EB-2013-0053

ONTARIO ENERGY BOARD

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

AND IN THE MATTER of an application by Hydro One Networks Inc. for an order or orders pursuant to section 92 of the *Ontario Energy Board Act, 1998* for Leave to Construct upgraded electricity Transmission Line Facilities in the Kitchener-Waterloo-Cambridge-Guelph area.

ENVIRONMENTAL DEFENCE'S COMPENDIUM
(Hydro One Guelph Area Transmission Line Leave to Construct Application)

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Lawyers for Environmental Defence

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Tab Contents and sub-tabs

Note: The below materials are arranged in the order they are referred to in Environmental Defence's Argument.

18. IESO, 18-Month Outlook <http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2013may.pdf>

19. Response to ED Interrogatory No. 21 (Ex. I, Tab 2, Schedule 21)

20. Response to ED Interrogatory No. 23 (Ex. I, Tab 2, Schedule 23)

21. Response to ED Interrogatory No. 8 (Ex. I, Tab 2, Schedule 8)

22. Remarks by Colin Anderson, CEO, OPA, to the Toronto Board of Trade, Powering Toronto's Electricity Future, October 25, 2012 < http://www.powerauthority.on.ca/sites/default/files/news/Andersen-Board-of-TradeOct-25-2012.pdf>

23. Supplementary Response to ED Interrogatory No. 5 (Ex. I, Tab 2, Schedule 5-S)

24. Guelph Hydro *peaksaver* Data (From Director of Metering and Conservation, Guelph Hydro, November 5, 2012)

25. Ontario Energy Board, 2011 Yearbook of Electricity Distributors, pages 56, 59, 61 and 66

26. OPA Interrogatory Responses re KWCG Diesel Back-up Generators (EB-2007-0707, Ex. I, Tab 31, Schedule 60)

27. Letter from the Vice President of the OPA, March 12, 2012 (Ex. B Tab 1, Schedule 4, Attachment 1)

28. Supplementary Response to ED Interrogatory No. 26 (Ex. I, Tab 2, Schedule 26-S)

29. Response to ED Interrogatory No. 29 (Ex. I, Tab 2, Schedule 29)

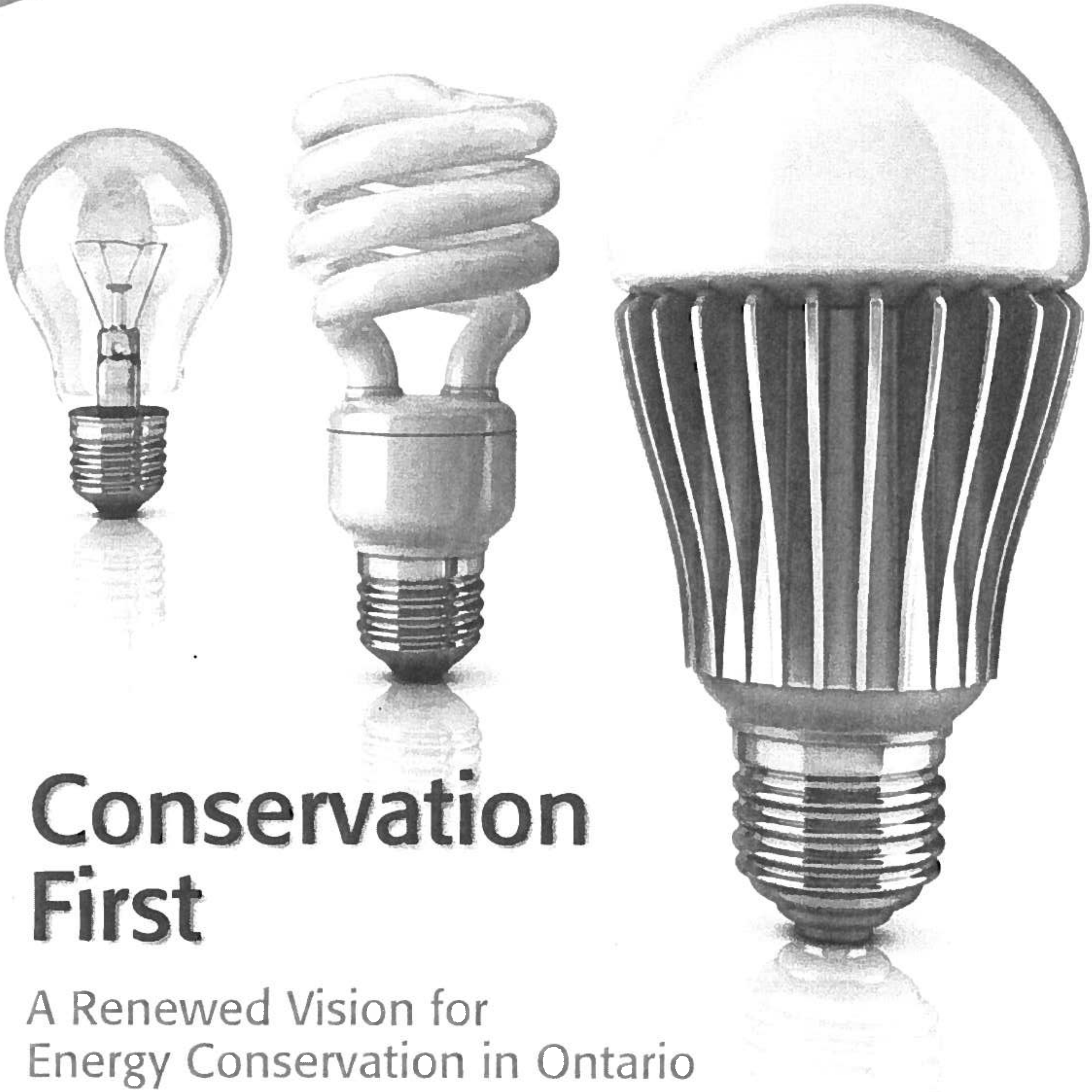
30. City of Guelph, *Community Energy Plan*, (April 3, 2007), Executive Summary

31. Response to ED Interrogatory No. 33 (Ex. I, Tab 2, Schedule 33)

32. Response to ED Interrogatory No. 34 (Ex. I, Tab 2, Schedule 34)

33. Ontario Energy Board, *Filing Requirements for Electricity Transmission and Distribution Applications*, last revised June 28, 2012, excerpts (EB-2006-0170)

Tab 1



Conservation First

A Renewed Vision for Energy Conservation in Ontario

Ontario

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Disponible en français

Alternate formats of this publication are available on request from: Ministry of Energy, 900 Bay Street, 4th Floor, Hearst Block, Toronto ON M7A 2E1 Canada
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MINISTER'S MESSAGE

Conservation is the cleanest and least costly energy resource, and offers consumers a means to reduce their electricity bills. That's why it is at the forefront of our plan to meet Ontario's electricity needs. As we review and update our Long-Term Energy Plan, we also want to set out our renewed vision for conservation and discuss how best to achieve it.

Ontario has already made great strides in reducing electricity use. From 2005 to 2011, families and businesses across this province conserved enough to reduce demand by more than 1,900 megawatts, the equivalent of powering more than 600,000 homes. Investments in conservation allowed Ontario to avoid building new capacity that would have cost almost $4 billion, equivalent to four peaking natural gas generation plants.

But we can do much more. The government is committed to expanding and enhancing our conservation efforts. With the current Conservation and Demand Management Framework set to wind down at the end of 2014, the time is right to create a new framework and set a policy of putting conservation first. Ontario's vision is to invest in conservation first, before new generation, where cost-effective.

This paper describes what we have accomplished over the past several years and looks to how we can leverage innovation and new approaches to build on the foundation we have put in place. It sets out a vision of even broader participation in conservation efforts, supported by important elements such as offering targeted programs to different customers, increasing awareness of incentives, and unleashing innovation and flexibility at the local level.

Individuals, businesses, institutions and organizations across Ontario can take pride in the conservation savings we've achieved to date. We look forward to working together to accomplish even more for Ontario's clean, sustainable energy future. I hope that the information and questions about the future of conservation in Ontario in this paper inspire you and your organization to share your thoughts and ideas with us.

Bob Chiarelli

The Hon. Bob Chiarelli
Minister of Energy

INTRODUCTION

Conservation plays a central role in energy management around the world. The reasons are simple. Saving energy means saving money – for families, businesses, hospitals, schools and other public institutions. Reducing or shifting electricity use avoids the need for new generation as well as transmission, reduces strain on the electricity system and improves the efficiency of the power grid. Conservation provides significant economic and environmental benefits; for every $1 invested in energy efficiency, Ontario has avoided about $2 in costs to the electricity system.

For every $1 invested in energy efficiency, Ontario has avoided about $2 in costs to the electricity system.

Ontario has been working for several years to create a culture of conservation in this province. Although the global economic downturn of the past few years dampened electricity demand in Ontario and elsewhere, a shortfall in capacity may emerge as early as 2018. As a result, conservation investments remain a priority for Ontario and conservation should be the first resource considered when planning for the province's electricity needs.

Ontario is not alone in aggressively pursuing conservation. Leading jurisdictions around the world are also pursuing ambitious energy efficiency goals:

- The United States has set a goal to double its energy efficiency by 2030.
- The European Union has committed to a cut of 20 per cent in its 2020 energy demand.
- China is targeting a 16 per cent reduction in energy intensity by 2015.
- Japan aims to cut 10 per cent from electricity consumption by 2030.

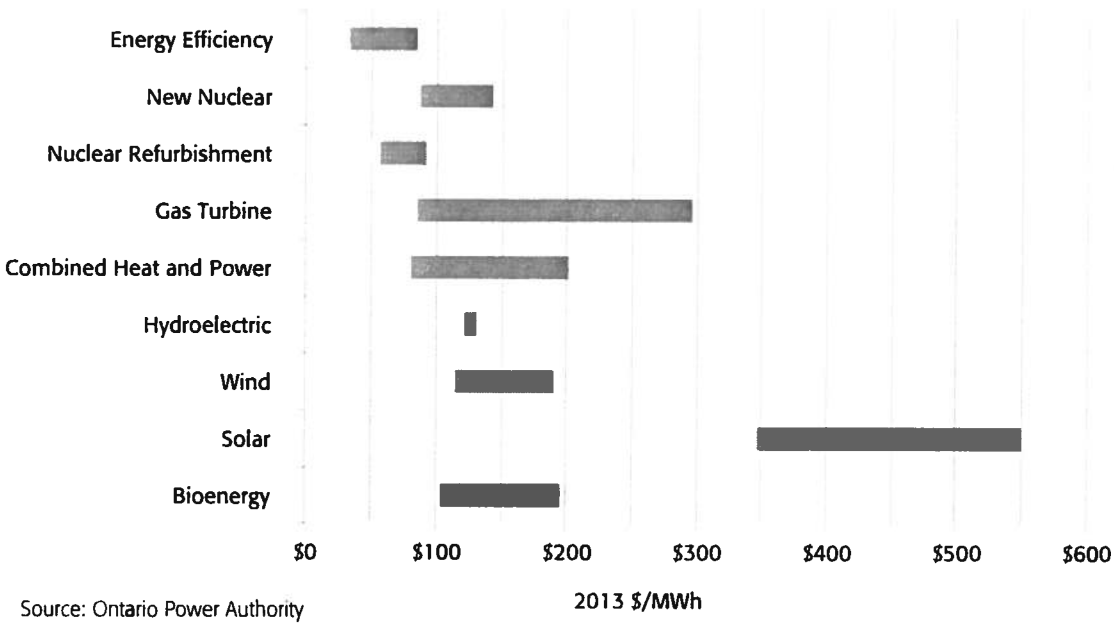
(Sources: 2013 U.S. Presidential State of the Union; International Energy Agency, World Energy Outlook 2012)

Conservation and demand management savings can be achieved in a range of ways:

- Energy efficiency: Using more energy efficient technology that consumes less electricity, such as LED lighting. Building codes and product efficiency standards help improve the energy efficiency of new buildings and appliances.
- Behavioural changes: Increasing awareness and encouraging different behaviour to reduce energy use, for example through social benchmarking.
- Demand management: Reducing or shifting consumption away from peak times, using time-of-use pricing with smart meters and programs like Peaksaver PLUS® and Demand Response 3.
- Load displacement: Reducing load on the grid by enabling customers to improve the efficiency of their energy systems by recovering waste heat or generating electricity required to meet their own needs.

Conservation initiatives must prioritize cost-effectiveness and balance customer benefits with system benefits. Conservation programs can motivate consumers by raising awareness of opportunities to save money and help the environment. Consumers will use less power or shift usage to other times of the day if they see that it lowers their electricity bills and they will invest in more energy-efficient products if they understand the short and long-term benefits.

Relative Cost of Electricity



Source: Ontario Power Authority

Ontario is already benefiting from its aggressive conservation efforts:

- Between 2006 and 2011, investing $2 billion in conservation allowed Ontario to avoid more than $4 billion in new supply costs.
- Based on preliminary analysis, between 2005 and 2012, Ontario achieved about 55 per cent of the 2015 demand savings target and almost 60 per cent of the 2015 energy savings target in the Long-Term Energy Plan.

Savings related to conservation and demand management can be measured two ways:

1. *Megawatt (MW) or Demand Savings: A reduction in the total supply of electrical resources needed by Ontario to meet peak demand. Valuable at a time of system peak, when lowering or shifting usage avoids the high costs of using electricity sources designed to meet short-term demand. Peak demand in Ontario on a hot summer day can be more than 25,000 MW.*

2. *Megawatt hour (MWh) or Energy Savings: Energy savings that follow from the need to deliver less electricity overall to homes, businesses, and institutions in Ontario. A typical home in Ontario consumes around 10 MWh over one year.*

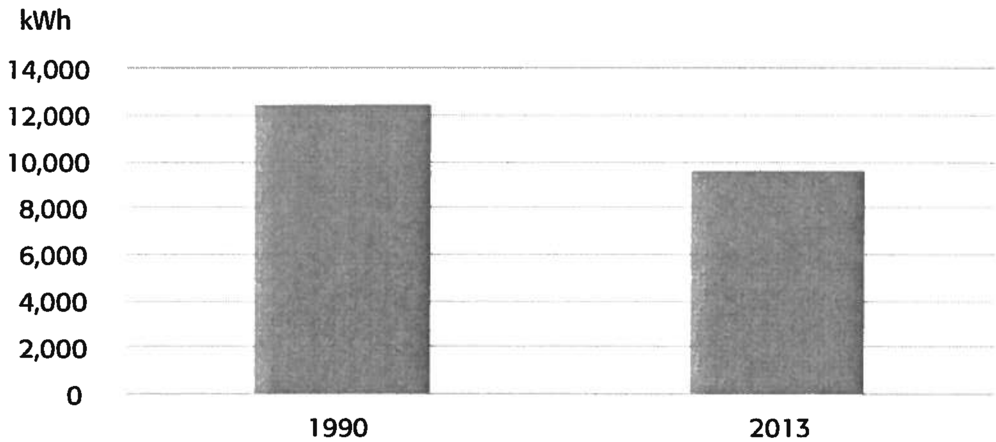
- In 2011, the most cost-effective year to date, most conservation programs delivered savings at a program cost to consumers of just over three cents per kilowatt-hour and influenced 717 gigawatt hours of verified and sustained annual energy savings.

- Since 1990, average household electricity consumption has declined by almost 25 per cent, representing about $350 in savings each year for the average household, based on current electricity costs.

(Sources: Ontario Power Authority; Natural Resources Canada; Ontario Energy Board; and Ministry of Energy)

These savings are the result of a wide range of initiatives, including improvements to building codes and product efficiency standards, programs delivered by local distribution companies (LDCs) and provincial agencies, time-of-use rates, and other conservation initiatives.

Electricity Use per Average Household in Ontario (kWh)



Sources: Natural Resources Canada and Ontario Energy Board

The government strongly believes that conservation should be the first priority in energy planning. This paper discusses the government's vision for conservation in Ontario and explores new opportunities and objectives that should be considered in developing a new conservation and demand management framework.

Part 1

A RENEWED VISION

Ontario is a leading North American jurisdiction for conservation and demand management. Conservation is helping families and businesses reduce their electricity bills while contributing to a cleaner environment and a more reliable electricity system.

Ontario's vision is to invest in conservation first, before new generation, where cost-effective. Recognizing that conservation is a long-term commitment that must be central to our electricity system planning, the Ontario government will continue its leadership in conservation by putting conservation first, inspiring action, providing different tools for different customers, encouraging innovation and leading by example.

Ontario's vision is to invest in conservation first, before new generation, where cost-effective.

Put Conservation First

Conservation should be the first resource considered in meeting Ontario's electricity needs. Cost-effective conservation brings environmental, economic and system benefits. It makes sense to invest as much to save a megawatt of power as it would cost to generate that same megawatt. When other benefits are factored in – conservation does not involve construction or the industrial processes that generation requires, it saves consumers money and relieves stress on the electricity system – the arguments in its favour become even stronger.

Conservation and generation differ in how their costs are accounted for. Investments in supply are amortized – that is, divided up and spread out – over the expected useful life of the assets that will supply the power. The **costs of conservation** initiatives are currently accounted for in the year they are incurred, even though savings from such programs can last for 10 to 15 years or more. The cost of conservation could be spread over the life of the investment, as is done with investments in supply. This would lessen short-term rate impacts and provide a more equitable sharing of costs across all ratepayers, current and future, who benefit from the programs. BC Hydro has used this approach since 1990 to smooth the impact of conservation costs on customers' bills.

The cost of conservation could be spread over the life of the investment, as is done with investments in supply.

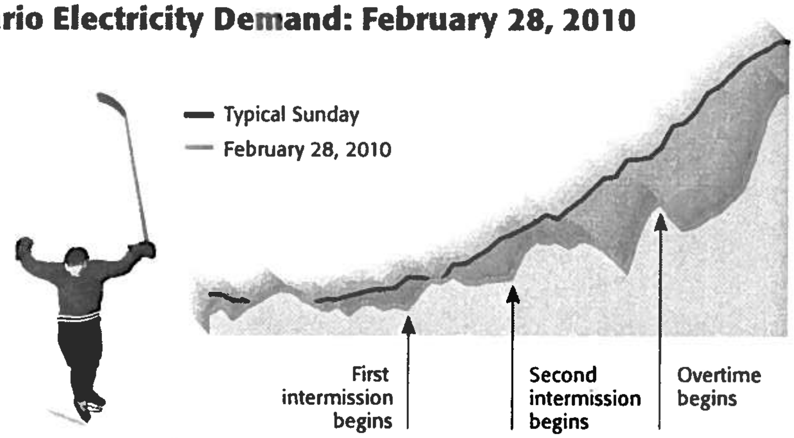
Demand response provides an excellent example of leveraging the economic value of conservation. More broadly, demand management initiatives provide price or financial incentives to residential, commercial and industrial users to shift or reduce their electricity usage away from peak periods. As well as benefiting the electricity system, demand response lowers energy costs for consumers and allows businesses to operate more competitively.

As one demand management measure, demand response could help meet regional reliability needs cost-effectively and help to better integrate renewable generation sources coming online. Demand management measures in Ontario include the Ontario Power Authority's Demand Response 3 program, the Independent Electricity System Operator's Dispatchable Load initiative, the Industrial Conservation Initiative, and time-of-use rates. These initiatives represent almost 8 per cent of Ontario's 2012 summer peak. Some jurisdictions, such as California, have set demand response targets.

Innovative demand response could enable faster, regionally targeted deployment, for periods that directly correspond with system needs.

There is potential for Ontario to expand and improve its demand response portfolio. Current demand response programs, for example, must be deployed for minimum blocks of time over broad geographic areas. Innovative demand response could enable faster, regionally targeted deployment, for periods that directly correspond with system needs.

Ontario Electricity Demand: February 28, 2010



The impact of consumer behaviour on demand is especially evident during the Men's Hockey finals at the Vancouver Olympics.

Source: Independent Electricity System Operator

Inspiring Action

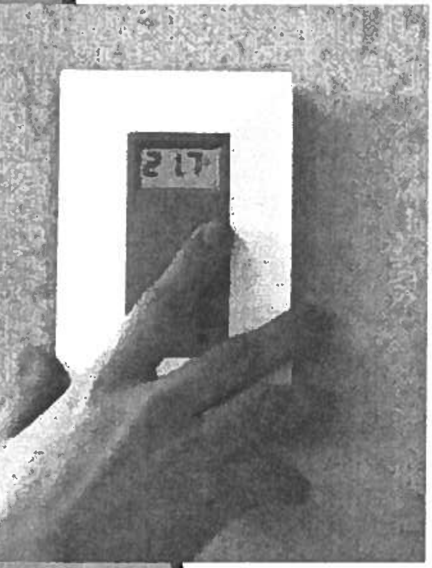
The electricity system and electricity pricing are complex and confusing to many customers. Both the Auditor General of Ontario and the Commission on the Reform of Ontario Public Services highlighted the need for electricity education. To inspire further action and behavioural changes, Ontario should build consumer awareness of the benefits of conservation and understanding of the electricity system as a whole, including expanding energy awareness in schools. The electricity sector must also better align incentives and tools with consumer needs, including providing access to energy consumption information. These actions would help consumers make more informed decisions.

Better aligning awareness with tools and incentives can include voluntary **dynamic pricing approaches**, some of which have been explored in a number of U.S. states. Dynamic pricing can build on time-of-use and smart grid infrastructure by pinpointing short time periods of extremely high demand – known as critical peaks – and permitting customers to sign up to receive a financial benefit for shifting their consumption from critical peak to the lowest-demand period, typically overnight. Customers can shift consumption by running appliances and equipment with timers, such as dishwashers, pool pumps, and electric vehicle chargers. The benefit is usually derived from a rebate or a much lower electricity rate during non-peak periods. Dynamic pricing programs work best when they are voluntary, because residential and small business consumers vary in their ability to respond and shift consumption.

Voluntary dynamic pricing programs could provide additional benefits to customers that shift their consumption to low demand periods.

Rating systems for buildings and benchmarking provide examples of how awareness can better drive decisions that result in sustainable savings. Property buyers can end up with high ongoing costs because of the low energy efficiency of the home or business they have purchased. Disclosure of actual energy performance, for example through a rating system, could allow consumers to benchmark the relative energy efficiency of various properties and inform their investment decisions. Building ratings could one day be considered as important as a pre-purchase building inspection.

Rating systems for buildings could allow consumers to benchmark the relative energy efficiency of various properties and inform their investment decisions.



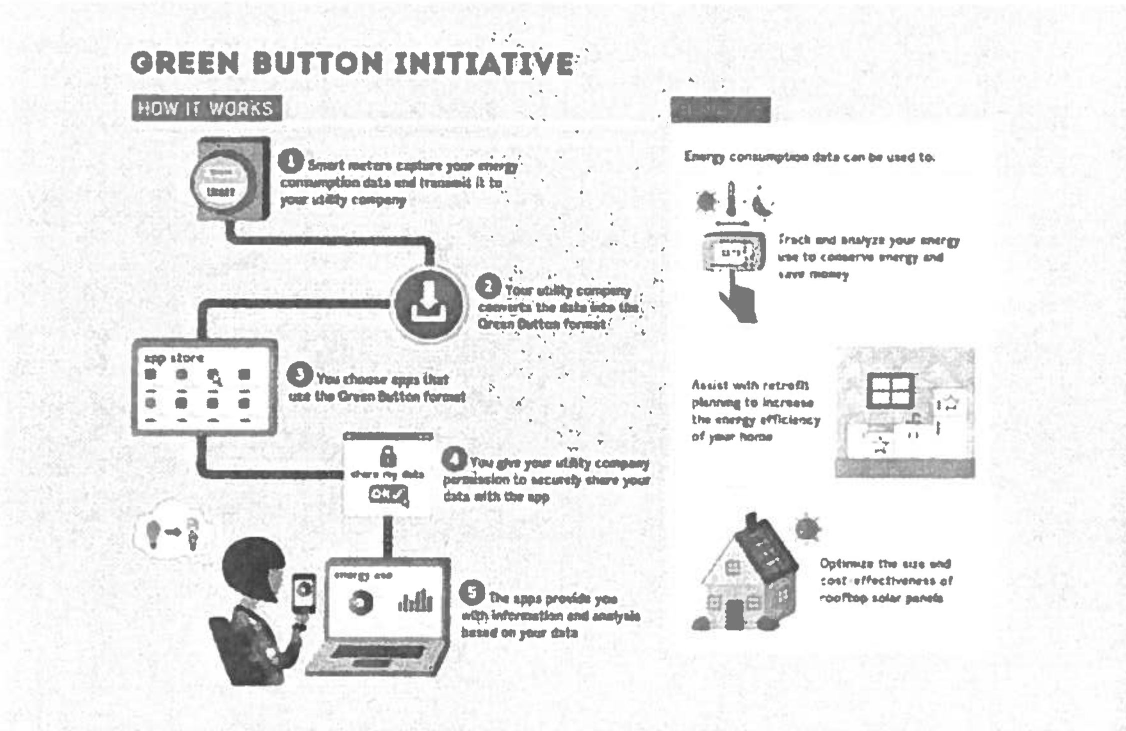
Smart Meters, Smart Grid, Smart Choices

More than 4.4 million electricity consumers in Ontario are currently billed on a time-of-use basis using data provided by smart meters, which communicate consumption information at regular intervals, at a minimum every hour. The adoption of smart meters enables the development of Ontario's Smart Grid. Through its use of modern technology, including sensors, wireless communication, automation and computers, the smart grid helps consumers participate more readily in conservation efforts and make more informed decisions, and allows for more distributed and renewable generation sources. It also paves the way for electric vehicle re-charging infrastructure, creative energy storage solutions and "Smart Home" features. Ontario's early implementation of smart meters and time-of-use pricing has established the province as a leader in smart grid technology.

Providing Different Tools for Different Customers

Closely related to the need to provide the right incentives is the ability to tailor tools to the needs of different customers. Ontario should encourage both the public and private sectors to continue to develop new tools that enable consumers to take full advantage of smart technologies. By establishing incentives and ensuring the regulatory framework supports innovation, Ontario could accelerate the development of cutting-edge solutions for all customers.

Through the **Green Button Initiative**, Ontario electricity consumers will have secure access to their energy usage information. As a common data standard that adheres to strict privacy rules, the Green Button Initiative allows utilities to work with the private sector to create secure, value-added apps for download by consumers. Energy apps would have a wide range of uses, such as giving consumers the ability to track and control their home energy usage via smartphone. More than 50 per cent of Ontario consumers already have access to their data in the Green Button format, and pilot programs to develop wide-ranging services and solutions are being developed.



By enabling a household or business to compare their energy consumption with other similar consumers, **social benchmarking** increases awareness of energy usage and promotes conservation. Regular energy reports, for example, can be delivered to electricity customers, providing useful energy usage data and a comparison to local conservation leaders. The Ontario Power Authority is working with a number of partner LDCs on a pilot program to test four residential social benchmarking approaches that, where feasible, will adopt the Green Button standard. Pending the success of these pilots, the government could explore expanding social benchmarking and including other sectors.

The government could explore expanding social benchmarking and including other sectors.

Consumers in some jurisdictions can finance conservation investments through their utility bills or other **financing alternatives**. Initiatives such as on-bill financing for home energy retrofits have strong potential to boost conservation. British Columbia, Manitoba and Nova Scotia allow utilities to offer on-bill financing to residential customers. This eliminates up-front costs for small capital upgrades that can yield major long-term savings. Over time, the savings on the bill from lower energy consumption help offset the repayment of the up-front costs.

Initiatives such as on-bill financing for home energy retrofits have strong potential to boost conservation.

The province could also explore a **revolving fund** concept to help finance energy efficiency retrofits for residential and business customers. Revolving funds, unlike grants or incentives, self-replenish by using re-payment for subsequent financing. Based on experience in other jurisdictions and sectors, revolving funds can unlock private capital and accelerate growth by demonstrating successful investment strategies in the conservation sector.

The province could also explore a revolving fund concept to help finance energy efficiency retrofits for residential and business customers.

Encouraging Innovation

The current framework was built with the expectation that LDCs should be the face of conservation to their customers. We have seen the value of this approach, and are committed to **expanding the role of LDCs** in order to better support local needs and innovation. The private sector and broader public sector also contribute significantly to encouraging greater innovation.

The microFIT program has been successful in distributing generation across the grid, which can help offset local power demand. The program could evolve from a generation purchasing program to a **net-metering** program, where cost-effective, with the generation being used first by the homeowner, before being made available to the grid. A net-metering program could help match generation with local demand, helping reduce local load and related infrastructure needs.

The microFIT program could evolve to a net-metering program, where cost-effective, with the generation being used first by the homeowner.

Electricity storage is emerging as another option to help address challenges such as peaking demand, efficiently integrating renewable generation, managing slight variations in output, and resolving congestion and power quality issues that reduce distribution system performance. In the United States, Europe and Asia, demonstration projects are under way, and regulators are opening up traditional markets to storage providers. Like any emerging technology, energy storage must prove that its benefits exceed its costs, including building and operating new infrastructure. Ontario is home to a number of emerging, innovative energy storage companies that are working hard with Ontario utilities to demonstrate various technologies, address their challenges and realize their potential.

Ontario's early leadership in the use of smart meters has provided significant operational benefits for local distributors. Some LDCs have configured meters to collect consumption information more frequently – for example, every 15 minutes. LDCs will likely begin moving towards real-time interaction between the meter and in-home **energy management systems**, providing more opportunities for direct benefits to end consumers. For instance, Guelph Hydro has installed Zigbee chips in their smart meters, allowing wireless communication with devices in the home. Some PeaksaverPLUS® implementations are also using these chips for direct communication with PeaksaverPLUS® in-home devices. Building information technology into appliances is expected to pave the way to a smart home future in which devices automatically respond to consumer preferences. LDCs are likely to play a central role in leveraging this and other innovations developed in partnership with the private sector.

Some electrical power is lost to heat as it is transmitted through wires and transformers. **Line losses** increase exponentially as the system gets busier, making on-peak losses substantially higher than off-peak losses. According to analysis by Navigant Consulting, distribution system losses across Ontario between 2007 and 2011 averaged 4.4 per cent. There are precedents for reductions in losses being considered as conservation, based on improved efficiency of the electricity system. Reducing line losses generally involves upgrading technology and equipment, and it may be appropriate to allow utilities to recover the associated costs. In Alberta, for example, the regulator agreed to allow Enmax Power Corporation to recover its costs from the pool of savings accrued from reducing loss levels.

Reducing line losses generally involves upgrading technology and equipment, and it may be appropriate to allow utilities to recover the associated costs.

Leading by example

The Ontario government as well as broader public sector should continue to play a leadership role in conservation efforts. The government has already achieved significant conservation savings by strengthening the energy efficiency standards for products available to consumers and prescribed in the building code. It has also improved energy efficiency in its own buildings and facilities. There is an opportunity to build on these efforts.

Improving the energy efficiency of products and buildings represents a significant portion of Ontario's long-term conservation targets. The Ontario Building Code is considered the strongest in Canada in supporting energy efficiency. As well, Ontario regulates the energy efficiency of more products than the federal government or any other province. Ontario intends to continue keeping pace with the top North American jurisdictions in raising the bar for energy efficiency standards. One approach being considered is to automatically adopt leading efficiency standards of other jurisdictions in North America, where it would improve Ontario's own regulatory process. The Ministry of Energy is also looking at working with other ministries to strengthen the synergies between the building code and product efficiency standards. This could result in both streamlining standards and better aligning the regulations with the province's conservation goals.

One approach being considered is to automatically adopt leading efficiency standards of other jurisdictions in North America where it would improve Ontario's own regulatory process.

As part of the government's new conservation reporting requirement under the *Green Energy Act, 2009*, all **broader public sector organizations**, such as hospitals, colleges, universities and school boards, as well as Ontario municipalities, began reporting this year on their annual energy consumption, and, next year, will develop and post five-year conservation plans. Given that conservation lowers operating costs, these organizations have a strong incentive to build robust targets into their plans. Using the energy conservation reports, these organizations and their LDCs should work together to find and leverage conservation opportunities. Going forward, the government will explore requiring them to establish individual targets as part of their conservation plans.

By establishing targets, organizations will be encouraged to pursue energy efficiency improvements that could yield monetary savings. The government will also explore ways to drive conservation among these organizations. For example, the strength of an organization's conservation plan could be among the considerations when evaluating capital or operating funding requests to the province.

The strength of broader public sector organizations' conservation plans could be among the considerations when evaluating funding requests to the province.

Shoppers Drug Mart (2010-2011)

Shoppers Drug Mart undertook lighting retrofits in 280 stores across Ontario, installing LED freezer strips and LED signage and exterior lighting.

The project resulted in 338 kilowatts (kW) in demand savings and almost 2 million kilowatt hours in energy savings per year. As a result of these investments, Shoppers Drug Mart will save almost $500,000 annually on electricity costs. Typically, for lighting, the saveONenergy RETROFIT PROGRAM provides incentives of about 40 per cent total project cost. At the corporate level, these incentives helped meet the company's payback-period guidelines of 24 to 36 months.

