be done in Ontario as well?

19. The Board's *Rules of Practice* require "full and adequate" responses to relevant interrogatories.[18] The fact that an organization does not normally collect certain information as part of their business processes is not valid justification to refuse to provide that information. Instead, the Rules permit a party to refuse to provide a response if "an answer is not available or cannot be provided with reasonable effort."[19] That is not the case here.

<u>Interrogatory #3 (c)</u>

20. This interrogatory asked for estimates of the average transmission energy losses for transmission companies in the United States and Canada. It would be helpful to compare these figures to Hydro One's losses as a preliminary first step in determining whether additional consideration regarding transmission losses is warranted.

21. Hydro One and the IESO stated that they do not have this information. However, this would appear to be relatively easy information for an engineer at either organization to seek out and provide in response to an interrogatory. Although Environmental Defence could obtain this information via an expert consultant, it would be more efficient and effective for Hydro One or the IESO to do so. These organizations have the expertise and knowledge to do so and can select what they know to be the most reputable sources. If the appropriate personnel in these organizations make best efforts to seek the information and are unable to do so, Environmental Defence would be satisfied by these best efforts attempts to provide a response.

<u>Interrogatory #4 (a) & (c)</u>

22. Interrogatory #4 (a) reads as follows:

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[17] *Assessment of Transmission and Distribution Losses in New York*, EPRI, Palo Alto, CA: 2012. PID071178 (NYSERDA 15464), Appendix A [Motion Record, tab 10].
[18] Ontario Energy Board, *Rules of Practice and Procedure*, rule 27.01 (1).
[19] Ontario Energy Board, *Rules of Practice and Procedure*, rule 27.02 (b).

a) Please provide a detailed description of the various sources of Hydro One's transmission energy losses. Please include a percentage breakdown by geographic region and type (e.g. line losses versus losses from equipment such as transformers). Please also attach any internal documents, reports, presentations, etc. on this issue.

23. Hydro One stated in response that "Energy losses on the transmission system are largely due to line losses and transformer losses."[20] The IESO did not elaborate. These responses did not satisfy the requirement in the Board's *Rules of Practice* that response be "full and adequate."[21] Nor did it satisfy the requirement to explain why the information or "alternative available information" is unavailable.[22]

24. Environmental Defence requests more detail. For example, what losses occur other than line losses and transformer losses? Approximately what percentage of the losses are from line losses versus transformer losses? Are there certain transmission lines that generate a particularly large proportion of the losses? Are the losses larger in some regions versus others? Although it may not be possible to provide precise figures, a general discussion based on an engineer's knowledge of the sources of losses and Hydro One's system would be of great assistance.

25. Part (c) of this interrogatory requested a list of the steps that Hydro One could be taking to reduce transmission losses but will not be taking. Hydro One's answer was not responsive to the question. If Hydro One is not aware of specific projects that could be undertaken (whether operational improvements or capital investments), it could at least provide high-level information on the kinds of actions that can be taken. This kind of information is widely available and it must be the case that Hydro One's engineers would be aware of the actions that can be taken to reduce transmission losses and could provide a meaningful response.[23]

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[20] Hydro One response to Interrogatory #4 [Motion Record, tab 5].
[21] Ontario Energy Board, *Rules of Practice and Procedure*, rule 27.01 (a).
[22] Ontario Energy Board, *Rules of Practice and Procedure*, rule 27.02 (b).
[23] For examples of the actions that can be taken to reduce transmission losses see: *Assessment of Transmission and Distribution Losses in New York*, EPRI, Palo Alto, CA: 2012. PID071178 (NYSERDA 15464), p. viii - ix [Motion Record, tab 10]; National Grid, *Strategy Paper to address Transmission Licence Special Condition 2K: Electricity Transmission Losses*, September 2014, p. iii [Motion Record, tab 13].

<u>*Interrogatory #5*</u>

26. This interrogatory requests an estimate of the annual cost of the Hydro One transmission losses for each of the past 10 years. Neither Hydro One nor the IESO provided a response. However, it would be possible to estimate this figure without an unreasonable amount of effort. The total system losses are available in 5-minute intervals.[24] It would therefore be possible to determine the losses on an hourly basis and multiply those losses by the Hourly Ontario Electricity Price. Alternatively, the losses could be summed for a year and multiplied by the weighted average price for that year. Both of those figures could be provided along with any provisos or qualifications that the IESO's or Hydro One's engineers feel are appropriate. It may also be that other methods of estimating the cost are available.

27. Once the cost of the total system transmission losses have been calculated, Hydro One's portion of those losses could be derived therefrom (see paragraphs 16 and 17 above for a discussion of methods to estimate Hydro One's portion of the total losses).

28. The cost figures would help confirm the importance of the transmission loss issue and is relevant to the degree of study and analysis that this issue merits in the future. Although our initial estimate is that the losses on the Hydro One system are worth over $389,000,000 per year, this is only a rough estimate that does not account for the fact that losses are highest at the peak when electricity costs are the highest. The actual number is likely higher.

Conclusion

29. This motion engages procedural fairness as it relates to important information that Environmental Defence would use to make its case. It also engages the Board's core objectives because decreasing transmission losses and increasing the capacity to import inexpensive power could lead to lower bills, significant environmental benefits, and the furtherance of government objectives such as the pursuit of "conversation first" and increases in Ontario's ability to utilize renewable energy.

[24] Letter from the IESO dated September 16, 2016 [Motion Record, tab 9].

30. Furthermore, ordering that the IESO and Hydro One provide responses to these questions would be more efficient and effective than the IESO's suggestion, which is that Environmental Defence obtain and manipulate the raw data. This would likely require hiring an expert. It may be that the IESO or Hydro One would disagree with that expert's conclusions, taking up valuable hearing time. The most efficient and effective way to proceed would be for the IESO to work with Hydro One (to the extent that co-operation is necessary) to provide full and adequate responses to the interrogatories above.

31. For those and other reasons, Environmental Defence requests and order that the IESO and/or Hydro One provide full and adequate responses to Environmental Defence interrogatories 1 to 5.

THE FOLLOWING DOCUMENTARY EVIDENCE will be used at the hearing of the motion:

a. Evidence on the record in this proceeding;

b. The materials listed in the index to the Motion Record; and

c. Any further evidence as counsel may advise and the Board may permit.

Date: September 29, 2016

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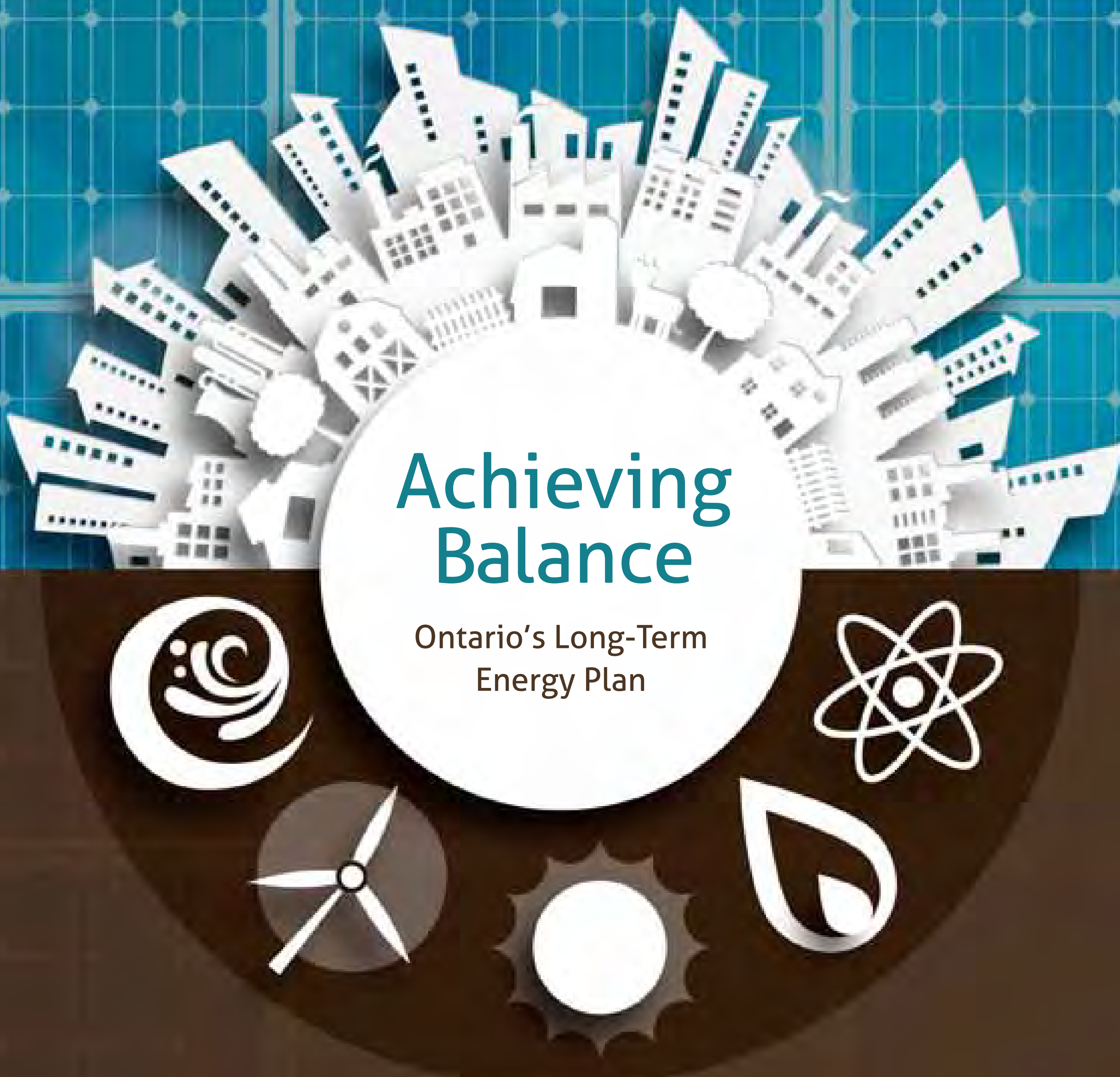


Achieving Balance

Ontario's Long-Term Energy Plan

Ontario

2 Putting Conservation First

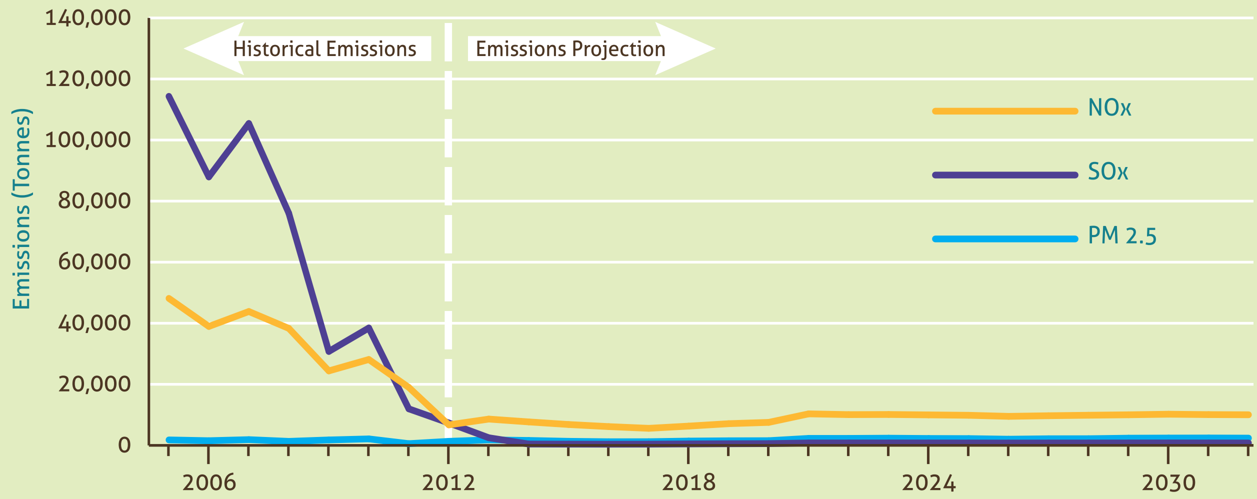
As we plan for Ontario's electricity needs for the next 20 years, conservation will be the first resource to be considered. It is the cleanest and most cost-effective energy resource, and it offers consumers a way to reduce their electricity bills. The government intends to ensure that conservation will be considered before building new generation and transmission facilities, and will be the preferred choice wherever cost-effective.

The ministry will work with its agencies to ensure that they put conservation first in their planning, approval and procurement processes. The ministry will also work with the OEB to incorporate the policy of Conservation First into distributor planning processes for both electricity and natural gas utilities.

Our agencies and partners will achieve this goal with a combination of tools, including the Total Resource Cost Test, the Program Administrator Cost Test and a hurdle rate, to screen program proposals. A hurdle rate would consider the cost of delivering a conservation program against the avoided cost of procuring supply.

Ontarians are making considerable progress in embracing a culture of conservation. Since 2005, conservation efforts have

Figure 21: Nitrogen Oxides, Sulphur Oxides and Particulate Matter Emissions Forecast



Note: Emissions in any one year could be higher, or lower, than the projection depending on the specific operating conditions experienced in the system. For example, changes in demand and/or energy production from non-emitting resources could contribute to higher or lower emissions.

Most EFW facilities burn the waste material directly to obtain energy but there are alternative technologies being developed that promise better efficiency and lower greenhouse gas emissions than conventional EFW.

To encourage the development of these new technologies in Ontario, the OPA is considering projects that have received Ministry of the Environment approval. These Ontario-based projects offer the potential for job creation and export opportunities. Testing will verify whether new technologies can operate successfully with environmental performance superior to conventional EFW technologies.

Clean Imports

Ontario has several interconnections with the provinces of Manitoba and Quebec as well as with the states of Minnesota, Michigan and New York. Taken together, Ontario has approximately 4,500 to 5,200 MW of import-export capacity. However, actual power flows do not reach these levels because of operational constraints in and outside Ontario.

Ontario exports and imports a significant amount of electricity as part of the regular operation of its electricity market and is expected to have sufficient energy and capacity in the near term to meet province-wide needs. The electricity wholesale market has proven to be extremely effective in enabling power to flow between Ontario and its neighbours.

Ontario will continue to rely on the wholesale market to provide flexibility and to balance power flows on a short-term basis. However, an import arrangement with a neighbour to guarantee the firm delivery of clean power could offer a cost-effective alternative to building domestic supply. Import contracts can be structured to meet multiple system needs such as capacity for peaking, ramping, backup or reserve purposes, or the firm delivery of energy over a specified timeframe, or a combination.

