EB-2015-0029
EB-2015-0049

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 Union Gas Ltd. pursuant to Section 36(1) of the *Ontario Energy Board Act, 1998,* S.O. 1998, for an order or orders approving its Demand Side Management Plan for 2015-2020;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. pursuant to Section 36(1) of the *Ontario Energy Board Act, 1998,* S.O. 1998, for an order or orders approving its Demand Side Management Plan for 2015-2020.

ASSOCIATION OF POWER PRODUCERS OF ONTARIO (APPrO) COMPENDIUM OF MATERIALS FOR OSEA CROSS-EXAMINATIONS

31 August 2015

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TAB 1

Ministerial Directive O.C. 467/2014 dated March 26, 2014, attached hereto and marked as Exhibit "F" [2014 Ministerial Directive].

IV. <u>SUSTAINABLE ENERGY OPPORTUNITIES RELATED TO INTEGRATED DSM AND CDM</u>

14 The 2014 Ministerial Directive requiring gas and electric distribution companies to collaborate more closely should be recognized as an opportunity for a broader range of activities for both gas DSM and electric CDM. This includes a fuller realization of the vision enunciated by the Green Energy Act Alliance and the *Green Energy and Green Economy Act* and implementation of sustainable energy measures, such as high efficiency CHP, ground source heat pumps and solar thermal water heating.

15 The following are examples of opportunities that Enbridge and Union can implement in their DSM Plans pursuant to a broader energy systems approach to conservation and related sustainable energy applications.

A. COMBINING AVOIDED COSTS FOR NATURAL GAS AND ELECTRICITY

16 The current approach of regulating natural gas and electric utilities independently leads to overlooked efficiencies. Currently, Ontario's supply of electricity is dominated by large central power plants that have relatively low overall efficiency rates, which results in a large waste of heat energy.

17 Combining the avoided costs for both electricity and natural gas, plus using the prescribed 15% adder for non-energy benefits would allow a broader range of technologies, measures and applications than gas only analyses or electric only analyses.

> *Compared to single-fuel programs, combined natural gas and electric energy efficiency programs often deliver additional energy*

> *and dollar savings at lower cost to utilities and consumers. They also enhance customer satisfaction. Many leading dual-fuel programs demonstrate these benefits. Energy efficiency programs that include both gas and electricity measures have many benefits that are not available to standalone programs. Chief among these are the increased savings that result from programs and portfolios of larger size and greater resources. A gas-only program (or a particular gas measure or project) may not be cost effective enough to meet applicable benefit-cost (BC) test requirements, but when it is combined with electric measures as part of a dual-fuel efficiency program, the project as a whole has a high enough BC ratio to pass screening tests. Home weatherization programs are an obvious example.*
>
> **American Council for an Energy-Efficient Economy, *Successful Practices in Combined Gas and Electric Utility Energy Efficiency Programs*, dated August 2014.**

18 Water savings have played a major role in natural gas DSM since 1995. The interconnection between energy and water is increasingly viewed as a critical element of conservation and sustainability.

> *Water and energy are linked, intersecting at both the supply side (electric generation and water/wastewater facilities) and the end-use side (residential, commercial, industrial, and agriculture sectors). This linkage is commonly called the energy-water nexus. On the supply side, this intersection is apparent in the massive amounts of water needed to produce electricity and the while large amounts of energy required to treat, process, and transport water. On the end-use side, energy and water are connected in our homes, businesses, and industrial facilities. The water-energy linkage means that end-use efficiency programs that save water will also save energy and vice versa.*
>
> **American Council for an Energy-Efficient Economy, *Watts in a Drop of Water: Savings at the Water-Energy Nexus*, dated November 2014.**

B. NET ZERO BUILDINGS

19 While both Enbridge and Union are pursuing opportunities in new construction, their involvement in the new construction market could be much more robust with a full market transformation approach rather than a hybrid of resource acquisition programs and market transformation.

20 Traditionally, the programs have used a process to build better than code by a fixed per cent while no research has been done to understand how Ontario's Building Code actually performs with the current patchwork of compliance at the municipal level, where traditional code compliance has focused on safety, not energy. The potential for working with the local electric distribution utilities is further limited given their short term focus on saving kWh as embedded in their targets. Without strong policy or regulatory direction to avoid lost opportunities, Ontario will not be able to address all of the new construction opportunities.

> *Approximately one third of Canada's GHG emissions are attributed to building energy consumption. Buildings also account for about 53% of Canada's electricity consumption. They are largely responsible for the peaks in electricity demand associated with space heating, cooling, lighting and appliances. These peaks, if not reduced and shifted in time, will impose additional requirements to build new power plants. Without a major transformation in the way we design, build, and operate buildings, Canada cannot expect to meet its goals for reductions in greenhouse gas (GHG) emissions and for clean air in its cities. Mechanisms that allow the building to act as a net energy generating system and also shift peak demand can provide the basis for this transformation. At the same time, a comparison of the Canadian construction industry with that in other industrialized nations, points out the urgent need for Canadian innovations. This convergence of the need for innovation and the requirement for drastic reductions in energy use and GHG emissions provides a unique opportunity to transform the way we conceive buildings and their energy systems. This Network is a vital step along the way to achieving these goals. It links researchers from academia, industry and government in a united effort to develop the technologically advanced smart net-zero energy buildings (NZEBs) of the future. A net-zero energy building is defined as one that, in an average year, produces as much energy (electrical plus thermal) from renewable energy sources as it consumes.*
>
> **NSERC Smart Net-Zero Energy Buildings Strategic Research Network, online: <http://www.solarbuildings.ca/documents/FINAL%20SNEBRN_executive%20summary%20extended%20-%20REVISED%20JULY%202014.pdf>.**

C. PERFORMANCE BASED CONSERVATION – ACHIEVING THE ADDITIONAL DSM SAVINGS

21 Performance based conservation begins with identifying high energy intensity buildings through benchmarking and then works systematically towards identifying and fixing the particular inefficiencies causing the high use in each building covering gas, electricity, district energy and water. The nature of the inefficiencies runs the range of errors in design and construction, through equipment deterioration over time, to changes in use and operation of the building, and poor performance of controls and automation systems. It is the compound effect of these problems that leads to energy use levels in some buildings which is 3 to 5 times what is needed and already achieved by comparable, more efficient buildings. Fixing these problems requires a systematic methodology. The work involved in equipment repairs and replacement, right-sizing and rebalancing, refurbishment and re-programming, typically provides relatively short payback periods.

D. FUEL USE EFFICIENCY

22 An overall energy systems perspective means that improving the efficiency of the generation of electricity from natural gas from the typical efficiency of less than 40 per cent to a CHP efficiency well in excess of 90 per cent is conservation of energy. Related avoided transmission and distribution losses also represent conservation.

> *By generating much more useful energy from a single fuel input, CHP offers tremendous economic and environmental benefits to individual system owners, the local grid and society as a whole.*
>
> **Anna Chittum and Kate Farley, *Utilities and the CHP Value Proposition*, dated July 19, 2013.**

23 While efficiencies of CHP systems are dependent on the end use activity, the typical efficiency of conventional energy systems is relatively constant. For conventional thermal power plants like nuclear, coal or gas, an estimated 55-65% of energy generated is in the form of waste heat from steam turbines that is then discharged into the environment. The result is an overall energy efficiency rating which is much lower than that of a well-designed CHP system driven by heat utilization requirements. An illustration of the typical energy losses in conventional and renewable energy sources is attached hereto and marked as **Exhibit "G"**. A table setting out the characteristics of CHP plants is attached hereto and marked as **Exhibit "H"**.

24 Regulatory practices in Ontario have not been revised to reflect the broader societal benefits of CHP.

> *While some of the benefits of CHP confer to individual CHP-using facilities, most of them are public benefits conferring to society and the local grid. Individual facilities cannot fully enjoy system wide benefits but utilities can. Utilities are best positioned to help monetize the public benefits provide by CHP, and in turn convey the benefits to all of their customers.*
>
> **Anna Chittum and Kate Farley, *Utilities and the CHP Value Proposition*, dated July 19, 2013.**

25 While the principal of CHP is not new, its deployment in North America has been limited due to the focus on overwhelming emphasis on large central power plants.

26 Although large central power plants dominate today's infrastructure, this was not always the case as historically factories and communities were at one time responsible for their own electricity generation needs. The advent of new technologies like wind and solar power coupled with innovations in CHP systems

will bring a return to localized energy generation. In the case of CHP, significant grid reliability benefits exist beyond the reduction in waste heat. A comparison of energy-efficiency of a standard power plant versus a district energy/CHP plant is attached hereto and marked as **Exhibit "I"**.

27 From my analysis of the electricity generation mix of the Ontario electricity grid and the energy consumption profiles of Ontario's residential and commercial building stock, it is estimated that a shift away from large central power plants to on-site CHP could save approximately 63.3 TWh/yr of electricity and reduce electricity bills by as much as $12.5 billion dollars per year for Ontarians.

> **C. Young, Green Building, infrastructurecanada.ca, *Putting Conservation First Means Big Savings For Ontarians*, online: <http://cuksbn.org/wp-content/uploads/Green-Building-in-Canada.pdf> at page 2.**

E. DISTRICT ENERGY

28 A broader use of thermal energy distribution (district energy) and shared renewable energy (both thermal and electrical) amongst clusters of buildings improves efficiency and conserves energy.

> *Utilities are well versed in making long-term investments, and they are well positioned to encourage strategically sited CHP that can provide major benefits to the grid. Utilities have existing relationships with most of the customers that would be good candidates for CHP and they can enjoy many of the benefits of CHP much more directly than individual CHP users might be able. Utilities also have the ability to use ratepayer funds to support projects that will provide system wide benefits and their CHP programs can help accelerate market adoption of the technology, all while providing economic and environmental benefits to all system users.*
>
> **Anna Chittum and Kate Farley, *Utilities and the CHP Value Proposition*, dated July 19, 2013.**

F. GROUND SOURCE HEAT PUMPS

29 Changes to the natural gas utilities' mandates in 2009 made eminent sense. For decades the companies have put pipes in the ground to transport a fossil fuel which, although less polluting than coal, remains a cause of greenhouse gas emissions. Both ground source heat pumps and solar thermal water heating, the two major uses of natural gas in buildings, use pipes to transport renewable energy that are not intermittent. Both applications represent a long term business opportunity in a carbon constrained world.

30 The use of ground source heat pumps can make more efficient use of electricity for cooling and reduce the peak demand for natural gas in the winter with greenhouse gas emissions reductions in both seasons. Subdivision scale systems or systems serving more than one building in a complex will enable unit cost reductions from scope and scale.

> *A ground-source heat pump uses the earth or ground water or both as the sources of heat in the winter, and as the "sink" for heat removed from the home in the summer. For this reason, ground-source heat pump systems have come to be known as earth-energy systems (EESs). Heat is removed from the earth by using a liquid, such as ground water or an antifreeze solution; the liquid's temperature is raised by the heat pump; and the heat is transferred to indoor air. During summer months, the process is reversed: heat is taken from indoor air and transferred to the earth by the ground water or antifreeze solution. A direct-expansion (DX) earth-energy system uses refrigerant in the ground-heat exchanger, instead of an antifreeze solution. Earth-energy systems can be used with forced-air and hydronic heating systems. They can also be designed and installed to provide heating only, heating with "passive" cooling, or heating with "active" cooling. Heating-only systems do not provide cooling. Passive-cooling systems provide cooling by pumping cool water or antifreeze through the system without using the heat pump to assist the process. Active cooling is provided as described below, in "The Cooling Cycle." As with air-source heat pumps, earth-energy systems are available with widely*

> *varying efficiency ratings. Earth-energy systems intended for ground-water or open-system applications have heating COP ratings ranging from 3.6 to 5.2, and cooling EER ratings between 16.2 and 31.1. Those intended for closed-loop applications have heating COP ratings between 3.1 and 4.9, while EER ratings range from 13.4 to 25.8. The minimum efficiency in each range is regulated in the same jurisdictions as the air-source equipment. There has been a dramatic improvement in the efficiency of earth-energy systems. Today, the same new developments in compressors, motors and controls that are available to air-source heat pump manufacturers are resulting in higher levels of efficiency for earth-energy systems.*
>
> **Natural Resources Canada, *Ground-Source Heat Pumps (Earth Energy Systems),* dated April 15, 2014, online: <http://www.nrcan.gc.ca/energy/publications/efficiency/heating-heat-pump/6833>.**

G. ENERGY (INCLUDING THERMAL) STORAGE

31 To date, Ontario's approach to energy storage has been centered on electricity. In fact an overall energy systems approach combining thermal and storage and electricity storage would yield greater benefits. Such a broader approach is common in Europe. An illustration of potential energy storage integration opportunities is attached hereto and marked as **Exhibit "J"**.

> *Energy storage technologies can support energy security and climate change goals by providing valuable services in developed and developing energy systems. A systems approach to energy system design will lead to more integrated and optimised energy systems. Energy storage technologies can help to better integrate our electricity and heat systems and can play a crucial role in energy system decarbonisation by: improving energy system resource use efficiency; helping to integrate higher levels of variable renewable resources and end-use sector electrification; supporting greater production of energy where it is consumed; increasing energy access and improving electricity grid stability, flexibility, reliability and resilience.*
>
> **International Energy Agency, *Technology Roadmap – Energy Storage*, online: <http://www.iea.org/publications/freepublications/publication/technologyroadmapenergystorage.pdf>.**

32 The International Energy Agency Energy Storage Roadmap outlines a variety of storage technologies which are at various stages of commercial deployment. The use of energy storage technologies is a widely acknowledged tool to facilitate broad based deployment of renewable energy systems. A copy of the IEA Energy Storage Roadmap is attached hereto and marked as **Exhibit "K"**.

33 One example of a renewable energy storage approach that is closely linked to CHP and natural gas which could be adopted here in Ontario as a DSM initiative is the injection of Bio-Methane into the natural gas network. This is an activity that produces green gas from agricultural activities and food waste to offset fossil fuel consumption. Integration of Bio-Methane into traditional natural gas networks is being pursued in the UK and other jurisdictions in Europe where over 160 Bio-Methane plants currently feed renewable gas into the natural gas network.

> **UK Government, Department of Energy & Climate Change, *RHI Biomethan Injection to Grid Tariff Review*, online: <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384202/Biomethane_Tariff_Review_-_Government_Response_-_December_2014.pdf>.**
>
> **S. Strauch, J. Krassowski, A. Singhal, *Biomethane Guide for Decision Makers – Policy guide on biogas injection into the natural gas grid* dated September 2013, online: <http://www.greengasgrids.eu/fileadmin/greengas/media/Downloads/Documentation_from_the_GreenGasGrids_project/Biomethane_Guide_for_Decision_Makers.pdf>.**

H. DENMARK – REAL WORLD EXAMPLE

34 Other jurisdictions, such as Denmark, provide proven examples of integrated energy policy and regulation.

35 In 1979, the Danish government introduced the *Danish Heat Supply Act*. The act is similar to Ontario's *Green Energy Act* and was intended to assist Denmark

meet its Energy Efficiency, Renewable Energy and Climate Change policy targets and transition to 50% wind power by 2020 and 100% renewables by 2050.

> **Denmark Official Website, *Wind Energy*, online: <http://denmark.dk/en/green-living/wind-energy/>.**

36 The policy affects Buildings, Residential Appliances, Space heating, Commercial/Industrial Equipment, Heating Ventilation and Air Conditioning (HVAC), Energy Utilities, Electricity, Generation, Energy Utilities, Heating (including district heating), multiple Renewable Energy Sources, CHP, District Heating and Cooling and other Multi-sectoral Policy.

> *The Heat Supply Act from 1979 (revised extensively in 1990, 2000 and 2005) empowers the Minister for Energy to ban the use of electric heating in new buildings located within a district heating or natural gas supply network. The Minister made use of this empowerment in 1988. In 1994 the Heat Supply Act was revised to extend the Ministers empowerment to also include a ban on conversion to electric heating in existing buildings. The Minister made use of this extended empowerment in the same year. This measure has reduced the number of electrically heated homes by over 9000. In 1994 6.5 % of the Danish homes were electrically heated, while in 2008 only 5.3 % were. Other provisions in the Heat Supply Act include: obligatory connection to the district heating or natural gas supply network, the principle of co-generated heat and electricity and the principle for heat pricing. The possibility to ensure that all buildings in a given area connect to the district heating or natural gas network, has increased the coverage of district heating considerably. Only about 650,000 of Denmark's 2.7 million households have an individual heat supply. About 80% of district heating is co-produced with electricity, due to the Heat Supply Acts provision, that plants larger than 1 MW have to be operated as combined heating plants. As a result, Denmark has the most extensive co-generated heat and electricity system in EU, with more than half of all Danish electricity co-generated with heat. The principle for heat pricing stipulates that heat supplies must be priced according to actual costs on a non-profit basis. To increase the utilization of renewable energy resources and industrial surplus heat, heat based on these resources can though be sold with a*

certain profit within boundaries, set by the Danish Energy Regulatory Authority

International Energy Agency, *Heat Supply Act*, online: <http://www.iea.org/policiesandmeasures/pams/denmark/name-21778-en.php>.

37 Since its introduction in 1979 the *Heat Supply Act* has spurred the development of many smaller renewable and fossil fuel CHP plants throughout Denmark. Major manufacturers (the automotive sector) as well as distributed district heating companies utilize the heat.

A. Andresen et al, *Overview of the Danish Power system and RES integration* dated July 2013 online <http://www.store-project.eu/documents/target-country-results/en_GB/energy-needs-in-denmark-executive-summary> at page 13.

38 These distributed CHP plants are a form of energy "storage" providing demand management services akin to other bulk energy storage technologies. CHP has enabled Denmark's grid operators to integrate large amounts of fluctuating production from wind turbines by ramping up when demand outreaches renewables supply while absorbing surplus power using electric boilers to create valuable heat that can be used for hot water, heating, manufacturing as well as absorbed using heat pumps and thermal stores for use later. By valuing both power and heat in an integrated way, value can be captured and created for the system as well as for consumers. In 2014 more than 41% of Denmark's demand was met by wind power because of the integration of thermal and electrical networks.

39 Denmark's integrated energy transition has resulted in a significant shift in fuel consumption for electricity and heating. The Danish Energy Agency's baseline scenario highlights this shift and is attached hereto and marked as **Exhibit "L"**.

40 The integration of thermal and power systems in Denmark has led to an important shift in the supply mix that is consumed with a significant reduction in power from large centralized facilities as well as a reduction in the consumption of combustible fuel overall and fossil fuels. Charts showing power consumption and generation and fuel consumption in Denmark are attached hereto and marked as **Exhibit "M"**.

41 The reduction in combustible fuel use, better technology and the use of cleaner fuels in the CHP systems has resulted in a significant reduction of emissions of CO_2 (41%), SO_2 (97%) and NO_X (84%) in Denmark. A chart showing the emissions in Denmark between 1990 and 2010 is attached hereto and marked as **Exhibit "N"**.

42 Denmark's 2.7 million households are benefitting from this shift directly. About 650,000 of Denmark's 2.7 million households have an individual heat supply with the remainder receiving space heating and hot water from district energy systems. Those connected to the district hot water systems pay an average cost of just 3% of the average household income for these services compared to 22% in Canada.

> **Danish Energy Agency, *Basic facts on Heat Supply in Denmark*, online: <http://www.ens.dk/en/supply/heat-supply-denmark/basic-facts-heat-supply-denmark>.**
>
> **Danish Energy Agency, *The Danish Energy Model – Innovative, Efficient and Sustainable*, online: <http://www.ens.dk/sites/ens.dk/files/dokumenter/publikationer/downloads/dk_model_150422.pdf> at page 13.**
>
> **C. Aguilar, D.J. White, and D. L. Ryan, *Domestic Water Heating and Water Heater Energy Consumption in Canada*, dated April 2005, online: <http://sedc-coalition.eu/wp-content/uploads/2011/07/CREEDAC-Canadian-Residential-Hot-Water-Apr-2005.pdf>.**

43 From an emissions perspective the Danes integrated approach holds significant insights into how we could lower our heating emissions over time while reducing the overall cost to ratepayers through a distributed approach to energy generation and use. A summary of Ontario and Denmark's comparable Green House Gas Emissions is attached hereto and marked as **Exhibit "O"**.

44 Ontario CHP and district energy services providers such as Markham District Energy and Toronto's Enwave could provide these types of services immediately while new proponents could offer similar services if the regulatory environment was further strengthened in Ontario.

Document #: 872316

Exhibit “A”

Chris Young

916 Hamlet Rd. Ottawa, Ontario K1G 1R5 P: 613.322.2472 email: norsunenergy@me.com

Highlights

Strong market entry skills focused on conceptualizing and implementing business solutions through improved processes and innovative technology.

- Over 11 years experience developing and delivering Energy Management and Environmental Services including successful Financing and Construction of a 33.6MW, $145 million power project sold to a publicly listed company
- Demonstrated Leadership on Energy Policy Matters – invited speaker to The Senate of Canada Standing Committee on Energy the Environment and Natural Resources
- Solid understanding of Project Finance and Business Case Development with non-recourse finance
- Built a strong sales and technical team to originate and assess over 300MW of Solar and Wind projects
- Participated in the launch of two licensed hazardous waste treatment facilities specializing in the treatment of Mercury and PCB containing lighting industry. Helping to advance environmental regulations across Canada
- Developed a first of it's kind National Product Stewardship program for mercury contaminated lighting waste
- Former Board Member, Ontario Sustainable Energy Association policy advisory on climate change issues
- Positioned Stoked Power Generation to become selected to join Sustainable Development Technology Canada – Natural Gas Technology Incubator for the development of small scale Combined Heat and Power technology

Skills

A demonstrated ability to realize Multi Million Dollar business concepts in complex Government Regulated environments and a challenging global financial market.

Market Definition - Identification of new market opportunities technology and processes including product validation with early adopters.

Competitive Analysis – Examination of external firms in direct competition and, broader technical developments which can impact on success.

Product Positioning – Worked with potential clients and the CTO to define functional requirements incorporated into the product development plan.

Pricing and Business modeling – Participated in the development of a number of business plans. Contributed to, market definition and sales forecasts.

Market Research – Primary and secondary market research techniques for competitive intelligence and customer analysis.

Strategic Sales – Identification of key accounts that can lead to significant growth through an industry vertical.

Strong Network of energy related colleagues that span Europe, North America and Asian.

Employment History

November 2010 – 2014

Volunteer Board Member – Ontario Sustainable Energy Association

Assisting non-profit organization in policy initiatives to advance renewable energy with various government stakeholders.

September 2012 – Present

Business Development – Biogas and Combined Heat and Power
Initial development of anaerobic digestion projects identified a significant technical challenge with prime mover technologies available in the North American market. To address the shortcomings of existing small scale CHP technology, partnered with **Stoked Power Generation** to commercialize innovative Combined Heat and Power technology.

January 2012 – September 2012

Consultant – Green Energy Finance Company
Advised an international merchant banker on dynamics of utility scale PV market as they position to raise funding for project acquisition.

January 2008 – November 2011

Managing Director – Enfinity Canada

Initiated and lead the market entry of one of Europe's leading renewable energy companies into the Canadian Market.

Originated, and lead the successful acquisition of Solaris Energy Partners, a 244 acre, 33.6MWp Solar farm in Eastern Ontario. Guided Solaris through remaining permitting requirements, including completion of Ontario Municipal Board hearings and Hydro One Interconnection requirements.

Worked closely with Engineering and Finance teams to advance Solaris from concept through design, procurement and construction, to a $140 million exit to a TSE listed company.

In addition to the Solaris project, established a business development program that created a pipeline of rooftop and groundmount projects that will be valued in excess of $500Million once constructed.

Worked collaboration with an international team of technical specialists, to lead due diligence review on a number of wind development opportunities representing potential installed capacity of approximately 900MW located across Canada.

Participated on management board of Enfinity America's Group

- Strong understanding of Non-Recourse Finance and capital structures
- Ability to convey complex technical issues to political decision makers
- **Broad understanding of electricity markets in European and North American markets**
- Ability to work with colleagues and vendors across many countries
- Execution of an EPC strategy for construction of 33MW Solar Facility
- Definition of Value Proposition and Commercial terms on competitive PPA's

December 2006 – November 2007

Vice-President of Solar Farm Development, Solstice Solar Energy

Secured early stage seed investment from two of Canada's leading Internet Entrepreneurs to launch a Solar Development Company

Collaborated on the development of the business plan and developed a marketing program targeted at potential community partners.

Conducted extensive market research into the Ontario Renewable Energy Standard Offer Program including; detailed review with legal and financial advisors.

Development of detailed Solar Resource assessments using a variety of Solar Energy Modeling tools including RETSCREEN and PVWatts for various locations in Ontario.

Lead discussions with equipment manufacturers regarding equipment supply for utility scale solar farm developments.

September 2000 - January 2006

Non- Environment/Power Related Business Development

Various software related startup companies.

May 1993 - September 1999

Business Development, Material Resource Recovery

Secured lead customers to anchor the construction of a hazardous waste incinerator to treat hazardous waste, including Poly Chlorinated Biphenols.

Contributed to plans and procedures to meet due diligence of clients that included The Government of Canada and some of Canada's largest Financial Institutions.

Assisted in preparing facts based response to community concerns and designed a community engagement process that satisfied the needs of

May 1993 - September 1999

Business Development, RLF Canada,
Secured several noted, "Blue Chip" clients as lead customers for an innovative treatment facility for mercury contaminated lighting waste. Amongst others: GE Canada, Royal Bank of Canada, BCE Place, and Public Works Government Services Canada

Succeeded in raising awareness of environmental liabilities from mercury contaminated lighting waste amongst Municipal landfill operators and Government Regulators.

Obtained a "Certificate of Approval" from the Ontario Ministry of Environment to exempt the reverse distribution and recycling of Fluorescent lights from Regulation 347 of the Environmental Protection act.

Developed a product stewardship program with Industry partners that enabled the recycling of lighting waste for building owners on a national basis without the need for Hazardous Waste Permits

Education: University of Ottawa, Bachelor of Social Science 1993

Relevant Courses: Environmental Impact Assessment, Natural Resource Management, Geography of Economic Systems, Business, Marketing, Promotional Management, Business Law, Services Marketing.

TAB 2

OSEA Response to APPrO Interrogatories

Question #1

Ref: Paragraph 2 and paragraph 4

Preamble: In the above references, Mr. Young indicates that he is providing expert opinion on sustainable energy opportunities and he also discusses his own experience in developing combined heat and power (CHP) projects in Ontario. APPrO would like to better understand his experience.

a) Please provide a list all of the operating CHP plants in Ontario that Mr. Young has been involved in developing and/or operating and include the size in MW, the location and the year in which it went into service, the input energy source, the annual capacity factor of each plant, and Mr. Young's ownership percentage, if any.

b) Please describe the role that Mr. Young played in developing and/or operating each of the plants identified in (a), above.

c) Please describe the commercial arrangements for the "sale" of the resulting energy outputs of each of the CHP plants.

Response

a) I do not operate or have any ownership percentage of any operating Combined Heat and Power (CHP) plants in Ontario. I am involved with Stoked Power Generation in the design and development of new technology for CHP systems including bio-gas equipment. Stoked Power General was selected by Sustainable Development Technology Canada to join its Natural Gas Technology Incubation Program.

b) See response a)

c) See response a)

Question #2

Ref: Paragraphs 9, 10, 13 and 21

Preamble: In the above references, Mr. Young speaks to greenhouse gas (GHG) emissions and Ontario's electricity sector and indicates: "*Sustainable energy approaches are critical to both energy conservation and environmental protection. Despite progress in specific areas, significant programmatic, institutional and regulatory processes and practices within many key organizations in the energy sector have had limited progress on these two matters. With respect to greenhouse gas emissions, Ontario's challenge is moving beyond phasing out coal and reducing the carbon content of applications such as heating and transportation.*"

a) Please provide, in the following chart format, the information on energy conservation and greenhouse gas emissions applicable to various programs initiatives and sectors and all supporting primary resources and documentation.

Response

a) The Environmental Commissioner of Ontario has the legislative authority to report on conservation results as well as progress in meeting Ontario's greenhouse gas emissions reductions. The references provided in my evidence cited the Environmental Commissioner's latest report. It is unnecessary to transcribe the data from the report into the chart form when the report is readily available to the public.

Question 3

Ref: (i) Paragraph 16, 18 (ii) Paragraphs 21, 22, and 27

Preamble: In Reference (i) Mr. Young notes that the electricity market is dominated by existing large central power plants. APPrO would like to better understand Mr. Young's position on gas-fired power generation.

a) Please confirm that these gas-fired power plants were developed based on, and operate in accordance with, long-term contracts between the developer and the IESO (formerly the OPA), or the Ontario Electricity Financial Corporation? If not explain.

b) Please confirm that, among other functions, gas-fired power plants provide the necessary operational back-up generation capability that is required when alternate forms of renewable energy are not available. If not confirmed, please explain.

c) In Reference ii) Mr. Young indicates the typical efficiency of electricity generation from natural gas is less than 40%.

   i. Please explain in full how Mr. Young arrived at this efficiency percentage.

   ii. Please provide all the studies of, or works on, the Ontario natural gas-fired electricity generation fleet that Mr. Young has personally worked on in order to assess the efficiency of electricity generation from natural gas in Ontario.

   iii. Please provide any and all other third party documentation and information that Mr. Young has relied on to arrive at this result.

   iv. Mr. Young states that the efficiency of CHP is "well in excess of 90 per cent". Please provide detailed calculations from both (a) an Ontario CHP plant and (b) the Ontario CHP fleet that supports this stated efficiency level. Please reconcile this statement with Exhibit H, which indicates that the overall efficiency of CHP plants range from 60-92%.

   v. Please confirm that the majority of gas-fired generation facilities in Ontario are, in fact, of a combined cycle or CHP nature or utilize waste heat for secondary power generation, to meet industrial steam or other heating requirements.

   vi. Please provide: (a) the total and average annual amount of water usage by Ontario's natural gas-fired generation fleet and (b) the total and average annual amount of water usage by Ontario's combined cycle natural gas-fired generation fleet.

   vii. Please confirm that Appendix H in Mr. Young's evidence illustrates that combined cycle power plants have overall efficiencies in the 73-90%.

   viii. Please provide the estimated capital costs and projected energy savings from converting an existing single cycle gas-fired generating facility to CHP (a) not adjacent or within 1 km of an operating industrial facility (b) adjacent to an operating industrial facility and (c) within 1 km of an operating industrial facility.

d) Please provide a map of Ontario illustrating the location of all electrical generation facilities by type.

Response

a) The IESO electricity production data herein indicates that Ontario's energy supply is produced by primarily large central power plants including nuclear and gas-fired power plants. Large central power plants, such as the Bruce, Pickering or Darlington nuclear power plants generate approximately 65% of the energy in the form of waste heat, which is discharged into water bodies.

Ontario Grid-Connected Electricity Production by Fuel Type 2013-2014[1]

	Nuclear	Hydro	Coal	Gas/Oil	Wind	Biofuel	Solar
2014	94.9 TWh	37.1 TWh	0.1 TWh	14.8 TWh	6.8 TWh	0.3 TWh	0.0185 TWh
2014%	62%	24%	<1%	10%	4%	<1%	<1%
2013	91.1 TWh	36.1 TWh	3.2 TWh	18.2 TWh	5.2 TWh	0.2 TWh	n/a
2013%	59%	23%	2%	12%	3%	<1%	n/a

b) Gas-fired power plants provide the type of ultra-flexible backup generation capacity that enables high penetration levels of variable renewable energy sources like wind and solar.

c)

i. Equipment manufacturers and government agencies routinely report efficiency calculations of this nature with the 40% cited at the higher end of these estimates.

ii. I have not personally worked on a study of natural gas-fired electricity generation fleet in Ontario to assess the efficiency of electricity generation. However, I will note that power generation data reported by IESO/OPA do not provide the level of detail found in other markets such as Germany or the United Kingdom. As such, omission

[1] http://www.ieso.ca/Pages/Power-Data/2014-Electricity-Production-Consumption-and-Price-Data.aspx

of thermal efficiency by the IESO/OPA makes it impossible to accurately assess the efficiency level of a natural gas power plant in Ontario.

iii. Table 1-3 of the "Catalog of CHP Technologies from the U.S. EPA Combined Heat and Power Partnership"(http://www.epa.gov/chp/documents/catalog_chptech_full.pdf) provides an indication of maximum electrical efficiency range (24-41%) based on HHV of various established generation technologies. Data from the U.K. government provides additional data on electrical efficiencies (https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes).

iv. Please refer to Table 1-3 of the "Catalog of CHP Technologies from the U.S. EPA Combined Heat and Power Partnership". My assertion of higher level claims are based on virtual prototyping of proprietary microCHP technology in development where high heat utilization is possible.

v. While I know there are a number of CHP facilities in Ontario, data from IESO gives no indication of thermal efficiency of these power plants. As such I'm not in a position to comment.

vi. This data is not disclosed in the IESO data and would likely be considered commercially sensitive by those operators.

vii. Yes, so long as thermal production is consumed by the load customer.

viii. This would be highly dependent on a number of factors however the "Catalog of CHP Technologies from the U.S. EPA Combined Heat and Power Partnership" can provide a reference point.

d) It is not feasible to provide a map of <u>all</u> electrical generation facilities in Ontario and it is outside the scope of this hearing.

Question 4

Ref: (i) Paragraphs 24-27, (ii) Exhibit I

Preamble: In Paragraph 24-27 Mr. Young indicates that regulatory practices in Ontario have not been revised to reflect the broader societal benefits of CHP. In Paragraph 27 Mr. Young states that based on his analysis, 63.3 TWh/yr. of electricity could be saved annually by shifting away from centralized power plants in favour of CHP. The reference associated with Reference i) states that "*Based on a full conversion rate, there is potential to replace upwards of 8,000 MW of relatively low efficiency thermo electric generation capacity.*" In Reference ii) Mr. Young references efficiency information related to 'standard power plants'. APPrO would like to better understand this information.

a) Please file the reference associated with Paragraph 27 and all supporting documentation

b) Please provide the total electrical consumption in Ontario for each of the last 3 years and express the 63.3 TWh/yr. of purported potential annual savings as a percentage of the provincial total. Please also confirm that these savings are related to the replacement of 8,000 MW of low efficiency thermo electric generation capacity

c) Please provide a full copy of Mr. Young's analysis and include all major assumptions that support the claim of 63.3 TWh/yr. annual savings.

d) In Reference ii) Mr. Young references a standard power plant. Please state what Mr. Young means by a "standard power plant". Please confirm that Mr. Young's reference to a "standard power plant" is not a reference to a natural gas-fired combined cycle power plant. Please explain if this is not the case.

e) Please confirm that the efficiency estimates in Reference ii) were not developed by Mr. Young.

f) Please provide an itemization of any and all expertise that Mr. Young has in analyzing the OPA/IESO's Clean Energy Supply Agreements and early mover contracts for combined cycle natural gas-fired electricity generation.

g) Please provide a list of the Ontario "regulatory practices" that Mr. Young believes do not reflect any societal benefits.

h) Please provide Mr. Young's working definition of a "large central power plant" as stated in Paragraphs 25-27.

Response

a) This calculation is a high level estimation that conceptually converts all building heating systems in Ontario to building appropriate sized CHP systems and the resulting electricity production that could be achieved. Data sets for electricity were obtained from the IESO (http://www.ieso.ca/Pages/Power-Data/Supply.aspx). Building energy consumption data for Ontario Residential and Commercial/Institutional buildings was generated by Natural Resources Canada “Comprehensive Energy Use Database Query System” (http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm).

b) For the year 2012, for which this estimate applies the 63.3 TWh, represents a theoretical potential of 42% of the electricity generated in the Province. This figure is intended to be illustrative.

c) This calculation takes the total energy consumed to heat buildings in Ontario as reported by the Comprehensive Energy Use Database (reference provided above) and, adjusts for a furnace efficiency of 80% to derive a theoretical primary fuel input estimate required for space and water heating. With this understanding of potential availability of primary fuel inputs from existing use as the input source, a theoretical HHV electrical efficiency of 27% for generic CHP generation technologies (reference CHP Catalogue Table 1-3 cited above) which has been adjusted to reflect a 6% electricity savings for avoided transmission and distribution losses to arrive at an estimated 63.3TWh generation potential utilizing existing heating fuel consumption. See attached, *Linking heat and electricity in Ontario buildings to generate energy efficiency and savings*.

d) By standard power plant, I am referring to nuclear plants which dominate the Ontario electricity supply mix.

e) As cited, Exhibit I was prepared by the International District Energy Association.

f) I have not analyzed any specific commercial agreements.

g) Behind the meter CHP installations are not compensated for providing power capacity and frequency regulation services that reinforce the provincial power system. In the case of major system outages such as experienced in 2003 or as a result of severe weather (hurricanes, ice storms and flooding) such installations add local resilience to the system; a feature that is becoming more and more important, but goes unrecognized by the current market arrangements. The attached analysis, *The Grid Related Benefits of Distributed Generation* by David Engle, provides a generic summary of additional benefits.

h) My definition of a large central power plant is nuclear power plants or other facilities over 500 MW capacity that by design do not make use of low grade heat for a secondary purpose other than supporting electricity production.

Question #5

Ref: Exhibit G

Preamble: Mr. Young provides a publication called “Up in Smoke””. APPrO would like to better understand the information referenced in this exhibit.

a) Please confirm that this information references power generation in the United Kingdom and not Ontario.

b) Please indicate if Mr. Young conducted any of the underlying analyses that resulted in the percentages in the Exhibit. If so, please provide such detailed calculations and include all major assumptions.

Response

a) Yes, however the figure illustrates generating technologies that operate both in Ontario and the U.K.

b) No additional analyses were completed.

Question #6

Ref: Paragraphs 1-4, and Exhibit A

Preamble: In the above references, Mr. Young set out his qualifications and scope of work, which includes providing expert opinion on sustainable energy opportunities that the utilities can incorporate into their DSM plan, and identification of barriers that prevent conservation and GHG reduction.

a) Please provide any background or expertise that Mr. Young has had in relation to the Ontario integrated energy initiatives including: the 2014 Natural Gas Market Review, the Natural Gas Electricity Interface Review, the IESO/OPA conservation and demand management initiatives, and the IESO technical panel and market rule amendment process, and any supporting reports or documents that he has produced or relied upon in those matters.

b) Please provide a list all sustainable energy opportunities that you considered and rejected in light of the Ontario energy context.

Response

a) As a former board member of the Ontario Sustainable Energy Association, I've contributed extensively to numerous policy documents developed by OSEA and submitted to IESO/OPA either directly or through stakeholder engagements. Additionally, I have attended OPA stakeholder engagement sessions related to development of the Feed-in-Tariff program and Community Energy. In the course of my business activities I've attended numerous meetings with community based stakeholders including Commercial and Multi-Unit Residential building managers, manufacturers from different segments of the economy, electricity grid operators, and numerous community engagement activities related to siting of proposed biogas/CHP projects. In addition, I currently participate in the Sustainable Development Canada Natural Gas Technology Incubation Program.

b) The sustainable energy opportunities I considered are described in the evidence I submitted.

Question #7

Ref: Paragraphs 28-33

Preamble: In the above references, Mr. Young indicates that to date the Ontario approach has been focused on electricity and has not considered combined thermal and storage initiatives.

a) Please provide an itemization or any and all CHP and energy storage programs or initiatives in the province and the associated responsible authority.

Response

a) The following energy storage and CHP programs are currently administered by IESO/OPA:

    i. Combined Heat and Power Standard Offer Program (CHPSOP) 2.0 (http://www.powerauthority.on.ca/combined-heat-power-procurement)

    ii. IESO Energy Storage Procurement Phase II (http://www.ieso.ca/Documents/procurement/Energy-Storage/Technical-Information-Session-ESP-Phase-II.pdf)

TAB 3

Ontario Sustainable Energy Association

Undertakings of Mr. Young to Ms. DeMarco

Undertaking JT3.10

OSEA to reproduce the question as asked in its entirety, with the fullness of the charts that were asked for specifically

Response

Ref: Paragraphs 9, 10, 13 and 21

Preamble: In the above references, Mr. Young speaks to greenhouse gas (GHG) emissions and Ontario's electricity sector and indicates: "*Sustainable energy approaches are critical to both energy conservation and environmental protection. Despite progress in specific areas, significant programmatic, institutional and regulatory processes and practices within many key organizations in the energy sector have had limited progress on these two matters. With respect to greenhouse gas emissions, Ontario's challenge is moving beyond phasing out coal and reducing the carbon content of applications such as heating and transportation.*"

a) Please provide, in the following chart format, the information on energy conservation and greenhouse gas emissions applicable to various programs initiatives and sectors and all supporting primary resources and documentation.

i. Energy Conservation

Energy conservation measure	Resulting energy saved (MWh or GJ, as applicable)	Corresponding GHG emissions factor	Corresponding GHG emissions reduced over the defined period of time	Cost to end-use customer (corresponding rate or bill increase over applicable period ($)
Gas DSM (a) EGD 2005-2015 (b) EGD 2010-2015 (c) Union 2005-2015 (d) Union 2010-2015				
Electricity CDM (a) OPA/IESO programs (b) LDC Programs				

(c) Customer Initiatives				
Phase-out of coal-fired electricity in Ontario				
All other energy conservation programs and regulatory measures in Ontario				

ii. GHG Emissions

Relevant sector of Ontario economy	Total GHG emissions from sector in 2005 (MT) and contribution to Ontario's total economy-wide GHG emissions in 2005(%)	In each of (a) 2010 (b) 2014 and (c) 2015: total GHG emissions from sector in (MT) and contribution to Ontario's total economy-wide GHG emissions (%)	Corresponding GHG emissions reduced over the 2005 to 2015 period	Cost to end-use customer (the published rate or bill increase over the applicable period ($))
Electricity				
Transportation				
Industry (a) process emissions (b) energy combustion emissions				
Buildings				
Agriculture				
Waste				

a) The Environmental Commissioner of Ontario has the legislative authority to report on conservation results as well as progress in meeting Ontario's greenhouse gas emissions reductions. The references provided in my evidence cited the Environmental Commissioner's latest report. It is unnecessary to transcribe the data from the report into the chart form when the report is readily available to the public.