"For a large corporation like Shoppers, which operates in all regions of Ontario, having a single point of contact like Burlington Hydro to manage all our applications for all our locations, made the entire process move smoother and faster…"

Tammy Smitham, Vice President,
Communications & Corporate Affairs,
Shoppers Drug Mart

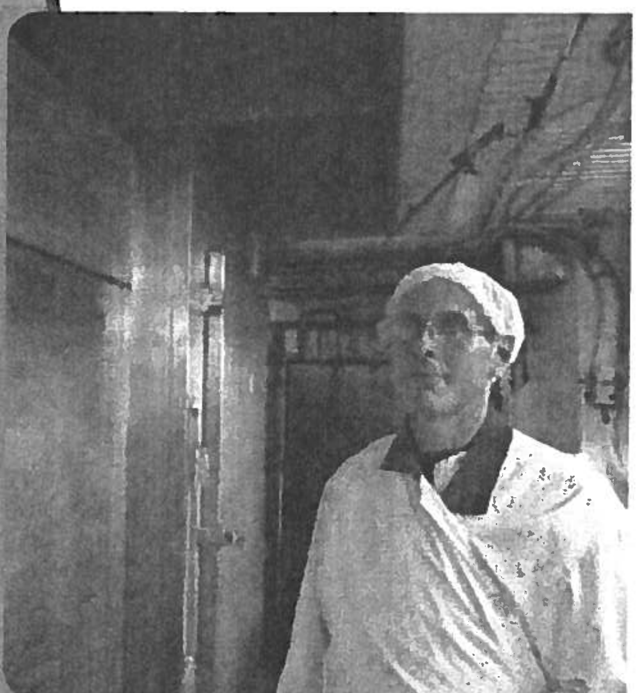
Part 2

TOWARDS A NEW FRAMEWORK

Evolution of Conservation Efforts

With the current Conservation and Demand Management framework expiring at the end of 2014, the government is interested in receiving feedback and ideas about proposed innovative new conservation measures as well as the key elements and structure of the next conservation framework. The government has observed challenges as well as successes with the current framework and has received feedback from stakeholders, such as:

- A fixed multi-year funding framework with fixed targets provides certainty, but cannot be easily adjusted or revised to reflect changing circumstances or pressures at the provincial or local level.
- Targets created a focus for efforts, but a one-size-fits-all approach does not fully reflect the varying needs and conservation capacity of individual LDCs.
- LDCs' influence over program design, operations and how targets were achieved was limited.
- Innovation was encumbered by approvals and heavy contractual requirements.
- Program enhancements were slow and not agile in their response to customer or market.
- Local and regional programs were constrained in their development and approval.



Walnut Hill Farm (March 2012 to August 2012)

Walnut Hill Farm, a pork processor in Gads Hill, Ontario retrofitted their operation by installing a new high efficiency refrigeration system, which has more efficient compressors, evaporators and insulated panels throughout the facility.

The project resulted in 7 kW in demand savings and 42,000 kWh in energy savings per year. Walnut Hill Farm's investment in the new refrigeration system is about $175,000. The business will also receive a saveONenergy RETROFIT PROGRAM incentive of over $5,000 from Hydro One.

"The electricity cost savings we gained by investing in more energy-efficient equipment will be used to pay for addition electricity we need for expanding the business"

John Koch, Owner - Farmer,
Walnut Hill Farm

Despite these challenges, conservation and demand management programs have evolved over the past decade. LDCs have developed more experience and capacity to take a larger role in delivering programs to their customers. Conservation programs and options are now more sophisticated and comprehensive than ever, highly cost-effective and deliver lasting energy savings. They are offered across the province, including to First Nation and Métis communities, and cover all sectors (residential, including low-income; commercial and institutional; and industrial).

Building the New Framework

Based on the lessons from the current framework, as well as the government's commitment to conservation as a first priority, objectives of the new framework should include:

- Empowering LDCs by giving them more autonomy and programming choice for their customers, with streamlined oversight and reduced administrative burdens. This would enable LDCs to focus more fully on innovation and cost-effectiveness, whether by working alone, with private sector partners or with other LDCs.
- Establishing clear accountability and mechanisms for meeting the conservation goals in the updated Long-Term Energy Plan.
- Emphasizing the importance of prudent, efficient and effective conservation expenditures to contribute to the important goal of controlling price increases.
- Investing in conservation initiatives that balance benefits to consumers with benefits to the electricity system, and ensuring a fair allocation of costs in line with benefits.
- Maintaining balance, in provincial planning, among various sectors – residential, commercial, and industrial – while recognizing that the value of conservation investments can be higher in some regions than others, due to local conditions
- Renewing efforts to deepen consumer awareness.
- Enhancing the role of LDCs in the delivery of conservation programming for Aboriginal communities, and particularly for on-reserve First Nation customers.
- Leveraging programs and provincial investments to encourage innovation, such as electricity storage and smart grid technologies.
- Improving conservation program delivery for low-income residential consumers.

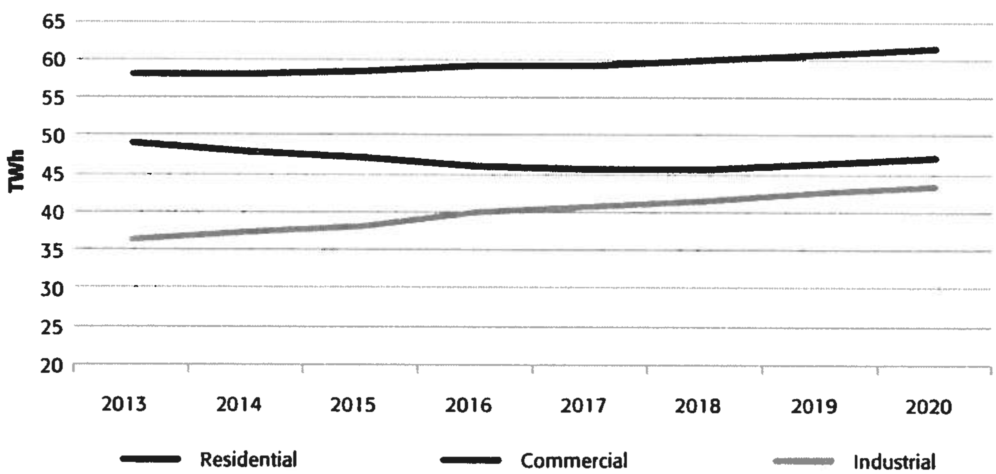
Together, these objectives would help unleash and streamline conservation delivery, encourage cost-effectiveness and leverage market forces and partnerships to boost innovation and economies of scale.

As the government develops a new multi-year conservation framework, input is being sought on these objectives as well as the following areas:

- **Role of Targets**

  The *Green Energy and Green Economy Act, 2009* made conservation integral and core to LDCs' regulated tasks and assigned conservation targets which LDCs must meet as a condition of licence. In 2010, the government's Long-Term Energy Plan set province-wide conservation targets out to 2030. The current framework established four-year (to 2014) demand (MW) and energy (MWh) targets for LDCs, which have helped focus the sector's attention on conservation. This approach may not adequately take into account differing or changing circumstances of individual utilities, the economy, or the system as a whole. In particular, changes in the supply-demand outlook in the past few years indicate a surplus in baseload generation. Flexibility to adjust both the approach and the timing of targets should be considered going forward.

Gross Forecast Demand by Sector



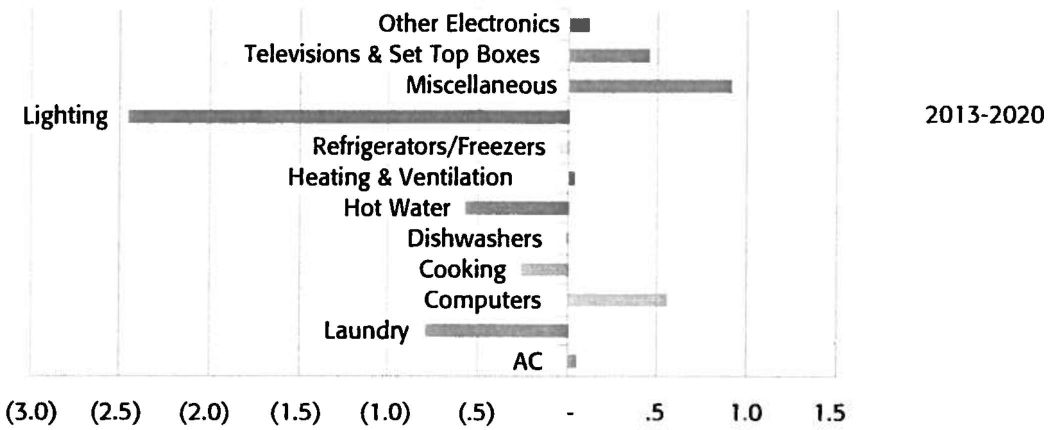
Source: Ontario Power Authority

- **Program Portfolio**

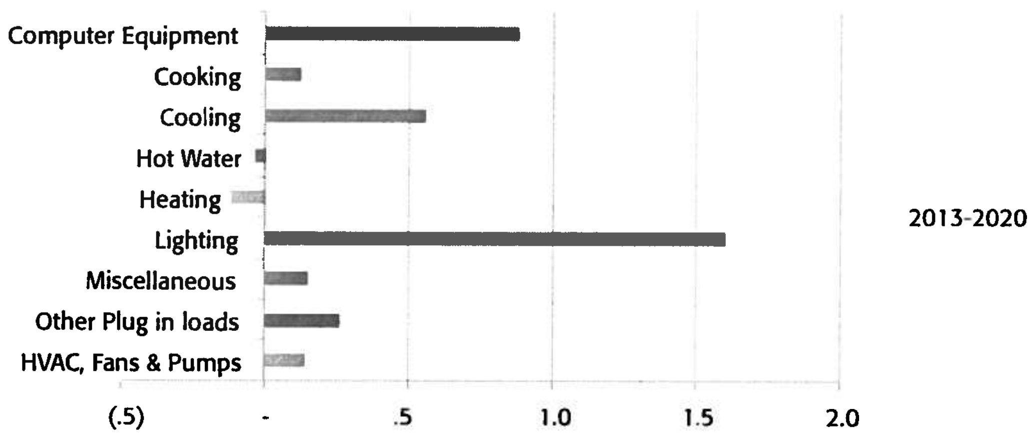
  As Ontario's conservation efforts continue to evolve, so too will the portfolio of programs and options available to customers. Consumers are more conservation-savvy and interested in energy savings. A wide range of service providers, such as contractors, retailers, LDCs and mobile service providers, offer ways of meeting consumers' needs. New cost-effective programs leveraging customer and private-sector investments will continue to transform the market to greater energy efficiency.

  Supporting this transformation will involve, for example, optimizing tools for consumers, allowing a role for the private sector in working with larger customers, bringing new entities into the market to take advantage of innovative energy storage and management technologies, and making greater use of codes and standards.

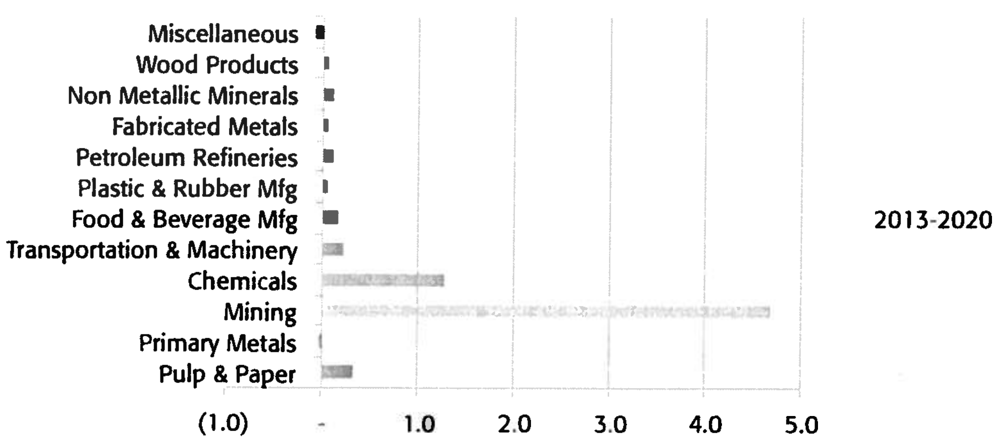
Residential Forecast Changes in Energy by End Use, TWh



Commercial Forecast Changes in Energy by End Use, TWh



Industrial Forecast Changes in Energy by End Use, TWh



Source: Ontario Power Authority

- **Roles and Responsibilities**

  The current electricity conservation framework in Ontario involves the Ministry of Energy, Ontario Energy Board, Ontario Power Authority, and LDCs.

  The Ministry sets overall conservation policy and provincial conservation targets based on the advice of the Ontario Power Authority, issues directives to its agencies, regulates product efficiency standards and energy conservation reporting and plans for the broader public sector, and delivers targeted programs such as Municipal Energy Plans.

  LDCs are responsible for creating, marketing and delivering conservation initiatives directly to their customers. They are also responsible for reporting annually on their results and achieving their conservation targets, which are a condition of their licence.

  The Ontario Power Authority has planning and reporting functions for province-wide conservation programs and provides marketing, technical and training support for LDC program delivery as well as the evaluation, measurement and verification of program results. In line with these responsibilities, LDCs and the Ontario Power Authority have signed commercial agreements to deliver province-wide conservation programs.

  The Ontario Energy Board is Ontario's independent natural gas and electricity utility regulator. It develops and maintains conservation targets as a licence condition for each LDC, reviews and approves their conservation and demand management strategies and regional program plans, and monitors and reports on progress toward LDC targets.

  In addition, the Environmental Commissioner of Ontario is responsible for reporting annually to the Legislature on the progress of activities to reduce and make more efficient use of electricity, natural gas and other fuels, as well as barriers to conservation.

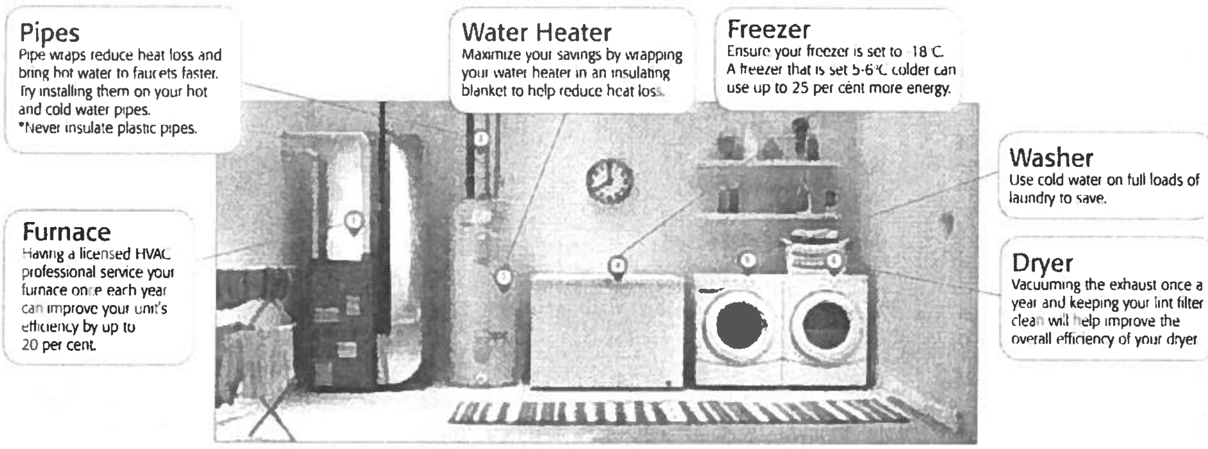
  In developing a new conservation framework, greater focus could be placed on such elements as market-driven innovation, private-sector involvement and better alignment of economic costs and benefits. Consideration must be given to what oversight model can best work with these and other key objectives.

- **Allocating the Costs**

  The allocation of conservation costs should align fairly and closely with benefits. The Global Adjustment mechanism – part of the government's regulation-based cost-recovery approach to conservation, demand management and generation procurement – allocates these costs to all electricity customers. All ratepayers pay such costs either in accordance with their peak or overall consumption. The Global Adjustment may be the most appropriate mechanism for recovery of province-wide program costs, as benefits accrue to the system as a whole. For programs of more local benefit and/or those that directly address regional needs, rate-based cost recovery by LDCs, as approved by the Ontario Energy Board, may be more appropriate. Determining which, if any, programs might more appropriately be available only locally and not province-wide will need consideration. At the level of the individual consumer, those who invest in conservation products and services for their homes, businesses or organizations should pay in line with the economic benefit they receive. In the case of residential consumers, special programs will continue to help those for whom income is a barrier.

Targets, roles and programs are important considerations that will shape conservation efforts in the coming years. Both experience and the sector outlook suggest that a range of market mechanisms, working hand-in-hand with consumer awareness and enhanced standards, should play a greater role in achieving conservation. An important aspect of this evolution will be improving the alignment of conservation costs and benefits, as well as giving sector participants greater flexibility to respond to changing market conditions. To that end, new technologies, such as the smart grid and Green Button Initiative, will strongly enhance the ability of the sector to serve consumers more effectively.

Electricity Savings in Your Home



Source: Ontario Power Authority

Your Insights on Conservation

Ontario is committed to conservation and demand management as a priority for electricity system planning. The government recognizes that conservation brings a unique combination of economic, reliability, and environmental benefits that make it a competitive, attractive option when balancing energy supply and demand.

Achieving our long-term commitment to conservation requires us to look both to immediate needs and opportunities, as well as those in the future. Several factors are at play that are likely to put upward pressure on electricity prices over the next several years, including the costs of rebuilding and renewing the electricity system and the supply gap that is likely to emerge toward the end of the current decade. This means that conservation will become increasingly valuable as a resource to drive efficiencies and reduce costs.

Conservation ideas and technologies are evolving. Meeting our long-term commitment will therefore require strategic approaches and the ability to adapt quickly. Together, foresight and flexibility are needed to allow us to provide best-in-class programs and initiatives. In this document, we have set out a series of possible conservation opportunities, as well as questions that will help to guide discussion on them. We welcome your thoughts and insights as we develop a new streamlined, innovative conservation and demand management framework for Ontario that puts conservation first.

APPENDIX

CONSULTATION QUESTIONS

OUR RENEWED VISION

1. How can the government ensure that conservation is the first resource considered to meet energy needs?
2. How can the economic value of conservation be embedded in Ontario's electricity system?
3. What relative weight should be placed on reduction in demand versus load-shifting from peak demand?

EXPLORING NEW INITIATIVES

4. What new tools and initiatives will help engage customers in conservation?
5. How can conservation awareness and education be improved to drive greater action on conservation?
6. What opportunities should Ontario explore to help consumers finance energy-efficiency improvements?
7. Through what means (regulatory and/or voluntary) can electricity and natural gas conservation activities be better coordinated?
8. What innovative programs could help capture conservation potential across key sectors (e.g. residential, commercial and industrial)?
9. Which technology and smart grid innovations do you believe could offer the greatest benefit to you, your community and the system as a whole?
10. What role should energy storage play in meeting Ontario's future energy needs and how should it be valued?

TOWARDS A NEW FRAMEWORK

11. What are the top needs of residential, commercial and industrial customers?
12. Are there additional objectives that the government should consider in developing a new framework? If so, what?
13. Is there value in targets and, if so, what type (e.g., fixed, dynamic, directional)?
14. Should government introduce targets for municipalities, hospitals, post-secondary institutions and schools?
15. Should Ontario pursue mandatory energy labelling for commercial/institutional buildings upon sale?
16. What can government do to further encourage the sector and the market to deliver on conservation objectives?
17. What should be the roles and responsibilities of LDCs, natural gas distributors, government agencies and the private sector in meeting Ontario's conservation goals?
18. How can province-wide conservation program delivery be streamlined and enable a greater role for LDCs?
19. Considering that conservation can benefit the whole system and/or specific regions, how should it be funded?
20. What conservation measures can be implemented to support regional energy needs?

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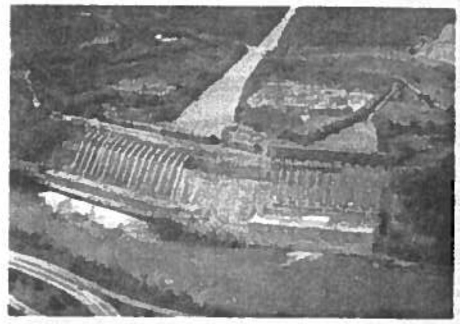
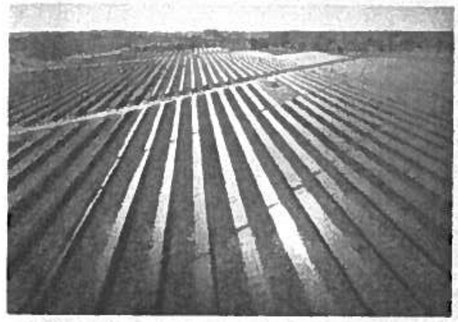
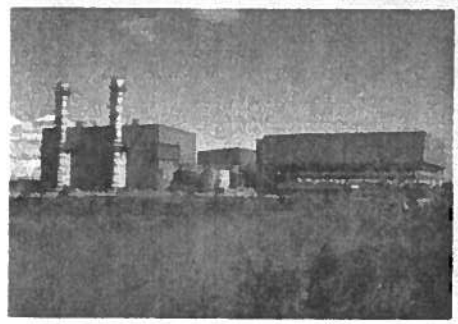
Ontario

Tab 2







Kitchener-Waterloo-Cambridge-Guelph Area

March, 2013

ONTARIO POWER AUTHORITY

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Contents

1 Executive Summary

Near- and medium-term supply capacity and other reliability needs have been identified in the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area. Specifically, three of the KWCG subsystems (the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems) are expected to exceed their supply capacity within the next ten years. Additionally, two subsystems (the Kitchener and Cambridge, and Waterloo-Guelph subsystems) do not comply with prescribed service interruption criteria. To address these needs, the OPA recommends an integrated package composed of 1) conservation, 2) distributed generation resources, and 3) transmission reinforcements in the KWCG area.

Conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the KWCG area. Together, these resources are expected to off-set more than 35% of the forecast load growth in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems between 2010 and 2023. By 2023 achievement from provincial conservation efforts within these subsystems is expected to reduce peak demand by over 130 MW at an estimated delivery cost of $65 million (based on an allocation of forecast expenditures for provincial conservation programs). Over the same time period, approximately 16 MW of distributed generation facilities are expected to come into service in South-Central Guelph, Kitchener-Guelph and Cambridge subsystems, representing a capital investment of approximately $70 million.

The transmission reinforcements recommended in the near-term include the Guelph Area Transmission Refurbishment (GATR) project, as well as a project to install a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support. The GATR project includes the installation of two new 230/115 kV autotransformers, four 115 kV circuit breakers, and the advancement of the relocation of the existing Hydro One Distribution Operating Centre at Cedar TS (approximately $52 million), rebuilding approximately 5 km of existing 115 kV double circuit transmission line between Campbell TS and CGE junction in Guelph to a 230 kV double circuit configuration (approximately $27.5 million), and installing two new 230 kV circuit breakers at a new station (Inverhaugh SS) at Guelph North Junction in Centre Wellington (approximately $16 million). Project completion for the GATR project is expected by the end of

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2015. The installation of the Preston TS autotransformer facilities is a separate project that will be coordinated with completion of the GATR project and it is estimated to cost approximately \$15 million to \$25 million. Together these facilities will meet the near- and medium-term needs of the KWCG area, and substantially meet the KWCG area needs over the longer-term.

It is the OPA's view that this integrated solution is a cost-effective and technically-effective solution for meeting the capacity and reliability needs of the KWCG area.

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2 Introduction

The KWCG area is one of the larger population and electrical demand centres in Ontario. The existing electrical facilities in the area serve a diverse range of commercial, industrial and residential customers. The demand for electricity in the area is expected to grow substantially over the next 20 years, driven by population growth and strong economic activity. Much of the existing electricity infrastructure in the area is reaching capacity and therefore plans for future conservation, distributed generation and electricity infrastructure expansion and investment need to be developed and, as necessary, implemented in order to maintain a reliable supply of electricity to the area.

Planning to meet the electrical needs of a large area or region is done through a regional planning process that considers the multi-faceted needs of the region and seeks to address them through an integrated range of solutions. The plan takes into consideration, among other things, the electricity requirements, anticipated growth and existing electricity infrastructure. The outcome of the regional planning process is an integrated plan to guide electricity infrastructure, resource development and procurement decisions for the region. The plan's recommendations are typically organized into three timeframes: near-term (first 5 years), medium-term (5-10 years out) and longer-term (10-20 years out or longer). Solutions to address near-term and medium-term needs are presented as action items for immediate or early deployment, while solutions to address potential longer-term needs are identified along with the conditions that would trigger their implementation and the key development work required to maintain their viability. In this sense, regional plans are not static documents, but rather dynamic processes which evolve and are adapted as circumstances and conditions change.

A working group (the KWCG Working Group) was established in 2010 to develop a regional plan for the KWCG area. The KWCG Working Group was formed in a manner consistent with the process described by the Planning Process Working Group's Report to the OEB as part of the Renewed Regulatory Framework for Electricity. The KWCG Working Group is comprised of members from the Ontario Power Authority (OPA), Hydro One Networks Inc. (Hydro One), the Independent Electricity System Operator (IESO) and local distribution companies (LDCs).

In the course of developing a regional plan for the KWCG area, the Working Group identified certain near- and medium-term supply capacity and other reliability needs to be addressed. The purpose of this evidence is to explain those needs and to recommend solutions – i.e., planned conservation and existing and committed distributed generation, along with transmission reinforcements – to address them. Based on expected growth in electricity demand in the KWCG area, these recommended solutions will provide a significant improvement to the reliability of electricity supply. They will also defer the potential need for additional major infrastructure (such as new transmission or large generation) in the area to beyond the study horizon, and will provide time to explore opportunities for increased cost effective conservation, distributed generation, and transmission investments (such as switching facilities). Monitoring of growth in electricity demand, as well as the achievement of conservation and distributed generation in the KWCG area will also be key components of ongoing electricity planning in the region.

3 Background

3.1 Kitchener-Waterloo-Cambridge-Guelph Area Population and Electricity Demand

The KWCG area is located to the west of the greater Toronto area in southwestern Ontario. It is a growing community with an estimated population of over 625,000 people.[1] The region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties. In 2011, the Region of Waterloo[2] (which does not include Guelph) was Canada's 13th and Ontario's 7th largest urban centre[3]. The region was also noted as one of Ontario's Places to Grow.[4] The area's electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to automobile manufacturing.

A large part of the area's electricity supply is serviced by four LDCs: Kitchener Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro and Guelph Hydro Electric

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[1] 2011 Statistics Canada
[2] Waterloo Region contains the cities of Kitchener, Waterloo, and Cambridge, as well as the Townships of North Dumfries, Wellesley, Wilmot and Woolwich
[3] 2011 Statistics Canada
[4] Ontario Ministry of Infrastructure, Places to Grow

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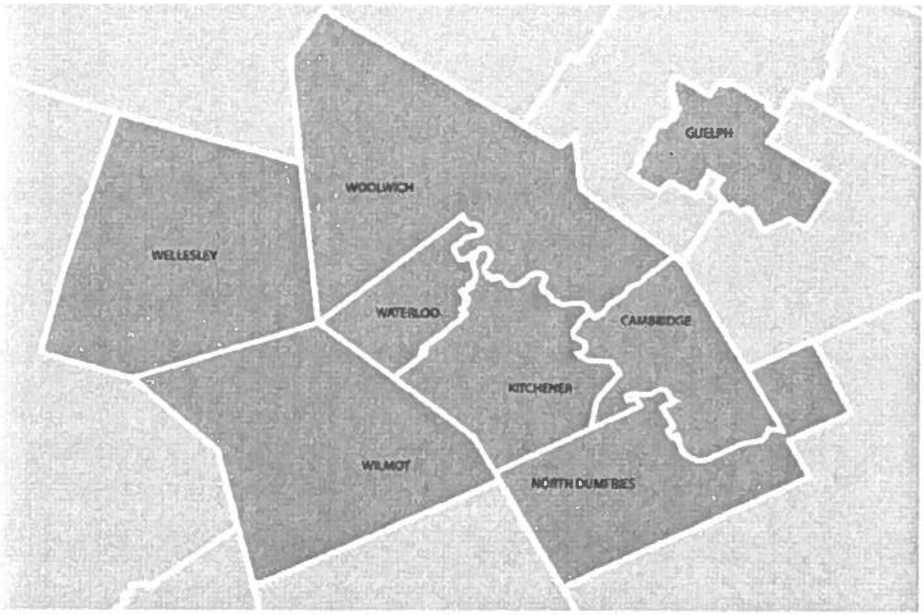
Systems. Figure 1 highlights, in dark brown, the area served by these four KWCG LDCs. Hydro One Distribution generally provides service to loads outside of these municipal areas (shown in light brown). Additionally, there are three directly-connected industrial customers in the area served by Hydro One Transmission.

Figure 1: The KWCG Area



In the summer of 2012 the demand for electricity in the KWCG area peaked at over 1,400 MW. Of this, the KWCG LDCs served approximately 1,300 MW: Kitchener Wilmot Hydro served approximately 380 MW, Waterloo North Hydro approximately 290 MW, Cambridge & North Dumfries Hydro approximately 290 MW, Guelph Hydro Electric Systems approximately 290 MW, and Hydro One Distribution approximately 60 MW. While the economic downturn in 2008 and 2009 impacted growth in the region, the demand for electricity recovered to pre-recession levels in the summer of 2010.

3.2 KWCG Area Generation and Transmission Facilities

There are no major sources of generation supply within the KWCG area. As a result, the area relies predominantly on the transmission system to deliver electricity to its customers. This system includes the 230 kV circuits between Detweiler TS (in Kitchener), Orangeville TS (in Orangeville), and Middleport TS (near Hamilton), as well as eight 115 kV circuits emanating from Detweiler TS and Burlington TS (in Burlington). High voltage autotransformers tie the

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115 kV and 230 kV systems together at Detweiler TS, Burlington TS, and Preston TS (in Cambridge). For the purpose of this evidence, the transmission system in the KWCG area can be divided into the following subsystems:

- The South-Central Guelph 115 kV Subsystem (South-Central Guelph): customers supplied from Burlington TS via B5G/B6G;
- The Kitchener-Guelph 115 kV Subsystem (Kitchener-Guelph): customers supplied from Detweiler TS via D7F/D9F and F11C/F12C;
- The Waterloo-Guelph 230 kV Subsystem (Waterloo-Guelph): customers supplied from D6V/D7V;
- The Cambridge 230 kV Subsystem (Cambridge): customers supplied from M20D/M21D via the "Preston Tap"; and
- The Kitchener and Cambridge 230 kV Subsystem (Kitchener and Cambridge): customers supplied from M20D/M21D, including the Preston Tap.

Figure 2 provides a graphical representation of these five subsystems.