Contracted energy imports can provide value if their price is less than domestic generation. They can also further diversify Ontario's supply. While clean energy imports offer potential benefits to Ontario, the value to Ontario depends on the willingness of those supplying imports to offer a product that matches Ontario needs and represents better value than the domestic alternatives.

Ontario will only pursue contractual arrangements for firm imports where cost effective and well matched to Ontario's electricity needs.

Ontario

September 2016 Mandate letter: Energy

Premier's instructions to the Minister on priorities.

September 23, 2016

The Honourable Glenn Thibeault
Minister of Energy
900 Bay Street
4th Floor, Hearst Block
Toronto, Ontario
M7A 2E1

Dear Minister Thibeault:

Welcome to your role as Minister of Energy. As we mark the mid-point of our mandate, we have a strong and new Cabinet, and are poised to redouble our efforts to deliver on our top priority — creating jobs and growth. Guided by our balanced plan to build Ontario up for everyone, we will continue to work together to deliver real benefits and more inclusive growth that will help people in their everyday lives.

We embark on this important part of our mandate knowing that our four-part economic plan is working — we are making the largest investment in public infrastructure in Ontario's history, making postsecondary education more affordable and accessible, leading the transition to a low-carbon economy and the fight against climate change, and building retirement security for workers.

Building on our ambitious and activist agenda, and with a focus on implementing our economic plan, we will continue to forge partnerships with businesses, educators, labour, communities, the not-for-profit sector and with all Ontarians to foster economic growth and to make a genuine, positive difference in people's lives. Collaboration and active listening remain at the heart of the work we undertake on behalf of the people of Ontario — these are values that ensure a common purpose, stimulate positive change and help achieve desired outcomes. With this in mind, I ask that you work closely with your Cabinet colleagues to deliver positive results on initiatives that cut across several ministries, such as our Climate Change Action Plan, Business Growth Initiative, and the Highly Skilled Workforce Strategy. I also ask you to collaborate with the Minister Responsible for Digital Government to drive digital transformation across government and modernize public service delivery.

We have made tangible progress and we have achieved the following key results:

- On January 1, 2015, Ontario launched its new six-year Conservation First Framework. The framework, together with the Industrial Accelerator Program for transmission-connected customers, is expected to achieve 8.7 terawatt-hours (TWh) of electricity savings in 2020, and help achieve our conservation target of 30 TWh (terawatt-hours) in 2032.
- On December 22, 2014, Ontario launched its new six-year Demand Side Management Framework, which brings Ontario's total spending on natural gas conservation programs in-line with leading US jurisdictions, allowing natural gas utilities to pursue greater levels of natural gas savings.
- Since January 1, 2016, the Ontario Electricity Support Program has been providing ongoing assistance directly on the bills of eligible low-income electricity consumers.

In addition to the priority activities above, I ask that you also deliver results for Ontarians by driving progress in the following areas:

- Continue to partner and collaborate with the Province of Québec on key energy issues, including:
  - Working together on the existing working group to identify common interests and positions concerning the Energy East project.
  - In co-operation with the IESO (Independent Electricity System Operator) and Hydro-Québec, further the intention to explore an electricity trade agreement that would provide value to Ontario ratepayers.
- Based on Ontario's pipeline principles, continue to be proactive in promoting Ontario's interests in the Energy East pipeline project and participate in the National Energy Board (NEB) regulatory process.
- Working with the ministers of Infrastructure and Agriculture, Food and Rural Affairs, local distribution companies, municipalities and Indigenous partners, continue to identify opportunities to expand natural gas access and affordability in a manner consistent with the Climate Change Action Plan.
- Following recommendations from the Premier's Advisory Council on Government Assets, continue to move forward with broadening the ownership of Hydro One and proceed with future offerings in a careful, staged and prudent manner.
- Continue to implement government oversight of the refurbishment of nuclear reactors to ensure projects remain on budget and on time to protect ratepayers.

As you know, taking action on the recommendations contained in the Truth and Reconciliation Commission report is a priority for our government. That is why we released *The Journey Together*, a document that serves as a blueprint for making our government's commitment to reconciliation with Indigenous peoples a reality. As we move forward with the implementation of the report, I ask you and your fellow Cabinet members to work together, in co-operation with our Indigenous partners, to help achieve real and measurable change for Indigenous communities.

Having made significant progress over the past year in implementing our community hubs strategy, I encourage you and your Cabinet colleagues to ensure that the Premier's Special Advisor on Community Hubs and the Community Hubs Secretariat, at the Ministry of Infrastructure, are given the support they need to continue their vital cross-government work aimed at making better use of public properties, encouraging multi-use spaces and helping communities create financially sustainable hub models.

Responsible fiscal management remains an overarching priority for our government — a priority echoed strongly in our 2016 Budget. Thanks to our disciplined approach to the province's finances over the past two years, we are on track to balance the budget next year, in 2017–18, which will also lower the province's debt-to-GDP (Gross domestic product) ratio. Yet this is not the moment to rest on our past accomplishments: it is essential that we work collaboratively across every sector of government to support evidence-based decision-making to ensure programs and services are effective, efficient and sustainable, in order to balance the budget by 2017–18, maintain balance in 2018–19, and position the province for longer-term fiscal sustainability.

Marathon runners will tell you that an event's halfway mark is an opportunity to reflect on progress made — but they will also tell you that it is the ideal moment to concentrate more intently and to move decisively forward. At this halfway mark of this government's mandate, I encourage you to build on the momentum that we have successfully achieved over the past two years, to work in tandem with your fellow ministers to advance our economic plan and to ensure that Ontario remains a great place to live, work and raise a family.

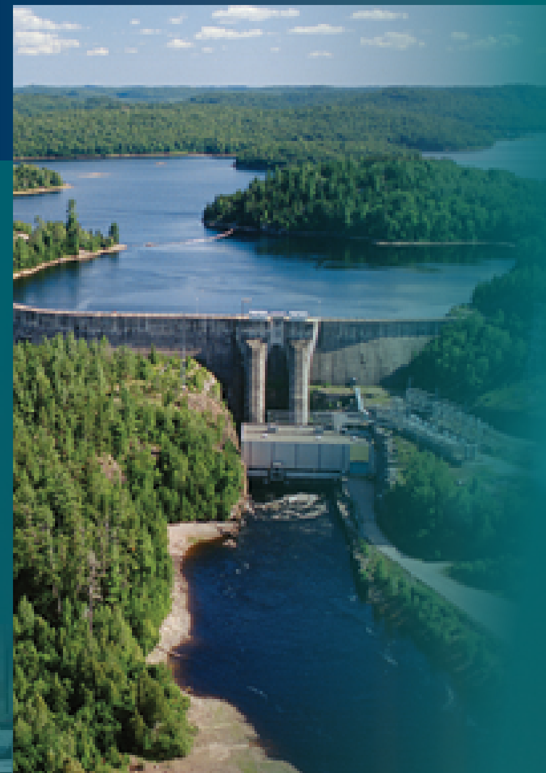
I look forward to working together with you to build opportunity and prosperity for all Ontarians.

Sincerely,

Ontario Planning Outlook

A technical report on the electricity system prepared by the IESO

SEPTEMBER 1, 2016



Connecting Today.
Powering Tomorrow.

"Over the planning period, a number of foreseeable changes are expected to result in a power system that is increasingly variable and complex to operate on a day-to-day basis."

The IESO has successfully integrated over 6,000 MW of wind and solar PV into Ontario's electricity system. The IESO has made strides in integrating significant amounts of variable generation while maintaining reliable operations of the power system. This has been achieved through efforts such as the Renewable Integration Initiative (RII), which brought in centralized forecasting of variable generation and the capability to dispatch variable generators.

While the IESO is working on methods for improving short-term forecasting, measures are also being taken to maintain reliable and efficient operations in the face of an evolving power system. These measures include additional frequency regulation, flexibility, control devices, and system automation. Greater coordination between the grid operator and embedded resources, directly or through integrated operations with LDCs, could also improve visibility into the distribution system and reduce short-term forecast errors.

Load-following capability is primarily provided by peaking water-power resources, the Sir Adam Beck Pump Generating Station and natural gas-fired generation, and is sufficient in the near term. However, the need for flexibility will increase over time. In addition to existing mechanisms for acquiring ancillary services, consideration is being given to expanded markets that would allow for more dynamic real-time coordination.

Going forward, regulation and flexibility requirements will be assessed on an ongoing basis, along with the resource fleet available to provide these services. Electricity markets will play a stronger role in ensuring adequate supply of flexible resources through signals that price and dispatch these services. It is anticipated that many resource types will be able to compete to provide regulation and/or flexibility, including resources such as energy storage and aggregated loads. Some of these newer technologies can provide operability characteristics that are not achievable from some traditional resources, such as very fast ramp rates, which may allow efficiency improvements in how these services are currently dispatched.

3.5. Transmission and Distribution Outlook

Current transmission projects already at various stages of planning and implementation are outlined in Table 3.

No significant new transmission investments would be required in an outlook of flat electricity demand served by existing and currently planned resources. However, additional transmission or local resources to address specific regional needs may be identified in the future as regional planning continues across the province.

The need to replace aging transmission assets over coming years will also present opportunities to right-size investments in line with evolving circumstances. This could involve up-sizing equipment where needs exist such as in higher demand outlooks; downsizing, to reduce the risk of underutilizing or stranding assets; or even removing equipment that is no longer required, such as in the low demand outlook or in parts of the province that have seen reduced demand. Such instances may also present opportunities to enhance or reconfigure assets to improve system resilience and allow for the integration of variable and distributed energy resources.

In higher demand outlooks, investments in transmission will be required to accommodate new resources. Transmission to integrate those resources would have significant lead time requirements of up to 10 years. Much of Ontario's undeveloped renewable resource potential is located in areas with limited transmission capacity – new investments in Ontario's transmission system would be required to enable further resource developments in the province or significant imports into the province. For example, incorporation of renewable resources located in northern Ontario would require reinforcements to the major transmission pathway between northern and southern Ontario, the North-South Tie. A number of transmission upgrades within Northern Ontario would also be required to alleviate constraints within the region. To facilitate any potential large firm import capacity arrangement from Quebec/Newfoundland, major system reinforcements in eastern Ontario would be required – a new high-voltage direct current (HVDC) intertie to Lennox would be an example. The incorporation of new resources in Southwestern Ontario would require reinforcement of the transmission system, such as in the West of London area, as well as additional enabling facilities. Similarly, investments in new resources in the Greater Toronto Area might also trigger the need to reinforce the bulk transmission system.

In the near term, the system can manage increases in electricity demand driven by electrification. However, LDCs and transmitters may be more significantly impacted as local peak demands grow.

Environmental Defence INTERROGATORY #001

Reference:

Reference: Ex. B1, Tab 1, Sch. 2, Page 8

Interrogatory:

a) Please provide the theoretical maximum import and export capacity (MW) of each of Hydro One's 26 interconnections with adjoining jurisdictions (Manitoba, Quebec, Minnesota, Michigan and New York);

b) Please provide Hydro One's best estimate of the actual maximum amount of electricity (MWhs) that can be imported per year via each of these interconnections;

c) Please provide Hydro One's best estimate of the actual maximum amount of electricity (MWhs) that can be exported per year via each of these interconnections;

d) Please describe all the actions that Hydro One is taking to increase the amount of electricity (MWhs) that can be imported and/or exported via each of these interconnections. In each case where actions are being taken, please state the expected increase in annual imports and/or exports (MWhs) that these actions will allow.

e) Has Hydro One estimated the benefits and costs of upgrading its transmission system to permit increased imports and/or exports of electricity? If yes, please provide copies of these analyses.

Response:

a) The import and export capability for individual interconnections is not computed. The concept of import and export capability applies to a collection of interconnections rather than individual interconnections. Import and export capability for a collection of interconnections is a function of not just the thermal capability of the individual interconnections, but also many other factors, not all of which are within the scope of Hydro One as a transmitter of electricity, including: the dispatch, loading patterns and constraints inside and outside of Ontario.

b) & c) Hydro One owns and operates the transmission assets. The use of these transmission assets for imports and exports depends on the transactions by market participants and the IESO who administers the electricity market. As stated in part (a) the import and export capability can vary significantly depending on many factors that are not all within Hydro One's control; therefore Hydro One is not able to provide the information as requested.

d) There is only one investment included in Hydro One's capital plan related to existing interconnections. The "Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade" project is needed to address an internal constraint that will enable a 500 MW firm capacity agreement between the Provinces of Ontario and Quebec on the existing interconnections with Quebec. Details on this specific project are available in Exhibit B1, Tab 3, Schedule 11, Investment Summary Documents Ref# D03.

e) No, Hydro One has not estimated the benefits of and costs of upgrading its transmission system to permit increased levels of imports or exports.

Environmental Defence INTERROGATORY #002

Reference:

Ex. B2, Tab 1, Sch. 1

Interrogatory:

a) Please provide, for each of the last 10 years, Hydro One's annual transmission energy losses as a percent of its total annual transmission throughput volumes; and

b) Please provide, for each of the last 10 years, Hydro One's transmission energy losses during the annual peak demand hour as a percent of the total demand of its customers during the peak hour.

Response:

a) and b)

Information on transmission system losses resides with the IESO. Hydro One does not have information on the electricity (i.e. generation) supplied into the transmission system, nor does it have information for all the delivery points where electricity exits from the transmission system. Accordingly, Hydro One cannot calculate transmission system losses.

Environmental Defence INTERROGATORY #003

Reference:

Ex. B2, Tab 1, Sch. 1

Interrogatory:

a) Has Hydro One undertaken benchmarking studies which compare its annual transmission energy losses as a percent of its total annual transmission throughput volumes to those of other electricity transmission companies? If yes, please provide these studies; and

b) Has Hydro One undertaken benchmarking studies which compare its transmission energy losses during the annual peak demand hour as a percent of the total demand of its customers during the peak hour to those of other electricity transmission companies? If yes, please provide these studies; and

c) What are the average transmission energy losses for transmission companies in (i) the United States and (ii) Canada? To the extent that they are available, please provide the figures for both the annual transmission energy losses as a percent of total annual transmission throughput volumes and the transmission energy losses during the annual peak demand hour as a percent of the total demand of its customers during the peak hour.

Response:

a) No, Hydro One has not undertaken such studies.

b) No, Hydro One has not undertaken such studies.

c) Hydro One does not have this information.

Environmental Defence INTERROGATORY #004

Reference:

Ex. B2, Tab 1, Sch. 1

Interrogatory:

a) Please provide a detailed description of the various sources of Hydro One's transmission energy losses. Please include a percentage breakdown by geographic region and type (e.g. line losses versus losses from equipment such as transformers). Please also attach any internal documents, reports, presentations, etc. on this issue.

b) Please provide a detailed description of Hydro One's plans to reduce its transmission energy losses from the various sources of those losses. Please also attach any internal documents, reports, presentation, etc. on this issue.

c) Please describe and list all of the actions that Hydro One could take but will not be taking to reduce its transmission energy losses (e.g. due to cost, viability, priorities, etc.).