Undertaking JT3.11

OSEA to provide pinpoint references to those reports that are being relied upon; and to provide the information in three final columns.

Response

As set out in Mr. Young's evidence, the report relied on is the Environmental Commissioner of Ontario's report, "Feeling the Heating: Greenhouse Gas Progress Report 2015". Information requested about GHG emissions can be found at pages 12, 14 and 15.

The Environmental Commissioner of Ontario's report relied on the "Environment Canada, National Inventory Report – Greenhouse Gas Sources and Sinks in Canada 1990-2013 (2015)" as the source of data.

The Environment Canada National Inventory Report cited by the Environmental Commissioner of Ontario is attached for reference. Refer to Table A10-12 for Ontario's 1990-2013 GHG Emissions listed by sector (page 54) and Table A11-7 for Ontario's 1990-2013 GHG Emissions for electricity generation (page 78). This information can be used by APPrO to compare GHG emissions over various years. Similar conservation reports are available at http://eco.on.ca/category/ecr/.

An increase or decrease in emissions could result from a number of initiatives, some of which may be unrelated to DSM programs. This is outside the scope of the evidence provided.

Undertaking JT3.12

OSEA to provide an equipment list

Response

Mr. Young's evidence refers to a "<u>typical</u> efficiency of less than 40 per cent" [emphasis added].

The IESO does not publish the detailed performance data including primary fuel input and thermal output utilization,[1] which are necessary to determine overall operational energy efficiency of gas or nuclear power plant operation within Ontario.

Because information specific to Ontario is not published or available, Mr. Young considered the efficiencies of operations in other jurisdiction. See Exhibit M.OSEA.APPRO.3,(c)(iii) for efficiencies in the United States of America and the U.K.

In addition, Mr. Young reviewed specifications of equipment vendors and industry groups. Refer to the attached Siemens brochure indicating typical efficiencies for turbines and generators using fossil fuels. Further, refer to a publication prepared by the Canadian Nuclear Safety Commission setting out typical efficiencies of nuclear power plants.[2]

1 http://reports.ieso.ca/public/GenOutputCapability/PUB_GenOutputCapability.xml

2 Canadian Nuclear Safety Commission, *CANDU Fundamentals*, (June 6 2003) online: <https://canteach.candu.org/Content%20Library/20040700.pdf> at pp 95-99.

Undertaking JT3.13

OSEA to provide the calculation for a cost of $12 Billion to cover 8,000 megawatts of power to CHP using existing natural gas demand and producing electricity with that, based on data from the CHP handbook

Response

The $12 Billion cost estimate is derived by multiplying an estimated 8,000 MW capacity by $1.5 Million/MW CAPEX cost estimate as outlined in the "Catalog [sic] of CHP Technologies" (referenced in Exhibit M.OSEA.APPrO.3).

TAB 4

Table 3: Efficiency Benefits that Put Downward Pressure on Rates

	NPV of Lifetime Benefits per Annual m^3 Saved[36]		Average Annual Value from Utilities'2016-2020 DSM Plans (millions $)[37]		Benefits as a % of Average Annual (2016-2020) DSM Plan Budget[38]	
Benefit	Enbridge	Union	Enbridge	Union	Enbridge	Union
1 Avoided carbon regulation costs[39]	$0.98	$0.98	$73.2	$73.9	101%	129%
2 Price suppression effects[40]	$0.08	$0.08	$6.2	$6.3	9%	11%
3 Reduce purchase of most expensive gas[41]	$0.10	$0.18	$7.2	$13.3	10%	23%
4 Avoided distribution system costs[42]	$0.38	$0.24	$28.1	$18.2	39%	32%
Total	**$1.54**	**$1.49**	**$114.7**	**$111.7**	**158%**	**195%**

[36] Assumes an average measure life of 16 years. All values in 2015 Canadian dollars (CDN).
[37] This is NPV of benefits per annual m3 saved multiplied by the average incremental annual m^3 savings forecast for the 2016-2020 period by Enbridge (74.4 million m^3) and Union (75.1 million m^3).
[38] Enbridge's average annual budget is $72.3 million; Union's is $57.4 million (both in 2015 dollars).
[39] Valued at Mr. Chernick's estimate of avoided costs of carbon emission regulations. As noted above, Mr. Chernick suggests such values would start at approximately $20 (2014 USD) per ton of CO_2 or $1.18 USD per MBtu of natural gas in the first year of a regulatory scheme. The values per m^3 of reduction are the same for both Enbridge and Union as the market clearing price unit of emissions is likely to be a provincial price.
[40] Mr. Chernick estimates that a 1 billion m^3 reduction in annual gas demand would produce a $0.00027 reduction in price per m^3. Over the 2016-2020 period, I assume that average annual gas sales in Ontario will be approximately 27 billion m^3. Thus, the price reduction benefit to Ontario gas users from a 1 billion m^3 reduction in gas demand would be worth approximately $7.2 million. That equates to a benefit of approximately $0.0072 for one year's worth of a single m^3 of demand reduction. That, in turn translates to a benefit of approximately $0.083 for 16 years (the average measure life) of one m^3 of demand reduction. The magnitude of this benefit is assumed to be the same (per m^3 of savings) for both utilities.
[41] For Enbridge, Mr. Chernick estimates that this benefit is equal to approximately $0.013 per m^3 of space heating gas saved per year and $0.011 per m^3 of combined space heating and water heating energy saved per year; there are essentially no such savings from baseload measures (industrial and water heating). For Union, I used the average of the differences Mr. Chernick reports for 2015 and 2016 (Chernick p. 28): $0.015 for baseload and $0.017 for space heating measures. Data on the mix of end use gas saved in the utilities' proposed plans were not included in their filing. Thus, I have assumed that the mix (in percentage terms) will be the same as in 2014 for Enbridge and the same as in 2014 for Union excluding the T2/Rate 100 savings. To the extent that the utilities will get more of their savings in future years from space heating these estimated benefits will be conservatively low."
[42] Enbridge used estimates of avoided distribution system costs developed for the Company by Navigant Consulting (Exh. C/T1/S4). The magnitude of those avoided costs varied by a factor of 4, depending on whether the savings were from space heating or from baseload measure end uses like water heating or industrial process efficiency improvements (See Navigant Table 7). Mr. Chernick has found that Enbridge's avoided distribution costs are actually three to five times higher than Navigant estimated for the Company. I have used the mid-point (factor of four) of that range. In this case, I estimated the lifetime NPV of an annual savings of an m^3 using a nominal discount rate (i.e. the 4% real discount rate adjusted for an assumed annual inflation rate of 1.68%) because Navigant estimates were expressed in constant nominal dollars. A weighted average value for the entire Enbridge portfolio was estimated based on the Company's 2014 distribution of savings by end use. Absent better information, the values for Union were assumed to be the same as for Enbridge per end use. However, because Union's savings are assumed to be more baseload heavy and less space heating focused, the weighted average value per m^3 is estimated to be lower for Union.

As Table 3 shows, under the utilities filed plans, the system-wide benefits that accrue to all gas ratepayers, participants and non-participants alike, are more than one and a half times greater than the magnitude of the DSM budgets necessary to produce them. Put another way, the combined effects on rates of *both* DSM budgets *and* the system-wide benefits they produce (under the spending and savings levels the Companies have proposed) would be more than a $1 per month *reduction* over the life of the efficiency measures installed. Thus, if the Board were to determine that a rate impact of $2 per month is still as large as it was comfortable accepting, there is clearly much more room for increase in DSM spending and savings before that level is reached.

V. Budget Sensitivity Analyses

Both Enbridge and Union present the results of sensitivity analyses that they conducted. However, both utilities' analyses are fraught with problems. To some extent that is understandable because the utilities had relatively little time to develop extensive new plans that were responsive to a number of different new directions given to them by the Board. Nevertheless, their sensitivity analyses provide very little, if any value, in understanding what the impacts of significant variations in DSM budgets might be.

1. Union's Sensitivity Analyses

Union examined three budget sensitivity scenarios – one in which it spends several million dollars less in 2020, another in which it spends approximately $5 million more (as well as all of its 15% DSMVA) and a third in which it spends about $10 million more (as well as all of its 15% DSMVA).[43] In the case of the two increased budget scenarios, the Company identified three existing programs on which it would increase spending, with resulting increases in participation and savings, and one new program it would launch for which it estimated only the cost (suggesting savings could not be estimated because the program was not sufficiently defined). There are a number of concerns with Union's analysis:

- The range of potential budget increases examined is far too limited. The largest budget increase considered - $10 million – represents only about a 17% increase in budget. Even if one includes the 15% DSMVA, the maximum increase considered is only 32%.
- The economic impacts – i.e. the TRC economic benefits of the increased spending, which should be one of the most important considerations when deciding whether the additional spending was warranted – were not reported to the Board.
- Union assumes that 20% of all increased spending would need to go towards administration and evaluation because that is the portion of its base budget that is allocated to those overhead items. This is a highly problematic assumption. The costs of evaluating a program will not change because higher rebates were offered and/or because participation increased. The only thing that might increase evaluation costs is the launch of a new program, and Union included only one very small new program in their analysis. Similarly, the costs of administering programs will not go up – at least not significantly, and certainly not linearly – because rebates are increased and/or participation increases. Thus, Union's sensitivity analysis significantly understates the additional savings that could be acquired by over-estimating how much of the increased spending would go towards items that do not produce savings.

[43] Exh A/T3/Appendix G. All of these amounts are expressed in 2015 dollars, unadjusted for inflation.

- The Company's estimates of the volume of additional participation and savings it could achieve from increase rebate levels for its home retrofit program are unsupportable. In its base budget, the Company has estimated that it would only have 5000 participating homes in 2020. In contrast, Enbridge exceeded that number with its home retrofit program in 2014 and is forecasting that it will have approximately 13,500 participants in 2020. Even after adjusting for the fact that Enbridge has roughly 50% more residential customers, Enbridge's forecast participation is nearly twice the participation rate Union has forecast for its own program with comparable incentive levels. Thus, Union should be able to achieve significant additional participation in this program without raising rebate levels.

2. Enbridge's Sensitivity Analyses

Enbridge also analyzed three budget sensitivity scenarios – one that represented 25% less spending than in its base plan, one that represented 25% greater spending than in its base plan and a third that represented 50% greater spending than in its base plan. Enbridge appeared to approach the sensitivity analysis in a more structured way than Union. In particular, it started by assessing each of its programs to determine which were "scalable" (i.e. could grow with additional funds) and which were not. Nine different program offerings were deemed to be scalable.[44]

The Company then developed estimates of how much of the increased budget would be allocated to different functions and programs. To Enbridge's credit (and in contrast with Union), only a small portion of the increased budget was assumed to be needed for additional overhead costs (e.g. evaluation and administration), so the 25% budget increase was assumed to be more like a 30% increase for programs. Note that because only a portion of programs are assumed to be scalable, the percent increase for the scalable programs is estimated to be even larger than that.

For the programs that generate trackable savings, Enbridge then developed and applied a formula that was supposed to correlate increased spending with increased savings. The formula was supposedly based on the relationship between changes in spending and changes in savings from Enbridge's recently completed potential study. Unfortunately, there are numerous and important problems with the approach that Enbridge took that render its sensitivity scenarios virtually useless:

- Additional budget is allocated to "scalable programs" in the same proportion as it was allocated to those programs in the Company's base budget. No effort was made

[44] Exh B/T1/S5.

to optimize how additional spending would be allocated – either to maximize additional savings or to address other strategic goals. Again, this is somewhat understandable given the very limited time the Company had to develop a complex filing of which the sensitivity analysis was only one part. However, the fact that it is understandable does not change the fact that it is problematic.

- Related to the point above, Enbridge assumed that its market transformation budget would increase in the same proportion as its resource acquisition and low income budgets – all to support the existing base budget programs. For example, of the roughly $32 million increase in spending in 2016 under the 150% budget scenario, Enbridge assumed that nearly $7 million would go to market transformation programs (none of which produce immediately quantifiable savings). That does not make sense. For the programs that are truly designed to transform markets (e.g. the residential and commercial new construction programs),[45] the base budget should already have been designed to be sufficient to put the targeted markets on a path to market transformation.
- Any formulaic reliance on its potential study estimates of declining yield per dollar spent is problematic. First, even well done efficiency potential studies are inherently conservative.[46] Second, the potential study estimated gross savings potential, not net potential after adjusting for free riders. However, free ridership typically declines as financial incentives for efficiency measures – one of the key drivers to increased budgets – increase. Thus, the relationship of increased savings to increased spending that Enbridge tried to derive from the potential study results inherently understates the magnitude of increased *net* savings (the only metric that matters). Third, and probably most importantly, Enbridge's recent potential study is fraught with so many methodological problems that it has almost no value for informing conclusions regarding achievable savings potential. A few illustrative examples are as follows:
    - In analyzing efficiency potential at the time that new products are being purchased, one needs to estimate how many products are sold each year. Typically, potential studies develop such estimates by assessing the number of a particular type of product in use and dividing by the average measure life for that product. For example, if there are 100,000 commercial boilers in use and the average boiler has a measure life of 25 years, then approximately 4000 boilers are being replaced each year and efficiency programs have the opportunity to influence whether the most efficient boilers are being

[45] Enbridge has some programs in its "market transformation" portfolio that are not really about transforming markets. They are arguably more like resource acquisition programs, or customer education programs (e.g. OPower and Run it Right).

[46] Goldstein, David, "Extreme Efficiency: How Far Can We Go If We Really Need To?", Proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 10, pp. 44-56.

purchased at the time of those replacements. However, Navigant's potential study makes what I consider to be a mathematical error that implicitly leads it to assume that the number of replacement products being sold each year is declining.[47] The result is that it understates the size of equipment replacement markets in the 10th year of its analysis by about 33% for measures with 25 year lives, by about 50% for measures with a 15 year life and by more than 60% for measures with a 10 year life. Needless to say, those underestimates lead to significant under-estimates of savings potential.

- Navigant estimates that economic potential in the commercial and industrial sectors is 96% of technical potential. In other words, virtually all efficiency that is technically feasible is also cost-effective under current (relatively low) avoided costs. That conclusion strongly suggests that the analysis did not truly look at a full range of potential efficiency measures; rather, it just looked at the measures that the utilities were already pursuing and/or anticipating that they might pursue and which are already known to be cost-effective. Put simply, it is not plausible that the supply curve of efficiency is a gradual upward slope to the current cost-effectiveness threshold and then becomes almost vertical.
- Navigant does not appear to have analyzed potential from industry-specific and/or facility-specific custom industrial measures. Indeed, in reviewing the stratified random sample of industrial projects analyzed under Enbridge's 2014 Custom Project Savings Verification process I found that approximately half of the projects employed measures that do not appear to have been addressed in the Navigant study. I should note that is not uncommon for potential studies. They tend to assess only relatively common measures. However, that is an important limitation that makes such studies' conclusions regarding efficiency potential very conservative.
- Navigant appears to have estimated the maximum technical potential for

[47] Rather than taking the entire existing stock of equipment and dividing it by the measure life to get an annual turnover rate for each year of its analysis, Navigant apparently does that only for the first year. For the second year it adjusts the size of the existing stock downward by the number of units replaced in year 1 and divides that smaller number by the measure life, producing a smaller eligible market in year 2. The farther out in time one goes, the smaller the eligible market becomes under this flawed approach. Navigant suggests this approach is reasonable because not all equipment lasts exactly the same amount of time (JT1.22). I concur with that statement. For equipment that has an average measure life of 25 years, a very small number will last only a few years (the "lemons"), some will last 15 years, some 20, some 30 and some 40 or 50 or more. However, what Navigant fails to realize in its analysis is that distribution applies to all products installed 10, 20, 30, 40, and 50 years ago. Thus, all other things being equal (the climate, the economy, etc.) the turnover this year, and next and the year after are all likely to be very similar. There is absolutely no basis for thinking the number of units sold for use in existing buildings will decline over time (except to the extent the existing building stock is demolished, which is only a very small fraction of buildings per year). More importantly, there is no evidence from sales data of major appliances, HVAC equipment, etc. that sales of replacement products decline over time.

operational efficiency improvements in commercial buildings to be no more than about 3%.[48] That is implausibly low.[49]

- Navigant's estimate of savings from do-it-yourself residential air sealing measures (e.g. caulking, weatherstripping, outlet gaskets, etc.) is implausibly high. The level of savings estimated is achievable, but only through more sophisticated blower-door guided air sealing by professionals. In other words, Navigant got the savings about right, but grossly under-estimated what it would cost to acquire.

- Even if one were to ignore all of the concerns about the use of the potential study, Enbridge made a basic mathematical error in developing the formula it used to apply the decline in savings yield per additional dollar spent derived from its potential study (what the Company calls its "decay factor"). The Company starts by noting that at the level of its base plan budget, the potential study suggests that for every 9% increase in budget there is approximately a 4% increase in savings.[50] It then makes the mistake of using those assumptions in a formula that not only adjusts savings from new spending but adjusts the base level of savings as well. The result is a formula that mistakenly suggests that it is impossible to achieve more than 17% more savings than Enbridge has forecast and that savings would actually start to decline once budgets were increased by about 70%. Those conclusions are inconsistent with the results of the flawed potential study that Enbridge's formula was designed to represent. More importantly, they are inconsistent with the experience of the leading jurisdictions discussed above.

3. Opportunities for Utilities to Acquire Substantial Additional Savings

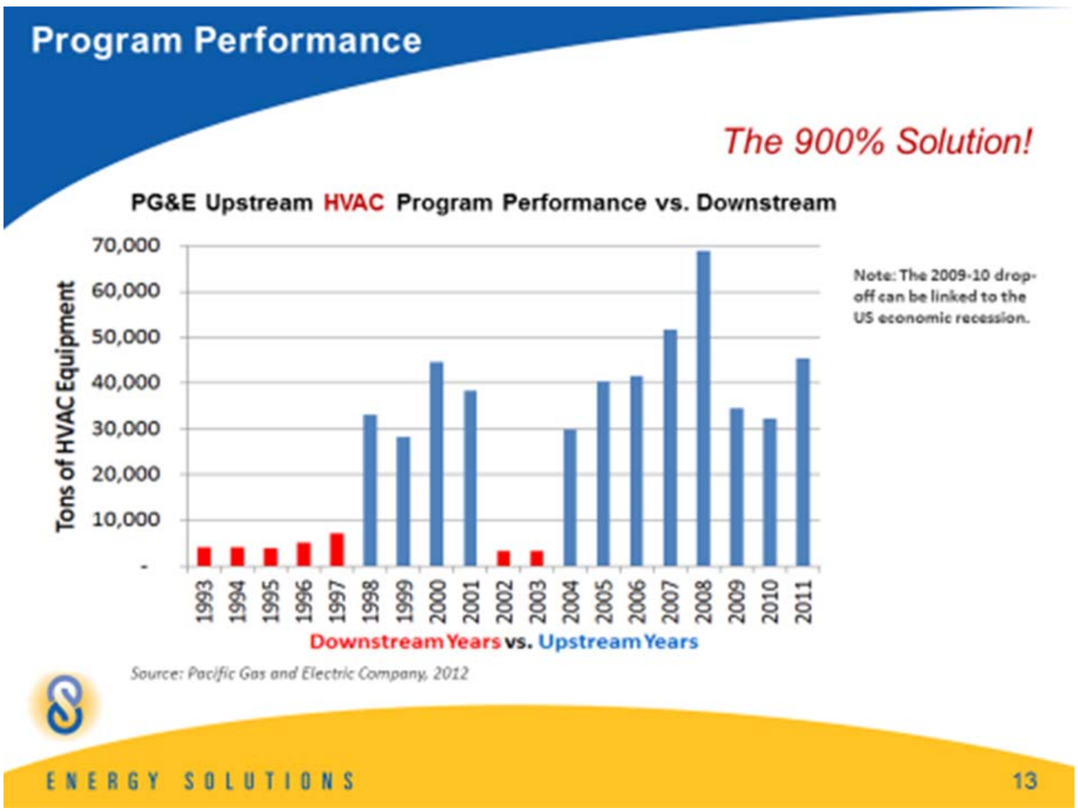
There are a number of ways in which the utilities could acquire significant additional cost-effective savings. These include:

- **Beginning to use "upstream incentive" program designs.** Upstream incentives – that is, incentives paid to manufacturers, distributors, contractors and/or other key players in the supply chain rather than to the end use customers – can have several advantages. Most importantly, they typically lead to much higher market penetration rates for efficient equipment. That can be seen in Figure 3, which shows that a commercial cooling equipment upstream incentive program (blue bars) run by Pacific Gas and Electric in California for over a decade achieved nine times the level of participation that its former "downstream" customer rebate program design

[48] Exh C/T1/S2 p. 18.
[49] See EB-2012-0451, Exhibit L.EGD.ED.1
[50] Enbridge response to GEC.42.

(red bars) achieved. Interestingly, when the program design was changed back to a customer rebate after four years of the upstream model, participation plummeted again. After two years of that much lower participation rate, the upstream incentive approach was re-initiated and participation skyrocketed again.

Figure 3: Upstream vs. Downstream Incentive Approaches[51]



Very similar results have been achieved in California for commercial gas boilers and other products.[52] Similarly, in September 2013 Efficiency Vermont launched an upstream incentive for high efficiency circulator pumps for boilers and saw the market share (from one of the leading HVAC wholesalers) for those products increase from 2% or less to about 50% in the span of just one year. It took about six months to get the program off the ground, but it continues to grow steadily.[53] These types of increases in market penetration happen for several reasons. First, it is generally easier to inform and work with a relatively small number of strategic market actors who influence (through their own stocking and sales practices) the purchases of thousands of end use customers. Second, because the cost of products is typically marked up at every step in the supply chain, a financial incentive paid to a distributor will cover a

[51] Hanna, James, et al., "The 900% Solution: Supercharging HVAC Efficiency Portfolios", Presentation at the 2012 ACEEE Summer Study (informal session), August 16, 2012.
[52] Personal communication between Jim Hanna (Energy Solutions) and Jim Grevatt (Energy Futures Group), who was collecting this information under my direction, July 2015.
[53] Personal communication with Jake Marin, Efficiency Vermont, July 2015.

TAB 5

GEC Response to APPrO Interrogatory #1

Question:

Reference: L.GEC.1

i) Page 27, first bullet point[1]

> ***Continuing Union's large industrial program for T2/R100 customers****.*
> *Experience from 2013 and 2014 suggests that would – by itself – roughly double Unions forecast savings for 2016 to 2020*

ii) Page 31

> *While Union's estimate of free ridership is admittedly based on an outdated study, its implicit conclusion that there are substantial cost-effective savings that large customers would not pursue absent efficiency programs is consistent with assessments from other jurisdictions. For example, a recent jurisdictional scan conducted by Navigant Consulting for the Ontario gas Technical Evaluation Committee found that the average free rider rate from evaluations of twenty-four different gas utility Custom C&I programs – which are typically targeted to the largest customers – was between 30% and 40% (meaning 60% to 70% of savings would not have occurred without the utility programs).*

ii) Page 32

> *"allowing Union to terminate its large industrial program would mean foregoing a huge portion of achievable savings and – because these savings tend to be more cost effective than those that can be acquired from other, smaller customers – an even larger portion of economic benefits"*

Preamble: Mr. Neme makes a statement about potentially doubling Union Gas Limited's (**Union**) savings 2016-2020 by continuing Union's large industrial program for T2/Rate 100 customers. This statement may rely on a free ridership estimate. APPrO would like understand the basis for this statement and whether the Navigant study is representative of Union's T2/Rate 100 customers.

a) Please confirm that the statement made in Reference i) was based on the free ridership rate of 54% that was established in 2008 by Summit Blue. If not confirmed, please explain.

b) Please confirm that the above-noted 2008 Summit Blue study was based on a study published using data that was collected pre-2008.

c) In Reference ii) Mr. Neme recognizes that the Union's free ridership study is out of date, and uses a Navigant report to support the contention that there are still significant savings in utility Custom Commercial and Industrial (**C&I**) programs based on an evaluation of 24 US jurisdictions.

   i. The link in footnote 69 of Mr. Neme's evidence was broken; please provide a correct link to the referenced Navigant Study.
   ii. Please indicate if Mr. Neme assisted Navigant in its research or preparation of the report in any way. If so, please provide details regarding the support that was provided.
   iii. Please provide a description of the methodology used by Navigant to obtain the information for its report.
   iv. Please list the major assumptions that Navigant used to collect and analyze the information.
   v. Please confirm that Union offers custom C&I programs to the following rate classes: M4, M5, M7, T1, and Rate 20 categories, in addition to T2 and Rate 100. If not confirmed, please explain.
   vi. Please confirm that Enbridge Gas Distribution Inc.'s (**EGD**) custom C&I programs are offered to rate classes 6, 110, 115, 135, 145, and 170. If not confirmed, please explain.

vii. Please list each of the 24 jurisdictions that were used to come up with Navigant's conclusions noted in Reference ii). Please also provide the rationale why these 24 jurisdictions were selected vs a comprehensive review.

viii. Please confirm that the Navigant also expressed concern about the accuracy of their results. If not confirmed, please explain.

ix. Please provide the specific Navigant reference to support Mr. Neme's statement " *.the average free rider rate .was between 30% and 40%".*

d) Please confirm that if the customer were to complete energy efficiency measures independent of a mandatory rate payer funded DSM program, the energy savings could still occur. If so, please confirm that such independent measures would not be accounted for within the utility DSM program. If not confirmed, please explain.

e) Please confirm that if DSM budgets were to be reallocated to T2 and Rate 100 rate classes, the DSM budget for other rate classes would decline and the related energy savings in those rate classes would also decline. If not confirmed, please explain.

f) Please provide an estimate of the annual energy savings that would be lost from other rate classes if DSM budgets were to be reallocated to rate T2 and Rate 100.

Response:

a) It implicitly assumes a net-to-gross ratio that is consistent with the combination of a free rider rate in that ballpark and no spillover.

b) The 2008 Summit Blue study was not based on another study (regardless of vintage). Rather it collected its own data during the winter of 2007-2008.

c) Responses as follows:

i. See attached.

ii. He did not. The study was commissioned by the Technical Evaluation Committee (TEC). A subcommittee of the TEC was created to oversee the work. Once the subcommittee felt a draft report was ready for the full TEC to review, the full TEC review took place. Mr. Neme was a member of the TEC at the time the study was commissioned (and is still now), so he did have an opportunity to review and provide comments on the draft report. He was not a member of the TEC subcommittee overseeing the work.

iii. Navigant provides an extensive description in its report.

iv. See the attached Navigant report.

v. Union Gas can confirm which rate classes are eligible for custom programs.

vi. Correct, according to EB-2015-0049, Exh B/T2/S1 pages 8 and 11.

vii. My understanding is that intention of the study was to be as broad and comprehensive as possible. As the report states, Navigant started by reviewing the net-to-gross (NTG) approaches used in 42 different jurisdictions. A portion of those do not do not adjust gross savings, so they were obviously not candidates for review of NTG studies. Ultimately, a short list of jurisdictions and programs that were deemed comparable to Union's and Enbridge's programs (in terms of customer segments and program design) was chosen. The results cover nine jurisdictions, nineteen different studies and thirty-eight different programs. The list of jurisdictions whose studies were reviewed is provided in Navigant's report.

viii. Not confirmed. A search of the document suggests that Navigant did not use the word accuracy even once. The word "concern" arises only once, in a sentence in which Navigant notes that there is a slight trend in recent years to higher net-of-free rider estimates, but that the trend isn't so significant that the TEC should have concern about using Navigant's estimated average values (see p. 20 of the report).

ix. See the following quote from the Executive Summary of the report regarding gas C&I programs:

The average net-of-free ridership value is 68%. As expected, NTG values are larger when considering spillover. Average net-of-free ridership & PSO value is 86% and average net-of-free ridership & spillover value is 87%... (p. iv)

Also, see the Figure 9 on p. 24 which graphs values separately for custom C&I programs and prescriptive C&I programs. It appears to suggest that the average NTG when considering only free ridership is in the 60% to 70% range. If one also accounts for spillover effects, the values increase. In fact, there is not a single study that estimated NTG less than about 55% for custom C&I programs when including both free ridership and spillover effects, and the average appears to be on the order of 80% to 85%.

d) Confirmed.

e) Not confirmed. That statement would only be true if one presumed that Union was not permitted to increase its budget to account for spending on T2/R100 customers. As noted in my testimony, the Board's DSM guidelines are just guidelines, not binding regulatory constraints. Moreover, the budget suggested for Union in the guidelines was presumably established while the Board was cognizant of the fact that it was simultaneously suggesting not offering programs to those rate classes. It is not clear whether the same budget guideline would have been put in place by the Board if it has not suggested terminating Union's self-direct program.

f) A precise answer would require careful consideration of which program and/or budget categories in Union's proposed 2016-2020 plan would be most appropriate to reduce. However, a rough estimate can be developed as follows:

- Union spent approximately $4.1 million on its large industrial program in 2014; approximately 80% of that – or $3.25 million – could be said to be associated with just the T2 and R100 customers. That is roughly equal to 5.7% of Union's proposed average annual 2016-2020 DSM budget.

- Union forecasts in its plan that it will achieve an average of 1.23 billion lifetime m^3 savings per year from its 2016 to 2020 programs.

- If Union reduced its budget equally for all other programs by 5.7% of its annual budget, it would reduce savings from non-T2/R100 customers by approximately 70 million lifetime m^3 each year.

Note that Union estimates that the level of budget shift contemplated above produced roughly billion lifetime m^3 savings from T2/R100 customers in 2014 – even after adjusting for an assumed 54% free rider rate.

Executive Summary

Union Gas Limited (Union) and Enbridge Gas Distribution (Enbridge) have delivered Demand Side Management (DSM) initiatives since 1997 and 1995, respectively, including programs that involve custom projects in the commercial and industrial (C&I) sectors. In 2007-2008, Summit Blue Consulting (now part of Navigant's Energy Practice) conducted the first attribution study of Union and Enbridge's custom C&I programs to evaluate free ridership (FR) and spillover effects. After the study, the Ontario Energy Board (OEB) approved the FR adjustment, but did not approve the spillover factor. Since that time, there have been a host of program environment changes, including economic conditions, energy prices, advances in technology, as well as changes in the design and delivery of the custom programs. As a result, Ontario's Technical Evaluation Committee (TEC) is prioritizing updates to FR and spillover adjustment factors as part of its mandate.

This report provides information to support a sub-committee of Ontario's TEC in its deliberations on the appropriate approach to Net-to-Gross (NTG) values in Ontario. Through a jurisdictional review of the approach to net savings, and a review of researched NTG values for programs comparable to Union and Enbridge's custom C&I gas programs, Navigant provides an assessment of the various approaches to NTG.

ES 1. Report Objectives

There are a range of options for NTG that could be adopted for natural gas DSM programs in Ontario, from transferring NTG values from similar jurisdictions and programs to conducting research to estimate a NTG value.

The objective of this report is to provide information to assist the TEC sub-committee in their determination on the appropriate approach to NTG for DSM programs in Ontario, and not to provide a specific recommendation. While this report is not comprehensive in addressing all potential considerations, such as other benefits of accurate (costs of inaccurate) NTG values, it provides important information relevant to the discussion. In addition to summarizing the regulatory and methodological approach taken by other jurisdictions, and summarizing NTG values for programs with characteristics similar to Union and Enbridge's custom C&I programs, Navigant provides insight into the risks associated with inaccurate NTG values and the approximate cost of mitigating those risks.

ES 2. Key Findings

To achieve the objective of this report, Navigant (1) reviewed the approach to net savings across a wide array of jurisdictions in the United States and Canada to identify trends in the regulatory and methodological approach to net savings, (2) conducted a review of researched NTG values of non-residential gas programs in selected jurisdictions, and (3) conducted a decision analysis to assess the options for NTG. Key findings are presented for each of these.

Approach to Net Savings

Navigant conducted research to provide a summary of the regulatory and methodological approach to net savings adopted by jurisdictions across North America. In total, Navigant reviewed the approach to net savings taken by 42 jurisdictions across North America, representing the vast majority of jurisdictions with ratepayer-funded energy efficiency programs.

The majority of jurisdictions with ratepayer funded energy efficiency programs conduct NTG research, though only half adjust gross savings based on research. While there appears to be a trend towards considering participant and non-participant spillover in NTG research in recent years, the majority of research only includes FR adjustments. Both FR and spillover are most commonly estimated through a self-report (participant survey) approach, though econometric methods (e.g., billing analysis) and market share modeling approaches are occasionally used.

Navigant also researched whether jurisdictions offer utility performance incentives for meeting their savings goals. U.S. states that provide a performance incentive mechanism for utilities or program administrators are more likely to make deemed or researched NTG adjustments.

Researched NTG Values in Selected Jurisdictions

Navigant reviewed a total of 19 documents that conducted NTG research of non-residential gas programs covering nine jurisdictions in North America, including: California, Colorado, Massachusetts, Minnesota, New Jersey, New Mexico, Oregon, Washington, and Wisconsin. Within these 19 documents, 38 distinct NTG values were reported.

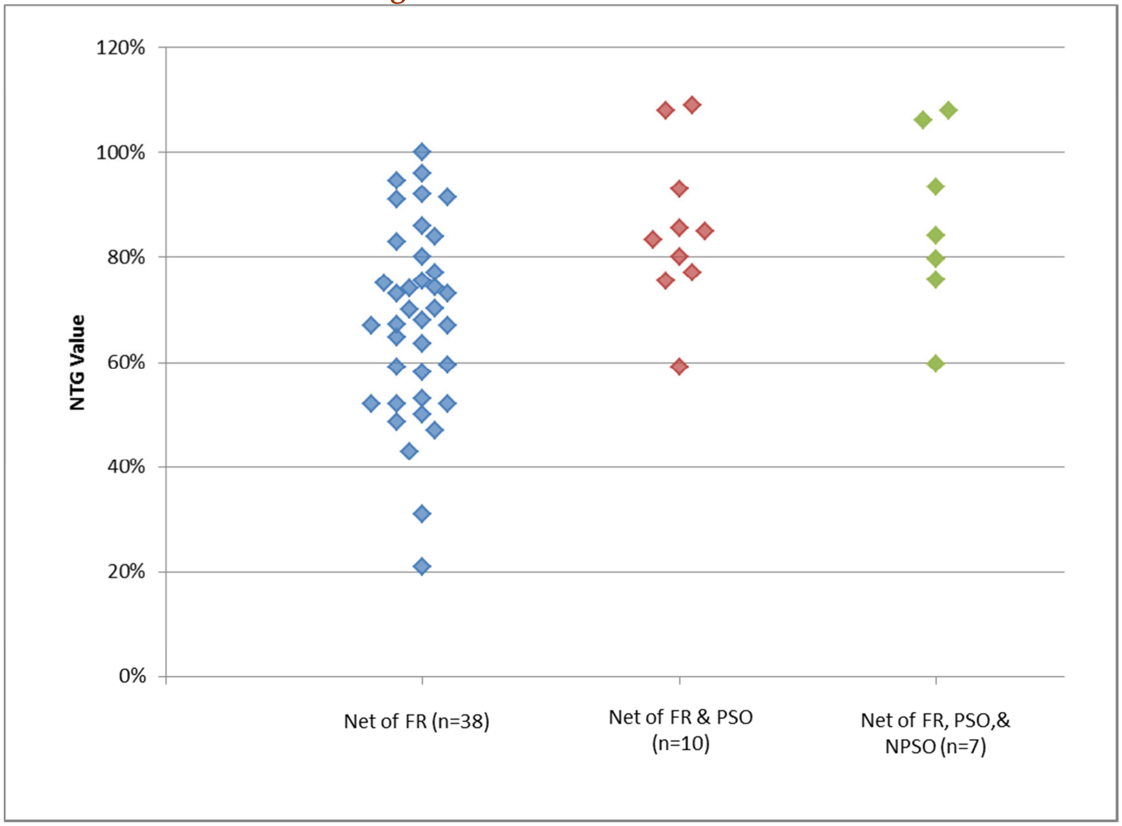
Different formulations of NTG values are presented, with each including or excluding different NTG factors. In particular, the following NTG values are presented:

- Net-of-free ridership = 1- FR,
- Net-of-free ridership and participant spillover = 1 – FR + PSO, and
- Net-of-free ridership and all spillover = 1- FR + PSO + NPSO
  (Note: NPSO is non-participant spillover)

This approach conveys information on NTG values based on the common definitions across the studies, and avoids inappropriate comparisons that could result from comparing the studies' reported NTG values when they include different components.

A review of researched net-of-free ridership values for non-residential gas programs exhibits a wide dispersion (21% to 100%) with a slight "clustering" of values between 40% and 90%, as shown in Figure ES-1. The average net-of-free ridership value is 68%. As expected, NTG values are larger when considering spillover. Average net-of-free ridership & PSO value is 86% and average net-of-free ridership & spillover value is 87%, suggesting that NPSO is small for non-residential gas programs.

Figure ES-1. NTG Values



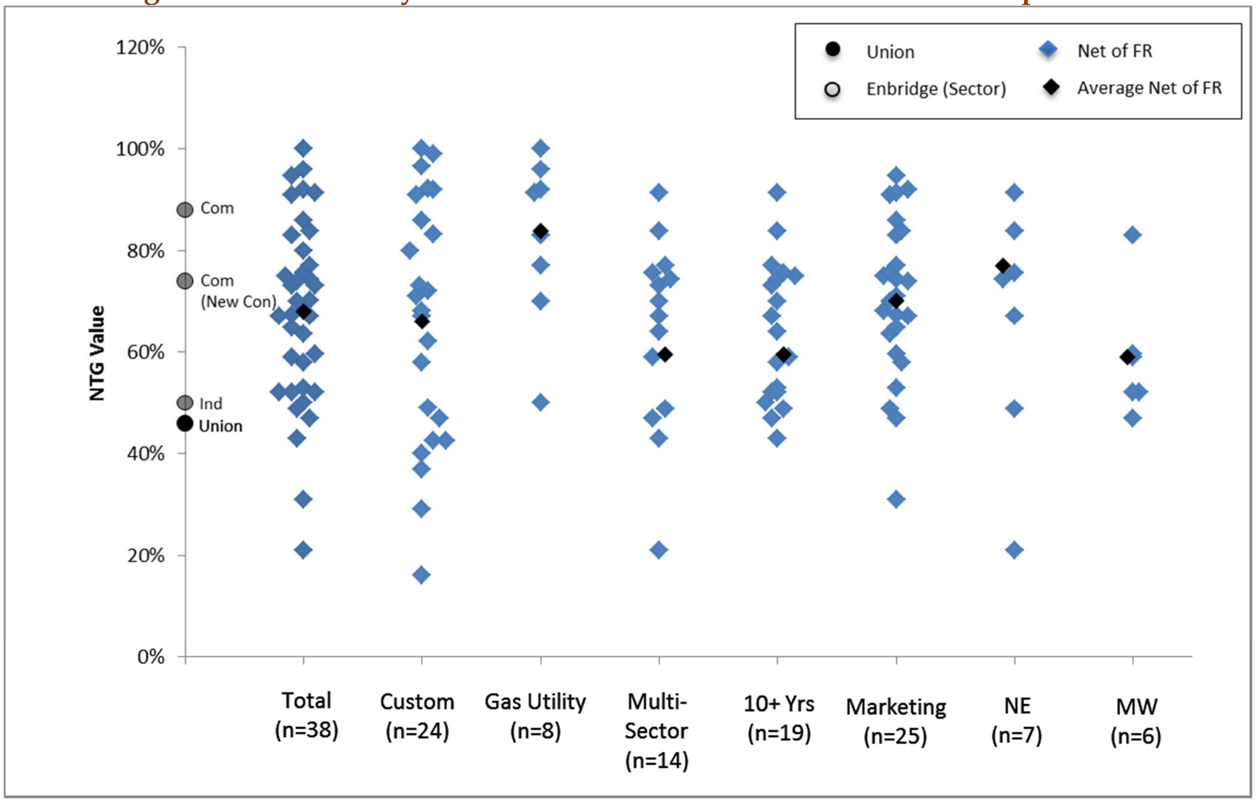
Source: Navigant analysis. Note that the sample size (n) represents the number of unique NTG values (program-utility-year combinations) reported in the 19 studies.

To provide additional context Navigant reviewed NTG values by study, program year and region and found that the variation in NTG values did not appear to be driven by the program evaluator, program year, or region. Navigant also examined whether variation in NTG values resulted from differences in the analytic rigor of the methodology (all used self-reports), using enhanced self-report methods in the form of trade ally feedback as a proxy. Free ridership values appeared lower with the inclusion of trade ally feedback. Finally, Navigant compared electric NTG values to gas NTG values for studies that reported both values and found that gas NTG values exhibited a wider dispersion.

Navigant also reviewed researched NTG values based on specific program characteristics: program type, customer segment, utility-type, program maturity, and program marketing strategy. Trends in NTG values are less defined and should be interpreted with caution due to the small sample sizes. Nevertheless, some trends emerged: NTG values for custom programs exhibited a wider dispersion than programs offer prescriptive incentives or both, programs offered by gas-only utilities appear to have lower FR than programs offered by combination utilities, and FR appears to be greater with program maturity.

Figure ES-2 presents the net-of-free ridership values for program characteristics that are most similar to Union and Enbridge's custom C&I programs. In addition, Union and Enbridge's current NTG values, based on the 2007-2008 research conducted by Navigant (formerly Summit Blue Consulting) are presented. Note that Union currently uses one NTG value for C&I custom programs while Enbridge uses sector-specific NTG values.

Figure ES-2. Summary of Relevant Researched Net-of-Free Ridership Values



Source: Navigant analysis. Note that the sample size (n) represents the number of unique NTG values (program-utility-year combinations).