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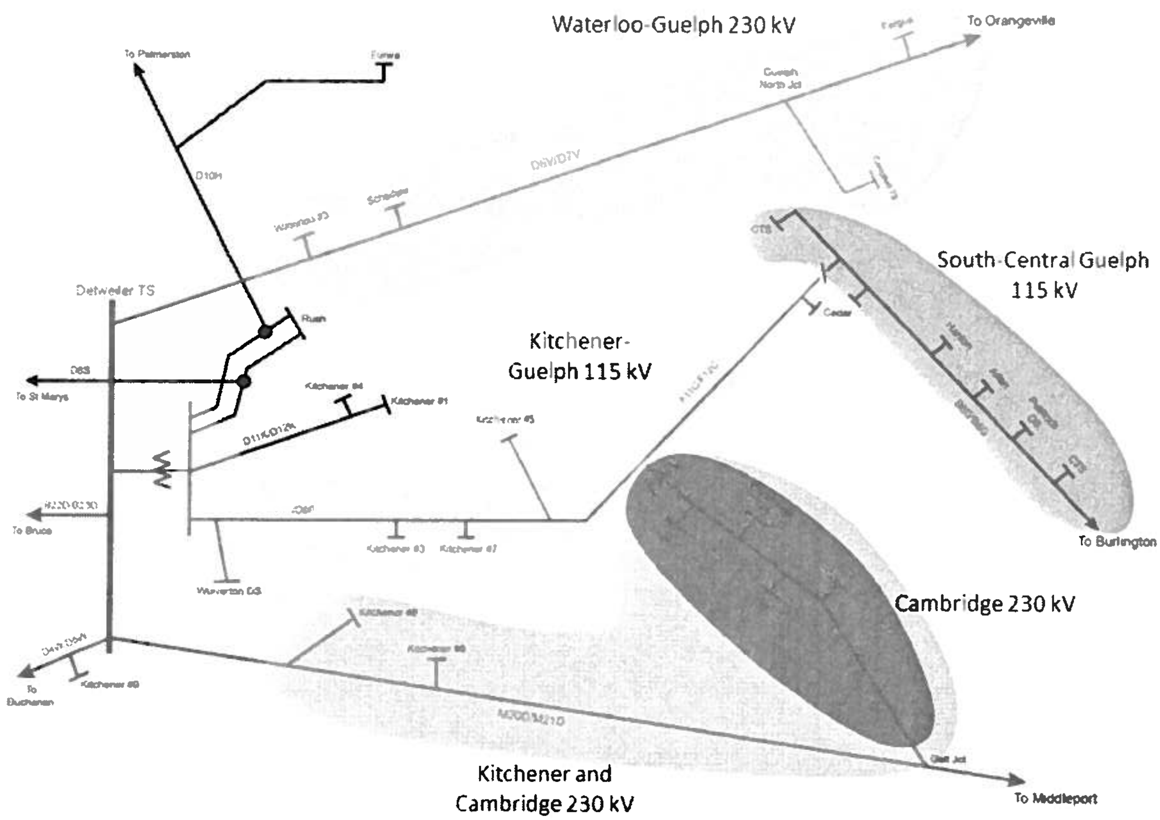
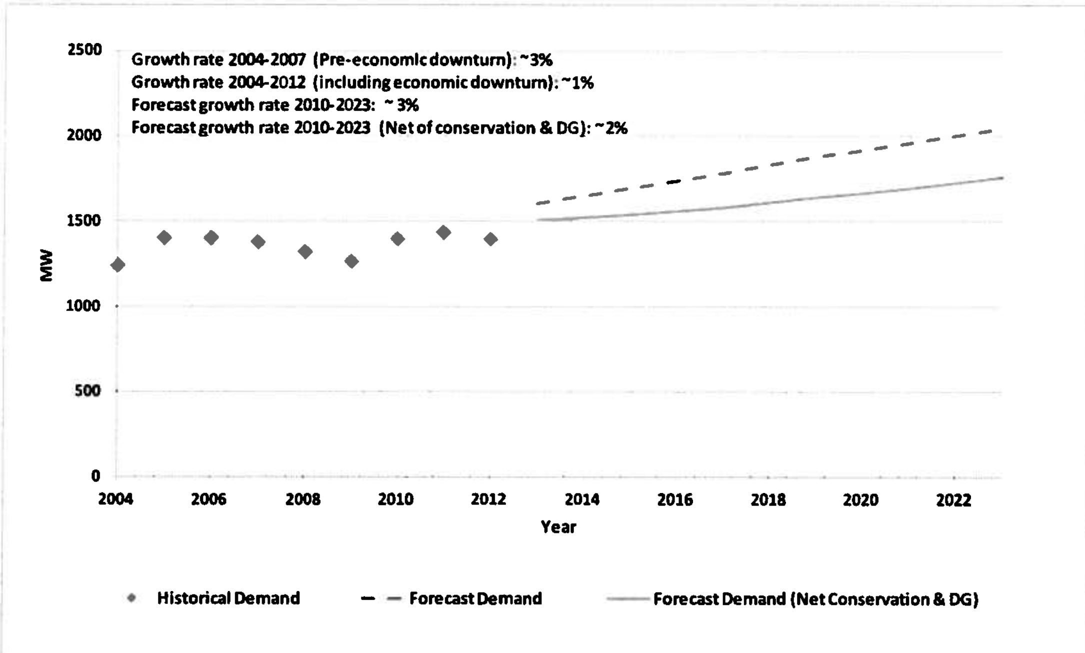
Figure 2: KWCG Area Transmission Subsystems



4 Historical and Forecast Electricity Demand

As previously mentioned, in the summer of 2012 the demand for electricity in the KWCG area peaked at over 1,400 MW. This represented an increase of approximately 10% from the low experienced in 2009 during the economic downturn. Despite the economic downturn, demand in the KWCG area has grown by approximately 1% per year between 2004 and 2012 (prior to the recession, growth was closer to 3%), and based on forecasts provided by the area LDCs, is expected to continue to grow at a pace of nearly 3% per year between 2010 and 2023. Figure 3 provides an overview of the historical and forecast future electricity demand in the KWCG area, inclusive of natural conservation. It also highlights the impacts of expected conservation and distributed generation resources, which are further discussed in Section 6.1 of this exhibit.

Figure 3: Historical and Forecast Demand in the KWCG Area



The demand for electricity in the KWCG area is influenced by a number of factors such as economic, household and population growth. While these factors do not have a one-to-one correlation with electricity consumption, they do provide an indication of trends in electricity demand growth. Changes in the demand for electricity in the KWCG area that took place between 2004 and 2012 were directionally consistent with changes in these indicators. For example, growth in gross domestic product (GDP), one indication of economic growth, was nearly 2% per year throughout the 2004 to 2011 period in the Kitchener Region (an area defined by Statistics Canada that includes most of the KWCG area).[5] From 2004 to 2007, the period prior to the economic downturn, GDP growth in the area averaged over 3% annually. The direction of this GDP growth trend is consistent with the trend in historical electricity demand in the KWCG area.

Looking forward, GDP growth in the Kitchener Region is forecast to continue at a rate of about 2% annually, amongst the strongest in the province. Again this is in line with the expectation for growth in electricity demand in the KWCG area.

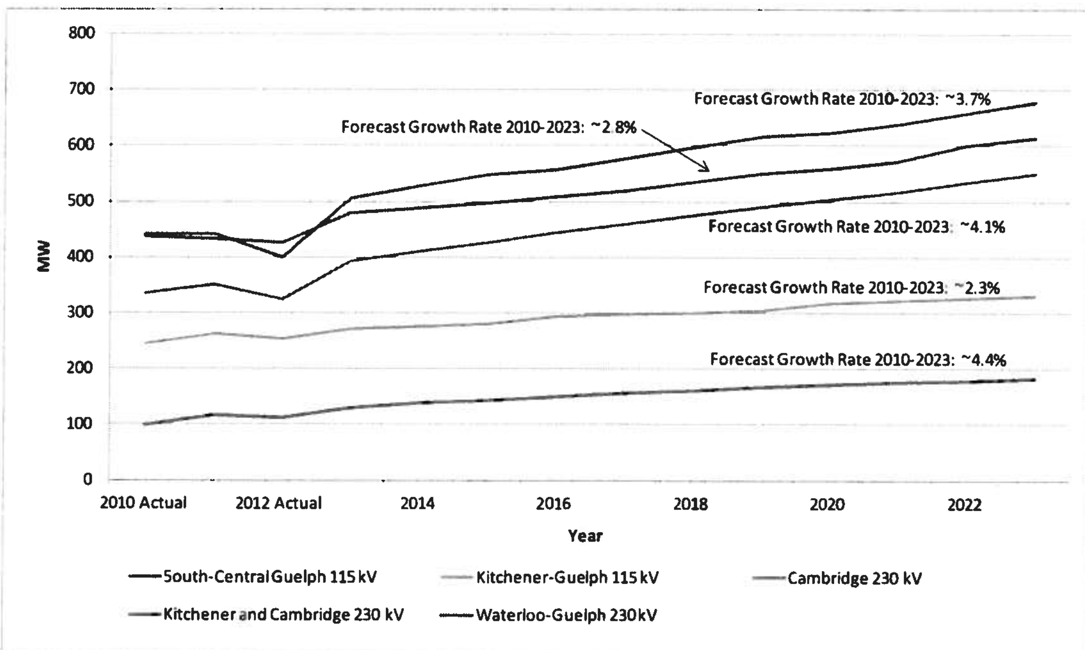
[5] Kitchener Region includes the municipalities of Kitchener, Cambridge, North Dumfries, Waterloo, and Woolwich.

Within the KWCG area, growth in electricity demand amongst the KWCG subsystems is expected to vary due to differences in the types and maturity of the loads they serve. The summer peak demand forecasts of the subsystems, as well as the remaining stations in the KWCG area, are shown in Table 1. Figure 4 provides a graphical representation of the subsystem forecasts.

Table 1: Demand Forecast for the South-Central Guelph, Kitchener-Guelph, Cambridge, and Kitchener and Cambridge Subsystems

(MW)	2010 Actual	2011 Actual	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
South-Central Guelph 115 kV	99	117	112	131	139	144	150	155	161	167	172	175	179	182
Kitchener-Guelph 115 kV	244	262	254	272	275	281	294	297	301	304	317	321	326	330
Waterloo-Guelph 230 kV	436	433	425	480	489	498	507	518	535	550	560	571	602	615
Cambridge 230 kV	335	351	325	392	410	427	443	459	475	491	504	518	534	549
Kitchener and Cambridge 230 kV	442	442	401	506	528	547	557	577	596	616	622	639	659	678
Other Stations in the KWCG Area	184	190	211	216	221	227	233	237	242	247	251	256	242	247

Figure 4: Demand Forecast for the South-Central Guelph, Kitchener-Guelph, Cambridge, and, Kitchener and Cambridge Subsystems



As shown in Figure 4, the two subsystems with the highest growth expectations are the Cambridge 230 kV and South-Central Guelph 115 kV subsystems. This demand growth is driven by a number of factors including growth in the Region of Waterloo East Side Lands (a prime industrial area north of the 401 served by Cambridge and North Dumfries Hydro) and in the Hanlon Industrial Park (an area served by Guelph Hydro's newest transformer station Arlen MTS).

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5 Needs in the KWCG Area

The IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC), (see Exhibit B, Tab 6, Schedule 3, Appendix A) establishes planning criteria and assumptions to be used for assessing the present and future reliability of Ontario's transmission system. Based on an application of these criteria, there are two near- and medium-term needs in the KWCG area: 1) needs relating to supply capacity to meet demand, and 2) needs relating to minimizing the impact of supply interruptions to customers. Each of these is explained below.

Supply Capacity

In accordance with ORTAC, the transmission system supplying a local area (i.e., subsystem) shall have sufficient capability under peak demand conditions to withstand specific outages prescribed by ORTAC while keeping voltages, line and equipment loading within applicable limits. More specifically, the maximum demand that can be supplied following the outage of a single element, as prescribed by ORTAC, is the "supply capacity" or the "load meeting capability" of the line or subsystem.[6] Due to the configuration of the transmission network serving an area, the load meeting capability may vary depending on growth in the surrounding region.

Minimizing the Impact of Supply Interruptions

In accordance with ORTAC, in the event of a major outage (for example a contingency on a double-circuit tower line resulting in the outage of both circuits), the transmission system shall be planned to minimize the impact of supply interruptions to customers both by reducing the number of customers affected by the outage and by restoring power to those affected within a reasonable timeframe. ORTAC therefore prescribes service interruption standards for certain sized load centres following such major transmission outages. Specifically, it provides that following a major outage no more than 600 MW of load will be interrupted, and that for load pockets less than 600 MW, load be restored within the following timeframes:

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[6] ORTAC

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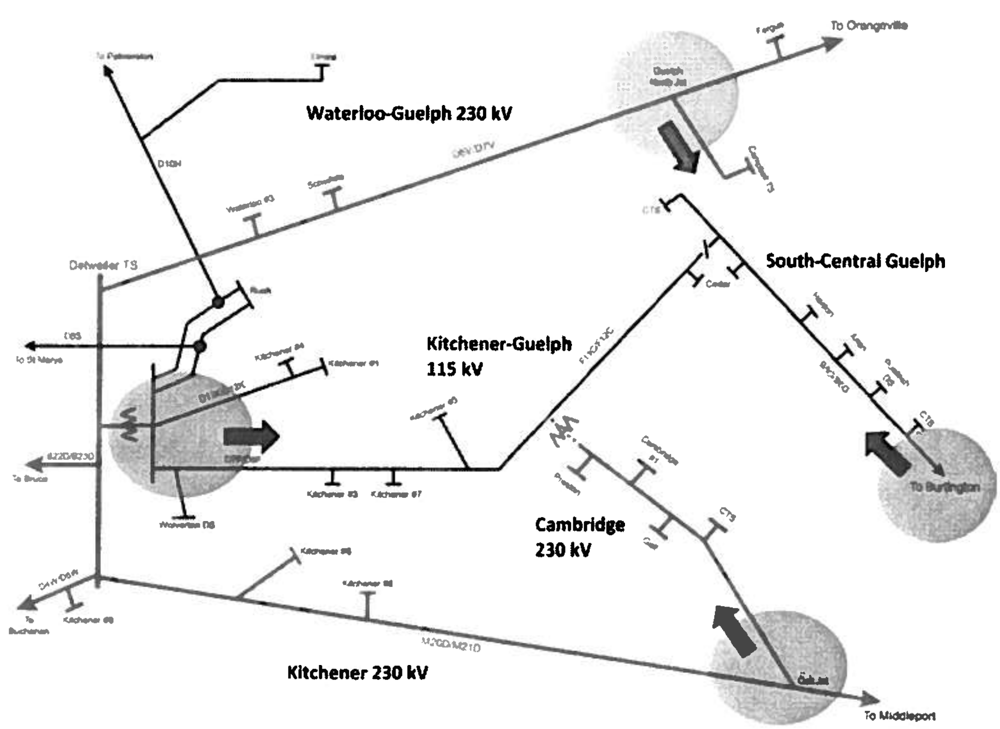
- all load lost in excess of 250 MW must be restored within half an hour;
- all load lost in excess of 150 MW must be restored within four hours; and finally
- all load lost in the area must be restored within eight hours.[7]

<u>Application of ORTAC Criteria</u>

Based on the application of the ORTAC criteria, three of the four sources of supply to the KWCG area (shown by the red circles in Figure 5) have reached, or are close to reaching, their load meeting capability. Additionally, a number of the subsystems are not meeting the service interruption criteria.

The following sections provide an overview of the capability of the existing KWCG transmission system and the need to increase supply capacity and to minimize the impact of supply interruptions to customers in the area.

Figure 5: Sources of Supply to the KWCG Area



[7] ORTAC

5.1 Need for Additional Supply Capacity

Over the next ten years, demand for electricity is expected to exceed the existing system's load meeting capability in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems. Details of the needs in each of these three subsystems are explained below.

South-Central Guelph 115 kV Subsystem

Today, the double-circuit 115 kV transmission line (B5G/B6G) supplying South-Central Guelph from Burlington TS has a load meeting capability of approximately 100 MW. This limit is based on the voltage limitations of either the B5G or B6G circuit following the loss of the companion circuit. Based on the summer peak demand in the South-Central Guelph area, this supply capacity was exceeded in 2012 and is expected to remain beyond capacity over the next decade. Additional capacity is therefore required to meet current and growing electricity demand in the area. Until additional capacity is provided, operating measures (such as opening bus-tie breakers) will be required, resulting in a degradation of the level of supply security to the area.

Kitchener-Guelph 115 kV Subsystem

Today, the Kitchener-Guelph area is supplied by one double-circuit 115 kV transmission line (D7F/D9F and F11C/F12C) from Detweiler TS and supported by the existing 230/115 kV autotransformer at Preston TS. Following the loss of the D9F circuit, the remaining transmission supply to the area has a load meeting capability of approximately 260 MW depending on electricity demand in the surrounding area. This limit is based on thermal overloading of the D7F circuit from Detweiler TS. Based on the forecast electricity demand for the area, peak demand is expected to reach the 260 MW supply capacity limit in the summer of 2013. Additional capacity is therefore required to meet growing electricity demand in the area.

Cambridge 230 kV Subsystem

Today, the Cambridge area is supplied by one double-circuit 230 kV transmission line (the Preston Tap) tapped off of the main 230 kV transmission line (M20D/M21D) between Detweiler TS and Middleport TS. Following the loss of the M20D circuit, the companion circuit on the Preston Tap has a load meeting capability of approximately 375 MW. This limit is based on the thermal overloading of the M21D circuit between Galt Junction and Preston Junction in

Cambridge. Based on the forecast electricity demand for the area, peak demand is expected to reach the 375 MW supply capacity limit in the summer of 2013. Additional capacity is therefore required to meet growing electricity demand in the area.

5.2 Need to Minimize the Impact of Supply Interruptions to Customers

In addition to the above capacity needs, based on current and forecast demand, two subsystems within the KWCG area, namely the Waterloo-Guelph and Kitchener and Cambridge subsystems, currently fail to comply with the ORTAC service interruption criteria. Additionally, over the medium-term, supply to both of these areas is expected to exceed the maximum 600 MW load interruption level for a major outage as prescribed by ORTAC.

Waterloo-Guelph 230 kV Subsystem

Today, the Waterloo-Guelph subsystem is supplied by an approximately 77 km double-circuit 230 kV transmission line (D6V/D7V) between Detweiler TS and Orangeville TS. In the event of the loss of both the D6V and D7V circuits, all load supplied by this transmission line (which exceeded 400 MW in 2012) will be interrupted. The existing system lacks the capability to restore power to these customers in accordance with the ORTAC criteria which specifies that all load interrupted over 250 MW must be restored within 30 minutes. A major outage of this type took place on February 29th, 2012 when a forced outage on one of the D6V/D7V circuits, coupled with scheduled maintenance on the companion circuit, resulted in the interruption of electricity supply for roughly three hours to approximately 350 MW of customers in parts of the cities of Waterloo, Kitchener and Guelph.

Additionally, over the medium-term (by 2022), demand supplied by the D6V/D7V circuits is expected to exceed 600 MW. Reinforcement will be required to ensure that following a major outage to the D6V/D7V circuits, supply to this large load pocket will, as required by ORTAC, remain uninterrupted.

Kitchener and Cambridge 230 kV Subsystem

Today, the Kitchener and Cambridge subsystem is supplied by an approximately 82 km double-circuit 230 kV transmission line (M20D/M21D) between Detweiler TS and Middleport TS, including the Preston Tap. In the event of the loss of both the M20D and M21D circuits, all load

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supplied by this transmission line (which was approximately 400 MW in 2012) will be interrupted. The existing 230/115 kV autotransformer and 230 kV disconnect switches at Preston TS allow power to be restored to only approximately 65 MW of demand within half an hour following a major outage. This is insufficient to meet the ORTAC criteria, which specifies that all load interrupted over 250 MW must be restored within 30 minutes. Prior to the installation of the autotransformer and disconnect switches at Preston TS, power could not be restored to any customers in the area in a timely manner. Such was the case in 2003 when the supply of power to parts of the City of Cambridge, the Township of North Dumfries and the City of Kitchener, totaling over 250 MW, was interrupted for nearly four hours.

Additionally, over the medium- term (by 2019), demand supplied by the M20D/M21D circuits is expected to exceed 600 MW. Reinforcement will be required to ensure that following a major outage to the M20D/M21D circuits, supply to this large load pocket will, as required by ORTAC, remain uninterrupted.

5.3 Summary of the Needs

The needs in the KWCG area identified above based on the application of the ORTAC are summarized in Table 2.

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Table 2: Summary of the Needs in the KWCG Area

Need Type	Subsystem	Need Description	Need Date
Capacity to Meet Demand	South-Central Guelph 115 kV	Loading on B5G/B6G exceeds load meeting capability	Now
	Kitchener-Guelph 115 kV	Loading on F11C/F12C exceeds load meeting capability	Now
	Cambridge 230 kV	Loading on M20D/M21D exceeds load meeting capability	Now
Minimize the Impact of Interruptions	Kitchener & Cambridge 230 kV	M20D/M21D does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2019
	Waterloo-Guelph 230 kV	D6V/D7V does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2022

6 Integrated Solutions to Address the Needs in the KWCG Area

In considering potential solutions for addressing the needs of the KWCG area, the OPA first considered conservation and distributed generation. These options reduce electricity demand and have the potential to negate or defer the need for investment in large-scale generation or transmission infrastructure. The OPA then considered large-scale generation or transmission infrastructure to meet any remaining needs in the area.

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6.1 Conservation and Distributed Generation Options

6.1.1 Conservation

Conservation means reducing or shifting the consumption of and/or the demand for electricity. Such reductions or shifting help support the ability of the existing electricity system to meet growing electricity demand.

In February 2011, the Minister of Energy established conservation targets for Ontario over the next 20 years: 4,550 MW of peak demand reduction by 2015, increasing to 7,100 MW by 2030. Included in these targets is a peak demand reduction of 1,330 MW to be achieved by 2014 by Ontario's LDCs. These goals are aggressive, and large load centres, such as the KWCG area, are expected to be key contributors to ensuring Ontario's peak demand reduction targets can be met.

Based on an allocation of the provincial targets, nearly 270 MW in peak demand reduction is expected from conservation achievement within the KWCG area by 2023. Within the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems specifically, the planned peak demand reduction from conservation efforts by 2023 is over 130 MW. This planned conservation is expected to be achieved through a combination of peak demand savings resulting from province-wide conservation and demand management programs, improved building codes and equipment standards, and customer response to time-of-use pricing. These savings have an estimated delivery cost of $65 million, based on an allocation of forecast expenditures for provincial conservation programs. This planned conservation reduction is expected to off-set nearly 35% of the forecast load growth in these subsystems (on aggregate) between 2010 and 2023, and will contribute to meeting the KWCG area's capacity needs as shown in Table 4 below.

While conservation can be an effective means of addressing capacity needs, conservation cannot aid in the restoration of power to customers following a major transmission outage, and therefore cannot resolve the KWCG area's restoration needs.

Planned conservation efforts are important contributors to the reliable supply of electricity to the KWCG area, however further solutions will be needed to fully address the area's electricity needs; a capacity gap of nearly 70 MW remains in 2016, growing to nearly 200 MW by 2023, in

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the South-Central Guelph. Kitchener-Guelph, and Cambridge subsystems. Based on the OPA's experience with conservation programs, the amount of planned conservation forecasted for the region, and the immediate nature of the needs, it is the OPA's view that additional conservation is not a feasible means of addressing the KWCG area's near- and medium-term needs as shown in Table 4. The OPA will continue to monitor conservation program uptake and success in the KWCG area, and look for opportunities for further cost effective conservation to maintain a reliable supply of electricity to the area over the longer-term.

6.1.2 Distributed Generation

Distributed generation is small-scale generation sited close to load centres; as such, it helps supply local energy needs while at the same time contributing to meeting provincial demand. Along with other OPA procurement processes, the introduction of the Green Energy and Green Economy Act, and the associated development of the Feed-In Tariff (FIT) program, has encouraged the development of distributed generation resources in Ontario. These procurements take into consideration the system need for generation as well as cost.

Within the KWCG area, nearly 150 MW of distribution and transmission connected renewable generation has been contracted through the FIT program and previous procurements (such as the Renewable Standard Offer Program), and is expected to come into service by the summer of 2016. This generation is spread throughout the KWCG area, with the majority located in the area north of Elmira and around Fergus TS. Additionally, some small-scale generation, such as Combined Heat and Power, totaling nearly 10 MW of installed capacity is in operation in the region.

It should be noted that distributed generation resources are not always available at the time of system peak, in particular, intermittent renewable generation resources such as wind and solar. The full installed capacity of these facilities therefore cannot be relied upon to meet the KWCG area's electricity needs. The OPA estimates that the existing and contracted distributed generation resources in the KWCG area will contribute approximately 35 MW of effective

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capacity to meeting area peak demand.[8] Of this, approximately 1 MW of effective capacity is located within the South-Central Guelph subsystem, 1 MW in the Kitchener-Guelph subsystem, and 2 MW within the Cambridge subsystem, representing an estimated capital investment of approximately $70 million in these areas. This generation will contribute to addressing the KWCG area's capacity needs.

While distributed generation can be an effective means of meeting capacity needs, its ability to help minimize the impact of major outages to customers is limited. For example, the specific connection point of the facility, the technical design specifications of the generator, and safety protocols on the electricity system, can impact the ability of a distribution connected generator to restore power to customers following a major transmission outage.

The existing and contracted distributed generation resources in the KWCG area are important contributors to maintaining a reliable supply of electricity, however further solutions will be needed to fully address the area's electricity needs. It is the OPA's view that additional distributed generation is not a feasible means of addressing the KWCG area's near- and medium-term needs. There is uncertainty associated with the development of further distributed generation facilities. With regards to renewable generation facilities, there is uncertainty related to local development interest and contract awards under the ongoing FIT program, as well as the siting and connection of facilities at the specific location in which they are needed. For non-renewable distributed generation facilities there is risk associated with the availability of future procurements, as well as the siting and connection of facilities at the specific location in which they are needed. Additionally, it is the OPA's view that further distributed generation resources are not a cost effective means for addressing the needs of the KWCG area, due to the robust load growth anticipated in the region combined with the relatively low cost of the recommended transmission reinforcement discussed in section 6.3 below. Distributed generation may be an effective option to meet an area's needs when low load growth is anticipated and/or the cost of the alternative solutions is high in comparison. The OPA will continue to monitor the uptake of

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[8] Effective capacity is that portion of installed capacity that contributes at the time of system peak.

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distributed generation in the KWCG area, and look for opportunities for further cost effective distributed generation to maintain a reliable supply of electricity to the area over the longer-term.

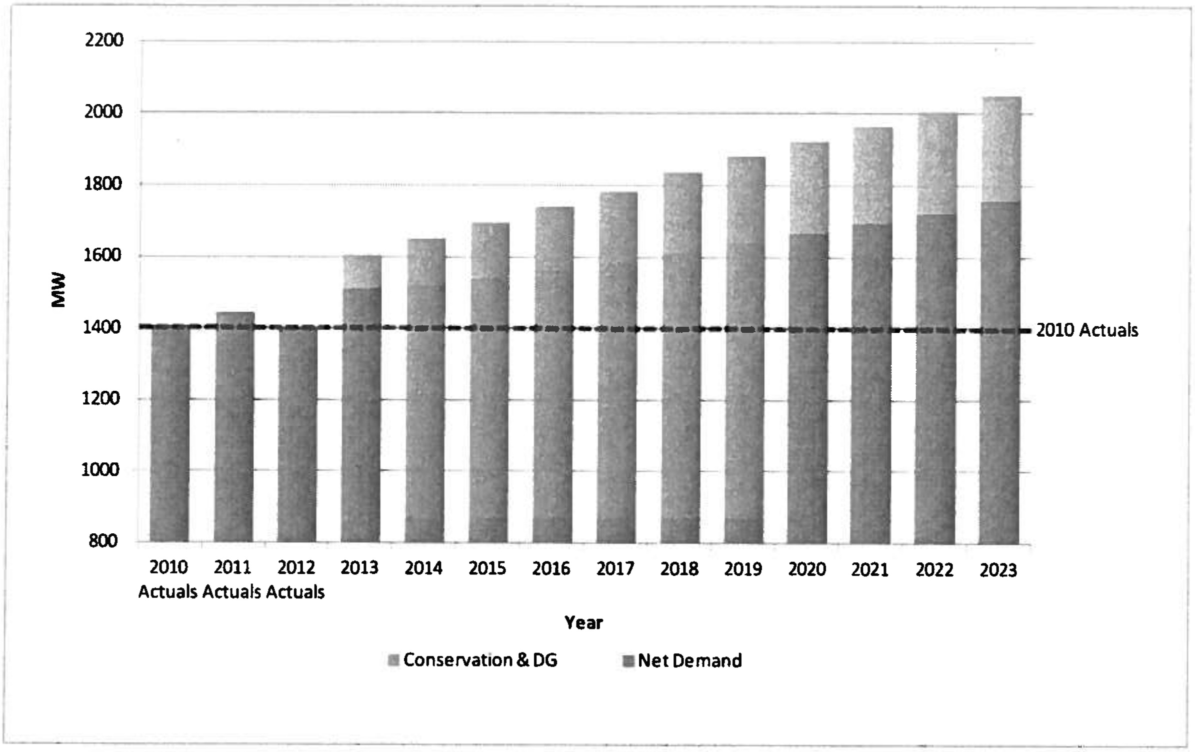
6.1.3 KWCG Area Electricity Demand Net of Conservation and Distributed Generation Resources, and Remaining Reliability Needs

Conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the KWCG area. The net summer peak demand in the KWCG area, after taking into account the contributions of conservation and distributed generation resources, is shown in Table 3 below. Additionally, the portion of growth in summer peak electricity demand forecast for the KWCG area met by conservation and distributed generation is shown in Figure 6.

Table 3: Demand Forecast for the South-Central Guelph, Kitchener-Guelph, Cambridge, and Kitchener and Cambridge Subsystems Net of Conservation and Distributed Generation

(MW)	2010 Actual	2011 Actual	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
South-Central Guelph 115 kV	99	117	112	123	129	132	136	140	144	148	153	155	157	159
Kitchener-Guelph 115 kV	244	262	254	257	254	255	264	263	263	263	274	275	277	280
Waterloo-Guelph 230 kV	436	433	425	448	448	450	451	455	466	477	482	489	516	526
Cambridge 230 kV	335	351	325	372	383	393	404	415	426	438	447	458	471	484
Kitchener and Cambridge 230 kV	442	442	401	480	491	504	506	519	532	546	548	561	576	592
Other Stations in the KWCG Area	184	190	211	199	199	199	201	203	205	206	209	212	196	199

Figure 6: Forecasted Demand Growth in the KWCG Area met by Conservation and Distributed Generation Resources



Conservation and distributed generation resources alone are not sufficient to address the KWCG area's needs and will need to be supplemented by additional solutions. A summary of the remaining reliability needs in the area over the next ten years, after accounting for the contributions of conservation and distributed generation is provided in Table 4. This table also shows the contribution of conservation and distributed generation resources to deferring some of the near-term reliability needs of the KWCG area.

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Table 4: Summary of the Needs in the KWCG Area after the Contribution of Conservation and Distributed Generation Resources

Need Type	Subsystem	Need Description	Before Conservation & DG	After Conservation & DG
Capacity to Meet Demand	South-Central Guelph 115 kV	Loading on B5G/B6G exceeds load meeting capability	Now	Now
	Kitchener-Guelph 115 kV	Loading on F11C/F12C exceeds load meeting capability	Now	2019 (deferment of 6 years)
	Cambridge 230 kV	Loading on M20D/M21D exceeds load meeting capability	Now	2014 (deferment of 1 year)
Minimize the Impact of Interruptions	Kitchener & Cambridge 230 kV	M20D/M21D does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2019	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: Longer-term
	Waterloo-Guelph 230 kV	D6V/D7V does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2022	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: Longer-term

6.2 Generation Options

As noted in Table 4, even after taking into consideration the contribution of conservation and distributed generation, three of the KWCG subsystems (the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems) already exceed or are expected to exceed their supply capacity within the next ten years. Additionally, two subsystems (the Kitchener and Cambridge, and Waterloo-Guelph subsystems), currently do not comply with the ORTAC service interruption criteria. The development of large-scale generation can be an effective solution for meeting these needs.

In the KWCG area, a large-scale gas-fired generator (e.g., 200 MW plus) can only be accommodated on the 230 kV transmission system. The optimum location to site such a facility would be in the Cambridge area near Preston TS (a less central location would necessitate added transmission reinforcement costs and/or provide shorter-lasting benefit). This generation facility would meet the capacity and restoration needs of the Cambridge, and Kitchener and Cambridge subsystems, but would not address the capacity needs of the South-Central Guelph and Kitchener-Guelph subsystems, nor the restoration needs of the Waterloo-Guelph subsystem. These remaining reliability needs would necessitate significant transmission upgrades, or the installation of additional large-scale generation facilities. It is the OPA's view that such an option is not cost effective when compared to the recommended transmission reinforcement discussed in section 6.3 below. Additionally, it could be challenging to site a large gas generation plant in the KWCG area within the time necessary to address the area's needs.

The 115 kV transmission system within the KWCG area could accommodate a smaller gas-fired generator, e.g. 100 MW, in size. The optimum location to site such generation would be near Cedar TS. A centralized location near Cedar TS could meet the near and medium-term capacity needs of the South-Central Guelph and Kitchener-Guelph subsystems, however, additional facilities would be required to address the near-term capacity and restoration needs of the Cambridge, and Kitchener and Cambridge, and Waterloo-Guelph subsystems. Given the centralized location of Cedar TS, it would be difficult be difficult to site such a facility. If a site other than Cedar TS was to be selected multiple gas-fired generation facilities would be required to meet the capacity needs of South-Central Guelph and Kitchener-Guelph subsystems. It is the OPA's view that smaller gas-fired generation is not cost effective when compared to the recommended transmission reinforcement discussed in section 6.3 below.

6.3 Transmission Options

Transmission reinforcements are a final option for addressing the remaining reliability needs of the KWCG area. Transmission options are discussed first in terms of their ability to meet the supply capacity needs of the KWCG area, followed by their ability to minimize the impact of

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supply interruptions to customers. It is important to note that given the highly integrated nature of the KWCG area transmission system, transmission options identified as addressing reliability needs in one of the KWCG subsystems may also contribute to addressing reliability needs of the neighbouring subsystems.

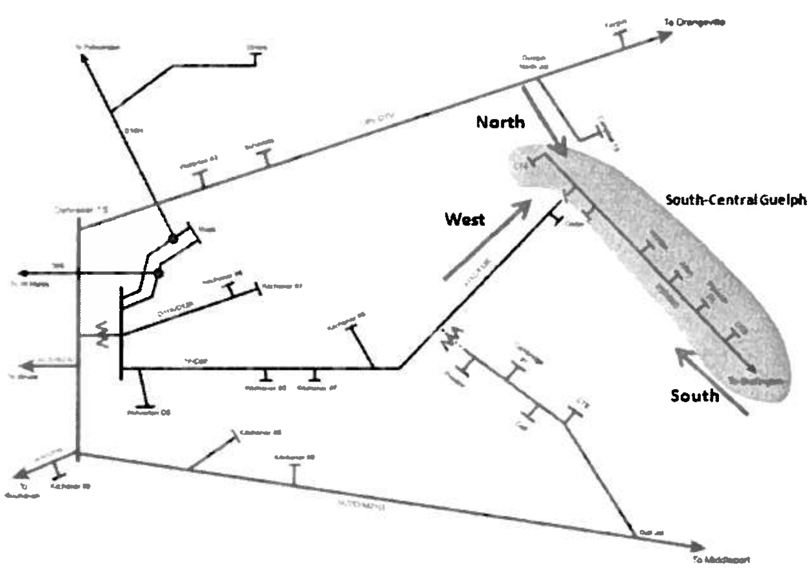
6.3.1 Transmission Options to Address Supply Capacity Needs

As noted in Table 4, three of the KWCG subsystems, namely the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems, already exceed or are expected to exceed their supply capacity. Transmission options for addressing these needs are discussed below.