Response:

a) Energy losses on the transmission system are largely due to line losses and transformer losses. For the reasons identified in ED # 2 (I-05-002) Hydro One does not have information on historical transmission system losses.

b) Hydro One does not have the information to forecasts annual transmission system energy losses. Hydro One does not have specific plans to reduce transmission energy losses.

c) See response to b).

Environmental Defence INTERROGATORY #005

Reference:
Ex. B2, Tab 1, Sch. 1

Interrogatory:
a) Please make best efforts to estimate the gross cost of the energy lost in each of the last 10 years via transmission energy losses. Please make and state assumptions as necessary.

b) To the extent that the figure would be different than the one provided in response to (a) above, please estimate the cost of the transmission energy losses to Hydro One's customers.

c) Please estimate the cost of transmission energy losses to Hydro One itself.

Response:
a), b) and c)

Hydro One does not have the information required to determine the cost of energy associated with transmission losses. The cost of transmission losses is included as one component of the uplift charges that the IESO charges all transmission-connected customers. The cost of transmission losses have no impact on the revenue requirement requested in Hydro One's application.

Environmental Defence INTERROGATORY #006

Reference:

Ex A, Tab 3, Schedule 1, Pages 16 & 17: Proposed Transmission Scorecard

Interrogatory:

a) Would Hydro One support modifying its Proposed Transmission Scorecard to include "Actual annual import capacity (MWhs)/maximum theoretical annual import capacity (MWhs)" and "Actual annual export capacity (MWhs)/maximum theoretical annual export capacity (MWhs)"? If no, please explain why not.

b) Would Hydro One support modifying its Proposed Transmission Scorecard to include "annual transmission energy losses as a percent of its total annual transmission throughput volumes" and "peak hour transmission energy losses as a percent of its peak hour demand". If no, please explain why not.

Response:

a) Hydro One would not support this measure at this time. The calculation involves a small number of transmission assets whose operation is directed by the IESO. Measuring the performance of these assets would not provide meaningful insight of Hydro One's system or business performance.

b) Refer to response to Exhibit I, Tab 5, Schedule 2. Additionally, transmission losses are to a large extent a function of generation dispatch, which is the purview of the IESO. For these reasons, this would not be an appropriate metric for Hydro One.

Witness: Michael Vels

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September 8, 2016

BY EMAIL

Nancy Marconi
Manager
Independent Electricity System Operator
1600 - 120 Adelaide Street West
Toronto, Ontario M5H 1T1
nancy.marconi@ieso.ca

Dear Ms. Marconi:

Re: EB-2016-0160 – Hydro One – Cost of Service

I am writing on behalf of Environmental Defence to request that the Independent Electricity System Operator ("IESO") provide certain relevant information to assist with the above hearing.

Environmental Defence made a number of interrogatory requests relating to transmission losses. Hydro One did not provide complete responses on the basis that information on transmission system losses resides with the IESO. We therefore ask that the IESO either answer the following interrogatories and file them with the Board or provide the relevant information to Hydro One so that it can provide further and better interrogatory responses. Note that the numbering below matches the numbering from Environmental Defence's original interrogatories to Hydro One.

2. Reference: Ex. B2, Tab 1, Sch. 1

   a) Please provide, for each of the last 10 years, Hydro One's annual transmission energy losses as a percent of its total annual transmission throughput volumes; and

   b) Please provide, for each of the last 10 years, Hydro One's transmission energy losses during the annual peak demand hour as a percent of the total demand of its customers during the peak hour.

3. Reference: Ex. B2, Tab 1, Sch. 1

   a) Has Hydro One undertaken benchmarking studies which compare its annual transmission energy losses as a percent of its total annual transmission throughput volumes to those of other electricity transmission companies? If yes, please provide these studies; [Please answer this from the perspective of any benchmarking done by the IESO]

   b) Has Hydro One undertaken benchmarking studies which compare its transmission energy losses during the annual peak demand hour as a percent of the total demand of its customers during the peak hour to those of other electricity transmission companies? If yes, please provide these studies; [Please answer this from the perspective of any benchmarking done by the IESO] and

c) What are the average transmission energy losses for transmission companies in (i) the United States and (ii) Canada? To the extent that they are available, please provide the figures for both the annual transmission energy losses as a percent of total annual transmission throughput volumes and the transmission energy losses during the annual peak demand hour as a percent of the total demand of its customers during the peak hour.

4. Reference: Ex. B2, Tab 1, Sch. 1

a) Please provide a detailed description of the various sources of Hydro One's transmission energy losses. Please include a percentage breakdown by geographic region and type (e.g. line losses versus losses from equipment such as transformers). Please also attach any internal documents, reports, presentations, etc. on this issue.

b) Please provide a detailed description of Hydro One's plans to reduce its transmission energy losses from the various sources of those losses. Please also attach any internal documents, reports, presentation, etc. on this issue. [Please provide the IESO's planning in this regard as it relates to Hydro One's network]

c) Please describe and list all of the actions that Hydro One could take but will not be taking to reduce its transmission energy losses (e.g. due to cost, viability, priorities, etc.).

5. Reference: Ex. B2, Tab 1, Sch. 1

a) Please make best efforts to estimate the gross cost of the energy lost in each of the last 10 years via transmission energy losses. Please make and state assumptions as necessary.

b) To the extent that the figure would be different than the one provided in response to (a) above, please estimate the cost of the transmission energy losses to Hydro One's customers.

c) Please estimate the cost of transmission energy losses to Hydro One itself.

Please do not hesitate to contact me if you wish to discuss this matter.

Yours truly,

Kent Elson

cc: Participants in EB-2016-0160

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September 8, 2016

BY EMAIL

Gordon Nettleton
McCarthy Tetrault LLP
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66 Wellington Street W.
Suite 5300
Toronto Ontario M5K 1E6
gnettleton@mccarthy.ca

Dear Mr. Nettleton:

Re: EB-2016-0160 – Hydro One – Cost of Service

I am writing on behalf of Environmental Defence to request further and better responses to Environmental Defence's interrogatories.

Interrogatory #1 asked about the import and export capacity of Hydro One's interconnections with adjoining jurisdictions (Manitoba, Quebec, Minnesota, Michigan and New York). Hydro One noted that import and export capability is based on a number of factors but did not provide the relevant figures. It is clearly possible to calculate import and export capacity (see attached IESO document that does so for Quebec).

Hydro One noted that import/export capability is not computed with respect to each of its 26 interconnections. Although Environmental Defence does not require a figure for each interconnection, it does request that the import and export capability be calculated for each of the adjourning jurisdictions. I have therefore revised the interrogatory to be less granular by asking for the information on a jurisdiction-wide basis rather than for each interconnection, which should be easier for Hydro One to respond to. Therefore, Environmental Defence requests the following information:

a) Please provide Ontario's theoretical maximum import and export capacity (MW) through Hydro One's system with adjoining jurisdictions (Manitoba, Quebec, Minnesota, Michigan and New York);

b) Please provide Hydro One's best estimate of the actual maximum amount of electricity (MWhs) that can be imported per year via each of these jurisdictions;

c) Please provide Hydro One's best estimate of the actual maximum amount of electricity (MWhs) that can be exported per year via each of these jurisdictions;

d) Please describe all the actions that Hydro One is taking to increase the amount of electricity (MWhs) that can be imported and/or exported via each of these jurisdictions. In each case where actions are being taken, please state the expected increase in annual imports and/or exports (MWhs) that these actions will allow.

Interrogatories 2, 3, 4, and 5 requested information relating to transmission losses. Hydro One stated that this information resides with the Independent Electricity System Operator ("IESO") and therefore provided either incomplete responses or no response at all to these interrogatories. Environmental Defence requests that Hydro One, as the applicant, obtain the necessary information from the IESO so as to provide a response to the interrogatory.

Please do not hesitate to contact me if you wish to discuss this matter.

Yours truly,

Kent Elson

Encl.

cc: Participants in EB-2016-0160

IESO Response to Questions from the Ontario Clean Air Alliance

1. **How much energy (TWh) can Ontario currently import per year from Quebec using the existing interties and transmission system?**

   Ontario cannot rely on the energy from Quebec to meet the IESO's adequacy requirements without the enhancements to the transmission system that are described in the *Review of Ontario Interties* report. Without those enhancements Ontario would not be able to import the energy when it needs it the most (i.e. under low water conditions and peak load levels in Ontario). To plan the system in a manner capable of reliably delivering power to consumers, firm imports must meet adequacy planning criteria as set out by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and the IESO. These take into account variables such as operating characteristics, weather and extreme weather patterns, generator and transmission outages, transmission transfer capabilities, and availability of fuel. All of these variables factor into the analysis to determine the amount of *firm* energy that can be relied upon to serve Ontario consumers. Ontario's ability to import firm energy from Quebec is limited by transmission constraints in the Ottawa area, as noted in the Review of Ontario Interties.

   Unlike Ontario's interties with other neighbours (e.g. New York); most of the interties with Quebec are radial interconnections that can only be used to deliver power from very specific generators in Quebec. Ontario has one non-radial intertie with Quebec (the "HVdc intertie"), which can be used to deliver power from any generator in Quebec. The IESO estimates that the non-radial HVdc intertie has the hypothetical capability of delivering between 8.7 and 9.8 TWh of energy from Quebec in 2015. Additionally if the radial interties with Quebec are considered, then this hypothetical range becomes 16.5 TWh to 18.5 TWh. Quebec's ability to export this hypothetical amount of energy is dependent on the availability of the specific generators in Quebec that could connect to the radial interties.

   Although Ontario is able to hypothetically import between 16.5 and 18.5 TWh in a year from Quebec, Ontario typically imports 3 TWh of energy and exports 1.6 TWh of energy. This indicates that either energy is not available in Quebec to export to Ontario or it is not economical to export this energy to Ontario.

2. **What is the breakdown of the $500 million transmission upgrade cost estimate for each of the three measures listed in Appendix F of *Review of Ontario Interties*?**

Item	Cost
New 230 kV double circuit line between Cornwall and Ottawa	$300 M

New 230 kV circuit, approximately 8 km in length, to connect existing circuits in the west of Ottawa	$75 M
Additional voltage control equipment in the Ottawa area	$75 M
Other enhancements (e.g. converting circuit H9A to 230 kV operation)	$50 M

3. **What is the breakdown of the $1.4 billion transmission cost estimate for each of the measures listed in Appendix F and on Page 25 of the Review of Ontario Interties report?**

Item	Cost
New HVdc Interconnection	$1.1 B
New 500 kV double circuit line from Bowmanville to Cherrywood	$225 M
Replacement of existing phase-angle regulating transformers	$40 M

4. **What is the IESO's estimate of how many MW Ontario's firm import capability from Quebec will be increased for every 1 MW of incremental conservation and demand management (CDM) and/or distributed generation (DG) in the west end of Ottawa?**

Reducing the demand in the west end of Ottawa, either through CDM or DG, would increase Ontario capability to source firm capacity from Quebec. However, the precise ratio would depend on a number of variables that would require further clarification, including:

- future transmission system enhancements
- where the CDM and/or DG is located in the Ottawa area (on the 230 kV network or the 115 kV network)
- type of CDM and/or DG

These types of considerations would be part of the work conducted through an Integrated Regional Resource Plan process. For more information please visit: http://www.powerauthority.on.ca/power-planning/regional-planning/greater-ottawa/ottawa.

5. **If the IESO were to assume that imports from Quebec were used to replace the output of Bruce B, would that change the conclusions of the Review with respect to the transmission upgrades needed to accommodate firm water power imports from Quebec?**

   The upgrades identified in the *Review of Ontario Interties* would remain as described in the report. However, the loss of the Bruce B facilities and accompanying energy would necessitate further analysis and likely require transmission system changes to accommodate such a significant change to the overall Ontario electricity system.

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September 15, 2016

Klippensteins
Barristers & Solicitors
160 John Street, Suite 300
Toronto, Ontario M5V 2E5

Attention: Kent Elson

Dear Mr. Elson:

RE: EB-2016-0160

I am writing in response to your letter dated September 8, 2016.

I can advise that Hydro One Networks Inc. ("**Hydro One**") has reviewed your revised questions and remains unable to provide the requested information. The reasons remain those that are found in Hydro One's original interrogatory responses. The information sought regarding electricity imports and exports from/to jurisdictions interconnecting to the Hydro One transmission system is a function of many factors that are dependent on the transactions by market participants. This information is within the control of the Independent Electricity System Operator ("**IESO**") who administers the electricity market, and not Hydro One.

You may wish to review the IESO's website and review the IESO authored reports that are regularly posted concerning operations of the Ontario Transmission System. For example, Transmission Interfaces and Interconnection statistics are discussed in the IESO's June 21st 2016 Report.

With respect to your questions concerning transmission losses, and akin to those related to imports and export capabilities, it is not clear how these matters are within scope and relate to the relief requested in Hydro One's transmission rate application. Costs associated with transmission losses are included in the average uplift component of the electricity commodity price and not Hydro One's transmission rates.

Yours truly,

Gordon M. Nettleton

GMN/mpf

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September 16, 2016

VIA Email, Courier and RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
27th Floor, 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli,

Re: Hydro One Networks Inc.
2017 and 2018 Transmission Cost of Service Application
Board File Number EB-2016-0160

This letter is in response to correspondence to the Independent Electricity System Operator ("IESO") dated September 8, 2016, from Kent Elson of Klippensteins Barristers and Solicitors with respect to Hydro One's Cost of Service application (EB-2016-0160). On behalf of Environmental Defense, Mr. Elson requested that the IESO expand on responses from Hydro One for certain interrogatories regarding historical energy demands and transmission losses. Mr. Elson also requested that the IESO answer, or provide relevant information to Hydro One to answer, questions about the sources of Hydro One's transmission losses and benchmarking studies with other transmission service providers, among other things.

As noted in a letter issued to Kent Elson on September 15, 2016 from Gordon M. Nettleton of McCarthy Tétrault LLP on behalf of Hydro One, data related to the operations of Ontario's transmission system can be found in various public reports on the IESO's website.

The IESO, as Ontario's system operator, calculates and publishes estimated transmission system losses (MW) associated with total market demand (Ontario demand plus exports). Measurements are taken at points of generation and points of distribution across the entire system. Therefore, the data inherently includes losses from parts of the system that are not under Hydro One's jurisdiction. The IESO does not calculate transmitter-specific transmission losses nor has the IESO conducted any studies of transmission companies in Canada or the US. Estimates of recent total system transmission losses are published in 5-minute intervals at http://reports.ieso.ca/public/RealtimeConstTotals/. Historical data is available upon requests to customer.relations@ieso.ca.