Both Union and Enbridge's current NTG values are within the range of researched values. Union's NTG value is below the average value. Enbridge's NTG value for the commercial sector is above the average value while the NTG value for the industrial sector is below the average value.

Assessing Options for NTG

Gross savings can usually be estimated quite accurately, however, estimating net savings poses greater challenges. Given the uncertainty around any NTG value, Navigant applied a Decision Analysis approach for organizing information around alternative approaches to setting NTG values.

There are a number of benefits resulting from more precise NTG values, including the ability to improve program design and implementation, more accurate utility incentive payments, and the ability to consider energy savings as a resource. Navigant conducted a value of information

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(VIF) analysis on the second benefit, incentive payments, as the benefit/cost of improved information can be easily quantified.

To support the VIF analysis, Union and Enbridge conducted a sensitivity analysis of utility incentive payments resulting from their custom programs, using a +/- 10 percentage point margin of error on the custom programs NTG values. This analysis revealed that improving the precision of custom NTG values has a sizable impact on incentive payments. Table ES-1 and Table ES-2 present a value of information analysis for Union and Enbridge respectively at targeted net savings.

Table ES-1. Value of Information Assessment for Union

	NTG Value for Custom Programs		Incentives	Change in Incentives
Base Case:	**Current NTG** NTG = 0.46	→	Incentives = $2.73 M	
Scenario 1:	**Higher True NTG** NTG = 0.56	→	Incentives = $5.63 M	**(+$2.90 M)**
Scenario 2:	**Lower True NTG** NTG = 0.36	→	Incentives = $0.8 M	**(-$1.93 M)**

Source: Sensitivity analysis provided by Union.

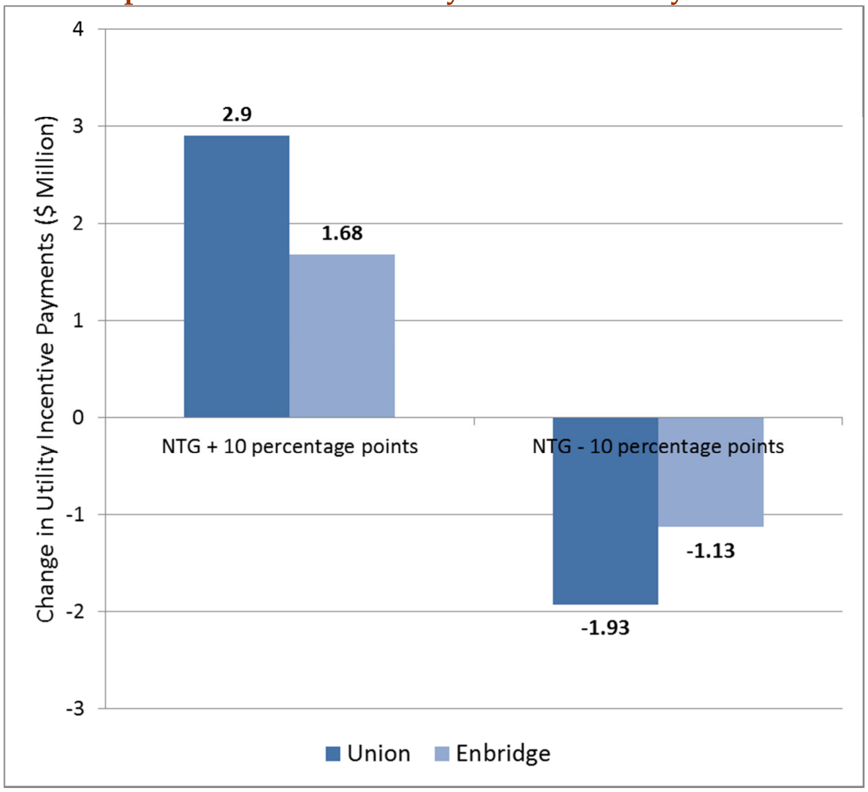
Table ES-2. Value of Information Assessment for Enbridge

	NTG Value for Custom Programs		Incentives	Change in Incentives
Base Case:	**Current NTG by Program** Commercial = 0.80 Commercial New Construction = 0.74 Industrial = 0.50	→	Incentives = $2.58 M	
Scenario 1:	**Higher True NTG** Commercial = 0.90 Commercial New Construction = 0.84 Industrial = 0.60	→	Incentives = $4.26 M	**(+$1.68 M)**
Scenario 2:	**Lower True NTG** Commercial = 0.70 Commercial New Construction = 0.64 Industrial = 0.40	→	Incentives = $1.45 M	**(-$1.13 M)**

Source: Sensitivity analysis provided by Enbridge.

The penalty for assuming a NTG value that is +/- 10 percentage points different from the actual NTG value is roughly $1 to $3 million in utility incentive payments, as shown in Figure ES-3. If the cost of revising the NTG values is less than $0.5 million then revising the values *could be judged to be warranted* assuming NTG research could reduce the margin of error by one-half (i.e., the range of the likely true NTG values).

Figure ES-3. Comparison of the Sensitivity of Incentive Payments to NTG Values



Source: Sensitivity analyses provided by Union and Enbridge.

Navigant provides a brief review of five general approaches to NTG, providing an estimate of the improved precision of the NTG value and the approximate cost per utility (Table ES-3). Alternate NTG approaches could improve the precision of NTG values by approximately 50% at an approximate cost of $0.25 - $0.50 million per utility.

Table ES-3. Ability of NTG Approaches to Produce More Precise NTG Values

General NTG Approach	Estimated Improved Precision (or Reduced Range) of NTG Value	Cost of NTG Approach per Utility (approximate)
Transfer NTG Values from Other Research	Little change	$3 – 5k
Adjust NTG Values based on Program Factors	Little change	$5 – 10k
Align NTG Values using Limited Primary Data	3 percentage points	$100 – 200k
Full NTG Research Study – After Program Year	5 percentage points	$250 – 500k
Integrated/Fast Feedback NTG Estimation	5 percentage points	$250 – 500k

Source: Navigant analysis.

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2. Methodology

This section describes the methodology Navigant employed to provide information to assist the TEC sub-committee in their deliberations on the appropriate approach to NTG for custom natural gas DSM programs in Ontario. The sub-sections that follow discuss the four distinct tasks conducted by Navigant:

- Reviews of the custom C&I natural gas programs,
- Summary of research methods and regulatory approaches to net savings,
- Review of researched NTG values in selected jurisdictions, and
- Assessing options for updating NTG values for these programs.

2.1 *Union and Enbridge Programs*

To develop an understanding of the portfolio of Union and Enbridge's custom C&I gas programs, Navigant conducted a review of the following:

- Description of programs included in the *2012 Custom Free Ridership and Participant Spillover Jurisdictional Review* request for proposal, and
- Union and Enbridge program websites.

Union and Enbridge also provided additional information on features of program design and implementation as requested by Navigant.

2.2 *Approach to Net Savings*

Navigant conducted research to provide a summary of the regulatory and methodological approach to net savings adopted by jurisdictions across North America, as well as whether jurisdictions offer utility performance incentives for meeting their savings goals. The research methodology included a review of:

- Utility websites,
- Regulatory agency websites,
- Websites of research/advocacy groups such as the Regulatory Assistance Project (RAP), American Council for an Energy-Efficiency Economy (ACEEE), Consortium for Energy Efficiency (CEE), and the Edison Foundation, and
- Studies that previously surveyed the approach to net savings.[3]

In total, Navigant reviewed the approach to net savings taken by 42 jurisdictions across North America, representing the vast majority of jurisdictions with ratepayer-funded energy efficiency programs. In addition, a review of the approach to net savings in nine selected jurisdictions is discussed in the following section.

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[3] Refer to 7.Appendix A for a list of references for methodological resources.

2.3 *Researched NTG Values in Selected Jurisdictions*

To provide the TEC sub-committee with a comprehensive review of researched NTG values Navigant worked with the TEC sub-committee in an iterative process to identify relevant jurisdictions/ programs and accompanying evaluation studies. The research methodology included:

- Review of program evaluations conducted by Navigant and Summit Blue Consulting (acquired by Navigant in 2010),
- Review of program evaluations identified by Navigant staff,
- Review of the Northeast Energy Efficiency Partnerships' Repository of State and Topical EM&V Studies,
- Search of the California Measurement Advisory Council searchable database,
- Search of the Consortium for Energy Efficiency searchable database,
- Review of State and Utility websites for program evaluations and filings,
- General internet searches for program evaluations, and
- Outreach to industry professionals.

This list was revised to develop a shortlist of programs comparable to Union and Enbridge's programs, accounting for factors such as customer segment and program design. Additional studies were excluded due to the methodology employed and/or the applicability of the reported NTG values.[4]

NTG values for programs targeting natural gas savings is the focus of this report due to the greater than expected availability of gas utility studies, as well as combination utility studies where natural gas NTG values were reported separately.

A total of 19 documents[5] were selected covering nine jurisdictions in North America, including: California, Colorado, Massachusetts, Minnesota, New Jersey, New Mexico, Oregon, Washington, and Wisconsin. In some cases, one document reported NTG values for multiple programs, multiple utilities, or multiple program years. In total, 38 distinct NTG values were reported. Table 1 presents the number of distinct values reported across the 19 documents.

[4] Refer to Appendix B for an example of two notable studies/jurisdictions excluded from the analysis.
[5] Refer to Appendix C for an annotated bibliography of these documents.

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Table 1. Documents Reviewed and Distinct NTG Values Reported

Document Number and Title	Number of Distinct Values Reported	Reason for Including Multiple Values
1. 2004/2005 Statewide Express Efficiency and Upstream HVAC Program Impact Evaluation	4	NTG values reported for 4 utilities: PG&E, SDG&E, SCE, and SCG.
2. 2004-2005 Statewide Nonresidential Standard Performance Contract Program Measurement and Evaluation Study	2	NTG values reported for 2 investor-owned utilities: PG&E and SDG&E.
3. 2006-2008 Retro-Commissioning Impact Evaluation	4	NTG values reported for 4 utilities: PG&E, SDG&E, SCE, and SCG.
4. 2011 Commercial and Industrial Natural Gas Programs Free-Ridership and Spillover Study	6	NTG values reported for 6 utilities: NSTAR, Unitil, New England Gas, National Grid, Columbia Gas, and Berkshire Gas.
5. Evaluation of 2011 DSM Portfolio	2	NTG values reported for 2 programs: Commercial Solutions and SCORE pilot.
6. Fast Feedback Results	3	NTG values reported for 3 programs: Existing Multifamily, Existing Buildings, and Industrial Production Efficiency.
7. Impact and Process Evaluation of the 2006-2007 Building Efficiency Program	2	NTG values reported for 2 program-years: 2006 and 2007.
8. Evaluation of Building Efficiency Program 2004 & 2005	2	NTG values reported for 2 program-years: 2004 and 2005.
9. Impact and Process Evaluation of the 2006-2007 New Building Efficiency Program	2	NTG values reported for 2 program-years: 2006 and 2007.
10. Focus on Energy Evaluation: Business Programs Impact Evaluation Report – Last Quarter of Calendar Year 2009 and First Two Quarters of Calendar Year 2010	2	NTG values reported for 2 program-years: 2009 and 2010.
11. 2006-2008 Evaluation Report for PG&E Fabrication, Process and Manufacturing Contract Group	1	N/A
12. Evaluation of the Southern California Gas Company 2004-2005 Non-Residential Financial Incentives Program	1	N/A
13. Comprehensive Process and Impact Evaluation of the Business Heating Efficiency Program - Colorado	1	N/A

Document Number and Title	Number of Distinct Values Reported	Reason for Including Multiple Values
14. New Jersey's Clean Energy Program Energy Impact Evaluation: SmartStart Program Impact Evaluation	1	N/A
15. Commercial and Industrial Energy Efficiency Retrofit Custom Programs Portfolio Evaluation	1	N/A
16. Focus on Energy Evaluation: Business Programs – Additional Looks at Attribution	1	N/A
17. Focus on Energy Evaluation: Semiannual Report (Second Half of 2009)	1	N/A
18. Focus on Energy Evaluation: Semiannual Report (First Half of 2009)	1	N/A
19. Achieving Natural Gas Savings Goals: Commercial Heating Programs Heat It Up	1	N/A
Total: 19 Documents Reviewed, 38 Distinct Values Reported		

Source: Navigant analysis.

Navigant reviewed these selected documents to summarize methods used to assess NTG values across these jurisdictions. The following estimates from these studies are reported:

- Net-of-free ridership = 1- FR,
- Net-of-free ridership and participant spillover = 1 – FR + PSO, and
- Net-of-free ridership and all spillover = 1- FR + PSO + NPSO
  (Note: NPSO is non-participant spillover)

This approach conveys information on NTG values based on the common definitions across these studies, and avoids inappropriate comparisons that could result from comparing the studies' reported NTG values when they include different components. Table 2 presents the distribution of the different NTG factors reported across the 38 distinct values.

Table 2. NTG Values Reported

	NTG Values Reported by Adjustment Factor Included	Net-of-NTG Factors
FR	28	38
FR & PSO	3	10
FR, PSO & NPSO	7	7

Source: Navigant analysis.

A total of 28 NTG values reported adjust for FR only, 3 adjust for FR and PSO, and 7 adjust for FR, PSO, and NPSO. The last column shows the information gained from presenting net-of-NTG component values. For example, all 38 of the NTG values reported include values for FR.

Rather than just present the NTG values that adjust for FR only (n=28), the net-of-NTG component values are presented. In this case, (1 – FR) (n=38).[6]

In addition to these studies, Navigant also reviewed the 2008 evaluation of Union and Enbridge's custom projects program conducted by Summit Blue Consulting.[7]

2.4 Assessing Options for NTG

Given the uncertainty around NTG values, Navigant applied Decision Analysis methods to illustrate the risks faced by utilities and ratepayers when NTG values are uncertain and provide information on the benefits and costs of choosing one approach to net savings over another.

Navigant took the following steps to conduct the Decision Analysis:

1. Define the benefits of accurate (and costs of inaccurate) NTG values in a general context.
2. Narrow the focus the analysis on the benefits/costs for which Navigant had access to data; specifically, the incentives paid to utilities based on the estimated net savings (m^3) achieved by custom programs.
3. Establish a baseline against which a sensitivity analysis can be conducted where a selected NTG value is assumed to be correct, but in fact is incorrect by some margin of error.[8] The sensitivity analyses were conducted independently by Union and Enbridge and were not verified by Navigant.
4. Conduct a "value of information" analysis by examining the change in incentive payments resulting from better information on NTG values compared to the cost of obtaining the information (e.g., through NTG research).

In addition, Navigant organized the results of the Decision Analysis to provide insight into the tradeoffs from using different approaches to setting an NTG value, ranging from transferring values based on the jurisdictional review to conducting NTG research.

The next section (Section 3) presents an overview of the Union and Enbridge C&I programs to provide context. Following this program overview, Section 4 discusses the regulatory approach and methodological approach to NTG used by different jurisdictions followed by a review of researched NTG values in selected jurisdictions (Section 5). Finally, Section 0 presents the decision analysis for assessing alternate approaches to NTG.

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[6] Because the documents reviewed contain varying degrees of detail and explanation, the Navigant team applied its best interpretation of these documents to synthesize the available information in a consistent manner.

[7] Summit Blue Consulting. 2008. *Custom Projects Attribution Study.* Union Gas Limited and Enbridge Gas Distribution, October 27, 2008.

[8] These first three steps are part of a "loss function" analysis which identifies the costs of selecting one NTG value when another value is the actual value.

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4. Approach to Net Savings

This section presents the findings from the jurisdictional review of the approach taken to net savings, as well as the availability of performance incentives. This section begins with a review of 42 jurisdictions in the United States and Canada, representing the vast majority of jurisdictions with ratepayer-funded energy efficiency programs. This is followed by a closer look at the nine jurisdictions selected for further review. The final section summarizes the findings that are most relevant to Union and Enbridge.

4.1 *Jurisdictional Review*

Table 3 presents a summary of the approach to net savings used in the 42 jurisdictions, including the treatment of a FR adjustment and whether spillover is considered.[9] The table also presents information on whether jurisdictions offer utility performance incentives for meeting their savings goals, though, as indicated below, these goals are linked to either *gross* or *net savings*. Following is a summary of key findings:

- One-third (33%) of the jurisdictions reviewed **do not adjust gross savings** for either FR or spillover; however, some of those states may conduct some NTG research to inform future program design. Half of the U.S. states that do not adjust gross savings provide performance incentives for utilities to achieve energy efficiency program goals or have a performance incentive pending.

- Relatively few (14%) of the jurisdictions reviewed use a **deemed approach** to NTG; the deemed NTG values may be determined at a portfolio level (ranging from 0.7 to 0.9) or on a measure-by-measure basis (as in California, Vermont, and Nevada). These deemed NTG values are typically developed after NTG research has been conducted through program impact evaluations, and are revised on a regular basis through negotiations between utilities and regulators (often informed by additional NTG research). Over three-quarters (83%) of the U.S. states that use a deemed NTG approach provide performance incentives for utilities to achieve energy efficiency program goals.

- Nearly half of all jurisdictions reviewed take a **research-based approach** to NTG analysis. The vast majority of those jurisdictions consider spillover in some capacity, at least for some program types, though spillover is still quantified much less often than FR. Both FR and spillover are most commonly estimated through a self-report (participant survey) approach, though econometric methods (e.g., billing analysis) and market share modeling approaches are occasionally used. Nearly three-quarters of the U.S. states that take a research-based NTG approach provide performance incentives for

[9] Note that within a given jurisdiction, the treatment of spillover may vary by program type (including whether participant, non-participant, or both types of spillover is researched), and evaluators may investigate the possibility of spillover but find that no spillover is occurring or that it cannot be quantified with enough precision to obtain regulatory approval. Thus, this column reflects jurisdictions which consider the possibility of spillover but have not necessarily quantified and received regulatory approval for spillover savings estimates.

utilities to achieve energy efficiency program goals or have a performance incentive pending.

Table 3. NTG Approaches, Treatment of Free Ridership and Spillover, and Availability of Performance Incentives by Jurisdiction

Jurisdiction	NTG Approach*	Free-Ridership Adjustment	Spillover Considered?	Performance Incentives?	Notes
Hawaii	Deemed (0.7)			Yes	
Arkansas	Deemed (0.8)			Yes	
Michigan	Deemed (0.9)			Yes	Some NTG research conducted but not currently required by regulators.
California	Deemed (varies by measure, 0.5 for custom gas measures)			Yes	Research conducted to inform deemed NTG values.
Nevada	Deemed (varies by measure)				Some NTG research conducted.
Vermont	Deemed (varies by measure)			Yes	
British Columbia	Researched	Yes	Yes		Deemed NTG of 1.0 used until researched.
Nova Scotia	Researched	Yes	Yes		
Colorado	Researched	Yes	Yes	Yes	
Connecticut	Researched	Yes	Yes	Yes	Gross savings are used to evaluate whether goals have been met.
Florida	Researched	Yes	Yes	Pending	
Georgia	Researched	Yes	Yes	Yes	
Illinois	Researched	Yes	Yes		
Indiana	Researched	Yes	Yes	Yes	
Kansas	Researched	Yes		Pending	
Maine	Researched	Yes	Yes		
Massachusetts	Researched	Yes	Yes	Yes	
Missouri	Researched	Yes	Yes	Pending	
New Hampshire	Researched		Yes	Yes	
New Mexico	Researched	Yes		Yes	

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Jurisdiction	NTG Approach*	Free-Ridership Adjustment	Spillover Considered?	Performance Incentives?	Notes
New York	Researched	Yes	Yes	Yes	Deemed NTG of 0.9 used for programs without recent evaluations.
Oregon	Researched	Yes	Yes		
Pennsylvania	Researched	Yes	Yes		Gross savings are used to evaluate whether goals have been met.
Rhode Island	Researched		Yes	Yes	
Utah	Researched	Yes	Yes	Pending	
Wisconsin	Researched	Yes	Yes	Yes	
Wyoming	Researched	Yes	Yes		
Arizona	No NTG adjustment			Yes	
Delaware	No NTG adjustment				
District of Columbia	No NTG adjustment				
Idaho	No NTG adjustment			Pending	Some NTG research conducted but not required by regulators.
Iowa	No NTG adjustment				
Kentucky	No NTG adjustment			Yes	
Maryland	No NTG adjustment				
Minnesota	No NTG adjustment			Yes	
Nebraska	No NTG adjustment				
New Jersey	No NTG adjustment				
North Carolina	No NTG adjustment			Yes	
Ohio	No NTG adjustment			Yes	
Texas	No NTG adjustment			Yes	

Jurisdiction	NTG Approach*	Free-Ridership Adjustment	Spillover Considered?	Performance Incentives?	Notes
Washington	No NTG adjustment				Some NTG research conducted but not required by regulators.
South Dakota	Varies by utility	Yes	Yes		

* Deemed NTG values are pre-determined values typically developed after NTG research has been conducted through program impact evaluations. Researched NG values are most commonly estimated through a self-report (participant survey) approach, though econometric methods (e.g., billing analysis) and market share modeling approaches are occasionally used. *Source:* Navigant analysis of various resources including utility websites, regulatory agency websites, websites of research/advocacy groups, and studies that previously surveyed the approach to net savings (Appendix A).

4.2 *Selected Jurisdictions*

As noted in the Methodology section, Navigant reviewed a total of 19 documents that researched NTG. These documents represent nine jurisdictions, including: California, Colorado, Massachusetts, Minnesota, New Jersey, New Mexico, Oregon, Washington, and Wisconsin.

While documents that research NTG were identified, the approach to net savings in these selected jurisdictions varies as shown in Table 4. Most notably, three of the jurisdictions make no NTG adjustment and one jurisdiction deems NTG even though NTG research is being conducted. Also note that three of the nine jurisdictions do not have performance incentives.

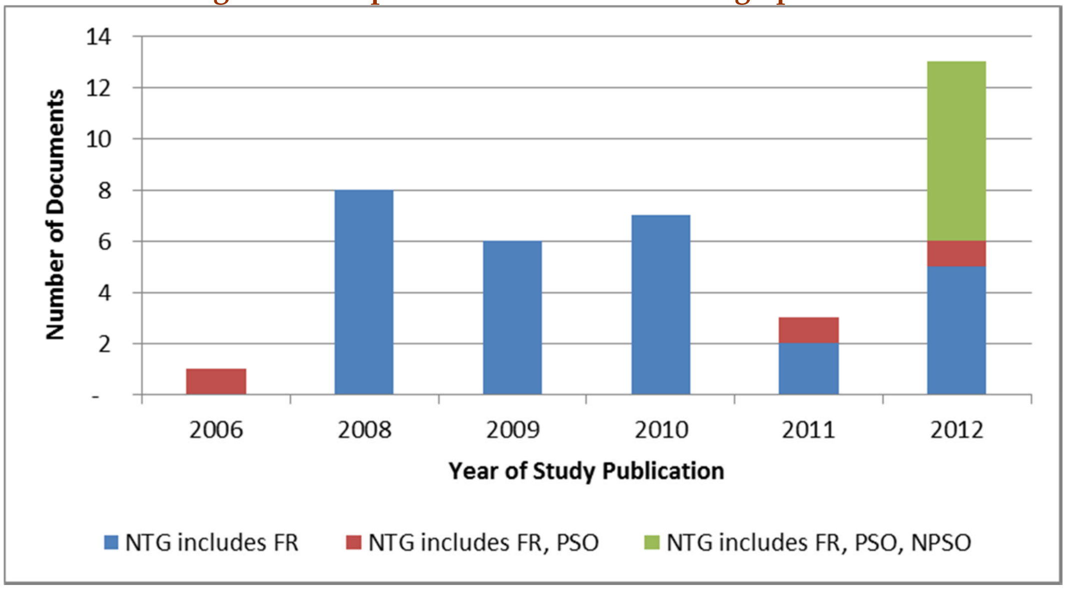
Table 4 . Approach to Net Savings in Selected Jurisdictions

Deemed	Researched Adjusts for Free Ridership and Spillover is Considered	No NTG Adjustment
California (0.5 for custom gas measures)	Colorado, Massachusetts, New Mexico (FR only), *Oregon*, and Wisconsin	Minnesota, *New Jersey*, and *Washington*

**Italics* indicate that the jurisdiction does not have performance incentives. *Source:* Navigant analysis.

Regional or temporal trends in whether participant and NPSO were also considered. Figure 1 presents the number of studies that include free-ridership, PSO, and NPSO by the year of study publication. Based on the sample of studies conducted in the selected jurisdictions, there is a clear trend towards including participant and NPSO in calculating NTG in recent years.

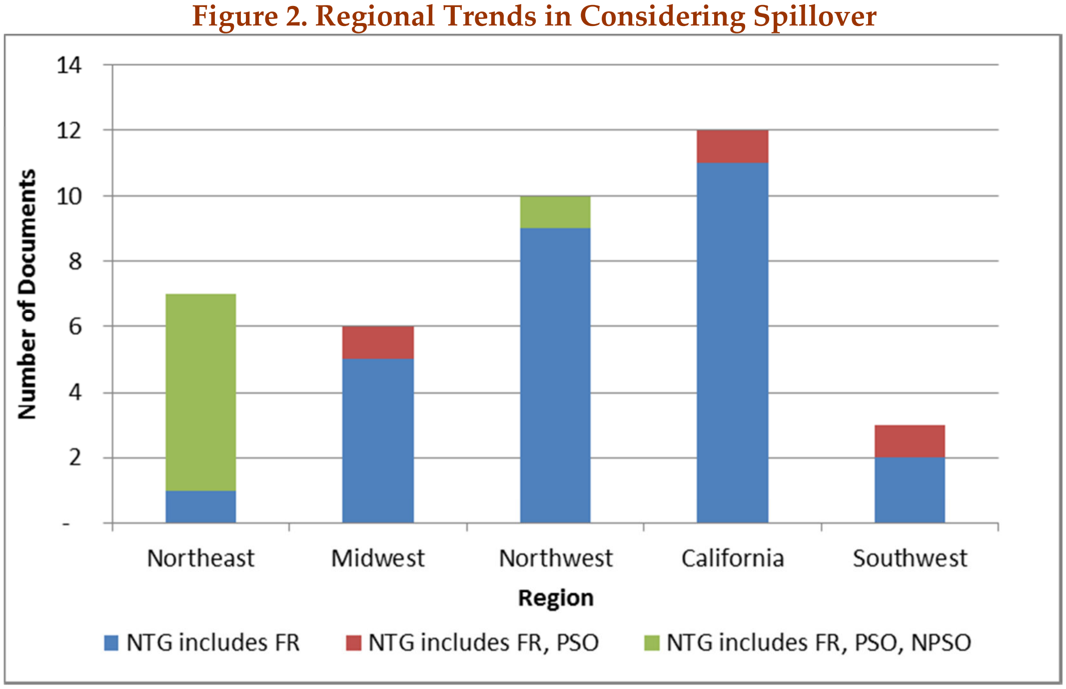
Figure 1. Temporal Trends in Considering Spillover



Source: Navigant analysis.

Figure 2 presents the number of studies that include free-ridership, PSO, and NPSO by region of the United States. Based on the sample of studies conducted in the selected jurisdictions, it appears that all regions consider PSO in calculating NTG values.

Figure 2. Regional Trends in Considering Spillover



Source: Navigant analysis.

4.3 Application to Union and Enbridge

Based on the jurisdictional review nearly half of the jurisdictions with rate-payer funded energy efficiency program conduct NTG research. Among the 33% that do not adjust gross savings some research is being conducted. For example, three of the nine jurisdictions selected for further review do not adjust gross savings while another one deems – yet NTG research is being conducted.

Trends in the included NTG factors are also identified. Among the nine selected jurisdictions there is a clear trend towards including both participant and NPSO in recent years, and that it is not a regional phenomenon. The next section of this report summarizes the researched NTG values resulting from the review of research conducted in the nine selected jurisdictions.

GEC Response to APPrO Interrogatory #2

Question:

Reference: L.GEC.1 i) Page 29

Preamble: The evidence indicates that: *"However, since the majority of the increase in savings I would expect from Union would come from T2/R100 customers, which have historically provided the most cost-effective savings in Union's portfolio, it is possible if not likely that the estimate of additional net benefits for Union are even greater than my simple extrapolation suggests".*

a) Please provide any and all data or documentation that you have used to support or assess the base level of efficiency and conservation measures that are undertaken by T2/R100 customers.

b) Please provide any and all data to support:
   i. Your assessment that Union's most cost-effective measures are for T2/R100 customers; and
   ii. The relative cost-effectiveness of Union's undertaking the efficiency measures on behalf of T2/R100 customers and T2/R100 customers undertaking the efficiency measures directly.

Please provide all assumed or estimated costs related to administration and overhead.

Response:

a) I have not estimated the "base level of efficiency and conservation measures that are undertaken by T2/R100 customers". That was not necessary to reach the conclusion referenced in the preamble. I do not doubt that those customers have undertaken efficiency investments in the past or that they would do so in the future. Frankly, all customers make some "base level" of investment or changes in behavior or operations. It is also true that DSM programs of all kinds, targeted to all markets, will end up providing incentives or other support for efficiency projects that would otherwise have been undertaken anyway. Few programs, other than low income programs, have free rider rates of zero or close to zero. However, as long as the programs are obtaining significant savings from non-free riders, and doing so at a reasonable cost, they are beneficial. Of course, efforts should always be made to refine program designs in ways that minimize free ridership (provided such changes do not have other significant adverse effects).

b) Responses are as follows:
   i. My assessment of the relative cost-effectiveness of the T2/R100 savings is based on Union's historic assessment of the cost-effectiveness of its various program offerings. For example, in 2014 the benefit-cost ratio for Union's savings from T2 and R100 customers was 4.15 and 6.90, respectively. The net benefits associated with those two sets of customers' savings – after adjusting for an

assumed 54% free rider rate and without accounting for any spillover effects – was over $90 million. The only other program that produced better benefit-cost ratios in that year was Union's Residential Efficiency Kits program (BCR of over 34 and net benefits of about $12 million); the custom offerings to T1 customers had a BCR of 5.61 (in the middle of the T2/R100 BCRs) and net benefits of about $11 million. All other programs had BCRs of less than 3.5.[1]

ii. The premise of this request is flawed. By definition, DSM program savings are only considered DSM savings because they would not have been undertaken without the program.

[1] Union Response to B.T6.Union.GEC.4, Attachment 3.

GEC Response to APPrO Interrogatory #3

Question:

Reference: L.GEC.1

i) Page 32

"*virtually all of Union's eligible large industrial customers are participating in its Self-Direct program*".

ii) EB-2012-0337 Exhibit B5.15, in which Union provided the following interrogatory response:

Filed: 2012-10-25
EB-2012-0337
Exhibit B5.15
Page 1 of 1

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Appendix B
Preamble: Union provides some of the program incentives on slide 8. APPrO would like to better understand these incentives proposed.

a) For customers that would typically be eligible for Rate 100 or T2, and for each of the 10 program elements shown on slide 8, please provide the average cost of implementing these program elements (where reasonably possible) and show the total cost of implementing the program, incentive amount provided by Union, the amount that the customer would fund on its own and the percentage funded directly by each of Union through ratepayer funded DSM and the percentage funded directly by the customer.

Response:

Union does not track the cost of implementing at the program element level. Union does track the incentives provided and customer project cost at the measure level. Please see the table below for incentive funding provided by Union, the amount the customer would fund on its own and the percentages funded directly by Union and the customer accordingly.

Rate T1 / Rate 100 - 2011 Results

				% Funding - average		$ Funding - average	
Offering	**# of Projects**	**Incentive $ Provided By Union**	**Customer Project $**	**By Union**	**By Customer**	**By Union**	**By Customer**
O & M	157	$ 1,989,254	$ 23,169,661	9%	91%	$ 12,670	$ 147,577
Capital	43	$ 1,180,959	$ 31,632,015	4%	96%	$ 27,464	$ 735,628
Engineering Feasibility	17	$ 104,373	$ 395,718	26%	74%	$ 6,140	$ 17,138
Process Improvement	33	$ 444,509	$ 1,394,046	32%	68%	$ 13,470	$ 28,774
Steam Trap	20	$ 80,243	$ 252,633	32%	68%	$ 4,012	$ 8,620
Education	2	$ 16,000	$ 45,185	35%	65%	$ 8,000	$ 14,593
	272	**$ 3,815,338**	**$ 56,889,258**				

iii) EB-2012-0337 Transcript Volume 2, February 1, 2013

Preamble: APPrO would like to review Mr. Neme's understanding of the participation in Union's DSM program by Rate T2 and Rate 100 customers.

a) Please confirm that T2 and Rate 100 rates currently include mandatory funding for Union's DSM program to fund customer incentives and Union overheads. If not confirmed, please explain.
b) Please confirm that all customers in T2 and Rate 100 are eligible to receive the customer incentive portion of the DSM funding that they paid for in rates via Union's Self-Direct program.
c) Please confirm that it would be logical for any T2 or Rate 100 customer that is interested in reducing its energy costs and reducing its emissions to offset a portion of the total cost to implement the energy efficiency measure to apply for a refund of a portion of the amount paid in rates. If not confirmed, please explain.
d) Please confirm that the Self-Direct program requires the customers to submit an energy plan to Union for "approval" prior to the customer knowing that the project will be funded.
e) From Reference ii), please confirm that the average amount of customer DSM incentive funds provided by Union as a percentage of the total cost to implement those customer projects funded by Union is approximately 6.7% ($3,815,338/$56,889,258).

Response:

a) Confirmed.
b) Confirmed.
c) If the question is asking whether a customer that would implement an efficiency measure without a DSM program would be smart to take advantage of a financial incentive the utility offers, the answer is generally "yes". That is why there is some amount of free ridership in almost every type of program.
d) That is my understanding.
e) Confirmed, for the time period for which the data were applicable.

GEC Response to APPrO Interrogatory #4

Question:

Reference: L.GEC.1, i) Page 16 ii) Ontario's Climate Change Update, page 16

Preamble: Mr. Neme's evidence indicates that natural gas accounts for approximately 30% of all greenhouse gas (**GHG**) emissions in the province of Ontario (the **Province**) and that the 2030 projected emissions are anticipated to be at 1990 levels in a business as usual (**BAU**) scenario.

a) Please provide any and all data and documentary support and all third party verification relied upon to arrive at the assertion that natural gas accounts for 30% of all GHG emissions in the Province.

b) Please confirm that 1990 GHG emissions in Ontario are approximately 25 MT lower than 2005 emissions and 2014 emissions are approximately 42 MT lower than BAU.

c) Please confirm that the assertion that Provincial emissions will increase to 1990 levels (they are currently more than 6% below 1990 levels) by 2030 is in the absence of the announced cap and trade program and conservation measures that are set out in footnote 32 of Mr. Neme's evidence.

d) Please confirm that the implementation of a carbon policy in Ontario will have a direct impact on Union and Enbridge's large volume customers (**LVC**), who are intended to be included in the cap and trade scheme.

e) Please confirm that the evidence suggests that LVCs should be required to both pay for DSM in rates and pay for any and all required emission allowances.

f) Please confirm that even if a customer responded to the intended carbon price signal and decreased usage, it would still be required to pay for DSM in rates under your proposal.

g) Please justify your adopted carbon price estimate and complete the following chart:

Auction Period		Auction Price		
2013	Q1	California	Québec	RGGI[2]*
	Q2			
	Q3			
	Q4			
2014	Q1			
	Q2			
	Q3			
	Q4**			
2015	Q1			
	Q2			

*while not technically linked, Québec provides for consideration of RGGI allowances in related export transactions for power.

**California/Québec linked auction.

h) Please provide the net present value (**NPV**) of each and all measures and their lifespans (a) using the actual carbon prices for Québec, (b) reflecting the actual lifespan of each measure, and (c) adjusting for free-ridership.

i) Please provide any and all assumptions that you have made about the point of carbon regulation for each and all of the following sectors:
i. transportation
ii. buildings
iii. electricity
iv. industry

Witness: Chris Neme

Response:

a) Please see reply to M.GEC.EP.3(a).

b) According to Canada's National Inventory Report 1990-2013 Ontario's GHG emissions were 182 mt in 1990 and 211 mt in 2005. Therefore emissions grew by 29 mt between 1990 and 2005. For 2014, based on Figure 9 in Ontario's Climate Change Update 2014 Ontario's "business as usual" emissions in 2014 would have to be ~213 mt for actual emissions (~171 mt) to be 42 tonnes lower. However based on Figure 9 the BAU projection for 2014 appears to be between 185 and 190 mt. Therefore 2014 emissions appear to be 14-19 mt below "business as usual".

c) Confirmed.

d) It is my understanding that the government intends to cover emissions from natural gas consumption under the cap. See M.GEC.IGUA.1 Attachment 1. It is not clear yet whether emissions from gas consumption by large users will be regulated as part of the cap on emissions by each large user, or as part of regulation of gas distributors, but the former is more likely.

e) Yes, the LVCs should pay for the gas and infrastructure they use, the allowances related to their carbon emissions (whether those are assessed on the LVC directly or through the utility) and the cost of DSM programs. The LVCs would benefit from gas utility DSM from their reduced purchases of gas, their reduced emission-allowance responsibility (whether that is regulated at the utility or emission-point level), and the lower price of allowances (for their gas use and other sources of emissions) as a result of the reduced demand for allowances. These benefits would be partially offset by the DSM charges in rates. Put another way, this would not be a "double payment" requirement as the wording of the question could be read to imply. Even if their emissions are regulated directly, the LVCs would only pay for emission allowances associated with the gas they are still consuming. They would not have to pay for the emission allowances that would have been associated with the gas that DSM helped them to avoid consuming.

f) A customer that is interested in reducing gas use through increased efficiency (as opposed to reducing economic activity) would be eligible for assistance from the DSM programs. Reducing its usage would reduce its payments for gas, infrastructure, emission allowances, and payments for DSM programs. As stated in my testimony, it may be appropriate to modify the design of the T2/R100 program so that the (probably rare) customer that has actually implemented all cost-effective DSM would no longer be obligated to pay for the program.

g) See Section III.B.1 of Mr. Chernick's evidence. For historical data on the requested carbon prices, see the following tables.

For California/Quebec:

		Current Vintage		Future Vintage		
	Settlement Price	USD	CAD	USD	CAD	Year
Joint Auctions						
3	May 2015	$12.29	$15.01	$12.10	$14.78	2018
2	February 2015	$12.21	$15.14	$12.10	$15.01	2018
1	November 2014	$12.10	$13.68	$11.86	$13.41	2017
Quebec						
	March 2014		$11.39			
California Air Resources Board Quarterly Auctions						
8	August 2014	$11.50		$11.34		2017
7	May 2014	$11.50		$11.34		2017
6	February 2014	$11.48		$11.38		2017
5	November 2013	$11.48		$11.10		2016
4	August 2013	$12.22		$11.10		2016
3	May 2013	$14.00		$10.71		2016
2	February 2013	$13.62		$10.71		2016
1	November 2012	$10.09		$10.00		2015

For RGGI:

Auction Number	**Clearing Price**
Auction 28 6/3/2015	$5.50
Auction 27 3/11/2015	$5.41

Witness: Chris Neme

Auction 26 12/3/2014	$5.21
Auction 25 9/3/2014	$4.88
Auction 24 6/4/2014	$5.02
Auction 23 3/5/2014	$4.00
Auction 22 12/4/2013	$3.00
Auction 21 9/4/2013	$2.67
Auction 20 6/5/2013	$3.21
Auction 19 3/13/2013	$2.80

h) The GEC witnesses have not conducted an analysis of all possible efficiency measures using the assumptions in the question. Such an analysis was not necessary to reach the conclusions we reach in our testimony and would be extremely time-consuming to pursue. Several other factors make the proposed analysis even more problematic:

- The T2/R100 program is a custom program, promoting custom measures. By their very nature, they cannot be anticipated or characterized ahead of time at the measure level.
- We do not know the "actual carbon prices for Québec" after 2015 (or 2018, if the future vintage allowances, plus interest, are considered to be "actual"). That said, as Mr. Chernick's testimony makes clear, fully valuing avoided carbon emissions will result in higher avoided costs and higher TRC net benefit across the board.
- It is inappropriate to include free ridership factors in measure screening. They should only be applied at the program level. That said, free ridership assumptions tend not to affect benefit-cost ratios very much under the TRC.

i) Mr. Neme did not make any explicit assumption about the point of regulation for any of these sectors. For the natural-gas component of the buildings sector, regulation is likely to be at the utility level, for efficiency. For electricity, regulation is likely to be at the generator or possibly the EDC. For the natural-gas component of industrial emissions, regulation may be at the utility or at the burner-tip. The point of regulation does not affect either the cost-effectiveness of reducing emissions or the benefits of reduced emissions for participants and energy consumers throughout the province.

GEC Response to APPRO Interrogatory #5

Question:

Reference: i) Evidence of Mr. Chernick page 24:

"The carbon emissions from the existing electric system would be almost entirely from gas-fired generation, which appears to be on the margin about 70% of the time.."

Preamble: APPrO would like to understand how Mr. Chernick arrived at his understanding of the amount of time that gas-fired generation is expected to be on the margin for the period 2016-2020.

a) Please explain in detail how Mr. Chernick arrived at the conclusion that gas-fired generation would be the marginal generation source 70% of the time for the period 2016-2020. Please provide all current, past and projected Independent Electricity System Operator (**IESO**) and Ontario Power Authority (**OPA**) data, including market clearing price data that was used to arrive at this conclusion.
b) Please provide the assumed system-wide emission factor that Mr. Chernick used for Ontario and all supporting sources of information.
c) Please provide the assumed Ontario gas-fired electricity generation fleet emission factor that Mr. Chernick used and all supporting sources of information.