Transmission Options for the South-Central Guelph Subsystem

The capacity needs of the South-Central Guelph subsystem can be addressed by reinforcing the transmission system from the West, South, or North as shown in Figure 7.

Figure 7: Transmission Reinforcement Options for South-Central Guelph



Reinforcing supply from the South (Burlington TS)

To improve the load meeting capability of the South-Central Guelph area, the existing 115 kV supply from Burlington TS could be reinforced. This could be accomplished by re-conductoring the existing B5G/B6G circuits (approximately 42 km in length) with a higher rated conductor (e.g. 1100 A), or by converting the existing B5G/B6G supply to 230 kV.

Given the age and design of the existing 115 kV transmission supply to South-Central Guelph, Hydro One has determined that it would not be feasible to reconductor the existing B5G/B6G circuits; instead, a new line would have to be constructed. Rebuilding the existing transmission line at either 115 kV or 230 kV would be complex, requiring bypass facilities to maintain supply to the area during construction. It would also be relatively expensive (over $200 million) given the significant distance between Burlington TS and Guelph and the number of stations that would potentially require conversion. Accordingly, this alternative was not considered further for meeting the capacity needs of South-Central Guelph.

Reinforcing supply from the West (Kitchener-Guelph Subsystem)

Similar to reinforcing supply to South-Central Guelph from the South, the existing 115 kV supply to the Kitchener-Guelph subsystem (the D7F/D9F and F11C/F12C circuits from Detweiler TS) could be reinforced through reconductoring or rebuilding. Due to the age and design of the existing F11C/F12C circuits, however, Hydro One has determined that it would not be feasible to reconductor this transmission line. Therefore, reinforcement from the west would have to be achieved through rebuilding the existing 115 kV transmission line between Detweiler TS and CGE Junction (near Cedar TS) to a higher rated 115 kV or 230 kV facility and installing switching facilities at Cedar TS. Similar to the southern option, rebuilding this line would be complex, would require bypass facilities to maintain supply during construction, and would be expensive (over $130 million) given the significant distance between Detweiler TS and CGE Junction (approximately 33 km) and the number of stations that would potentially require conversion. Accordingly, this alternative was not considered further for meeting the capacity needs of South-Central Guelph.

Reinforcing supply from the North (Waterloo-Guelph Subsystem)

Finally, additional transmission facilities could be constructed to reinforce the transmission supply to South-Central Guelph from the north. Upgrading the existing 115 kV transmission line between Campbell TS and CGE Junction to a double-circuit 230 kV transmission line, installing two new 230/115 kV autotransformers and four new 115 kV circuit breakers at Cedar TS, and transferring an existing directly connected customer in the area to the distribution system, would bring the northern 230 kV supply into the heart of Guelph.

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At a cost of approximately $80 million, this alternative would provide a supply capacity increase sufficient to meet the needs of the South-Central Guelph area until beyond 2030, and could be completed by the end of 2015. While other options for reinforcing the transmission supply to South-Central Guelph from the north were considered (such as alternative switching arrangements, transferring a portion of the Cedar TS load to the 230 kV supply, and locating the two 230/115 kV autotransformers at a new site near Campbell TS), this option provides the greatest increase in supply capacity to South-Central Guelph, reduces the exposure of customers supplied by Cedar TS to supply outages, and provides better flexibility with respect to the end-of-life replacement of station equipment at both Cedar TS and Hanlon TS, which is anticipated to be required over the near- to medium-term. As noted below, it will also address the supply capacity needs of the Kitchener-Guelph subsystem. For these reasons, this is the preferred option for reinforcing the supply to South-Central Guelph.

The proposed system arrangement following the completion of recommended transmission reinforcement is shown in Figure 8.

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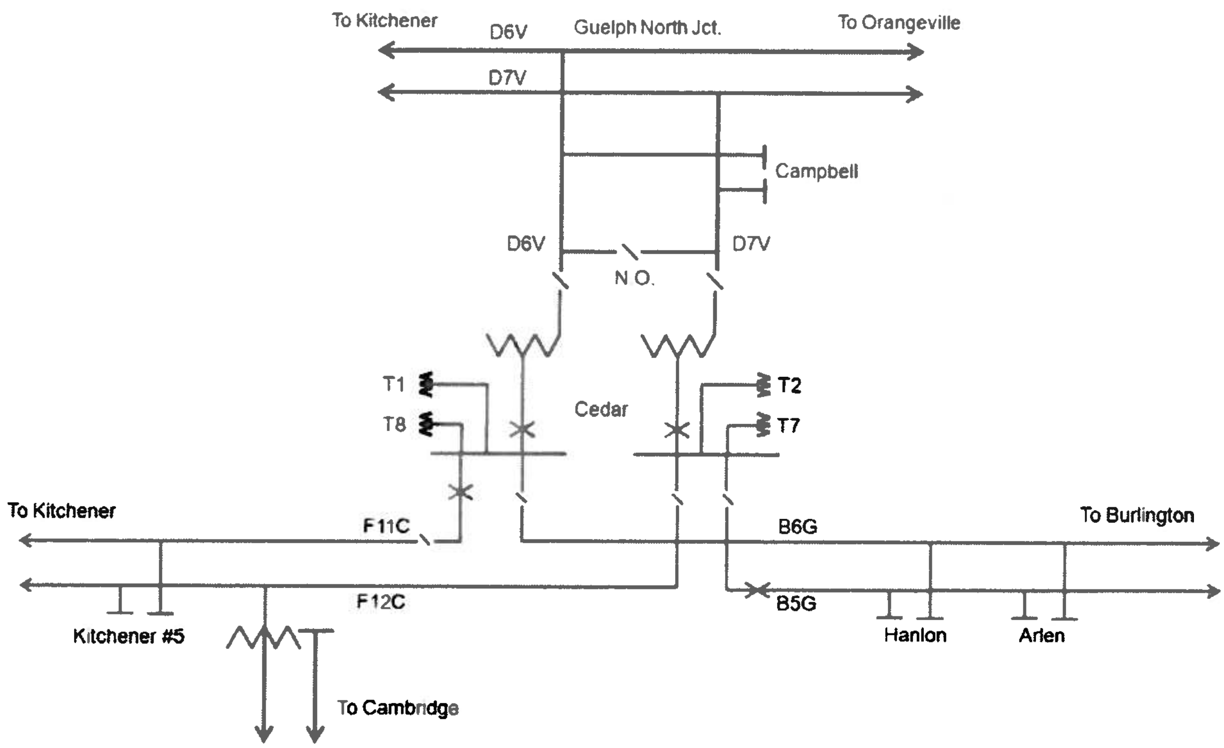
Figure 8: Proposed Arrangement for Reinforcing the Transmission Supply to South-Central Guelph from the North



Transmission Options for the Kitchener-Guelph Subsystem

The preferred solution for South-Central Guelph will make Cedar TS a strong source of supply within the KWCG area. In addition to addressing the capacity needs of South-Central Guelph, this strong source of supply will also be sufficient to satisfy the capacity needs of the Kitchener-Guelph subsystem until beyond 2030. Other alternatives to meet the capacity needs of the Kitchener-Guelph area (e.g. rebuilding of the existing 115 kV supply) would require incremental transmission investments, and are not recommended.

Transmission Options for the Cambridge Subsystem

The installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support, along with the preferred solution for South-Central Guelph, would result in improvements to the supply capacity of the Cambridge and Kitchener-Guelph areas. Following the installation of these facilities, sufficient capacity would exist on the Kitchener-Guelph 115 kV subsystem to accommodate the addition of a future Cambridge & North Dumfries Hydro

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station (approximately 100 MW in size). This would be sufficient to meet the capacity needs of the Cambridge area until the longer-term (2024), providing time to explore opportunities for further cost effective conservation and distributed generation, as well as transmission investments, such as voltage support and/or switching facilities. As further explained below, the addition of this second autotransformer will also partly address the supply restoration needs in the area. This work would be coordinated with the reinforcement of South-Central Guelph and could be completed by the end of 2015 at a cost of approximately $15 million to $25 million.

6.3.2 Preferred Option to Address Supply Capacity Needs

In summary, the preferred transmission options for addressing the near- and medium-term supply capacity needs of the KWCG area are:

- installing two new 230/115 kV autotransformers, four 115 kV breakers, and advancing the relocation of the existing Hydro One Distribution Operating Centre at Cedar TS ($52 million);
- rebuilding approximately 5 km of existing 115 kV transmission line between Campbell TS and CGE junction in Guelph with a double-circuit 230 kV transmission line, and transferring the existing directly connected customer in the area to the distribution system ($27.5 million); and
- installing a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support ($15 million to $25 million).

Together, these improvements will at a total estimated cost of approximately $95 million to $105 million meet the capacity needs of the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems until 2024 or beyond.

6.3.3 Options to Reduce the Impact of Supply Interruptions

As noted in Table 4, two of the KWCG subsystems, namely the Waterloo-Guelph, and Kitchener and Cambridge subsystems, are unable to restore power to customers in the area within half an hour following a major outage as prescribed by the ORTAC service interruption criteria. Additionally, over the longer-term, demand in these two areas is expected to exceed the maximum 600 MW load interruption level prescribed by ORTAC.

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These supply interruption needs can be partly addressed through the foregoing recommended capacity improvements, and the remaining supply interruption need can be satisfied through the following two transmission options 1) the implementation of load transfers following an outage, and/or 2) the installation of switching facilities, such as mid-span openers, motorized disconnect switches or circuit breakers. These potential options are evaluated below.

Options for the Waterloo-Guelph Subsystem

<u>Load Transfers</u>

One method of reducing supply interruptions to customers in the Waterloo-Guelph subsystem is to execute load transfers at the distribution level following a major transmission outage. KWCG area LDCs have identified little to no transfer capability of the loads in the area, and given the length of the D6V/D7V transmission line (about 77 km) and the amount of load served (over 400 MW), a number of load transfers, likely spanning significant distances (e.g. nearly 30 km between Orangeville TS and Fergus TS), would have to be implemented after each major transmission outage. It is the OPA's view that implementation of this option in order to comply with the ORTAC interruption criteria is not technically feasible. Accordingly, this alternative was not considered further as a means of reducing the impact of supply interruptions to customers in the Waterloo-Guelph subsystem.

<u>Mid-Span Openers</u>

Alternatively, installing mid-span openers at Guelph North Junction in the Township of Centre Wellington would facilitate the sectionalization of the D6V/D7V 230 kV circuits. Following a major transmission outage, the mid-span openers could be manually opened to isolate sections of the circuits and thus improve the restoration capability of the Waterloo-Guelph subsystem. However, because the mid-span openers are manually actuated, restoration capability could only be improved within 4 to 8 hours, which is insufficient to meet the 30 minute ORTAC requirement for the Waterloo-Guelph subsystem. For this reason, mid-span openers were not considered further as a means of reducing the impact of supply interruptions to customers in the Waterloo-Guelph area.

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Motorized Disconnect Switches

The installation of motorized disconnect switches at Guelph North Junction could also be used to facilitate the sectionalization of the D6V/D7V 230 kV circuits. These motorized switches could be operated remotely so that following a major transmission outage, load lost in excess of 250 MW in the Waterloo-Guelph area could be restored within 30 minutes. The estimated cost of this alternative is approximately $9 million to $12 million. While these facilities would address the near-term requirement for improved restoration capability, they would not address the longer-term need to prevent the interruption of demand in excess of 600 MW. To address this need, the installation of two 230 kV circuit breakers would be required in the longer-term at a cost of approximately $6 million to $15 million depending on the initial switching facilities installed. For the reasons noted below, this option was not preferred to installing new 230 kV circuit breakers at Guelph North Junction by 2015.

Circuit Breakers

Alternatively, two 230 kV circuit breakers could be installed at a new station (Inverhaugh SS) located at Guelph North Junction to facilitate sectionalization of the D6V/D7V circuits. The estimated cost of installing these breakers is approximately $16 million. This is roughly equivalent to the cost of installing motorized disconnect switches today and breakers in the longer-term. Compared to motorized disconnect switches, circuit breakers would reduce the exposure of customers in the area to supply outages by breaking the D6V/D7V circuits into three shorter sections (ranging from approximately 12 km to 35 km in length, compared to 77 km today). Circuit breakers also have a faster response time than motorized disconnect switches and would reduce the amount of time customers in the area would be without power following a major transmission outage. Finally, these facilities would address the future need to prevent the interruption of supply to customers in the area when demand on the D6V/D7V circuits exceeds 600 MW. For these reasons, the installation of two circuit breakers is the preferred option for reducing the impact of supply interruptions to customers in the Waterloo-Guelph subsystem. The proposed system arrangement after the installation of these breakers is shown in Figure 9.

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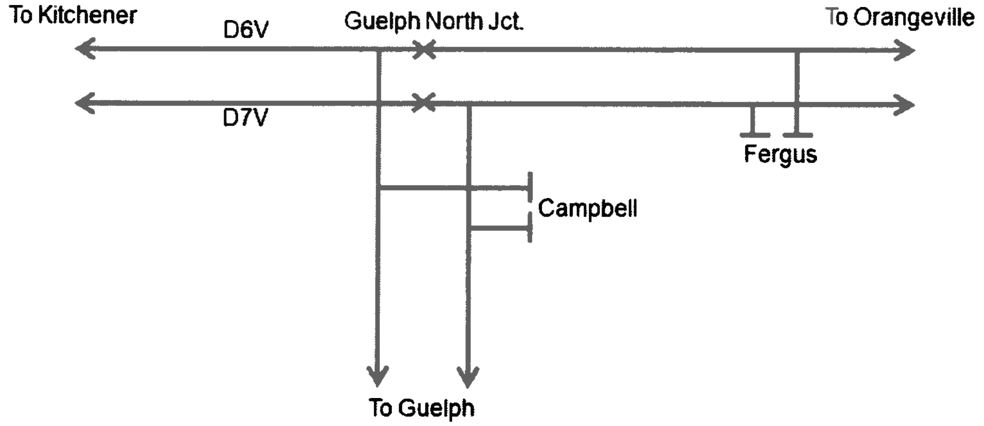
Figure 9: Proposed Transmission System Configuration after the Installation of two 230 kV Circuit Breakers at Guelph North Junction



These facilities, along with the refurbishment of the existing transmission line between Campbell TS and CGE Junction, and the installation of two 230/115 kV autotransformers and four 115 kV in-line breakers at Cedar TS, are referred to as the Guelph Area Transmission Refurbishment project, or GATR project.

Kitchener and Cambridge Subsystem

The preferred transmission reinforcements for meeting the capacity needs of the KWCG area would also increase the capability of the Kitchener and Cambridge subsystem to minimize the impact of major outages to customers in the area. With these reinforcements, the transmission system will have the capability to restore approximately 100 MW of load in the Cambridge area within 30 minutes. Additionally, approximately 100 MW of Cambridge area load will no longer be interrupted following the loss of the M20D/M21D circuits. This represents a significant improvement to the capability of the transmission system to minimize the impact of supply interruptions to customers, and is the preferred solution for contributing to meeting the restoration needs of the Kitchener and Cambridge area. This solution also defers the potential interruption of load in excess of 600 MW in the Kitchener and Cambridge area well into the longer-term.

The potential for further improvements to minimize the impact of major outages to customers in the Kitchener and Cambridge area will be investigated along with longer-term reliability planning for the region. Opportunities for further cost effective conservation and distributed

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generation, as well as other investments, such as voltage support and/or switching facilities, will be investigated.

6.3.4 Preferred Options to Reduce the Impact of Supply Interruptions

In summary, the preferred options to reduce the impact of supply interruptions to customers in the KWCG area are to install two 230 kV circuit breakers at a new station located at Guelph North Junction (at an approximate cost of $16 million) and to install a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support (contingent on the development of the preferred capacity improvements in South-Central Guelph). The estimated cost of a second autotransformer at Preston TS (approximately $15 million to $25 million) is included in the overall estimated costs (approximately $95 million to $105 million) for the recommended capacity improvements. The potential for further improvements to minimize the impact of major outages to customers in the Kitchener and Cambridge area will be investigated along with longer-term reliability planning for the region.

7 Recommended Integrated Solution for the KWCG Area

The recommended solution for the needs of KWCG area is an integrated package composed of 1) conservation, 2) distributed generation resources, and 3) transmission reinforcements in the KWCG area (specifically the GATR project, and the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support).

Together, conservation and distributed generation resources are expected to off-set more than 35% of the forecast load growth in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems between 2010 and 2023. These resources help to meet the existing reliability needs of the KWCG area, and also help to defer the need for longer-term investments in the region.

Transmission reinforcements are the final components of the integrated plan for the KWCG area. The total estimated cost of the transmission investments included in the integrated solution is approximately $110 million to $120 million: approximately $95 million for the GATR project, and approximately $15 million to $25 million for the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support. Project completion

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is expected by the end of 2015, with development of the Preston TS autotransformer facilities being coordinated with completion of the GATR project.

It is the OPA's view that these facilities are a cost-effective and technically-effective solution for improving the supply capacity of the South-Central Guelph, Kitchener-Guelph, and Cambridge subsystems, and for reducing the impact of supply interruptions in Waterloo-Guelph, and Kitchener and Cambridge subsystems. Through longer-term planning for the KWCG area, opportunities for further cost effective conservation and distributed generation, as well as transmission investments will be investigated. Monitoring of growth in electricity demand and the achievement of conservation and distributed generation in the KWCG area, will also be key components of ongoing electricity planning in the region.

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Tab 3

Ontario Energy Board (Board Staff) INTERROGATORY #1 List 1

Interrogatory

Historical and Forecast Electricity Demand

Reference:

(1) Ontario Power Authority Report, March 2013-Exhibit B/Tab 1/Schedule 5

Preamble:

Board staff seeks clarification of the load growth forecast in the KWCG area:
The OPA reports (Reference 1 at line 10, page 8) that demand "... is expected to continue to grow at a pace of nearly 3% per year between 2010 and 2023."

In Reference (1), at page 6, line 12 the OPA advises that the demand for electricity recovered to pre-recession levels in the summer of 2010.

Reference 2 at line 23 indicates that customers of Cedar TS will reduce the exposure of customers supplied by Cedar TS to supply outages, provide increased supply diversity and reliability of supply, lower losses and improve operational flexibility to the area.

Question(s)/Request(s):

1. Has the OPA reviewed the figures from the area LDCs so that it is able to verify the forecast growth rates and assure there is no double counting by the LDCs making up the area load? Does the OPA adopt the forecast growth as it own evidence
2. Is the OPA defining the pre-recession period as 2004-2007 as shown in Figure 3 page 9 of ref 1 as "pre-economic downturn"?
3. Is it correct to deduce from the Figure 3, page 9 that the growth from 2005 to 2012 was 0%?
4. A 3% growth rate for 2010 to 2023 (2% net of CD and DG) is reflected in Reference 1, page 13, line 10. However, electrical demand from 2004 to 2011 is lagging by 1% or more behind the GDP growth, yet in the years 2010-2023 it is equal. What are the factors that make this higher demand a credible result? Please provide comment on the following table:

	2004-2007	2004-2011	2010-2023	
GDP Per Ref 1	>3% lines10-11, p9	2% lines 8-9,p9	2%	
Actual/forecast [Per Ref 1]	3% [page 8, line 9]	1% [page 8 lines 8-9]	2% net of CD & DG [Note page 9 in Fig 3]	
ratio	>1:1	2:1	1:1	

5. Reference 1, Table 1, page 10 indicates an increase in Demand forecast for "Kitchener and Cambridge" from 2012 to 2013 as 401 to 506 MW, which is greater than 25%. Also Reference 1, Figure 6, page 21 has a large discontinuity between 2012 and 2013 in the net Demand. This is not identified as a high growth area in the paragraph at line 11 on page 10. Please explain the basis for this specific increase.

6. Figure 3 shows no actual growth in demand from 2010 to 2012, a period which overlaps the 2010-2013. Has this "actual" been considered in the forecast for 2010-2023? What average annual growth is predicted then for the period 2012-2023?

7. Reference 1, section 5.1 "Need for Additional Supply Capacity", at page 13 identifies 3 need areas. Please clarify if each of the "needs" is met by the upgrading which is the subject of the current Leave to Construct application. If the current project does not on its own fulfil the need then indicate which additional projects will be required to meet that need.

8. Reference 1 Section 6.1page 17, line 19 indicates that 35% of the load growth will be off-set by Conservation. Please

   a) provide information on the confidence level or certainty with which this will be achieved
   b) indicate the consequences of reductions in load through conservation being under-achieved, say by 50%
   c) indicate the possibility for increasing the off-set through conservation by further expenditure.

Response

1. For regional planning, it is the responsibility of the LDCs to provide demand forecasts based on their knowledge of proposed developments and growth trends in their service area. The OPA's role in the load forecasting process is to provide a provincial perspective and facilitate the discussion between area LDCs. The sharing of LDC forecasts and demand growth information avoids the potential for the double counting of load.

   The OPA reviewed the KWCG area's long-term demand forecast. Based on economic forecasts for the Kitchener Census Metropolitan Area ("CMA") obtained from an independent economic forecast service, OPA's analysis shows that there are factors that support the demand growth trend. These factors include forecasted GDP, population and household growth.

   The KWCG working group, of which the OPA is a member, has adopted the KWCG area demand forecast.

2. For the purpose of the report, the period between 2004 and 2007 is used to describe the few years leading up to the 2008/2009 recession, i.e. the pre-economic downturn or pre-recession period.

Tab 4

POLLUTION PROBE INTERROGATORY 47

QUESTION

Please provide the OPA's forecast of electricity load growth (MW and MWh) for KWCG for each year from 2007 to 2020 inclusive.

RESPONSE

The OPA's forecast of electricity load growth in KWCG (MW) for 2007 to 2015 is shown in the Table below.

The OPA did not forecast MWh load growth.

KWCG Area Total Forecasted by OPA	2007	2008	2009	2010	2011	2012	2013	2014	2015
	MW	MW	MW	MW	MW	MW	MW	MW	MW
	1473	1518	1563	1610	1655	1705	1752	1800	1851

Source: OPA

POLLUTION PROBE INTERROGATORY 48

QUESTION

Please provide copies of all of the studies that support the OPA's electricity load growth forecasts for KWCG.

RESPONSE

The OPA's load growth (MW) forecast for KWCG is based on transformer station load growth forecast data provided by the area LDCs and the peak loads of directly connected industrial customers in the area estimated by the OPA based on their historical data. These forecast data are shown in the Table below.

Loads Forecasted by Cambridge & North Dumfries Hydro	2007	2008	2009	2010	2011	2012	2013	2014	2015
Station	MW	MW	MW	MW	MW	MW	MW	MW	MW
Cambridge #1	67.0	79.1	91.5	95.1	101.7	101.7	101.7	101.7	101.7
Cambridge #2	0.0	0.0	0.0	0.0	0.0	6.4	20.7	35.5	50.9
Galt TS J	84.6	84.6	84.6	84.6	88.0	91.7	91.7	91.7	91.7
Galt TS Y	84.6	84.6	84.6	84.6	88.0	91.7	91.7	91.7	91.7
Preston TS J	50.7	50.7	50.7	55.4	55.4	55.4	55.4	55.4	55.4
Preston TS Q	50.7	50.7	50.7	55.4	55.4	55.4	55.4	55.4	55.4
	337.6	349.7	362.1	375.1	388.5	402.3	416.6	431.4	446.8

Loads Forecasted by Guelph Hydro	2007	2008	2009	2010	2011	2012	2013	2014	2015
Station	MW	MW	MW	MW	MW	MW	MW	MW	MW
Campbell TS JQ	47.1	47.9	48.2	47.5	48.4	49.3	50.3	51.3	52.3
Campbell TS BY	47.1	47.9	48.2	47.5	48.4	49.3	50.3	51.3	52.3
Campbell TS ZE	47.1	47.9	48.2	47.5	48.4	49.3	50.3	51.3	52.3
Cedar TS T1/T2 BY	43.4	44.1	44.4	43.6	44.4	45.2	46.0	46.8	47.8
Cedar TS T1/T2 ID	28.1	30.9	32.8	34.3	37.0	39.6	42.4	45.1	48.1
Cedar TS T7/T8	40.8	40.7	40.4	39.0	39.0	39.1	39.2	39.2	39.3
Guelph Hanlon TS	33.0	35.6	39.0	50.0	51.5	53.0	54.6	56.3	58.0
	286.7	295.0	301.3	309.2	317.1	324.8	333.0	341.3	350.0

Loads Forecasted by Kitchener-Wilmot Hydro	2007	2008	2009	2010	2011	2012	2013	2014	2015
Station	MW	MW	MW	MW	MW	MW	MW	MW	MW
Detweiler TS	30.4	30.9	31.3	31.8	32.3	32.7	33.2	33.6	34.1
Kitchener #1	29.7	30.1	30.9	31.3	31.9	32.5	33.1	33.6	34.2
Kitchener #3 A	23.6	23.8	24.1	24.4	24.8	25.1	25.4	25.7	26.0
Kitchener #3 B1	16.2	16.6	16.9	17.2	17.6	17.9	18.2	18.5	18.8
Kitchener #3 B2	16.2	16.6	16.9	17.2	17.6	17.9	18.2	18.5	18.8
Kitchener #4 B1	35.7	36.4	37.2	37.9	38.5	39.2	39.8	40.4	41.1
Kitchener #4 B2	35.7	36.4	37.2	37.9	38.5	39.2	39.8	40.4	41.1
Kitchener #5 B1	36.8	37.5	38.3	39.0	39.8	40.5	41.3	42.1	42.8
Kitchener #5 B2	36.8	37.5	38.3	39.0	39.8	40.5	41.3	42.1	42.8
Kitchener #6 B1	36.7	37.4	38.0	38.7	39.3	40.0	40.7	41.3	42.0
Kitchener #6 B2	36.7	37.4	38.0	38.7	39.3	40.0	40.7	41.3	42.0
Kitchener #7	36.6	37.2	37.8	38.4	39.0	39.6	40.3	40.9	41.5
Kitchener #8	31.8	34.1	36.2	38.2	40.5	42.7	44.9	47.2	49.4
	402.7	411.7	421.0	429.6	438.6	447.5	456.6	465.4	474.5

Loads Forecasted by Waterloo North Hydro	2007	2008	2009	2010	2011	2012	2013	2014	2015
Station	MW	MW	MW	MW	MW	MW	MW	MW	MW
Elmira TS	31.1	29.8	30.1	30.4	30.0	30.0	30.0	30.0	30.0
Rush MTS	35.9	36.2	36.6	36.9	37.3	54.6	56.5	58.6	60.7
Scheifele T1/T2	60.9	59.6	60.2	60.8	61.5	59.3	59.9	60.5	61.1
Scheifele T3/T4 JH	49.0	47.5	48.0	48.5	49.0	46.3	46.8	47.2	47.7
Scheifele T3/T4 QT	50.1	47.8	49.5	42.2	43.7	47.3	47.8	48.3	48.8
Waterloo #3	42.9	62.4	74.1	67.8	74.6	73.4	69.9	76.9	75.4
Waterloo #4	0.0	0.0	0.0	27.3	30.2	32.7	46.3	50.1	63.3
	269.7	283.3	298.5	314.0	326.3	343.7	357.2	371.6	387.0

Loads Forecasted by Hydro One	2007	2008	2009	2010	2011	2012	2013	2014	2015
Station	MW	MW	MW	MW	MW	MW	MW	MW	MW
Fergus TS	88.0	89.6	91.1	92.7	94.2	95.8	97.3	98.9	100.5
Puslinch DS B1	11.0	11.1	11.2	11.4	11.5	11.7	11.8	11.9	12.1
Puslinch DS B2	11.0	11.1	11.2	11.4	11.5	11.7	11.8	11.9	12.1
Wolverton DS T1	9.7	9.8	9.8	10.0	10.1	10.2	10.3	10.4	10.4
Wolverton DS T2	9.7	9.8	9.8	10.0	10.1	10.2	10.3	10.4	10.4
	129.3	131.3	133.1	135.4	137.3	139.4	141.3	143.4	145.4

Loads Forecasted by OPA	2007	2008	2009	2010	2011	2012	2013	2014	2015
Station	MW	MW	MW	MW	MW	MW	MW	MW	MW
Cambridge CTS	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
Cambridge CTS	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
Cambridge CTS	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Guelph CTS1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Guelph CTS2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0

KWCG Area Total Forecasted by OPA	2007	2008	2009	2010	2011	2012	2013	2014	2015
	MW	MW	MW	MW	MW	MW	MW	MW	MW
	1473	1518	1563	1610	1655	1705	1752	1800	1851

Notes:
Loads at several transformer stations include supply to downstream embedded Local Distribution Companies.

Cambridge & North Dumfries Hydro
- Preston TS includes supply to Waterloo

Kitchener-Wilmot Hydro
- Detweiler TS includes supply to Wellesley DS

Waterloo North Hydro
- Elmira TS includes Hydro One Distribution load (approx 3 MW)

Hydro One
- Wolverton DS includes CNDH load (approx 7 MW)
- Fergus TS includes supply to Waterloo

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Tab 5

Kitchener-Waterloo-Cambridge-Guelph (KWCG)

Integrated Regional Resource Planning Report (IRRP) 2013

- DRAFT -

Kitchener-Waterloo-Cambridge Guelph
(KWCG) Working Group

Contents

1 Executive Summary

Near- and medium-term supply capacity and other reliability needs have been identified in the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area. Specifically, three of the KWCG subsystems (the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems) are expected to exceed their supply capacity within the next ten years. Additionally, two subsystems (the Kitchener and Cambridge, and Waterloo-Guelph subsystems) do not comply with prescribed service interruption criteria. To address these needs, the OPA recommends an integrated package composed of 1) conservation, 2) distributed generation resources, and 3) transmission reinforcements in the KWCG area.

Conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the KWCG area. Together, these resources are expected to off-set more than 35% of the forecast load growth in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems between 2010 and 2023. By 2023 achievement from provincial conservation efforts within these subsystems is expected to reduce peak demand by over 130 MW at an estimated delivery cost of $65 million (based on an allocation of forecast expenditures for provincial conservation programs). Over the same time period, approximately 16 MW of distributed generation facilities are expected to come into service in South-Central Guelph, Kitchener-Guelph and Cambridge subsystems, representing a capital investment of approximately $70 million.

The transmission reinforcements recommended in the near-term include the Guelph Area Transmission Refurbishment (GATR) project, as well as a project to install a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support. The GATR project includes the installation of two new 230/115 kV autotransformers, four 115 kV circuit breakers, and the advancement of the relocation of the existing Hydro One Distribution Operating Centre at Cedar TS (approximately $52 million), rebuilding approximately 5 km of existing 115 kV double circuit transmission line between Campbell TS and CGE junction in Guelph to a 230 kV double circuit configuration (approximately $27.5 million), and installing two new 230 kV circuit breakers at a new station (Inverhaugh SS) at Guelph North Junction in Centre Wellington (approximately $16 million). Project completion for the GATR project is expected by the end of

2015. The installation of the Preston TS autotransformer facilities is a separate project that will be coordinated with completion of the GATR project and it is estimated to cost approximately $15 million to $25 million. Together these facilities will meet the near- and medium-term needs of the KWCG area, and substantially meet the KWCG area needs over the longer-term.

In anticipation for longer term growth in this area, the Working Group indicates the need to investigate opportunities for further cost effective conservation and distributed generation, as well as transmission investments. Monitoring of growth in electricity demand and the achievement of conservation and distributed generation in the KWCG area, will also be key components of on-going electricity planning in the region. The needs and the options in the longer term will be reviewed in subsequent KWCG regional planning study.

2 Introduction

The Kitchener-Waterloo-Cambridge-Guelph (KWCG) area is one of the larger population and electrical demand centres in Ontario. The existing electrical facilities in the area serve a diverse range of commercial, industrial and residential customers. The demand for electricity in the area is expected to grow substantially over the next 20 years, driven by population growth and strong economic activity. Much of the existing electricity infrastructure in the area is reaching capacity and therefore plans for future conservation, distributed generation and electricity infrastructure expansion and investment need to be developed and, as necessary, implemented in order to maintain a reliable supply of electricity to the area.

Planning to meet the electrical needs of a large area or region is done through a regional planning process that considers the multi-faceted needs of the region and seeks to address them through an integrated range of solutions. The plan takes into consideration, among other things, the electricity requirements, anticipated growth and existing electricity infrastructure. The outcome of the regional planning process is an integrated plan to guide electricity infrastructure, resource development and procurement decisions for the region. The plan's recommendations are typically organized into three timeframes: near-term (first 5 years), medium-term (5-10 years out) and longer-term (10-20 years out or longer). Solutions to address near-term and medium-term needs are presented as action items for immediate or early deployment, while solutions to address potential longer-term needs are identified along with the conditions that would trigger their implementation and the key development work required to maintain their viability. In this sense, regional plans are not static documents, but rather dynamic processes which evolve and are adapted as circumstances and conditions change.

2.1 Purpose and Scope of the Plan

The purpose of this report is to present the key findings and recommendations identified through the Integrated Regional Resource Planning ("IRRP") process for the KWCG area. In 2010, a working group (the "KWCG Working Group", or the "Working Group"), which comprised of members from the Ontario Power Authority (OPA), Hydro One Networks Inc. (Hydro One), the Independent Electricity System Operator (IESO) and local distribution companies (LDCs) in the KWCG area, was established to assess the reliability needs of the KWCG area, and to develop an integrated plan to address these needs. This regional planning process carried out by the KWCG Working Group is consistent with the IRRP process described by the Planning Process Working Group's ("PPWG") Report to the OEB as part of the Renewed Regulatory Framework for Electricity ("RRFE").