With respect to Ontario and market demand peak values, the total energy consumed from the transmission system within Ontario ("Ontario demand") and both inside and outside of Ontario ("total market demand") back to market opening in 2002 can be found in hourly intervals in the

Hourly Ontario and Market Demands 2002-2015 on the IESO's website at http://www.ieso.ca/Pages/Power-Data/Data-Directory.aspx.

Information on transfer capability limits for each major interface between Ontario and other jurisdictions can be found in the Ontario Transmission System reports available at the following link http://www.ieso.ca/Documents/marketReports/OntTxSystem_2016jun.pdf.

The amount of power that can be transferred at Ontario's interjurisdictional interfaces at any given time is affected by many dynamic factors in and outside Ontario. In accordance with NERC practices and standards, the value used by the IESO to calculate and report on transmission transfer limits incorporates complex considerations such as generation, customer demand and limits imposed on the transmission system due to thermal, voltage, and stability conditions during a particular time period.

We hope that this information will be useful.

Yours truly,

Nancy Marconi

Nancy Marconi
Manager, Regulatory Proceedings

cc: Mr. Kent Elson, Klippensteins Barristers & Solicitors (email)
EB-2016-0160 Intervenors (email)
Harold Thiessen, Case Manager, Ontario Energy Board (email)

Assessment of Transmission and Distribution Losses in New York

PID071178 (NYSERDA 15464)

Final Report, November, 2012

Assessment of Transmission and Distribution Losses in New York State

Final Report

Prepared for

THE NEW YORK STATE
ENERGY RESEARCH AND DEVELOPMENT AUTHORITY
Albany, NY

Michael Razanousky
Project Manager

Prepared by

EPRI

Tom Short

SAIC

Trishia Swayne

Contract #
15464

November, 2012

CITATIONS

This report was prepared by

SAIC Energy, Environment and Infrastructure, LLC
131 Saundersville Rd., Suite 300
Hendersonville, TN 37075

Principal Investigator

T. Swayne
K. Fagen
D. Andrus
P. Mullen

This report describes research sponsored by the Electric Power Research Institute (EPRI).

This publication is a corporate document that should be cited in the literature in the following manner:

Assessment of Transmission and Distribution Losses in New York. EPRI, Palo Alto, CA: 2012. PID071178 (NYSERDA 15464).

NOTICE

ACKNOWLEDGMENTS

EPRI wishes to express their heartfelt appreciation to the leadership team who provided thoughtful guidance as well as countless project details:

Mike Razanousky, NYSERDA

Central Hudson Gas & Electric Corp.

Consolidated Edison Co. of New York, Inc.

New York State Electric & Gas Corporation

Rochester Gas & Electric Corporation

Orange and Rockland Utilities, Inc.

Long Island Power Authority

New York Independent System Operator

New York Power Authority

Niagara Mohawk Power Corporation (National Grid)

We wish to acknowledge all members of Project PID071178 for their support and participation.

EXECUTIVE SUMMARY

This report presents industry practices for loss calculations; examines industry trends on loss mitigation, including emerging trends; and explores techniques to determine the cost effectiveness of loss reduction measures.

In 2008, the State of New York Public Service Commission (PSC) established an Energy Efficiency Portfolio Standard for the state and adopted the goal of reducing New York's electricity usage by 15 percent by 2015 (15 x 15).[1] The PSC required the utilities to submit reports within six months of the order "identifying measures to reduce system losses and/or optimize system operations."[2]

The New York State Energy Research and Development Authority (NYSERDA); Electric Power Research Institute, Inc. (EPRI); and SAIC Energy, Environment & Infrastructure, LLC (SAIC) worked together with eight participating New York utilities and the New York Independent System Operator (NYISO) to identify practices and methodologies for performing evaluations of losses in electric systems and reduction studies. This report reviewed:

- Industry practices and methods used by the New York utilities to calculate losses in electric transmission and distribution (T&D) systems
- Measures to reduce system losses
- The effect of reactive power tariffs on electric losses

Results and Findings

Losses in electric transmission and distribution systems in the service territories of the participating New York utilities ranged from 1.5 to 5.8 percent for transmission losses and from 1.9 to 4.6 percent for distribution losses based on utility loss studies presented to the PSC in 2008 and 2009. These are comparable to other reported electric utility losses in the United States as reported by EPRI's Transmission Efficiency Initiative Study[3] and EPRI's Green Circuits Study[4].

Analysis confirms that New York utilities are using normal industry practices in calculating system losses and that there is not a single best practice that can be followed by every utility.

---

[1] PSC, Case 07-M-0548, "Proceedings on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard," Order dated June 23, 2008.

[2] PSC, Case 08-E-0751, "Proceedings on Motion of the Commission to Identify the Sources of Electric System Losses and the Means of Reducing Them," Order dated July 17, 2008.

[3] *Transmission Efficiency Initiative*, EPRI, Palo Alto, CA. 2009. 1017894.

[4] *Green Circuits: Distribution Efficiency Case Studies*, EPRI, Palo Alto, CA. 2011. 1023518.

Table ES-1 presents options for calculating losses that might benefit utilities in performing future loss studies, gaining precision in calculations, and evaluating losses across the state cohesively.

Table ES-1
Noteworthy Industry Practices

Approach	Benefit	Requirements and Costs
Separate losses into technical and non-technical categories, and identify the cause and type of losses.	Target specific areas of loss contribution; develop appropriate strategies to mitigate losses; Document energy savings (in more specific areas) so that they can be properly credited for energy efficiency claims.	Adjustment in reporting of categories. Additional calculation methods, data, and/or metering may be required.
Install metering down to the distribution feeder level that captures kW, kVAR, kWh, kVARh.	Provide the necessary information to validate models and assumptions and help identify target areas for loss improvements. Gain precision in loss calculations by using actual metered data over assumptions and in calculating load and loss factors.	Adjustments in calculation methods in eliminating some assumptions and using actual metered data. Additional metering and/or updates to current metering technologies in use.
Move towards hourly transmission load flows or evaluate multiple load levels for various time periods (typically seasonal) in calculating transmission losses.	This type of modeling can provide a better representation of operating conditions that occur at different load levels and times of year. Gain precision in loss calculations.	May require updates to software, additional modeling of system components, additional metering.
Obtain more detailed system information (such as using a GIS/mapping system for identifying primary and/or secondary facilities).	Aides in reducing assumptions for loss calculations and in developing more detailed engineering models. Aides in identifying specific areas that will benefit from loss reduction where sampling methodology cannot accomplish this. Gain precision in loss calculations.	May require updates to software; additional effort in collecting system facility information if not already recorded. Additional expenses for collecting and maintaining system data.

Based on the work performed by the New York utilities, EPRI, and SAIC, as well as reviews of other industry studies, electric losses can be reduced by system improvements both on the transmission and distribution systems. Generic or case-specific cost/benefit analysis is required to justify required expenditure for these system improvements.

For transmission systems:

1. Optimization of existing controls for transformer taps, generator voltages, and switched shunt capacitor banks reduces current flow and minimizes losses.
2. Addition of shunt capacitor banks, fixed and switched, at points on the system closest to the reactive load source reduces current flow and minimizes losses.

For distribution systems:

3. Phase balancing reduces line and neutral conductor losses.
4. Distribution capacitor banks on the feeders to improve the feeder power factor reduces line losses.

5. Capacitor banks at or near the substation improve the station power factor caused by the substation power transformer VAR requirement, measured at the high side of the power transformer and reduce load losses in the substation transformer.
6. Use of life-cycle evaluation for equipment sizing (initial installation of distribution transformers and conductors) reduces transformer core and coil losses.

Not traditionally considered part of methods to reduce transmission and distribution losses, conservation voltage reduction (CVR) has shown in recent studies that reducing voltage can reduce demand and energy consumption without impact to customers. Voltage optimization (VO), which is a technique that first "tunes" the distribution system by implementing system improvements and then applies voltage reduction, increases the amount that the voltage can be reduced for most feeders, thereby reducing energy consumption, and can reduce losses by two to four times as compared to just lowering the voltage. The loss reduction comes from the no-load losses in the distribution transformers and from implementing system improvements to tune the distribution system, in addition to the minor reduction in line losses from reducing the energy consumption of end-use loads. Voltage optimization is not strictly T&D efficiency, but many of the same approaches to analyzing losses and T&D efficiency apply to voltage optimization. It has the potential for much larger energy savings than loss reduction.

Utilities can identify areas of the electric system that might have a higher potential for loss reduction and can perform specific analysis for these systems to determine whether system improvements can be cost-effective in reducing losses. Approaches to calculating the cost of losses and performing an economic evaluation of efficiency improvements are reviewed in this report.

From the review of reactive power tariffs, the participating New York utilities are incorporating provisions for reactive demand similar to other utilities across the country. Documentation and feedback on the impact of reactive power charges to utility customers are sparse and inconsistent in the industry. Some challenges identified in the industry and for the New York utilities include:

- Rates in place at several utilities in the industry are not applied consistently or are made so transparent that it is difficult to be able to determine whether the rate structure design is actually motivating customers to perform corrective actions.
- Choosing a requirement for an optimal reactive demand level can be challenging. There are other unique challenges in dealing with real-time control of reactive power resources such that having a single requirement would not produce optimal solutions at every point in the system.
- The penalties at several utilities in the industry may not be steep enough to motivate the applicable customers to take action.

Industry research demonstrates that the efficiency of the power-delivery system can be improved. If the main criterion for economic justification is the marginal cost of energy, the research tends to show that many initiatives to reduce losses cannot be cost-justified. If ancillary benefits such as carbon credits or power quality impacts are considered, project economics may change. For targeted areas, loss reduction can often be economically justified by implementing changes in the way that the system is operated—such as voltage set points, capacitor settings, and switching—and cost-justified capital investment that can reduce losses in the electric grid.

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A
SUMMARY OF UTILITY DATA

Following is a summary of data submitted by utilities in New York in the six-month reports required by the PSC in its order dated June 23, 2008, establishing an Energy Efficiency Portfolio Standard in the State of New York (Case 07-M-0548). Reports were submitted by the following utilities:

Central Hudson Gas & Electric Corp.

Consolidated Edison Co. of New York, Inc.

New York State Electric & Gas Corporation

Rochester Gas & Electric Corporation

Orange and Rockland Utilities, Inc.

Long Island Power Authority

New York Power Authority

Niagara Mohawk Power Corporation (National Grid)

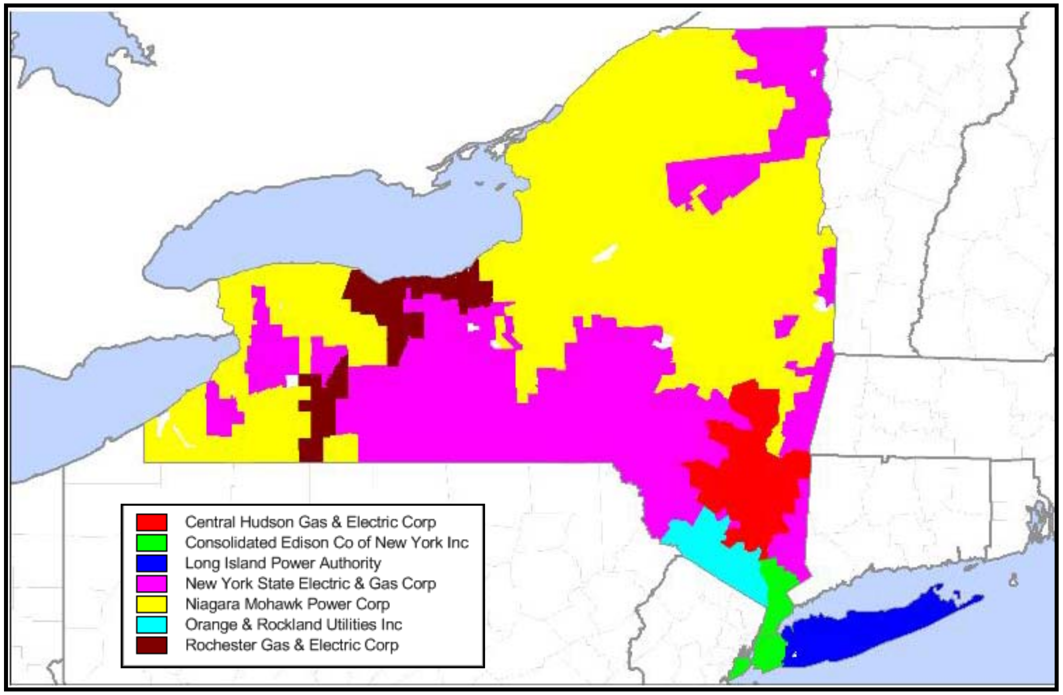

Figure 8-1: Location of Participating Utilities

Table A-2
Evaluation Comparison

	Utility A
System Statistics	2007 Peak – 1,185 MW Customers – 300,000 2007 Losses – 6.73% Transmission 345 kV – 76 miles 115 kV – 245 miles 69 kV – 294 miles Distribution 34.5 kV – 69 miles 13.8 kV – 6,830 miles 4 kV – 2,832 miles
Last Full Loss Study	2010 based on 2007 Losses
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. Hoebel Coefficient method used. Loss Factors for each voltage level. The following are the energy loss factors: • Transmission: 1.02071 • Primary Substation: 1.03205 • Primary Lines: 1.05489 • Secondary: 1.09042
Calculation Inputs/Other	A loss model, in Excel, was used to house all of the calculations for primary and secondary losses, transformers, conductors MWH generation – MWH sales = losses.
Total Transmission Losses	2.03% or 30.2% of total losses (broken down into voltage classes).
Transmission Losses Calculation Method/Inputs	PSLF- peak load flows – conductors only. Load factors developed for each voltage level.
Substations	0.9% or 13.1% of total losses (<u>separate</u> from transmission losses).
Substation Transformer Losses Calculation Method/Inputs	Peak loading, manufacturer test reports, and loss factor. Core losses held constant.
Total Distribution	3.9% or 56.8% of total losses.
Primary Distribution	1.7% or 24.7% of total losses (<u>included</u> in total distribution losses above) conductors and distribution transformers.
Secondary Distribution	2.2% or 32.1% of total losses (<u>included</u> in total distribution losses above) conductors (secondary and services).
Unaccounted For Category (theft, metering, etc.)	NONE Reconciliation of kW and kWh sales by voltage level was done by adjusting the initial loss factor estimates until the mismatch or difference was eliminated.