Response:

a) The marginal emissions avoided by electric CDM in the 2016–20 period would be some combination of (1) gas-fired power plants in Ontario, when Ontario needs fossil generation to meet load or the US, (2) a mix of gas and coal-fired generation in the US, when Ontario is exporting, and (3) zero, when Ontario is spilling water. Mr. Chernick cited the analysis that he relied on, which is attached as Attachment 1. Mr. Chernick has not located any other forecasts of surplus baseload generation (SBG), spillage or marginal emission rates from IESO or OPG. From page 26 of Attachment 1, it appears that OPG was projecting that about 50% of hours in 2016 would experience SBG. Since page 27 shows SBG declining to near zero by 2020, Mr. Chernick estimated that the average marginal emissions on the Ontario system in 2016–2020 would be equivalent to 70% of typical gas emissions.
b) Mr. Chernick assumed an average 9 MMBtu/MWh marginal heat rate for a mix of marginal gas generation, and emissions of 53.1 kg/MMBtu of gas burned, or about 480 kg/MWh when gas is at the margin, or an average of about 335 kg/MWh including the 30% of the time that the marginal emissions are zero, since IESO is spilling water. The 9 MMBtu/MWh is in the middle of the range of about 7 MMBtu/MWh for the best combined-cycle units operating baseloaded, to 11 MMBtu/MWh for combustion turbines and steam plants with extensive cycling. The 53.1 kg/MMBtu value is from www.eia.gov/environment/emissions/co2_vol_mass.cfm.

Witness: Paul Chernick

c) See part (b). Mr. Chernick assumed that marginal fossil emissions from the Ontario generation system would be entirely from natural gas combustion.

Witness: Paul Chernick

GEC Response to APPRO Interrogatory #6

Question:

Reference: i) Evidence of Mr. Chernick page 9 and Table 1.
ii) Evidence of Mr. Chernick page 15.

Preamble: The evidence indicates that:

> "*Most of these analyses estimated that a 1% reduction in US gas consumption would reduce gas prices by about 1%-3%. For the current forward Henry Hub supply prices for 2016-2020, a price reduction of 1%-3% would be about US \$0.034-\$0.10/MMBtu or about \$0.001-\$0.004/m3 (in U.S. dollars).*"

a) Please provide any and all forward price curves for gas at Henry Hub that Mr. Chernick considered or relied upon for this statement.
b) Please provide any and all updated forward price curves for gas at Henry Hub following the recent release of the U.S. Environmental Protection Agency's final Clean Power Plan (**CPP**).
c) Please provide any and all assessments of the impact of the CPP on U.S. gas demand.
d) Please provide data for Table 1 to reflect the period and estimates in years from 2005 to 2015.
e) Please comment on how load reductions and decontracting affected the costs of gas transportation in Canada along the TransCanada Pipeline (**TCPL**) mainline routes with specific reference to the regulated tolls resulting from the National Energy Board RH-003-2011 and RH-001-2014.

Response:

a) Mr. Chernick did not record the specific forwards he consulted before making this statement. See Excel Attachment 1 Tab 1 for a table of Henry Hub prices for July 1, July 15 and July 31.
b) See Excel Attachment 1 Tab 2 for the forwards for settlements on August 3 (the date the final CPP was released) through August 7.
c) Mr. Chernick has not attempted to assemble all such assessments. The following table is reproduced from the Regulatory Impact Analysis for the Clean Power Plan Final Rule, Table 3-18, Projected Average Henry Hub (spot) and Delivered Natural Gas Prices.

	Henry Hub (2011\$/MMBtu)		
	2020	2025	2030
Base-Case	\$5.20	\$5.12	\$6.01
Rate-based	\$5.48	\$4.73	\$6.21
Mass-based	\$5.40	\$4.97	\$5.92
Change from Base Case			
Rate-based	5.4%	-7.5%	3.3%
Mass-based	3.9%	-3.0%	-1.4%

Witness: Paul Chernick

d) See p. 8-302 of "Putting Downward Pressure on Natural Gas Prices: The Impact of Renewable Energy and Energy Efficiency," Wiser, R., et al, 2004 ACEEE Summer Study on Energy Efficiency in Buildings, pp. 8-294 to 8-308, attached as Attachment 2. That Attachment also provides complete cites to the studies, if APPrO wishes to investigate further.
e) Load reductions reduce the cost of transportation on the TCPL mainline (or any other pipeline). Under some circumstances, reductions in throughput result in higher rates (as largely fixed costs are spread over lower sales), but the total cost to customers will stay the same or decline.

Putting Downward Pressure on Natural Gas Prices: The Impact of Renewable Energy and Energy Efficiency

Ryan Wiser, Mark Bolinger, and Matthew St. Clair, Lawrence Berkeley National Laboratory[1]

ABSTRACT

Increased deployment of renewable energy (RE) and energy efficiency (EE) is expected to reduce natural gas demand and in turn place downward pressure on gas prices. A number of recent modeling studies include an evaluation of this effect. Based on data compiled from those studies summarized in this paper, each 1% reduction in national natural gas demand appears likely to lead to a long-term average wellhead gas price reduction of 0.75% to 2.5%, with some studies predicting even more sizable reductions. Reductions in wellhead prices will reduce wholesale and retail electricity rates, and will also reduce residential, commercial, and industrial gas bills. We further find that many of these studies appear to represent the potential impact of RE and EE on natural gas prices within the bounds of current knowledge, but that current knowledge of how to estimate this effect is extremely limited. While more research is therefore needed, existing studies suggest that it is not unreasonable to expect that any increase in consumer electricity costs attributable to RE and/or EE deployment may be substantially offset by the corresponding reduction in delivered natural gas prices. This effect represents a wealth transfer (from natural gas producers to consumers) rather than a net gain in social welfare, and is therefore not a standard motivation for policy intervention on economic grounds. Reducing gas prices and thereby redistributing wealth may still be of importance in policy circles, however, and may be viewed in those circles as a positive ancillary effect of RE and EE deployment.

Introduction

Renewable energy (RE) and energy efficiency (EE) have historically been supported due to perceived economic, environmental, economic development, and national security benefits. More recently, price volatility in wholesale electricity and natural gas markets has increasingly led to discussions about the potential risk mitigation value of these resources. Deepening concerns about the ability of conventional North American gas production to keep up with demand have also resulted in a growing number of voices calling for resource diversification.

RE and EE offer a direct hedge against volatile and escalating gas prices by reducing the need to purchase variable-price natural gas-fired electricity generation, replacing that generation with fixed-price RE or EE resources. In addition to this *direct* contribution to price stability, by displacing marginal gas-fired generation, RE and EE can reduce demand for natural gas and *indirectly* place downward pressure on gas prices.[2] Many recent modeling studies of increased RE and EE deployment have demonstrated that this "secondary" effect on natural gas prices

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[2] Improvements in natural gas conversion efficiency, and end-use natural gas efficiency measures, would also directly reduce gas demand, as would increases in coal or nuclear generation.

could be significant, with the consumer benefits from reduced gas prices in many cases more than offsetting any increase in electricity costs caused by RE/EE deployment.[3] As a result, this effect is increasingly cited as justification for policies promoting EE and RE. Yet to date, little work has focused on reviewing the reasonableness of this effect as portrayed in various studies, and benchmarking that output against economic theory. This paper begins to fill that void.

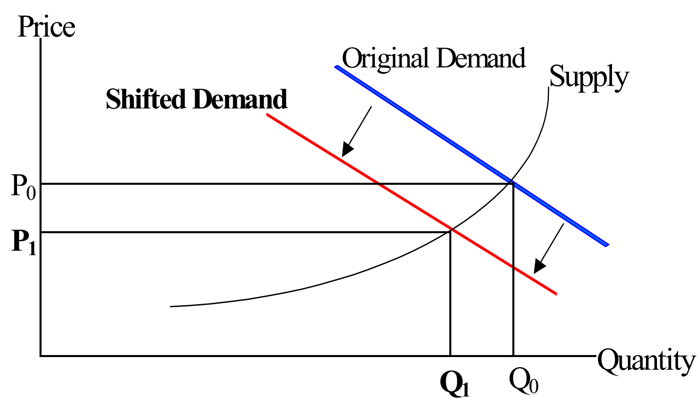
We first review economic theory to better understand the economics underlying the price suppression effect. We then review many of the modeling studies conducted over the past five years that have measured this effect, illustrating the potential impacts of RE and EE deployment on consumer electricity and gas bills, and calculating the inverse price elasticity of gas supply implied by the modeling output. We compare the resulting range of inverse price elasticities with each other (to test for model consistency across time and across models), as well as to empirical estimates from the economics literature (to test for model consistency with the real world). We end the paper with a summary or our findings.

Natural Gas Supply and Demand: A Review of Economic Theory

Supply and Demand Curves

Whether today's inflated natural gas prices represent merely a short-term imbalance between supply and demand, or instead a longer-term effect that reflects the true long-term marginal cost of production, is unclear (see, e.g., EMF 2003; Henning, Sloan & de Leon 2003; NPC 2003). In either case, economic theory predicts that a reduction in natural gas demand, whether caused by enhanced electric or natural gas efficiency, or by increased deployment of RE, will generally lead to a subsequent reduction in the price of gas relative to the price that would have been expected under higher demand conditions. As shown in Figure 1, this price reduction ($P_0 \rightarrow P_1$) results from an inward shift in the aggregate demand curve for natural gas ($Q_0 \rightarrow Q_1$). Because gas consumers are "price takers" in a market whose price is determined by national supply and demand conditions (with some regional differentiation), the price reduction benefits consumers by reducing gas prices for electricity generators (assumed to be passed through, in part, in the form of lower electricity prices), and by reducing gas prices for direct use in the residential, commercial, industrial, and transportation sectors.

Figure 1. The Effects of a Shift in Demand for Natural Gas



The magnitude of the price reduction will clearly depend on the amount of demand reduction: greater amounts of gas displacement will lead to greater drops in the price of the

[3] Note that any increase in costs associated with renewable energy or energy efficiency could be due to technology-forcing standards (e.g., a renewables portfolio standard or appliance energy efficiency standards), or to the imposition of a system-benefits charge used to support these clean energy technologies.

commodity.[4] As long as gas prices remain within reasonable bounds, RE and EE are expected to largely displace gas generation; the higher gas price forecasts of recent years, however, suggest that RE and EE may increasingly displace coal over time, muting the impact on gas prices. As importantly, the shape of the gas supply curve – the relationship between the level of natural gas production and the price of supply – will also have a sizable impact on the magnitude of the price reduction. The shape of the supply curve for natural gas will, in turn, depend on whether one considers short-term or long-term effects. Economists generally assume upward, steeply sloping supply curves in the short term when supply constraints exist in the form of fixed inputs like labor, machinery, and well capacity. In this instance, gas producers are unable or unlikely to quickly and dramatically increase (decrease) supply in response to higher (or lower) gas prices.

In the long term, however, the supply curve will flatten because supply will have time to adjust to lower demand expectations, for example, by reducing exploration and drilling expenditures. Because natural gas is a non-renewable commodity, the long-term supply curve must eventually slope upward as exhaustion of the least expensive resources occurs. If the pace of technological innovation in exploration and extraction is rapid, however, the transition to more expensive reserves may be delayed and the long-term supply curve may remain relatively flat. The shape of the long-term supply curve is an empirical question, and is subject to great uncertainty and debate. Nonetheless, economists generally agree that, while both the short- and long-term supply curves are upward sloping, the long-term supply curve will generally be flatter than the short-term supply curve. This implies that the impact of increased RE and EE deployment on natural gas prices will be greater in the short term than in the long term. We return to these issues later, when reviewing modeling output.

In this paper, we emphasize the long-term impacts of RE and EE investments, and hence focus our attention on the shape of the long-term supply curve. We do this for two principal reasons. First, RE and EE investments are typically long-term in nature, so the most enduring effects of these investments are likely to occur in the long term. Second, the model results presented in this paper often do not clearly distinguish between short-term and long-term effects, and most models appear better suited to long-term analysis. We also focus on the *national* impacts of increased RE and EE deployment; future work will review the impacts of *regionally* focused RE and EE investment.

Measuring the Inverse Price Elasticity of Supply

To measure the degree to which shifts in gas demand affect the price of natural gas, it is convenient to use elasticity measures. The *price elasticity of natural gas supply* is a measure of the responsiveness of natural gas supply to the price of the commodity, and is calculated by dividing the percentage change in quantity supplied by the percentage change in price:

$E = (\%\Delta Q)/(\% \Delta P)$, where Q and P denote quantity and price, respectively.

[4] One would not generally expect any particular threshold of demand reduction to be required to lower the price of gas. Instead, greater quantities of gas savings should simply result in higher levels of price reduction. The impact on prices, however, need not be linear over the full range of demand reductions, but will instead depend on the exact – yet unknown – shape of the supply curve in the region in which it intersects the demand curve.

In the case of induced shifts in the demand for natural gas, however, we are interested in understanding the change in price that will result from a given change in quantity, or the *inverse price elasticity of supply* ("inverse elasticity"):

$$E^{-1} = (\%\Delta P)/(\%\Delta Q)$$

Given greater supply responsiveness over the long term than in the short term, the long-term supply curve should experience *lower* inverse price elasticities of supply than will the short-term supply curve.

Social Benefits, Consumer Benefits, and Wealth Transfers

We have made the case that increased deployment of RE and EE can and should lower the price of natural gas relative to a business-as-usual trajectory. The magnitude of the expected price reduction is an empirical question that we address in later sections of this paper. Before proceeding, however, it is important to address the nature of the "benefit" that is obtained with the price reduction, because mischaracterizations of this benefit are common, and may lead to unrealistic expectations and policy prescriptions.

In particular, according to economic theory, lower natural gas prices that result from an inward shift in the demand curve do not lead to a gain in net economic welfare, but rather to a shift of resources (i.e., a transfer payment) from natural gas producers to natural gas consumers. While natural gas producers see their profit margins decline (a loss of producer surplus), natural gas consumers benefit through lower natural gas bills (a gain of consumer surplus). The net effect on aggregate social welfare (producer plus consumer surplus) is zero assuming a perfectly competitive and well-functioning aggregate economy.

This effect is shown graphically in Figures 2 and 3. Figure 2 shows consumer and

Figure 2. Consumer and Producer Surplus

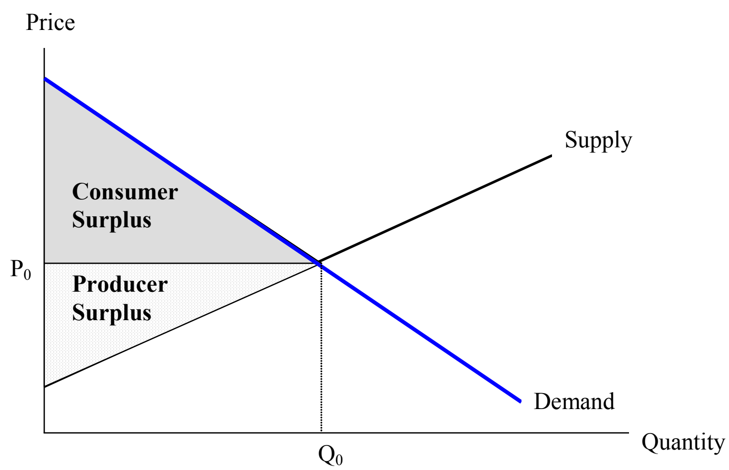
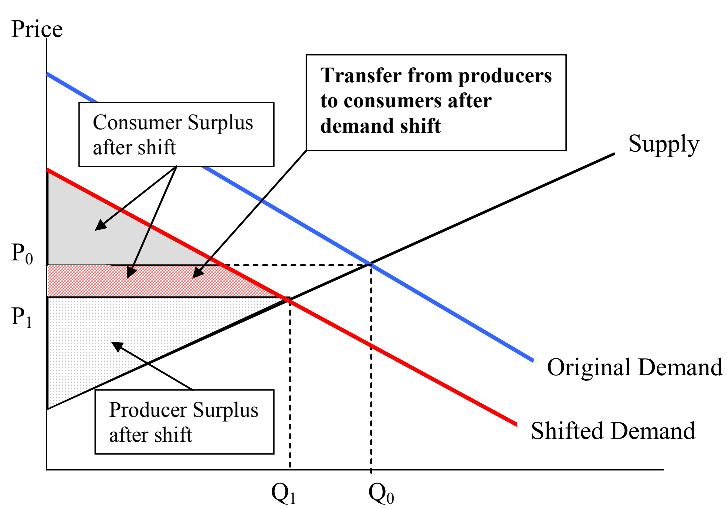


Figure 3. The Effect of a Demand Shift



producer surplus before the demand shift, while Figure 3 shows the impact of the demand shift on consumer and producer surplus. After the shift, the market price and quantity of natural gas fall to P_1 and Q_1, and consumer surplus now also includes the cross-hatch area in Figure 3 that was previously producer surplus. This area represents the price reduction benefit that consumers gain, and represents a redistribution of wealth from producers to consumers.

Wealth transfers of this type are not generally considered justification for policy intervention on economic grounds. Reducing gas prices and thereby redistributing wealth may still be of importance in policy circles, however, and may be viewed in those circles as a positive ancillary effect of RE and EE deployment; energy programs are frequently assessed using consumer impacts as a key evaluation metric. Furthermore, this effect may in fact provide a welfare gain if economy-wide macroeconomic adjustment costs are expected to be severe in the case of gas price spikes and escalation, or if the demand reduction is significant enough to mitigate the potential for market power in the gas market. Additionally, if consumers are located within the U.S., and producers are located outside of the U.S., the wealth redistribution would serve to increase aggregate U.S. welfare, an increasingly likely situation as the country becomes more reliant on imports of natural gas (especially liquefied natural gas). Finally, lower gas prices may help preserve U.S. manufacturing jobs, lead to displacement of more polluting energy sources, and reduce the cost of environmental regulatory compliance. We leave it to others to further debate the merits of considering this effect in policy evaluation.

A Review of Previous Studies

Previous studies of RE and EE policies have estimated the impact of increased clean energy deployment on natural gas prices. Many of these studies have exclusively evaluated a *renewables portfolio standard* (RPS) – a policy that requires electricity suppliers to source an increasing percentage of their supply from RE over time – while others have also looked at EE and environmental policies. These studies have focused on national as well as state-level policies, and have most typically used the National Energy Modeling System (NEMS), a model that is revised annually, and that is developed and operated by the DOE's Energy Information Administration (EIA) to provide long-term (e.g., to 2020 or 2025) energy forecasts.

While the shape of the short-term natural gas supply curve is a transparent, exogenous input to NEMS, the model (as well as other energy models reviewed for this study) does not exogenously define a transparent long-term supply curve; instead, a variety of modeling assumptions are made which, when combined, implicitly define the supply curve. For this reason, in order to evaluate the long-term gas price effect of RE and EE by measuring the inverse price elasticity of supply, it is necessary to do so implicitly by reviewing modeling results.

For the purposes of this paper, we have sought to compile information on a subset of the relevant studies. These include: (1) five studies by the EIA focusing on national RPS policies, two of which model multiple RPS scenarios; (2) five studies of national RPS policies by the Union of Concerned Scientists (UCS), two of which model multiple RPS scenarios, and one of which also includes aggressive energy efficiency investments; (3) one study by the Tellus Institute that evaluates three different standards of a state-level RPS in Rhode Island (combined with the RPS policies in Massachusetts and Connecticut); and (4) an ACEEE study that explores the impact of national and regional RE and EE deployment on natural gas prices. The EIA, UCS, and Tellus studies were all conducted in NEMS (note that NEMS is revised annually, and that these studies were therefore conducted with different versions of NEMS), while the ACEEE study used a gas market model from Energy and Environmental Analysis (EEA).

Table 1 presents a summary of some of the results of these studies.[5] A majority of the studies predict that increased RE generation (and EE, if applicable) will modestly increase retail electricity prices on a national basis, though this is not always the case. Increased RE and EE also cause a reduction in gas consumption, ranging from less than 1% to nearly 30% depending on the study. Reduced gas consumption, in turn, suppresses gas prices, with price reductions ranging from virtually no change in the national average wellhead price to a 50% reduction in that price. As one might expect, the more significant reductions in gas consumption and prices are typically associated with those studies that evaluated aggressive RE/EE deployment.

Table 1. Summary of Results from Past RPS Studies

Author	RPS/EE	**Increase in US RE Generation** *Billion kWh*	**Reduction in US Gas Consumption** *Quads (%)*	**Gas Wellhead Price Reduction** *$/MMBtu (%)*	**Retail Electric Price Increase** *Cents/kWh (%)*
EIA (1998)	10%-2010 (US)	336	1.12 (3.4%)	0.34 (12.9%)	0.21 (3.6%)
EIA (1999)	7.5%-2020 (US)	186	0.41 (1.3%)	0.19 (6.6%)	0.10 (1.7%)
EIA (2001)	10%-2020 (US)	335	1.45 (4.0%)	0.27 (8.4%)	0.01 (0.2%)
EIA (2001)	20%-2020 (US)	800	3.89 (10.8%)	0.56 (17.4%)	0.27 (4.3%)
EIA (2002a)	10%-2020 (US)	256	0.72 (2.1%)	0.12 (3.7%)	0.09 (1.4%)
EIA (2002a)	20%-2020 (US)	372	1.32 (3.8%)	0.22 (6.7%)	0.19 (2.9%)
EIA (2003)	10%-2020 (US)	135	0.48 (1.4%)	0.00 (0.0%)	0.04 (0.6%)
UCS (2001)	20%-2020, & EE (US)	353	10.54 (29.7%)	1.58 (50.8%)	0.17 (2.8%)
UCS (2002a)	10%-2020 (US)	355	1.28 (3.6%)	0.32 (10.4%)	-0.18 (-2.9%)
UCS (2002a)	20%-2020 (US)	836	3.21 (9.0%)	0.55 (17.9%)	0.19 (3.0%)
UCS (2002b)	10%-2020 (US)	165	0.72 (2.1%)	0.05 (1.5%)	-0.07 (-1.1%)
UCS (2003)	10%-2020 (US)	185	0.10 (0.3%)	0.14 (3.2%)	-0.14 (-2.0%)
UCS (2004)	10%-2020 (US)	181	0.49 (1.6%)	0.12 (3.1%)	-0.12 (-1.8%)
UCS (2004)	20%-2020 (US)	653	1.80 (5.8%)	0.07 (1.87%)	0.09 (1.3%)
Tellus (2002)	10%-2020 (RI)	31	0.13 (0.4%)	0.00 (0.0%)	0.02 (0.1%)
Tellus (2002)	15%-2020 (RI)	89	0.23 (0.7%)	0.01 (0.4%)	-0.05 (-0.3%)
Tellus, (2002)	20%-2020 (RI)	98	0.28 (0.8%)	0.02 (0.8%)	-0.07 (-0.4%)
ACEEE (2003)	6.3%-2008, & EE (US)	NA	1.37 (5.4%)	0.74 (22.1%)	NA

Notes:

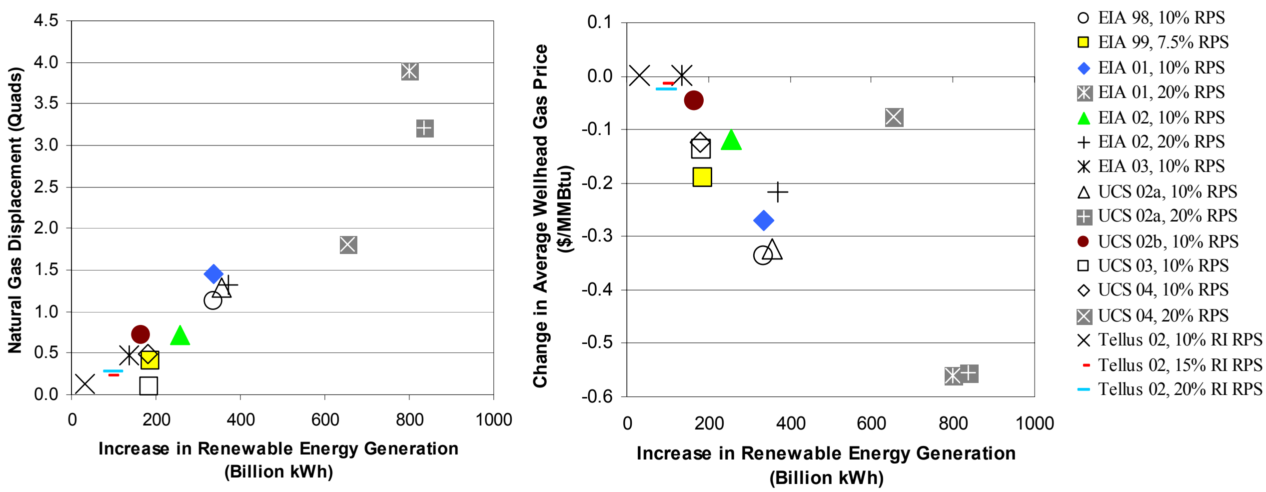
- The data for the ACEEE study are for 2008, the final year of the study's forecast. All other data are for 2020.
- All dollar figures are in constant 2000$.
- The reference case in most studies reflects the EIA AEO, with some studies making adjustments based on more recent gas prices or altered renewable technology assumptions. The one exception is UCS (2003), in which the reference case reflects a substantially higher gas price environment than the relevant AEO reference case.
- The Tellus study models an RPS for RI, also including the impacts of the MA and CT RPS policies. All the figures shown in this table are for the predicted *national* level impacts of these regional policies.

Wellhead price reductions translate into reduced bills for natural gas consumers, and also moderate the expected RE-induced increase in electricity prices predicted by many of the studies by reducing the price of gas delivered to the electricity sector. Though not shown in Table 1,

[5] Table 1 presents the projected impacts of increased RE and EE deployment in each study relative to some baseline. These baselines differ from study to study, which partially explains why, for example, a 10% RPS in two studies can lead to different impacts on renewable generation.

with some exceptions, the absolute reduction in electric and non-electric sector delivered natural gas prices largely mirrors the reduction in wellhead gas prices, suggesting that changes in wellhead prices largely flow through to delivered prices on an approximate one-for-one basis.

Focusing on just those studies that *exclude* EE deployment (i.e., all but ACEEE 2003, and UCS 2001),[6] Figure 4 presents the impact of increased RE generation on the displacement of national gas consumption in 2020. Figure 5, meanwhile, shows the impact of increased RE on the national average wellhead price of natural gas.



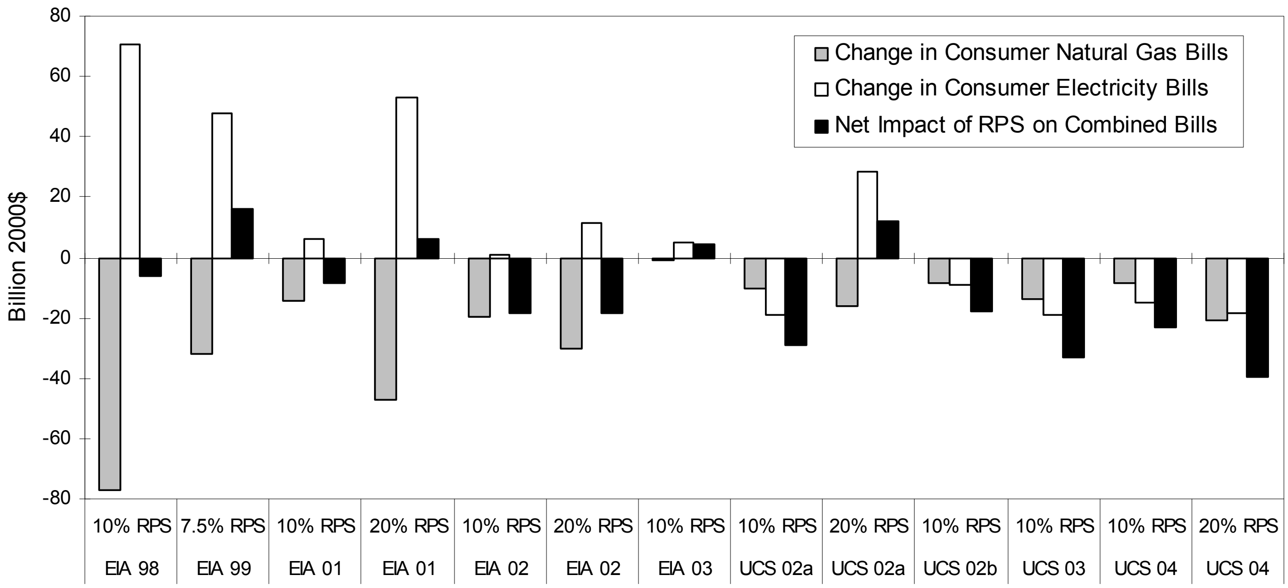
These figures, along with Table 1, show clearly that increased RE and EE are predicted to reduce natural gas consumption and prices, while retail electricity prices are predicted to rise in at least some instances. The net predicted effect on consumer energy bills can be positive or negative, depending on the relative magnitude of the electricity and natural gas bill effects.

Again taking a subset of the studies, Figure 6 presents these offsetting effects.[7] While variations exist across the different studies, the net present value of the cumulative (2003-2020) predicted increase in consumer electricity bills (if any) in the RPS cases compared to the reference case is often on the same order of magnitude as the net present value of the predicted decrease in consumer natural gas bills. From an aggregate *consumer* perspective, therefore, the net impact of these policies is typically predicted to be rather small, with nine of thirteen RPS analyses even showing net consumer savings (i.e., negative cumulative bill impacts).[8]

Though not shown explicitly in these tables and figures, also note that RE and EE are expected to lead to greater reductions in gas consumption in those studies that rely on lower gas price forecasts in the business-as-usual scenario. More recent studies that often rely on higher gas price forecasts (e.g., UCS 2003, 2004) generally find greater coal displacement (and less gas

[6] We exclude the two studies that involve EE deployment here only to simplify the graphical results.
[7] Figure 6 shows the energy bill impacts only for the national RPS studies for which these data were available (i.e., it excludes the Tellus analysis as well as the two studies in which EE investments were also modeled).
[8] Note that in several of these studies, RPS cost caps are reached, ensuring that consumers pay a capped price for some number of *proxy* renewable energy credits (and leading to increased electricity prices) while not obtaining the benefits of increased RE generation on natural gas prices. Accordingly, if anything, Figure 6 underestimates the possible consumer benefits of a well-designed renewable energy program with less-binding cost caps.

displacement) over time as coal out-competes gas for new additions. In a high gas-price environment, this effect may mitigate the benefit of RE and EE in reducing those prices.



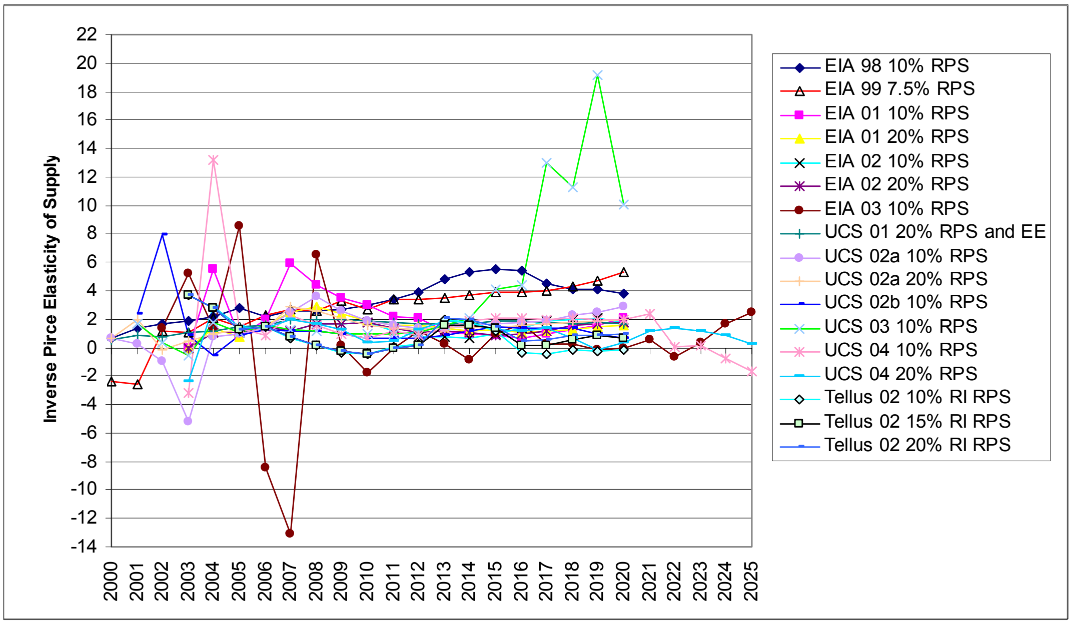
Summary of Implied Inverse Price Elasticities of Supply

Ignoring for now the different impacts of RE/EE on gas consumption across studies, to compare the natural gas price response to increased RE and EE deployment we can calculate the inverse price elasticity of supply implied by the results of each study. Doing so requires data on the predicted average national wellhead price of natural gas and total gas consumption in the United States, under both the business-as-usual baseline scenario as well as the policy scenario of increased RE and/or EE deployment.[9] With the possible exception of the ACEEE study, the resulting inverse elasticities can be considered long-term elasticities.[10]

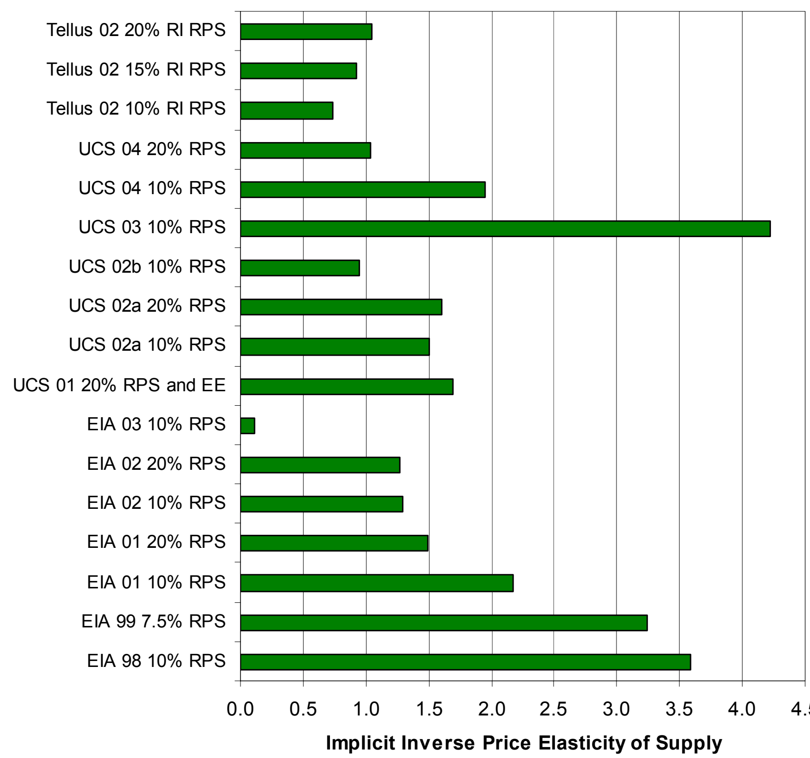
Figure 7 presents a comparative analysis of *long-term* implicit inverse elasticities across studies and years (excluding the ACEEE 2003 results, which are presented later). As shown, the implied inverse elasticity in each study exhibits a great deal of variation over the forecast period. Though some of the studies show a reasonable level of consistency in the inverse elasticity over time, others show large inter-annual swings. This is especially (though not always) true when the aggregate reduction in gas demand is small, leading to substantial "noise" in the results.

[9] The inverse elasticity calculations presented here use U.S. price and quantity data, under the assumption that at present the market for natural gas is more regional than worldwide in nature (Henning, Sloan & de Leon 2003). Of course, the market for natural gas consumed in the U.S. is arguably a North American market, including Canada and Mexico, with LNG expected to play an increasing role in the future. Trade with Mexico is relatively small, however, and Canadian demand for gas pales when compared to U.S. demand. LNG, meanwhile, remains a modest contributor to total U.S. consumption.

[10] It deserves note that our review of NEMS output in the national RPS studies shows that predicted natural gas prices in NEMS do not appear to be more sensitive to demand changes in the short-term than in the long-term. Because of this, one might question NEMS' treatment of long-term and short-term natural gas supply elasticities.



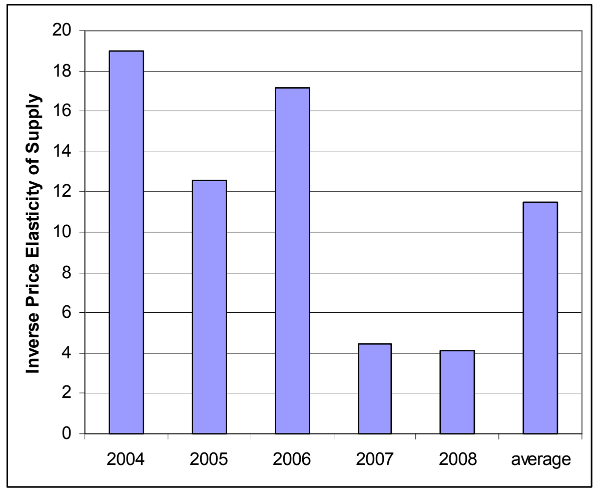
Because relying on the implied inverse elasticity for any single year could be misleading, Figure 8 summarizes the average value of the implied inverse elasticities over an extended forecast period (2003-2020). Despite substantial inter-annual and inter-study variations, there is some consistency in the *average* long-term inverse elasticities, with twelve of seventeen analyses (all of which use NEMS) having elasticities that fall within the range of 0.7 to 2.0.[11]



Though the implied inverse elasticities derived from NEMS appear to represent the long-term supply curve for natural gas,

[11] UCS (2003) has a substantially higher average inverse elasticity than most of the other studies. As noted earlier, UCS (2003) evaluated the potential impact of an RPS under a scenario of higher gas prices than in a typical AEO reference case, making this study not totally comparable to those covered in the body of this paper (the study includes a more constrained gas supply than most of the other analyses, especially in the later years).

this does not appear to be the case in the ACEEE study. The ACEEE study reports the impact of increased RE/EE over a shorter period (2004-2008), and uses a gas market model from EEA that reports impacts on a more disaggregated basis by region and by time interval. While the ACEEE study did analyze the potential impact of state and regional RE and EE deployment, Figure 9 reports the results of the national deployment scenario. As shown, early year inverse elasticites are high (at over ten). By 2008, the inverse elasticity drops to four, still over twice as large as the average long-term inverse elasticities implicit in the latest versions of NEMS.[12]



Because the other studies reviewed in this paper do not seek to present short-term impacts at the same level of disaggregation as ACEEE, it is difficult to benchmark the ACEEE results with those of other studies. The national short-term impacts forecast by ACEEE are aggressive (arguably open to critique for being too aggressive), however, and at the least should not be extrapolated into later years (but should instead be considered shorter-term impacts that are unlikely to persist for the long-term). By the same token, the ACEEE results demonstrate that the positive impacts of increased RE and EE may be more significant in the short-run than estimated by other modeling studies, whose approaches are arguably better able to address longer-term influences.

Benchmarking to Other Markets and Energy Models

In evaluating the results presented in the previous section, it is useful to compare these inverse elasticities to those calculated for natural gas and other fossil fuels in other EIA NEMS analyses, as well as other national energy models altogether.

In particular, the RE and EE studies reviewed above are only one example of an exogenous demand shock that triggers a natural gas price response. The low- and high-economic growth scenarios published as part of the EIA's Annual Energy Outlook (AEO) each year are another such example. Low economic growth, compared to the reference case, leads to less demand for fossil fuels, while high economic growth results in the opposite effect. Figure 10 shows the range of average (2003-2020) implied inverse elasticities for natural gas, coal, and oil from Annual Energy Outlook 2000-2004, focusing on the low economic growth case relative to the reference case forecast.[13]

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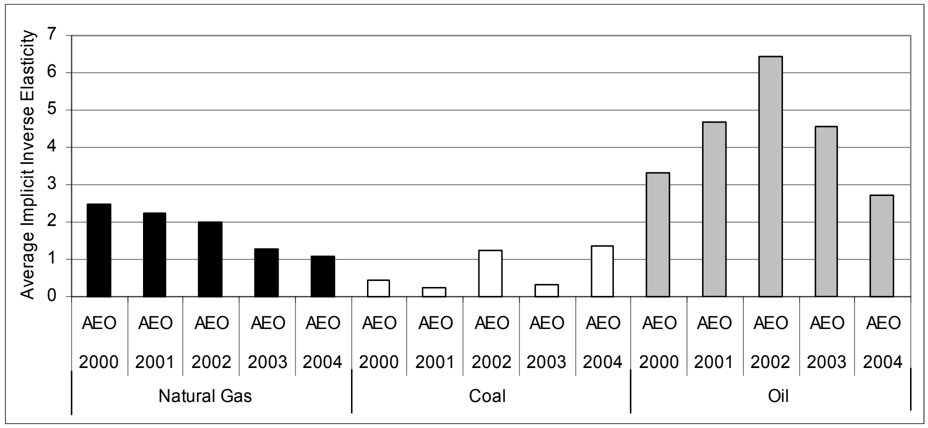
[12] Note that the natural gas price data used to construct the inverse elasticities implicit in the ACEEE results are projected Henry Hub prices, while the previous studies relied upon wellhead price projections. Because Henry Hub prices are typically higher than wellhead prices, inverse elasticities calculated with Henry Hub data will be lower than if wellhead prices were used.

[13] Like natural gas, the coal market is assumed to be national, and the implicit inverse elasticity was calculated using forecasts of U.S. coal minemouth prices and total U.S. coal consumption. Oil, on the other hand, is assumed to be a world market, so the elasticity calculation used the world oil price and total world oil consumption from the AEOs.

The average implicit inverse elasticities for natural gas presented in Figure 10 are broadly consistent with – though perhaps somewhat higher than – the results of the NEMS-based EE and RE studies presented earlier – i.e., they range from 1.1 to 2.5. Figure 10 also shows that the implicit inverse elasticities for natural gas appear to have generally decreased with successive versions of NEMS, which the EIA updates each year, perhaps implying that EIA has tried to moderate its treatment of this effect in recent years. As might be expected given plentiful and relatively inexpensive domestic coal supplies, the implicit inverse elasticity for coal is lower than that for natural gas and oil. The inverse elasticity for oil, on the other hand, is *much* higher than those for coal and gas, reflecting an assumption of highly inelastic supply.