In the course of developing a regional plan for the KWCG area, the Working Group identified certain near- and medium-term supply capacity and other reliability needs to be addressed. The Working Group identified that these near-term needs were best met through a combination of conservation, local generation and transmission. Accordingly, a near-term transmission project was advanced to the transmitter led Section 92 and Environmental Assessment processes. This approach is consistent with the PPWG report to the Board that in certain cases, a 'wires' solution for a near -term transmission/distribution need may be advanced outside of the IRRP process.

This report, which covers a 20 -year planning horizon (2010-2030), will present and explain the near-, medium-, and long-term needs in the KWCG area, the preferred solutions for the near-and medium-term, and potential options for needs that may arise in the long-term. Consistent with IRRP process, an implementation and monitoring plan has been developed as part of the report to facilitate the implementation of the Working Group's recommendations. On a regular basis, the Working Group will review the needs of the KWCG area and updated this report as necessary.

B.2 LDCs Gross Demand Forecast and Methodologies

As part of the KWCG regional planning study, the LDCs in the KWCG area, consisting of Cambridge and North Dumfries Hydro, Guelph Hydro Electric Systems Inc., Hydro One Distribution, Kitchener-Wilmot Hydro Inc. and Waterloo North Hydro Inc. provided the gross demand forecast for their service area over the a 20-year planning horizon (2010-2030) for median weather conditions. These forecasts were developed under coincident, median-weather assumptions, and adjusted to extreme weather conditions by the OPA. While the 2010 coincident summer peak for the KWCG area was initially used to establish the reference demand forecast and updates were made to the reference case after review of the 2012 information

Table B2-1 is the gross demand forecast for the KWCG area. The detailed documentation related to the methods and assumptions used to develop the gross demand forecast can found in this section.

Table B2-1: KWCG Reference LDC Gross Demand Forecast

	2010 Actual	2011 Actual	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cambridge & North Dumfries Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Cambridge #1	78.2	70.4	74.8	62.8	74.7	86.3	97.9	109.9	109.9	111.7	112.4	113.0	113.5	114.0	114.3	114.7	114.9	115.2	115.5	115.6	115.9
Galt TS	135.4	137.6	133.9	170.2	173.8	176.7	179.5	182.2	184.5	186.7	188.4	190.1	191.4	192.7	193.8	194.7	195.5	196.2	197.1	197.6	198.2
Preston TS	81.8	102.5	75.8	119.4	121.8	123.6	125.4	127.1	128.6	130.0	131.0	132.1	133.0	133.8	134.4	135.0	135.6	136.0	136.5	136.8	137.3
Cambridge #2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.3	22.8	31.8	42.6	55.5	68.8	82.6	96.8	101.7	101.7	101.7	101.7	101.7
Cambridge #3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	24.5	34.7	50.4	66.5
Guelph Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Campbell TS	142.8	135.4	143.4	147.0	147.7	148.1	149.9	151.6	153.2	154.9	156.7	160.6	164.8	169.0	173.3	177.7	181.4	185.3	189.1	193.1	197.2
Cedar TS T1/T2	74.6	73.2	64.9	78.2	78.8	79.1	80.4	81.6	82.7	84.0	85.2	87.1	89.1	91.1	93.1	95.2	95.8	96.3	96.9	97.5	98.1
Cedar TS T7/T8	27.3		45.1	33.5	34.0	34.3	34.7	35.1	35.5	36.0	36.4	36.8	37.3	37.7	38.2	38.7	39.2	39.7	40.2	40.7	41.2
Hanlon TS	39.4	33.8	28.1	32.1	32.5	32.8	33.6	34.4	35.1	36.0	36.8	37.0	37.3	37.6	37.9	38.2	38.3	38.3	38.4	38.4	38.4
Arlen MTS	0.0	0.0	5.8	24.7	31.3	35.1	39.1	42.7	46.2	50.1	54.0	55.6	57.3	59.0	60.8	62.6	67.0	71.6	76.3	81.1	86.0
Kitchener-Wilmot Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Detweiler TS	29.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #1	25.5	33.9	32.4	28.7	29.3	30.9	31.6	32.2	32.9	33.6	34.2	34.9	35.6	36.3	36.9	37.6	38.3	38.9	39.6	40.3	40.9
Kitchener #3	41.9	46.2	54.0	54.0	55.0	57.1	67.9	69.1	70.4	71.6	82.4	83.6	84.8	86.1	87.3	88.6	89.8	91.0	92.3	93.5	94.7
Kitchener #4	55.8	54.8	67.8	68.5	69.1	70.2	70.9	71.5	72.2	72.9	73.6	74.2	74.9	75.6	76.2	76.9	77.6	78.2	78.9	79.6	80.2
Kitchener #5	68.9	78.2	77.1	74.8	75.4	76.5	76.9	77.4	77.8	78.2	78.6	79.0	79.4	86.2	86.6	87.0	87.4	87.8	88.2	88.6	89.0
Kitchener #6	75.3	77.4	61.3	72.9	74.0	75.0	75.4	75.8	76.2	76.6	77.0	77.4	77.8	78.2	78.6	79.0	79.5	79.9	80.3	80.7	81.1
Kitchener #7	39.7	46.0	39.9	44.7	45.5	46.9	47.3	47.7	48.1	48.5	48.9	49.3	49.7	43.8	44.2	44.6	45.0	45.4	45.8	46.2	46.6
Kitchener #8	31.3	14.3	14.6	41.2	43.3	45.4	38.8	41.8	44.8	47.8	41.2	44.2	47.2	50.2	53.1	56.1	59.1	62.1	65.1	68.0	71.0
Kitchener #9	0.0	28.7	33.3	33.5	34.1	34.6	35.1	35.6	36.1	36.6	37.1	37.6	38.1	38.6	39.1	39.6	40.1	40.6	41.1	41.6	42.1
Waterloo North Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Elmira TS	32.4	32.9	32.5	32.9	33.9	34.9	29.5	30.3	31.2	32.5	33.8	35.1	36.6	38.0	39.5	41.1	42.8	28.4	29.6	30.8	32.0
Rush MTS	40.7	39.9	44.7	52.7	54.2	55.9	65.6	67.5	69.5	70.9	72.4	73.8	57.2	58.4	66.6	67.9	69.3	74.6	76.1	69.7	71.0
Scheifele TS	143.9	154.0	141.2	163.4	168.5	173.8	171.2	176.6	156.5	159.6	162.8	166.0	169.4	172.7	169.2	172.6	176.0	175.5	164.0	163.3	166.6
Waterloo #3	54.4	49.1	53.9	59.3	61.6	64.0	72.9	75.8	78.7	83.3	68.9	62.3	81.6	83.2	84.9	86.6	88.3	70.0	71.4	72.9	74.3
Snider TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.5	36.7	54.2	64.4	67.0	69.6	72.4	75.3	83.3	86.7	74.1	77.1	80.2
Bradley TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.1	67.8	81.2	82.8
Hydro One Distribution	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Fergus TS	95.4	94.2	86.7	110.0	111.0	112.0	113.0	114.0	114.9	116.0	117.0	118.0	119.0	120.0	121.0	122.1	123.5	125.0	126.5	128.1	129.6
Puslinch DS	25.2	25.0	26.5	33.2	33.9	34.6	35.4	36.1	36.8	37.5	38.3	39.0	39.7	40.5	41.2	41.9	43.2	44.1	44.9	45.8	46.8
Wolverton DS	18.9	18.6	18.3	20.5	20.7	20.9	21.2	21.4	21.6	21.9	22.1	22.3	22.5	22.8	23.0	23.3	23.6	23.9	24.2	24.5	24.8
OPA	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Total CTS	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
Area Total (Gross)	1,405	1,393	1,403	1,605	1,651	1,696	1,740	1,784	1,834	1,883	1,922	1,963	2,007	2,051	2,095	2,141	2,192	2,240	2,283	2,332	2,381

Cambridge and North Dumfries Hydro

The load forecast supplied by Cambridge and North Dumfries Hydro (CNDH) covers the electrical loads in the City of Cambridge and the Township of North Dumfries excluding one large industrial load that is directly connected to the 230kV transmission system.

Cambridge and North Dumfries Hydro developed the reference level forecast growth rate by looking at historical actual system peak load data for each year between 1978 and 2012 then averaging the annual percentage change in summer peak load. The long term annual percentage change was approximately 3%. Therefore, a 3% annual growth rate was used for years 2012 through 2030. Cambridge and North Dumfries Hydro experienced negative peak summer load growth for four consecutive years prior to 2010 due to a combination of cooler summer weather and a poor economy. Since 1978, Cambridge and North Dumfries Hydro had never experienced more than two consecutive years of negative peak summer load growth. Growth reversed in 2012 with summer peak load falling 5% from 2011; this reflected a slow economy, especially on the industrial side as well as the impact of conservation and generation. CNDH noted that the KWCG and provincial peak occurred in July (for 2012) when one of their large industrial customers was on a week summer shutdown. If the large industrial customer had been in production, then CNDH's summer 2012 peak would have fallen only 2.3% from 2011. For the forecast starting point, CNDH assumed that the large industrial customer was in production during 2012 since it cannot be assumed that large industrial customer will always be out of production during the hottest, most humid weather conditions.

The timing for new stations was determined when the forecasted load (with a 6% adjustment for extreme weather) at existing stations exceeded the ten day summer LTR.

The methodology for determining when new stations are required under the high growth scenario remained the same. The timing moved up because of the higher growth rate.

Guelph Hydro Electric Systems Inc.

Introduction

Guelph Hydro Electric Systems Inc. (GHESI) owns and operates the electricity distribution system in its licensed service area in the City of Guelph and the Village of Rockwood serving approximately 50,000 Residential, Commercial and Industrial customers.

GHESI is supplied through the Hydro One transmission system at primary voltages of 115kV and 230kV. Electricity is then distributed through Hydro One owned transformer stations, Campbell TS, Cedar and Hanlon TS as well as a GHESI owned transformer station to be in-service in 2011.

Methodology used for developing the reference level load forecast

GHESI's methodology for developing the reference case load forecast consisted of a number of elements including historical loading trends, local knowledge of planned development and City of Guelph development planning information. Planning information from the City of Guelph was the starting point to formulate a maximum development forecast in order to set the parameters of the long range load forecast for our service territory given the 20 year study period. Using this information along with 20+years of historic peak loading information, local knowledge and information regarding transformer stations limitations within our service territory, the reference level load forecast was created for each delivery point location.

GHESI has experienced an on average system growth rate of approximately 1.95% over the past 20 years. The coincident peak of 284.1 MW in 2010 was used to establish the reference case load forecast for the study period until 2030; updates were made to the reference case after review of the 2012 load information. GHESI reached an all-time system peak of 293.2 MW in July 2011. For the reference case load forecast, a growth rate of approximate 2.4% is expected during the study period. In order to support the load growth for the reference case load forecast, upgrades at Campbell TS in 2015 as well as an upgrade to stations in the south end of Guelph are expected near 2025.

Methodology used for developing the high level load forecast

The same methodology was used to create the high level forecast. The forecasted growth rate for the high level forecast was calculated to be approximately 1.5 times that of the reference case. Under the high growth scenario, a load growth rate of 3.4% is expected during the study period.

Kitchener-Wilmot Hydro Inc.

Introduction

Kitchener-Wilmot Hydro owns and operates the electricity distribution system in its licensed service area in the City of Kitchener and the Township of Wilmot, serving approximately 85,800 Residential, General Service, Large Use, Street Light, Unmetered Scattered Load and Embedded Distributor Customers. Kitchener-Wilmot Hydro is supplied through the Hydro One transmission system at primary voltages of 115kV and 230kV. Electricity is then distributed through Kitchener-Wilmot Hydro's service area by 8 Municipal Transformer Stations and 7 Municipal Distribution Stations.

Methodology used for developing the reference level forecast growth rate

In developing the reference forecast, Kitchener-Wilmot Hydro uses Trend Analysis (trending) to extend past growth rates of electricity demand into the future. A linear-trend method that uses the historical data of demand growth to forecast future growth has been applied. The coincident peak data (July 7th, 2010 at hour 16) has been used as the base for load forecast. A long-term 6.86MW annual demand growth from 2011 to 2030 has been projected, with 60% annual load growth (4.12MW) attributable to the residential customers and 40% (2.74MW) attributable to the commercial and industrial customers. The annual demand growth has been allocated to each transformer station based on the municipal development plan, available vacant lands and other local knowledge.

This annual demand growth rate covers both load additions of the new customers and load maturation of the existing customers. The projected long-term annual demand growth is derived from the average load growth for the observed summer peaks from 1993 to 2006. The more recent data of 2007-2009 were biased and ignored due to loss of the largest load customer and the economic downturn after credit crisis.

In order to reflect some one-time new large load additions that are not covered by the historical trend (like the proposed regional LRT stations and a proposed solar panel fabrication facility), additional loads (6.5MW in total between 2011-2015) have been added to the 5 year short-term forecast on top of the long-term annual demand growth rate. That is, an average annual demand growth of 8.16MW is projected for the period 2011 to 2015.

Reference scenario load forecast (chart form)

See Table B2-1 below.

Based on the reference level forecast, expansion of Kitchener #5 TS from 83.3MVA to 100MVA is required in 2020. And expansion of Kitchener #8 TS from 50MVA to 100MVA is required in 2023.

Methodology used for developing the higher level forecast growth rate

The linear-trend method has also been applied to forecast the high growth scenario.

Different from the reference forecast, the projected long-term annual demand growth is derived from the average load growth for the observed summer peaks from 1997 to 2003, when relatively higher load growth was experienced.

A long-term 10.04MW annual demand growth from 2011 to 2030 has been projected, with 60% annual load growth (6.02MW) attributable to the residential customers and 40% (4.02MW) attributable to the commercial and industrial customers.

In order to reflect some one-time new large load additions that are not covered by the historical trend, higher additional loads (12.5MW in total between 2011- 2015) have been added to the 5 year short-term forecast on top of the long-term annual demand growth rate. That is, an average annual demand growth of 12.54MW is projected for the period 2011 to 2015.

High scenario forecast (chart form)

See Table B2-2 below.

Based on the high scenario forecast, expansion of Kitchener #8 TS from 50MVA to 100MVA is required in 2017, expansion of Kitchener #7 TS from 50MVA to 100MVA is required in 2022, and expansion of Kitchener #5 TS from 83.3MVA to 100MVA is required in 2025.

Table B2-2: Kitchener-Wilmot Hydro Inc. Reference Scenario Forecast

			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Kitchener-Wilmot Hydro	**Station Limits MVA**	**Station Limits MW**	**Base MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
Detweiler TS			34.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #9	**83.3**	**79.1**	0.0	30.5	31.0	31.6	32.1	32.7	33.1	33.6	34.1	34.5	35.0	35.5	35.9	36.4	36.9	37.3	37.8	38.3	38.7	39.2	39.7
Kitchener #1	**50.0**	**45.0**	25.4	26.0	26.5	27.1	27.6	29.2	29.8	30.4	31.0	31.7	32.3	32.9	33.6	34.2	34.8	35.5	36.1	36.7	37.4	38.0	38.6
Kitchener #3	**100.0**	**95.0**	40.6	43.0	50.0	51.0	51.9	53.9	64.0	65.2	66.4	67.5	77.7	78.9	80.0	81.2	82.4	83.5	84.7	85.9	87.0	88.2	89.4
Load Transfer									9.0				9.0										
Kitchener #4	**83.3**	**79.1**	57.0	57.5	64.1	64.6	65.2	66.2	66.9	67.5	68.1	68.8	69.4	70.0	70.7	71.3	71.9	72.5	73.2	73.8	74.4	75.1	75.7
Load Transfer					6.0																		
Kitchener #5	**83.3 (100 in 2020)**	**79.1 (95 in 2020)**	69.0	69.5	70.1	70.6	71.2	72.2	72.6	73.0	73.4		74.1	74.5		81.3	81.7	82.0	82.4	82.8	83.2	83.6	84.0
Load Transfer																6.0							
Kitchener #6*	**83.3**	79.1	77.9	78.9	67.9	68.8	69.8	70.7	71.1	71.5	71.9	72.3	72.7	73.0	73.4	73.8		74.6	75.0	75.3	75.7	76.1	76.5
Load Transfer					-12.0																		
Kitchener #7*	**50.0**	47.5	39.9	40.7	41.4	42.2	42.9	44.2	44.6	45.0	45.4		46.1	46.5	46.9	41.3	41.7	42.0	42.4	42.8	43.2	43.6	44.0
Load Transfer																-6.0							
Kitchener #8*	**50 (100 in 2023)**	47.5 (95 in 2023)	31.4	33.4	35.3	38.8	40.8	42.8	36.6	39.4	42.3												
Load Transfer																							

Notes:

1. Based Year: 2010 Summer peak (371MW, coincident peaks at 1600 on July 7th 2010 based on NV90 data - slightly lower than IESO billing data (372MW)
2. Wellesley DS (owned by Waterloo North) load included; DG (Waterloo LFG power plant) coincident peak considered (at 1600 on July 7th 2010).
3. Linear Load Growth Rate: 6.86MW/year based on historical data (1993-2006), data 2007-2009 ignored (loss of big customers, ecnomic downturn)
4. Total load growth be projected to each TS based on previous experience;
5. Large one-time load been added on top for 5-year short-term
6. 12 MW Load at Kitchener #6 TS to be transferred to #3 and #4 TS in 2012, 6 MW to #3TS, 6MW to #4 TS
7. 9 MW Load at Kitchener #8 TS to be transferred to #3 TS in 2016
8. #5 TS to be expanded to 100MVA in 2020.
9. 9 MW Load at Kitchener #8 TS to be transferred to #3 TS in 2020
10. #8 TS to be expanded to 100MVA in 2023
11. 6 MW Load at Kitchener #7 TS to be transferred to #5 TS in 2023
11. Load from Detweller TS DESN to be transferred to #9 TS by end of 2010, Detweiler TS DESN to be decommissioned after

B2-3: Kitchener-Wilmot Hydro Inc. High Scenario Forecast

			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Kitchener-Wilmot Hydro	**Station Limits MVA**	**Station Limits MW**	**Base MW**	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Detweiler TS			**34.8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #9	**83.3**	79.1	**0.0**	30.7	31.5	32.3	33.1	33.9	34.6	35.3	35.9	36.6	37.3	38.0	38.7	39.4	40.0	40.7	41.4	42.1	42.8	43.5	44.1
Kitchener #1	**50.0**	45.0	**25.4**	26.2	27.0	27.8	28.6	30.4	31.3	32.3	33.2	34.1	35.0	36.0	36.9	37.8	38.7	39.7	40.6	41.5	42.4	43.4	44.3
Kitchener #3	**100.0**	95.0	**40.6**	43.5	50.9	52.3	53.7	62.1	75.8	77.5	79.2	80.9	82.6	84.3	74.1	75.8	77.5	79.2	80.9	82.6	84.3	86.0	87.7
Load Transfer					6.0				12.0						-12.0								
Kitchener #4	**83.3**	79.1	**57.0**	57.8	64.6	65.4	66.2	67.5	68.4	69.4	70.3	71.2	72.1	73.0	74.0	74.9	75.8	76.7	77.7	78.6	76.5	77.4	78.4
Load Transfer					6.0																-3.0		
Kitchener #5	**83.3 (100 in 2025)**	79.1 (95 in 2025)	**69.0**	69.8	70.6	71.4	72.2	73.5	74.0	74.6	75.2	75.7	76.3	76.8	77.4	78.0	78.5	79.1	79.7	80.2	83.8	84.3	84.9
Load Transfer																					3.0		
Kitchener #6*	**83.3**	79.1	**77.9**	79.3	68.7	70.1	71.6	73.0	73.5	74.1	74.6	75.2	75.8	76.3	76.9	77.5	78.0	78.6	79.1	79.7	77.3	77.8	78.4
Load Transfer					-12.0																-3.0		
Kitchener #7*	**50 (100 in 2022)**	47.5 (95 in 2022)	**39.9**	41.0	42.1	43.2	44.3	46.0	46.5	47.1	47.6	48.2	48.8	49.3	61.9	62.4	63.0	63.6	64.1	64.7	71.3	71.8	72.4
Load Transfer															12.0						6.0		
Kitchener #8*	**50 (100 in 2017)**	47.5 (95 in 2017)	**31.4**	34.3	37.2	41.6	44.5	47.4	39.5	43.7	47.8	51.9	56.0	60.1	64.2	68.4	72.5	76.6	80.7	84.8	85.9	90.1	94.2
Load Transfer									-12.0												-3.0		

Notes: (High-Growth Scenario)

1. 1. Based Year: 2010 Summer peak (371MW, coincident peaks at 1600 on July 7th 2010 based on NV90 data - slightly lower than IESO billing data (372MW).
2. 2. Wellesley DS load included.
3. 3. Linear Load Growth Rate: 10.04MW/year based on high-growth historical data (1997-2003).
4. 4. Total load growth be projected to each TS based on local knowledge.
5. 5. Large one-time load been added on top for 5-year short-term.
6. 6. 12 MW Load at Kitchener #6 TS to be transferred to #3 and #4 TS in 2012, 6 MW to #3TS, 6MW to #4 TS.
7. 7. 12 MW Load at Kitchener #8 TS to be transferred to #3 TS in 2016.
8. 8. 12 MW Load at Kitchener #3 TS to be transferred to #7 TS in 2022.
9. 9. 6MW Load to be transferred to #7 TS in 2028, 3MW from #8TS, 3MW from #5TS.
10. 10. 6MW Load at Kitchener #4TS to be transferred to #5TS, and 3MW from #6 TS to #4 TS in 2028.
11. 11. #8 TS to be expanded to 100MVA in 2017.
12. 12. #7 TS to be expanded to 100MVA in 2022.
13. 13. #5 TS to be expanded to 100MVA in 2025.
14. 14. Load from Detweller TS DESN to be transferred to #9 TS by end of 2010, Detweiler TS DESN to be decommissioned after.
15. Dependable Capacity of existing DGs during summer peak has been included in the forecast.

Waterloo North Hydro Inc.

Waterloo North Hydro owns and operates the electricity distribution system in its licensed service area in the City of Waterloo and the Townships of Woolwich and Wellesley, serving approximately 52,000 customers. WNH's customer base is comprised of primarily residential and commercial/institutional loads. WNH's largest loads include universities, high-tech companies and financial institutions. A small component of the WNH load base comes from industrial/manufacturing sector.

Waterloo North Hydro is supplied through the Hydro One transmission system at primary voltages of 115kV and 230kV. Electricity is then distributed through Waterloo North Hydro's service area by 3 Municipal Transformer Stations and 16 Municipal Distribution Stations. The WNH distribution system is divided into the 13.8kV system servicing the core of the City of Waterloo and the 27.6kV system servicing the outskirts of the City of Waterloo as well as the township areas.

The system supply study is performed by WNH management, based in part on information gathered from regional and municipal authorities and development community stakeholders to evaluate the long-term (10+ years) supply needs of WNH and ensure system capacity to meet future growth. The study considers historical growth trends, forecasts and considers such factors as regional and provincial objectives and initiatives, regional/municipal development initiatives and plans and potential for development; the study also considers potential changes to development and growth rates, forecasts of electrical demand and future population, all of which provide a basis for determining transmission and transformation requirements at major supply facilities to ensure system capacity availability.

Methodology used for developing the reference case load forecast

In developing the load forecasts, Waterloo North Hydro gathers development projection data from the local municipalities and developers to determine areas and timing of planned development as well as land uses. This information is then converted to electrical demand quantities and analyzed against past trends. A forecast is developed for each transformer station that is consistent with load growth potential within the service area of that station and overall system growth.

WNH uses geometric growth trend method (trending) to extend past growth rates of electricity demand into the future. WNH has been trending the system peak data for the past 18 years and has analyzed this data with respect to typical rolling 3 year, 5 year, and 10 year growth rates. WNH service territory has consistently experienced rolling 10 year growth rates above 3%, sometimes reaching almost 4% (compared to the provincial average of 1%). Due to the fabric of the WNH customer base, the system peak for WNH is affected to a higher degree by weather and local development conditions and to a lesser degree by provincial or global factors. WNH's system peak has a tendency to rebound from recessions faster than in other Ontario jurisdictions. The historical load data from 1992 to 2010 includes 2 recessions as well as a mixture of hot and cool summers, and was therefore considered an appropriate blend to be used as a basis for future trending. The rolling geometric growth rate since 1992 is 3.0%. The latest 10 year geometric growth rate is 3.3%.

The coincident peak data (July 7th, 2010 at hour 16) has been used as the base for load forecast. A load forecast has been prepared such that by the end of the study period in 2030, the geometric growth rate is consistent with past trends and long term development potential. Year-to-year load projections were adjusted in terms of timing and location (station) based on knowledge with respect to local development conditions. This resulted in an overall geometric system growth rate of 3.3% up to year 2018 and 2.5% thereafter. This represents an addition of, on average, 10.3 MW of load per year over the study period. To support this level of load growth, multiple load transfers between stations plus 2 new Transformer Stations will be required, both connected to the D6V/D7V transmission lines: one in 2018 and one in 2027.

Methodology used for developing the high growth load forecast

The rolling geometric growth trend method has also been applied to forecast the high growth scenario. The projected long-term annual demand growth is derived from the 5 year rolling geometric growth rates observed a number of times in the past at over 4.5%. Such growth rates could very realistically be sustained if new types of loads developed such as high-tech data centres, Light Rail Transit supply stations, greater re-intensification of downtown core, or more aggressive development of new greenfield growth areas.

The high growth rate forecast was prepared using similar methods as well as timing and location adjustment factors as the reference case. This resulted in an overall geometric system growth rate of 4.25% up to year 2018 and 3.25% thereafter. This represents an addition of, on average, 14.9 MW of load per year over the study period. To support this level of load growth, multiple load transfers between stations plus 3 new Transformer Stations will be required, all connected to the D6V/D7V transmission lines: one in 2017, one in 2020, and one in 2029. In addition, upgrade of facilities from 13.8kV to 27.6kV will also be required: at Scheifele "A" transformer station in 2025 and at a major load customer in 2026.

Tab 6

Environmental Defence INTERROGATORY #1 List 1

Reference: Ontario Power Authority, *Kitchener-Waterloo-Cambridge-Guelph Area*, March, 2013 (the "OPA KWCG Report"), Ex. B, Tab 1, Schedule 5, Page 10, Table 1

Interrogatory

Please provide the actual total peak demand (MW) for electricity in the KWCG area for each year from 2000 to 2012 inclusive. Please also break out these demands according to the six sub-categories shown in Table 1.

Please also provide the actual annual MWh demand for electricity in the KWCG area for each year from 2000 to 2012 inclusive. Please also break out these demands according to the six sub-categories shown in Table 1.

Response

Historical annual total peak demand (MW) and energy (MWh) is available from 2004 to 2011. Please refer to Attachment 1 to this exhibit.

Peak Demand (MW)							
Year	South-Central Guelph	Kitchener-Guelph	Waterloo-Guelph	Cambridge	Kitchener and Cambridge	Other Stations in the KWCG Area	Total
2004	103	227	362	320	376	180	1,248
2005	116	236	422	349	449	187	1,410
2006	116	231	425	349	450	188	1,410
2007	116	233	412	344	442	183	1,386
2008	114	224	397	333	413	181	1,329
2009	104	226	387	327	409	147	1,274
2010*	107	233	430	335	442	184	1,396
2011	117	262	433	351	442	190	1,444
2012	112	254	425	325	401	211	1,403

*LDC metered coincident peak data was used in GATR evidence as IESO hourly data was not available.

Annual Demand (GWh)							
Year	South-Central Guelph	Kitchener-Guelph	Waterloo-Guelph	Cambridge	Kitchener and Cambridge	Other Stations in the KWCG Area	Total
2004	613	1,413	2,263	1,846	2,209	1,019	7,517
2005	631	1,363	2,389	2,013	2,482	1,025	7,889
2006	629	1,310	2,351	1,973	2,435	982	7,707
2007	655	1,339	2,337	1,983	2,455	986	7,772
2008	648	1,306	2,328	1,932	2,409	949	7,639
2009	614	1,252	2,220	1,809	2,292	879	7,258
2010	648	1,266	2,406	1,860	2,353	950	7,623
2011	654	1,323	2,415	1,872	2,280	994	7,666
2012	679	1,309	2,430	1,866	2,234	1,035	7,688

Tab 7

Environmental Defence INTERROGATORY #6 List 1

Reference: Ex. B, Tab 1, Schedule 5, Page 10, Table 1

Interrogatory

Please provide the OPA's estimate of the peak demand (MW) for electricity for the KWCG area and each of the six subsystems shown in Table 1 for each year from 2013 to 2026 inclusive: a) before conservation and demand management (CDM) and distributed generation (DG); b) net of CDM; and c) net of CDM and DG.

Response

Please refer to Attachment 1 to this exhibit.

Gross (MW)														
Subsystem	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
South-Central Guelph 115 kV	131	139	144	150	155	161	167	172	175	179	182	185	188	195
Kitchener-Guelph 115 kV	272	275	281	294	297	301	304	317	321	326	330	334	339	341
Waterloo-Guelph 230 kV	480	489	498	507	518	535	550	560	571	602	615	621	634	653
Cambridge 230 kV	392	410	427	443	459	475	491	504	518	534	549	565	581	597
Kitchener and Cambridge 230 kV	506	528	547	557	577	596	616	622	639	659	678	697	716	736
Other Stations in the KWCG Area	216	221	227	233	237	242	247	251	256	242	247	258	263	268
Total KWCG Area	1605	1651	1696	1740	1784	1834	1883	1922	1963	2007	2051	2095	2141	2192

Net of CDM (MW)														
Subsystem	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
South-Central Guelph 115 kV	124	130	133	137	141	145	149	154	156	158	161	163	166	172
Kitchener-Guelph 115 kV	258	256	256	265	264	264	264	275	276	278	281	283	286	288
Waterloo-Guelph 230 kV	457	458	460	463	467	478	489	493	501	528	538	542	553	569
Cambridge 230 kV	374	385	395	406	417	428	440	449	460	473	486	500	514	528
Kitchener and Cambridge 230 kV	482	494	506	509	521	535	548	550	564	579	595	611	628	646
Other Stations in the KWCG Area	205	205	207	210	211	213	215	217	220	205	208	218	221	225
Total KWCG Area	1526	1542	1563	1584	1605	1635	1666	1690	1717	1749	1782	1818	1855	1900

Net of CDM and DG (MW)														
Subsystem	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
South-Central Guelph 115 kV	123	129	132	136	140	144	148	153	155	157	159	162	165	170
Kitchener-Guelph 115 kV	257	254	255	264	263	263	263	274	275	277	280	282	285	287
Waterloo-Guelph 230 kV	448	448	450	451	455	466	477	482	489	516	526	530	541	557
Cambridge 230 kV	372	383	393	404	415	426	438	447	458	471	484	498	512	526
Kitchener and Cambridge 230 kV	480	491	504	506	519	532	546	548	561	576	592	609	626	643
Other Stations in the KWCG Area	199	199	199	201	203	205	206	209	212	196	199	210	213	217
Total KWCG Area	1508	1522	1540	1559	1580	1610	1640	1665	1692	1723	1757	1792	1829	1875

Tab 8

ONTARIO DEMAND PEAKS

Electricity Demand Records

The all-time record for Ontario demand was set on Tuesday, August 01, 2006, when peak demand for electricity reached 27,005 MW. Here are the top twenty record demand days for Ontario:

Rank	Date	Ontario Demand (MW)
1	Tuesday, August 01, 2006	27,005
2	Wednesday, July 13, 2005	26,160
3	Monday, June 27, 2005	26,157
4	Monday, July 31, 2006	26,092
5	Monday, July 17, 2006	25,898
6	Tuesday, June 28, 2005	25,861
7	Monday, July 18, 2005	25,857
8	Wednesday, August 02, 2006	25,816
9	Tuesday, August 09, 2005	25,816
10	Tuesday, July 12, 2005	25,808
11	Tuesday, June 26, 2007	25,737
12	Thursday, August 02, 2007	25,584
13	Monday, July 11, 2005	25,506
14	Wednesday, June 27, 2007	25,467
15	Thursday, July 21, 2011	25,450
16	Tuesday, August 13, 2002	25,414
17	Wednesday, August 01, 2007	25,402
18	Thursday, July 21, 2005	25,383
19	Thursday, July 14, 2005	25,362
20	Monday, August 12, 2002	25,349

RELATED INFORMATION

Demand Overview

Supply Overview

Price Overview

Monthly Market Update

NEWS RELEASE

Ontario's Independent Electricity System Operator Releases 2012 Electricity Production, Consumption and Price Data

January 11, 2013

Ontario's Independent Electricity System Operator (IESO) today released its annual statistics on electricity supply, demand and price, which reflect the changes taking place in the provincial electricity system in the way electricity is produced and consumed.

"Over the last number of years, Ontario has made significant investments in new supply, new transmission, and now virtually every Ontarian is under time-of-use pricing," said IESO President and CEO Paul Murphy. "These numbers demonstrate just how far the transition of Ontario's electricity sector has come."

Supply

Nuclear units remained the cornerstone of Ontario's supply mix. Gas and hydroelectric units continued to provide important flexibility by ramping production up and down in response to changes in demand and wind output. Wind generation has grown to become a mainstream resource.