Summary of Utility Data

	Utility A
Distribution Losses Calculation Method	WindMil for primary distribution peak losses for a sample of circuits and then extrapolated to represent entire distribution system. Secondary and distribution transformers not included in model. Distribution transformer losses calculated in spreadsheet with assumption on # of customers and loading and test reports – core losses held constant. Secondary and service drop losses estimated in spreadsheet based on lengths, size, and loading.
Loss Mitigation Strategies	Evaluated cost/benefit: • Reconductor transmission line • Install sub capacitor bank • Convert three phase circuit from 4.16 kV to 13.8 kV • Convert single-phase spur line from 2.4 kV to 7.9 kV • Poly-phase a single-phase spur line • Replace pole-top transformers to lower impedance xfmrs • Switched distribution capacitors • Transformer load management • New substation transformer None of them proved to be economical. The following are currently underway: • Consideration of I^2R losses in transformer purchases and in distribution conductors • Purchase DOE distribution transformers • Capacitor Placement • Feeder/Load Balancing

	Utility B
System Statistics	2006 Peak – 1,617 MW Customers – 300,000 2007 Losses – 4.64% Transmission 345 kV, 138 kV, 69 kV, 34.5 kV – 540 miles Distribution 34.5 kV, 13.2 kV, 4 kV – 5,600 miles
Last Full Loss Study	2008 based on 2007 losses
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. Hoebel Coefficient method: Loss Factor = 0.2913 Load Factor = 0.48

	Utility B
Calculation Inputs/Other	Losses determined on monthly basis: Transmission Losses = Total Energy Send out (minus) Substation Output Energy Distribution Losses = Total Losses (minus) Transmission Losses Total Losses = Total Send out (minus) Billed Sales Three types of metering used to get data for losses: inter-utility and net generation; substation output; customer billing.
Total Transmission Losses	1.70% or 36.6% of total losses (broken down into voltage classes) – includes substation transformer losses.
Transmission Losses Calculation Method/Inputs	PSS/E – peak load flows – conductors only. *Dielectric*, I^2R
Substations	0.76% or 16.5% of total losses (included in transmission losses above).
Substation Transformer Losses Calculation Method/Inputs	Peak kW x Transformer Adjustment for Peak Load (TAPL) ^2 x Loss Factor. No-load losses from manufacturer's test reports..
Total Distribution	2.94% or 63.4% of total losses
Primary Distribution	2.53% or 54.5% of total losses (included in total distribution losses above) – broken down by voltage levels – includes conductors and distribution transformers.
Secondary Distribution	0.41% or 8.8% of total losses (included in total distribution losses above).
Unaccounted For Category (theft, metering, etc.)	Transmission – 0.33% or 7.1% of total losses (included in transmission losses above). Distribution – 0.41% or 8.8% of total losses (included in total distribution losses above).
Distribution Losses Calculation Method	Distributed Engineering Workstation (DEW) software for distribution (model contains primary to distribution transformers). Peak kW x loss factor for distribution primary losses. Full load loss x Transformer Load Factor (TLF)^2 x time for distribution transformer losses (where peak losses from DEW load flows). Street lighting use = # of lights x 12 hrs of operation x light wattage. Secondary, station service, and unaccounted for losses are difference between total measured losses by category and sum of calculated losses.
Loss Mitigation Strategies	Evaluated cost/benefit: • Transmission line reconductor • Install capacitors (transmission level) • Substation transformer upgrades • Distribution phase balancing • Install capacitors (distribution level) • Single-phase to three-phase distribution line conversions • Voltage conversion (distribution level) • New distribution circuit • Distribution line reconductor The following are currently underway: • Phase balancing, capacitor installations (distribution), single-phase line conversions. • In the past, transmission line conversions led to decrease in losses significantly. • Investigating Optimal Power Flow – Real-time reactive power management.

	Utility C
System Statistics	2011 peak – 13,189 MW Customers – 3.25 million 2007 Losses – 6.64% Transmission & Distribution 500 kV, 345 kV, 138 kV, 69 kV – 998 miles Distribution 33 kV, 27 kV, 13 kV, 4 kV 63,025 miles
Last Full Loss Study	2008 based on 2007 losses
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. System loss factor = 0.325
Calculation Inputs/Other	Additional losses were added in due to contingency operations of networks.
Total Transmission Losses	1.75% or 26.4% of total losses (broken down into voltage classes).
Transmission Losses Calculation Method/Inputs	*PSS/E – peak load flows* *conductors only* *Dielectric*, *I^2R, Corona (345 kV only)*
Substations	1.07% or 16.1% of total losses (<u>included</u> in transmission losses above).
Substation Transformer Losses Calculation Method/Inputs	Manufacturer's test reports for full and no-load losses, with 105% voltage rating used to calculate no-load losses.
Total Distribution	4.06% or 63.8% of total losses *Dielectric*, *I^2R*
Primary Distribution	2.89% or 43.5% of total losses (<u>included</u> in total distribution losses above – conductors & distribution transformers)
Secondary Distribution	1.17% Or 17.6% of total losses (<u>included</u> in total distribution losses above – conductors & metering). UG on the network system has capacity factor of 57.6%. OH on the network system has capacity factor of 68.2%.
Unaccounted For Category (theft, metering, etc.)	0.83% (theft = 0.16%, metering = 0.18%, and other = 0.49%).
Distribution Losses Calculation Method	PVL (in house distribution load flow software) used in loss study to get current through different conductor/cables sizes on the distribution modeled. Property records used to determine conductor/cable lengths for the loss calculations. Does not contain all distribution and only primary down to distribution transformers. Distribution transformer losses calculated from test reports and number of transformers. Secondary losses determined from average normal loading of distribution transformers, and conductor/cable sizes per transformer kVA size.

	Utility C
Loss Mitigation Strategies	Evaluated cost/benefit: • Distribution phase balancing • Install capacitors (distribution level) • Single-phase to three-phase distribution line conversions • New distribution circuit • Distribution line reconductor • Transmission conductor/cable replacement • Substation equipment replacement • Transmission system operation methods The following are currently underway: • PILC cable replacement program. • Install capacitors in substations. • Migrate smaller customer installations to spot networks. • Standard conductor sizing with standardized ratings and loading criteria. • DOE transformer installations. • Smart Grid 3G System. • Network split at Yorkville. • Conservation voltage reduction (CVR). • Capacitor placement on non-network area of distribution system. • Distribution phase balancing. • Theft-detection program. • New LEED certified substation. • Investigating Optimal Power Flow – Real-time reactive power management.

	Utility D
System Statistics	2006 Peak – 3,405 MW Losses - ~ 3% (From Ventyx Velocity Suite Online (VSO)) Transmission 765 kV – 155 miles 345 kV – 908 miles 230 kV – 336 miles 115 kV – 53 miles
Last Full Loss Study	2008 based on 2007 losses
Peak Losses Versus Annual Energy Losses	Annual energy losses <u>not</u> calculated for voltage classes, just system-wide.
Calculation Inputs/Other	Supply in – deliveries = annual energy losses.

	Utility D
Total Transmission Losses	Losses - ~ 3% (1) Broken down into voltage classes – include conductors, GSU transformers, and substation transformer . Peak Losses only
Transmission Losses Calculation Method/Inputs	PSS/E – peak load flows – conductors, GSU and substation transformers. For the Zone D (115 kV) system a separate model was developed and an hourly analysis was performed using revenue metering data.
Substations	Included in Transmission Losses above.
Substation Transformer Losses Calculation Method/Inputs	Peak load flows with transmission model.
Total Distribution	NONE
Primary Distribution	NONE
Secondary Distribution	NONE
Unaccounted For Category (theft, metering, etc.)	NONE
Distribution Losses Calculation Method	N/A
Loss Mitigation Strategies	The following are currently being done: • Participating in Interregional Reactive Power Management (EPRI project 39) – evaluating voltage controls. • Participating in Efficient T&D Systems for a Low Carbon Future (EPRI project 172) – energy efficiency at generating facilities. • Transmission voltage conversion or reconductoring being investigated for aging infrastructure. • Investigating Optimal Power Flow – Real-time reactive power management.

	Utility E
System Statistics	2011 Peak – 3,346 MW Customers – 878,000 1998 Losses – 10.0% Transmission 345 kV – 533 miles 230 kV – 233 miles 115 kV – 1398 miles 46 kV – 675 miles 34.5 kV – 1,692 miles Distribution 31,122 miles where 35 kV is 15%, 12 kV is 35%, and 5 kV is 50%.
Last Full Loss Study	1998 (percentages shown reflect 2007 estimates though).
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. Hoebel Coefficient method Load Factor = 0.64

	Utility E
Calculation Inputs/Other	Loss calculations from full 1998 study used as starting point for 2007 estimates. Metered purchases – sales = annual energy losses.
Total Transmission Losses	5.76% or 57.6% of total losses (broken down into voltage classes) – including Bulk Power transmission, Bulk Power substations, Regional Transmission, Regional Substations, Substations, and Distribution Substations. Generator Step-Up units not included.
Transmission Losses Calculation Method/Inputs	PSS/E – peak load flows.
Substations	1.99% or 19.9% of total losses (<u>included</u> in transmission losses above) – Bulk Power substations, Regional Substations, Substations, Distribution Substations.
Substation Transformer Losses Calculation Method/Inputs	Database of transformers, core and coil losses obtained from manufacturer test reports; load losses at nameplate were extrapolated to reflect actual load reads at each substation.
Total Distribution	4.56% or 45.6% of total losses.
Primary Distribution	4.27% or 42.7% of total losses (<u>included</u> in total distribution losses above – conductors & equipment).
Secondary Distribution	0.29% or 2.9% of total losses (<u>included</u> in total distribution losses above – secondary & services).
Unaccounted For Category (theft, metering, etc.)	From the 1998 study, the following values were calculated: • Unmetered Company Use – 21,000 MWH • Customer Meter Inaccuracies – 18,000 MWH • Theft of Service – 10,000 MWH • Interchange Metering – 2,000 MWH Total = 51,000 MWH These categories were not accounted for in the updated 2007 loss calculations.
Distribution Losses Calculation Method	In-house Primary Circuit Analysis (PCA) software used to calculate peak losses on a sample of primary, secondary, and service drops and extrapolated to represent entire distribution system. Distribution transformer losses were calculated from Transformer Load Management (TLM) database using load factor (62.4%) to calculate core and load losses.

	Utility E
Loss Mitigation Strategies	Evaluated cost/benefit: • Review/revise planning criteria for capacitor placement on transmission and distribution. • Asset management. • Switched capacitors. • VAR compensation, SVCs. • Line reconductor. • Use of trapezoidal conductor. • Superconductor. • PILC replacement. • Distribution transformer sizing, removal of unused, replacement of underutilized, DOE standards. • Substation transformer purchasing criteria review, sizing, tap changing. • Transmission and distribution voltage conversion. • Review guidelines for new secondary installation and replacements for sizing. • Distribution primary and secondary engineering models. • Distribution line configuration and spacing. • AMI. • Distribution system control points. • Theft detection. • Infrared surveying. • Transmission retention. • DG VAR support. • Low corona hardware and testing. • Phase shifting transformers. The following are currently underway: • Seasonally bypassing reactors. • Flexible AC transmission system. • HVDC. • Secondary network monitoring. • EPRI Green Circuits initiative. • Smart Grid. • Phase balancing. • Phase ID program. • Distribution circuit optimization. • Standardized distribution transformer purchasing (DOE), adding capacitors to achieve 97% PF (Distribution). • Capacitor installation and studies for transmission.

	Utility F
System Statistics	2011 Peak – 1,752 MW Customers – 367,000 1998 Losses – 3.8% Transmission 115 kV – 117 miles 34.5 kV – 559 miles Distribution 7,597 miles where 35 kV is 2%, 12 kV is 26%, and 5 kV is 72%.
Last Full Loss Study	1998 (percentages shown reflect 2007 estimates though).
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. Hoebel Coefficient method Load Factor = 0.55
Calculation Inputs/Other	Loss calculations from full 1998 study used as starting point for 2007 estimates. Metered purchases – sales = annual energy losses
Total Transmission Losses	1.9% or 50% of total losses.
Transmission Losses Calculation Method/Inputs	PSS/E – peak load flows.
Substations	Not presented separately, but included in distribution losses.
Substation Transformer Losses Calculation Method/Inputs	Database of transformers, core and coil losses obtained from manufacturer test reports; load losses at nameplate were extrapolated to reflect actual load reads at each substation.
Total Distribution	1.9% or 50% of total losses.
Primary Distribution	0.6% or 15.8% of total losses (included in total distribution losses above).
Secondary Distribution	1.3% or 34.2% of total losses (included in total distribution losses above).
Unaccounted For Category (theft, metering, etc.)	Unaccounted for losses were included in the full 1998 Loss Study, but not in the 2007 update.
Distribution Losses Calculation Method	In-house Primary Circuit Analysis (PCA) software used to calculate peak losses on a sample of primary, secondary, and service drops and extrapolated to represent entire distribution system. Distribution transformer losses were calculated from TLM database using load factor (62.4%) to calculate core and load losses.

	Utility F
Loss Mitigation Strategies	Evaluated cost/benefit: • Review/revise planning criteria for capacitor placement on transmission and distribution. • Asset management. • Switched capacitors. • VAR compensation, SVCs. • Line reconductor. • Use of trapezoidal conductor. • Superconductor. • PILC replacement. • Distribution transformer sizing, removal of unused, replacement of underutilized, DOE standards. • Substation transformer purchasing criteria review, sizing, tap changing. • Transmission and distribution voltage conversion. • Review guidelines for new secondary installation and replacements for sizing. • Distribution primary and secondary engineering models. • Distribution line configuration and spacing. • AMI. • Distribution system control points. • Theft detection. • Infrared surveying . • Transmission retention. • DG VAR support. • Low corona hardware and testing. • Phase shifting transformers. • Seasonally bypassing reactors. • Flexible AC transmission system. • HVDC. The following are currently underway: • Secondary network monitoring. • EPRI Green Circuits initiative. • Smart Grid. • Phase balancing. • Phase ID program. • Distribution circuit optimization. • Standardized distribution transformer purchasing (DOE). • Capacitor installation and studies for transmission.

	Utility G
System Statistics	2006 Peak – 6,754 MW Customers – 1.6 Million 2007 Losses – 9.8% Transmission 4,540 miles of sub-transmission 6,000 miles of transmission Distribution 41,800 miles of distribution
Last Full Loss Study	2004 (percentages shown reflect 2007 estimates though).
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses.
Calculation Inputs/Other	Revenue metering is the primary source for load or the NY Energy Management System (EMS). Load In (including NYISO NMPC estimated losses) – sales = annual energy losses. Expansion Factors calculated from 2004 Study and used to estimate 2007 losses.
Total Transmission Losses	Transmission Expansion Factor = 0.021 5.8% or 59.4% of total losses (transmission) Subtransmission: 27% of sales estimated to pass through sub-transmission 0.7% or 7.1% of total losses (sub-transmission including transformers – 15 kV to 115 kV)
Transmission Losses Calculation Method/Inputs	PSS/E –conductors only. 12 snap-shots were taken at various on/off peak periods.
Substations	Not presented separately but included in sub-transmission losses.
Substation Transformer Losses Calculation Method/Inputs	Based on NY Energy Management System (EMS) sampled data on an hourly basis. Peak loading, manufacturer test reports. No load losses estimated by average no-load loss for range of transformer voltages and sizes and multiplying the results by the number of transformers in each category.
Total Distribution	3.3% or 33.6% of total losses.
Primary Distribution	Primary Expansion Factor = 0.014 1.1% or 10.9% of total losses (<u>included</u> in total distribution losses above) – conductors only.
Secondary Distribution	Secondary Exp. Factor = 0.021 Transformer core losses estimated to be 57% of secondary losses. 2.2% or 22.7% of total losses (<u>included</u> in total distribution losses above) includes distribution transformers.
Unaccounted For Category (theft, metering, etc.)	NONE Trued up in measured categories.

	Utility G
Distribution Losses Calculation Method	CYMDIST for peak distribution losses – conductors only, sampled data (16 ckts). Distribution transformer losses based on average losses and manufacturer test reports, includes load and no-load losses. Secondary losses were based on number and size of distribution transformers connected to feeders analyzed, as well as typical wire configurations chosen based on size of transformer.
Loss Mitigation Strategies	Evaluated cost/benefit: • Distribution voltage conversion. • Distribution line reconductor. • Phase balancing. • Single-phase line conversion. • Distribution transformer sizing. • Installing DOE compliant distribution transformers. • Review distribution substation transformer purchasing criteria. • Distribution line capacitors. • Shunt compensation at transmission level. • Transmission line reconductor. • Increasing conductor size of an approved transmission project. • AMI. The following are currently underway: • Phase balancing pilot (1 of the circuits is part of the EPRI Green Circuits project). • Distribution capacitor placement. • Installing DOE transformers. • Installation of shunt compensation and Investigating Optimal Power Flow – Real-time reactive power management. • Conservation voltage reduction pilot (CVR).

	Utility H
System Statistics	2007 Peak – 5,256 MW Customers – 1.1 Million 2007 Losses – 6.37% Transmission 1,292 miles of transmission and sub-transmission (345 kV, 138 kV, 69 kV, 33 kV, 23 kV) Distribution 13,611 miles of distribution (13 kV and 4 kV)
Last Full Loss Study	2008 based on 2007 losses.
Peak Losses Versus Annual Energy Losses	Annual energy losses were calculated using peak demand losses and a load-duration curve. For transmission, the losses calculated from the load snapshots were used with the load-duration curve to calculate annual energy losses. Load-duration curve shows the average percent energy at each delivery voltage level for each hour of the year.

	Utility H
Calculation Inputs/Other	Metered purchases – sales = annual energy losses
Total Transmission Losses	1.5% or 23.5% of total losses (transmission). (broken down by voltage classes – includes lines step-up/down transformers at transmission level voltages). Subtransmission: 0.13% or 1.9% of total losses (subtransmission).
Transmission Losses Calculation Method/Inputs	PSS/E – conductors and transformers. 8 snap-shots were taken representing different loading levels.
Substations	Percentage of losses not presented separately but losses were calculated by voltage level. Calculated losses included in transmission losses.
Substation Transformer Losses Calculation Method/Inputs	Load losses calculated in load flow model for transmission level transformer step-up/down units. No-load losses calculated separately from manufacturer test reports. Distribution substation transformer losses were calculated using the Area Load Forecast (ALF) in-house tool and manufacturer test reports.
Total Distribution	3.89% or 60.83% of total losses.
Primary Distribution	1.39% or 21.7% of total losses (included in total distribution losses above) – conductors only.
Secondary Distribution	2.50% or 39.1% of total losses (secondary, services, distribution transformers, metering).
Unaccounted For Category (theft, metering, etc.)	0.88% or 13.8% of total losses (theft, metering errors, etc.).
Distribution Losses Calculation Method	Distribution primary conductor/cable losses were calculated using CYMEDIST. 60% of the distribution system was modeled for a sampling technique (530 feeders). Losses were calculated at the coincident summer peak. From this an average watt loss per mile was determined and used to calculate losses for the other 365 feeders. Distribution transformers were not modeled. Core losses were calculated from manufacturer test reports. A transformer load monitored computer (TLM) program was used to determine the transformer load losses. A secondary conductor of 1/0 triplex was assumed as the typical size. Historical data provided a basis for estimated lengths. I^2R losses were calculated based on typical distribution transformer loading for residential loads. The losses were extrapolated out to reflect the rest of the secondary system. Service losses were calculated using typical OH size of #4 and 1/0 AL and typical UG size of 1/0 and 3/0 AL. Historical data provided average length of services, and the number of residential meters was used as a base to determine the amount of wire that is on the system. Resistance per foot of the wire sizes and the estimated lengths of services were used to calculate losses. Meter losses were accounted for.

	Utility H
Loss Mitigation Strategies	Evaluated cost/benefit: • Transmission/Sub-transmission o New 345 kV backbone. o New superconductor backbone. o New HVDC backbone. o 69kV reconductoring/undergrounding. o Load transfers. o Undergrounding new transmission circuits. o North shore 138 kV loop, south shore 138 kV loop, conversions. o Transformer replacements. • Distribution o Load balancing. o Replace inefficient distribution substation transformers. o Install new and efficient distribution substation transformers. o Economic conductor. o 4 kV conversion to 13 kV. o Split higher loaded circuits. o Conversion of some overhead primary to underground. The following are currently underway: • Load balancing. • Switched capacitor additions on the distribution system. • Buying low-loss (DOE) distribution transformers. • Use larger conductors when economically justified.

A Study on the Efficiency of

Alberta's Electrical Supply System

Project # CASA-EEEC-02-04

For Clean Air Strategic Alliance (CASA)

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jem energy

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I. Executive Summary

JEM Energy and its associates were retained by the Clean Air Strategic Alliance (CASA) to provide a report on the efficiency of Alberta's electric supply system. The objectives were to determine the efficiency of Alberta's electricity supply system and identify where there could be room for improvement. This involved two main elements:

- establishing a baseline for the losses at the various parts of the supply chain by providing a baseline assessment for generation, transmission, distribution and related equipment losses and
- determining whether improvements could be made, based on "best practices" in comparable jurisdictions.

For this project, JEM Energy examined the efficiency of Alberta's electricity supply chain at each step from the energy source to the meter. This included the various types of generation, transmission and distribution lines, and transformers. A short survey was designed and sent by email to all major Canadian utilities and a cross section of international organizations, to gather information on generation, transmission, distribution and transformer efficiencies. The raw numbers for Alberta were compared to established best practices or experience in other jurisdictions. This information was used to examine how the Alberta system was performing and what targets for improvement might be possible.

There are many types of generating plants currently in use in Alberta. They consist of hydro, fossil fuel thermal (coal & gas), simple cycle gas, combined cycle gas, cogeneration gas, hydro, biomass and wind. Each type employs a different technology and yields a different conversion efficiency. For example, efficiencies range from over 95% for hydro generation to under 30% for some fossil thermal plants. Generation from coal and gas comprises about 90% of Alberta's total. Efficiencies for large coal and gas generation range from 23% to 38% in Alberta. In Canada, the comparative efficiencies range from 13.1% to 35.9% with an overall average of 33.6%. Much of the new generation installed since 1996 has been smaller gas turbine generating units, either simple cycle, combined cycle or cogeneration. Cogeneration has the highest overall efficiency of over 80%.

On the Alberta transmission system, power flows have increased significantly over the past decade. The load on the system has continued to grow due to increasing economic activity while very little new transmission has been built. In 2002, total annual system losses were 2,765 GWh, or 4.45% of total energy transmitted – very close to the Canadian average - and reflect mainly conductor and transformer losses.

Compared to other jurisdictions, Alberta's distribution systems have lower losses and all but one is less than the Canadian average of 4.2%. One contributing factor is the age of the system. Distribution systems are relatively newer in Alberta compared to other systems in Canada.

Overall, the Alberta system efficiency is calculated to be 37.32%, based on the assumptions cited in the generation section of the report. Table 7 compares efficiencies of the various generation types in Alberta with those in other jurisdictions. The transmission and distribution system efficiency in Alberta was calculated to be 92.49 %, which is higher than all of the Canadian utilities that responded to the research. They ranged from 89.3% to 91.9%. There are a few countries that reported higher efficiencies for combined transmission and distribution, but further study is needed to determine the methodologies and protocols used.

The research indicates that there is some potential to improve efficiencies at each stage of Alberta's electricity supply system as follows.

To improve generation efficiency, a balanced approach to all generation sources and supply system in general would result in overall system efficiencies. For example, cogeneration can provide efficiency in excess of 80%. Though these forms of generation are not suitable for all situations, they can be used very effectively and efficiently in some cases.

The two major areas with potential for improving efficiency in transmission and distribution are conductors and transformers. In the short term, there is not much available for improving conductor efficiency. In the longer term, current research into future power lines, that are lighter and can transmit far more electricity than the materials used in conventional lines, indicates great improvement in efficiencies.

Transformers offer an area for increased efficiency. Though small efficiencies are gained per transformer, the estimate of over 281,000 distribution transformers on the Alberta grid would mean substantial savings.

Future research and study aimed at improving efficiency for Alberta's electricity supply system should consider:

- potential of incentives for combined cycle and cogeneration gas turbines
- potential for high efficient station power drives at generating plants
- economics of generation efficiency improvements, such as those in other Canadian jurisdictions like Nova Scotia and Ontario
- potential for distributed generation in Alberta
- processes for standard protocols for assessing distribution losses in Alberta and other jurisdictions
- potential for voluntary Energy Star distribution transformer initiative
- barriers, drivers, economics and emissions impacts of investing in Energy Star transformers versus other generation resource options

V. Transmission and Distribution

The transmission system (grid) is an interconnected network of wires (transmission lines) that facilitate the transfer of electricity from points of supply (generators) to points of delivery (distributors or loads). Losses occur in exactly the same manner on the transmission and distribution systems and in various pieces of equipment, such as transformers, used in the delivery of electricity to customers.

Electricity is pushed through the grid by the voltage and flows along the grid in the form of current. This current experiences resistance in the transmission lines. The magnitude of the current is a function of how much load is flowing along the transmission line and the operating voltage of the transmission line. For a given fixed load, the current along the transmission line will vary in direct proportion to the operating voltage of the transmission line.

Once a transmission line has been designed and built, the operating voltage and the conductor size are fixed. The only variable left is the amount of current flowing in the line. The higher the power flow, the higher are the losses. The only possibility for a reduction in losses is a decrease in load. Electric load on a transmission line tends to increase over time due to increasing customer demands driven by economic forces. Transmission losses increase as well. There is a load-carrying limit for a transmission line, which is established by system stability and voltage drop considerations.

JEM Energy's project team attempted to answer two main questions:

1. What are the components of conductor line losses? For example, are these losses due to the conductor size and/or number of conductors per phase or by the distance of generation to load centers?
2. Could greater efficiencies be achieved with modern equipment? If we separate transformers' significant losses from conductor losses and apply data on the improved transformer design efficiency over time, can we provide estimated improvements?

Through the AEUB, AESO and other sources, the project team examined the total annual system losses, as determined by the metered energy entering the transmission system less the metered energy leaving the system. Unaccounted for energy (UFE) was also addressed, since the delivery of electricity over an electricity transmission and distribution system results in a portion of the electricity being consumed or lost before it reaches the customer. However, unaccounted for energy is not a consideration in transmission. This is an issue more prominent in the distribution system.

What is Alberta's current situation?

On the Alberta transmission system, power flows have increased significantly over the past decade. The load on the system has continued to grow due to increasing economic activity while very little new transmission has been built. This is particularly true in the main transmission corridor between Edmonton and Calgary.

Over the past few years, the transmission administrator (AESO) has managed the transmission flows in this heavily loaded corridor through the introduction of locational-based pricing incentives for generators located around Calgary. Although the main driver for these generators was to solve voltage collapse problems in the Calgary area, a resulting benefit has been reduced line losses on this corridor.

Six 240 kV transmission lines connect Edmonton to Calgary regions. (See Figure 2). These transmission lines average about 300 km in length. They represent about 10% of the total transmission lines in Alberta but account for approximately 25% of the transmission line losses This occurs for two reasons: the Calgary load, which represents one of the two major load centres in Alberta, and the 500 kV tie line to B.C. In 2001, exports to B.C. increased significantly. The load in Calgary has grown faster than the rest of the province.

While there are many similarities in the networks of different transmission and distribution companies there are also important and significant differences, including:

- geographical size of the area where the network is located
- number of customers connected to the network
- quantity of electricity distributed
- degree of dispersion of customers across the network
- proportion of different types of customers connected to the network, and
- amount of underground cables compared to overhead lines.

In addition to these differences, individual companies have historically adopted different designs, operating and investment principles, all of which have led to very different network configurations.

In Alberta, all transmission efficiency related data required for this study resides with the Alberta Electricity System Operator (AESO). The transmission owners are strictly operators and maintainers of their respective systems.

All transmission line owners, transmission capacity (total km of lines) and system voltages are listed in Table 14.

In 2003, total annual system losses were 2,765 GWh, or 4.45% of total energy transmitted – 62,089 GWh. This was determined by the metered energy entering the system plus scheduled imports (point of supply/POS) less the sum of the metered energy leaving the system plus the scheduled exports (point of delivery/POD). These losses reflect both conductor and transformer losses on the grid. AESO does not delineate between conductor and transformer losses.

Table 14.Total Circuit Kilometres of Alberta Transmission and Distribution Lines

Utility	Transmission Lines (>60 kV)	Distribution Lines (60 kv or less)	Total lines (in kilometers)
ATCO Electric	8,911	58,240	67,151
ENMAX	279	6,185	6,464
EPCOR	188	4,315	4,503
ALTALINK	11,246	10	11,256
FORTIS	0	94,231	94,231
CITY OF LETHBRIDGE	35	700	735
CITY OF MEDICINE HAT	54	606	660
CITY OF RED DEER	0	672	672
OTHER TOWNS	0	376	376
TOTALS	20,714	165,334	186,048

Ref: EUB 2002 Annual Electricity Statistics

What's happening in other jurisdictions?

The ECR report indicated an overall efficiency of 96.01% in 2002 for transmission in Canada. This compares very closely to the 95.55% efficiency experienced by the Alberta system. These efficiencies are the ratio of kilowatt-hours out to kilowatt-hours in. JEM Energy initiated research by contacting individual contributing ECR members. Their responses are illustrated in Table 15. The Department of Energy, Utilities and Sustainability in New South Wales, Australia also responded to a similar request and their response is included in Table 15.

Distribution

Total distribution system losses were collected from reliable sources such as the Alberta Energy Utilities Board (EUB) and distribution companies. A comparison of distribution losses similar to the comparisons done for transmission was conducted.

Utilities estimate distribution wire losses based on distribution voltage levels and conductor sizes and are determined by the total metered energy entering the distribution system less the total metered energy consumed by the customers.

Electricity losses occur in the operation of the following components of an electrical distribution system:

- distribution feeder conductors
- distribution service transformers, and
- secondary wires to individual customers.

Alberta distribution system losses shown in Table 15 were obtained from:

- Fortis distribution loss study to EUB, March 24, 2003
- EPCOR distribution loss study to EUB, September 30, 2003
- ENMAX distribution losses to EUB, October 10, 2003
- ATCO Electric distribution losses to EUB, 2004
- City of Red Deer, direct response to research team.

It is only recently that the EUB has been collecting losses studies and calculations as part of distribution tariff applications. Some companies indicated to JEM Energy that there is no standard protocol for the conduct of distribution losses studies so it is premature to draw conclusions by direct comparison of one study result to another.

Unaccounted for energy (UFE) or non-technical losses are those losses that cannot be determined analytically. These losses include a large list of items and are determined by subtracting the energy delivered from the energy accepted. They include physical losses from the distribution system such as contact with vegetation, contact with the ground resulting from vehicular or storm damage, lightning and corona. These non-technical losses also include administrative losses such as non-billed service, error in the estimation of un-metered delivery and meter/meter data management error. Non-technical losses also include losses that result from fraud and theft. Only one distribution utility addressed UFE as a percentage of total losses. It indicated UFE represented 0.46% of total losses, of which theft and fraud accounted for 0.32%.

What's happening in other jurisdictions?

The ECR report indicates an overall efficiency of 95.8% for Canadian distribution systems. The report also documents distribution transformer efficiencies at 98.91% for single phase up to 25 KVA to 99.5% for those in the range of 3-phase 1000 KVA to 3000 KVA. Table 15 also illustrates Alberta's distribution system efficiencies with those in other jurisdictions.

Table 15. Transmission & Distribution System Efficiencies

Utility or Jurisdiction	Transmission System Efficiencies	Distribution System Efficiencies	Distribution Transformer Efficiencies (at 50% load)
Alberta	95.55%	ATCO 95.0%	99.2% (2003 purchases only)
		ENMAX 97.0%	99.3% (lg. 3 Ø) to 98.8% (sm.1Ø)
		EPCOR 97.6%	98.99% (500 kVa/10% to 100% load range) to 98.3% (<150 kVA)
		FORTIS 96.2%	99.44%
Sask Power	95.8%	95.3%	98.8%
Hydro One/Ontario	97.2%	92.7%	99.3% (11,158 Transformers)
Maritime Electric/PEI	96.3%	94.9%	99.2%
NS Power	97.1%	94.7%	98.8%
Manitoba Hydro	93.4%	95.6%	N/a
New South Wales/Australia	96.9%	93.8%	98.0%
Canadian Average (CEA/ECR)	96.0%	95.8%	98.9% (1Ø) to 99.5% (3Ø)

1Ø to 3Ø= single phase to three phase

Table 16 lists transmission and distribution losses by percentage for electricity supply systems for Western Europe, Australia and New Zealand compared to North America.

Table 16. Transmission and Distribution Losses (by percentage of total system) Europe, Australia, New Zealand and North America 1980 to 2000

Country	% losses 1980	% losses 1990	% losses 1999	% losses 2000
Finland	6.2	4.8	3.6	3.7
Netherlands	4.7	4.2	4.2	4.2
Belgium	6.5	6.0	5.5	4.8
Germany	5.3	5.2	5.0	5.1
Italy	10.4	7.5	7.1	7.0
Denmark	9.3	8.8	5.9	7.1
United States	10.5	10.5	7.1	7.1
Switzerland	9.1	7.0	7.5	7.4
France	6.9	9.0	8.0	7.8
Austria	7.9	6.9	7.9	7.8
Alberta	**N/a**	**N/a**	**N/a**	**8.0***
Sweden	9.8	7.6	8.4	9.1
Australia	11.6	8.4	9.2	9.1
United Kingdom	9.2	8.9	9.2	9.4
Portugal	13.3	9.8	10.0	9.4
Norway	9.5	7.1	8.2	9.8
Ireland	12.8	10.9	9.6	9.9
Canada	**10.6**	**8.2**	**9.2**	**9.9**
Spain	11.1	11.1	11.2	10.6
New Zealand	14.4	13.3	13.1	11.5
European Union	7.9	7.3	7.3	7.3
Average	**9.4**	**8.1**	**7.9**	**7.9**

(Ref: International Energy Agency through U.K. Office of Gas & Electricity Markets)
* Distribution component is average of 4 utilities from table 15

Can improvements be made to Alberta's transmission and distribution?

Transmission
Table 15 illustrates that transmission system efficiencies are relatively consistent in most Canadian jurisdictions. Alberta's system is very close to the national average of 96%.

However, there could be some efficiencies attainable. One of the areas for potential improvement is reducing the load on the transmission system by building generation closer to the markets they serve. This model was tried in the past with locational-based pricing incentives, such as the Invitation to Bid on Credits (IBOC), which incented new generators starting in 2001 and resulted in 281 megawatts of generation. The second was the Locational Based Credit Standing Offer (LBCSO), which resulted in 215 megawatts.

Two major initiatives are currently being studied to supply additional transmission capacity in Alberta and could provide opportunities to incorporate efficiencies:

- AESO application for 500 kV north/south line
- DC line Fort McMurray to the U.S. with major Alberta points of access (Northern Lights project)

In the U.S., the Oak Ridge National Transmission Technology Research Centre in Oak Ridge, Tennessee is conducting research into next-generation power lines that are lighter and can transmit far more electricity than the materials used in conventional lines. Though in a very preliminary stage, the claim is that "3M's new conductors can increase current-carrying capacity by three fold for the same size cable at minimal cost and environmental impact."[4]

There may also be scope for improvements in transmission transformer efficiencies. For example, AltaLink has a total of 445 transformers on the Alberta system, of which 292 are operating at 138 kilovolts (kV), and up to 83 MVA. The balance operates at 500 kV, 245 kV, 69 kV, 34.5 kV, 25 kV or 13.8 kV and range from 10 MVA to 400 MVA. The cost of these large transformers prohibits any economical replacements. However, Energy Star rated transformers would provide improved efficiencies, when replacements are required due to failures or upgrades.

Distribution

Compared to other jurisdictions, Alberta's distribution systems have lower losses and all but one is less than the Canadian average of 4.2%, as was illustrated in Table 15. One contributing factor is the age of the system. Distribution systems, including transformers are relatively newer in Alberta compared to other systems in Canada.

The CEA's ECR report shows the national average for transmission and distribution combined losses were 8.2% in 2002. Overall, transmission and distribution losses in Alberta averaged 7.68% during that same period.

Table 16 reports Canada's transmission and distribution losses at 9.9% for 2000. The most efficient is Finland with 3.7%, which represents a 40% reduction in losses since 1980. Non-technical reasons for the variances in losses can also be attributed to a country's geography, customer density, urban versus rural ratios, or loss calculation protocols. One reason Canada has higher transmission and distribution losses than other countries is due to the long distances of the transmission and distribution systems. However, the losses trend increased for Canada in 1999 and 2000 compared to a flat or downward trend in many other countries. There are also other variances, which could be further explored. For example why is Finland's loss rate is at 3.7% and New Zealand's at 11.5%, or what caused the U.S. to go from 10.5% for 10 years to 7.1% in 1999 and 2000? It is possible that some of these significant loss reductions may be attributed to increases in costs associated with losses in recent years. Therefore, greater attention and time is now paid to the accuracy of loss calculations. The source document for Table 16 does not

[4] Stovall, ORNL Engineering Science & Technology Division, 2002

indicate the protocols used by the various jurisdictions for the determination of their system losses. Further study into the protocols used would provide for better comparisons between Alberta and other jurisdictions.

In Alberta, the losses vary by distribution wires companies, due in part to rural vs. urban systems. Urban utilities such as ENMAX and EPCOR experience lower losses (up to 3%) due to shorter distances between substations and loads, and a higher concentration of customers, compared to ATCO Electric and Fortis with their many kilometers of rural distribution lines. Table 17 below illustrates the comparisons of Alberta's distribution system losses and customers per kilometer with those in Saskatchewan, Nova Scotia and PEI.[5] Although customers/km is a factor in distribution losses, utilities faced with low customers/km ratios have addressed this issue to a large degree with technological solutions, such as voltage regulators and capacitor banks.

Table 17. Customers/ KM to Distribution Losses Comparisons

Utility	KM of Distribution Lines	# of Distribution Customers	Cust/KM	Distribution Losses %age
ENMAX	6,185	359,942	58.2	3.0
EPCOR	4,315	287,732	66.7	2.4
Fortis	94,231	359,917	3.8	3.8
ATCO Electric	58,240	162,133	2.8	5.0
SaskPower	139,460	425,209	3.0	4.7
NS Power/Halifax Metro	2,677	165,217	61.7	5.3
NS Power/non-urban	22,047	284,265	12.9	
Maritime Electric	4,500	69,480	15.4	5.1

Variations may also be attributed to different protocols for calculating losses. Consequently, consistent protocols should be in place to accurately compare distribution system losses.

Unaccounted for energy is a prominent issue in the distribution system. Although included as losses, they are outside the scope of an efficiency study because they are non-technical losses and need to be addressed by specialists in those areas.

Transformers are an integral component of the transmission and distribution systems and have been considered a relatively high efficiency component. However, recent advances in technology have produced improvements and high efficiency Energy Star transformers are now available. The U.S. Energy Star transformer program is a voluntary program that recognizes utilities that make a commitment to purchase high efficiency distribution transformers. Partners agree to perform an economic analysis of total transformer-owning costs and to buy transformers that meet Energy Star guidelines only when they are cost

[5] EUB Electric Industry Annual Statistics 2002; SaskPower 2003 Annual Report; NS Power/J.Fraser email response Sept/04; Maritime Electric/N.Warren email response Sept/04

effective. Five Canadian firms are members of this initiative. Canada has not developed an Energy Star transformer program as yet. The U.S. Energy Star's website includes a transformer efficiency calculator that allows engineers and building personnel to evaluate options by comparing efficiencies and operating costs of Energy Star transformers with other models. The link to this site is listed in Appendix 2 of this report.

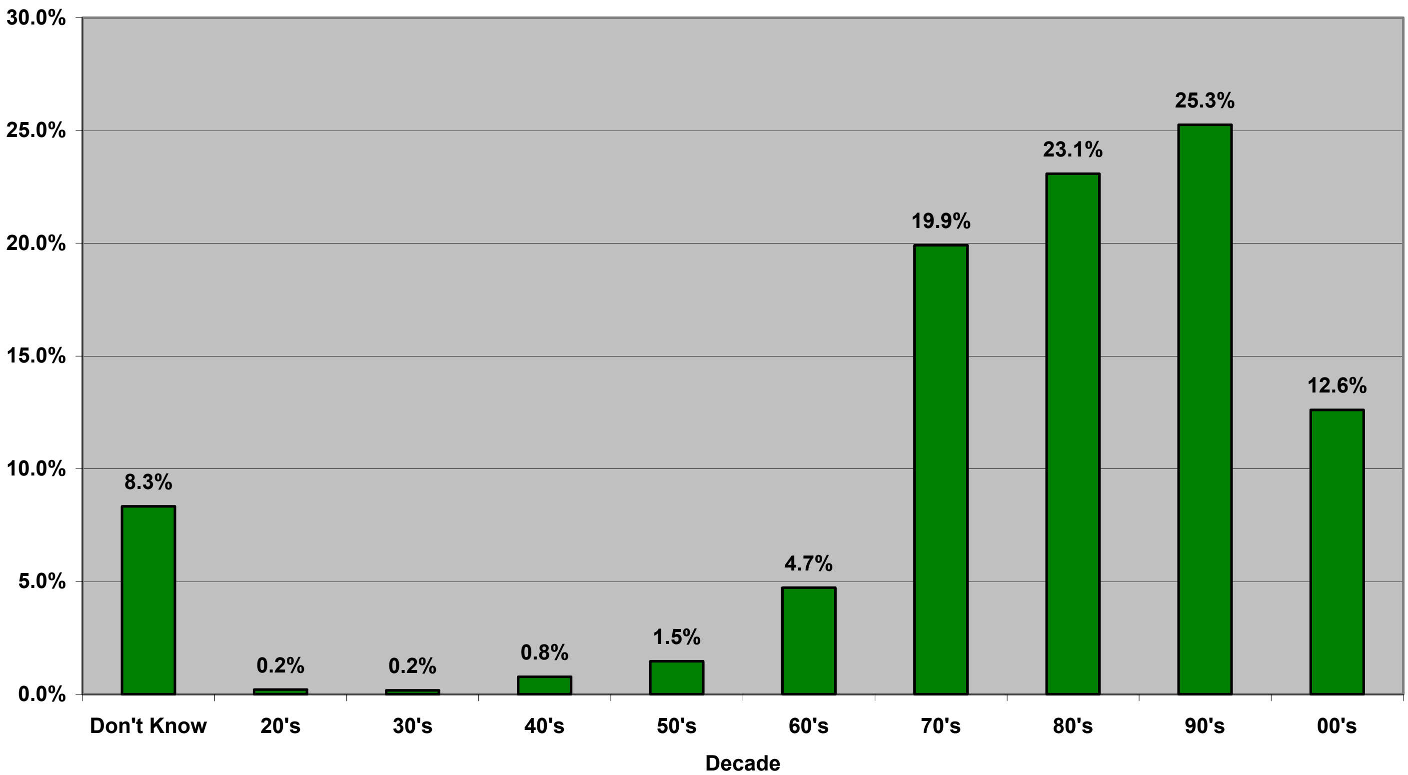
A U. S. Environmental Protection Agency (EPA) study on high efficiency distribution transformers estimated potential savings to be just under 100 kWh per transformer per year. (At 25% average load and expected life of 30 years, savings would be 2.9 billion kWh equating to 1,780,000 MT of CO_2 emission reductions). This is based on an average efficiency improvement of 1/10th of 1 percent for all transformers sold to U.S. utilities in one year.[6] A link to the complete study is in Appendix 2. Other studies have indicated even greater savings, depending on loading assumptions and current transformer inventories.

It is estimated there are 340,000 in-service distribution transformers in Alberta. This is based on Fortis' in-service inventory of 179,902 [147,420 Fortis owned, balance customer owned], Enmax in-service inventory of 43,316, plus EPCOR's design criteria of 12 distribution transformers per customer. ATCO Electric was assumed to have same transformer per customer ratio as Fortis; Red Deer, Lethbridge, Medicine Hat & other towns assumed to have same transformer per customer ratio as EPCOR.[7]
Assuming a saving of 100-kWh/ transformer/year for all transformers currently in use in Alberta, estimated savings of 1,020 million kWh would result over an expected life of 30 years.

Future work could investigate barriers and financial challenges, such as mechanisms that provide balanced incentives between cost-effective investments in high-efficiency transformers and other resource options, or the potential for a Canadian Energy Star Transformer Program. Further study is required in this area to determine the potential savings, emission reductions, costs and economics. Figure 14 illustrates the Fortis in-service transformers age range by decade. This inventory represents just over half of the total in-service transformers in Alberta and of these over 25% are at least 25 years old. This data could form the basis for further study into the savings potential for an Energy Star initiative for Alberta.

[6] The Economic & Environmental Benefits of High-Efficiency Distribution Transformers/US EPA
[7] email from J.Holmes/Fortis Aug. 2004; email from K.Hawrelko/Enmax Sept. 2004; EPCOR distribution loss study to EUB, September 30, 2003

Figure 14
Fortis In-Service Transformer's Age by Decade



National Grid Electricity Plc
Special Condition 2K.4 – Transmission Losses Report
Reporting Period 1 April 2014 to 31 March 2015

Introduction

National Grid Electricity Transmission (NGET) has a licence obligation that, “On or before 31 October 2014 and for each subsequent year, unless the Authority directs otherwise, the licensee must publish an annual Transmission Losses report for the previous Relevant Year prepared in accordance with the provisions of this condition to be published on, and be readily accessible from its website, and to include in reasonable detail:
(a) the level of Transmission Losses from the licensee’s Transmission System, measured as the difference between the units of electricity metered on entry to the licensee’s Transmission System and the units of electricity metered on leaving that system;
(b) a progress report on the implementation of the licensee’s strategy under paragraph 2K.2, including the licensee’s estimate of the contribution to minimise Transmission Losses on the licensee’s Transmission System that has occurred as a result; and
(c) any changes or revisions the licensee has made to the strategy in accordance with paragraph 2K.2 of this condition.
There is also the requirement, as part of SC2K.5 to include “a description of any calculations the licensee has used to estimate Transmission Losses on the licensee’s Transmissions System.”

2K.4 (a) Transmission Losses for this reporting period

Transmission Losses have been calculated for the 2014/15 financial year for the GB system as a whole and for each separate licencee system. The calculation is based on the latest applicable settlement metering currently available for generation, demand and French / Moyle Interconnector BMUs, together with operational metering for the boundaries between the Scottish Hydro Electric and Scottish Power systems and the Scottish Power and England and Wales systems.

Overall the losses arising from the GB transmission system are calculated by taking the difference between the sum of infeed to and the sum of the offtakes from the transmission system. This is carried out using data from the Elexon SAA-IO14 data feed. At a GB level the Total Generation (sum of positive metered active power) and Total Demand (sum of negative metered active power) values can be used.

Table 1 shows last year’s losses and the Table 2 shows historical losses for comparison purposes in order to see changes based on the losses strategy and changes to load and non-load related activities.

Table 1 – 2014/15 losses from the UK transmission system

Period – 1 Apr 2014 to 31 Mar 2015		
TRANSMISSION SYSTEM	Loss (TWh)	Loss %
England and Wales (NGET)	4.60	1.65
South Scotland (SPTL)	0.42	1.17
North Scotland (SHETL)	0.67	8.04
TOTAL NETWORK LOSSES	5.68	1.84

Table 2. Historical losses from the UK Transmission System

Losses (TWh)	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
E/W	5.15	4.92	5.36	4.22	5.23	4.93	4.45	4.60
South Scotland	0.74	0.67	0.49	0.53	0.55	0.44	0.49	0.42
North Scotland	0.29	0.37	0.29	0.24	0.36	0.27	0.38	0.67
GB	**6.18**	**5.96**	**6.14**	**4.99**	**6.14**	**5.64**	**5.32**	**5.68**
Losses (%)	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
E/W	1.62	1.59	1.77	1.40	1.80	1.67	1.57	1.65
South Scotland	2.17	1.81	1.46	1.54	1.47	1.30	1.29	1.17
North Scotland	2.38	2.86	2.59	2.55	3.04	3.05	3.55	8.04
GB	**1.75**	**1.73**	**1.82**	**1.49**	**1.92**	**1.72**	**1.70**	**1.84**

It is not possible to quantify the exact causes for the small increase in losses from 2013-14 to 2014-15 (1.57% to 1.65%). It can be seen from data from previous years that losses will vary from year to year due to various factors, the effect of which cannot be easily quantified. Transmission losses can be affected by various factors including the volume of electricity transmitted and the amount of resistive equipment electricity travels through from generation to load point. This is affected by the location of generation and the distribution of demand across the system causing varying levels of flow on the network throughout the year. Operational measures are also taken to manage system compliance and security which may affect transmission losses.

Operational measures which affect transmission losses could, amongst others, include the use of Quad Boosters and Series Reactors to divert power away from overloaded lines under particular circumstances or use of Voltage Control Circuits (switching out of certain circuits) to manage high Volts on the system. For example, in 2014-15 National Grid experienced an increased need to undertake operational measures to mitigate voltage increases on the system (due to low levels of transmission on parts of the network) which can have the impact of increasing transmission losses.

Reactive compensation equipment (MSC, reactors, SVC) all have resistive losses associated. But because they will compensate for VAr travelling on the OHLs from far sources, they also have the effect of reducing losses by providing VAr locally. It is not certain whether the total effect will be positive or negative because this can vary depending on situations.

National Grid's approach for the management of transmission losses remains unchanged from that outlined in the December 2013 published strategy document (as required by Special Condition 2K paragraph 2 of the Transmission Licence) and the subsequent update in October 2014 (SpC 2K, paragraph 4).

In addition to ongoing network investment and to ensure effective and innovative future development of the network, National Grid is investigating new conductor types to install on the network which could provide benefits including increased capacity, reduced noise and reduced resistance. These conductors may be considered for use on the network in due course following R&D activities and Type Registration.

As more generation is connected at the periphery of the network, the losses are expected to increase. Load losses do not linearly change with circuit loading being proportional to the square of the current carried. A particularly heavily loaded circuit in one year contributing significantly to the total losses may be less loaded the next year and have a much smaller proportion of the total losses. Local reactive support for voltage management avoids the transmission of reactive power over distances that would otherwise increase system losses.

2K.4 (b) Progress on implementation of Transmission Losses Strategy for this reporting period

Information shown in this section is in the context of National Grid operating the full GB system but only owning and being responsible for the assets of the England and Wales transmission system.

National Grid's approach for the management of transmission losses remains unchanged from that outlined in the December 2013 published strategy document. Utilisation of National Grid's Whole Life Value framework assists the selection of economically justified investments based on a broad range of investment criteria, including consideration of transmission losses. Where the Whole Life Value framework identifies that the cost of transmission losses are material to the investment decision and that sufficient certainty of future year-round transmission flows make the analysis worthwhile, then further detailed transmission loss assessments will be undertaken that quantify year-round transmission losses.

National Grid has been considering transmission losses in equipment specifications and procurement processes in line with this strategy prior to its launch, so non-load related investments delivered can be attributed to this strategy.

Further like-for-like replacement schemes delivered in 2014/15 are reported via updates to section 5 of the strategy.

Transmission network developments that have passed or shall pass through the optioneering phase after National Grid's transmission losses strategy release in December 2013 present the greatest opportunity for the consideration of transmission losses to influence the chosen investment solution. All schemes where optioneering has taken place since December 2013 (load and non-load) have been assessed under National Grid's Whole Life Value framework. Of these investment decisions, optioneering has identified that losses could be material to the investment decision in some instances.

In alignment with the Whole Life Value assessment, transmission losses have been considered for different transmission solutions. Studies concluded that under peak system conditions, investment solutions that employed a new circuit would experience up to a 25% reduction in losses on local transmission circuits, justifying a clear losses benefit from investment for system peak conditions.

As a result of the 2014 Network Development Policy (the economic decision making process for undertaking load related investment on the Transmission Network) as published in the ETYS, the following schemes are being progressed by National Grid Transmission Owner which were identified as reducing losses on the system in the Transmission Strategy.

The reconductoring works completed between Harker, Hutton and Quernmore Tee have increased transfer capability across B7 boundary and also reduced transmission losses due to the less resistive conductor type used. The same is also true for the reconductoring works completed on the Trawsfynydd-Treuddyn circuit.

2K.4 (c) Proposed changes to Transmission Losses Strategy for future reporting periods

In this section the aim is to give an overview of the proposed changes or recommendations and the Strategy document itself will have the full details that list refers to. These are not changes to the overall strategy as that is unchanged, merely amendments to reflect the actual output from each year. These updates show the latest information available.

- An update of load related and non-load related investments will be provided in sections 4 and 5 of the Strategy assessing the impact on transmission losses of additional transmission developments (delivered and planned) since the Strategy's first publication in 2013 and last year's updates.
- Section 5 of the strategy outlines the treatment of non-load related investments that are deemed to have a material impact on transmission losses, namely; transformer, cable and overhead line replacement schemes. To assess the benefits in terms of indicative losses that replacement schemes can offer, this section will be modified to include all replacement schemes delivered in the year 2014/15
- For transformer replacements, section 5.1 will be updated to estimate losses for all like-for-like replacements in the previous Relevant Year, discounting replacements where transformer capacity has been increased or transformers are replaced for load-related investments. All transformers assessed under this methodology demonstrate a reduction in transformer losses as a result of each recent replacement scheme.
- Similarly, cable and overhead line sections of the strategy (5.2 and 5.3) will also be revised to account for further replacements for the 2014/15 year. No further cable replacement schemes were delivered for the previous Relevant Year, leaving the conclusion of cable assessments unchanged, i.e. they must be considered on a per replacement basis.
- We are continually refining our transmission losses assessment methodology for load related developments, and as a result the use of a modelling tool for assessment of losses will be replaced with a different system over the next two years.

2K.5 Calculations used to estimate Transmission Losses

The calculations outlined below show how we estimate the overall Transmission Losses, taking into consideration the collection of metered information detailing the power flow onto and off of the Electricity System

$$BoundaryLosses(TWh) = \frac{(\frac{ConstrainedFlow}{100})^2 \times kmWT \times R\%/km}{\frac{CCTWT}{CapWT}}$$

$$Annual\ MWh\ Losses = \frac{\left(\frac{(LoadLoss_{Old} - Load\ Loss_{New})}{\Delta} + (No\ LoadLoss_{Old} - No\ Load\ Loss_{New})\right) \times \frac{50}{52} \times 8760h}{1000}$$

$$\Delta = \frac{1}{(RMS\ average\ transformer\ loading)^2}$$

$$TotalLosses(TWh) = \left(\sum BoundaryLosses\ per\ boundary\right) + Load\ Related\ Losses + Fixed\ Losses$$

National Grid Strategy Paper

National Grid's Strategy Paper to address

Transmission Licence Special Condition 2K:

Electricity Transmission Losses

Reporting Period: 1 April 2013 to 31 March 2021

Published: November 2013

Revised: September 2014

Executive Summary

This paper presents National Grid Electricity Transmission's strategy for the consideration and mitigation of transmission losses over the RIIO-T1 Price Control period. This second edition (published October 2014) is prepared in accordance with Special Condition 2K of the electricity Transmission Licence, providing a review and update of the strategy to support the submission of the 2013/2014 transmission losses annual report (published separately).

Throughout the design and development of the transmission network, National Grid's Whole Life Value framework is utilised to support the selection of a preferred option to meet the investment need. This framework assists selection of the appropriate investment, backed by economically justified decisions based on a broad range of investment criteria that include transmission losses.

This updated strategy paper describes this approach, its employment in investment decision making, and updates transmission developments (and loss estimates) delivered in the 2013/14 financial year. Where the Whole Life Value framework identifies that the cost of transmission losses are material to an investment decision and that sufficient certainty of future year-round transmission flows make the analysis worthwhile, then further detailed transmission loss assessments will be undertaken that quantify year-round transmission losses.

Detailed year-round loss assessments are likely to impact investment decisions for, amongst others, incremental wider works and overhead line reconductoring schemes. For the former, detail of the key transmission reinforcements, the method of associated transmission loss estimation and results expected under the 2013 Electricity Ten Year Statement (ETYS) Gone Green base case are outlined. As an updated ETYS publication will not be provided until November 2014, wider works results are unchanged in this revision and will be reviewed via the 2014/15 strategy update (and subsequent transmission losses annual report). Proposals to revise the method of wider works loss calculation for future revisions of this strategy (i.e. 2015 onwards) are discussed. Transmission loss estimates for key enabling works developments are also defined. Where transmission losses increase for recommended investments, this demonstrates that transmission losses are one in a number of factors considered by National Grid when selecting the most economic and efficient transmission solutions.

Recent overhead line reconductoring, transmission cable replacement, and grid transformer replacement examples are provided as an indication of the likely impacts on transmission losses of similar replacements in the RIIO-T1 period. In the case of both overhead line and cable schemes, transmission losses are considered on a case-by-case basis, whereas material and manufacturing improvements indicate that a transmission loss reduction can be expected from replacing 'old' for 'new' transformers. Published data from National Grid indicates that future system-wide transmission losses are likely to increase as a result of developments that include the connection of more generation to the periphery of the network. As of this revision, this forecast will be compared to annual metered data via the National Grid's transmission losses annual report.

The methods by which National Grid account for transmission losses in equipment specifications and procurement processes are outlined for cables, overhead lines and transformers. For transformer tenders, associated losses are often a significant or deciding factor in the choice of a winning bid. National Grid has deployed extra high conductivity (EHC) alloy in all non – load related overhead line conductor replacements. All Aluminium Alloy Conductor (AAAC) has been utilised to counteract an increase in transmission losses. For load related replacements, overhead line conductors such as GAP, ACCC (Aluminium Conductor Carbon Core) and ACCR (Aluminium Conductor Composite Reinforced) have been developed to provide significant increases in transmission capacity. The increase in transmission loss (cost) resulting from increased transmission capacity must be considered alongside the capital saving of avoiding new lines build to meet system requirements.

The trade-off between capital investment and transmission loss costs are clear throughout this strategy paper. This will continue to be the case with future technology developments where the capital cost of increased capacity on existing (e.g. series compensation) or new (e.g. HVDC links) assets must be considered alongside their impacts on transmission losses.