Finding a degree of consistency between the results of the RE and EE studies presented earlier and the AEO's economic growth cases presented here should perhaps come as little surprise: with the exception of the ACEEE study, each of these studies has used the same basic model, NEMS (though again, we note that NEMS is revised annually). We therefore also sought to compare the long-term inverse elasticites implicit in NEMS with those of other national energy models. Data from a recent study by Stanford's Energy Modeling Forum (EMF 2003) allows for this comparison. In particular, this study presents the potential impact of high gas demand on natural gas consumption and price in 2010 and 2020 using seven different energy models. Table 2 presents the results of this analysis.

Table 2. Implicit Inverse Elasticities in a Range of National Energy Models

Energy Model	Natural Gas Consumption Change		Natural Gas Price Change		Inverse Price Elasticity of Supply	
	2010	2020	2010	2020	2010	2020
NEMS	3.0%	4.5%	6.4%	0.5%	2.13	0.11
POEMS	4.0%	4.3%	7.1%	7.8%	1.75	1.81
CRA	8.7%	11.9%	20.3%	11.1%	2.33	0.93
NANGAS	1.2%	3.1%	7.8%	14.8%	6.67	4.76
E2020	4.0%	8.4%	4.2%	6.3%	1.03	0.76
MARKAL	3.2%	6.3%	6.5%	13.4%	2.04	2.13
NARG	-2.3%	-0.2%	8.4%	9.7%	-3.57	-50.00

As shown, inverse elasticity estimates among these major national energy models vary substantially. Five of the seven models (NEMS, POEMS, CRA, E2020, and MARKAL) report inverse elasticity estimates that are broadly consistent with those presented earlier, while two of the models (NANGAS and NARG) create anomalous results. It deserves note, however, that several of these models (e.g., POEMS and MARKAL) rely in part on modeling inputs to NEMS, making consistency among the models perhaps less useful than otherwise would be the case. Finally, the National Petroleum Council recently issued a national study relying on the EEA model, and whose sensitivity cases show an average implicit long-term inverse elasticity of approximately four (consistent with the 2008 ACEEE results presented earlier) (NPC 2003).

Benchmarking to Empirical Elasticity Estimates

With few exceptions, the energy modeling results reviewed previously present a consistent basic story: reducing the demand for natural gas, whether through the use of RE and/or EE or through other means, is expected to lead to lower natural gas prices than in a business-as-usual scenario. While the magnitude of the long-term implicit inverse price elasticity of supply varies substantially across model and years, the central tendency appears to be 0.75 to 2.5: a 1% reduction in national gas demand is expected to cause a corresponding wellhead price reduction of 0.75% to 2.5% in the long-term, with some models predicting even larger effects (up to a 4% reduction in long-term gas prices for each 1% drop in gas consumption).

These are merely modeling predictions, however, based on an estimated shape of a gas supply curve that is not known with any precision. It would also not be an overstatement to say that the historic ability of modelers to estimate future natural gas prices has been dismal, leading to obvious questions about the degree of confidence to place in these modeling results. It is therefore useful to benchmark these forecasts against empirical estimates of historical inverse elasticities. While empirically-derived estimates of historical inverse elasticities may not predict future elasticities accurately (the natural gas supply curve may have a different shape in 2010 than it did in 1990), and data and analysis difficulties plague such estimates, these estimates nonetheless offer a dose of empirical reality relative to the modeling results presented earlier.

Unfortunately, empirical research on energy elasticities has focused almost exclusively on the impact of supply shocks on energy *demand* (demand elasticity) rather than the impact of demand shocks on energy *supply* (supply elasticity). Our literature search uncovered only one recently published empirical estimate of the long-term supply elasticity for natural gas. Krichene (2002) estimates this long-term supply elasticity to be 0.8 (for the period 1973-1999), yielding an *inverse* elasticity of 1.25. Surprisingly, this is *larger* than Krichene's short-term inverse elasticity, estimated to be -10. Examining the 1918-1973 time period separately, Kirchene estimates inverse elasticities of 3.57 in the long-term and -1.36 in the short term. Krichene estimates these elasticities using U.S. wellhead prices and international natural gas production, however, making a direct comparison to the model results presented earlier impossible.

With only one published figure (of which we are aware) for long-term gas supply elasticity, it may be helpful to review published estimates for other non-renewable energy commodities, namely oil and coal. Unfortunately, few supply constraints exist for coal, and long-term inverse elasticities are therefore expected to be lower than for natural gas. Oil production, while clearly a worldwide rather than regional market, has more in common with gas, but OPEC inserts uncompetitive influences into oil supply behavior. The comparability of natural gas, oil, and coal elasticities is therefore questionable.

Hogan (1989) estimates short- and long-term inverse elasticities for oil in the United States of 11.1 and 1.7, respectively. Looking more broadly at the *world* oil market, Krichene (2002) calculates the long-term inverse elasticity for oil to be 0.91 from 1918-1973, and 10 from 1973-1999. Ramcharran (2002) finds evidence of an uncompetitive supply market for oil for the period 1973-1997, with a short-term inverse elasticity estimate of -5.9. For non-OPEC nations, meanwhile, he found a more competitive short-term inverse elasticity of 9.4.

The EIA (2002b) found only two studies that sought to estimate the supply elasticity for coal. The first, by Beck, Jolly & Loncar (1991), reportedly estimates an inverse elasticity for the Australian coal industry of 2.5 in the short term and 0.53 in the long term. The second study focuses on the Appalachia region of the United States (Harvey 1986), and estimates inverse elasticities of 7.1 in the short term and 3.1 in the long term.

In summary, there are few empirical estimates of supply elasticities, and data and analysis problems plague even those estimates provided above. Nonetheless, empirical estimates of historical long-term inverse elasticities for gas, coal, and oil are positive, and the modeling output presented earlier for natural gas and other non-renewable energy commodities is not wildly out of line with historical empirical estimates. Nonetheless, the range of implicit inverse elasticities of gas presented earlier is broad, and the empirical literature does not facilitate a narrowing of that range. Further, while not clearly supported by either the empirical literature or modeling output, there are some who believe that technological progress is likely to keep the long-term supply curve for natural gas relatively flat, implying a large overstatement of the magnitude of the natural gas price reduction effect in the modeling results presented earlier.

Conclusions

Concerns about the price and supply of natural gas have grown in recent years, and futures and options markets predict high prices and significant price volatility for the immediate future. Whether we are witnessing the beginning of a major long-term nationwide crisis, or a costly but shorter-term supply-demand adjustment, remains to be seen.

Results presented in this paper suggest that resource diversification, and in particular increased investments in RE and EE, have the potential to help alleviate the threat of high natural gas prices over the short and long term. Whether through gas efficiency measures, or by displacing gas-fired electricity generation, increased deployment of RE and EE is expected to reduce natural gas demand and consequently put downward pressure on gas prices. A review of the economics literature shows that this effect is to be expected, and can be measured with the inverse price elasticity of gas supply. Due to the respective shapes of long- and short-term supply curves, the long-term price impact is expected to be less significant than shorter-term impacts.

Importantly, the direct impact of this natural gas price reduction does not represent an increase in aggregate economic wealth, but is instead a benefit to consumers that comes at the expense of natural gas producers. Conventional economics does not support government intervention for the sole reason of shifting the demand curve for natural gas and thereby reducing gas prices. If policymakers are uniquely concerned about the impact of gas prices on consumers, however, then policies to reduce gas demand might be considered appropriate on wealth redistribution grounds; at a minimum, such policymakers might view reduced gas prices as a positive secondary effect of increased RE and EE deployment.

A large number of modeling studies have recently been conducted that implicitly include an evaluation of this effect. Though these studies show a relatively broad range of inverse price elasticities of natural gas supply, we also find that many of them exhibit some central tendencies. Benchmarking these results against other modeling output, as well as a limited empirical literature, we conclude that many of the studies of the impact of RE and EE on natural gas prices appear to have represented this effect within reason, given current knowledge.

Despite this, there are sometimes significant changes in the implicit inverse elasticities not only across models, but also between years within the same modeling run and between modeling runs using the same basic model. Inverse elasticities do not always remain within reasonable bounds. Combine this with the fact that the natural gas supply curve is unknown, and that the historic ability of energy modelers to predict future gas prices is dismal, and we do not believe that much weight should be placed on any *single* modeling result. More effort needs to be placed on accurately estimating the supply curve for natural gas, and in validating modeling treatment of that curve, before any single modeling result can reasonably be relied upon.

In the mean time, in estimating the impact of RE and EE on natural gas prices, it would be preferable to consider a range of natural gas elasticity estimates to bound this effect. Relying on the data summarized in this paper, we conclude that each 1% reduction in national gas demand could lead to a long-term average wellhead price reduction of 0.75% to 2.5%, with some of the models predicting even more aggressive price reductions. Reductions in the wellhead price will not only have the effect of reducing electricity rates, but will also reduce residential, commercial, and industrial gas bills. Based on the results presented in this paper, it is not unreasonable to expect that any increase in consumer electricity costs that are caused by RE and/or EE will be substantially offset by the expected reduction in delivered natural gas prices.

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GEC Response to APPRO Interrogatory #7

Question:

Reference: i) Evidence of Mr. Chernick pages 18-25.

Preamble: In the evidence, Mr. Chernick indicates that: (i) Ontario proposes to impose a charge on gas use; (ii) Ontario recently joined the Western Climate Initiative (**WCI**); and (iii) the forward price of carbon is in the range of $20 USD/tonne in 2014 rising linearly to $35 USD/tonne in 2030 and $61.50 USD/tonne in 2040.

a) Please confirm that Synapse is providing other paid evidence in this proceeding.
b) Please provide any and all information that Mr. Chernick relied upon indicating that the point of regulation for carbon pricing will be the gas user (i.e. end-use gas customer).
c) Please indicate when Ontario joined the WCI and its terms of entry.
d) Please provide the actual carbon allowance auction prices in California and Québec in accordance with the following table:

Auction Period		Auction Price		
2013	Q1	California	Québec	RGGI[1]*
	Q2			
	Q3			
	Q4			
2014	Q1			
	Q2			
	Q3			
	Q4**			
2015	Q1			
	Q2			

*while not technically linked, Québec provides for consideration of RGGI allowances in related export transactions for power.
**California/Québec linked auction.

e) Please provide any and all assumptions of carbon pricing in multi-state cooperation programs, such as RGGI and WCI both pre- and post-implementation of the U.S. CPP.
f) Please provide any and all factual/technical support for the 1.89 kg CO_2/m^3 emission factor used in the analysis.
g) Please provide any and all relevant currency exchange forecasts for the 2016-2020 period.
h) Please provide all carbon and related cost estimates set out in this section of the evidence on a metric tonne basis.
i) Please provide all assumptions and limitations implicit in the proposed social cost of carbon estimates.
j) Please confirm that Mr. Chernick assumed that the avoided cost of carbon emissions would be, in part, a function of the prevailing carbon price.
k) Please provide any and all data supporting the implied CO_2 costs in footnote 15.

Response:

a) Mr. Chernick understands that two Synapse staff (Tim Woolf and Kenji Takahashi) will be testifying in this proceeding. Their evidence was coauthored by Erin Malone, Alice

Napoleon, and Jenn Kallay. None of these individuals were authors of the Synapse 2015 carbon-price report.

b) Mr. Chernick did not make that assertion in his evidence. It is likely that some very large emitters of CO_2 will be included as regulated entities, based on previous proposals for carbon cap-and-trade, California practice, and the Greenhouse Gas Emissions Reductions Consultation on Cap and Trade presentation (M.GEC.IGUA.1 Attachment 1).
c) Ontario joined the WCI in 2008. Mr. Chernick does not have the "terms of entry."
d) See response to GEC.APPrO.4g.
e) Mr. Chernick has not reviewed the detail of the RGGI and WCI regulations to determine whether they may be affected by the CPP. APPRO is welcome to review the RGGI and WCI documents, many of which are available on line. The California GHG rules may need to be revised to harmonize with features of the CPP rules, such as the lack of offsets; alternatively, California could request a waiver of rules if it can convince the EPA that the proposed state rule would exceed the reductions required by EPA.
f) The value of 1.89/kg is consistent with Enbridge (B/T1/S2 fn 2) which cites *Guideline for Greenhouse Gas Emissions Reporting* (as set out under Ontario Regulation 452/09 under the Environmental Protection Act), Appendix 10; ON.20, General Stationary Combustion, Calculation Methodology 1, Ontario Ministry of the Environment, December 2009, PIBS# 7308e. The molecular composition of gas varies; it is mostly methane, with some heavier hydrocarbons and some inert gases (nitrogen, CO_2), all of which affect both the energy content and the CO_2 emissions per m^3. (See https://www.uniongas.com/about-us/about-natural-gas/Chemical-Composition-of-Natural-Gas for more detail.) The 1.89kg/m^3 value is also consistent with other sources, including:
   - the Greenhouse Gas Protocol spreadsheet at ghgprotocol.org/sites/default/files/ghgp/Stationary_combustion_tool_%28Version4-1%29.xlsx,
   - 53.1 kg/MMBtu (from www.eia.gov/environment/emissions/co2_vol_mass.cfm) and about 28 m^3/MMBtu,
   - 1879 g/m^3 for Ontario and 1918 g/m^3 for Alberta, from https://ec.gc.ca/ges-ghg/default.asp?lang=En&n=AC2B7641-1.

g) Mr. Chernick has not assembled all potentially "relevant currency exchange forecasts for the 2016-2020 period."
   - The most recent traded forward contracts are available at http://www.cmegroup.com/trading/fx/g10/canadian-dollar.html.
   - The CIBC foreign-exchange forecast is available at http://research.cibcwm.com/economic_public/download/fxmonthly.pdf
   - The Scotiabank forecast is available at http://www.gfx.gbm.scotiabank.com/Chart_Feed/fxout.pdf
   - The National Bank of Canada forecast is available at www.nbc.ca/content/dam/bnc/en/rates-and-analysis/economic-analysis/forex.pdf

- The Royal Bank of Canada forecast is available at http://www.rbc.com/economics/economic-reports/pdf/financial-markets/rates.pdf

h) Mr. Chernick believes that he has presented all the carbon prices and costs he mentions (in Table 3, Table 4, and page 22, lines 11–13) in terms of metric tonnes.
i) The available documentation of the social-cost analysis is at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.
j) Yes. Mr. Chernick assumed that the gas utilities and/or large users would need to buy allowances for additional emissions and would be able to sell allowances for emissions reductions, compared to a baseline.
k) Mr. Chernick does not have any information other than the Boland/OPG presentation cited in the footnote and provided as Attachment 1 to M.GEC.APPRO.5. APPRO may want to direct the question to IESO.

Contract	Year	15-07-01	15-07-15	15-07-31
Jan-16	2016	3.214	3.3	3.152
Feb-16	2016	3.213	3.295	3.146
Mar-16	2016	3.173	3.25	3.108
Apr-16	2016	3.032	3.09	2.966
May-16	2016	3.039	3.087	2.965
Jun-16	2016	3.073	3.113	2.995
Jul-16	2016	3.112	3.143	3.026
Aug-16	2016	3.128	3.157	3.037
Sep-16	2016	3.123	3.155	3.031
Oct-16	2016	3.153	3.185	3.062
Nov-16	2016	3.233	3.265	3.146
Dec-16	2016	3.394	3.427	3.312
Jan-17	2017	3.517	3.535	3.434
Feb-17	2017	3.51	3.523	3.424
Mar-17	2017	3.454	3.46	3.367
Apr-17	2017	3.219	3.198	3.127
May-17	2017	3.217	3.196	3.122
Jun-17	2017	3.253	3.232	3.148
Jul-17	2017	3.293	3.272	3.178
Aug-17	2017	3.304	3.283	3.189
Sep-17	2017	3.294	3.273	3.179
Oct-17	2017	3.316	3.295	3.203
Nov-17	2017	3.388	3.369	3.283
Dec-17	2017	3.55	3.533	3.448
Jan-18	2018	3.677	3.663	3.572
Feb-18	2018	3.658	3.646	3.555
Mar-18	2018	3.595	3.586	3.495
Apr-18	2018	3.283	3.272	3.185
May-18	2018	3.283	3.272	3.183
Jun-18	2018	3.318	3.307	3.217
Jul-18	2018	3.355	3.344	3.254
Aug-18	2018	3.367	3.356	3.269
Sep-18	2018	3.359	3.348	3.261

Oct-18	2018	3.381	3.37	3.285
Nov-18	2018	3.451	3.445	3.36
Dec-18	2018	3.611	3.613	3.525
Jan-19	2019	3.738	3.738	3.649
Feb-19	2019	3.718	3.718	3.63
Mar-19	2019	3.656	3.656	3.57
Apr-19	2019	3.344	3.354	3.265
May-19	2019	3.347	3.357	3.266
Jun-19	2019	3.381	3.391	3.3
Jul-19	2019	3.417	3.427	3.336
Aug-19	2019	3.434	3.444	3.352
Sep-19	2019	3.426	3.436	3.344
Oct-19	2019	3.45	3.46	3.368
Nov-19	2019	3.529	3.54	3.45
Dec-19	2019	3.711	3.722	3.635
Jan-20	2020	3.843	3.854	3.771
Feb-20	2020	3.822	3.834	3.752
Mar-20	2020	3.759	3.772	3.692
Apr-20	2020	3.447	3.472	3.4
May-20	2020	3.448	3.473	3.401
Jun-20	2020	3.478	3.503	3.431
Jul-20	2020	3.509	3.534	3.462
Aug-20	2020	3.534	3.559	3.487
Sep-20	2020	3.53	3.555	3.483
Oct-20	2020	3.559	3.584	3.515
Nov-20	2020	3.639	3.669	3.597
Dec-20	2020	3.821	3.855	3.783
	2016	3.157	3.206	3.079
	2017	3.360	3.347	3.259
	2018	3.445	3.435	3.347
	2019	3.513	3.520	3.430
	2020	3.597	3.619	3.545
Average 2016-2020		3.414	3.425	3.332

Contract	Year	15-08-03	15-08-04	15-08-05	15-08-06	15-08-07
Jan-16	2016	3.164	3.204	3.175	3.184	3.179
Feb-16	2016	3.158	3.196	3.168	3.178	3.180
Mar-16	2016	3.117	3.152	3.123	3.133	3.132
Apr-16	2016	2.966	2.982	2.961	2.973	2.974
May-16	2016	2.964	2.977	2.958	2.97	2.970
Jun-16	2016	2.992	3.001	2.984	2.996	2.998
Jul-16	2016	3.025	3.034	3.015	3.026	3.027
Aug-16	2016	3.035	3.044	3.026	3.037	3.035
Sep-16	2016	3.027	3.036	3.018	3.03	3.028
Oct-16	2016	3.057	3.066	3.05	3.062	3.059
Nov-16	2016	3.142	3.146	3.131	3.142	3.135
Dec-16	2016	3.307	3.307	3.296	3.307	3.296
Jan-17	2017	3.425	3.421	3.411	3.422	3.424
Feb-17	2017	3.415	3.41	3.402	3.413	3.415
Mar-17	2017	3.358	3.35	3.342	3.35	3.350
Apr-17	2017	3.108	3.092	3.085	3.1	3.103
May-17	2017	3.103	3.086	3.08	3.095	3.100
Jun-17	2017	3.128	3.109	3.103	3.118	3.123
Jul-17	2017	3.156	3.137	3.131	3.147	3.147
Aug-17	2017	3.167	3.148	3.146	3.162	3.162
Sep-17	2017	3.157	3.138	3.136	3.152	3.152
Oct-17	2017	3.181	3.162	3.164	3.18	3.160
Nov-17	2017	3.261	3.242	3.244	3.258	3.250
Dec-17	2017	3.426	3.406	3.408	3.422	3.422
Jan-18	2018	3.55	3.526	3.528	3.54	3.540
Feb-18	2018	3.533	3.509	3.511	3.52	3.520
Mar-18	2018	3.473	3.449	3.451	3.46	3.460
Apr-18	2018	3.163	3.137	3.136	3.14	3.140
May-18	2018	3.161	3.135	3.134	3.138	3.138
Jun-18	2018	3.195	3.169	3.168	3.172	3.172
Jul-18	2018	3.232	3.206	3.205	3.209	3.209
Aug-18	2018	3.247	3.221	3.22	3.224	3.224
Sep-18	2018	3.239	3.213	3.212	3.216	3.240
Oct-18	2018	3.263	3.237	3.236	3.24	3.240
Nov-18	2018	3.338	3.312	3.311	3.315	3.315
Dec-18	2018	3.503	3.477	3.476	3.48	3.480
Jan-19	2019	3.627	3.601	3.6	3.604	3.604
Feb-19	2019	3.608	3.581	3.58	3.584	3.584
Mar-19	2019	3.548	3.521	3.52	3.524	3.524
Apr-19	2019	3.243	3.216	3.215	3.214	3.220

May-19	2019	3.244	3.217	3.216	3.215	3.215
Jun-19	2019	3.278	3.249	3.248	3.247	3.247
Jul-19	2019	3.314	3.284	3.283	3.282	3.282
Aug-19	2019	3.33	3.3	3.299	3.298	3.298
Sep-19	2019	3.322	3.292	3.291	3.29	3.290
Oct-19	2019	3.346	3.316	3.315	3.314	3.314
Nov-19	2019	3.428	3.396	3.395	3.394	3.394
Dec-19	2019	3.613	3.578	3.577	3.576	3.576
Jan-20	2020	3.749	3.712	3.711	3.711	3.700
Feb-20	2020	3.73	3.692	3.691	3.691	3.691
Mar-20	2020	3.67	3.632	3.631	3.631	3.631
Apr-20	2020	3.375	3.327	3.326	3.321	3.321
May-20	2020	3.376	3.328	3.327	3.321	3.321
Jun-20	2020	3.406	3.358	3.357	3.349	3.349
Jul-20	2020	3.437	3.389	3.388	3.378	3.378
Aug-20	2020	3.462	3.414	3.413	3.402	3.402
Sep-20	2020	3.458	3.41	3.409	3.396	3.396
Oct-20	2020	3.49	3.442	3.441	3.426	3.426
Nov-20	2020	3.573	3.525	3.524	3.507	3.507
Dec-20	2020	3.759	3.711	3.71	3.691	3.691
	2016	3.080	3.095	3.075	3.087	3.084
	2017	3.240	3.225	3.221	3.235	3.234
	2018	3.325	3.299	3.299	3.305	3.307
	2019	3.408	3.379	3.378	3.379	3.379
	2020	3.540	3.495	3.494	3.485	3.484
Average 2016-2020		3.319	3.299	3.294	3.298	3.298

TAB 6

Green Energy Coalition

Undertaking of Mr Chernick

To Ms. DeMarco

Undertaking:

GEC to provide any and all additional sources that Mr. Chernick looked at to substantiate the 53.1 kilograms per MMBTU value that he cites the EIA report for

Response:

The following table provides seven such cites from four sources. Most of the estimates were stated in units other than Kg/MMBtu, so I converted the units using the factors shown at the bottom of the table. Note that the North American estimates are in the 52.9–53.2 Kg/MMBtu range, while the IPCC generic estimates are about 10% higher. Also, since this section of the testimony concerns the conversion of carbon prices from ¢/kWh of gas-fired generation to \$/m^3 of direct gas combustion, the exact emission rate for natural gas combustion does not change the results.

Natural Gas Emission Rates

Source	Emissions as Stated	Stated Units	Kg CO_2/ MMBtu	Link
US EIA			53.1	eia.gov/environment/emissions/co2_vol_mass.cfm
US EPA pipeline gas				
2013	14.46	MMT C/QBtu	53.0	epa.gov/climatechange/Downloads/ ghgemissions/ US-GHG-Inventory-2015-Annex-2-Emissions-Fossil-Fuel-Combustion.pdf, Table A-38
2003 (min est.)	14.44	MMT C/QBtu	52.9	
2000 (max est.)	14.47	MMT C/QBtu	53.1	
Canada National Inventory Report 2014, for Ontario				
	1,879	g/m^3	53.2	unfccc.int/files/national_reports/annex_i_ghg_inventories/ national_inventories_submissions/application/zip/ can-2014-nir-11apr.zip, Table A8–1
2006 IPCC Guidelines for National Greenhouse Gas Inventories				
Low	54,300	kg CO_2/TJ	57.3	
Default	56,100	kg CO_2/TJ	59.2	ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/ V2_2_Ch2_Stationary_Combustion.pdf, Table 2.2
High	58,300	kg CO_2/TJ	61.5	

Assumptions and conversions

3.67	gCO_2/gC
1,000	Btu/ft^3
35.3	ft^3/m^3
947.8	MMBtu/Tj

Green Energy Coalition

Undertaking of Mr Chernick

To Ms. DeMarco

Undertaking:

GEC to provide the actual conversion factor used from the Synapse short tons to metric tonnes.

Response:

The computation included 1.1023 short tons per metric tonne.

TAB 7

UNDERTAKING JT4.5

UNDERTAKING

August 18, 2015 Technical Conference Transcript, page 33.

To advise what literature or materials did Synapse review, what research did Synapse undertake, about the history of low-income DSM programming offered by Union and Enbridge in Ontario over the last ten years.

RESPONSE

Synapse focused its review on the utilities current plan filings. Synapse did not review past plans and reports for information about previous low-income offerings.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNDERTAKING JT4.6

UNDERTAKING

August 18, 2015 Technical Conference Transcript, page 33.

To advise Synapse's awareness of the low-income working group and the discussions that were had within that group between stakeholders, intervenors, and the companies over the last two years when discussing DSM and the programming and low-income customer needs.

RESPONSE

Synapse’s awareness of low-income working group discussions was supplemented through OEB Staff clarifications and OEB Staff interrogatories regarding the utilities low-income program proposals.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNDERTAKING JT4.7

UNDERTAKING

August 18, 2015 Technical Conference Transcript, page 34.

To advise whether Synapse requested any specific materials about low-income DSM before preparing its report and, if there was a request, to provide the information about the discussion or the terms of reference or whatever there may be.

RESPONSE

Synapse's review of the utility filings and subsequent phone discussions with OEB Staff contributed to our understanding of low-income specific issues in Ontario.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNDERTAKING JT4.8

UNDERTAKING

August 18, 2015 Technical Conference Transcript, page 36.

To confirm if there is anything in addition to what appears in Enbridge Interrogatory 3, with respect to low income multi-family dwellings and low-income new construction programs.

RESPONSE

No, there was nothing reviewed in addition to what appears in Enbridge Interrogatory 3.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNDERTAKING JT4.9

UNDERTAKING

August 18, 2015 Technical Conference Transcript, page 37.

To confirm whether union's proposal to pilot or demo the market rate part of its multi-res program this year and then launch it next year makes good sense and fits within Synapse's recommendations.

RESPONSE

Yes, the pilot or demo is reasonable given that it is coupled with a launch next year.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNDERTAKING JT4.10

UNDERTAKING

August 18, 2015 Technical Conference Transcript, page 38.

To provide a response to LIEN's Interrogatory No. 1; to advise what local condition or low income customer-specific information for Union's territory forms the basis for Synapse's recommendation that Union offer a similar new construction low income offering to that that Enbridge is offering as a pilot.

RESPONSE

This recommendation is not based on a detailed assessment of local conditions or low-income customer specific information. This recommendation is based on our understanding that there typically are significant savings opportunities from low-income new construction programs, and that ignoring this sector and market altogether can result in significant lost opportunities.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNDERTAKING JT4.11

UNDERTAKING

August 18, 2015 Technical Conference Transcript, page 41.

To review Union's furnace end of life upgrade program or offering and Union's home weatherization offering and advise whether Synapse considers them to be incremental rather than duplicative.

RESPONSE

If the Furnace-End of Life offering is "trying to capture those low income customers [with furnaces that have failed] who aren't going to be covered and qualified for, and participate in the home weatherization offer", Synapse considers this program to be incremental to the Home Weatherization program (Transcript of Technical Conference, page 40).

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNDERTAKING JT4.12

UNDERTAKING

August 18, 2015 Technical Conference Transcript, page 56.

Synapse to provide any additional information related to direct large-volume customer energy efficiency and conservation measures Synapse has directly done, or been involved with.

RESPONSE

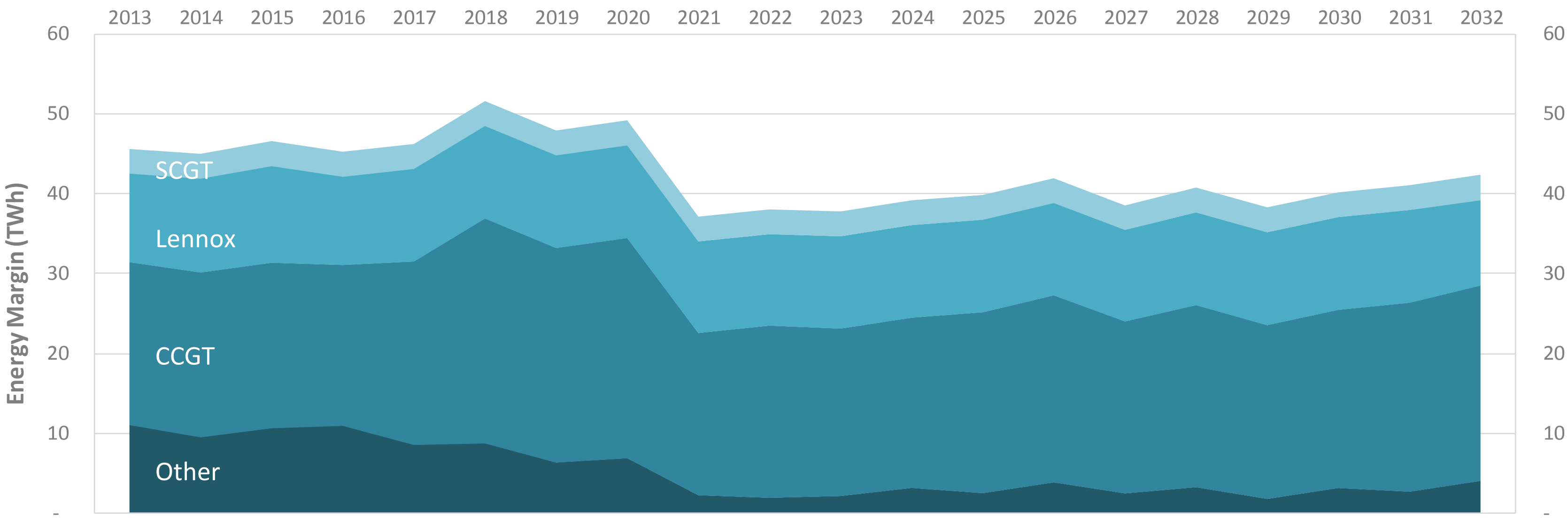
The authors of the Synapse report (including Mr. Woolf) have not directly designed or implemented engineering projects involving the measures that were listed in response to APPRO-3 (motors, CHP, compressors, pumps, lighting, air handling, process changes, and energy management systems).

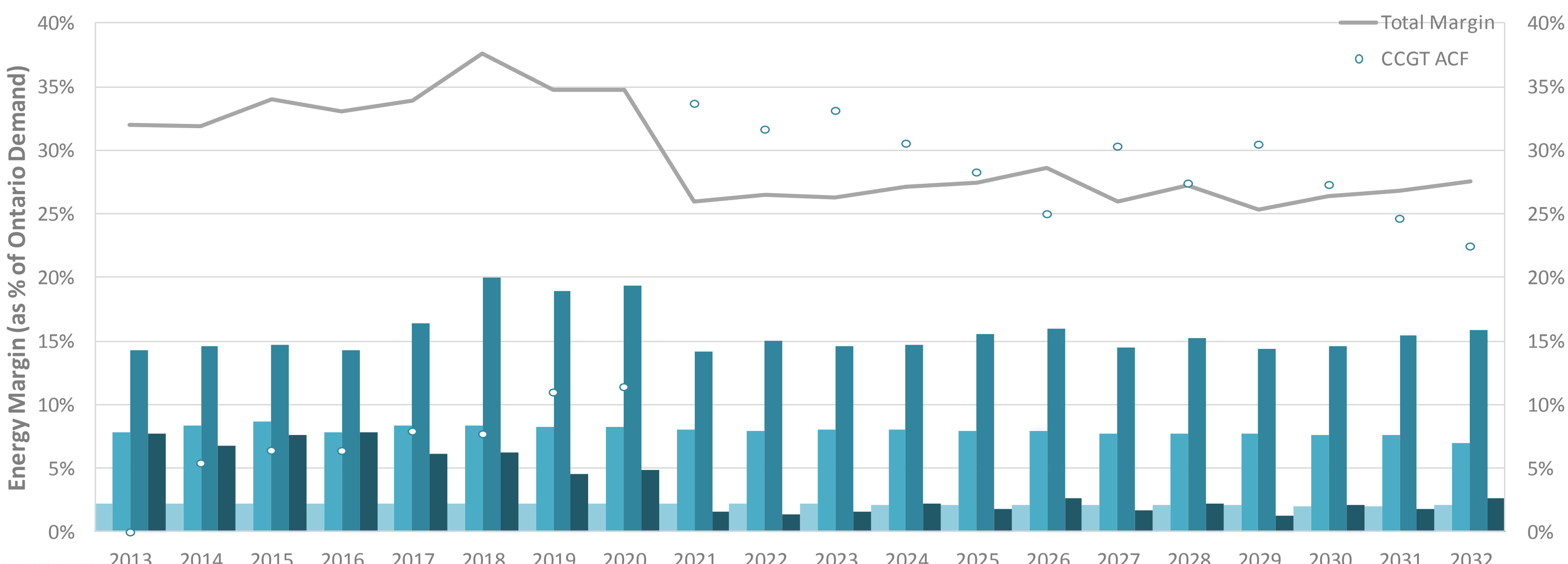
Synapse's experience with these measures is in the area of program/offering design and review including cost effectiveness, based on utility or third party reports of actual energy savings and cost.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

TAB 8

Existing, committed and directed resources can produce the required energy: the need is for additional peak capacity





TAB 9

Subject: FW: Gas fired generators
Date: Tuesday, 18 August, 2015 8:28:24 PM Eastern Daylight Time
From: John Wolnik
To: Joanna Kyriazis

Further to my earlier note, here is data directly from the IESO that indicates that gas has recently been on the margin between 32-39% of the time

BTW- MCP = marginal clearing price

John

From: David Butters [mailto:david.butters@appro.org]
Sent: Wednesday, August 05, 2015 10:20 AM
To: Lisa DeMarco; John Wolnik
Subject: Fwd: Gas fired generators

Note difference between 70% and this actual #.

David Butters
President & CEO
The Association of Power Producers of Ontario (APPrO)
Suite 1602, 25 Adelaide St. E.
Toronto, ON M5C 3A1
tel. 416-322-6549 fax 416-481-5785

Begin forwarded message:

> **From:** "Agavriloai, Ioan" <ioan.agavriloai@ieso.ca>
> **Date:** August 5, 2015 at 10:15:39 AM EDT
> **To:** David Butters <david.butters@appro.org>
> **Cc:** "Campbell, Bruce" <bruce.campbell@ieso.ca>, "Warren, Kim" <kim.warren@ieso.ca>, "Kula, Leonard" <leonard.kula@ieso.ca>
> **Subject: RE: Gas fired generators**
>
> Hello David,
> The percentages you are looking for are:
> 1. 2014 – 32%
> 2. 2015 (to July 31) – 39%
>
> Best,
> **Ioan Agavriloai** | Manager – Operational Effectiveness
> Independent Electricity System Operator (IESO) | T: (905) 855-6276 | C: (905) 601-6627
> Station A, Box 4474, Toronto, ON M5W 4E5

Web: www.ieso.ca | Twitter: IESO_Tweets | LinkedIn: IESO
Conservation: www.saveONenergy.ca | Twitter: saveONenergyOnt | LinkedIn: saveONenergy

---

From: David Butters [mailto:david.butters@appro.org]
Sent: August 03, 2015 7:39 PM
To: Warren, Kim
Cc: Campbell, Bruce; Agavriloai, Ioan
Subject: Re: Gas fired generators

Fantastic. 2014 through 2015 would do it.

David Butters
President & CEO
The Assn. of Power Producers of Ontario (APPrO)
1602-25 Adelaide St. E
Toronto, ON M5C 3A1

Sent from my iPad

DISCLAIMER: This e-mail message is intended only for the named recipient(s) above and may contain information that is privileged, confidential and/or exempt from disclosure under applicable law. If you have received this message in error, or are not the named recipient(s), please immediately notify the sender and delete this e-mail message

On Aug 3, 2015, at 4:35 PM, "Warren, Kim" <kim.warren@ieso.ca> wrote:

> Hi Dave. We can get that for you in a few days. Ioan will forward you that but likely need a few more specifics (ie what time frame are you looking for etc?)
> Kim
>
> Sent from my BlackBerry 10 smartphone on the Bell network.
>
> ---
>
> **From:** David Butters
> **Sent:** Monday, August 3, 2015 2:54 PM
> **To:** Campbell, Bruce; Warren, Kim
> **Subject:** Gas fired generators
>
> Do you or anyone else in your shop know the percentage of hours gas-fired generators set the MCP?
>
> David Butters
> President & CEO
> The Association of Power Producers of Ontario (APPrO)
> Suite 1602, 25 Adelaide St. E.
> Toronto, ON M5C 3A1
> tel. 416-322-6549 fax 416-481-5785

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This e-mail message and any files transmitted with it are intended only for the named recipient(s) above and may contain information that is privileged, confidential and/or exempt from disclosure under applicable law. If you are not the intended recipient(s), any dissemination, distribution or copying of this e-mail message or any files transmitted with it is strictly prohibited. If you have received this message in error, or are not the named recipient(s), please notify the sender immediately and delete this e-mail message.

TAB 10

2. Ontario's Latest GHG Numbers

The Environmental Commissioner of Ontario reports annually to the Legislative Assembly of Ontario on the progress of the Ontario government towards reducing the province's GHG emissions, as required by the *Environmental Bill of Rights, 1993*. This section uses the most recent Environment Canada data to assess the province's progress towards meeting its GHG emissions reduction targets, established in 2007.[43] The three provincial targets are to reduce Ontario's annual GHG emissions by:

- 6 per cent below 1990 levels by 2014 (to approximately 171 Megatonnes [Mt] CO_2 equivalent);
- 15 per cent below 1990 levels by 2020 (to approximately 155 Mt); and
- 80 per cent below 1990 levels by 2050 (to approximately 36 Mt).

Ontario recently announced a 2030 mid-term target of 37 per cent below 1990 levels (equivalent to 115 Mt).

2.1 Overall Emissions in 2013

According to the 2015 National Inventory Report (NIR), Ontario's GHG emissions in 2013 were 171 Mt, equivalent to emissions in 2012 (and 2009).[44] This figure is the lowest annual level of emissions since the baseline year of 1990 (and 1991), when emissions were 182 Mt. (Note: this baseline number is higher than previously reported based on the use of newer methods of calculating GHG emissions; see box.)

Revised Framework for Calculating GHG Emissions

In this year's edition of the National Inventory Report, it became mandatory for Environment Canada to use the revised United Nations Framework Convention on Climate Change emissions reporting guidelines. This resulted in recalculations of previous years' emissions, and the 1990 baseline year is now higher than was reported in previous years (e.g., the baseline was reported to be 177 Mt in 2014, but was increased to 182 Mt in 2015).[ii] The recalculation is mainly due to an updated value for the global warming potential of two greenhouse gases, methane and nitrous oxide, resulting in higher carbon emissions across all years. The sectors most affected by this change are residential buildings, agriculture, and waste.

[ii] Each year Canada produces a National Inventory Report, which provides the most recent, as well as historic, GHG data for Canada and each province. Due to continual improvements to the way emissions estimates are modelled and calculated, historic data is often restated. Accordingly, historic numbers for some years, including the baseline year of 1990, may not exactly align with data on which the ECO has previously reported and commented.

With Ontario's emissions projected to be lower in 2014 due to the closure of its final coal-powered electricity plant, Ontario looks likely to meet its 2014 target (which is also 171 Mt). As shown in **Figure 1**, the last several years have witnessed a significant decline from the peaks experienced roughly between 2000 and 2005, when emissions from coal-fired electricity generation were highest.

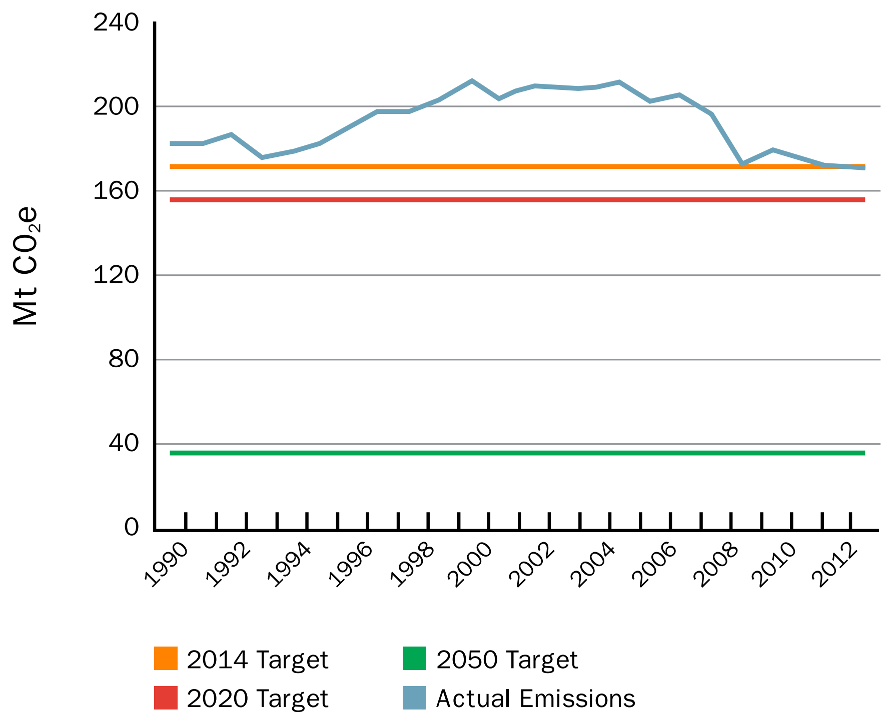

Figure 1. Ontario greenhouse gas emission trends and targets (1990-2013). (Sources: Environment Canada. National Inventory Report – Greenhouse Gas Sources and Sinks in Canada 1990-2013 (2015); Go Green: Ontario's Action Plan on Climate Change (2007); Ontario's Climate Change Update 2014 (2014)).