In 2012, nuclear output showed a modest increase to 85.6 TWh, up from 85.3 TWh the year before, representing 56.4 per cent of total generation. Contributions from renewable resources continued to grow. Wind production increased from 3.9 TWh to 4.6 TWh. On a percentage basis, it represented 3.0 per cent of total output - up from 2.6 per cent in 2011 - and exceeded the output of Ontario's coal plants.

Output from hydroelectric and natural gas facilities was essentially unchanged from 2011, coming in at 33.8 TWh and 22.2 TWh respectively. Ontario's coal-fired units remained at less than three per cent of production.

Electricity transactions between Ontario and its interconnected markets picked up in 2012, resulting in higher import and export volumes. Scheduled imports rose to 4.7 TWh from 3.9 TWh in 2011, while exports increased to 14.6 TWh from 12.9 TWh the year before. Total production from Ontario's power generators rose in 2012, for a total of 151.8 TWh.

The table below reflects total electricity production in 2012, broken out by fuel type.

Year	Nuclear	Hydro	Coal	Gas	Wind	Other
2012	85.6 TWh 56.4%	33.8 TWh 22.3%	4.3 TWh 2.8%	22.2 TWh 14.6%	4.6 TWh 3.0%	1.3 TWh 0.8%
2011	85.3 TWh 56.9%	33.3 TWh 22.2%	4.1 TWh 2.7%	22.0 TWh 14.7%	3.9 TWh 2.6%	1.2 TWh 0.8%
2010	82.9 TWh 55.0%	30.7 TWh 20.4%	12.6 TWh 8.3%	20.5 TWh 13.6%	2.8 TWh 1.9%	1.3 TWh 0.8%
2009	82.5 TWh 55.2%	38.1 TWh 25.5%	9.8 TWh 6.6%	15.4 TWh 10.3%	2.3 TWh 1.6%	1.2 TWh 0.8%
2008	84.4 TWh 53.0%	38.3 TWh 24.1%	23.2 TWh 14.5%	11.0 TWh 6.9%	1.4 TWh 0.9%	1.0 TWh 0.6%

Due to rounding, percentages may not add to 100.

CONTACT US

IESO Media Desk:
416-506-2823 or media@ieso.ca

PUBLIC APPEALS

In periods of tight electricity supplies, the IESO may issue a public appeal urging consumers to reduce electricity consumption. Typically, public appeals are issued when extreme weather or unexpected generator outages stretch the system's ability to provide enough electricity to meet demand and required levels of reserve.

- Full list of public appeals since May 1, 2002.

Demand
Electricity demand patterns in Ontario continued to change; peaks in demand fell far below historical highs, while the growth in overall consumption remained in check.

In response to price signals and programs such as the OPA's DR3 and peaksaver PLUS, Ontario's consumers had a direct impact on reducing the year's summer peak. For example, industrial, commercial and institutional consumers helped reduce at least 400 megawatts (MW) during the year's demand peak on July 17, helping to bring the peak down to 24,636 MW. This peak was lower than the previous year's, when record-breaking heat and humidity pushed hourly demand to 25,450 MW.

Total annual electricity consumption stayed virtually flat at 141.3 TWh. Factors constraining growth include the current economic conditions, the growth in embedded generation capacity (which reduces demand for electricity from the bulk power system) and ongoing conservation and demand management initiatives.

Price
The total cost of power in 2012 was 7.37 cents per kilowatt hour (kWh), up from 7.16 cents/kWh in 2011. This cost includes the average weighted wholesale market price of 2.41 cents/kWh and the average Global Adjustment of 4.96 cents/kWh*.

The IESO is responsible for managing Ontario's bulk electricity power system and operating the wholesale market. It provides a range of historical and real-time electricity data, such as hourly demand, generator output and prices on its web site at www.ieso.ca.

*incorporates an estimate for the December Global Adjustment

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Tab 9

Environmental Defence INTERROGATORY #18 List 1

Reference: Ex B, Tab 1, Schedule 5, Pages 17-20

Interrogatory

Has the OPA estimated the potential for incremental cost-effective CDM in the KWCG area in excess of the nearly 270 MW of CDM referenced on page 17?
If yes, please provide:

a) The OPA's incremental cost-effective CDM potential estimates for the KWCG area and each of the subsystems referenced in Table 1 on page 10 for each year from 2013 to 2026 inclusive; and

b) The OPA's studies and analyses that support these estimates.

Response

a) The OPA does not estimate the potential for incremental cost effective CDM in the KWCG area in excess of the nearly 270 MW of CDM referenced on page 17 of Exhibit B, Tab 1, Schedule 5.

b) Not applicable.

Tab 10

Environmental Defence INTERROGATORY #10 List 1

Reference: Ex. B, Tab 1, Schedule 5, Page 10, Table 1

Interrogatory

Please provide for the KWCG area and each of the subsystems shown in Table 1 for each year from 2013 to 2026 inclusive:

a) The cumulative number of *peaksaver* and *peaksaver plus* participants;

b) The cumulative peak demand reductions from the *peaksaver* and *peaksaver plus* participants;

c) The cumulative total number of potential *peaksaver* and *peaksaver plus* participants; and

d) The cumulative total potential demand reductions from the total number of potential *peaksaver* and *peaksaver plus* participants.

Response

a) As of the end 2011, there were a total of 6,542 *peaksaver* participants in the KWCG area, excluding any Hydro One Networks participants in the area (due to the unavailability of location specific information of Hydro One Networks participants). 503 of these participants were incremental in 2011. Verified 2012 data is not currently available. Conservation program results are not recorded on an electrical connection point basis, and therefore the 2011 *peaksaver* participant results are not available at the electrical subsystem level.

   Cambridge and North Dumfries Hydro Inc., Guelph Hydro Electric Systems Inc., Kitchener-Wilmot Hydro Inc. and Waterloo North Hydro Inc. are not currently delivering the *peaksaver Plus* initiative. They are expected to deliver this initiative by summer 2013.

   The OPA has not forecast the number of future *peaksaver* and *peaksaver* Plus participants for the KWCG area and its subsystems.

b) As of the end of 2011, the total peak demand reduction from the enrolled *peaksaver* participants in the KWCG area, excluding any Hydro One Networks participants, was 3.7 MW. The incremental peak demand reduction in 2011 was 0.4 MW. Verified 2012 data is not currently available. Conservation program results are not recorded on an electrical connection point basis, and therefore the 2011 total peak demand reduction from the enrolled *peaksaver* participants is not available at the electrical subsystem level.

The forecast cumulative peak demand reductions from *peaksaver* and *peaksaver* Plus resources for the KWCG area and each of the sub-systems are shown in Attachment 1. These totals are derived from an allocation of the provincial forecast to the KWCG area and subsystems and are incremental to 2010.

c) The OPA does not have an estimate of the cumulative total number of potential *peaksaver* and *peaksaver Plus* participants for the KWCG area. The OPA will investigate opportunities in the KWCG area for additional cost effective conservation, including additional residential and small commercial demand response, to address supply capacity needs of the area over the longer term.

d) The OPA does not have an estimate of the cumulative total potential demand reductions from the total number of potential *peaksaver* and *peaksaver Plus* participants for the KWCG area. The OPA will investigate opportunities in the KWCG area for additional cost effective conservation, including additional residential and small commercial demand response, to address supply capacity needs of the area over the longer term.

Peak reduction (MW, cummulative, peaksaver)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
South-Central Guelph	0.6	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Kitchener-Guelph	1.7	2.5	2.5	2.6	2.7	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Waterloo-Guelph	2.5	3.7	3.7	3.9	4.0	4.1	4.2	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Cambridge	2.1	3.0	3.1	3.2	3.3	3.4	3.5	3.5	3.5	3.6	3.6	3.6	3.6	3.6
Kitchener-Cambridge	2.7	4.0	4.1	4.2	4.3	4.4	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.7
Other	1.3	1.9	1.9	2.0	2.0	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Total KWCG area	**8.9**	**12.9**	**13.2**	**13.6**	**14.0**	**14.4**	**14.8**	**15.0**	**15.1**	**15.1**	**15.1**	**15.2**	**15.2**	**15.3**

Tab 11

Environmental Defence INTERROGATORY #12 List 1

Reference: Ex. B, Tab 1, Schedule 5, Page 10, Table 1

Interrogatory

Please provide the OPA's best estimate of the non-*peaksaver* and non-*peaksaver plus* demand response potential (MW) in the KWCG area and each of the subsystems shown in Table 1 for each year from 2013 to 2026 inclusive.

Response

The OPA does not have an estimate of the non-*peaksaver* and non-*peaksaver Plus* demand response potential for the KWCG area and each of the subsystems.

Environmental Defence INTERROGATORY #11 List 1

Reference: Ex. B, Tab 1, Schedule 5, Page 10, Table 1

Interrogatory

Please provide the OPA's existing and forecast non-*peaksaver* and non-*peaksaver plus* demand response resources (e.g., DR1, DR2, DR3) for the KWCG area and each of the subsystems shown in Table 1 for each year from 2013 to 2026 inclusive.

Response

The total existing peak demand savings from DR3 participants in the KWCG area is approximately 34 MW, including a single large customer of approximately 18 MW. The peak demand savings incremental to 2010 for DR3 participants in the KWCG area is 24 MW. There are no DR1 or DR2 participants in the KWCG area.

The OPA is unable to provide a breakdown of the non-*peaksaver* and non-*peaksaver Plus* demand response resources at the electrical subsystem level since conservation program results are not recorded by subsystem, and due to the commercially sensitive nature of participant information.

The forecast cumulative peak demand reductions from non-*peaksaver* and non-*peaksaver Plus* demand response resources for the KWCG area and each of the sub systems are contained in Attachment 1 to this exhibit. These totals are derived from an allocation of the provincial forecast to the KWCG area and subsystems and are incremental to 2010. This forecast does not assume the availability of the aforementioned large KWCG area customer. The OPA believes this is a prudent approach for regional planning purposes due to the risk to system reliability associated with counting on one specific customer's relatively large demand response contribution.

Tab 12

Environmental Defence INTERROGATORY #25 List 1

Reference: Ex. B, Tab 1, Schedule 5, Pages 17-21

Interrogatory

Why is the OPA not implementing programs to pursue all the cost-effective CDM and DG opportunities in the KWCG area that could defer the need for the proposed transmission line upgrade and generation projects in the rest of Ontario?

Response

As described in the response to Board Staff Interrogatory 8 c) at Exhibit I, Tab 1, Schedule 8 c), it is the OPA's view that additional conservation is not a feasible means of fully addressing the KWCG area's near- and medium-term needs. As described in the response to Environmental Defence Interrogatory 26 a) at Exhibit I, Tab 2, Schedule 26 a), it is the OPA's view that additional distributed generation is neither feasible, nor a cost-effective means, of addressing the area's near- and medium-term needs, compared to the recommended transmission reinforcements.

Tab 13

Environmental Defence INTERROGATORY #28 List 1

Reference: Ex. B, Tab 1, Schedule 5, Pages 17-21

Interrogatory

Has the OPA or Hydro One completed a system-wide comparison of the cost-effectiveness of (i) implementing the lowest cost combination of CDM and DG options that could avoid the need for the proposed transmission line versus (ii) constructing the proposed transmission line, which accounts for all system-wide benefits from CDM and DG (such as avoiding the cost of increased generation, distribution, and transmission capacity and decreasing consumer costs resulting from conservation)? If no, why not. If yes, please provide the analysis.

Response

Neither the OPA nor Hydro One has completed a system-wide comparison of the cost-effectiveness of combinations of CDM/DG versus the recommended transmission reinforcements. As per the responses to Environmental Defence Interrogatories 18, 44 and 26 a), found at Exhibit I, Tab 2, Schedules 18, 44 and 26 a), it is the OPA's view that additional conservation is not a feasible means of fully addressing the KWCG area's near- and medium-term needs, and additional distributed generation is neither feasible nor cost-effective compared to the recommended transmission reinforcements.

Tab 14

Environmental Defence INTERROGATORY #44 List 1

Reference: Ex. B, Tab 1, Schedule 5, Section 6, Page 18

Interrogatory

On page 18, the OPA states that it is the view of the OPA that additional conservation is not a feasible means of addressing the KWCG area's near- and medium-term needs. Please describe the background to the OPA's experience with conservation programs on why additional conservation is not feasible. Please cite examples in other regions of the provinces.

Response

The KWCG area has both a supply capacity need and a restoration need in the near- to medium- term.

Conservation is not a resource that can be used to restore power to customers following a transmission outage and thus cannot resolve the KWCG area's restoration needs.

Conservation can be an effective resource for addressing capacity needs. The planned conservation of nearly 270 MW by 2023 for the KWCG area will contribute to deferring the KWCG area's capacity needs as shown in Exhibit B, Tab 1, Schedule 5, page 22.

The OPA's view that additional conservation is not a feasible means of addressing the KWCG area's near and medium-term needs is based on the OPA's experience coordinating province-wide conservation efforts. Since 2006 the OPA has worked closely with industry partners including LDCs and a broad range of stakeholders to design and deliver energy saving initiatives for homes and businesses. The amount of additional conservation that would be required to fully address the KWCG area's near- and medium-term capacity needs is significant compared to the amount of planned conservation, especially for the South-Central Guelph and Cambridge subsystems.

As shown in the table below, by 2016, this would mean achieving more than four times the amount of conservation as a percentage of load for South-Central Guelph and more than twice the amount of conservation as a percentage of load for the Cambridge subsystem relative to the planned conservation amounts. Due to this immediate nature and magnitude of the capacity needs in the KWCG area, it is not feasible for conservation to fully address the region's near- and medium-term needs.

	2016 Gross Demand (MW)	2016 Planned Conservation (MW)	Planned CDM as % of Load	2016 Incremental Conservation Required	Planned & Incremental CDM as % of Load
South-Central Guelph	150	12	8%	37	33%
Cambridge	443	37	8%	31	15%

The amount of planned conservation savings for the KWCG area was allocated from the OPA's Provincial conservation forecast, which is in line with the conservation targets described in the Long-Term Energy Plan ("LTEP") and prescribed in the Supply Mix Directive. These targets are aggressive and will require a significant level of effort to achieve.

On November 12, 2010, the OEB established two mandatory CDM targets for each LDC: a 2014 net annual peak demand savings target and a 2011-2014 net cumulative energy savings target. These LDC targets are included as part of the planned conservation savings for the KWCG region.

The table below shows the KWCG LDC's progress towards their peak demand savings target. The KWCG LDCs are among the top performing LDCs, performing well compared to the provincial average. However, there is still a significant amount of work remaining for them to achieve the 2014 target.

	2011 Net Annual Peak Demand Savings (MW)	Net Annual Peak Demand Savings Persisting in 2014 (MW)	2014 Annual CDM Capacity Target (MW)	% of Target Achieved
Cambridge and North Dumfries Hydro Inc.	3.21	2.45	17.68	14%
Guelph Hydro Electric Systems Inc.	3.42	2.93	16.71	18%
Kitchener-Wilmot Hydro Inc.	4.63	2.49	21.56	12%
Waterloo North Hydro Inc.	2.10	1.45	15.79	9%
Hydro One Networks Inc.*	35.05	17.42	213.66	8%
Provincial LDC Total	215.7	128.9	1330.0	10%

*Note: Hydro One serves a significant number of customers outside of the KWCG area, and as such only a portion of their savings will have taken place in the KWCG area

It may be possible in the longer term to achieve more conservation in the KWCG area above currently planned amounts. As such, the OPA will continue to monitor conservation results in the KWCG area and look for opportunities for further cost effective conservation to address supply capacity needs of the area over the longer term.

Tab 15

Environmental Defence INTERROGATORY #26 List 1

Reference: Ex. B, Tab 1, Schedule 5, Pages 17-21

Interrogatory

a) Please describe and list all steps taken by the OPA to assess whether increased CDM and/or DG could avoid or defer the need for a new transmission line in the KWCG area as well as the dates that each of these steps were taken. Please include a listing of the dates and subjects of all memos and reports prepared in this regard.

b) Please provide a copy of all documentation (e.g. memos, reports, etc.) prepared by the OPA in relation to an assessment of whether increased CDM and/or DG could avoid or defer the need for a new transmission line in the KWCG area.

c) Please describe and list all steps taken by Hydro One to assess whether increased CDM and/or DG could avoid or defer the need for a new transmission line in the KWCG area as well as the dates that each of these steps were taken. Please include a listing of the dates and subjects of all memos and reports prepared in this regard.

d) Please provide a copy of all documentation (e.g. memos, reports, etc.) prepared by Hydro One in relation to an assessment of whether increased CDM and/or DG could avoid or defer the need for a new transmission line in the KWCG area.

Response

a) Please refer to the response to Exhibit I, Tab 2, Schedule 44 for a description of the assessment of the feasibility of CDM in the KWCG area.

Over the course of the KWCG study, the OPA on be half of the working group evaluated additional distributed generation as a potential alternative to the recommended transmission reinforcements to address the near- and medium-term supply capacity needs in the area. While additional distributed generation is technically capable of meeting the supply capacity needs in the KWCG area, it is the OPA's view that additional distributed generation is not a feasible means of fully addressing these needs due to the immediate nature and magnitude of the needs, the uncertainty associated with the development of further facilities, as well as siting and connection of facilities at the specific locations at which they are needed.

In addition, analysis was conducted to compare the cost of additional distributed generation to that of the recommended transmission reinforcements; it was concluded as the result of this analysis that additional distributed generation is not cost-effective compared to the recommended transmission reinforcements.

This analysis included the value that the distributed generation resources could provide by concurrently contributing to both the local area peak capacity needs, which exist today, and those of the broader system, which are anticipated to emerge in 2018, thereby reducing the need for generation elsewhere in the Province. It is anticipated that the system will have sufficient generation output from the existing fleet of supply resources to meet energy needs at non-peak times. Accordingly, the analysis took into account the energy displacement and excess energy that could occur through the operation of additional distributed generation alternatives.

A summary of the cost assessment, using typical examples of distributed generation, is shown in Attachment 1 to this Exhibit. The inputs to the cost assessment are estimates and based on generic facilities and planning assumptions. It is recognized that each generation project is unique and costs for actual projects can differ from those described in Attachment 1. This approach is appropriate for planning purposes and for relative comparison of the different alternatives.

It is the OPA's view that this analysis is sufficient to explain why the OPA and the working group determined that additional CDM and/or DG was not feasible or cost-effective for addressing the KWCG area's needs; and production of underlying documents is not necessary.

b) Please see part a) above.

c) Hydro One depends on the OPA to conduct integrated planning including CDM, DG and transmission to meet the needs of the area. Hydro One therefore did not undertake any such steps and does not have such documents.

d) Please see part c) above.

Step 1: Estimate the All-In Annualized Cost of Typical DG Alternatives and the Recommended Transmission Alternative

All-in annualized costs represent the annual portion of the total cost of building and operating a particular asset; they are determined by allocating the total costs over the asset's useful life. The all-in annualized costs of typical DG alternatives and the recommended transmission reinforcements are shown below in Table 1 in 2012 $/MW-month; the assumptions underpinning these costs are described below.

a) All-in annualized costs include capital, fixed, variable and fuel costs of the distributed generation alternatives, and capital and fixed costs of the recommended transmission reinforcements. Input costs for the distributed generation alternatives is informed by a combination of: OPA program parameters (e.g. from CHPSOP and FIT 2.0), publically available capital and operating cost information and planning assumptions that include annual capacity factors, heat rates and fuel commodity costs. The cost of the recommended transmission reinforcements were provided by Hydro One.

b) All-in annualized costs are derived using a useful life of 20 years for generation assets, and 45 years for transmission assets.

c) The all-In costs do not include costs of land or additional transmission reinforcements that may be required to connect distributed generation facilities, or to address any remaining supply capacity needs that could arise from generation facilities being sited in non-optimal locations (from a transmission perspective).

d) All-in annualized costs are converted from 2012 $/MW-yr to 2012 $/MW-month by dividing by 12.

Table 1

Estimated All-In Annualized Costs of Typical DG Alternatives and the Recommended Transmission Reinforcements	2012 $/MW-month
Combined Heat and Power (CHP) on Natural Gas	40,000
Peaking Natural Gas	13,000
Solar - Ground Mount	29,000
Solar - Rooftop (10-250 kW)	45,000
Recommended Transmission Reinforcements	2,200

Step 2: Estimate the Present Value Total Cost of Each of the Alternatives

The purpose of this step is to estimate the present value of the annual cash flows associated with building and operating the distributed generation alternatives and recommended transmission reinforcements (refer to Step 1 above), and to reflect the value of the distributed generation in meeting broader system peak capacity needs (that are expected to emerge in 2018) as well as the energy that would be displaced in the system through the operation of the distributed generation alternative in the local area. The estimated present value of the alternatives is presented below in Table 3 in 2012$; the assumptions underpinning these costs are described below.

a) The installed amount of distributed generation required to meet the peak capacity need in South-Central Guelph, Kitchener-Guelph and Cambridge was calculated using the magnitude of the area's need by 2023 and the capacity contribution of each of the distributed generation alternatives. Refer to Table 2 below.

Table 2

Peak Capacity Needs (MW) by 2023 in: South-Central Guelph Kitchener-Guelph Cambridge	**186**
DG Alternative	**Installed Capacity (MW) Required to Meet Peak Capacity Needs**
Combined Heat and Power (CHP) on Natural Gas	190
Peaking Natural Gas	190
Solar - Ground Mount	620
Solar - Rooftop (10-250 kW)	620

b) The required installed capacity for each of the distributed generation alternatives was multiplied by its corresponding all-in annualized cost to represent the annual cash flow associated with building and operating the facility in 2012 $. For the recommended transmission reinforcements, the all-in annualized cost was multiplied by 186 MW - the peak needs in 2023 in South-Central Guelph, Kitchener-Guelph and Cambridge.

c) The annual value of displaced system energy that would occur through distributed generation operation was determined by multiplying an estimate of the system marginal cost by an estimate of the amount of energy that would be produced by each of the distributed generation alternatives (based on planning assumptions). The annual value of displaced energy was subtracted from the annual cost described in step b) above; the present value of the resultant cash flows to 2023 is shown in COLUMN A of Table 3, below.

d) The value that distributed generation can provide to the broader system in contributing to peak capacity needs was factored in by including the cost of building and operating a peaking natural gas facility (sized at 190 MW as per Table 2) to the cost of the recommended transmission reinforcements, starting in 2018 (the time frame in which peaking needs are expected to emerge). In terms of technical and cost considerations, a peaking natural gas facility is assumed to be the most appropriate resource to meet the system's peak capacity needs. This cost is represented in COLUMN B of Table 3, below.

e) The total estimated present value cost of each alternative is determined by adding COLUMN A and COLUMN B of Table 3, below. The relative performance of the alternatives, compared to the recommended transmission reinforcements, is shown in COLUMN C of Table 3 below.

f) A social discount rate of 4 percent was used to estimate the present value costs.

Table 3 (2012 $ in Millions)

	COLUMN A	COLUMN B	COLUMN A+B	COLUMN C
Typical DG Alternatives and the Recommended Transmission Reinforcements	**Estimated PV of All-In Costs & Energy Displacement to 2023**	**Estimated PV of All-In Cost for Additional Generation (@ peaking natural gas) Required in the Rest of the Province Starting in 2018**	**Total Estimated PV Cost**	**Delta from Recommended Transmission Reinforcements**
Combined Heat and Power (CHP) on Natural Gas	395	-	395	250
Peaking Natural Gas	160	-	160	15
Solar - Ground Mount	1,245	-	1,245	1,100
Solar - Rooftop (10-250 kW)	2,045	-	2,045	1,900
Recommended Transmission Reinforcements	**45**	**100**	**145**	-

Tab 16

Environmental Defence INTERROGATORY #17 List 1

Reference: Ex B, Tab 1, Schedule 5, Page 19

Interrogatory

The OPA KWCG Report states as follows:

> Additionally, it is the OPA's view that further distributed generation resources are not a cost effective means for addressing the needs of the KWCG area, due to robust load growth anticipated in the region combined with the relatively low cost of the recommended transmission reinforcement discussed in section 6.3 below. Distributed generation may be an effective option to meet an area's needs when low load growth is anticipated and/or the cost of the alternative solutions is high in comparison.

a) Does the OPA agree that incremental distributed generation in the KWCG area could contribute to avoiding or deferring the need for additional generation resources in the rest of Ontario (e.g., Darlington re-build, Bruce re-build, Darlington new build). If "no", please fully explain why not.

b) Please provide the OPA's best estimates of the cost per MWh of: i) the Darlington re-build project; ii) the Bruce B re-build project; and iii) the Darlington new build project. Please fully justify and document your estimates.

c) Does the OPA agree that incremental CDM in the KWCG area could contribute to avoiding or deferring the need for additional generation resources in the rest of Ontario? If "no", please explain why not.

Response

a) In general, additional distributed generation in the KWCG area can help contribute to meeting system needs at the Provincial level. However, the extent of the contribution depends on a number of factors including the nature and magnitude of the system needs and the output characteristics of the distributed generation. The role of distributed generation in deferring the need for nuclear refurbishments and/or new build is also a policy decision to be made by the Government of Ontario.

b)

i. The cost of Darlington refurbishment was provided by Ontario Power Generation ("OPG") in EB-2010-0008 (Exhibit D2, Tab 2, Schedule 1), where OPG indicates it "has high confidence that the project will have a Levelized Unit Energy Cost ("LUEC") of between 6 and 8 cents per kilowatt-hour (2009 $)".

ii. At the moment there are no commercial agreements with respect to the refurbishment of Bruce B. Future commercial agreements may go beyond the scope of the existing commercial contracts with Bruce Power. Costs related to any such future commercial agreements will be subject to negotiation.

iii. The cost of the Darlington new build project is currently being estimated. In June 2012, OPG signed agreements with Westinghouse and SNC-Lavalin/Candu Energy Inc. to prepare detailed plans and cost estimates for two potential reactors at Darlington. The resulting reports are expected to be complete in mid-2013 and the completed reports will be analyzed and forwarded to the Province for its consideration.

c) In general, additional CDM in the KWCG area can contribute to meeting system needs at the Provincial level. However, the extent of the contribution depends on a number of factors including the nature and magnitude of the system needs and the characteristics of the demand savings.

Tab 17

UNDERTAKINGS

Undertaking

To provide numbers for capitalized interest during Darlington construction.

Response

OPG's low and high estimate total cost of the Darlington Refurbishment, including capitalized interest during construction and escalation due to inflation is provided below. The range does not reflect OPG's CWIP in rate base proposal.

	Overnight	Escalation	Interest	Total
Low Range	$6B	$1.3B	$1.2B	$8.5B
High Range	$10B	$2.2B	$1.8B	$14.0B

The recalculated range is a bounding range of median to very high confidence including capitalized interest and escalation. OPG will, during the project definition phase, confirm the project scope, cost and baseline schedule.

Tab 18

18-MONTH OUTLOOK

From June 2013 to November 2014

Power to Ontario. On Demand.

An Assessment of the Reliability and Operability of the Ontario Electricity System

	Normal Weather Scenario	Extreme Weather Scenario
Planned Scenario	• There are no weeks when reserve is lower than required	• There are no weeks when reserve is lower than required
Firm Scenario	• There are no weeks when reserve is lower than required	• There are no weeks when reserve is lower than required

Transmission Adequacy

- Ontario's transmission system is expected to reliably supply the demand under the normal and extreme weather conditions forecast for this Outlook period.
- The IESO, OPA, Transmitters and affected distributors are reviewing system needs and considering solutions under the Regional Planning Process established by the Ontario Energy Board (OEB).
- Several local area supply improvement projects are underway and will be placed in service during the timeframe of this Outlook. These projects, shown in Appendix B, will help relieve loadings of existing transmission stations and provide additional supply capacity for future load growth.
- To help control voltages in northwestern Ontario, Hydro One will be installing new reactors. Reactors at Marathon are scheduled to be installed and in service by Q4 2013 and reactors at Dryden are scheduled for Q4 2014.
- The IESO, Hydro One and OPA are also considering long term solutions to help control high voltages in southern Ontario during low demand periods.
- To improve the transmission capability into the Guelph area, Hydro One will be proceeding with the Guelph Area Transmission Refurbishment project to reinforce the supply into Guelph-Cedar TS, with an expected completion date in the second quarter of 2016.
- In the Cambridge area, to help meet the IESO's load restoration criteria following a contingency, a second 230/115 kV autotransformer is expected to be installed at Preston TS. Longer-term solutions to fully address meeting restoration criteria are being developed.
- Transmission enhancements at Manby TS, which include 230kV switchyard reconfiguration and breaker upgrades are planned for Q4 2014. Hydro One has also planned to upgrade 115kV breakers at Hearn and Leaside by Q4 2014. These upgrades will help manage long-term load supply in the south-western GTA.
- In the eastern portion of the GTA, a new Clarington TS that provides 500/230 kV transformation and 230 kV switching facilities is scheduled to be in-service as soon as spring 2015 to maintain supply reliability beyond Pickering end-of-life. Clarington TS will also improve restoration capability to the loads in the Pickering, Ajax, Whitby, Oshawa and

Tab 19

Environmental Defence INTERROGATORY #21 List 1

Reference: Guelph City Council Report No. FIN-CE-12-03 re: Guelph Area Transmission Refurbishment Project and the Community Energy Initiative (December 3, 2012).[1]

Interrogatory

According to the above captioned report (enclosed for your reference), generation projects totalling approximately 60 MW in the City of Guelph have been submitted to the OPA pursuant to its Feed-in-Tariff (FIT) Program and the Combined Heat and Power Standard Offer Program (CHPSOP). The report states as follows:

> Across the community it is estimated that there are projects before the Ontario Power Authority with a total generation capacity of 60 Mega-Watts (MW). 60 MW represents approximately 25% of the average community-wide load electrical load of 240 MW and 20% of the approximate maximum peak summer load of 300 MW.
>
> The 60 M W being proposed across the community roughly break down as follows:
>
> - 30 MW Solar PV, including:
>   - 1 MW City-owned Facilities
>   - 8 MW Eastview closed landfill (Cooperative model)
>   - 7.5 privately held land (Cooperative Model)
> - 28 MW Combined Heat and Power (CHP), including:
>   - Downtown
>   - Hanlon Creek Business Park
> - 2 MW Biogas

a) Please provide the OPA's best estimate of the amount of solar PV, CHP and biogas generation that it will contract for in the City of Guelph during each year from 2013 to 2026 inclusive.

b) Has the OPA estimated the cost-effectiveness of each of these projects in terms of deferring the need for an upgrade of the Guelph transmission line and new or re-built electricity generation capacity in the rest of Ontario? If yes, please provide the OPA's analysis and estimates.

[1] http://guelph.ca/wp-content/uploads/council_agenda_120312.pdf#page=132 (see pg. 132)

Response

a) Over the past year, the OPA and the Ministry of Energy have been reviewing a number of initiatives, including the Feed-in-Tariff ("FIT") Program and the Combined Heat and Power Standard Offer Program ("CHPSOP"), in the context of rising electricity prices and the current needs of the Ontario electricity system.

Review of the FIT Program was completed in 2012, and based on the April 2012 directive from the Minister of Energy, the OPA is currently in the process of reviewing smallFIT ($\leq$ 500 kW) applications to support the award of up to 200 MW of smallFIT contracts. The renewable generation projects referenced in the Guelph City Council report are for facilities >500 kW in size, and therefore are not eligible for the smallFIT procurement.

The review of CHPSOP is nearing completion. Subject to the outcome of the program review, only those applications that are eligible and complete will receive a contract offer under CHPSOP. There are numerous requirements that applications must meet, and the OPA does not expect that all applications received will be offered a contract.

Accordingly, at this time, the OPA cannot reasonably estimate the amount of additional solar PV, CHP or biogas generation, if any, that may be contracted in the City of Guelph during each year from 2013 to 2026 inclusive.

b) The OPA has not estimated the cost-effectiveness of the proposed projects in the City of Guelph to the Feed-in-Tariff Program and Combined Heat and Power Standard Offer Program. These proposed projects even if contracted, in total, are not sufficient to defer the need for the recommended transmission reinforcements.

As noted in the response to Environmental Defence Interrogatory 8 at Exhibit I, Tab 2, Schedule 8, the OPA considered additional potential distributed generation in the KWCG area as an alternative to the recommended transmission reinforcements. As described in the response to Environmental Defence Interrogatory 26 a) at Exhibit I, Tab 2, Schedule 26 a), it is the OPA's view that additional distributed generation is not a feasible or cost-effective option for meeting the area's near- and medium-term needs.

Tab 20

Environmental Defence INTERROGATORY #23 List 1

Reference: Ex B, Tab 1, Schedule 4, Page 2

Interrogatory

a) Please provide a break-out of the electricity generation facilities in the KWCG area by size and fuel.

b) Could a rise in the magnitude of local generation in the KWCG area increase its security of supply in the event of provincial blackout or a failure of the Hydro One grid?

c) Please confirm that New York City is required to have sufficient local generation capacity to meet 80% of its peak day needs?

d) Does the OPA believe that it would be in the public interest for the KWCG area to have sufficient local generation to meet at least: a) 25%; b) 50%; or c) 80% of its peak day needs? Please fully justify your response.

Response

a) Please refer to the response to Environmental Defence Interrogatory 8, at Exhibit I, Tab 2, Schedule 8.

b) It is possible for distributed generation in the KWCG area to increase the region's security of supply in the event of a provincial blackout or failure of the Hydro One grid. However, the extent of the contribution is dependent on a number of factors, including:
- Safety protocols and other operating procedures of the distribution/transmission system;
- The ability of the generator to restart without an external power supply;
- The facility's start-up time, time to sync to minimum loading and ramp rate;
- The existence of fast-acting isolating switching in the distribution/transmission system;
- The location of the generation facilities in relation to the restoration needs.

c) The OPA is not able to confirm whether New York City has a planning criteria that requires it to have sufficient local generation capacity to meet 80% of its peak day needs.

d) The OPA believes that it is important to consider a number of alternatives to address the needs of an area, such as conservation, transmission, and local generation. However, when evaluating the potential options to address area needs, the OPA considers the potential attributes of various resource options along with other factors, such as broader system needs, technical feasibility and economic feasibility.

Tab 21

Environmental Defence INTERROGATORY #8 List 1

Reference: Ex. B, Tab 1, Schedule 5, Page 10, Table 1

Interrogatory

Please provide the OPA's best estimate of the actual and forecast distributed generation (MW) in the KWCG area overall and broken out for each of the six subsystems shown in Table 1 for each year from 2010 to 2026 according to the following categories:

a) Solar;

b) Gas-fired generation;

c) Gas-fired combined heat and power (CHP);

d) Renewable CHP; and

e) Other renewable.

For each year please also state the size (MW) of each: i) gas-fired CHP facility, ii) all other gas-fired generation facilities; and iii) renewable CHP facility.

Response

The existing and committed (i.e., contracted) distributed generation (MW) in the KWCG area from 2010 to 2026 is shown by sub-system, fuel type and technology type (where applicable) found in Attachment 1 to this exhibit.

The OPA does not forecast future amounts of distributed generation due to the uncertainty associated with un-contracted facilities. Rather, distributed generation above the existing and committed amounts was assessed as an alternative to the recommended transmission reinforcements.

Nameplate Capacity (MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
South-Central Guelph																	
Solar		0.1	0.3	0.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Gas-fired generation																	
GF CHP	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Ren. CHP																	
Other Renewable																	
Total South-Central Guelph	**1.5**	**1.6**	**1.8**	**2.3**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**
Kitchener-Guelph																	
Solar		0.5	1.0	1.6	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Gas-fired generation																	
GF CHP	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Ren. CHP																	
Other Renewable					0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Kitchener-Guelph	**4.1**	**4.6**	**5.1**	**5.7**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**
Waterloo-Guelph																	
Solar		0.4	4.2	7.6	9.5	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Gas-fired generation																	
GF CHP																	
Ren. CHP																	
Other Renewable	2.8	13.5	13.6	36.6	36.6	36.6	46.8	46.8	46.8	46.8	46.8	46.8	46.8	46.8	46.8	46.8	46.8
Total Waterloo-Guelph	**2.8**	**13.9**	**17.8**	**44.2**	**46.1**	**46.4**	**56.6**	**56.6**	**56.6**	**56.6**	**56.6**	**56.6**	**56.6**	**56.6**	**56.6**	**56.6**	**56.6**
Cambridge																	
Solar	0.3	1.3	2.0	3.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Gas-fired generation																	
GF CHP																	
Ren. CHP																	
Other Renewable		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Cambridge	**0.3**	**1.8**	**2.5**	**4.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**
Kitchener and Cambridge																	
Solar	0.3	1.3	2.4	4.0	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Gas-fired generation																	
GF CHP																	
Ren. CHP																	
Other Renewable		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Kitchener and Cambridge	**0.3**	**1.8**	**2.9**	**4.5**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**
Other Stations in the KWCG Area (including Tx Connected DG)																	
Solar		0.4	1.3	1.8	2.1	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Gas-fired generation																	
GF CHP																	
Ren. CHP																	
Other Renewable	6.2	6.2	6.2	75.2	75.2	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1
Total Other Stations in the KWCG Area	**6.2**	**6.7**	**7.6**	**77.1**	**77.3**	**80.4**	**80.4**	**80.4**	**80.4**	**80.4**	**80.4**	**80.4**	**80.4**	**80.4**	**80.4**	**80.4**	**80.4**

Tab 22

"Powering Toronto's Electricity Future"

Remarks by Colin Andersen
CEO, Ontario Power Authority

to the

Toronto Board of Trade

October 25, 2012

This is not a new trend. Toronto has been getting bigger, taller and denser for some time. Until now, we've managed the growth pretty well. Conservation, new building codes and new buildings being connected to deep lake water cooling have all helped keep growth-related peak electricity demand in check. The recent economic slowdown has also played a role. So has the fact that many of the people who live in the new downtown condo towers work during the day and use less electricity at peak times.

But as intensification intensifies, increased demand will come, and we need to be ready.

There are many options to choose from. Generation, transmission, distribution and conservation are all possibilities. Lots of permutations and combinations. But this much is clear: There are no easy solutions.

Each option has its advantages and disadvantages.

We've made progress on GENERATION. Thanks to progress we've made province-wide and in the Toronto area, we've moved from having to contemplate having diesel generators on rooftops and barges in our harbour. Just this week Bruce Nuclear unit 2 came back into commercial operation.

Here in Toronto, the Portlands Energy Centre is now in service, providing made-in-Toronto electricity supply to help meet Toronto's peak demand. But as we saw in the Portlands, and as we saw more recently in Mississauga and Oakville, getting community buy-in for local generation projects is challenging.

And while distributed generation options like combined heat and power plants show promise, they are not abundant in Toronto. Even still, only 25 per cent of Toronto's electricity needs are met by generation. Not too long ago it was the reverse. Toronto's 25% is a stark contrast to other world-class cities, like NYC, which has a policy objective of having 80% of their electricity needs met by internal generation.

Tab 23

Environmental Defence Supplemental Interrogatory #5(a) List 2

Original Interrogatory

Interrogatory No. 5 (a) reads as follows:

> Approximately when were (i) the OPA and (ii) Hydro One first aware of the need to take steps to ensure compliance with the ORTAC criteria described in section 5 of the OPA KWCG Report?

Supplemental Interrogatory

While the original interrogatory is as above, in the Board's July 8, 2013 Decision and Order on Motion, the Board Findings indicate the following:

> *At the hearing, the OPA stated that it became aware of the ORTAC compliance issue in 2007, the same time it began to assess the options for the KWCG area.*[1] *Upon examination by the Board Panel, the OPA undertook to further investigate and provide additional information, if any, to satisfy Environmental Defence's request in relation to when ORTAC protocols were breached*[2]*. The Board is satisfied that the OPA's response (including any additional information that can be provided by the undertaking) is sufficient and will not require anything further.*

Supplemental Response

Based on historical peak demand information, two of the subsystems in the Kitchener-Waterloo-Cambridge-Guelph ("KWCG") area (the South-Central Guelph and Kitchener-Guelph subsystems) have exceeded their load meeting capability ("LMC"), and therefore have been noncompliant with the supply capacity criteria prescribed by Ontario Resource Transmission and Assessment Criteria ("ORTAC").

Demand in the South-Central Guelph area first exceeded the area's LMC in the summer of 2004. Demand in the Kitchener-Guelph subsystem first exceeded the area's LMC in the summer of 2011; however, demand in the Kitchener-Guelph subsystem subsequently fell to below the LMC in the summer of 2012. The remaining subsystems in the KWCG area have not exceeded their LMC to date, and therefore have been compliant with the supply capacity criteria prescribed by ORTAC.

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[1] Transcript, p. 69, lines 17 – 20.

[2] *Ibid*, p.69, lines 22 – 27.

With respect to the requirement to minimize supply interruptions, to date none of the subsystems in the KWCG area have exceeded the 600 MW load level, and thus the area has been compliant with this ORTAC criteria. Additionally, while the timeframes for restoration of load at the 250 MW and 150 MW thresholds were planning guidelines in the past, in June 2007 these requirements were prescribed as ORTAC criteria.[3] The Waterloo-Guelph 230 kV and Kitchener and Cambridge 230 kV subsystems have not been compliant with this restoration criteria since the ORTAC revisions came into effect.

As noted in Exhibit I, Tab 2, Schedule 5, the OPA and Hydro One began to assess the needs and options of the KWCG area, based on the ORTAC criteria, as part of the 2007 Integrated Power System Plan ("IPSP"). While the review of the 2007 IPSP was suspended in late 2008, the OPA and Hydro One continued to proceed with the implementation of some of the key recommendations identified in the IPSP, including the implementation of the Guelph Area Transmission Refurbishment ("GATR") project. In 2009, the GATR project was put on hold while the impacts of the economic downturn were monitored; however a broader regional planning study of the KWCG area, undertaken in 2010, confirmed the need to proceed with the GATR project.

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[3] http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=3083. http://www.ieso.ca/imoweb/consult/consult_se30.asp

Tab 24

Jack Gibbons

From:	mweninger@guelphhydro.com
Sent:	November-05-12 8:41 AM
To:	Jack Gibbons
Subject:	Re: FW: peaksaver market share

Hello Jack:

From OEB 2010 statistics, Guelph Hydro has approximately 46,000 residential and 3,600 small commercial customers.

Peaksaver customer participation is just over 3% of the above residential & small commercial customer total, with over 98% of the participants in the residential category.

Regards

Matt Weninger
Director of Metering & Conservation

From: "Jack Gibbons" <jack@cleanairalliance.org>
To: <mweninger@guelphhydro.com>,
Date: 11/03/2012 09:55 AM
Subject:FW: peaksaver market share

Hi Matt,

Just checking in to see if you will be able to provide me with the peaksaver data soon?

Thanks,

Jack

From: Jack Gibbons [mailto:jack@cleanairalliance.org]
Sent: October-28-12 7:46 PM
To: 'mweninger@guelphhydro.com'
Subject: peaksaver market share

Hi Matt,

I am hoping you can provide me with some data about your peaksaver program. Specifically, could you please tell me:

a) Your number of residential peaksaver customers as a percentage of your total potential number of residential peaksaver customers; and

b) Your number of small business peaksaver customers as a percentage of your total potential number of small business peaksaver customers.

Thank you.

Jack

Jack Gibbons
Chair, Ontario Clean Air Alliance
160 John St., #300
Toronto M5V 2E5

Tel: 416-260-2080 x 2
Fax: 416-598-9520
Email: jack@cleanairalliance.org
Web sites:
Ontario Clean Air Alliance
Coal Must Go
Ontarios Green Future
HealthPower
Sign Our Petition

untitled

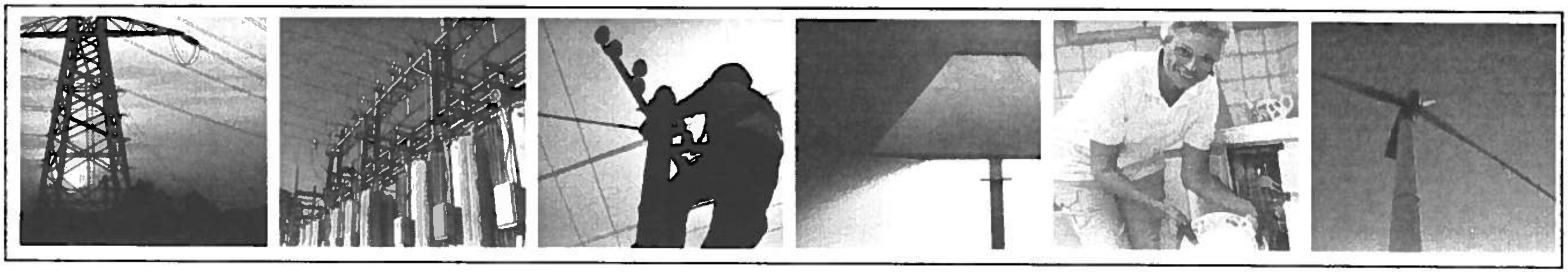
Tab 25

Ontario Energy Board
Commission de l'énergie de l'Ontario

2011 Yearbook of Electricity Distributors

Ontario Energy Board

Published on September 13, 2012



General Statistics For the year ended December 31, 2011	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	COLLUS Power Corporation
Population Served	139,500	27,698	21,640	2,428	94,769	27,000
Municipal Population	139,500	27,698	28,530	2,428	107,615	27,000
Seasonal Population	0	0	0	3	0	0
Residential	46,122	14,369	5,725	1,117	28,649	13,897
General Service (<50 kW)	4,691	1,215	710	162	3,083	1,682
General Service (50-4999 kW)	768	124	61	14	400	144
Large User (>5000 kW)	3	0	0	0	0	0
Sub Transmission	0	0	0	0	0	0
Total Customers	51,584	15,708	6,496	1,293	32,132	15,723
Rural Service Area (sq km)	213	133	0	0	0	0
Urban Service Area (sq km)	90	35	10	2	70	57
Total Service Area (sq km)	303	168	10	2	70	57
Overhead km of Line	713	482	91	26	581	207
Underground km of Line	406	44	70	1	230	132
Total km of Line	1,119	526	161	27	811	339
Total kWh Delivered (excluding losses)	1,482,362,966	277,229,589	148,893,383	26,893,563	721,042,396	307,217,400
Total Distribution Losses (kWh)	33,176,467	14,241,598	5,230,000	1,581,064	26,631,121	13,362,696
Total kWh Purchased	1,515,539,433	291,471,187	154,123,383	28,474,627	747,673,517	320,580,096
Winter Peak (kW)	235,762	45,700	26,436	6,676	104,348	58,755
Summer Peak (kW)	309,690	55,600	28,006	4,532	134,861	50,957
Average Peak (kW)	246,578	45,067	24,928	4,374	119,604	49,878
Capital Additions in 2011	$ 9,845,215	$ 4,418,808	$ 778,340	$ 10,450	$ 5,234,719	$ 2,074,625
Full time equivalent number of employees	95	72	14	5	43	11

General Statistics For the year ended December 31, 2011	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.
Population Served	136,466	45,212	59,008	5,620	575,673	2,650
Municipal Population	136,466	45,212	59,008	5,620	670,580	9,500
Seasonal Population	0	0	0	0	0	0
Residential	46,519	18,554	19,354	2,341	215,025	1,055
General Service (<50 kW)	3,735	2,376	1,708	437	18,124	142
General Service (50-4999 kW)	601	140	170	39	2,167	11
Large User (>5000 kW)	4	0	0	0	11	0
Sub Transmission	0	0	0	0	0	0
Total Customers	50,859	21,070	21,232	2,817	235,327	1,208
Rural Service Area (sq km)	0	1,216	255	0	88	0
Urban Service Area (sq km)	93	36	25	93	338	9
Total Service Area (sq km)	93	1,252	280	93	426	9
Overhead km of Line	430	1,642	888	57	1,523	18
Underground km of Line	654	92	576	11	1,891	3
Total km of Line	1,084	1,734	1,464	68	3,414	21
Total kWh Delivered (excluding losses)	1,676,960,266	433,877,303	495,779,981	78,735,142	5,401,979,776	25,502,853
Total Distribution Losses (kWh)	18,897,762	24,638,202	27,731,801	2,527,814	124,739,680	638,769
Total kWh Purchased	1,695,858,028	458,515,505	523,511,782	81,262,956	5,526,719,456	26,141,622
Winter Peak (kW)	253,600	81,845	84,038	16,328	819,019	6,368
Summer Peak (kW)	297,500	100,582	110,391	11,855	1,092,560	3,940
Average Peak (kW)	254,900	80,013	84,825	14,023	845,981	4,179
Capital Additions in 2011	$ 24,307,230	$ 4,947,158	$ 4,345,429	$ 28,365	$ 39,548,836	$ 65,521
Full time equivalent number of employees	105	50	49	6	389	2

General Statistics For the year ended December 31, 2011	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.	Middlesex Power Distribution Corporation
Population Served	58,000	243,445	22,000	22,641	366,151	7,831
Municipal Population	123,363	551,300	22,000	36,682	366,151	21,749
Seasonal Population	0	0	0	192	0	0
Residential	23,258	79,391	8,767	7,930	134,714	7,111
General Service (<50 kW)	3,226	7,616	1,076	1,567	11,962	782
General Service (50-4999 kW)	357	955	133	101	1,652	94
Large User (>5000 kW)	3	2	0	0	3	1
Sub Transmission	0	0	0	0	0	0
Total Customers	26,844	87,964	9,976	9,598	148,331	7,988
Rural Service Area (sq km)	0	280	0	128	258	0
Urban Service Area (sq km)	32	125	27	16	163	26
Total Service Area (sq km)	32	405	27	144	421	26
Overhead km of Line	233	1,046	95	257	1,363	97
Underground km of Line	129	832	20	76	1,457	38
Total km of Line	362	1,878	115	333	2,820	135
Total kWh Delivered (excluding losses)	708,614,220	1,833,881,351	232,901,730	206,424,706	3,316,999,124	217,136,935
Total Distribution Losses (kWh)	30,676,163	63,294,062	26,357,172	12,188,627	91,629,033	10,788,690
Total kWh Purchased	739,290,383	1,897,175,413	259,258,902	218,613,333	3,408,628,157	227,925,625
Winter Peak (kW)	136,597	309,627	44,452	41,419	531,481	32,939
Summer Peak (kW)	109,026	377,020	44,011	34,472	717,155	38,524
Average Peak (kW)	111,249	301,899	40,058	34,529	540,982	35,731
Capital Additions in 2011	$ 6,208,435	$ 22,909,723	$ 1,355,826	$ 2,535,289	$ 29,231,898	$ 1,279,611
Full time equivalent number of employees	-	174	20	16	302	13

General Statistics For the year ended December 31, 2011	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.
Population Served	2,503,281	316,309	17,300	160,278	50,331	7,200
Municipal Population	2,503,281	413,710	17,300	160,278	50,331	11,500
Seasonal Population	0	1,589	1,000	0	0	0
Residential	629,049	104,060	11,504	46,525	19,905	3,103
General Service (<50 kW)	67,261	8,595	785	5,418	1,695	478
General Service (50-4999 kW)	12,961	1,050	35	667	167	45
Large User (>5000 kW)	52	4	0	1	1	0
Sub Transmission	0	0	0	0	0	0
Total Customers	709,323	113,709	12,324	52,611	21,768	3,626
Rural Service Area (sq km)	0	386	8	607	0	0
Urban Service Area (sq km)	630	253	53	65	86	14
Total Service Area (sq km)	630	639	61	672	86	14
Overhead km of Line	4,168	1,331	127	1,051	213	66
Underground km of Line	5,893	1,078	116	491	87	10
Total km of Line	10,061	2,409	243	1,542	300	76
Total kWh Delivered (excluding losses)	24,707,585,912	2,553,128,713	121,664,686	1,436,920,488	430,932,302	99,140,087
Total Distribution Losses (kWh)	884,493,026	122,948,782	5,797,346	51,792,434	19,174,970	6,485,611
Total kWh Purchased	25,592,078,938	2,676,077,495	127,462,032	1,488,712,922	450,107,272	105,625,698
Winter Peak (kW)	4,060,630	433,549	24,245	240,964	75,412	17,539
Summer Peak (kW)	4,919,150	526,513	28,946	294,349	98,478	16,621
Average Peak (kW)	3,914,700	412,902	21,915	238,844	76,704	16,373
Capital Additions in 2011	$ 470,688,548	$ 25,290,429	$ 617,101	$ 38,214,923	$ 2,484,168	$ 576,440
Full time equivalent number of employees	1,740	219	19	116	42	12

Tab 26

POLLUTION PROBE INTERROGATORY 60

QUESTION

Please provide the OPA's best estimate of the existing number of diesel emergency back-up electricity generators in KWCG and their aggregate capacity. Please explain and justify your response.

RESPONSE

The OPA does not have an estimate of the number and total capacity of diesel emergency back-up generators in KWCG.

Anecdotal evidence suggests that a total capacity of between 2,000 and 4,000 MW from diesel emergency back-up generators is currently available in Ontario (see the response to Pollution Probe Interrogatory 13 at Exhibit I-31-13). The OPA ascribed a portion of the provincial estimate to KWCG based on the local area's estimated share of commercial activity and industrial load relative to that of the province as a whole.[1] Based on this apportionment, the OPA estimates that there is a capacity of between 100 and 200 MW from diesel emergency back-up generators in the KWCG area.

[1] The KWCG share of commercial activity was estimated as 16-17% of the Southwest region. The KWCG share of industrial load was estimated at 28-29% of the Southwest region. The Southwest regional share of provincial commercial activity and industrial load are given on Pages 9 and 11, respectively, of Attachment 1 to Exhibit D-1-1. Seventy-five percent of diesel emergency back-up generation capacity was assumed to be in the commercial sector and 25% in the industrial sector.

Tab 27

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

COPY

March 8, 2012

Mr. Mike Penstone
Vice President, Transmission Project Development
Hydro One
483 Bay Street
Toronto, Ontario M5G 2P5

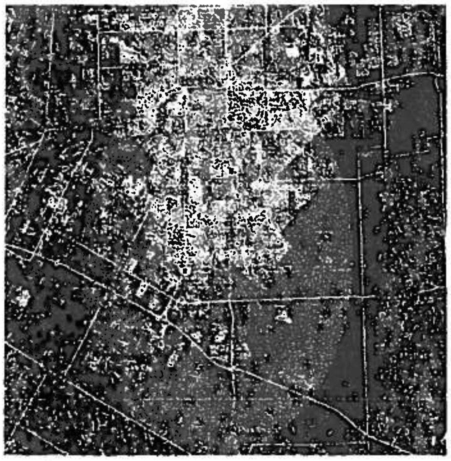
Dear Mike:

Continuing with the Project Development Work for the Guelph Area Transmission Refurbishment Project

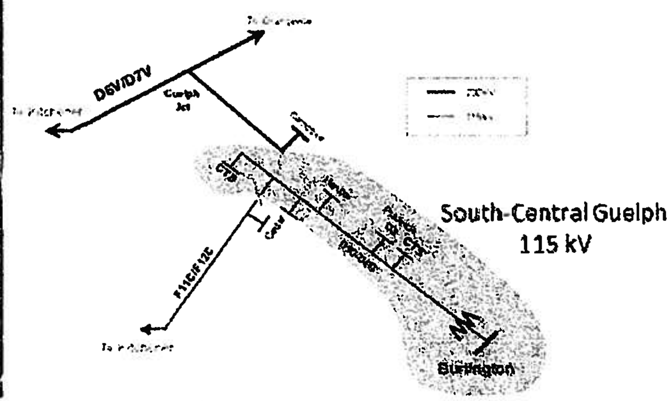
The purpose of this letter is to recommend continuing with the project development work for the Guelph Area Transmission Refurbishment project, including completion of the necessary environmental and regulatory approval processes.

In 2009, Hydro One Networks Inc. (Hydro One) began the necessary environmental approvals for the upgrading of an existing 115 kV transmission line, approximately 5 km in length, from Cedar TS to near Campbell TS along the Hanlon Expressway in the City of Guelph, and the installation of transformers at either Cedar TS or Campbell TS. This project is referred to as the Guelph Area Transmission Refurbishment (GATR) project. Two public information centers were held in Guelph to present the need and options for this project and to solicit feedback from the public. Since then, Hydro One has been developing study estimates for a number of transmission alternatives and working with the OPA and Guelph Hydro Electric Systems to determine the preferred option for the GATR project. As well, a broader regional planning study, initiated in 2010, examined and confirmed the need for the GATR project as part of the 20-year study, in consideration of updated demand forecast and recent conservation and distributed generation developments.

The purpose of the GATR project is to reinforce the electricity supply to a portion of the City of Guelph, as well as the neighboring town of Puslinch, known as South-Central Guelph, as shown in Figure 1. This area has experienced significant growth in electricity demand and is forecast to continue to grow over the next 20 years. Continuing development of the Hanlon Industrial Park is one of the key contributors to this growth.



Source: OPA
Figure 1: South-Central Guelph



Source: Hydro One Networks and OPA
Figure 2: South-Central Guelph Transmission System

The existing electricity supply to the South-Central Guelph area is primarily through a double circuit 115 kV transmission line from Burlington, B5G/B6G, as shown in Figure 2 above. This transmission line was originally built starting in 1910, and for planning purposes, has a supply capacity of approximately 100 MW. In the summer of 2011 peak demand in the South-Central Guelph area was about 115 MW, which exceeded the capability of the supply circuits for planning purposes.

Over the past several months the OPA has worked closely with Hydro One staff to review the cost and feasibility of options for reinforcing the supply to South-Central Guelph. Based on technical considerations, it is the OPA's recommendation that the preferred option is comprised of the following:

- two 230/115 kV autotransformers at Cedar TS;
- revitalization of the existing 115 kV transmission line between Campbell TS and CGE Junction near Cedar TS (approximately 5 km) to 230 kV;
- connection of the existing F11C/F12C and B5G/B6G 115 kV circuits at Cedar TS; and
- initial switching facilities at Guelph North Junction to facilitate sectionalization of the existing D6V/D7V 230 kV circuits.

This recommendation has the support of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area working group.

The proposed arrangement of Cedar TS, as well as the proposed transmission upgrade, are shown in Figure 3 and Figure 4 below.

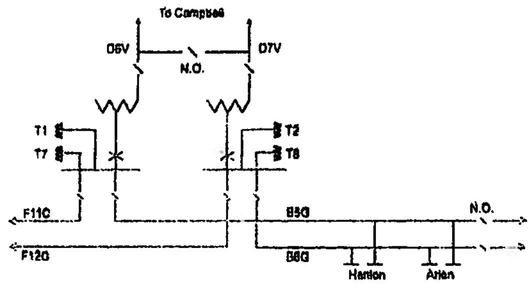


Figure 3 Proposed Cedar TS Arrangement

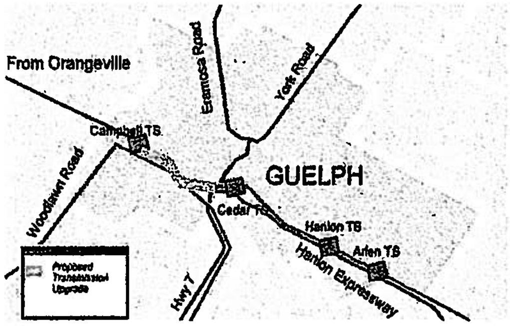


Figure 4 Map of Proposed Transmission Upgrade

Upon completion, Cedar TS will become an additional strong source of supply within the KWCG region, providing improved supply capability to both South-Central Guelph as well as neighbouring Kitchener. Additionally, it will provide an opportunity to improve the reliability of supply to customers in the Cambridge area. Hence, the addition of a second 230/115 kV autotransformer at Preston TS in Cambridge will also be required.

The above recommendation is subject to the outcome of the project's environmental assessment.

It is our understanding that the GATR project will take approximately 3-4 years to complete, including the necessary environmental and regulatory approvals. The OPA recommends Hydro One proceed with the project's development work.

We look forward to the opportunity to continue working with Hydro One to further develop these options.

Regards,

Amir Shalaby
Vice President, Power System Planning
Ontario Power Authority

CC
Bob Chow
Bing Young
John Sabiston
Susan Frank
Michael Lyle
Charlene de Boer

Tab 28

Environmental Defence Supplemental Interrogatory #26(a)(b) List 2

Reference: Ex. B, Tab 1, Schedule 5, Pages 17-21

Original Interrogatory

a) Please describe and list all steps taken by the OPA to assess whether increased CDM and/or DG could avoid or defer the need for a new transmission line in the KWCG area as well as the dates that each of these steps were taken. Please include a listing of the dates and subjects of all memos and reports prepared in this regard.

b) Please provide a copy of all documentation (e.g. memos, reports, etc.) prepared by the OPA in relation to an assessment of whether increased CDM and/or DG could avoid or defer the need for a new transmission line in the KWCG area.

Supplemental Interrogatory

While the original interrogatory is as above, in the Board's July 8, 2013 Decision and Order on Motion, the Board Findings indicates the following:

> *The Board is of the view that interrogatories no. 26(a) and (b) are very broad and questions the relevance of the information that is being requested. The Board is also concerned about the considerable effort entailed in collecting and assembling the requested information. To that end, the Board notes that Environmental Defence acknowledges that its request may be construed as being too broad and agreed that the provision of only the key documents is acceptable.*
>
> *The Board also notes that in part (a), the OPA has provided a description of the planning process and the consideration of alternatives.*
>
> *The Board will require Hydro One and/or the OPA to produce any reports and "thorough analysis" (in whatever format) that they have on the very specific topic of "assessment of whether increased CDM and DG could avoid or defer the need for new transmission line in KWCG area".*[1]

[1] Environmental Defence Interrogatory No. 26 (a) and (b)

Supplemental Response

The OPA did not commission any external reports nor prepare any internal reports on whether increased conservation and demand management ("CDM") and distributed generation ("DG") could avoid or defer the need for a new transmission line in the Kitchener-Waterloo-Cambridge-Guelph ("KWCG") area. The OPA also does not have any "thorough analysis" on this topic apart from what has already been filed. The OPA's evidence found in Exhibit B, Tab 1, Schedule 5, as well as the interrogatory responses provided in Exhibits I, Tab 2, Schedules 26, 44 and 30 (Attachment 1) (the draft Kitchener-Waterloo-Cambridge-Guelph area Integrated Regional Resource Plan) is, in effect, the analysis completed by the OPA with respect to the assessment of whether increased CDM and DG could avoid or defer the need for a new transmission line in the KWCG area. However, to assist the Board in better understanding the OPA's analysis on this topic, the OPA is attaching to this interrogatory response additional relevant data that informed the OPA's analysis. This is explained below.

The OPA's analysis regarding the assessment of whether increased CDM could avoid or defer the need for a new transmission line in the KWCG area was informed by a number of factors including the OPA's experience with conservation programs as described in Exhibit I, Tab 2, Schedule 44, discussions with the Conservation Subcommittee of the KWCG Working Group, as well as the information contained in the KWCG area Local Distribution Companies' ("LDCs") CDM Strategies and CDM 2011 Annual Reports, at Attachments 1-10 to this exhibit. The CDM Strategies of the KWCG area LDCs illustrate their plans for achieving their CDM targets, and the LDC's CDM 2011 Annual Reports describe their achievement towards their CDM targets as of December 2011. Both of these reports are based on the unique composition of the LDCs' service territories. These factors influenced the OPA's view that the LDCs' 2011-2014 CDM targets are aggressive and will require a significant level of effort to achieve. This further reinforced the OPA's view that additional conservation is not a feasible means of addressing the KWCG area near- and medium-term needs.

The OPA's analysis regarding the assessment of whether increased DG could avoid or defer the need for a new transmission line in the KWCG area was informed by the OPA's recent experience with generation procurement programs, the characteristics of different generation resource types, as well as the cost analysis conducted to compare the cost of additional distributed generation to that of the recommended transmission reinforcements (as described in Exhibit I, Tab 2, Schedule 26).

Regarding the OPA's experience with generation procurement programs, as discussed in Exhibit I, Tab 2, Schedule 21, over the past year the OPA and the Ministry of Energy have been reviewing a number of initiatives, including the OPA's Combined Heat and Power Standard Offer Program ("CHPSOP") and Feed-in-Tariff ("FIT") Program, in the context of rising electricity prices and the current needs of the Ontario electricity system. The reviews of these programs highlight the considerable uncertainty associated with the development of non-contracted distributed generation facilities.

Within the KWCG area, as indicated by Environmental Defence in Exhibit I, Tab 2, Schedule 21, approximately 60 MW of potential solar, biogas and combined heat and power projects have been proposed in the City of Guelph through the CHPSOP and FIT programs.[2] As discussed in Exhibit I, Tab 2, Schedule 21, these proposed projects even if contracted, in total, are not sufficient to defer the need for the recommended transmission reinforcements. Attachment 11 to this exhibit provides more detailed information that supported the OPA's view that these projects could not address the supply capacity needs of the KWCG area.

With respect to the OPA's cost assessment of distributed generation resources, in the hope of providing further assistance to the Board and intervenors, at Attachment 12 to this exhibit, a more detailed breakdown of the OPA's cost assessment of distributed generation resources is provided. This assessment helped to inform the OPA's view that additional distributed generation is not a cost-effective means of addressing the KWCG areas near- and medium-term supply capacity needs.

Finally, in addition to the above analyses, the OPA conducted a sensitivity analysis that considered the impact of higher and lower demand scenarios. As indicated in Section 5.4 of the draft Kitchener-Waterloo-Cambridge-Guelph area Integrated Regional Resource Plan, "while lower than expected demand growth may defer the supply capacity in the Kitchener-Guelph 115 kV in the longer-term, the majority of the needs in the KWCG area will need to be addressed in the near-to-medium timeframe under the lower demand scenario" (Exhibit I, Tab 2, Schedule 30, Attachment 1). The low demand scenario complements the "thorough analysis" completed by the OPA to assess whether increased CDM and DG could avoid or defer the need for a new transmission line in the KWCG area.

[2] 30 MW of solar, 2 MW of biogas and 28 MW of combined heat and power as noted by Environmental Defence in Exhibit I-2-21.

Figure 4: Board-Approved CDM Programs

Program Name	Projected Budget ($)	Total Projected Reduction in Peak Provincial Demand (MW)	Total Projected Reduction in Electricity Consumption (GWh)	Cost Effectiveness Tests	
				TRC Ratio	PAC Ratio
Community Education Events	1,350,000	0.2	10	1.7	1.6
Neighborhood Benchmarking	3,150,000	2	61	1.2	1.2
Monitoring & Targeting	4,250,000	5	10	1.6	1.5
Small Commercial Energy Management and Load Control	15,200,000	20	20	1.7	1.9
Municipal and Hospital Energy Efficiency Performance	3,950,000	1	26	1.4	1.1
Double Return Plus	4,100,000	21	52	11.3	7.4
Total	**32,000,000**	**49**	**179**		

The MW and GWh estimates are based on past programs' EM&V (e.g. Double Return) and data from third party consultants.

As part of Hydro One's process to develop the proposed OEB Approved Programs, the Company carried out cost effectiveness tests, including Total Resource Cost ("TRC") and Program Administrative Cost ("PAC") tests. Hydro One has also worked with other distributors and gas companies in order to maximize program efficiencies. Joint delivery of Board Approved Programs by CLD members can generate cost efficiencies for CLD members. Further synergies with the gas companies are also being investigated to further

Tab 29

Environmental Defence INTERROGATORY #29 List 1

Reference: Ex. B, Tab 1, Schedule 4, Page 1

Interrogatory

a) Did any members of the KWCG Working Group request that the OPA implement *additional* CDM programs and/or procure more DG in the KWCG area relative to what the OPA's evidence in this proceeding states that it is proposing to do? If "yes", please identify all the members that made such a request and fully describe their requests and the OPA's responses.

b) Please provide copies of all of the KWCG Working Group's meeting agendas and minutes and reports.

Response

a) No members of the KWCG working group requested that the OPA implement additional CDM programs and/or procure more distributed generation in the KWCG area relative to what the OPA is proposing in its evidence.

b) The KWCG Working Group's report is not finalized; however, to assist the Board and intervenors, the OPA is providing a copy of the draft report at Exhibit I, Tab 2, Schedule 30, Attachment 1. The OPA is not providing copies of all Working Group documentation.

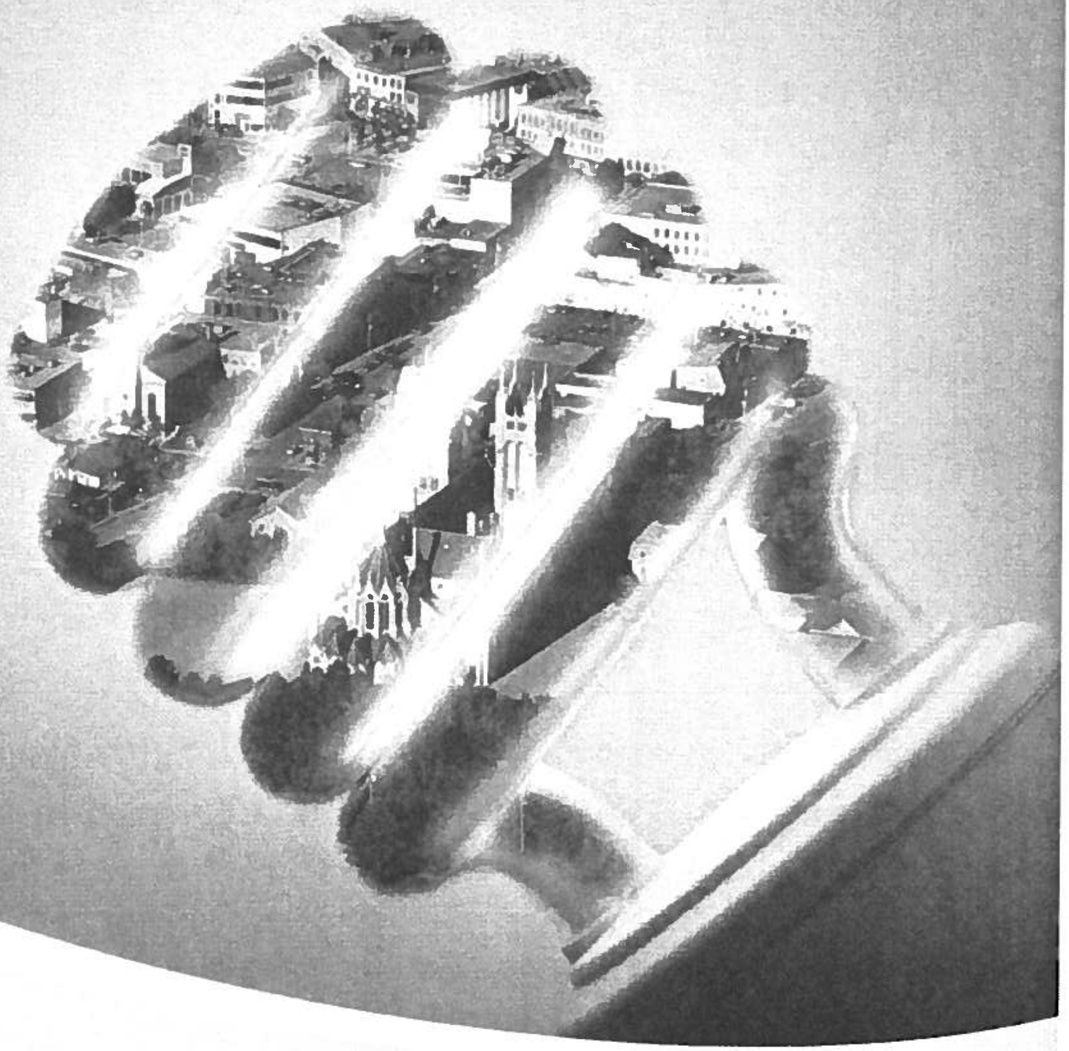
Tab 30

COMMUNITY ENERGY PLANNING

Garforth International llc
Energy Productivity Solutions

CITY OF Guelph
Making a Difference

Community Energy Plan



Garforth International llc
Energy Productivity Solutions

Owens Corning

MVV·Energie

Rannier Consulting

Final Report dated 3rd April 2007

Prepared For
Guelph Community Energy Plan Consortium

The overall vision of the CEP is simple:

Guelph will create a healthy, reliable and sustainable energy future by continually increasing the effectiveness of how we use and manage our energy and water resources

This vision is supported by five goals that focus on the CEP's role in attracting quality investment, in ensuring reliable and affordable energy, in reducing environmental impacts, in enhancing Guelph's competitiveness, and in aligning public investment with the CEP. Each has recommended long-term measurements detailed in the plan.

- ***Guelph will be the place to invest, supported by its commitment to a sustainable energy future***
- ***Guelph will have a variety of reliable, competitive energy, water, and transport services available to all***
- ***Guelph energy use per capita and resulting greenhouse gas emissions will be less than the current global average***
- ***Guelph will use less energy and water per capita than comparable Canadian cities***
- ***All publicly funded investments will visibly contribute to meeting the other four CEP goals***

Successful delivery of these goals brings tangible financial and other benefits to residents, local business, the city administration, developers and builders, banks and investors, and the energy suppliers.

Guelph was an early pioneer in the development of community energy solutions by being a key player in developing municipal energy distribution in Ontario 100 years ago. Taking the lead for the next 100 years is entirely consistent with this tradition. Today the city covers about 86,000 km2. The population of 115,000 is estimated to grow by at least 2% per year to approximately 180,000 by 2031. Residential growth will be from a mixture of redevelopment in some older areas, and new development on greenfield sites. Industrial and commercial developments are planned in six areas around the city.

Today, Guelph uses a total of 6,030 gigawatt hours of equivalent energy (GWh_e) from fuels of all types, or 52.45 megawatt hours of equivalent energy (MWh_e) for every inhabitant of the city. If the heat wasted in the production of electricity for the city is included, the total rises to 8,475 GWh_e or 73.71 MWh_e/capita. This is the energy directly consumed in the cities buildings, vehicles, and industries, and does not include energy used in ships, airplanes, long-haul freight or other transportation. In general, the Guelph CEP focuses on the energy directly used in the city as this can be more easily influenced by community action. In 2005 a total of 19.2 million cubic meters of water was pumped and treated. Lost water totaled approximately 14 percent of all water pumped. The average daily water demand was 52,579 cubic meters.[2]

---

[2] http://guelph.ca/uploads/ET_Group/waterworks/Waterworks_Summary_Report_2005.pdf

This use is comprised of 230-250 litres per equivalent population per day for household use, with the balance being used by commerce and industry.

Guelph's climate, with over 4,352 heating degree days compared to only 180 cooling degree days, puts a high demand on space heating, and the plan addresses the heating alternatives in some detail.

The CEP was developed using the following priorities:

- Maximize the energy and water efficiency for buildings, vehicles and industry
- Maximize use of heat generated in electricity generation and existing industrial processes
- Incorporate as many renewable energy sources as feasible
- Team with the existing electricity and gas networks to avoided wasteful duplication of assets

Cities that systematically implement these principles year after year typically have energy levels at least half of the current levels of Guelph, with all the associated economic and environmental benefits that this brings.

On the first priority, efficiency, detailed assessments were made of the present 33,000 homes and 1.7 million m^2 non-residential buildings by age and energy use. The needs for the future industrial energy use and transport fuels use were similarly assessed.

Following these priorities, the CEP recommendations are:

Use efficiency to create at minimum all the energy needed to support the growth of the residential sector

It is feasible to add about 20,000 homes with no net increase in energy needs and this is the recommended target. Ontario recently passed stringent new energy efficiency building codes that will be fully in force by 2012. The CEP is recommending that the city explore incentives and other approaches to immediately implement the full code. This alone, combined with energy efficiency requirements on major residential renovations creates all the energy needed for growth.

From 2012 onwards, the CEP is recommending a steady annual improvement in energy efficiency of about 1% per year, which by 2031, would be a level that aligns with global best practice from Scandinavia and Germany.

Use efficiency to create all the energy needed to support the growth of the commercial and institutional sectors

Similarly, all the energy needed to support the entirety of the growth of commercial and institutional buildings energy needs can be met by the same combination of immediate implementation of the new codes and efficient renovation.

Adopt an energy performance labeling scheme for buildings as a voluntary initiative for the city, teamed with Natural Resources Canada and a local mortgage bank, to act as a pilot for the whole of Canada to gain about 5% incremental delivered efficiency

The CEP is recommending that all new and existing buildings have an Energy Performance (EP) Certificate that guarantees the building's energy consumption in normal operation at the time the building is sold or even rented. There is no Canadian EP Certification at present. It is the subject of much discussion at a Federal level in Canada, and the recommendation is to offer Guelph as a national pilot.

The recommendation is to model around an emerging approach being discussed in Canada that is an amalgam of the Canadian Energy Guide and the European Union approach.

The experience in other jurisdictions is that this stimulates somewhat higher quality buildings and a certain amount of "efficiency competition" between developers.

Add to Guelph's attractiveness for quality industrial investment by offering world class tailored energy services and achieve annual investment growth rates higher than the underlying population growth, with no overall increase of the primary energy needed to serve the first fifteen years of growth.

Increasingly, industrial investors are looking at energy services as a key part of their decision on where to invest. The CEP is recommending developing tailored energy services for selected industrial development areas that not only deliver gas and electricity, but also selectively deliver other energy forms such as compressed air, process steam heating and cooling, etc.

Meet Guelph's growing transport requirements while reducing the transportation energy use by 25%, using sensitive urban design, effective alternative transport options, and encouraging vehicle efficiencies.

Transport fuels collectively represent 30% of all the energy used in Guelph, and account for a huge 45% of all the greenhouse gas emissions caused by the city. The CEP recommends a multi-pronged approach that includes various measures to encourage more efficient vehicles, urban design that reduces vehicle journeys, and focused attention on appropriate competitive mass transit.

Many of these measures were already being developed in detail in Guelph's wider transport and urban planning. The CEP is underlining the importance of their success to meeting the overall energy and climate change goals.

Incrementally create energy distribution architecture in Guelph that will allow the majority of the city to be served with fuel choices that optimize cost, availability, and environmental impact long into the future.

Over the coming years major changes will happen in energy and environmental legislation, fuel availability, the viability of emerging alternative energy technologies and their relative costs. To be able to achieve maximum benefit from these changes, the CEP is recommending a stepwise development of district heating networks covering the higher density areas of the city to supply space heating and domestic hot water. These networks also provide an efficient and economic way to distribute heat from a variety of existing and new energy sources.

In evaluating benchmark cities such as Mannheim or Copenhagen, we find that a common feature of these very efficient and reliable energy and water systems was the existence of all energy services being supplied by a single company. This avoids the inefficient use of primary fuel, and allows a rational integration of alternative energy sources. The CEP is recommending this approach.

Within fifteen years, at least a quarter of Guelph's total energy requirement will be competitively sourced from locally created renewable resources

The challenge around climate change will increasingly turn the focus on renewable fuels as a viable and essential way to reduce greenhouse gas emissions. Currently the economic value of greenhouse gas reductions is zero, but this is likely to change as various market mechanisms come into force.

The CEP is strongly recommending a target to install the equivalent of a "Thousand Roofs" of solar photovoltaic electricity.

The heat demand of the area makes it a natural fit for integrating bio-mass heat sources combined with district heating to provide about 10% of the base load heat needs through the winter. The local wind quality makes energy from turbines marginal under the current technology. Last but not least, the growing need to find environmentally acceptable ways to manage municipal waste merits a rigorous assessment of the waste-to-energy potential.

Target – At least 30% of Guelph's anticipated electricity requirements will be associated with Combined Heat and Power (cogeneration) by 2031.

As the city's energy evolves to include more district energy, it begins to include small and medium scale combined heat and power installations. Today Guelph's 1,627 GWh annual electricity use in reality uses 4,074 GWh_e of fuel, the difference being lost as heat, creating non-productive costs and significant greenhouse gas emissions. By implementing CHP within larger developments, much of this heat can be effectively captured and used, creating major cost and environmental benefits. The CEP recommendation is to proactively seek CHP projects with a total electric capacity in the 75 to 100 MW range with a comparable level of heat recovery.

Guelph will reduce the magnitude of the summer grid electrical peak by at least 40% by 2031 to avoid the need for investment in new electrical infrastructure to serve the growth of the city

One of the consequences of growing prosperity and the norms of new construction is the increasing use of air-conditioning, even though climatically there is relatively little need. The result is very high electrical demands for a few hours a day during the summer months. This peak drives substantial investments in underutilized generation, transmission and distribution assets by the electric utility.

The cumulative effect of many of the preceding measures including efficiency, cogeneration, heat recovery and solar PV will moderate and reduce the peak.

Guelph will systematically create an integrated energy metering, billing and management network across the entire city to allow cost-effective management of all energy forms

The energy breakthroughs foreseen by the CEP arise as a result of seamless integration of energy efficiency along electrical, gas and district heating networks, with a flexible and, over time, changing mix of renewable and non-renewable energy sources. Such an approach requires a high degree of management and data sharing across the different parts of the system to deliver maximum benefit. The recommendation is to establish a common data management and metering architecture within the city.

Guelph will implement large area high-efficiency Scale Projects that accelerate progress towards a successful implementation of the CEP by creating early success and developing a deep pool of community expertise

All too often, CEPs fail to deliver due to a lack of sufficient scale and early success. The Consortium was committed to make sure that did not happen in Guelph. As a result, the CEP is recommending implementing neighborhood energy plans in relatively large, but bounded areas of the city.

The plan is calling for the early identification and implementation of Scale Projects. Some specific ideas are included as part of the CEP, and include various business and industrial areas, the greenfield mixed use developments targeted for the south of the city, the University of Guelph Campus as a whole, and the revitalization of the St. Patrick's Ward. These are offered as viable examples of potential Scale Projects.

The CEP also recommends elements that will ensure long-term successful implementation. Many Federal, Provincial and local programs exist and the CEP is recommending the city maintain information and offer assistance to capture as many of these resources as possible. The Consortium clearly recognizes that some of the measures proposed will require adjustment or interpretation of regulatory or other legal constraints, and is committed to clear these kinds of market barriers wherever possible. Since many of these challenges will be of interest beyond Guelph, the CEP is suggesting that Guelph can be a national prototype as these market and regulatory structures emerge. A high priority in this area will be to establish the market framework of a municipal energy service organization that is structured to ensure the highest reliability, least cost and least environmental impact energy services of all types.

Guelph's elected officials, business community, financial institutions, neighborhood groups, utilities, architects, developers, construction industry, academia and the city administration are clearly committed to the vision, goals, recommended actions and progress of the CEP as a key measure of Guelph's overall success in becoming a world class city in which to live, work and play.

In support of this, the CEP is recommending community and neighborhood groups be instrumental in ensuring Scale Projects are sensitively implemented and the energy and environmental goals are fully achieved. The CEP also presents an amazing opportunity for the University of Guelph and other colleges to build on the city's commitment to the CEP by developing specialist areas of study, training and research such that Guelph will become a center of excellence on the theory and practice of sustainable urban development.

The goals that the CEP has established are intentionally very aggressive and are generational in nature. The CEP is strongly recommending the city put in place a regular reporting system to track the progress towards the goals and to share best practices with the community, both through conventional and electronic media, and as a regular topic at City Council Meetings.

Guelph is already blessed with a number of commercial, non-profit and general interest groups as well as individuals working towards sustainability, energy efficiency and alternative energy in some way. The CEP made a first step to create an inventory of some of these resources, and this should be the basis of a developing resource database.

Despite the anticipated growth of the population and increase in economic activity, the overall fuel use required by the city to deliver all its energy service will actually decrease from today's total of 8,475 GWh_e to 6,135 GWh_e in 2031. This represents a decrease of greenhouse gas emissions, currently at an estimated 16 tonnes per inhabitant, to about 7 tonnes. This is still some distance from the ambitious goal, but at a level that is clearly putting Guelph among the top energy performers in the world.

At the same time, Guelph will take its place as one of the most competitive and attractive cities in Ontario and Canada, with a core energy productivity expertise that will be sought out around the world.

Environmental Defence INTERROGATORY #33 List 1

Reference: Ex. B, Tab 1, Schedule 4, Page 1

Interrogatory

a) Please state the maximum financial incentive that each LDC member of the KWCG Working Group can receive from the OPA if it under spends its CDM budget.

b) Please confirm that an LDC can earn the maximum financial incentive for under spending its CDM budget even if it fails to achieve 100% of its CDM target as established by the Ontario Energy Board.

Response

a) LDCs do not have a set budget for spending on CDM programs; however LDCs do have a maximum defined Program Administration Budget ("PAB").

LDCs may be eligible to receive a Cost Efficiency Incentive for each Registered CDM Program as a percentage of the cost savings represented by the difference between the Program Administration Budget and the eligible Program Administration Expenses.

The maximum Cost Efficiency Incentive that a LDC could receive is 15% of their PAB, in the case where their eligible Program Administration Expenses represent 80% of their PAB.

The formula for calculating the Cost Efficiency Incentive available to LDCs is set out in Schedule A-5, Section 2 of the Master CDM Program Agreement available at: http://www.powerauthority.on.ca/sites/default/files/new_files/industry_stakeholders/current_electricity_contracts/pdfs/Master%20CDM%20Program%20Agreement.pdf

The total maximum available funds for the KWCG LDC's PAB are set out in the table below as well as their maximum Cost Efficiency Incentive (e.g., 15% of PAB).

LDC	**Total Maximum Available Funds for LDC Program Administration Budgets (rounded to nearest $10,000)**	**Maximum Cost Efficiency Incentive (15% of PAB)**
Cambridge and North Dumfries Hydro Inc.	$3,210,000	$481,500
Guelph Hydro Electric Systems Inc.	$3,100,000	$465,000
Kitchener-Wilmot Hydro Inc.	$4,400,000	$660,000
Waterloo North Hydro Inc.	$3,060,000	$459,000
Hydro One Networks Inc.*	$52,610,000	$7,891,500

* Note: Hydro One Networks serves a significant number of customers outside of the KWCG area, and as such only a portion of their budget is for the KWCG region

b) Achievement of the conservation targets is a condition of the LDC's license, as set out by the OEB. The eligibility criteria to receive the Cost Efficiency Incentive are set out in Article 4.5 of the Master CDM Program Agreement available at: http://www.powerauthority.on.ca/sites/default/files/new_files/industry_stakeholders/current_electricity_contracts/pdfs/Master%20CDM%20Program%20Agreement.pdf

Tab 31

Environmental Defence INTERROGATORY #33 List 1

Reference: Ex. B, Tab 1, Schedule 4, Page 1

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Tab 32

Environmental Defence INTERROGATORY #34 List 1

Reference: Ex. B, Tab 1, Schedule 5, Page 28

Interrogatory

a) Please provide an estimate (or various estimates) of the impact on Hydro One's net income for each of the next 20 years that will result from constructing the facilities proposed in this proceeding. Please make and state any reasonable assumptions necessary to provide an estimate.

b) Please provide an estimate (or various estimates) of the impact on Hydro One's net income (if any) for each of the next 20 years that would result from sufficient CDM and DG being implemented to avoid the need for the transmission line proposed in this proceeding. Please make and state any reasonable assumptions necessary to provide an estimate.

Response

a) Hydro One's net income resulting from the proposed transmission facilities has been estimated based on the revenue requirement impact provided as Exhibit B, Tab 4, Schedule 3, Table 2. Incremental return on common equity is assumed to be a proxy for net income for each of the next 20 years.

Guelph Area Transmission Reinforcement *Calculation of Incremental Return on Common Equity ($ millions)*	Project YE 31-Dec 2016 1	Project YE 31-Dec 2017 2	Project YE 31-Dec 2018 3	Project YE 31-Dec 2019 4	Project YE 31-Dec 2020 5	Project YE 31-Dec 2021 6	Project YE 31-Dec 2022 7	Project YE 31-Dec 2023 8	Project YE 31-Dec 2024 9	Project YE 31-Dec 2025 10
Rate Base (Exhibit B, Tab 4, Schedule 3, Table 2)	42.5	84.2	82.5	80.7	79.0	77.3	75.5	73.8	72.1	70.3
Common Equity (60% of Rate Base)	25.5	50.5	49.5	48.4	47.4	46.4	45.3	44.3	43.2	42.2
Allowed Equity Return	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%
Return on Common Equity	**2.3**	**4.5**	**4.4**	**4.3**	**4.2**	**4.1**	**4.0**	**4.0**	**3.9**	**3.8**

Guelph Area Transmission Reinforcement *Calculation of Incremental Return on Common Equity ($ millions)*	Project YE 31-Dec 2026 11	Project YE 31-Dec 2027 12	Project YE 31-Dec 2028 13	Project YE 31-Dec 2029 14	Project YE 31-Dec 2030 15	Project YE 31-Dec 2031 16	Project YE 31-Dec 2032 17	Project YE 31-Dec 2033 18	Project YE 31-Dec 2034 19	Project YE 31-Dec 2035 20
Rate Base (Exhibit B, Tab 4, Schedule 3, Table 2)	68.6	66.8	65.1	63.4	61.6	59.9	58.2	56.4	54.7	53.0
Common Equity (60% of Rate Base)	41.1	40.1	39.1	38.0	37.0	35.9	34.9	33.9	32.8	31.8
Allowed Equity Return	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%
Return on Common Equity	**3.7**	**3.6**	**3.5**	**3.4**	**3.3**	**3.2**	**3.1**	**3.0**	**2.9**	**2.8**

b) With the required CDM and DG being largely implemented by the local LDCs, given their much larger service areas in the KWCG region compared with Hydro One Distribution's, it is a reasonable assumption that any resulting impact to Hydro One's net income would be minimal.

Tab 33

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

Ontario Energy Board

Chapter 4 of the Filing Requirements For Electricity Transmission and Distribution Applications

May 17, 2012

Table of Contents

4.4 Filing Requirements for Projects under Section 92

The analysis of public interest implications may vary depending on the Applicant (rate-regulated or non rate-regulated) and type of transmission project being reviewed. The following minimum filing requirements apply to projects in a leave to construct proceeding. The exhibit designation is a suggestion and is not mandatory.

Exhibit A: Index

An index table listing exhibit numbers, tabs and schedules, and each of their contents shall be provided.

Exhibit B: The Application

1. Administrative

This section should include the formal signed application, which must include the following:

- the name of the applicant and partnerships involved in the application;
- the authorized representative of the applicant, phone, e-mail, fax and delivery address;
- an outline of the business of the applicant and parties in the application;
- an explanation of the purpose of the project for which leave to construct is being sought ;
- the financial structuring for the project, as necessary;
- a concise description of the routing and location of the project, including the affected municipalities and regions;
- a description of project components and their locations, activities, and related undertakings;
- the rationale for selecting the proposed project as opposed to any for alternatives considered
- an explanation of how the project is in the public interest, as defined by section 96(2) of the Act; and,
- the project schedule.

2. Project Overview Documents

The evidence in this section provides the background and a summary of the application, and assists the Board in drafting a Notice of Hearing for potential interested parties. This must include:

- a detailed description of location of the project and its components;
- maps (1:50,000 or larger) showing: the route, facility sites and any proposed ancillary facilities;

- the location of project components and related undertakings;
- line drawings of the proposed facility, showing supply connection(s) to the proposed facility and delivery facilities from the proposed facility to any adjacent transmission and/or distribution system(s); and
- the nominal rating of the main components of the project, including the transformers.

3. Need for the Project

In leave to construct applications, the Board's consideration is limited to the interests of consumers with respect to prices and the reliability and quality of electricity service and, where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources. This is mandated by section 96(2) of the Act, and the Board does not have the power to consider broader issues. The Board's consideration of the "need" for a project, therefore, can relate only to matters described in section 96(2).

Project justification delineates the responsibilities and necessary evidentiary components required for the project review. The responsibility for the provision of all evidence for the entire case rests with the applicant.

The applicant's evidence in support of the need for the project is required to be submitted and can be supported as necessary by evidence of the Independent Electricity System Operation ("IESO"), the transmitter, and/or the Ontario Power Authority: ("OPA"):

Where the Board has already considered aspects of the "price" consideration through a rates proceeding the applicant must still provide with their application:

- a description of the need for the project;
- a detailed reference to those approvals for any projects forming part of an approved plan or rate order; and,
- the reasons given for the inclusion of the project in those proceedings.

Classification of Project Need for Rate-regulated Transmitters:

This section relates to additional information required to be provided by rate-regulated Transmitters. Project Categorization, Classification and Justification assist in determining the need for the project. The categorization and classification are considered in a matrix as shown:

PROJECT NEED			
		PROJECT Categorization	
		Non-discretionary	Discretionary
PROJECT Classification	Development		
	Connection		
	Sustainment		

The classification and categorization is discussed in further detail here.

a) Project Classification

Project Classification is the classification of a project into one of three project classes:

- **Development projects** are those for providing:
  - an adequate supply capacity and/or maintaining an acceptable or prescribed level of customer or system reliability for load growth meeting increased stresses on the system; or
  - enhancing system efficiency such as minimizing congestion on the transmission system and reducing system losses.

- **Connection projects** are those for providing connection of a load or generation customer or group of customers to the transmission system.

- **Sustainment projects** are those for maintaining the performance of the transmission network at its current standard or replacing end-of-life facilities on a "like for like" basis.

It is acknowledged that projects can have elements of development, connection, or sustainment. In these cases, the applicant should identify the proportional make-up of the project, and then classify the project based on the predominant driver.

An investment in the Network may be required in any of these three project classifications. Network facilities are comprised of network stations and the transmission lines connecting them.

b) Project Categorization

The categorization stage identifies the project need as:

- **Non-discretionary** – a "must do" project, the need for which is determined beyond the control of the applicant ("Non-discretionary"), or
- **Discretionary** – the need is determined at the discretion of the applicant ("Discretionary").

The purpose of project categorization is to distinguish whether the project need is **beyond** the control of the ("Non-discretionary") or **at the discretion** of the Applicant ("Discretionary").

Non-discretionary projects may be triggered or determined by such things as:

- mandatory requirement to satisfy obligations specified by regulatory organizations including NPCC/NERC (the designated ERO in the future) or by the IESO;
- a need to connect new load (of a distributor or large user) or new generation (connection);
- a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
- projects identified in a Board or provincial government approved plan;
- projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and
- a need to comply with direction from the Ontario Energy Board in the event it is determined that the transmission system's reliability is at risk.

Discretionary projects are proposed by the applicant to enhance the transmission system performance, benefiting its users. Projects in this category may include:

- projects to reduce transmission system losses;
- projects to reduce congestion;
- projects to build a new or enhance an existing interconnection to increase generation reserve margin within the IESO-controlled grid, beyond the minimum level required;
- projects to enhance reliability beyond a minimum standard; and
- projects which add flexibility to the operation and maintenance of the transmission system.

4. Evidence in Support of Need

The reasons that a project is necessary must be identified. The basic form for such evidence should be cost-benefit analyses, if applicable, of various options. The Board expects that Applicants will present:

- the preferred option (i.e. the proposed project); and
- alternative options.

It should be recognized, however, that the Board will either approve or not approve the proposed project (i.e. the preferred option). It will not choose a solution from among the alternative options. The applicant should present the smallest number of alternatives consistent with conveying to the Board the major solution concepts available to meet the same objectives that the preferred option meets.

When providing evidence on the need for the applied-for project, support may arise from a comparison with alternative possible projects. Where a proposed project is best compared to other viable transmission alternatives, the comparison should include "doing nothing".

Where the applicant lists the benefits of a leave to construct project as avoiding non-transmission alternatives such as a peaking generation facility or a "must run" generation requirement, it is helpful for the applicant to include corroborative evidence from the IESO or the OPA regarding the Applicant's quantitative evaluation of such a benefit. In any event, this evidence is required to support the need for the project.

The applicant is expected to also compare the alternatives versus the preferred option along various risk factors including, but not limited to:

- financial risk to the applicant;
- inherent technical risks;
- estimation accuracy risks; and
- any other critical risk that may impact the business case supporting the proposed project.

If the proposed project alternatives are expected to have significant qualitative benefits that cannot reasonably be quantified, evidence about these qualitative benefits should be provided. These benefits may be taken into account in ranking the alternatives. Incorporating qualitative criteria may result in a different ranking of projects compared to the ranking based on quantitative benefits and costs alone. For example, a project may be compared on the basis of its degree of disruption to property owners (least, more and most disruptive).

In addition to the evidence regarding the need for the project, the Applicant must address how it proposes to accomplish the project including the identification of relevant options.

For connection projects, in addition to the cost benefit analysis, the applicant must supply specific information on the nature and magnitude of the network impacts. Certain connection projects may require network reinforcement in order to proceed. A description of the additional information requirements in such cases is provided in Appendix 4 -A to this Chapter. Some of these requirements could affect an evaluation of projects and this should be taken into account.

Where an applicant attributes to a proposed project market efficiency benefits such as lower energy market prices, congestion reduction, or transmission loss reduction, the evidence submitted must include quantification of each of the market efficiency benefits listed for that proposed project.

Evidence of Need in Non-discretionary Projects

In the case of a non-discretionary project, the preferred option should establish that it is a better project than the alternatives. The applicant need not include "doing nothing" as an alternative since this alternative would not meet the need. One way for a rate-regulated applicant to demonstrate that a preferred option is the best option is to show that it has the highest net present value as compared to the other viable alternatives. However, this net present value need not be shown to be greater than zero. In contrast, in the case of a discretionary project, "doing nothing" would count as a viable option.

External Need Factors

In some cases, a discretionary or non-discretionary project's need is driven by factors external to the applicant, such as the need to satisfy an IESO requirement or to serve an incremental customer load. Where the applicant identifies a customer or agency (such as the IESO or the OPA) as the driver behind a project:

- It is the Applicant's responsibility to include evidence from that customer or agency as part of the evidence in the application.
- The customer or agency must be prepared to provide witnesses as needed to support the filed evidence if an oral hearing is held.
- It is not sufficient for the applicant to state that the customer or agency has established the need for the project; the Board must be able to test that assertion.
- The Board expects the applicant to work with that external party in the development of the required evidence. The external party will often be the IESO and/or the OPA, although the additional evidentiary requirement could apply to any external party on whom the applicant has relied for the justification of the need for the project.

The evidence may include:

- written material prepared by the customer or agency specifically addressing the proposed project, and,
- a list identifying the key driving factors of the evidence justifying the project need, and the party (e.g. the applicant, the IESO, or the OPA) which has prepared the evidence to justify a given key driving factor.

5. Project Shared Costs

Where there are costs which are shared between rate regulated and non rate-regulated parties, proponents must provide details of project costs to the rate-regulated party. Applicants should provide details covering:

- labour - including a breakdown by facility installations;
- materials - including a breakdown of all facility costs;
- cost of similar projects constructed by the applicant or by other entities for baseline cost comparisons covering:
    - in-service year of the comparator project, and
    - similarities and differences in terms of voltage level, type of towers, type of terrain, etc.
- acquisition of land use rights, and land acquisition including permanent and working easements, survey and appraisals, legal fees, crop and damage compensation;
- direct and indirect overheads broken down by facility installation; and,
- allowance for funds used during construction ("AFUDC").

6. Transmission Rate Impact Assessment

The Board requires information relating to the rate impacts anticipated from transmission investments. Information should cover the short-term impacts as well as long-term impacts of the proposed project.

7. Establishment of Deferral Accounts

The Board would consider applications by licensed transmitters requesting that the Board include with its grant for leave to construct, the establishment of a deferral account (under the Uniform System of Accounts) to track the project construction costs and that such accounts would be reviewed for prudence and inclusion in rate base in a future rate proceeding.

Exhibit C: Project Planning

The applicant must provide the Board with time estimates for construction and service dates, including:

- the critical path and time frame for the completion of construction and operational start-up of the proposed facilities;
- any aspects of the start-up of operation relative to the introduction of the new or