However, meeting the 2020 target will prove more difficult. Ontario faces a large gap (19 Mt – equal to 11 per cent of its total current GHG emissions[iii]) between the province's projected 2020 emissions based on current policies and trends and the 2020 target. Without new policy initiatives, the majority of Ontario's emissions reductions (78 per cent in 2020) will have come from the single initiative of phasing out the use of coal in the electricity sector. The government's biggest climate change challenge going forward is to achieve sufficient GHG reductions beyond the electricity sector to meet its 2020 target.

[iii] This 19 Mt gap was as of September 2014 and is based on the previous year's National Inventory Report.

2.2 Sector-Specific Emissions

Figure 2 shows Ontario's GHG emissions from each sector and how they have changed from 1990 to 2013. The electricity sector alone has seen a 58 per cent reduction in emissions over this time period, with the industrial sector contributing a further 26 per cent reduction, mostly due to reduced industrial production in the province.[46] The closure of the coal plants will not be fully reflected in Ontario's emissions profile until the 2015 emissions data becomes available.

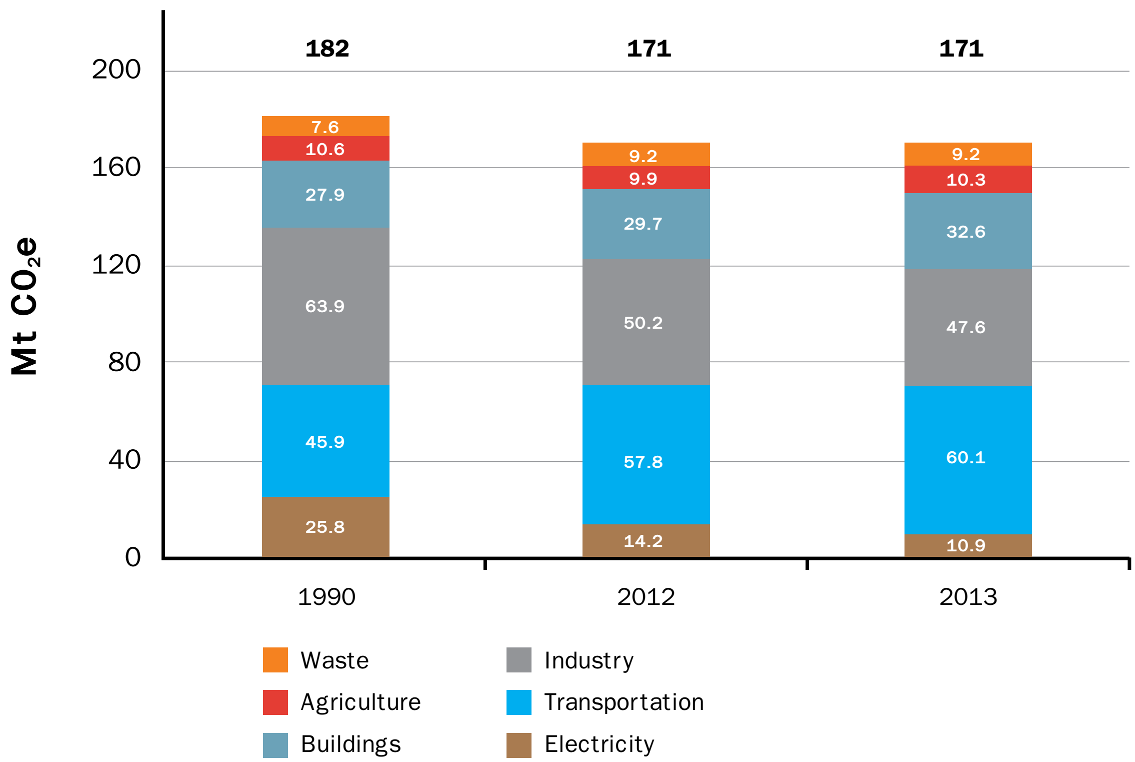

Figure 2. Ontario greenhouse gas emissions by sector for 1990, 2012 and 2013. (Source: Environment Canada. National Inventory Report – Greenhouse Gas Sources and Sinks in Canada 1990-2013 (2015)).

Since 1990, emissions reductions in the electricity and industry sectors have been partially offset by the 31 per cent increase in emissions from the transportation sector. Emissions in the buildings and waste sectors have also risen (17 per cent and 20 per cent, respectively). The transportation sector remains the largest contributor to the overall provincial inventory, with emissions rising 4 per cent from 2012 to 2013. Although emissions intensities have fallen in many sectors, in some sectors these gains are at least partially offset by economic and population growth.[47]

A more detailed breakdown of sector emissions is provided in **Table 1**.

Table 1. Ontario's Greenhouse Gas Emissions 1990–2013 (Source: Environment Canada. National Inventory Report – Greenhouse Gas Sources and Sinks in Canada 1990-2013 (2015)).

Sources	Emissions ($Mt\ CO_2e$)		Change from 1990 - 2013		Percentage each sector contributes to 2013 total
	1990	2013	$Mt\ CO_2e$	%Δ	%
Electricity	25.8	10.9	-14.9	-58	6
Transportation	45.9	60.1	+14.2	+31	35
Road (passenger)	27.3	32.7	+5.4	+19.8	
Road (freight)	8	13.4	+5.4	+67.5	
Off-road (gasoline and diesel)	5.6	9.2	+3.6	+64.3	
Domestic Aviation	2.2	2.3	+0.1	+4.5	
Domestic Marine	1.0	1.2	+0.2	+20	
Rail	1.8	1.3	-0.5	-27.8	
Industry	63.9	47.6	-16.3	-25.5	28
Fossil fuel refining	6.1	6.1	0	0	
Manufacturing	22	16.1	-5.9	-26.8	
Mineral Production (cement, lime, mineral products)	4.1	3.6	-0.5	-12.2	
Chemical Industry	10	0	-10	-100	
Metal Production (iron and steel)	10.9	7.7	-3.2	-29.4	
Fugitive Sources	1.6	1.3	-0.3	-18.8	
Other[iv]	9.3	12.8	+3.5	+37.6	
Buildings	27.9	32.6	+4.7	+17	19
Commercial and Institutional	9.1	11.9	+2.8	+30.8	
Residential	18.8	20.7	+1.9	+10.1	
Agriculture	10.6	10.3	-0.3	-3	4
Enteric Fermentation	4.4	3.6	-0.8	-18.2	
Manure Management	2.1	1.9	-0.2	-9.5	
Agricultural Soils	3.9	4.6	+0.7	+17.9	
Waste	7.6	9	+1.4	+19	5
Solid Waste Disposal on Land	7.1	8.4	+1.3	+18.3	
Wastewater Handling	.2	.3	+0.1	+50	
Waste Incineration	.3	.3	0	0	
TOTAL	182	171	-11	-6	100

[iv] The "other" category includes emissions from stationary combustion in mining, construction, agriculture and forestry; emissions from pipelines; emissions associated with the production and consumption of halocarbons; and emissions from the use of petroleum fuels as feedstock for petrochemical products. Subsector figures do not exactly match sector totals due to rounding errors and the fact that this table does not list all minor subsectors. The ECO adds up the emissions subcategories to calculate the sector totals so they may not exactly match the rounded numbers presented in the NIR.

TAB 11

EB-2015-0029
EB-2015-0049

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 applications for approval of 2015-2020 demand side management plans by Union Gas Limited and Enbridge Gas Distribution Inc.

ENVIRONMENTAL DEFENCE'S DOCUMENT BOOK FOR UNION GAS CROSS-EXAMINATIONS

August 19, 2015

KLIPPENSTEINS
Barristers and Solicitors
160 John Street, Suite 300
Toronto, ON M5V 2E5

Murray Klippenstein, LSUC No. 26950G
Kent Elson, LSUC No. 57091I
Tel.: (416) 598-0288
Fax: (416) 598-9520

Lawyers for Environmental Defence

Index

Note: The above documents have been marked up by counsel. Most are excerpts of the relevant document.

---

[1] http://www.ieso.ca/Pages/Conservation/ConservatonFirstFramework/default.aspx
[2] http://www.hydroone.com/IndustrialLDCs/ConnectionProcess/Documents/Hydro%20One%20Tx%20Load %20Connection%20Customer%20Package.pdf
[3] https://www.enercare.ca/home/furnace/buynewfurnace#
custom5
[4] http://www.newyorker.com/magazine/2015/06/29/power-to-the-people

20,

VERESEN

Veresen Inc.
Suite 440, Livingston Place
222 – 3rrd Avenue S.W.
Calgary, Alberta T2P 0B4

Tel (403) 296-0140
Fax (403) 213-3648
www.veresenInc.com

October 11, 2011

Via Electronic Mail

John Pickernell
Board Secretary
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Atten: Board Secretary

Re: Demand Side Management Guidelines for Natural Gas Utilities
Issuance of DSM Guidelines

Further to the Ontario Energy Board's (OEB) letter dated June 30, 2011, regarding the Demand Side Management (DSM) Guidelines for natural gas utilities, Veresen Inc., (Veresen) wishes to express its views. Veresen is a publically traded energy infrastructure company that holds energy assets in Ontario consisting of natural gas fired electricity generation facilities including district heating, cogeneration and peaking generation, ranging in size from 15 MW to 400 MW.

Two of Veresen's facilities, the East Windsor Cogeneration Centre (EWCC) and our London District Energy (LDE) facility currently hold Union's T1 service contracts and thus are subject to the T1 rate class methodology. Both of these facilities have participated in the DSM programs offered through Union Gas with very good success. Veresen's position regarding this program is that it has played an important role in achieving increased energy effeciency at these facilities. In our view, eliminating these programs is not in the best interest of T1 shippers and importantly, may result in a reduction in DSM initiatives by generators such as ourselves. EWCC and LDE are not large industrials, and therefore the view's expressed by others such as IGUA or CME regarding the DSM programs are not representative of our position.

Veresen strongly encourages the Board to continue the DSM program as currently structured to further facilitate achivements in DSM in Ontario.

Yours truly,

Julia Ciccaglione
Vice President, Regulatory & Government Affairs
Veresen Inc.

Cc: Paul Eastman, VP Operations - East, Veresen Inc.

Environmental
Commissioner
of Ontario

2014 ANNUAL ENERGY CONSERVATION PROGRESS REPORT

Planning to ~~Build~~ Conserve

APPENDIX A: ONTARIO ENERGY CONSUMPTION

The ECO is responsible for reporting on the progress of government activities related to reducing, or making more efficient use of, electricity, natural gas, propane, oil, and transportation fuels. Throughout 2013 and 2014, the government continued to place emphasis primarily on policies and initiatives to reduce Ontario's consumption of electricity (see Figure 1). However, as the following analysis highlights, electricity accounts for just over one-fifth of Ontario's total energy demand by fuel type.

Appendix A provides an update on Ontario's fuel consumption with available data derived from energy consumption data contained in the Report on Energy Supply and Demand in Canada and supplementary tables published by Statistics Canada.[191]

Methodological changes made to the data surveys that supply information to the Report on Energy Supply and Demand in Canada[192] were outlined in a previous ECO report[193] and are incorporated into the following analysis. Since the publication of the ECO's 2012 Annual Energy Conservation Progress Report, revised data were published by Statistics Canada for the 2011 calendar year.[194] This report presents updated data for 2011 and preliminary data available for 2012, and analyzes trends in Ontario's energy consumption statistics for both calendar years.

Analysis

Ontario's 2012 energy demand (based on preliminary data) was 2,405 petajoules (PJ), 4 per cent lower than demand in 2011. Figure 22 shows the breakdown of energy demand by fuel type for Ontario in 2011 and 2012. In 2012, natural gas and transportation fuels together accounted for 69 per cent of the total energy demand (about 1 per cent less than in 2011). Meanwhile, electricity accounted for approximately 20 per cent of Ontario's overall energy demand in each year. Propane, oil and other fuels[195] accounted for roughly 10 per cent of Ontario's overall demand in both 2011 and 2012. These proportional trends are virtually identical to those observed between 2007 and 2010 (see Table 15).

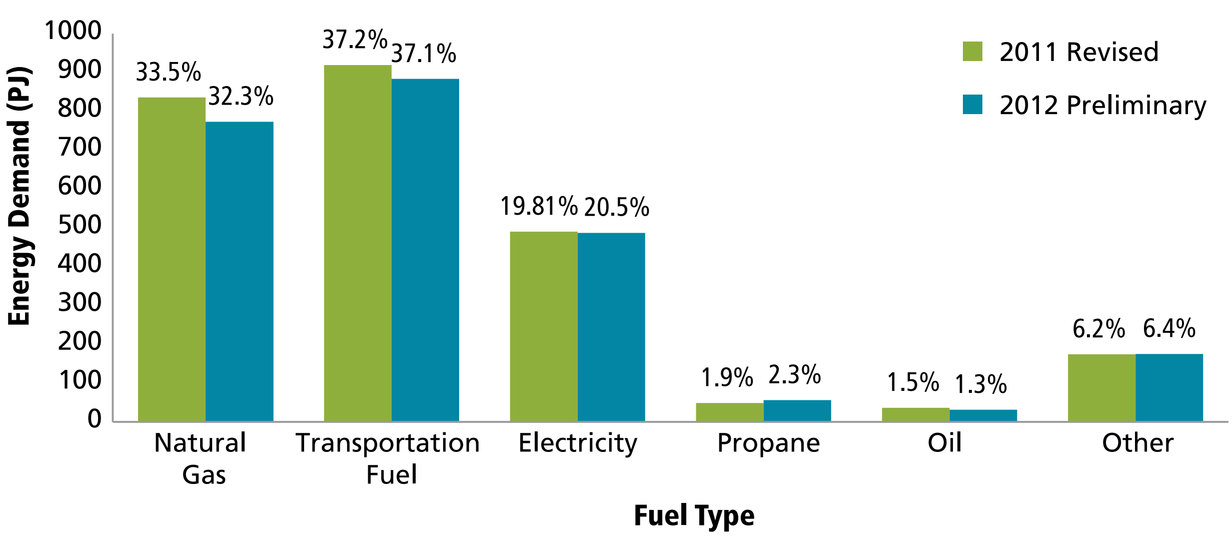

Figure 22: Ontario 2011 (revised) and 2012 (preliminary) Total Energy Demand by Fuel Type

Note: Oil demand includes kerosene and stove oil, and light fuel oil amounts; Transportation Fuel includes motor gasoline, diesel fuel oil, heavy fuel oil, aviation gasoline, and aviation turbo fuel amounts. Details of Oil and Transportation Fuels come from CANSIM table128-0016.

Source: Statistics Canada

Table 15: Annual Ontario Total Energy Demand by Fuel Type

Year	Natural Gas (PJ)	Transportation Fuel (PJ)	Electricity (PJ)	Propane (PJ)	Oil (PJ)	Other (PJ)	Total (PJ)
2007	892	909	548	40	41	192	2621
2008	884	908	586	43	34	187	2643
2009	801	897	464	38	34	152	2387
2010	776	918	480	41	34	173	2422
2011[r]	837	930	495	49	36	155	2503
2012	776	893	494	56	32	156	2405

r= revised by Statistics Canada since publication in previous ECO report.

Note: all values in Table 15 incorporate methodological changes made by Statistics Canada. In the Report on Energy Supply and Demand, total energy demand for propane includes demand for the fuel for non-energy end uses (76 PJ). For all other fuels, demand for non-energy uses is not included in total energy demand amounts. The table above excludes fuel for non-energy end uses. Propane demand for non-energy uses increased in Ontario by 24 per cent between 2010 and 2012, see CANSIM table 128-0012.

Source: Statistics Canada

Ontario's 2012 total energy demand declined by 4 per cent compared to 2011 levels. Although larger in magnitude, the decline was consistent with the 0.6 per cent Canada-wide decline in energy consumption in 2012. Energy demand in Ontario decreased across all major sectors of the economy.

Transportation fuel remained the main source of energy consumed in Ontario in 2012, followed by natural gas. Although transportation fuel demand accounted for the same proportion of Ontario's total energy demand in 2012 as in 2011 (~37 per cent), total consumption of transportation fuel in Ontario declined in 2012. Almost all of Ontario's 2012 energy demand reduction was due to lower demand for transportation fuel and natural gas (-37 PJ and -61 PJ, respectively), with smaller reductions in electricity and oil demand. In its 18-Month Outlook for December 2011 to May 2013, Ontario's Independent Electricity System Operator (IESO) noted that electricity demand would be moderated by conservation efforts in 2011 and 2012 and weaker than anticipated economic growth. A decline in motor gasoline demand was the primary driver of the transportation fuel decline, likely due to ongoing improvements in vehicle fuel efficiency and record-high fuel prices in 2012.[196] This is consistent with National Energy Board projections of slowing transportation-related petroleum consumption over the next 20 years in Canada as support for electric vehicles and alternative transportation fuel grows.

Although its contribution to total fuel demand is small, Ontario's propane demand increased by approximately 14 per cent in 2012. Propane is a natural gas liquid primarily consumed for heating purposes in the commercial and residential sectors. Since 2011, higher prices for natural gas liquids relative to the price of natural gas have encouraged the development of more liquids-rich natural gas.[197] Consumption of fuels in the 'other' category remained almost constant in 2011 and 2012.

TAB 12

Carbon Emissions value

	2014 USD $/MMBtu	2015 CDN $/m3		
2020	1.18	0.055		1
2021	1.27	0.059		2
2022	1.36	0.063		3
2023	1.45	0.067		4
2024	1.53	0.071		5
2025	1.62	0.075		6
2026	1.71	0.079		7
2027	1.80	0.083		8
2028	1.89	0.088		9
2029	1.98	0.092		10
2030	2.07	0.096		11
2031	2.22	0.103		12
2032	2.38	0.110		13
2033	2.53	0.117		14
2034	2.69	0.125		15
2035	2.85	0.132		16
2036	3.00	0.139		17
2037	3.16	0.147		18
2038	3.32	0.154		19
2039	3.47	0.161		20
2040	3.63	0.168		21
		$0.98	16 year NPV	

Conversion Assumptions

0.80%	2014 to 2015 USD conversion
28.33	m3 per MMBtu
1.303	2015 USD to CDN conversion

TAB 13

20.

VERESEN

Veresen Inc.
Suite 440, Livingston Place
222 – 3rrd Avenue S.W.
Calgary, Alberta T2P 0B4

Tel (403) 296-0140
Fax (403) 213-3648
www.veresenInc.com

October 11, 2011

Via Electronic Mail

John Pickernell
Board Secretary
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Atten: Board Secretary

Re: Demand Side Management Guidelines for Natural Gas Utilities
Issuance of DSM Guidelines

Further to the Ontario Energy Board's (OEB) letter dated June 30, 2011, regarding the Demand Side Management (DSM) Guidelines for natural gas utilities, Veresen Inc., (Veresen) wishes to express its views. Veresen is a publically traded energy infrastructure company that holds energy assets in Ontario consisting of natural gas fired electricity generation facilities including district heating, cogeneration and peaking generation, ranging in size from 15 MW to 400 MW.

Two of Veresen's facilities, the East Windsor Cogeneration Centre (EWCC) and our London District Energy (LDE) facility currently hold Union's T1 service contracts and thus are subject to the T1 rate class methodology. Both of these facilities have participated in the DSM programs offered through Union Gas with very good success. Veresen's position regarding this program is that it has played an important role in achieving increased energy effeciency at these facilities. In our view, eliminating these programs is not in the best interest of T1 shippers and importantly, may result in a reduction in DSM initiatives by generators such as ourselves. EWCC and LDE are not large industrials, and therefore the view's expressed by others such as IGUA or CME regarding the DSM program, are not representative of our position.

Veresen strongly encourages the Board to continue the DSM program as currently structured to further facilitate achivements in DSM in Ontario.

Yours truly,

J Ciccaglione

Julia Ciccaglione
Vice President, Regulatory & Government Affairs
Veresen Inc.

Cc: Paul Eastman, VP Operations - East, Veresen Inc.

MR. FRANK: Now, I understood you to say earlier that LDE is of the view that opt-out should be available?

MR. RUSSELL: Yes.

MR. FRANK: And can you please explain why LDE's views are like that today, notwithstanding what was in the letter of October 2011?

MR. RUSSELL: Yes. I think it can be most simply put as London District Energy was not fully aware of the full cost of the incentive payments in the various accounts and as they would be impacting our operating budgets.

MR. FRANK: Okay. And do you know anything about the circumstances under which the letter was written?

MR. RUSSELL: From what I understand from my colleagues at Veresen, that letter was written at the request of Union.

TAB 14

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2015-0029**	**Union Gas Limited**
	EB-2015-0049	**Enbridge Gas Distribution Inc.**

VOLUME: **Technical Conference**

DATE: **August 17, 2015**

EB-2015-0029
EB-2015-0049

THE ONTARIO ENERGY BOARD

Union Gas Limited and Enbridge Gas Distribution Inc.

Applications for approval of 2015-2020 demand side management plans.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Monday, August 17, 2015,
commencing at 9:37 a.m.

TECHNICAL CONFERENCE

We're moving through the estimates fairly efficiently, so we may well finish both GEC and OSEA with some time to spare today. If that happens, we do have Synapse available to answer questions. I know many people were expecting them tomorrow, so I am not sure if anyone is actually prepared to go today. And of course, they'll be back tomorrow regardless -- though I see from Dr. Higgin that he may be prepared to go today.

So if there are time left at the end of the day, I understand that they are available, so we could get at least some of the questions done with them.

With that, Ms. DeMarco, are you prepared to proceed?

QUESTIONS BY MS. DEMARCO:

MS. DeMARCO: Yes, thanks very much.

Mr. Chernick, just by way of reference, the vast majority of my questions are in relation to your response to interrogatories to APPrO, and the reference there is Exhibit M.GEC.APPrO.5 to 7 inclusive, if you just want to pull that up.

Just so I have an understanding of a few things here, the question asked was in relation to your assertion that gas-fired generation appears to be on margin about 70 percent of the time. And we asked specifically for you to provide the supporting IESO and OPA data for that conclusion.

I don't see that in the response. so is it fair to say that you did not refer to IESO data to arrive at the assertion that gas is on margin about 70 percent of the time in the response?

MR. CHERNICK: Well, as I say in --

MR. MILLAR: Is your mic on, Mr. Chernick?

MR. CHERNICK: I'm sorry, it is on, but I will --

MR. MILLAR: Try it again.

MR. CHERNICK: Oh, okay now it's on. It kind of glows green, no matter whether it's on or off.

As I say in response to APPrO 5(a), I have -- I was not able to locate any other forecasts of surplus base load generation, spillage, or marginal emission rates from OPG or IESO. They may be out there some place, but I didn't find them.

MS. DeMARCO: We'll come back to SPG or the surplus base loads, spillage, or marginal emission rates.

But very specifically, you make the assertion that gas is on margin about 70 percent of the time. So we had asked for support from the IESO; is it fair to say that there was none that you used?

MR. CHERNICK: Well, I had this one OPG presentation that unfortunately shows, I guess, daily fossil generation requirements, or exports or surplus base load generation for 2016. And I eyeballed that, and it looked like about 50 percent of the time, the marginal source of supply would be spilling water.

And then the same presentation showed that that condition would drop off quite quickly in the later years, and would basically be gone -- almost gone by 2020.

So I said, okay, so maybe it's 30 percent on average over those years, and used that value. I wish I had the numbers, but I don't have the numbers that -- I think what Mr. Boland used in his presentation.

MS. DeMARCO: Just so that I'm clear, crystal clear on this point, you've used the OPG data for the SPG numbers. But specifically a number for how often gas is on margin, you don't have that?

MR. CHERNICK: Well, there isn't enough are much else in Ontario other than gas. I mean, there's no coal. There is a very small amount of oil. So the fossil generation is basically gas. I'm not aware of anything else that would be in that category.

MS. DeMARCO: So how often gas is on margin specifically; it could be other forms of generation on margin.

MR. CHERNICK: Like?

MS. DeMARCO: At any point in time, you could have any other form of generation.

MR. CHERNICK: Such as what?

MS. DeMARCO: Well, any other form of generation. Wind on margin, in certain instances.

MR. CHERNICK: Well, no, that would be surplus base load generation.

MS. DeMARCO: So could you have water on margin?

MR. CHERNICK: That's surplus base load, because you are either spilling water, spilling wind, turning down a nuclear unit -- manoeuvring, I think they call it -- selling at the margin into the States, replacing some mix there of gas and coal, or you've got gas on the margin in Ontario.

It doesn't seem like there's much else to go into that picture. If you're talking fossil at the margin, in -- if you are using fossil fuel in Ontario, it pretty much has to be gas. I don't know what else there would be.

MS. DeMARCO: But the specific number on margin, you have no data. This is your estimate?

MR. CHERNICK: Exactly. I've told you I eyeballed it, and this is the best I can come up with. If you have better numbers, I would appreciate seeing them.

MS. DeMARCO: So to the extent that we can provide actual data, would it surprise you that it's possible that gas could be on margin, say, 30 to 40 percent of the time, or 28 to 40 percent of the time, as opposed to 70?

MR. CHERNICK: Currently?

MS. DeMARCO: Yes.

MR. CHERNICK: I would be surprised by that, but maybe that has to do with a definition.

For example, in some accountings of what's at the margin, storage Hydro can be counted as being at the margin. But you're not actually -- you're not spilling the hydro; you are not losing that hydro energy. you are just shifting it to another time period.

So I'd have to look at the data to see whether -- what it meant, trying to understand it, and also, you know, how the exports are being dealt with.

MS. DeMARCO: So fair to say that most of your experience, most of your hands-on knowledge is in the U.S.?

MR. CHERNICK: Well, that's where I've spent most of my time working, although I've done a fair amount of work on the electric system in Ontario going back to the late '80s.

MS. DeMARCO: And it would definitely surprise you to see, for example, 25 to 38 percent being the actual number for gas on margin, as opposed to --

MR. CHERNICK: It depends on what you mean by actual.

MS. DeMARCO: A reported IESO number.

MR. CHERNICK: Again, if somebody is going to say anytime hydro, including pumped hydro, is setting the price, we count that as being the avoided resource, then they're wrong. They may be right in terms of how the price is being set in that hour, or that 15-minute segment, whatever. But they are wrong about what's really being avoided, which is what we care about for emission rates.

If you hold back hydro and use it another hour, then the question is, well, what did it avoid in the hour that you used it in?

So if I save energy at eight:00 in the morning, and that lets you save that hydro until two o'clock in the afternoon and use it then, what's it avoiding? Are you spilling it at two o'clock, in which case hydro was really what was avoided? Or are you backing down a gas plant? That's what you need to look at.

So, the fact that somebody reports a marginal, that is price-setting resource, does not mean that that's really what's setting the -- that's not significant in terms of what's really avoided for -- certainly environmental purposes, or other energy purposes.

In the PJM financial transactions are often what's setting the margin, and that doesn't tell you anything about what's actually happening in the system.

MS. DeMARCO: Just so we're all on the same page here, you didn't have that data, the data that you speak about in terms of it you are holding back hydro and storing it at eight a.m. and then spilling it at two p.m., you didn't have the data about what's being avoided at two p.m., did you?

MR. CHERNICK: No, as I said, I haven't found an IESO data source for what's at the margin by any definition. And so I relied on that one OPG presentation.

MS. DeMARCO: In terms of your calculations specifically in 5(a)(ii) of your answer, I'm assuming that when you say, in terms of the avoided emissions there, a mix of gas and coal-fired generation in the U.S. would be a reduction of emissions in the U.S. when Ontario is exporting.

MR. CHERNICK: That's correct.

MS. DeMARCO: It is not a reduction of the emissions in Canada?

MR. CHERNICK: That's correct. Now, you know, depending upon what the Minister was concerned about, if he was concerned about the global environment, it doesn't really matter whether you are avoiding emissions in Canada or in the U.S., but again, all of this was in terms of trying to translate the 15 percent for electric to an adder for gas.

MS. DeMARCO: Can we just chat about that for a minute, because I'm a little confused. Specifically around that 15 percent adder and cause and effect -- so I believe the reference was GEC.EP.12(d).

Do you know how much is attributable to carbon pricing and how much is attributable to the 15 percent?

MR. CHERNICK: No --

MS. DeMARCO: To the DSM activities? Can we definitively say what caused, and where?

MR. CHERNICK: You mean what was the Minister thinking when he picked 15 percent? I don't know, and my evidence says I don't know, and I do some calculations -- doing it, perhaps a sensitivity analysis of, suppose that it were all carbon, and then suppose that it were half carbon, and you can do other cases as well.

So I was trying to inform the Board's attempt to use a consistent approach between the electric and gas sides, and I don't think that the Board has been consistent, and that applying a 15 percent adder to avoided cost for gas does not do the same things as a 15 percent adder for electricity.

MS. DeMARCO: And you very fairly put forward in your evidence that there is the potential for double-counting, and to the extent there is, you would discount that?

MR. CHERNICK: Yes, if you would believe that the

15 percent includes some carbon value, and you price carbon separately, then you should reduce the 15 percent before you then calculate what that would be in terms of gas.

MS. DeMARCO: And that top line item in EP 12(d) really does speak to those carbon reduction costs; is that right?

MR. CHERNICK: I'm sorry, I'm going to have to take a look at EP 12(d) and see whether --

MS. DeMARCO: I believe it's supported by the spreadsheet that we went to.

MR. POCH: Are you referring to the table 3 that was updated in that response?

MS. DeMARCO: That's right. It's the line number 1, which is at line 4 of the Excel spreadsheet. It's really looking at avoided carbon regulation costs, so...

MR. CHERNICK: Oh. Yes, this was Mr. Neme's attempt to quantify, at least roughly, what the benefits to non-participants, or to all customers, including non-participants would be, and he didn't include the 15 percent in here, so there's no double-counting in this table. I thought you were referring to another response.

MS. DeMARCO: I was, actually, in relation to the response regarding the potential of carbon savings, and your assertion that there is the potential for double-counting, and to the extent there is, it should be discounted.

To the extent that we count it, we just -- it is an art; it is not a pure science. It is not like pure mathematics; is that fair to say?

MR. CHERNICK: Well, now you've lost me. In the -- I mean, any forecast about the future is going to require some judgment. I don't know whether you would call that art or not, but the -- the -- I think in my evidence I laid out the cases we were talking about, assuming that the 15 percent was all supposed to be for carbon, which doesn't seem to be the case, given what the Minister said it was for. I'll assume it is half for carbon, and that you can interpolate or extrapolate however you want from there.

And there is certainly judgment. Some of it is -- some of the steps are mathematic, and some of them are -- involve judgment based upon facts that you have available. And I guess I'm -- I'm not sure what other -- what else you were asking about in your question.

MS. DeMARCO: I think we're there. I think you've confirmed that to the extent there is double-counting you would discount that in your evidence --

MR. CHERNICK: Yes, you want to avoid double-counting.

MS. DeMARCO: Yes. In relation to the surplus base load assumption, you've assumed that it's 50 percent of the hours in 2016 would be SBG?

MR. CHERNICK: That's what it looks like to me.

MS. DeMARCO: I'm a little confused by that. Can I ask you to turn to the OPG presentation that you referred to? And --

MR. CHERNICK: Do you remember where we gave that to you?

MS. DeMARCO: Yes. It was in response to 5(a), so M.GEC.APPrO.5, page 1 of 2. It's attachment 1. I'm going to ask you to turn to page 19 there. And on 19, the left-hand graph, as I read it -- and, you know, I could be wrong -- the line across appears to be the primary demand in Ontario.

MR. CHERNICK: Yes.

MS. DeMARCO: And the rest of the graph appears to be the available base load generation in Ontario. So it looks like to about 2016 we peak, where we've got about, I don't know, I'm going to estimate, 10 terawatt hours on a total of just shy of 160 terawatt hours that appears to be surplus. Have I got that right?

MR. CHERNICK: Round it off to the closest 10 terawatt hours? I think that's about right.

MS. DeMARCO: So I'm no mathematician, but ten on 106 is nowhere near 50 percent, as far as I calculate; is that right?

MR. CHERNICK: There are no hours in this graph, so you can't do the calculation you are trying to do.

MS. DeMARCO: Well, certainly if we had total available base load generation in around much higher than the available primary demand, we'd expect that to be closer to 50 percent. Would you say this is 50 percent?

MR. CHERNICK: You can't tell.

MS. DeMARCO: You can't tell at all based on --

MR. CHERNICK: I mean, you know, there have to be times when it's higher than primary demand. But above primary demand there is also exports, so there's -- before you get to surplus base load generation it starts spilling water.

If you look at the right-hand graph, where they add in the gas, you see they are running gas a lot as well. So there are times when base load is well below the primary demand line and there are times when it must be much above, and the question is, how many hours is above, how many hours is below. And you can't tell that from this kind of graph. This graph is telling you the total amount of energy that they are expecting in various categories in a year, not how many hours are going to be high and how many hours are going to be low.

MS. DeMARCO: On an annual basis, roughly, it doesn't look like there are many hours where they're in fact --

MR. CHERNICK: I don't know.

MS. DeMARCO: Doesn't look like there are many -- or an annual basis, terawatt hours.

MR. CHERNICK: You can't tell that by looking at this. I mean, that's like saying, you know, if somebody fires two arrows, one three feet to the right of you and one three feet to left, on average you're dead. That's what you can tell from this, is when you're on average you're dead. It doesn't tell you anything about the real world. If somebody fires one three feet to the left and one right in your forehead, then on average you are fine, but that's not much satisfaction. So what I'm telling you is you're looking at the wrong graph.

MS. DeMARCO: Let's go to the graph you looked at. Let's go to pages -- I believe it is 26 and 27 that you looked at.

Can you explain to me where on here it says on average SPG is 50 percent?

MR. CHERNICK: Well, your eyes might be different than my eyes. If you want to eyeball that top left-hand graph and tell me that surplus base load generation is much lower than 50 percent, or much higher than 50 percent of the hours -- who knows; you might be right. To me, it looks like it's about half the hours.

MS. DeMARCO: So --

MR. CHERNICK: That's all I can tell you.

MS. DeMARCO: Just so I'm clear, nowhere on this slide does it say that SPG is 50 percent?

MR. CHERNICK: And I think as I said earlier, I wish I had the data that Mr. Boland used in this analysis.

MS. DeMARCO: And similarly, on slide 27, that I believe you also quote, we don't see anything that says that SBG is 50 percent; is that right?

MR. CHERNICK: No, what I used 27 for is to say by 2020, the SBG is basically de minimis.

MS. DeMARCO: In fact, OPG says exactly that. It peaks in 2016 and then it's effectively de minimis.

MR. CHERNICK: Right, and that's why didn't use the 2016 -- my interpretation of that 2016 graph by itself.

MS. DeMARCO: Okay, great. Going back to the interrogatory now to number 3, this is 5(a) sub (iii) in terms of your response. You assume that the avoided emissions are at zero when Ontario is spilling water. Can you just explain that to me?

MR. CHERNICK: Well, I'm trying to figure out how it could be not true. Using water to turn a hydro turbine rather than spilling it over a spillway doesn't generate any carbon emissions.

So, if all that your DSM is doing, your -- for electric, I guess it's called CDM, and if all that you are doing is spilling water, then you're not reducing any emissions.

MS. DeMARCO: Wouldn't you need to know what was going on with renewables in the province to make that conclusion definitively?

MR. CHERNICK: Are you stepping away from looking at what's happening in that hour to what's happening over the course of years, as projects are -- economics are evaluated, and they're ordered and built and so on? Or -- I don't understand the connection otherwise.

MS. DeMARCO: It would be both in that hour. To make that assertion definitively, wouldn't you need to know what was going on with all power generation sources in the province to make that conclusion definitively in that hour?

And secondarily, wouldn't you need to assess, in the broader assertion, as to what's going on at a macro level?

MR. CHERNICK: I don't see why. If I'm missing something, feel free to guide me in the direction of enlightenment. But I just don't see how you are avoiding any carbon emissions if the effect of reducing load in an hour is to spill water.

MS. DeMARCO: What if we have a very high wind day --

MR. CHERNICK: Uh-hmm.

MS. DeMARCO: -- and we have a significant portion of the provincial power coming from wind and solar? Wouldn't we be avoiding emissions in the province?

MR. CHERNICK: Yes, the wind may be avoiding emissions from gas -- would be avoiding emissions from gas. And then it may get down to the point where, at the margin, the wind is just spilling water and it is not avoiding any emissions.

So the first -- some number of megawatts of wind may be avoiding gas, and then you're avoiding water.

MS. DeMARCO: So, in fact, the renewables are decreasing avoided emissions in the province?

MR. CHERNICK: Yes. What's at the margin goes down as you add more non-emitting base load.

MS. DeMARCO: Thank you. Can I ask you to turn to 5(b), and very specifically around the assumed emission factor under using 480 kilograms per megawatt-hour, and an average of 335 kilograms per megawatt-hour; is that fair?

MR. CHERNICK: Yes.

MS. DeMARCO: And again, those numbers are not based on actual IESO or MOECC data of actual emissions; is that right?

MR. CHERNICK: That's correct.

MS. DeMARCO: Thank you.

MR. CHERNICK: The closest I have to an actual there is that the 53.1 kilograms per million BTU of gas burned, 53.1 kilograms of CO_2 per MMBTU gas burned is typical of -- for actual composition in actual gas.

MS. DeMARCO: That's a U.S. value from EIA, is that correct?

MR. CHERNICK: I think somebody -- yes, here I cite EIA. But I've looked at other sources and they're very similar.

MS. DeMARCO: Would you provide those sources, please, all of them? Could I have an undertaking, please? And the undertaking request is to provide any and all additional sources that Mr. Chernick looked at to substantiate the 53.1 kilograms per MMBTU value that he cites the EIA report for.

MR. MILLAR: That's JT3.2.

UNDERTAKING NO. JT3.2: GEC TO PROVIDE ANY AND ALL ADDITIONAL SOURCES THAT MR. CHERNICK LOOKED AT TO SUBSTANTIATE THE 53.1 KILOGRAMS PER MMBTU VALUE THAT HE CITES THE EIA REPORT FOR

MS. DeMARCO: I'm going to ask you to turn to APPrO 6, please, and that is, just for the record, Exhibit M.GEC.APPrO.6.

MR. CHERNICK: I have that.

MS. DeMARCO: The point you're making here is that current prices are assumed to decrease by about 1 to 3 percent for a 1 percent decrease in U.S. gas consumption. That pricing assertion was based on data for what period, what year period?

MR. CHERNICK: I think it was the early 2000s, for the most part.

MS. DeMARCO: Does that come from the 2004 report that you cite later on, and provided in the IR response? That's the ACEE Wiser Report, is that right?

MR. CHERNICK: That's correct.

MS. DeMARCO: And that report was in 2004?

MR. CHERNICK: Yes, and the studies were from 1998 through 2004.

MS. DeMARCO: Has anything changed in the gas industry between 1998 and the current day?

MR. CHERNICK: A lot of things have changed.

MS. DeMARCO: Like what? What are some of the big major changes?

MR. CHERNICK: Let's see. The U.S. has gone from -- and North America have gone from the anticipation of significant LNG imports to the anticipation of possibly significant LNG exports; the shale gas development has reduced forecasts for gas prices.

In terms of what was expected in the say, 2000 or 2003 compared to what's expected today, I don't know. I'd have to go back and look at contemporaneous documents to really try to do a thorough job.

I don't think any of these studies anticipated the great recession. A lot of things have changed.

MS. DeMARCO: Particularly in terms of the gas predictions and the demand and supply forecast for the period.

MR. CHERNICK: Yes, and that's certainly one reason why I didn't use these values in my analysis.

MS. DeMARCO: Fair to say that gas supply predictions in 1998 would be radically outdated in 2014, 2015?

MR. CHERNICK: Well, they certainly would be very old. I'd have to go back and look at what was being projected back then, because there was a -- after that, there was a spike when we expected gas prices to go up very quickly, and then that turned around, and so certainly the forecasts from 2006 or 2007 are outdated. Those from some earlier period of time have probably come back into fashion.

It's rather like clothing styles, that you can usually go back and find some forecast from -- or even a set of forecasts from some previous year that look like they really nailed it for this year, even though it was 15 or 20 years ago. Of course, they may have been wrong for every year in between but -- so depending on what you mean by outdated.

MS. DeMARCO: So just fair to say when that 2004 study was published, gas was expected to increase in price; imports were expected to increase, and we're in a very different gas position now, where gas prices are, all things being equal, relatively low, and the U.S. and, in fact, North America is a net gas exporter; fair to say?

MR. CHERNICK: I don't know whether we're a net gas exporter yet, but that is certainly expected in the next -- within the next five years.

MS. DeMARCO: So in 2004 a number of LNG import projects were planned, 2014-15, almost an equal number, or a very significant number of LNG export projects planned; is that fair?

MR. CHERNICK: That's fair.

MS. DeMARCO: Thanks. Can I ask you a question about demand elasticity? This is in relation to (e). Is weather a relevant factor in natural gas demand elasticity calculations?

MR. CHERNICK: Well, you want to -- if you are trying to forecast demand at particular weather conditions at particular prices, then obviously you have to take both price and weather into account.

MS. DeMARCO: So weather would be a factor you'd want to consider?

MR. CHERNICK: If you were looking at data across a range of weather conditions, then you'd want to normalize or correct for those in one way or another before you estimated the response to price.

MS. DeMARCO: So fair to say, in a colder climate you expect weather to be a relevant factor in demand elasticity calculations?

MR. CHERNICK: Well, I think you want to take it into account, wherever you are, that -- I mean, depending upon your situation, it may be taken care of for you. For example, if you're looking at modelled data for the future, and it's the -- the models are all assuming the same weather patterns, and you're just looking at different demand conditions in terms of more nuclear being built or more LNG being exported or whatever, then --

MS. DeMARCO: Just to be clear --

MR. CHERNICK: -- you don't have to adjust for weather, because that's a constant, across the annual values. If you're looking at daily data or weekly data within -- over a relatively short period of time, consumers may not be seeing much in the way of price other than the big gas customers who are buying on a spot basis. And in that case, it may be very hard to see any price effect. It is much easier to see a weather effect. It depends on what data you are using and what you're trying to do with it.

MS. DeMARCO: So not so elastic, or at least apparently not so elastic in those situations?

MR. CHERNICK: I don't know -- I don't think what you just said is a summary of what I just said. Oh, in terms of if you're going from day to day, you can't see much consumer price reaction. If the price at Dawn jumps from $4 to $12, say, from one week to the next, there are generators who may reduce their usage. There are some large industrials who may switch over to oil if gas has gotten expensive enough. Various things may happen, but for the residential and bulk of commercial customers, they're not going to respond to that price because they're seeing a monthly price that was posted previously, and if the utilities wind up paying more for the gas now, they'll be paying for it at quarter, the customers will wind up paying for it next quarter or next year.

MS. DeMARCO: Just real simple, if it was minus 28 in the middle of February like it was this year, I'm going to turn up my heat regardless of what the price is; is that fair?

MR. CHERNICK: Yes, and the price on that day is not going to affect your decision, because you're going to be charged some average price for the shortfall between what the -- what your gas utility built into your rates and what they actually wind up paying. You are going to wind up paying that at some point in the future, but regardless of whether you were using gas or not, they're going to be doing it on a system-wide basis.

MS. DeMARCO: Great, thank you. In relation to 5(e), we asked a specific question around how load reductions and de-contracting actually affected the cost of gas transportation in Canada, along the TCPL mainline roads. And I really wanted to get your assessment of what happened in two actual cases.

Can you tell me what happened to the price of transportation as a result of decreased demand?

MR. CHERNICK: I haven't reviewed those dockets, and you didn't provide me anything other than the case numbers, and so I answered the part that I could, without doing a lot of additional research.

MS. DeMARCO: So those are publicly available, and I would have assumed your counsel had them. But your answer was load reductions reduce the cost of transportation on the TCPL mainline. Do you know if that's what happened in those two cases?

MR. CHERNICK: It's hard to see how a load reduction would increase the cost, but I would -- like I say, I haven't looked at those two cases, so I couldn't tell you.

MR. POCH: Can we just, in terms of terminology, can we just be clear? Mr. Chernick in his response was distinguishing between what happens to tolls and rates versus what happens to costs, and I just want to be sure we understand what the question is about here.

MR. CHERNICK: I'm talking about the cost in terms of the millions of dollars of revenue requirements to be collected from tariff customers.

MS. DeMARCO: So --

MR. CHERNICK: Not the dollars per cubic metre.

MS. DeMARCO: So the totals -- the cost to customers, would it surprise you to hear that they increased quite dramatically as a function of load reductions along the TCPL mainline?

MR. CHERNICK: That what increased?

MS. DeMARCO: The tolls.

MR. CHERNICK: Oh. And I say that, don't I?

MS. DeMARCO: Not directly.

MR. CHERNICK: In some circumstances reductions in throughput result in higher rates, as largely fixed costs are spread over lower sales.

MS. DeMARCO: So in these two cases that we've asked you to refer to, would it surprise you to hear that tolls increased quite dramatically as a function of decontracting?

MR. CHERNICK: I'm not prepared to categorize that. It wouldn't surprise me that TCPL's tolls would have increased, because I understand that their throughput has decreased as eastern Canada consumers have switched more to using U.S. gas.

MS. DeMARCO: I'm going to ask you to move on to IR No. 7, and very specifically sub (b). This was in relation to the point of regulation for carbon pricing.

Can you confirm for me that large industrial -- you refer in your response to California and specifically, it's very likely that some large emitters will be included as regulated emitters in a carbon pricing regime.

Can you confirm for me in California that in fact large industrials are included as directly capped entities in their carbon trading regime?

MR. CHERNICK: That's my understanding, yes.

MS. DeMARCO: Similarly, can you confirm for me that power generators are directly included in the scope of regulation as part of the California carbon trading regime?

MR. CHERNICK: Yes, I thought that they would be a category -- a sub-category of the group that we were just talking about, large consumers of gas above some level, and I don't have that level to hand at the moment.

MS. DeMARCO: So --

MR. CHERNICK: And that's also been proposed by the Ontario government, and I direct your attention to the IGUA response that the -- attachment to that, that lays out the government's thinking about the proposal.

MR. POCH: Just for the record, I think you're referring to M.GEC.IGUA.1, attachment 1; is that correct?

MS. DeMARCO: I was actually -- sorry, Mr. Chernick was referring to that?

MR. CHERNICK: Yes, that's what I was referring to, and it's referred to in the response that we're talking about here.

MS. DeMARCO: Right, and it's the response that I'd like to stay focused on. So instead of it being a charge on gas use indirectly in California, it's a charge on emissions directly; is that fair?

MR. CHERNICK: Well, the way that emissions are calculated in many cases is on the basis of the amount of gas used.

So, there's -- I'm not quite sure there's a real meaningful distinction between the two things you laid out.

I don't know whether they use smokestack emissions monitors to try and measure the CO2 emissions from large boilers, and turbines, and power plants, or whether they just calculate that based on the gas going in.

MS. DeMARCO: So fair to say that the regulation doesn't regulate gas use. The exact terms of the regulation are CO2 emissions; is that fair?

MR. CHERNICK: Well, the purpose is to regulate the -- we're talking here about the large customers, not smaller ones who are charged allowances, allowance costs through the utility.

But for the large customers, the objective is to determine how much gas -- excuse me, how much greenhouse gas they're emitting, how much CO2 they are emitting. And as I said, I think -- in many cases, anyway, that's estimated based on how much gas you're burning, how much oil you're burning, how much whatever else you're burning times emission rates and added up.

So the purpose is to cap carbon and assess implicitly a cost for using more carbon, or to reward for emitting less carbon. But it's essentially equivalent to a charge on the amount of gas you use, and another charge on the amount of oil you use, and so on.

MS. DeMARCO: Just so I'm crystal clear on this point, the point of regulation is the carbon emissions?

MR. CHERNICK: Yes.

MS. DeMARCO: Thank you. On to (c); you talk a little bit about Ontario's recent joining of WCI and 2008, you indicate, was the date of Ontario joining WCI; is that correct?

MR. CHERNICK: Yes, if I said recent --

MS. DeMARCO: You did.

MR. CHERNICK: That was not my intention. It is my understanding that the government has recently said that they are going to coordinate with the cap and trade systems that are already in place in the WCI.

They've been members for quite a few years.

MS. DeMARCO: So at page -- I'll find the pinpoint reference, but it is within the reference of 18-25, and we'll get the pinpoint reference where you say that Ontario recently joined the WCI.

There is a clarification in that they didn't recently join, in your view? Eight years or seven years a long time.

MR. CHERNICK: No, they recently announced an intention to join the trading scheme, and I'm sorry if I garbed that sentence.

MS. DeMARCO: Okay. Moving on to your response in 7(d), which refers to Mr. Neme's response in APPrO 4(g), you use a $20 carbon price generally to support your calculations; is that fair?

MR. CHERNICK: As a starting price, yes.

MS. DeMARCO: Yes.

MR. CHERNICK: Twenty dollars U.S., yes.

MS. DeMARCO: In terms of the actual prices and the actual forward prices that are predicted out to 2018, the most recent is $12 U.S.; is that fair?

If I could just -- while you're doing that, for the veracity of the record, the reference I made to recently joining is page 18 of Mr. Chernick's evidence.

MR. POCH: Just while we're at it, and Mr. Chernick, in APPrO 7, specifically says 2008. Just so that the record is clear, that's when they joined western coalition and he acknowledges that there.

And I believe -- I'll try to find you the cite -- we actually have the press release announcing Ontario linking -- its intention to link with Quebec and California. I'll see if I can find you that cite.

MS. DeMARCO: The point of reference there is that the joining is not recent, as Mr. Chernick has acknowledged.

MR. CHERNICK: Yes, and you're correct that that sentence did get garbled in my -- in getting it into press; my apologies. Have I answered whatever your last question was?

MS. DeMARCO: No, we were talking about carbon pricing.

MR. CHERNICK: Oh, okay, yes.

MS. DeMARCO: And you had used $20. I'm referring to APPrO 4(g) and I'm just looking at, in terms of WCI itself, and current prices are --

MR. CHERNICK: Right, about $15 for 2018. Yes.

MS. DeMARCO: Sorry, we're talking U.S. dollars?

MR. CHERNICK: Oh, U.S. dollars --

MS. DeMARCO: About $12.29; is that fair?

MR. CHERNICK: The last auction.

MS. DeMARCO: And that's a joint auction. That's an auction of California and Quebec?

MR. CHERNICK: That's correct.

MS. DeMARCO: It's a pretty indicative carbon price.

MR. CHERNICK: It indicates what the market was expecting for the California and Quebec joint market.

MS. DeMARCO: As you said, that's the exact market that Ontario is about to join, as clarified by your counsel; is that right?

MR. CHERNICK: Yes, although meeting Ontario's goals will require that a large number of -- large reductions, which may drive up the demand for allowances and drive down -- drive up the price as well.

MS. DeMARCO: Do you think Ontario is going to be in that system before 2018?

MR. CHERNICK: Could be in by 2017, could be 2018.

MS. DeMARCO: So let's look at the price in 2018, the actual carbon price that you've reported here.

We've got a U.S. price of $12.10; is that right?

MR. CHERNICK: That's correct, but again, not for the market including Ontario. This is for Quebec and California. Once Ontario joins, that's going to change the supply demand balance.

MS. DeMARCO: So to the extent that it is a future 2018 vintage price and parties were bidding into that auction with the knowledge that Ontario's joining, fair to say that the price should reflect that knowledge?

MR. CHERNICK: If the parties expected Ontario to be in and to be aiming for the size of reductions that we're talking about, then that should include that information. It doesn't show much of an --

MS. DeMARCO: Okay, and so the Canadian price there --

MR. CHERNICK: And doesn't show much increase compared to earlier auctions before the -- before Ontario opted in.

MS. DeMARCO: In fact, it's a decrease. If we look at the February 2015 price, which was 15.01 for 2018 future vintages, and we look at the May 2015 price of 14.78 for 2018 vintages, that is a decrease, isn't it?

MR. CHERNICK: Yeah, I think that may be due to the changing exchange rate on that day, because the -- there are some sort of coordinated bidding system in U.S. and Canadian dollars, and the higher of the two prices is converted to the other currency, so if the U.S. price set the auction price for both of those auctions and the exchange rate was different, then you'd wind up with a different Canadian price.

MS. DeMARCO: Can you undertake to provide us with some evidence that that price decrease for the forward 2018 vintages was as a result of exchange rate differentials?

MR. CHERNICK: Okay. First of all, I said that may be the case. It may be that it was actually the same in U.S. dollars and it was different in Canadian dollars due to the exchange rate. And I can check, and I believe -- I either provided the documents or links to the documents as part of my discovery responses, and I can check and see whether the description is detailed enough to know whether it was the Canadian or U.S. price that was binding.

MS. DeMARCO: I apologize if I've missed it, Mr. Chernick, but I didn't -- I don't recall seeing anything around the causation of that price drop being the exchange rate, but we had asked for exchange rates quite specifically, and you would agree that exchange rates may, in fact, be relevant to pricing?

MR. CHERNICK: Yes.

MS. DeMARCO: Thank you.

MR. CHERNICK: For gas and carbon allowances.

MS. DeMARCO: Okay. And can I take you now to the Régie numbers, which is a contiguous power market, at least, in terms of the North American-northeast power markets. Carbon prices there again, fair to say, nowhere near $20 a tonne?

MR. CHERNICK: That's correct.

MS. DeMARCO: In fact, right now we're maxing out at $5.50 a tonne in the most recent auction in June of this year?

MR. CHERNICK: That's correct.

MS. DeMARCO: Can we talk about some big changes in your jurisdiction, in the U.S., around the Clean Power plan, and this is -- the reference is (e) -- that's APPrO IR 7(e).

You've made no assumptions on the Clean Power plan impact on carbon pricing in the U.S.; is that fair?

MR. CHERNICK: 7(e)?

MS. DeMARCO: That's right.

MR. CHERNICK: Oh, I'm sorry, I was looking at the wrong response. Hang on a second.

Yes. That's correct.

MS. DeMARCO: And specifically no assumptions around the supply demand economics of carbon allowances in relation to changes that may result from the Clean Power plan?

MR. CHERNICK: That's correct. I haven't tried to do that analysis.

MS. DeMARCO: Thank you. And --

MR. CHERNICK: Which would require knowing what was in the minds of the bidders in May in terms of what they expected from the Clean Power plan.

MS. DeMARCO: Certainly the U.S. impact statement surrounding the regulation does some estimates. They make some...

MR. CHERNICK: Estimating the effect on the California allowance price?

MS. DeMARCO: On potential compliance prices, carbon pricing generally.

MR. CHERNICK: Yes, there is some -- there is an analysis of potential prices by state, assuming various kinds of responses.

MS. DeMARCO: Thank you. Moving on to (f) in relation to the associated emission factor. You are using 1.89 kilogram per metre cubed, and we understand that you've taken that from the rough calculation estimate associated with the reporting regulation in Ontario; is that fair?

MR. CHERNICK: Well, it is consistent with that. I don't actually recall where I first found the 1.89. I think I may have actually calculated it from other -- an emission factor in U.S. units or per gigajoule and done some conversions, but the 1.89 seems to be pretty typical.

MS. DeMARCO: Potentially a U.S. emission factor converted for presumed application to Canada?

MR. CHERNICK: Well, that may be where I initially got it, but as I point out, the Ontario regulations assume the same value, and given that Canadian gas flows to the U.S.

and U.S. gas flows to Canada, there are obviously differences depending on exactly where you are and when you are in the molecular composition of natural gas, but whether it's, you know, 1.87 or 1.92, it's around the 1.89.

MS. DeMARCO: So the actual number would be a function of the precise molecular nature of the gas that was being flowed. Fair?

MR. CHERNICK: Yes.

MS. DeMARCO: Thank you. We talked about the currency rate generally. We've established that it's a relevant factor. In terms of the metric tonne assessment, I missed this in terms of your -- this is in (h). All of your carbon prices and costs in -- are in metric tonnes as opposed to U.S. tons. Can you just confirm that that's the case? Because I understood it to be in t-o-n-s, as opposed to being t-o-n-n-e-s, and it could be my oversight and --

MR. CHERNICK: Well, and it may have been my oversight in leaving an n-e out of "tonnes" in one application or another.

I believe the Synapse values are in short tons. I convert those to metric tonnes. I --

MS. DeMARCO: What conversion factor did you use?

MR. CHERNICK: How about if we just make that an undertaking rather than --

MS. DeMARCO: That would be great. Thank you.

MR. MILLAR: That's JT3.3.

MS. DeMARCO: And the undertaking is to provide the actual conversion factor used from the Synapse short tons to metric tonnes.

UNDERTAKING NO. JT3.3: GEC TO PROVIDE THE ACTUAL CONVERSION FACTOR USED FROM THE SYNAPSE SHORT TONS TO METRIC TONNES.

MS. DeMARCO: I believe those are my questions. Thank you, Mr. Chernick.

MR. MILLAR: Thank you, Ms. DeMarco.

I think the last party in the room, other than the utilities, to have questions is in fact Board Staff. Takis Plagiannakos has joined to us ask the questions on behalf of Staff.

Mr. Plagiannakos, although I find it easy to spell, maybe to begin, you could just spell your name out so the court reporter has that, and then you can get right into your questions.

QUESTIONS BY MR. PLAGIANNAKOS:

MR. PLAGIANNAKOS: Thank you, Mr. Millar. It's T-A-K-I-S P-L-A-G-I-A-N-N-A-K-O-S. I'm the manager of energy conservation and operational policies at OEB and, Mr. Chernick, I have a few questions, and I will start with page 13 of your submission.

I have some high-level questions to I can understand better the model -- the U.S. model that has -- you have used the results from.

Please confirm that this is a national energy model of the U.S. economy that models the energy-economy kind of relationship and the impacts of supply of resources on gas prices, and all types of energy prices, but basically is a greenhouse-based initial design for a -- for a real-estate developer, so it's --

MR. BUONAGURO: Experience pending?

MR. YOUNG: Yeah, but, you know, we are going through the sort of load calculations literally as we speak, so...

MR. BUONAGURO: Now, back to how I started, for combined heat and power in particular -- and I'm looking specifically, obviously, with this sort of greenhouse type application where we have material natural gas uses to generate heat and the opportunity to generate electricity at the same time.

Did you identify, when you were viewing Enbridge and Union's proposed DSM plans, did you identify any structural elements in the guidelines that govern them or prevent that type of application from being in the DSM program that they can deliver?

MR. YOUNG: Not that I can point to specifically. I think that -- so in general, no, not that I see specifically, that they are supporting CHP as a tool, so...

MR. BUONAGURO: Thank you, those are my questions.

MR. MILLAR: Thank you, Mr. Buonaguro.

Ms. DeMarco, it looks like you are next.

QUESTIONS BY MS. DEMARCO:

MS. DeMARCO: Thank you very much. I just wanted to make sure I was clear on the characterization that your counsel provided of your evidence. Specifically, she's indicated that you are giving a high-level conceptual overview of the framework for DSM; do I have that right?

MR. YOUNG: The scope of the work was to talk to -- the engagement was to talk to sustainable technologies as it relates to DSM, as opposed to a DSM program, per se.

MS. DeMARCO: Okay, so I'm just -- I'm at odds understanding how to reconcile that with paragraphs 2 and 4 of your evidence, specifically at paragraph 4, which is at page 2. It indicates that you have been asked by OSEA to provide expert opinion on sustainable energy opportunities that natural gas utilities can incorporate into their demand-side management plans. I understood that to be the first task, and the second one to address some of the barriers that prevent action on conservation and greenhouse gas introduction. Have I got that right?

MR. YOUNG: That's as stated in the evidence, yes.

MS. DeMARCO: So you are providing expert opinions on opportunities for natural gas utilities to incorporate into their DSM, and talking about two types of barriers: conservation-related barriers and greenhouse gas -- and the short auction barriers.

MR. YOUNG: Okay.

MS. DeMARCO: So if I can take you -- and the vast majority my questions are simply clarifications in relation to the APPrO responses. So the specific references, if you want to turn them up, are predominantly M.OSEA.APPrO, and I believe they run IRs 1 through 7.

MR. YOUNG: Okay.

MS. DeMARCO: So in relation to APPrO IR number 1, sub (a), you had indicated that you are discussing this from

the position of your own experience in developing combined heat and power projects in Ontario. That's fair?
I'm not sure if I said projects or technologies.
MS. DeMARCO: We can look that up, if you want. I'm happy to provide the specific reference. It would be paragraphs 2 and 4, I think, where it was originally said. "“Development and implementation of biogas and CHP projects” was the exact term. Is that fair? Do I have that right?
MR. YOUNG: We can talk about that, yes. I initially thought it was including technologies that I'm developing as well.
MS. DeMARCO: So you both developed CHP projects and technology?
MR. YOUNG: Biogas projects and CHP technologies, to be specific.
MS. DeMARCO: Just so I'm clear on that, you've got biogas and CHP projects in Ontario. But what I understand to be the clarification, just if I've got this right, is biogas projects --
MR. YOUNG: Yes.
MS. DeMARCO: -- and CHP technology.
MR. YOUNG: So a biogas project could be a CHP application on a farm site, that sort of thing. So I mean it's -- my reference in scope, I think, is more related more related to scale.
When it comes to technologies, I'm developing sort of business building scale technology, so under 1 megawatt CHP

technology as opposed to an industrial CHP project -- a fairly big distinction. So, I just -- I think that may help frame the conversation a little bit better.

MS. DeMARCO: Okay, biogas projects, CHP projects less than 1 megawatt, and --

MR. YOUNG: I could care less about the size per se. The technology itself ranges from -- right now, the design is 30 kilowatts up to 1 megawatt.

MS. DeMARCO: So those are the type types of CHP projects?

MR. YOUNG: Technology.

MS. DeMARCO: Technologies. So you haven't worked on CHP projects?

MR. YOUNG: I've developed early stage biogas CHP projects, yes, that were unsuccessful in fit applications, but pre-feasibility and a number of energy balances along the way.

Those biogas projects were for a consortium of 70 farmers in Ontario, who were denied the right to connect.

MS. DeMARCO: I'm trying to understand that in the context of this expert evidence, which is very much in the context of CHP and how that plays into the specific evidence.

Can I ask you just to turn to your CV broadly, just to make sure I've got that right?

And thank you for that clarification. I think the technology project clarification is sort of difficult for me to get my head wrapped around. It could be the late stage in the afternoon.

So I'm at Exhibit A, and specifically you are experienced in energy management and environmental services. Is it fair to say that most is in business development for renewable energy?

MR. YOUNG: Business development, project financing, developing business teams in renewable energy, yes.

MS. DeMARCO: And so about the most recently two-and-a-half years for biogas technology, or project development?

MR. YOUNG: Project development.

MS. DeMARCO: Okay, so biogas project development.

MR. YOUNG: Yes.

MS. DeMARCO: And there is specific reference there to 33.6 megawatt; is that a biogas project?

MR. YOUNG: No, that's a solar project.

MS. DeMARCO: So that's a renewable energy project?

MR. YOUNG: That's an operating solar project, yes.

MS. DeMARCO: And it is not CHP, and it is not biogas.

MR. YOUNG: No.

MS. DeMARCO: Okay, and then about nine months as a financial consultant for solar; is that right?

MR. YOUNG: Correct.

MS. DeMARCO: And then two-and-a-half years for a solar EPC and work, s that right?

MR. YOUNG: Yes.

MS. DeMARCO: That's Infinity, and then about 11 months for the launch of a solar development company.

MR. YOUNG: Yes.

MS. DeMARCO: And then about six years in various positions with various software companies; is that right?

MR. YOUNG: Yes.

MS. DeMARCO: So with those software companies, your CV seems to indicate they have nothing to do with power or the environment.

MR. YOUNG: No, not at all.

MS. DeMARCO: And then prior to that, there was six years in hazardous waste incineration type work; is that fair?

MR. YOUNG: Correct, environmental management.

MS. DeMARCO: Again, nothing to do with power or environment?

MR. YOUNG: Correct.

MS. DeMARCO: And then prior to that, about six years for lighting-related mercury waste; is that --

MR. YOUNG: Those were combined companies that we serviced, most of the financial institutions and the banks under government-regulated programs that we developed for those institutions.

MS. DeMARCO: Okay, so that was not power development; that was very specific?

MR. YOUNG: No, it was not power development. What you've missed in the last -- in the past year, through the course of the sort of technology development is that partnered with an engineer in Ottawa, we are developing a company called Stoked Power Generation that is a participant in the sustainable development, technology

Canada, natural-gas incubation program. We've got a lot of interest from governments around the world for our design and our approach to CHP.

MS. DeMARCO: I had misunderstood that to be part of the last two-and-a-half years of biogas technology development that we chatted about, from September --

MR. YOUNG: Correct. They were two different strains of activities, I would say.

MS. DeMARCO: So that's really around the tech development of certain applications for biogas?

MR. YOUNG: Lines get blurred when it comes to sort of trying to find the proper solution for CHP.

So we started off as project developers -- or I started off as a project developer in CHP, sourcing equipment, looking at financing, finding project hosts and facilities and putting those projects together.

It was clear there was a need for technology and innovation, and I've partnered with a company now to make those innovations come to life, so that's what we're doing.

It is design work of combined heat and power engines.

MS. DeMARCO: That's in relation to the Stoked Power?

MR. YOUNG: Correct.

MS. DeMARCO: The last two-and-a-half years. It started off as a biogas CHP project, and it moved into the technology space.

MR. YOUNG: The activities that I undertook were biogas, yes.

MS. DeMARCO: Okay. Great. Thank you.

Just in terms of educational background to support that as well, I see that -- I'm reading from the last lines of Exhibit A of your evidence -- that your background is in social science; is that right?

MR. YOUNG: That is correct.

MS. DeMARCO: And the bulk of your relevant courses listed appear to be around business marketing, promotional management, business law, and service marketing?

MR. YOUNG: Service marketing, natural resource management, environmental impact assessment.

MS. DeMARCO: Those are the two relevant courses to the environment, but the rest appear to be business marketing, promotion, business law, service --

MR. YOUNG: Correct. General -- I'm not an engineer, don't pretend to be.

MS. DeMARCO: Great, so in relation very specifically to expertise in and around natural gas, I don't see any listed, and I'm sorry if I haven't reviewed in enough detail.

MR. YOUNG: Expertise within natural gas as opposed to project development, project financings. I don't think I need to know how a natural gas system works per se for this endeavour. I --

MS. DeMARCO: You don't think you need to know how a natural gas system works to provide expert evidence in...

MR. YOUNG: I think the scope of the conversation that I prepared is what are some of the options around sustainable technologies and sustainability options, and I think that I have a fair amount of educational experience and real-world experience in that area.

MS. DeMARCO: Just so I've got that right, the scope that you've provided is technology options and sustainability options; is that right?

MR. YOUNG: The scope is to look at the opportunities for sustainability options, and, you know, and having training in environmental impact assessment and natural resource management has led me into a number of areas over my career that I think are germane to the conversation.

MS. DeMARCO: Okay, just so that I'm crystal-clear on that point, I thought we were pretty clear that the scope was sustainable opportunities that natural-gas utilities can incorporate into their demand-side management plans.

MR. YOUNG: Sure.

MS. DeMARCO: Okay. I also -- I didn't specifically see any expertise listed in relation to sustainability. I'm sure you've probably got it characterized differently on your CV, so if you can just point me to what would be expertise in around sustainability.

MR. YOUNG: I'm a former board member of the Ontario Sustainable Energy Association. I've appeared in front of the government of -- Senate of Canada Natural Resources Committee.

MS. DeMARCO: On sustainability?

MR. YOUNG: On solar energy, which I would suggest is a sustainability matter, yes.

MS. DeMARCO: And specifically previous experience around energy opportunities for natural-gas utilities, any specific expertise there?

MR. YOUNG: Aside from general energy conservation measures, no.

MS. DeMARCO: And any specific expertise in and around natural-gas demand-side management specifically?

MR. YOUNG: Aside from establishing programs within property management firms for energy conservation when I was out of university, no.

MS. DeMARCO: And specific expertise in identification or quantification of barriers to energy conservation?

MR. YOUNG: Experience being one, I guess through OSEA primarily as a board member hearing, I guess, experiences of members and consumers.

So I speak to building owners all the time, and I hear their stories, and so I understand exactly where they're coming from, and I look for the technologies to solve those problems.

MS. DeMARCO: So it would be largely anecdotal experience in and around what you've --

MR. YOUNG: No, review -- well, if you are reviewing somebody's operational costs and finding appropriate technologies to reduce those costs for them, I don't think that's anecdotal.

MS. DeMARCO: So is that the opportunity side or is that the barrier side?

MR. YOUNG: That would be an opportunity.

MS. DeMARCO: Okay, so specific to barriers, any expertise relevant to both identification and quantification of the barriers?

MR. YOUNG: Experience being -- sorry, I think I'm having a hard time, because the notion that you're suggesting one has to be an expert in barriers to programs is kind of troublesome, because there are many people who experience these barriers all the time. They may be anecdotal, but nonetheless they exist. So --

MS. DeMARCO: Just to be clear, I'm referring specifically to your scope of work, which was, you are being qualified as an expert.

MR. YOUNG: Agreed, but my experience has been walking through some of these programs, either myself or with building owners as clients, so that is, you know, trial by fire, more or less.

MS. DeMARCO: Similarly in relation to barriers to achieving greenhouse gas reductions, specific expertise there?

MR. YOUNG: So when I look at solutions, I look at them as being the opportunity. I'm going to say no. Just leave it at that.

MS. DeMARCO: Okay, sustainable energy opportunities relating to integrating gas DSM and electricity CDM, specific expertise there?

MR. YOUNG: I have -- as I mentioned earlier, I've done energy conservation programs for commercial buildings in the past.

MS. DeMARCO: And so that's in relation to the integration of gas demand-side management and electricity conservation and demand management as those two terms are defined?

MR. YOUNG: The experience I've had has been actually implementing these approaches on the ground and doing them, and so it's -- part of the challenge I have, if you don't mind indulging me for a moment, part of the problem I have is the utilities are in this province operating in a silo, and, you know, not being integrated leads to these kind of conversations, as opposed to looking at energy as, you know, what it is, and it's a cost for businesses. It is a cost for citizens. And there are technologies that are widely available that can be deployed and should be deployed.

Instead we're having conversations as to: Is there a barrier? Do I have the right to connect, you know, as a building owner? There is a lot of people in this province that are screaming to generate their own electricity, and there are forces that don't want that to happen, and so I'll just leave it at that. We need to have a broader conversation on energy and what the purpose is and have a common goal.

MS. DeMARCO: I certainly read that directly in your evidence, and understand that to be your point, but it is really specific to the expertise relating to providing those services, the integration of gas DSM and electricity CDM, and if you can point me to something very specific that you've done --

MR. YOUNG: Sure. Sure, and if you don't mind, being able to engage, you know, a service company, you know, to put a financing framework around it and engage a program, I've done that for about $145 million in one case.

So, you know, it's a case of we can have these conversations around specific minutiae of programs, and it's difficult for, I think, most building owners to get around the fact that there are options for them, and they either don't do them because of the red tape which is really one of the options that faces them. They walk into a very difficult sort of administrative process, and so you know, how do we cut away at that and make it happen. That's all.

MS. DeMARCO: Thanks for that. I didn't see it reflected in your CV anywhere, and certainly somewhere in relation to your evidence, you speak very broadly to your expertise in the broader use of thermal energy distribution which you term as “district energy."

Can you point to specifically in your CV --

MR. YOUNG: No, and I do think it has to go back to the opening comment. This is a high-level conversation about what some of the options are available as opposed to, you know, what are my qualifications to build that. And it takes me back to the point that options exist, and they can be -- they can be deployed in a very reasonable manner.

MS. DeMARCO: Okay, we'll try and definitely circle that square.

The last question relates to a significant portion of

-- on this specific interrogatory, relates to a specific significant portion of your evidence pertaining to the Danish system for district energy and they are a good -- I think paragraph 34 to 44, a full ten pages of evidence, relates to that. Is that fair?

MR. YOUNG: Yes.

MS. DeMARCO: Have you worked in Denmark?

MR. YOUNG: No, but I do know a number of people who have worked in Denmark, live in Denmark and you know, has -- as I put that forward, the point was this is what's possible, is the example of putting Denmark in place.

Certainly we could have looked at Germany, and other countries as well for integration of renewables. But I think Denmark does a better job, at least from what I've seen.

MS. DeMARCO: I see. So it is more an identification of what's possible as opposed to I've worked on this project with Denmark?

MR. YOUNG: That is what the entire submission is based on, yes. This is about what is possible.

MS. DeMARCO: Okay, great. At paragraph 31, page 12 of your evidence, you speak very specifically to Ontario's approach to storage, and you indicate it's been centred on electricity.

MR. YOUNG: Yes.

MS. DeMARCO: As an expert on energy storage or the -- as a possibility of the opportunities, are you familiar with any government programs relating to energy storage?

MR. YOUNG: There was a small -- I believe there was a 50-megawatt call for energy storage technologies from the IESO. So yes, I'm aware of them.

MS. DeMARCO: Anything else historically?

MR. YOUNG: Not that I can -- that comes to mind for energy storage.

MS. DeMARCO: Okay. Would you accept that the OPA ran an RFP as well on energy storage?

MR. YOUNG: Yes. We may be talking about the same project -- the same call, actually.

MS. DeMARCO: Would you accept that there were two calls?

MR. YOUNG: Okay.

MS. DeMARCO: Subject to check?

MR. YOUNG: Subject to check, yes.

MS. DeMARCO: Are you familiar with the outcome of those calls?

MR. YOUNG: I know there are some new technologies that are -- I would call it being piloted. There's some compressed air storage in Lake Ontario. There is eCAMION. There are a few small projects like Enerstore's flywheel.

MS. DeMARCO: Is there anything in relation to natural gas, and the integration of gas and electricity?

MR. YOUNG: Not that I'm aware of, but I may be corrected.

MS. DeMARCO: Subject to check, would you accept that there's a Hydrogenics project that integrates gas and electricity?

MR. YOUNG: I do accept that Hydrogenics exists, yes.
MS. DeMARCO: And that it was successful under that storage?
MR. YOUNG: Yes.
MS. DeMARCO: And there are gas ramifications of the Hydrogenics project?
MR. YOUNG: Hydrogenics does consume gas, yes. Hydrogenics also has been used -- deployed in Germany to convert electricity to hydrogen, and so it's a straight power to gas scenario as well.
MS. DeMARCO: Power to gas would be one example of gas-electricity integration?
MR. YOUNG: Well, if you're calling gas hydrogen -- or are you referring to it as natural gas, CH4? Which gas are you talking about, please?
MS. DeMARCO: Any semblance of power to gas integration, not strictly electricity; that's fair?
MR. YOUNG: Fair.
MS. DeMARCO: We've established, pursuant to our first discussion, that you don't have any specific expertise developing or operating CHP plants in Ontario; is that right?
MR. YOUNG: Correct.
MS. DeMARCO: And looking at IR No. 1, sub (b), you haven't negotiated a CHP contract with the OPA, or now IESO?
MR. YOUNG: Correct.
MS. DeMARCO: Do I take it that you are not generally

familiar with the commercial terms or arrangements for the sale of the resulting energy outputs from CHP plants?

MR. YOUNG: Other than what is published, at this point, no. I'm not concerned about those details actually.

MS. DeMARCO: Okay. I'm going to move on to IR No. 2, quite specifically where we were talking about that barriers question, and specifically the scope of your expert evidence that pertains to barriers.

And you indicate that:

"Sustainable energy approaches are critical to both energy conservation and environmental protection. Despite the progress in specific areas, significant programmatic, institutional and regulatory processes and practices within many key organizations in the energy sector have had limited progress on these two matters. With respect to greenhouse gas emissions, Ontario's challenge is moving beyond phasing out coal and reducing the carbon content of applications such as heating and transportation."

And we really wanted to understand what those barriers were, and so we had asked an IR, including a chart with all the relevant information, and that chart seems to have been omitted from the question. I'm sure it was just an oversight on your counsel's part, and I know these interrogatories were provided on very short turnaround.

But those critical charts, sub 1 and sub 2, have been omitted from that question. So I wonder if you would undertake to correct the response, first and foremost, with the inclusion of the charts were included in the original question?

MR. YOUNG: If I can confer with counsel for a moment?

MS. VINCE: Just to clarify, is the undertaking a request to put in under the question (a), the table that had been provided by APPrO?

MS. DeMARCO: Yes, to reproduce the question as asked in its entirety, with the fullness of the charts that were asked for specifically. And there may be a subsequent undertaking that I will request in relation to those charts.

MS. VINCE: We can revise the interrogatory to include in APPrO's question that we have quoted, the table that was omitted.

MR. MILLAR: That's JT3.10.

UNDERTAKING JT3.10: OSEA TO REPRODUCE THE QUESTION AS ASKED IN ITS ENTIRETY, WITH THE FULLNESS OF THE CHARTS THAT WERE ASKED FOR SPECIFICALLY

MS. VINCE: Not filling it in, just in the question portion.

MS. DeMARCO: I just want to be clear on this point, there are two tables.

MS. VINCE: Both tables.

MS. DeMARCO: And thank you for that, Mr. Young.

In relation to those tables, as you said, it is really important to understand the integration of the gas and the electricity DSM/CDM initiatives, effectiveness, efficiency for the sector, and certainly that type of information would be extraordinarily useful, and we had asked for those charts to be filled in outlining energy conservation measures, and we've specifically looked at the gas DSM, the electricity CDM, the phase-out of coal-fired electricity in Ontario that you mentioned in that question, and all other energy conservation programs and regulatory measures in Ontario that you also measure -- that you also mention in that question.

And specifically we had asked you to provide the resulting energy saved, either in kilowatt or megawatt-hours or gigajoules as applicable, the corresponding GHG emissions factor, the corresponding GHG emissions reduced over the defined period of time, and really, we are concerned about the ratepayer here, so the cost to end-use customers, that being the corresponding rate or bill increase over the applicable time period.

And what we got back from you was an indication that the Environmental Commissioner of Ontario has alleged authority to report the references provided in my evidence, cited the Environmental Commissioner's latest report, and it is unnecessary to transcribe the data from the report into the chart when it is readily available to the public.

So I undertook, with my wrist duly slapped by you for not having gone through the report, to try and find the specific references, and the only references I could find were at pages 26 and 27 of that report.

Can you please pinpoint me to the exact pages that you are referring to in the report that answer each and all of those requests for information?

MR. YOUNG: Excuse me.

[Mr. Young confers with Ms. Vince]

MS. VINCE: So to clarify, the responsibility for providing the information on energy conservation and barriers is on the Environmental Commissioner and his reports to legislative assembly, and all the information that's available is in his reports. That includes the most recent report, as well as all past reports. So it would be -- the requirement would be to go back and look at all the old reports as well to see all of the information that's available.

MS. DeMARCO: With respect, we have examined the Environmental Commissioner's reports and cannot find corresponding data. I'm wondering if you would provide an undertaking, given that your evidence expressly references each of these aspects at the preamble provided in question 2.

MR. YOUNG: We will look into it.

MS. DeMARCO: Is that an undertaking, counsel?

MS. VINCE: It is my understanding that the only data that's available is in the Environmental Commissioner's reports. We could provide you with links to the Environmental Commissioner's reports, if that would be helpful.

MS. DeMARCO: As indicated, I've looked at the Environmental Commissioner's reports, and to the extent that I have not been able to find them, I'm very humbled to be pointed to exactly where I'm omitting the specific factors. So would you please provide an undertaking to complete the charts to the extent possible?

MS. VINCE: So the difficulty is we only have public access to the information that's been published in the Environmental Commissioner's reports. So what we could provide you is the Environmental Commissioner's reports.

MS. DeMARCO: So I'm going to try one more time, to the extent -- I've tried and failed, quite miserably and humbly -- to the extent the information is available on what has been asked for, if you could provide pinpoint references to those reports that you are now relying upon, not the one report that was relied upon in the response to the interrogatory, could you please undertake to do so?

MR. YOUNG: We will undertake to the best of our ability, yes.

MS. DeMARCO: Thank you, Mr. Young. I appreciate that.

MR. MILLAR: That is JT3.11.

UNDERTAKING NO. JT3.11: OSEA TO PROVIDE PINPOINT REFERENCES TO THOSE REPORTS THAT ARE BEING RELIED UPON; AND TO PROVIDE THE INFORMATION IN THREE FINAL COLUMNS.

MS. DeMARCO: And with apologies, we did find in relation to the second chart the majority of the information in the first column requested, so the total GHG emissions from the sectors in 2005 and contribution to the total emissions in 2005. We have not found, contrary to the response provided in the interrogatory, the requested three remaining portions of the data.

Can I ask you to please undertake to provide, to the best of your ability, the information in those three final columns?

MR. YOUNG: We will look into this, yes.

MR. MILLAR: The same undertaking, Ms. DeMarco, or is that a -- do you want it marked separately?

MS. DeMARCO: I'm fine to have it as the same undertaking.

MR. MILLAR: Okay. So that's part of JT3.11.

MS. DeMARCO: I'm going to move on to IR No. 3 specifically. I'm looking at -- the reference being, for your purposes, Mr. Young, is paragraphs 16 and 18, 21, 22, and 27, where you indicate that the electricity market is dominated by existing large central power plants, and APPrO's attempt to try and better understand that question.

So in relation to the first question, you were asked to confirm whether or not they were developed on the basis of and operate in accordance with long-term contracts that are entered into between the developer and the IESO or the OPA or the OEFC, and I don't believe that that question was answered in the response.

MR. YOUNG: Perhaps I wasn't clear in my response. These are all operational facilities that are contracted duly within the province that I'm referring to.

MS. DeMARCO: So you can confirm that they were developed and operate in accordance with --

MR. YOUNG: No, I can't, because I didn't develop them or operate them. These are your members.

MS. DeMARCO: So, I'll neither confirm or deny whether or not they are APPrO members, but certainly in relation to those gas-fired power plants, you have no knowledge of whether or not they were developed or operate in accordance with the long-term contract with...?

MR. YOUNG: I'm looking at this from the context of the overall generation fleet, not specific projects, and as for the purposes of this conversation, I'm really not clear as to why we're talking about electricity generators right now.

MS. DeMARCO: Well, in fairness, Mr. Young, you raised that quite specifically in your evidence, talking about large central power plants and each of their relevant efficiencies --

MR. YOUNG: Yes.

MS. DeMARCO: -- so to the extent that you've raised it, we're trying to better elucidate what exactly you met and your understanding of those power plants.

So do you know of any power plant, gas-fired power plant, that does not operate in accordance with a long-term contract?

MR. YOUNG: I cannot see that happening in this province.

MS. DeMARCO: So it is safe to assume that they all operate in accordance --

MR. YOUNG: Agreed.

MS. DeMARCO: Thank you. You were asked in relation to IR 3(b) to confirm that, among other functions, gas-fired power plants provide necessary operational back-up generation capability that's required when alternative forms of renewable energy are not available.

I take it from your answer that that can be taken as a confirmation. You indicate that gas-fired power plants provide the type of ultra flexible back-up capacity that enables high-penetration levels of variable renewable energy sources, like wind and solar?

Can that be taken as a confirmation?

MR. YOUNG: I take exception with the word "necessary" for anything. The electricity grid is highly flexible and necessity, I think, is subject -- so in general, yes, gas is a useful tool for generation. But is it absolutely necessary? If there's storage options -- I mean, we're talking about -- I'm talking about where we're going, not where we are today.

MS. DeMARCO: Let me confine my question accordingly. Based on where we are today, gas-fired power plants provide the necessary operational back-up generation capability.

MR. YOUNG: I think we had a conversation earlier this morning about surplus base load, and when you look mix of solar and wind in the generation mix, I'm not sure it's all that necessary.

If -- I don't have the data, and I don't think anybody does as to what the necessary requirements are for renewable back-up in this province today.

MS. DeMARCO: Is it your position that renewables can be dispatched on demand?

MR. YOUNG: Yes -- not dispatched; they can be curtailed on demand.

MS. DeMARCO: Can they be dispatched on demand?

MR. YOUNG: No.

MS. DeMARCO: So --

MR. YOUNG: With the exception by biogas.

MS. DeMARCO: So to the extent that alternate forms of renewable energy are not available, as per the question -- so wind and solar are not available, would you agree that gas-fired power plant fills the gap?

MR. YOUNG: Yes.

MS. DeMARCO: In relation to (c), here we are talking about the associated efficiency of electricity generation from natural gas, and you've indicated in your evidence that it's less than 40 percent. We had asked for the specific sources that you've relied upon to provide that expert opinion of 40 percent.

MR. YOUNG: Okay.

MS. DeMARCO: And in your evidence you've indicated that:

> "Equipment manufacturers and government agencies routinely report calculations of this nature."

Can you please provide us with the specific references as to whom you were relying upon for that 40 percent number?

MR. YOUNG: I can provide with you an equipment list, yes.

MR. MILLAR: That's JT3.12.

UNDERTAKING NO. JT3.12: OSEA TO PROVIDE AN EQUIPMENT LIST

MS. DeMARCO: And in relation to (c)(ii), in relation to the natural gas-fired generation fleet in Ontario, we have established that you haven't worked very specifically with the existing natural-gas-fired generation fleet in Ontario.

MR. YOUNG: Correct.

MS. DeMARCO: In relation to number (iii), we had asked for the external sources of third-party documentation that you have relied upon to come up with the 40 percent and the efficiency range, and you've provided the catalog of CHP technologies from the U.S. EPA combined heat and power partnership.

MR. YOUNG: Correct.

MS. DeMARCO: And that's the only resource you've relied upon?

MR. YOUNG: I think it's representative.

MS. DeMARCO: In addition to the data from the U.K. government that you provide?

MR. YOUNG: Sure.

MS. DeMARCO: So U.S. and U.K. data?

MR. YOUNG: Actually, the distinction is they have data that's widely available in terms of performance. We don't have that kind of data through IESO and I'm not sure of any other sites that do.

MS. DeMARCO: So it's your view that there is no data?

MR. YOUNG: There's a very different approach to data collection within Ontario, relative to other jurisdictions.

MS. DeMARCO: So it is not your view that there is no data, but there's just a different level of --

MR. YOUUNG: It is incomplete.

MS. DeMARCO: But there is data? It's incomplete, but there is data?

MR. YOUNG: It is IESO-published data. But it is not as robust and other jurisdictions.

MS. DeMARCO: Would you undertake to provide us with the IESO-published data, please?

MS. VINCE: If it's published and publicly available, I am not sure why you would need an undertaking to obtain it.

MS. DeMARCO: Apparently -- the response was that the your expert has relied upon strictly the U.S. EPA and the U.K. data to make strict conclusions about the efficiency of Ontario-based CHP plants, and has just indicated that there is actually Ontario data.

We would like an undertaking for him to provide that, please.

MR. YOUNG: I believe I said there wasn't the level of data required -- the distinction between U.K. data and Ontario data is Ontario gives power output. That's it; that's all. It doesn't talk about thermal efficiency. It doesn't do the kind of detailed calculations that the U.K.

data sets do, or allow you to do.

So the level of granularity that you are looking for right now isn't publicly available, that I'm aware of, within the IESO context.

MS. DeMARCO: So the power output data, in addition to the equipment manufacturer's data, is not available?

MR. YOUNG: The power output data is available, but to do an efficiency calculation, you require thermal utilisation data. That's not published in Ontario.

MS. DeMARCO: So to the extent you did a thermal efficiency calculation, you didn't use that data?

MR. YOUNG: It's not available in Ontario. As we go back to the general scope of this conversation, it is about a high-level -- what the lay of the land is for technologies.

I'm not going to get into a calculation for each specific power plant in this province.

MS. DeMARCO: I'm just curious, because you have provided a specific number. So to the extent that you've provided that number, we would like it supported with the relative calculations, unless you are willing to qualify that number as --

MR. YOUNG: I believe the reference I made was to the EPA CHP handbook.

MS. DeMARCO: I'm looking very specifically to physically to the evidence -- I believe it's paragraph 21, but I will the reference for you, where you specifically indicate that the efficiency is 40 percent.

MR. YOUNG: Perhaps I'm assuming that technology is universal in its function.

I'm probably wrong, by the way this questioning is going, that you are looking for specific calculations for specific scenarios with incomplete information.

MS. DeMARCO: It's paragraph 22 of your evidence; that's the specific reference. Fair to say that the efficiency of CCGT is quite different than CT?

MR. YOUNG: Yes.

MS. DeMARCO: And so the composition of the technology mix of CHP or gas-fired generation in the province will make a very big difference in the overall efficiency?

MR. YOUNG: It would, but the data that is presented by the IESO isn't broken out by specific facility-operating characteristics. It is the number of operating hours and the power that's produced, and there is no way to decipher anything beyond that.

MS. DeMARCO: So you couldn't for example decipher --

MR. YOUNG: Nobody could. Nobody could, because you don't have heat utilisation per project per hour.

MS. DeMARCO: So 40 percent is not accurate?

MR. YOUNG: We don't know what it is, do we?

MS. DeMARCO: We don't know what it is. Thank you. So in relation to number 4, the efficiency of CHP being greater than 90 percent, you indicate very specifically that that's the case. Again, the same issue applies.

MR. YOUNG: Again, case by case, please refer to the CHP catalogue, where it clearly indicates the performance ranges for the various technologies. So fuel cells are at the higher end of that range.

MS. DeMARCO: So the range of efficiencies for a range of technologies is in and around 90 percent?

MR. YOUNG: It always -- no, no, no, no, it is always case by case. It is driven by the heat utilization of a facility. Just because a gas CHP unit is running doesn't make it 80 or 90 percent efficient all the time; it is only efficient if the heat is utilized. If the heat is not utilized and it's dumped, then your efficiency ratings go out the window.

MS. DeMARCO: So is that how we justify or juxtapose the reported efficiency of 60 to 92 percent in Exhibit H of your evidence?

MR. YOUNG: Everything is flexible in this.

MS. DeMARCO: Everything is flexible. So that 90 percent is flexible?

MR. YOUNG: It depends on every installation. There is no universal standard.

MS. DeMARCO: Thank you. In relation to number 5, we had asked there -- this is 3(5), again, we had asked:

> "Please confirm that the majority of gas-fired generation facilities are in fact combined cycle or CHP nature and utilize waste heat for secondary power generation to meet industrial steam or other heating requirements."

You've indicated that you are not in a position to comment.

MR. YOUNG: Again, there is a lack of data on this.

MS. DeMARCO: So at paragraph 16 of your evidence you state that:

> "Currently Ontario's supply of electricity is dominated by large central power plants that have relatively low overall efficiency rates which result in large waste of heat energy."

Fair to say that there is not sufficient data to comment on this either?

MR. YOUNG: I'll take exception with that. I think the table that I provided sort of outlined the sources of power in this province. As far as I'm aware of -- and correct me if I'm wrong -- nuclear is the largest of the generating facilities in this province, and as far as I'm aware, there is no nuclear combined heat and power plant in this province.

So I think, to your point, that's a safe assumption, that, you know, the large plants waste a lot of power.

MS. DeMARCO: But you are not in a position to comment on the thermal efficiency?

MR. YOUNG: The data from nuclear power plants I don't think exists, but I did refer to the U.K. data set, not just the Up in Smoke article but the actual data set. They call it DUKES. And it's clear. 65 percent of the energy produced by nuclear plant is wasted heat.

MS. DeMARCO: I'm just scratching my head a bit here, because I'm not certain how you can indicate that you're not in a position to comment on the thermal efficiency of the power plant and then go on to comment on the thermal efficiency of a power plant; which one is it?

MR. YOUNG: I think that if we were to look at it officially, nobody knows. If you look at it rationally, it's well-known. So I think that trying to split hairs over, do I have -- if I see the problem, is it real, if I can't see it? No.

This conversation is about where is the heat wasted? How much of it is wasted? If you were to apply that 65 percent of waste heat to Ontario, that is enough to heat the entire province on a residential level.

MS. DeMARCO: I don't mean to be difficult, Mr. Young, in any way, shape, or form. We're just trying to get at the same thing: How much of that is wasted? So to the extent that you are not willing to comment on it and don't have -- not in the position to comment on it, for one purpose I'm really struggling to see how you are in a position to comment on it for another basis.

MR. YOUNG: We know what the waste thermal fraction is for nuclear plants operating in the U.K.

MS. DeMARCO: Know what it is in Ontario?

MR. YOUNG: The data is not published.

MS. DeMARCO: So can you comment on it if the data's not published?

MR. YOUNG: I think that if we had more information, then I would comment with more veracity, but I'm -- this is a high-level conversation that we're having, and a nuclear plant operating in Ontario, I can't see how it's any more efficient than a nuclear plant operating in any other jurisdiction. It would boggle the mind to think that.

MS. DeMARCO: You've got no data to support that assertion.

MR. YOUNG: Do I have -- it's a conclusion, and it's an assumption, is what it is.

MS. DeMARCO: Thank you. Going on to question number 4 quite specifically. This question relates to the assertion that there is the potential to replace upwards of 8,000 megawatts of low-efficiency thermal electric generation capacity in Ontario.

4(a), we had asked for all supporting documentation for that assertion, and we've got the Enercan report. Is that the extent of the data that you've relied upon to support that assumption?

MR. YOUNG: So that information is the federal government data on energy consumption by building, by sector, yes.

MS. DeMARCO: So that's not an actual feasibility study of replacing 8,000 megawatts of capacity in Ontario?

MR. YOUNG: No, that's the raw calculation of heat consumption per building in Ontario.

MS. DeMARCO: And certainly in relation to the cost of converting 8,000 megawatts of capacity that's existing.

MR. YOUNG: It's a ballpark assumption using figures from the CHP catalog, yes.

MS. DeMARCO: So we don't have specific cost assumptions there?

MR. YOUNG: Certainly not. I mean, it's a ballpark. This is trying to quantify the issue in a broad scope. If you want specific costs, then that's outside the scope of this conversation.

MS. DeMARCO: Similarly, in terms of the specific commercial agreements and potential contract breakage fees, no, it is outside the scope...

MR. YOUNG: So you are assuming that this is 8,000 megawatts of what size of power plants? I'm suggesting this can be done at the residential scale as an energy conservation tool for homeowners, commercial buildings, and other properties.

MS. DeMARCO: Let me be clear. I'm not assuming anything. I'm just working from the statement:

> "Based on a full conversion rate there is the potential to replace upwards of 8,000 megawatts of relatively low-efficiency thermo-generation."

It's paragraph 24 --

MR. YOUNG: Yes.

MS. DeMARCO: -- to 27.

MR. YOUNG: Yes.

MS. DeMARCO: So --

MR. YOUNG: That's the ballpark we're playing in, is 8,000 megawatts of power that could be converted to CHP using the existing natural gas demand and producing electricity with that.

MS. DeMARCO: And I'm just trying to assess, based on that, what would be the cost of that in Ontario.

MR. YOUNG: I think $12 billion or something and a payback of maybe 24 months, something like that.

MS. DeMARCO: I'd love any calculations you have to support that.

MR. YOUNG: It's an estimate, and it's based on costs out of the CHP handbook.

MS. DeMARCO: If you could undertake to provide those calculations, I would love to see them.

MR. YOUNG: I will do that.

MR. MILLAR: It's JT3.13.

UNDERTAKING NO. JT3.13: OSEA TO PROVIDE THE CALCULATION FOR A COST OF $12 BILLION TO CONVER 8,000 MEGAWATTS OF POWER TO CHP USING THE EXISTING NATURAL GAS DEMAND AND PRODUCING ELECTRICITY WITH THAT, BASED ON DATA FROM THE CHP HANDBOOK.

MR. MILLAR: Ms. DeMarco, we are probably close to time for an afternoon break. How are you in your -- is this a suitable time?

MS. DeMARCO: It's great.

MR. MILLAR: And about how much longer do you think you have?

MS. DeMARCO: Probably about 15 minutes.

MR. MILLAR: Okay. And Mr. O'Leary, you were down for 30. Is that how long you'll be?

MR. O'LEARY: At this point we don't. I thought we indicated we have no questions for OSEA.

MR. MILLAR: That's great. Let's break until --

MS. DeMARCO: Mr. Millar, what I'll undertake to do is just consolidate my thoughts, and if we can wrap up, we will, and if not, I'll try to be as brief as possible.

MR. MILLAR: Let's return at four o'clock.

--- Recess taken at 3:44 p.m.

--- On resuming at 4:00 p.m.

MR. MILLAR: Welcome back, everyone. Let's continue. Ms. DeMarco?

MS. DeMARCO: Thank you, Mr. Millar, I've had a chance to review my notes, and it is with great respect and appreciation that I think I'd like to thank Mr. Young, and I can wrap up at this point.

MR. MILLAR: So no further questions?

MS. DeMARCO: No further questions.

MR. MILLAR: Okay. Is there anyone else in the room with questions for Mr. Young? And anyone on the line with questions for Mr. Young? Okay. I think we had already told Synapse they won't be needed today. It is past four o'clock now, so I think we'll just start with them again at 9:30, so Mr. Young, you are excused with the Board's thanks.

MR. YOUNG: Thank you.

MR. MILLAR: What I'd like to do is, we're going to go off the record here, but I do want people to stick around, and if you're listening in, continue to listen, because I have to harangue everyone about the hearing plan, but best to do that off the transcript.

But if you are listening in, even if it's just through the Web, I will keep the on-air on, so do listen in, and

TAB 15

VT INCEPIT FIDELIS SIC PERMANET

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2015-0029**	**Union Gas Limited**
	EB-2015-0049	**Enbridge Gas Distribution Inc.**

VOLUME: **Technical Conference**

DATE: **August 18, 2015**

EB-2015-0029
EB-2015-0049

THE ONTARIO ENERGY BOARD

Union Gas Limited and Enbridge Gas Distribution Inc.

Applications for approval of 2015-2020 demand side management plans.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Tuesday, August 18, 2015,
commencing at 9:32 a.m.

TECHNICAL CONFERENCE
----

rate, and I don't know if that was captured correctly. I would just ask that Board Staff check that.

Page 71, it's mentioned as the Regie, as in the Regie de Gaz, Regie d'Energie, in Quebec. It's RGGI, capital R-G-G-I.

Page 113, line 19, it's refers to short auction. And it should be reductions.

Similarly, line 13 on page 113, it is mentioned as introduction. It should be reductions.

Page 130, line 19, it is mentioned as "alleged", and it should be legislative.

Those are the changes there.

MR. MILLAR: You had some questions as well?

MS. DeMARCO: Yes, very short.

MR. MILLAR: Go ahead.

QUESTIONS BY MS. DEMARCO:

MS. DeMARCO: Thank you, panel, and I'm referring specifically predominantly to the APPrO references, the APPrO IRs, which are Exhibit M.Staff.APPrO number 1 to 6, predominantly the first four.

Do I take it that your experience does not include implementing energy efficiency programs for large-scale power generation customers; is that correct?

MS. NAPOLEON: That's -- I'm sorry, this is Alice Napoleon, and that is correct.

MS. DeMARCO: Great. Thank you.

Do you know what a NUG is in the Ontario context?

MS. NAPOLEON: A non-utility generator.

MS. DeMARCO: And are you familiar with the contracts that govern the operation and maintenance and payments to and from electricity generators in the province?

MS. NAPOLEON: This is Alice Napoleon again. I am not specifically aware of the contracts that exist between -- for the non-utility generators.

MS. DeMARCO: Thank you. Now I'm referring, in particular, to your evidence at page 84 and Appendix A at A16. You recommend that efficiency recommendations be mandatorily undertaken in certain instances, so is it fair to say that you have no idea whether or not those would be permitted under the contracts that govern the operation and maintenance of electricity generation facilities in the province?

MS. NAPOLEON: I'm sorry, could you repeat the references? You said 84, page 84 of our report, and did you say something else?

MS. DeMARCO: I believe it's the summary of the recommendations outlined at A16 of your report as well.

MS. NAPOLEON: Perfect. So this is Alice Napoleon again. So the recommendation has been -- actually, I'm sorry, hold on for just one moment, please.

For one I would like to refer to our response to another interrogatory by -- excuse me, the exhibit is M.OEB.Union.13.

MS. MALONE: Sorry, it is actually Staff. It is M.Staff.Union.13. It is Union interrogatory; is that correct?

MS. NAPOLEON: Yeah, is this the reference for our...

[Witness panel confers]

MS. NAPOLEON: Oh, okay. Sorry about that. Erin, would you say the reference, please?

MS. MALONE: Sorry, this is Erin. It is Exhibit M.Staff.Union.13.

MS. DeMARCO: I've got that up, and I've reviewed it. I'm just scratching my head trying to understand how that relates to the question asked. And let me repeat the question. Specifically, you indicated that you have no knowledge of the contracts governing power generation operations and payments to and from the facilities themselves.

So is it fair to say that you have no idea as to whether or not mandatory energy efficiency recommendations and mandating implementation would be permitted under those contracts?

MS. NAPOLEON: The reason why the interrogatory response that I just referred you to -- this is Alice Napoleon -- is relevant is because it indicates that Union should consider, the word "consider" being that -- or meaning that various factors should be considered, and whether the requirement would be applicable to all customer classes or all manufacturing sectors is relevant to this question, including non-utility generators.

MS. DeMARCO: So just to be clear, you're not suggesting that Union is a party to those electricity generation contracts, are you?

MS. NAPOLEON: No --

MS. DeMARCO: No.

MS. NAPOLEON: -- I'm not suggesting that they are a party to it. I think that as a part of a collaborative undertaking to develop an appropriate mechanism to ensure that the large-volume customers are actually achieving savings, that APPrO and other similar entities could participate in the development of such a program.

MS. DeMARCO: You are not suggesting that APPrO is a party to those individual generator contracts, are you?

MS. NAPOLEON: I do not know whether or not APPrO is a party to those contracts or not.

MS. DeMARCO: Subject to check, would you accept that the industry association is not a party to an individual generator contract?

MS. NAPOLEON: I'm sorry, could you repeat the question?

MS. DeMARCO: Subject to check, would you accept that an industry association is not a party to an individual generation facility contract; i.e., a power purchase agreement or a form of an off-take agreement?

MS. NAPOLEON: Synapse has no knowledge whether they are a party to such a contract.

MS. DeMARCO: Have you ever heard of an industry association being a party to a power purchase agreement?

MS. NAPOLEON: I have not.

MS. DeMARCO: Thank you. So, really you've got no knowledge of the confidentiality provisions of those contracts, either?

MS. NAPOLEON: I am aware -- I have viewed power purchase agreements previously, and I am aware that confidentiality issues are significantly present in power purchase agreements.

MS. DeMARCO: So given that generally -- of course, you've got no experience on these specific contracts, as you've indicated -- generally there are confidentiality provisions, you have no clear idea as to whether or not a program administrator can be provided the information you've suggested; is that correct?

MS. NAPOLEON: I would volunteer that it's not -- it's not clear that the specific contracts need to have relevance to the development of a program for large volume customers.

MS. DeMARCO: So we've indicated that most of them do have confidentiality requirements; you agree?

MS. NAPOLEON: On some aspects of the contracts, yes.

MS. DeMARCO: And that could certainly limit information-sharing, broadly; you'd agree?

MS. NAPOLEON: Yes.

MS. DeMARCO: And to the extent that that information was relevant to energy efficiency, you would agree that --

MS. NAPOLEON: Sorry, certain aspects of the contract could have confidentiality provisions on them.

MS. DeMARCO: So to the extent that aspects of the contracts were relevant, or the information would be relevant to energy efficiency programs, you would agree that it's possible for those confidentiality agreements or provisions to restrict the information that could be provided?

MS. NAPOLEON: It is possible that it could restrict the information provided. In my experience, a lot of the elements that are confidential include price. That's one of the main elements that is held confidential.

It's not clear to me that all elements that would be relevant to a program administrator are going to be held confidential.

MS. DeMARCO: But you don't know. That's fair to say?

MS. NAPOLEON: That's fair to say.

MS. DeMARCO: Would it surprise you if there were efficiency standards or maintenance requirements in a power purchase agreement?

MS. NAPOLEON: There may be efficiency requirements or there may not be, to my knowledge.

MS. DeMARCO: And maintenance requirements? Would it surprise you to see that that would be a regular term of a power purchase agreement?

MS. NAPOLEON: Maybe.

MS. DeMARCO: I'm going to ask you specifically whether or not you've looked at the financial efficiency and effectiveness of the proposed recommendations, and I think this is along the lines of the questions that Mr. Higgins -- Dr. Higgins was asking you.

Have you assessed how much your recommendations would cost, first, the power generation customers that you are recommending them for, and secondly, end-use customers?

MS. NAPOLEON: So we have not done that form of an impact analysis, because it is outside the scope of what we were asked to do.

MS. DeMARCO: So we don't know the wallet impact for end-use customers? Fair?

MS. NAPOLEON: We don't specifically know. But as Mr. Takahashi noted earlier, there are elements that both would increase the cost, and elements that would tend to decrease the costs.

MS. DeMARCO: Can you really say that, if you have no idea about the off-take contract requirements?

MS. NAPOLEON: The response that I just made was relative to the whole portfolio, not specifically for any one individual offering.

MS. DeMARCO: Thank you. So, have you assessed which entity, whether it's the large volume customer itself, or the gas utility, or end use customers, is best placed financially, legally and contractually to undertake any energy efficiency measures?

MS. NAPOLEON: Would you repeat the first part of that question?

MS. DeMARCO: Have you assessed which entity the utility, the end use customer and/or the large volume customer is best placed financially, legally or contractually to undertake any energy efficiency measures?

MR. TAKAHASHI: I'm sorry, we are looking for information right now. Just give us a few moments, please.

MR. MILLAR: While they're discussing, Ms. DeMarco, we are past five minutes. Are you nearly done, or should we take a break?

MS. DeMARCO: Why don't we take a quick break, and I'll pop back?

MR. MILLAR: Synapse, if you can hear, we're going to take our morning break just because it's ten past eleven now. That will give you a moment to review the question and see if there is an answer for that.

We will come back at 11:30.

MS. MALONE: Okay, thank you.

--- Recess taken at 11:11 a.m.

--- On resuming at 11:31 a.m.

MR. MILLAR: Okay, everyone. Why don't we get started again? Just to confirm, are the Synapse folks on the phone?

MS. MALONE: We're here.

MR. MILLAR: Okay. Ms. DeMarco, would you like to continue?

MS. DeMARCO: I believe I was waiting on a response from Synapse.

MR. MILLAR: Yes, of course you are. So Synapse, are you prepared with a response to that question?

MS. NAPOLEON: Yes. I'd like to refer you to Exhibit M --

MR. MILLAR: This is -- sorry, this is Ms. Napoleon?

MS. NAPOLEON: I'm sorry, yes, this is --

MR. MILLAR: Okay.

MS. NAPOLEON: -- Alice Napoleon, and I'm going to -- referring to Exhibit M.Staff.APPrO.5, part (a).

MS. DeMARCO: I've got that, yes.

MS. NAPOLEON: So my understanding is that this is a very similar question to what you just asked, and if you want to ask a different question, maybe you could clarify how it's different.

MS. DeMARCO: The question was: Which entity is best placed. You haven't looked at that. So have you looked at it or have you not, yes or no?

MS. NAPOLEON: We have not specifically analyzed who is in the best position, and we're just drawing on our experience -- our experience with projects, as I provided -- we provided some information about the different large-volume programs that we have reviewed and critiqued, and also based on the literature.

MS. DeMARCO: So fair to say that you have not looked at this in the Ontario context; is that fair?

MS. NAPOLEON: That's fair.

MS. DeMARCO: Can I ask you to touch upon, I believe it's APPrO number 3 -- sorry, APPrO number 3, which refers to the Navigant report.

MS. NAPOLEON: Is that APPrO 2?

MS. DeMARCO: Sorry, that's APPrO 2. Thank you.

Just fair to say that in the U.S. many electricity generators using natural gas as a fuel are often not subject to DSM CRM measures in the U.S.?

MS. NAPOLEON: Yes, as we responded in part (a), we are aware that electric generators using natural gas in the U.S. are often not subject to cost recovery mechanisms such as a DSM CRM.

MS. DeMARCO: And there is a policy rationale for that particularly related to the economic bypass of the pipeline; is that correct?

MS. NAPOLEON: I cannot speak to the rationale for that.

MS. DeMARCO: So you are not aware as to whether or not there are economic bypass-related issues?

MS. NAPOLEON: We are not aware whether there -- I'm sorry, would you rephrase the question?

MS. DeMARCO: So you are not aware whether or not there are economic bypass-related issues?

MS. NAPOLEON: In the U.S. or in Ontario?

MS. DeMARCO: Either.

MS. NAPOLEON: I am not aware --

MS. DeMARCO: So you have no reason to disagree with the reference cited in the -- in the reference in the introduction to that interrogatory, which is EB-2012-0337?

MS. NAPOLEON: I have no reason to disagree with the passage cited in that interrogatory in APPrO.2.

MS. DeMARCO: Would you take it subject to check that there are instances of economic bypass in Ontario for power generators?

MR. MILLAR: Ms. DeMarco, when you say "subject to check", where should we check?

MS. DeMARCO: With the Board public documents.

MR. MILLAR: Okay. Ms. Napoleon, are you able to answer that question?

MS. NAPOLEON: I'm sorry, we're conferring. Give me a moment, please.

I'm sorry, so are you asking, would you like to submit an undertaking? I guess I'm a little unclear [voice cuts out]

MR. MILLAR: Could you repeat the question, Ms. DeMarco?

MS. DeMARCO: Yes, would you accept, subject to check, that there are instances of economic bypass for electricity generators in Ontario?

MS. NAPOLEON: I can't speak to whether there are instances of economic bypass in Ontario.

MS. DeMARCO: So would you accept, subject to check with your client, that there are at least two instances of economic bypass in Ontario, the Greenfield Energy Centre and the Green Electron project, that have been approved by the Board?

[Witness panel confers]

MR. MILLAR: I think we can accept that, Ms. DeMarco, if helps. The client is not -- or pardon me, Synapse is not specifically aware of those, but I don't think that's in dispute.

MS. DeMARCO: Thank you. My next question is in relation to, in part, APPrO 3(a) and (b), specifically the efficiency and effectiveness of large-volume customers, and particularly gas-fired power generation customers, to evaluate and undertake and implement energy efficiency programs on their own, and specifically in relation to 3(b)(ii)9. Do you have that reference up?

MS. NAPOLEON: (b)2... Oh. Okay. Yes. Yes, I have that up.

MS. DeMARCO: These were all measures that we had asked you to confirm whether or not they would be valid reasons for large-volume customers to directly undertake and invest in energy efficiency and conservation measures. 3(b)(ii)9 relates to avoiding border measures on higher-emission export products like electricity, such as the first jurisdictional delivered program measures in Quebec and California.

You indicate that you are not familiar with that; is that correct?

MS. NAPOLEON: That's correct.

MS. DeMARCO: In fact, you haven't looked at any carbon pricing-related measures in this analysis; is that correct?

MR. TAKAHASHI: Correct, we did not review.

MS. DeMARCO: Thank you. I'm going to move on to (c). You indicate in your response to (c) that Synapse is generally familiar with a variety of measures, including but not limited to motors, CHP compressors, pumps, lighting, air handling, et cetera.

I just want to explore exactly what you have done in relation to direct large-volume customer energy efficiency, and conservation measures. Have you designed them for large-volume customers?

MR. MILLAR: Ms. DeMarco, I don't mean to interrupt, and certainly I am happy to have the witnesses answer the questions. I do observe that Mr. Woolf is not on the call, and he may have some additional things that he's done. So I am happy to have these witnesses answer the questions. We may also want to take an undertaking to provide any additional information that Mr. Woolf has.

MS. DeMARCO: I'm happy to have that undertaking.

MR. MILLAR: Okay. Thank you. But let's hear from the witnesses first.

MS. DeMARCO: Why don't we take the undertaking at this point, and --

MR. MILLAR: Okay. So it will be JT4.12. Would it be easier just to do the whole thing by undertaking? Would that satisfy you? Or do you need to hear --

MS. DeMARCO: I would love to hear in relation to the specific evidence just that understanding of what "generally familiar with" means of the panel that's available to us.

MR. MILLAR: So just to mark the undertaking, it will be to provide any additional information related to --

MS. DeMARCO: Direct large-volume customer energy efficiency and conservation measures that Synapse has directly done, or been involved with.

MR. MILLAR: We'll take that undertaking. But if the witnesses on the phone can provide an answer, that will be helpful, too.

UNDERTAKING NO. JT4.12: SYNAPSE TO PROVIDE ANY ADDITIONAL INFORMATION RELATED TO DIRECT LARGE-VOLUME CUSTOMER ENERGY EFFICIENCY AND CONSERVATION MEASURES SYNAPSE HAS DIRECTLY DONE, OR BEEN INVOLVED WITH

MS. DeMARCO: Have you designed them?

MS. NAPOLEON: This is Alice Napoleon. I have not been involved with the design of any engineering program projects involving these measures that were listed.

MS. DeMARCO: Thank you. Have you implemented them any way, shape or form?

MS. NAPOLEON: We are involved in -- I've been involved in program or offering design, not with the actual implementation of the specific measure.

MS. DeMARCO: What about after the fact? Have you assessed the energy efficiency, (a), and the cost effectiveness, (b), of them?

MR. TAKAHASHI: Yes. Yes, we have assessed cost effectiveness of those measures.

MS. DeMARCO: After they were directly implemented by a large volume customer? That's the question.

MR. MILLAR: Mr. Takahashi, did you hear that question?

MS. NAPOLEON: Just to say we would like to clarify that we have used utility reporting of energy savings and of cost to consider the savings and the cost effectiveness of these measures.

MS. DeMARCO: Okay, that's distinct from directly doing it for the large volume customer; fair?

MS. NAPOLEON: Yes.
MR. MILLAR: Thank you. And then similarly, for -- directly for that large volume customer, have you assessed the impacts on their end use customers for their products or services?
MR. TAKAHASHI: Are you asking for experience?
MS. DeMARCO: Yes, "generally familiar with", as you report. I want to understand whether or not you've done that directly, or whether you've just come into contact with reporting, or some other range of experience.
MR. TAKAHASHI: Yeah, we have reviewed numerous energy efficiency potential studies across North America, which included numerous measures, and these measures included measures for large volume customers.
MS. DeMARCO: So your experience is in relation to review of studies; is that fair to say?
MR. TAKAHASHI: Correct, fair.
MS. DeMARCO: Thank you. I'm moving on to APPrO sub 4, that's IR 3 (4) in relation to viable measures. Specifically there, the response was -- sorry, it's sub (d), not sub 4.
When you talk about viable measures in your response, which indicates in about fourth line down:

> "The literature on this subject indicates that barriers to energy efficiency persist for the industrial sector, and not all viable measures are implemented."

I just want to better understand what you take to mean as viable measures. Do you mean financially viable measures?

MS. NAPOLEON: Sorry, I had the wrong question response up.

MS. DeMARCO: It's APPrO sub 3, sub (d). And that's my fault. I'm sorry, I said sub 4 and it's actually sub (d).

MS. NAPOLEON: By viable? I would say that that means cost effective from the program administrator's perspective, or from the total resource cost or societal benefits perspective.

MS. DeMARCO: So financially viable from the PA or TRC perspective?

MS. NAPOLEON: Also the customer's perspective, yes.

MS. DeMARCO: Legally viable? Would that be included in your definition of viable?

MS. NAPOLEON: Legally viable would be important. That's not -- I do not believe that legally viable was specifically looked at by the studies that I've consulted. However, it is suggested by these by these studies that since the efficiency measures were implemented as a result of the program administrator's efforts, that they were in fact legal.

MS. DeMARCO: It's more in relation to the measures that were not implemented. You didn't look at whether those measures were legally viable, did you?

MS. NAPOLEON: For measures that were not implemented? No, we did not look at those.

MS. DeMARCO: And similarly, you didn't look at those measures that were not implemented were contractually viable?

MS. NAPOLEON: We have not considered whether the projects that were not implemented were not implemented as a result of contractual issues.

MS. DeMARCO: Similarly, you haven't looked at whether or not those measures that weren't implemented were viable in the context of capital stock turnover cycles; is that fair?

MR. TAKAHASHI: That should be taken into account usually when utilities estimate energy savings potential.

MS. DeMARCO: As I understand your answer, it would be very prudent for a large industrial customer to directly themselves take into account capital stock turnover cycles when assessing whether or not to implement a measure; is that right?

MR. TAKAHASHI: Correct.

MS. DeMARCO: Similarly, you didn't take into account an examination of whether the measure is viable in the context of a carbon pricing regime?

MS. NAPOLEON: That's correct.

MS. DeMARCO: Then I'm going to ask you to move on to APPrO IR No. 6. I just want to get a sense of what you assumed in terms of the internal LVC resources relating to energy efficiency professionals, or professional engineering staff. Have you assumed that they don't have dedicated energy efficiency professionals?

MR. TAKAHASHI: Could you repeat the question?
MS. NAPOLEON: And define the acronym as well?
MS. DeMARCO: Large volume customer, LVC. Sorry about that.
MS. NAPOLEON: Thank you.
MS. DeMARCO: Have you assumed that the large volume customer has no internal professional engineering or energy efficiency professionals dedicated to energy efficiency and conservation measures on staff?
MS. NAPOLEON: We have not assumed that there are no -- there is or is not an internal energy manager on site.
MS. DeMARCO: Or many of them, in terms of even vice-presidents? There could be a whole range of staff dedicated to optimization and energy efficiency on staff; would that be fair?
MS. NAPOLEON: That would be fair, although I would not say that the presence of staff that are dedicated to energy efficiency means that there isn't a contribution that could be made by a utility that's providing technical assistance or other kind of assistance for supporting energy efficiency.
MS. DeMARCO: Would you accept that dedicated staff internal to the large-volume customer would have a much better knowledge of the operations of the entity than a third-party utility operator?
MS. NAPOLEON: In general, yes.
MS. DeMARCO: Those are my questions.
MR. MILLAR: Thank you very much, Ms. DeMarco.

MS. DeMARCO: Mr. Millar, if we could, we'll take our leave at this point and follow on.

MR. MILLAR: Of course. Of course.

MR. O'LEARY: Ms. DeMarco, just before you go, I just -- it is really just a matter of nomenclature, and I appreciate that all of your questions have been referring to large-volume customers, but there are several rate classes that the several utilities have.

If I look at the APPrO Interrogatory No. 1, your very first question refers to Enbridge's Rate 125 rate class, which is our -- we'll call it the gas generation rate class, and then there is the Union T2 and Rate 100 customers.

Am I correct in understanding that your questions, when you refer to large-volume customers, Ms. DeMarco, are referring to essentially the customers in those rate classes?

MS. DeMARCO: Yes, that's a fair assumption.

MR. O'LEARY: All right. Because it is understood that Enbridge has other rate classes, and sometimes they consume what some might call large volumes, but certainly not something of the equivalent of what we see in those rate classes. I just wanted to make sure we're clear on that.

MR. MILLAR: Thank you, Mr. O'Leary. Thank you, Ms. DeMarco. We'll see you tomorrow or in the coming days.

Mr. Elson, are you prepared to proceed? And just for the benefit of the witnesses, poor Mr. Elson has broken his

TAB 16

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2015-0029**	**Union Gas Limited**
	EB-2015-0049	**Enbridge Gas Distribution Inc.**

VOLUME:	**2**	
DATE:	**August 20, 2015**	
BEFORE:	**Christine Long**	**Presiding Member**
	Allison Duff	**Member**
	Susan Frank	**Member**

EB-2015-0029
EB-2015-0049

THE ONTARIO ENERGY BOARD

Union Gas Limited and Enbridge Gas Distribution Inc.

Applications for approval of 2015-2020 demand side management plans.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Thursday, August 20, 2015,
commencing at 9:33 a.m.

VOLUME 2

BEFORE:

CHRISTINE LONG	Presiding Member
ALLISON DUFF	Member
SUSAN FRANK	Member

MS. LYNCH: Certainly, CHP has been one area that has been identified, and an area that we have seen significant interest and certainly significant focus within the CDM program.

MS. VINCE: Are there any others?

MS. LYNCH: I can't say specifically. I know there has been some solar discussion, but I don't think there's been much along those lines.

MS. VINCE: Okay. What about net zero?

MS. LYNCH: We haven't had specific discussions with LDCs on net zero. Certainly there's been interest in whether or not there may be new construction opportunities going forward and how we might work together on those, but not specific to net zero at this point.

MS. VINCE: Okay, those are all my questions. Thank you.

MS. LYNCH: Thank you.

MS. LONG: Thank you, Ms. Vince. Ms. DeMarco?

CROSS-EXAMINATION BY MS. DEMARCO:

MS. DeMARCO: Thank you very much, Madam Chair, and thank you, panel. I have just a few questions in relation to large industrial and some of the non-energy benefits, which are referred to in Exhibit A, tab 2, appendix C, page 7 of 34 of your evidence and in responses to interrogatories at Exhibit B, tab 13 and tab 45, Union.GEC.3 and 55. So that's the scope of my questions.

Very specifically, you've had much questioning today in and around the environmental commissioner's report.

I've provided the actual excerpt that was spoken to this morning. Do you have that?

MS. LYNCH: Yes, I do.

MS. DeMARCO: Does the Panel have that?

MS. LONG: We have that. Could we mark that, please?

MR. MILLAR: Yes, it is Exhibit K2.3, entitled "Feeling the Heat -- Greenhouse Gas Progress Report 2015", from the Environmental Commissioner of Ontario.

EXHIBIT NO. K2.3: DOCUMENT ENTITLED "FEELING THE HEAT -- GREENHOUSE GAS PROGRESS REPORT 2015", FROM THE ENVIRONMENTAL COMMISSIONER OF ONTARIO.

MS. DeMARCO: And specifically it outlines the sector's specific missions.

If I could ask you to go to table 1, which is the last page of that excerpt, I wonder if you could point me to where on that table it indicates that natural gas distribution is responsible for 30 percent of province-wide emissions.

MS. LYNCH: I don't see anywhere that it specifically says that.

MS. DeMARCO: It's fair to say that it does not say that; yes?

MS. LYNCH: Yes.

MS. DeMARCO: Similarly, can I ask you to me point to where it says that natural gas combustion in the province accounts for 30 percent of province-wide emissions?

MS. LYNCH: I don't see that noted.

MS. DeMARCO: Is it fair to say that it doesn't say that? Is that correct?

MS. LYNCH: Correct.

MS. DeMARCO: Can I ask you to refer to the last column of that table? Based on 2013 data, is it fair to say that the table indicates that electricity accounts for 6 percent of the province-wide emissions?

MS. LYNCH: Yes, I see that in the top line.

MS. DeMARCO: And transportation counts for 35 percent of province-wide emissions?

MS. LYNCH: Yes, I see that.

MS. DeMARCO: And these all are oil-related fuels, if you look at the columns: road, off-road, domestic aviation, domestic marine and rail; is that fair?

MS. LYNCH: I would expect primarily.

MS. DeMARCO: And industry accounts for 28 percent of the emissions in the province; is that fair?

MS. LYNCH: Yes, I see that.

MS. DeMARCO: Buildings, 19 percent; is that fair?

MS. LYNCH: Yes, I see that.

MS. DeMARCO: And we would expect that to be a mix of electricity and HVAC type emissions; is that fair?

MS. LYNCH: Yes, perhaps some other fuels, maybe oil.

MS. DeMARCO: And agriculture is 4 percent?

MS. LYNCH: Yes, I see that.

MS. DeMARCO: And waste is 5 percent?

MS. LYNCH: Yes, I see that.

MS. DeMARCO: For a total of 100 percent; is that fair?

MS. LYNCH: Yes.

MS. DeMARCO: Thank you. In relation to T2 and R100 customers, have you looked at the impact of carbon pricing on your DSM budgets at all?

MS. LYNCH: No, we haven't, and certainly we'll talk more specifically on the next panel.

MS. DeMARCO: Thank you. In terms of working directly with it T2 and R100 customers, I know that you will look at that on the next panel, but just in terms of cost effectiveness or efficiency, is there any data in relation to direct reductions by the source versus DSM related activity?

MR. GOULDEN: Do you mean with regards to GHG emission, Ms. DeMarco?

MS. DeMARCO: With regards to carbon pricing, GHG emissions reductions and/or energy savings.

MR. GOULDEN: We haven't been involved in any of that work at this point.

MS. DeMARCO: Those are my questions, thank you.

MS. LONG: Thank you, Ms. DeMarco. Mr. Shepherd?

MS. DeMARCO: I wonder if we might be excused to take our leave at this point?

MS. LONG: That's fine. We will issue our decision later. It will either be by way email, or we'll make a decision from the dais after.

MS. DeMARCO: Thank you for your consideration, Madam Chair.

CROSS-EXAMINATION BY MR. SHEPHERD: