The Role of Solar in Ontario's Long Term Energy Plan

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Glossary of Terms

APS	Achievable Potential Study
ARBPRIA	Amended and Restated Bruce Power Refurbishment Implementation Agreement
CCAP	Climate Change Action Plan
CDM	Conservation and Demand Management
CNSC	Canadian Nuclear Safety Commission
DER	Distributed Energy Resources
DGTF	Distributed Generation Task Force
DSC	Distribution System Code
DSG	Distributed Solar Generation
FAO	Financial Accountability Office
ECO	Environmental Commissioner of Ontario
FIT	Feed-in Tariff
GA	Global Adjustment
GHG	Greenhouse Gas
HOEP	Hourly Ontario Electricity Price
HONI	Hydro One Networks Inc.
HST	Harmonized Sales Tax
IESO	Independent Electricity System Operator
kW	Kilowatt
kWh	Kilowatt Hour
LDC	Local Distribution Company
LRP	Large Renewable Procurement
LTEP	Long Term Energy Plan
LUEC	Levelized Unit Energy Cost
MDMR	Meter Data Management and Repository
MT	Megatonne
MW	Megawatt (this submission utilizes MW AC rather than DC)
MWh	Megawatt Hour
NGS	Nuclear Generating Station
OEB	Ontario Energy Board
OPG	Ontario Power Generation
OPO	Ontario Planning Outlook
OSTHI	Ontario Solar Thermal Heating Incentive
PPA	Power Purchase Agreement
RPP	Regulated Price Plan
SCADA	Supervisory Control and Data Acquisition
TOU	Time of Use
TSC	Transmission System Code
TWh	Terawatt Hour

Executive Summary

The Canadian Solar Industries Association (CanSIA) is a national trade association that represents the solar energy industry throughout Canada. CanSIA's vision is for solar energy to be a mainstream energy source and an integral part of Canada's diversified energy mix by 2020. CanSIA also intends for the solar energy industry to be sustainable, with no direct subsidies, and operating in a supportive and stable policy and regulatory environment within a similar time frame. In working to accomplish this goal, CanSIA is pleased to make this submission to the Ontario Ministry of Energy on the Long Term Energy Plan (LTEP).

Ontario currently enjoys a robust electricity supply, enough to meet our capacity and energy needs including our reserve requirements. This will not always be the case, however, and the province will need to think carefully about how it is going to address a number of risks and uncertainties that will materialize over LTEP's planning period to 2035. These risks include:

- On the electricity demand side:
  - Increased electrical demand as a result of the successful implementation of federal and provincial climate change mitigation policy including the Cap and Trade program and the Climate Change Action Plan (CCAP);
  - The high potential that Conservation and Demand Management (CDM) targets will not be hit, resulting to an increase in net electricity demand;

- On the electricity supply side:
  - Pickering Nuclear Generating Station (NGS) not operating until 2024;
  - Portions of the Bruce and Darlington NGS refurbishments being cancelled due to cost or schedule overruns;
  - End-of-life and end-of-contract existing generation facilities not being repowered due to a lack of revenue certainty;

- Greenhouse gas (GHG) emission increases:
  - Changes to the supply and demand pressures in the electricity sector identified above will change how the province utilizes natural gas generators. Any increased use of natural gas powered electricity in the province (such as to electrify other sectors of the economy like transportation and heating loads) will result in increases in GHG emissions. These impacts could jeopardize Ontario meeting it's GHG emission reduction targets.

Ontario has made great strides in greening the electricity grid, retiring coal, encouraging conservation, making investments in transmission and distribution, and piloting different types of storage and demand side management projects. The costs associated with maintaining and modernizing electricity infrastructure are not insignificant, however, the investment has resulted in a resilient, clean and versatile system which will serve Ontarians well going forward.

Solar has seen dramatic decreases in cost in Ontario. Since the introduction of the Feed-in Tariff (FIT) Program in 2009 the cost of solar in the province has fallen roughly 60%, with future forecasts pointing to continued reductions over the planning period. Ontario companies now install residential solar PV at lower costs than the United States.

With over 2 GW of solar installed in the province, and a further 600 MW in the pipeline, solar contributes just 5% to residential electricity bills – a massive achievement on the cost front. Greater levels of functionality are also materializing as inverter technology advances are made which allow solar systems to provide ancillary services to grid operators. Solar can meaningfully contribute to the provinces goals for the energy system. The LTEP needs to continue the conversation about what those goals are and make decisions on the type of grid we want to build over the next decade. To achieve this, the LTEP should include the following policy goals and considerations:

- Demand side risks mean the government should be developing an LTEP which plans for a demand outlook falling between Outlook B and Outlook C.

- Supply side risks mean the government should maintain realistic mechanisms for securing supply, when the need arises. This includes procuring utility scale renewable generation at the lowest possible cost via competitive procurements for long term contracts and ensuring market renewal initiatives support renewables.

- Maintaining low levels of GHG emissions from the electricity sector even in the face of potential risks to supply/demand and increased electrification of other sectors of the economy;

- Committing to full transparency on nuclear refurbishment off-ramps and cost thresholds that trigger them;

- Developing a robust net metering regulatory framework that encourages cost efficiencies, customer choice, and innovative business models including the implementation of Time of Use (TOU) rates for net metering customers, community/virtual net metering, and third party ownership;

- Transitioning the distributed solar industry to a net metering framework in a reasonable fashion using a capital cost incentive administered through the Climate Change Action Plan (CCAP);

- Working with the solar industry, Local Distribution Companies (LDCs), the Ontario Energy Board (OEB) to reduce the cost of solar;

- Modernizing electricity rate models to encourage innovation from utilities while protecting individuals and businesses ability to meet their own electricity needs at a reasonable cost; and

- Utilizing solar thermal technologies to offset natural gas use for space and water heating.

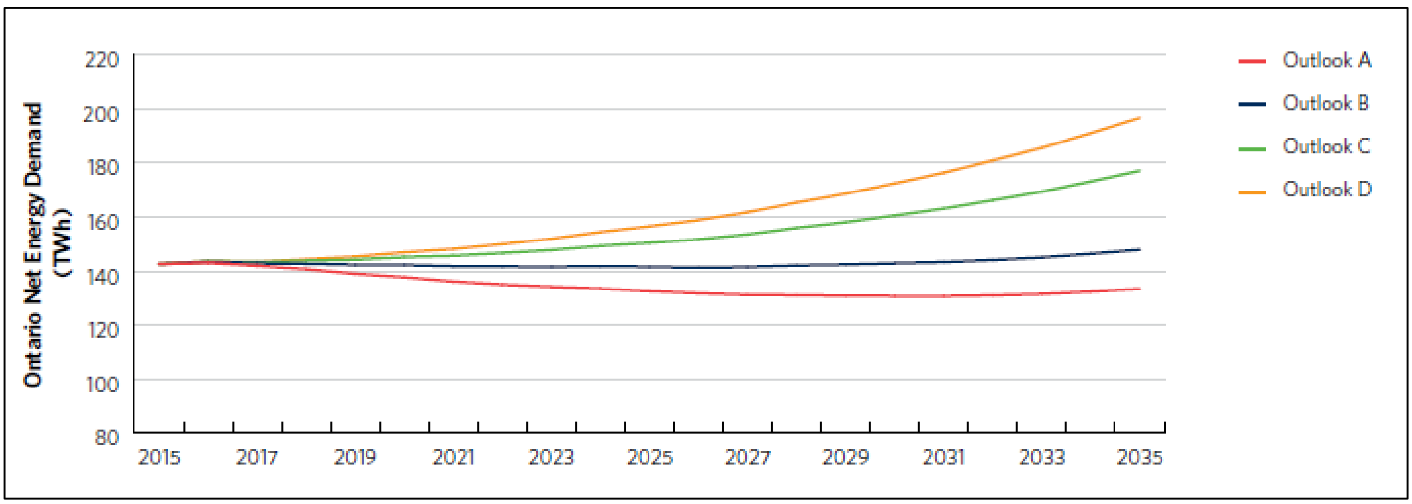
The province, in conjunction with all stakeholders, will need to ask questions about whether doubling down on costly and risky nuclear refurbishments makes sense in the face of the falling costs of renewables and storage, whether utilities should be incented in new ways to make new kinds of investments to enable distributed grid models, and how we ensure that decisions made in the energy sector do not negatively impact the environment but continue to maintain Ontario as a leader in North America. Solar can help with all aspects of the energy transition underway in the province and CanSIA and its members look forward to making that transition a success for the climate, ratepayers, and industry.

Assessment of the Ontario Planning Outlook

The Ontario Planning Outlook (OPO) lays out four demand outlooks (referred to as Outlooks A through D) which vary from declining demand (Outlook A) to increasing demand (Outlooks C and D). Essentially, the OPO does not recommend any action in the near-term for the Ontario power system due to variations in the demand outlook and a strong supply (at the bulk transmission level) to meet those demand outlooks, at least over the short term.

The current supply plan relies heavily on extending the life of the Pickering NGS, refurbishing the province's other nuclear facilities (Bruce and Darlington), and repowering existing generation after end-of-life or contract term. Both the total cost of electricity and the average unit cost of electricity are expected to be essentially flat over the planning period under Outlook B (flat demand outlook). The OPO does acknowledge that there will be a need for new supply should electrification due to the Climate Change Action Plan (CCAP) result in increased demand. GHG emissions are also estimated to remain low and flat over the planning period under Outlook B, however, may increase depending on the extent that the existing gas-fired generation fleet is used to meet growing demand under Outlooks C and D. The OPO concludes that there is significant uncertainty with regards to future electricity demand in the province and that actual demand could be reflected by any of Outlooks A through D.

Figure 1: Ontario Net Energy Demand across Demand Outlooks[1]



CanSIA agrees that there is significant uncertainty with regards to Ontario's future demand outlooks, however, that a range between Outlooks B and C is more reasonable than Outlook B. Outlook A has falling electricity demand over the planning period. Falling demand is unreasonable considering that the province is expected to grow economically in the near future, and, recent demand decreases were primarily due to one-time events related to effects from the 2007/2008 financial crisis (i.e., closure of pulp and paper mills and mining operations). In addition, Ontario's population is expected to grow by roughly 20% over the next 20 years which should push demand higher. Outlook B

[1] Independent Electricity System Operator, Ontario Planning Outlook, http://www.ieso.ca/Pages/Ontario%27s-Power-System/Ontario-Planning-Outlook/default.aspx, pg. 6.

assumes growing gross demand offset by Conservation and Demand Management (CDM) activities resulting in flat net demand, which is more reasonable compared to Outlook A. Outlooks C and D assume increased electrification. In fact 80% of the increase in demand from Outlook B to C is attributable to the displacement of fossil fuels with electricity (ex. Switching oil heating to heat pumps, electric space heating, water heating, and an increase in the use of electric vehicles). Outlook D incorporates a 50% reduction in market share in the gas market as these types of activities are switched to electricity. That level of penetration for electrical versions of traditionally fossil fuel powered activities is not unreasonable, however, it is aggressive and further supports that Outlook C is more reasonable than Outlook D.

Demand Side Uncertainty

Impact of Climate Change Policy

Whether Ontario's future demand ends up being closer to Outlook B or Outlook C will depend largely on the actions related to (and reactions to) climate change policy. Both the federal and provincial government are enacting strong climate change policies which should drive electricity demand towards Outlook C, including:

- Federal: Implementation of a national price of carbon of $10/tonne in 2018 increasing to $50/tonne by 2022;
- Ontario: Implementation of a Cap and Trade Program in 2017; and
- Ontario: Implementation of the CCAP beginning in 2017.

Electrification of transportation, industrial processes, and heating in buildings is widely viewed as essential to meeting GHG emission reduction targets. While the OPO discusses possible impacts of electrification of transportation and buildings on the gross electricity demand in Ontario, it is not clear whether any of the levels of impact accurately represent the impact if the government's climate change goals are being achieved. Research into electrification of transportation conducted on CanSIA's behalf found that if 25% of the Ontario vehicle fleet were to transition to electric vehicles over the next 15 years, the result would be an extra 6.6 TWh of energy consumption and an almost 1 GW increase in peak demand. These estimates do not account for an increase in the overall number of vehicles or the impacts of higher electrification of different vehicle types (such as commercial trucks compared to passenger vehicles).

If the CCAP initiatives, aimed mostly at fuel switching, are less successful than intended, then the electricity demand in Ontario could trend closer to Outlook B.

Impact of Conservation and Demand Management Initiatives

The IESO's planning assumption across all demand Outlooks is that the 2012 LTEP CDM target of 30 TWh by 2030 is achieved. Analysis conducted on CanSIA's behalf suggests that there are risks to achieving these CDM targets which would result in higher net demand than is currently used as the baseline assumption in the OPO. For example:

- The IESO's Achievable Potential Study (APS) assumes that short-term (2015-2020) residential consumption will decrease by 5.5% due to a variety of factors including continued conversion of space heating and water heating to non-electric fuels. Simultaneously, the CCAP is expected to reduce the amount of conversions from electric to fossil fuels in an effort to reduce GHGs from the building sector.

- One-third of the total TWh of savings is currently undefined (i.e. how those savings will be achieved is unknown), representing a significant amount of uncertainty both in terms of timing of CDM achievement and the amount of CDM that might actually be achieved.

- A recent Berkley study concluded that the results from an energy efficiency program in California showed that model projected savings were roughly 2.5 times higher than the actual savings due to inadequate measurement and verification being employed to certify conservation savings.[2]

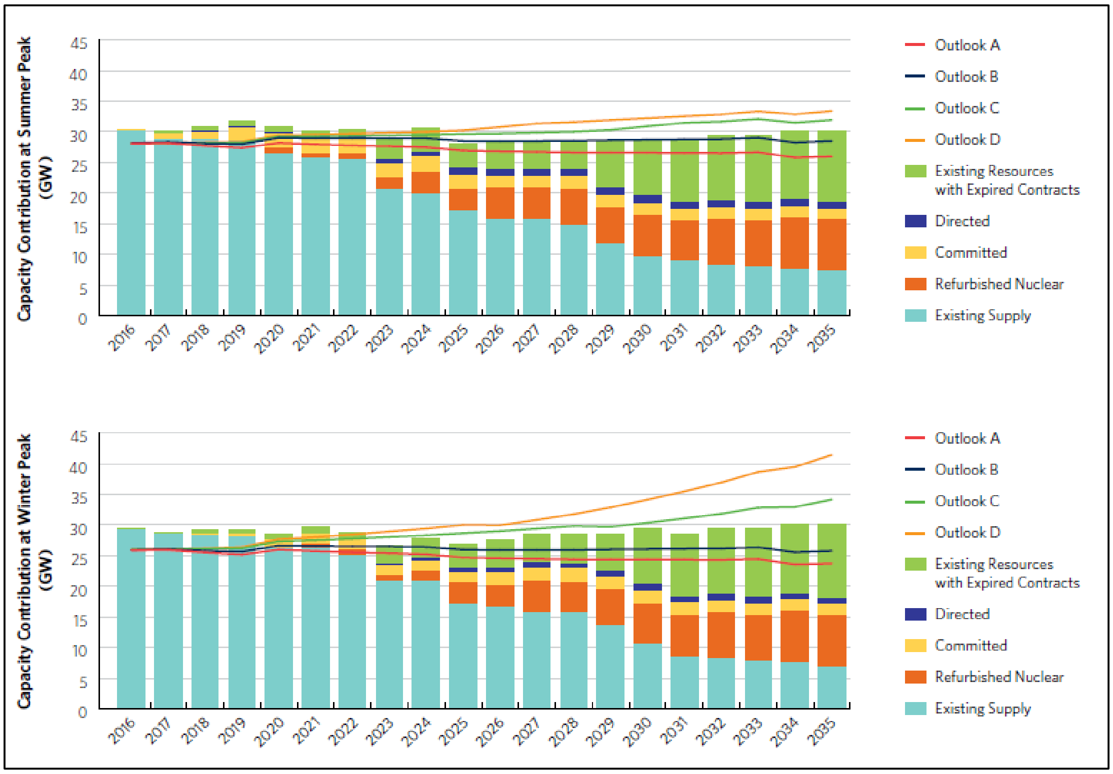
Additionally, because the IESO assumes that CDM impacts reduce gross demand, there is a multiplier effect on the overall need because impacts to gross demand must then have the reserve requirement added to the resulting gross demand if the assumed level of CDM is not achieved.

Supply Side Uncertainty

The OPO expects that Ontario will have sufficient electricity supply to meet the forecasted demand under Outlook B even in the long term. This assessment is based on the combination of Ontario's existing, committed, and directed resources, as shown in Figure 2 below.

[2] Do Energy Efficiency Investments Deliver? Evidence from the Weatherization Assistance Program", Meredith Fowlie, Michael Greenstone, and Catherine Wolfram, June 2015, https://econresearch.uchicago.edu/sites/econresearch.uchicago.edu/files/paper_draft_06_15_clean.pdf.

Figure 2: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements[3]



The OPO performs a limited assessment of supply side risk over the planning period and does not attempt to describe the type of future supply requirements that Ontario may need (e.g. energy, capacity, ancillary services, etc.). Instead of assessing supply side risks and describing alternative supply outlooks, the OPO concludes that in the near-term, no new supply resources are required based on existing generation and the ability repower all resources after end-of-contract or end-of-life.

Analysis conducted on CanSIA's behalf concludes that there are three primary supply assumptions in the OPO which carry significant risk to Ontario's supply adequacy over the planning period:

- Regulatory risk to Pickering NGS end-of-life extension;
- Nuclear refurbishment cost and timelines; and
- Lack of revenue certainty for repowering existing generation.

Regulatory Risk to Pickering End-of-Life Extension

The OPO assumes that Pickering NGS will extend the life of units 1 and 4 until 2022 and units 5, 6, 7 and 8 until 2024. In order to achieve this extension, Ontario Power Generation (OPG) must receive regulatory approval from both the

[3] Independent Electricity System Operator, Ontario Planning Outlook, http://www.ieso.ca/Pages/Ontario%27s-Power-System/Ontario-Planning-Outlook/default.aspx, pg. 10.

Ontario Energy Board (OEB) and from the Canadian Nuclear Safety Commission (CNSC). Both processes require submission of detailed evidence that will be vetted by regulators and stakeholders – success in both regulatory proceedings is not guaranteed.

The current operating permit from the CNSC for Pickering NGS is to August 2018. Within the OEB's purview, an economic approval of Pickering NGS must be completed through the OPG regulated generation assets rate approval process. Recently, OPG published updated information on the revenue requirement for their nuclear assets and have indicated that rates need to rise in order to extend the life of the facility. Using the IESO's base case evaluation of the merits of the Pickering NGS life extension, the expected electricity system cost benefits were expected to be between $300 – 500 million. There is potential, however, for capital cost increases to the Pickering life extension which would erode the potential savings from the extension. Additionally, the cost of natural gas can also have a significant impact on the expected savings as a portion of those savings relate to avoiding using natural gas genertors.

- Depending on assumptions for total energy production from extended Pickering NGS operation, capital and operating costs increases of between 15 – 22% would eliminate the expected cost savings.

- Pickering NGS cost savings assume natural gas pricing must increase beyond current future market prices to over $4/MMBTU. If natural gas prices remain low (current assessments place future costs at between $2.70/MMBTU - $3.70/MMBTU between 2020 and 2024) over the extended life of Pickering NGS, the cost-benefit case for the continued operation of the facility weakens substantially.

Nuclear Refurbishment Cost and Schedule

The OPO expects the refurbishment of ten nuclear units between 2016 and 2033 (4 units at Darlington between 2016 and 2026, and 6 units at Bruce Power between 2020 and 2033). At various times throughout the refurbishment process there will be multiple units that are offline – in 2024, for example, 4 units will be down for refurbishment simultaneously. The refurbishment carries a number of risks to Ontario's supply situation with regards to both timing and cost:

- Nuclear refurbishments require a significant number of nuclear professionals and tradespeople. Labour availability may be limited and impact the ability to meet the planned schedule.

- Recent experience with refurbishment in Canada has resulted in going over schedule and over budget.
  - Point Lepreau NGS in New Brunswick required 4 years to complete and was an estimated $1 billion over budget.
  - In 2008, Bruce Power announced an increase in forecasted costs by $350 - $650 million over the budget of $2.75 billion for the Unit 1 and 2 restart. The project was completed in late 2012, roughly 3 years after the original completion date.

- Recent experience with the construction of new nuclear facilities has resulted in even greater cost and schedule overruns:
  - Flamanville 3 in France cost estimate rose from €3.3 billion in 2005 to €10.5 billion in 2015
  - Watts Bar units 1 and 2 began construction in the early 1970s. Work on unit 2 was canceled in 1985 after the utility spent $1.7 billion. When work was resumed on Watts Bar unit 2 in 2007, the cost to

complete construction was estimated at \$2.5 billion, but was later revised to between \$4 and 4.5 billion.

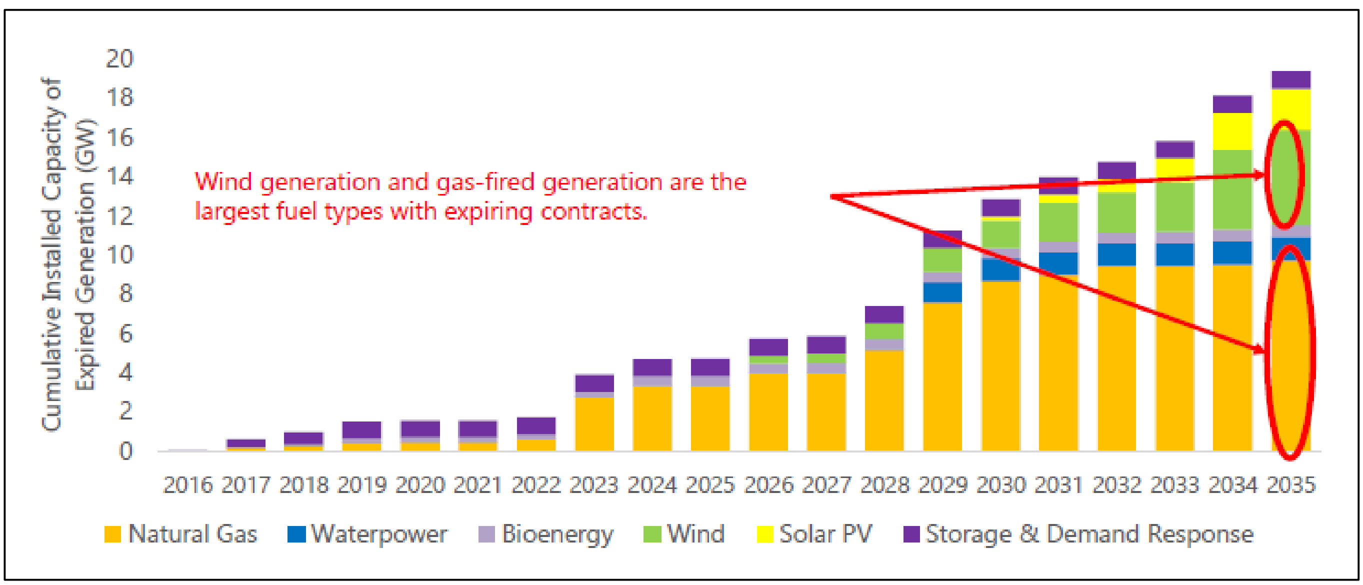
- Hinkley Point C NGS was originally estimated to cost £6 billion but was recently increased to as much as £18 billion.

It is important to note that the government does have off-ramps built into the Amended and Restated Bruce Power Refurbishment Implementation Agreement (ARBPRIA), and has only committed the refurbishment of the first unit at Darlington (with the recognition that it will assess refurbishments of each remaining unit on a go-forward basis). The OPO, however, does not provide an estimate as to how much uncertainty exists with the refurbishment schedule nor does it address how much flexibility there is to adjust the schedule of later refurbishments if earlier refurbishments go over budget or schedule. If the early refurbishments go over schedule or are cancelled due to costs, the OPO does not address how it will meet the resulting supply gaps from either a supply adequacy or GHG emissions perspective.

Lack of Revenue Certainty for Repowering Existing Generation

The OPO assumes that all existing contracted generation will be available for re-powering at the end of the facilities' contract term or end-of-life. Continued operation of generation assets at the end of their life or with expired contracts will, in actuality, depend on a number of factors including: the condition of the asset, power system needs at the time, project return expectations based on current market conditions, and government policy. Some of these factors, such as policy and power system needs, can be influenced directly by the IESO and government. Others, like asset condition and project return expectations, are outside of government and agency control. Installed capacity from expired contracts is expected to grow to almost 45% of Ontario's installed capacity by 2035 (not including refurbished nuclear generation), creating a massive risk to supply adequacy if these assets are unable to return to service, or choose not to based on market and policy conditions.

Figure 3: IESO Expiring Contracts



Recent announcements by the government and IESO have increased uncertainty within the Ontario electricity sector, adding to the risk that end-of-life and end-of-contract assets will not return to service. For renewable generation resources, the Ontario government announced the cancellation of the second round of the Large Renewable Procurement (LRP II) and provided no new timelines for possible future procurement. The IESO has also launched the Market Renewal Initiative (MRI) which envisions significant market design changes including the possible adoption of locational marginal pricing, a day-ahead commitment process, and the introduction of a capacity market.

In recent public speeches the Minister of Energy has also indicated the government's intent to move to technology agnostic procurements and to utilize a potential capacity market in the future in order to bring on new supply when the need arises. Depending on the type of generation, these approaches could have serious impacts for generators to participate in these new/modified procurement approaches. For example, renewable generators (including solar) have, to date, faced significant challenges in participating in capacity markets in other markets due to the need to supply firm capacity in order to participate. It is very unclear whether new market mechanisms like a capacity market will provide enough revenue certainty allow for the repowering of renewable generation at the end of contract term or end-of-life. If this is the case, new market mechanisms could favour natural gas generation to the exclusion of renewables (which would have a negative effect on the province's ability to meet GHG emission reduction targets).

Potential Need for New Supply

Based on the risks to both the demand and supply forecasts described above, analysis conducted on behalf of CanSIA was performed to describe potential future supply needs based on the impacts of certain of those described risks. Figure 4 below summarizes those potential impacts across, including:

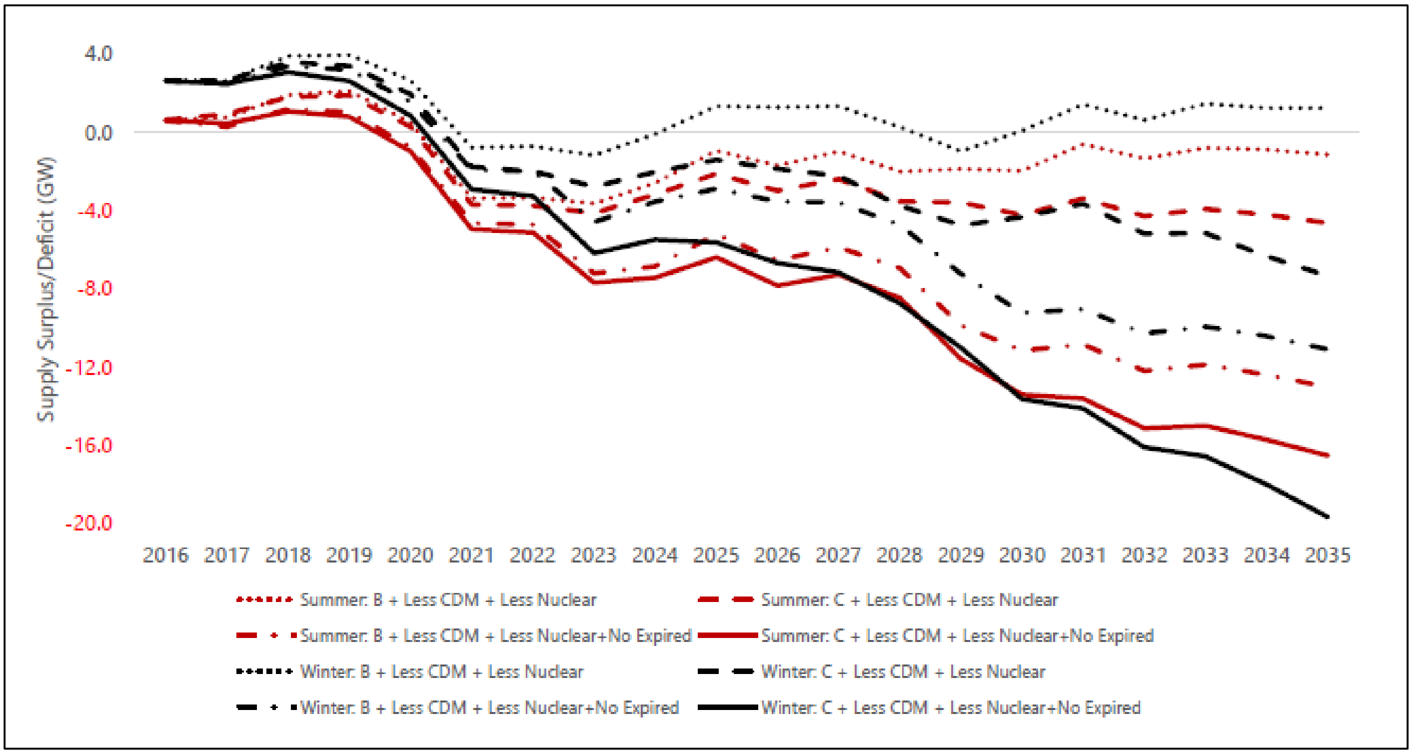
- Strong and successful climate policy trends net demand towards Outlook C rather than Outlook B.

- Less CDM
    - Reflecting the aggressiveness of the OPO's assumption that 100% of the CDM target will be achieved, the analysis assumes only 75% of the CDM target is achieved.

- Less Nuclear
    - Pickering NGS only operating only until end of 2020;
    - Half of all refurbished nuclear units will experience a delay of one peak period (i.e. returning in winter instead of summer); and
    - Reflecting the potential for cost and schedules to be higher than assumed and the continued drop in cost of renewables, the final 2 Bruce Power units (units 7 and 8) are assumed not be refurbished.

- End-of-life and end of contract asset repowering
    - Limited revenue certainty for repowering generation reduces the confidence that existing generation will be available to meet the need for supply after their contract expires or they reach end-of-life.
    - Supply assessment should assume no repowered assets are committed to meet system peak until the capability and cost of those assets are compared against other resource options.

Figure 4: Range of Potential Supply Needs in Ontario



Meeting the Potential Need for New Supply

As discussed in the previous sections, a range of potential supply needs could arise based on a critical assessment of the OPO. To meet the range of supply needs, the supply mix must be able to meet three objectives:

- Reliability: the Ability maintain peak reserve margin for peak demand periods and the ability to manage fluctuation in the supply/demand balance;

- Low emissions: GHG emissions should be maintained as low as possible; and

- Cost effectiveness: A reliable electricity system with low GHG emissions should be achieved as cost effectively as possible.

Achieving the above objectives requires a balance of different supply resources to leverage each resource's benefits and offset their drawbacks. Analysis conducted on CanSIA's behalf found that if, for example, the needs resulting from the risks identified above were met with primarily natural gas, cost would be kept relatively low but GHG emissions could balloon to over 27 MT annually by 2035. If imports from Quebec were primarily used to meet demand, GHG emissions could be kept relatively low (around 4 MT annually), however costs would increase as Ontario began to compete with New England and New York for energy from Quebec. Further, if Ontario were to shift to a winter peaking jurisdiction, imports would become even more costly as Quebec only exports firm capacity and energy that are in excess of their own internal requirements, and they do so at a premium.

Analysis conducted on CanSIA's behalf takes 4 reasonable scenarios (detailed fully in Appendix A) and determines the potential need for new supply, as well as how to meet that need using available resources. The GHG impacts of all scenarios are also assessed. The scenarios look at Ontario's supply and demand situation across the near-term (2017 – 2021), medium-term (2022-2026), and long term (2025-2035). The four scenarios analyzed are:

- Scenario 1: Outlook B demand + less CDM
- Scenario 2: Outlook B demand + less CDM and less nuclear
- Scenario 3: Outlook C demand + less CDM
- Scenario 4: Outlook C demand + less CDM and less nuclear

Figure 5: Summary of Potential Supply Scenarios

Scenario	Renewable Generation Opportunity	Near (MW)	Medium (MW)	Long (MW)	Average Annual GHG Emissions (MT - 2017-2035)
1: Outlook B	Repower	200	300	2,200	9.9
	New	0-200	250-500	500-1,000	
2: Outlook B less Nuclear	Repower	200	300	2,200	10.7
	New	200-300	250-500	250-500	
3: Outlook C	Repower	200	300	2,200	11.4
	New	200-300	1,000-2,000	1,000-3,000	
4: Outlook C less Nuclear	Repower	200	300	2,200	11.7
	New	200-300	1,000-2,000	2,000-5,000	

Figure 5 above illustrates that depending on the supply/demand parameters, both the extent of the need for new supply and the GHG impacts of the resulting supply mix can vary, but are likely to increase over time if policy does not dictate otherwise.

The LTEP should include policy priorities for meeting potential supply needs while managing GHGs including:

- Continuing to use competitive procurement for long-term contracts for utility scale renewables. Competitive procurement for long-term contracts for electricity generation clearly provides the best value for ratepayers, enabling adequate risk allocation between developers and rate-payers. The competitive tensions and long-term financial commitments allow rate-payers to realize the benefits through lower prices over the long term. Competitive procurement is the primary procurement mechanism used by other Canadian jurisdictions for this reason;

- Ensuring the IESO's Market Renewal Initiative supports renewables. Capacity auctions, one of the concepts under development, would favour emitting resources blocking out the potential for non-emitting resources to be further deployed. A capacity auction is a difficult system for renewables to operate under since financial commitments are for a short time period, necessitating generation developers to front load risk to the detriment of rate-payers. This system can work with dispatchable, emitting fossil fuel sources such as coal and natural gas, but with a variable fuel type, like solar or wind, this system could make a new renewable projects uneconomic and therefore unable to compete. The inability of renewable generators to compete reduces the pool of participants and could impact the price achieved for ratepayers; and

- Making better use of Distributed Solar Generation (as outlined later in this submission).

Summary of OPO Assessment

In summary, an assessment of the OPO indicates a high level of uncertainty with regards to the impacts of a number of key assumptions within the report. The impacts of strong climate policy at the provincial and federal level could drastically increase assumed demand for electricity. Similarly, not meeting CDM targets could also increase net electricity demand by achieving lower amounts of reductions to the province's gross demand. The combined impacts of these two demand side risks mean the government should be developing an LTEP which plans for a demand outlook falling between Outlook B and Outlook C. On the supply side, regulatory risks to the end-of-life extension of Pickering NGS, cost and schedule risks to other nuclear refurbishments, and revenue certainty risks affecting the repowering of end-of-life and end of contract term generating assets could create a need for electricity supply in the short to mid-term. The LTEP should plan for these impacts with realistic mechanisms for securing that supply should the need arise, including competitively procured long term contracts for renewables rather than capacity market mechanisms.

Compounding those risks are the province's GHG emission reduction commitments. If one, or a combination of, the risks described above materialize, Ontario would currently be forced to rely on its natural gas fleet to a greater extent. This would increase GHG emissions from the electricity sector (which jeopardizes hitting targets) and could also have run-on effects by reducing the emission reduction impact from electrifying other sectors of the economy (like transportation and heating). Utilizing the natural gas fleet to a greater extent could force Ontario to purchase more emissions permits from California and Quebec than intended in order to hit GHG emission reduction targets. In order to address these risks, the LTEP should include firm policy direction that GHG reductions must be prioritized in planning for potential risks to the supply/demand situation in the province.

Greenhouse Gas Emissions Risks

While supply adequacy is of central concern for the LTEP process, the LTEP also must deal explicitly with the GHG emission impacts of any energy planning decisions. As outlined by Dianne Saxe, the Environmental Commissioner of Ontario (ECO), "the LTEP is going to govern 70% of our GHG emissions."[4] According to the ECO, none of the scenarios outlined in the OPO will actually meet the province's GHG reduction targets of 37% below 1990 levels by 2030 and 80% below 1990 levels by 2050. This makes it essential for the LTEP to plan for future scenarios that allow the province to meet its GHG emission reduction targets by using renewables.

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[4] Environmental Commissioner of Ontario, https://magazine.appro.org/news/ontario-news/4551-ltep-at-risk-of-missing-the-mark-on-ghgs,-contingency-planning,-and-public-consultation,-commissioner-says.html.

Estimating Emissions from Ontario's Electricity Sector

As of 2015, the electricity sector accounted for roughly 7% of Ontario's GHG emissions.[5] Since the retirement of coal fired electricity generation in 2014, GHGs from the electricity sector have come primarily from the use of natural gas generation (a small portion is also produced from the transmission and distribution of electricity, or from imports from jurisdictions with dirtier grids). While relatively clean compared to other comparable US and Canadian jurisdictions, Ontario's electricity sector GHG emissions are a function of how the natural gas fleet is utilized to meet demand. The more the natural gas fleet is called into service to meet demand, the higher the emissions from the Ontario electricity sector will be. As such the forecasted emissions from the electricity sector, and actions taken to mitigate those emissions, should account for:

- The GHG emissions per unit of energy generated by the natural gas fleet;
- The current use of the natural gas fleet to meet existing electricity demand; and
- How the use of the natural gas fleet could change over time to meet changing electricity demand.

Estimating GHGs per Unit of Energy Generated from Ontario's Generator Fleet

Ontario's natural gas fleet is comprised of a combination of simple cycle and combined cycle generators. CanSIA has assumed that 85% of energy from natural gas generation is attributable to combined cycle facilities and 15% of energy is attributed to simple cycle facilities. Generally, simple cycle facilities (average heat rate of 7.5 MMBtu/MWh) contribute greater emissions than combined cycle generators (average heat rate of 11 MMBtu/MWh). CanSIA has excluded both the generation and associated GHG emissions from behind the meter natural gas generation (ex. Combined heat and power generators located behind the meter at industrial facilities), which would increase the overall emissions from natural gas electricity generation in Ontario, but is difficult to quantify.

For the purposes of this submission, emissions due to electricity imports are attributed to Ontario rather than the source, using the same emission factor that is applied to imports and to domestic generation. Emissions due to exports are also attributed to Ontario. Using the assumed split between simple cycle and combined cycle natural gas electricity generators, and the average energy generation from natural gas in Ontario, it is estimated that each kWh of generation in contributes approximately 0.43 kg of GHGs to the province's emissions profile. This assessment takes into account how natural gas is used in the province in conjunction with all other generating sources (which in Ontario are emissions free).

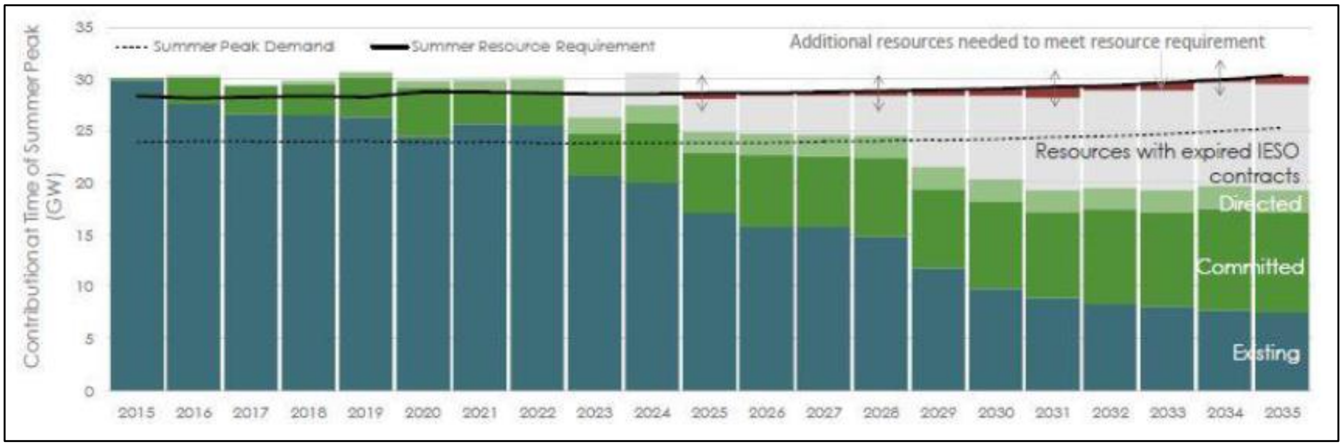
Forecasting Future Emissions from Ontario's Electricity Sector

In order to estimate future GHG emissions from the Ontario electricity sector, a forecast of electricity demand is required. A demand forecast establishes the electrical need that must be met by a resource supply mix over the time

[5] Ministry of the Environment and Climate Change, Ontario's Climate Change Action Plan, https://www.ontario.ca/page/climate-change-action-plan, pg. 6.

period under analysis. The supply mix and demand forecast utilized for this submission is based on the IESO's Ontario Planning Outlook (OPO).

Figure 6: IESO Outlook B Supply/Demand Forecast



The IESO has undertaken an analysis of assumed GHGs from the electricity sector under a baseline flat demand scenario (termed Outlook B in the OPO). Under this scenario the IESO assumes net electricity demand in the province will remain relatively stable and only experience minor increases over the planning period of 20 years. In the OPO the IESO estimates that under a flat demand scenario, that the electricity sector is expected to contribute approximately 80 MT CO2e between 2016 and 2035.[6]

Figure 7: Electricity Sector GHG Emissions under Outlook B

MT CO2e	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Electricity Sector GHG Emissions	34.5	29.9	32.9	27.4	14.9	19.8	14.2	14.2	10.9	7.1	7.1

MT CO2e	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast GHG Emissions (Outlook B)	4.6	3.8	3.5	3.1	3.4	3.6	3.7	4.2	3.4	4.7

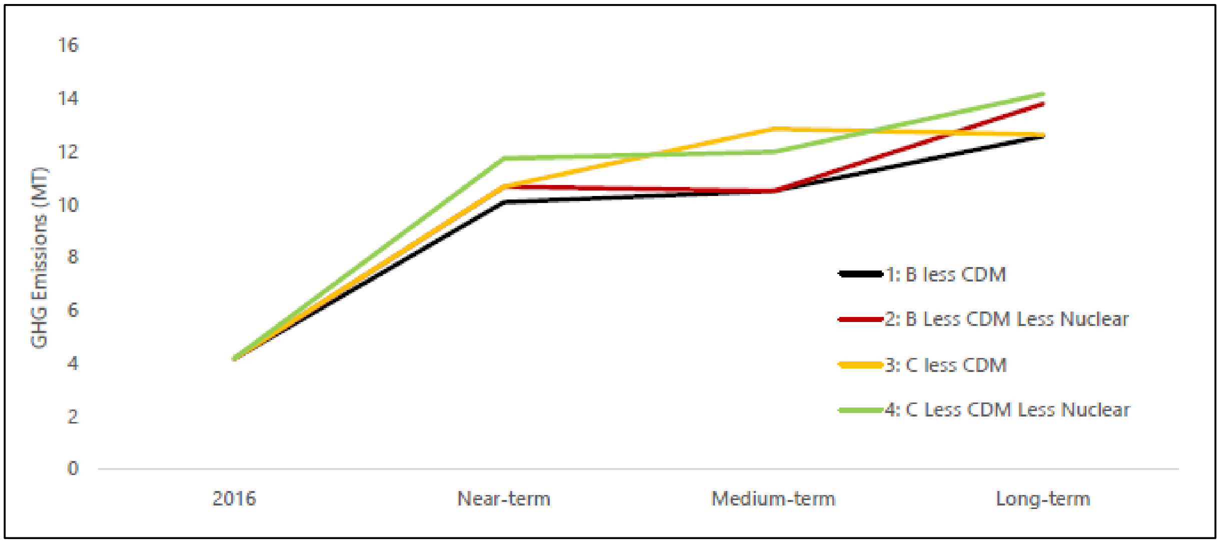
MT CO2e	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Forecast GHG Emissions (Outlook B)	3.8	3.9	3.7	3.9	3.8	4.5	4.0	4.2	4.6	5.3

The IESO's analysis assumes not only flat demand growth in the province, but also assumes that nuclear units will go down for, and return from, refurbishment on time and on schedule, that Pickering NGS will continue to operate until 2024, and that the provinces conservation targets will be met (through programs that do not contribute to further

[6] Independent Electricity System Operator, Ontario Planning Outlook, http://www.ieso.ca/Pages/Ontario%27s-Power-System/Ontario-Planning-Outlook/default.aspx, Pg. 38.

GHG emissions such as behind the meter natural gas). The preceding sections of this report test each of these assumptions to determine a reasonable upper bound for emissions from the electricity sector between 2016 and 2035. Using the scenarios described in the section above, and in Appendix A, analysis conducted on CanSIA's behalf has estimated potential increases to GHG emissions over the planning period.

Figure 8: GHG Emissions under Potential Supply Scenarios 1 – 4

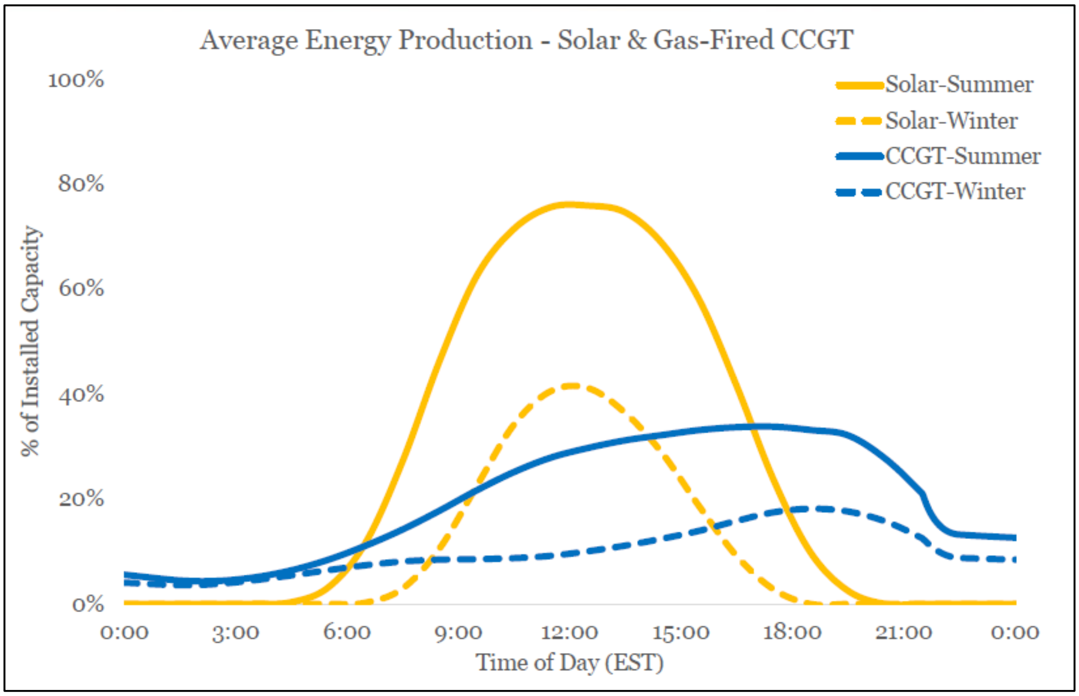


Under each of the potential supply/demand scenarios analyzed for this report, GHG emissions from the electricity sector increase due to increased use of the natural gas fleet to meet changes in net electricity demand.

Using Solar PV to Limit GHG Increases in the Electricity Sector

Solar PV's central contribution to emissions reduction in Ontario is through the avoidance of GHGs from natural gas fueled electricity generation. Each kWh generated by solar PV and consumed by electricity customers will avoid a kWh of grid based electricity. Further, solar PV generation will often directly correlate to production when natural gas generation is used most. This is due to both natural gas generation and solar PV generating during peak times, when electricity demand and price are highest. CanSIA's analysis has factored in Ontario's historical demand profile as well as the generation profiles of natural gas (and all other generation) and solar and what the GHG composition of a kWh from the grid would be based on the amount of natural gas being utilized to meet demand. Currently, natural gas generation in Ontario is generally used to meet periods of peak demand on the electricity grid. When possible, the IESO tends not to dispatch natural gas generators for purposes other than meeting peak demand or providing ancillary services as the continued and steady operation of natural gas facilities is expensive and inefficient. The congruence between the generation profiles for solar PV and the natural gas fleet in Ontario are presented in Figure 9, below.

Figure 9: Solar PV vs Natural Gas Generation Profiles



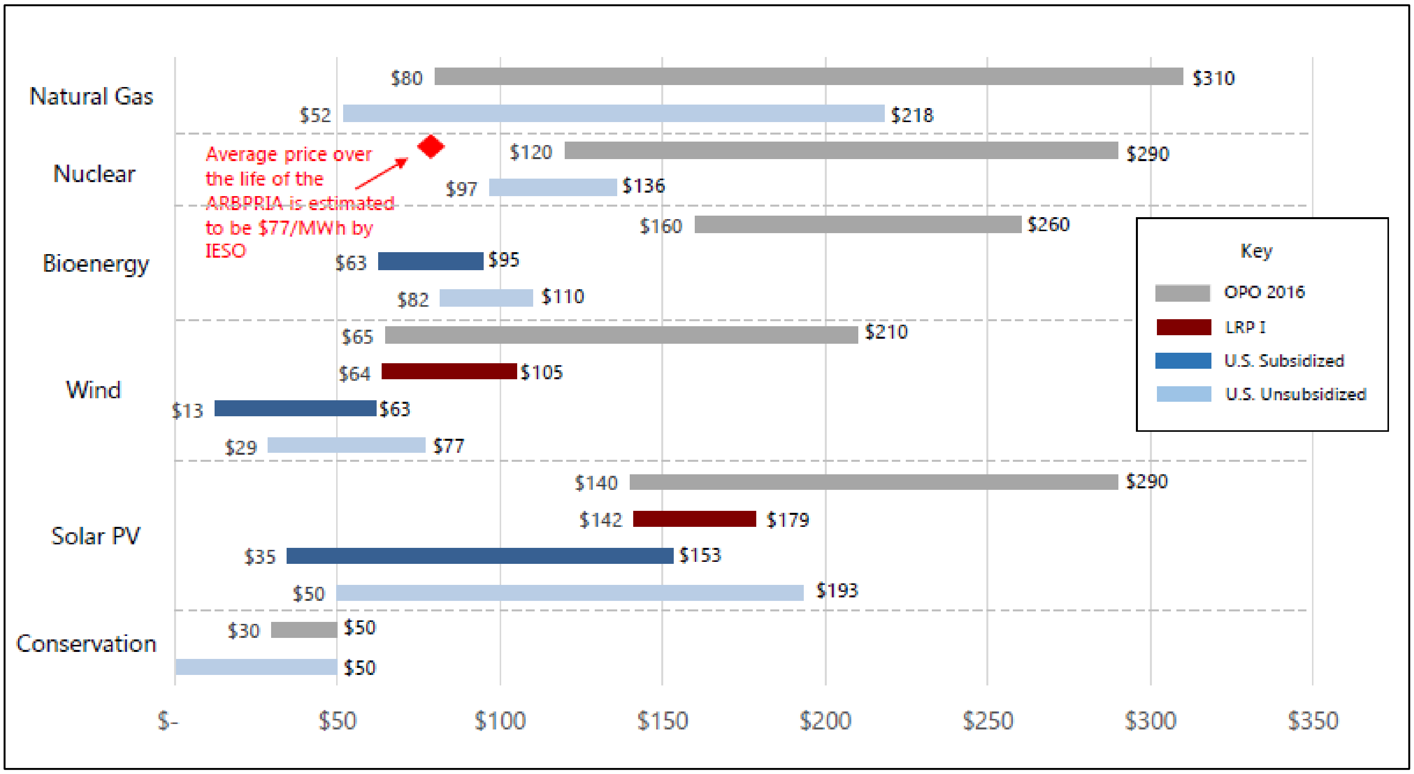
A further contribution to emissions avoidance from solar PV is provided by avoiding the need to generate electricity from centralized natural gas generators and transmit that electricity through the transmission and distribution system. This helps avoid line losses which would otherwise result in additional natural gas generation being required to ensure local demand, often located far away from the source of generation, is met. A small amount of GHGs are also generated from the functioning of transmission and distribution infrastructure which can also be reduced.

Solar PV should be utilized in order to limit any increases in the GHG profile of the electricity sector. Limiting emissions will become more important over time as other sectors of the economy (buildings and transportation) are electrified in order to reduce their emissions. If emissions from the electricity sector increase, electrification will have an overall lower impact on reaching the provinces GHG emissions reduction targets. Solar's usefulness as a source of clean electricity to meet GHG emission reduction goals is, of course, tied to its cost and its impact on the cost of electricity. These two topics are explored in greater detail below.

Declining Cost of Solar

Based on recent analysis completed by Lazard Asset Management and Lawrence Berkeley National Laboratories (Berkeley Lab) on the Levelized Unit Energy Cost (LUEC) of different technologies, the OPO estimates higher costs for solar PV than is reasonable. The OPO's maximum value for Solar PV is 150% ($97/MWh) greater than Lazard's estimate for the US, and there is a 280% ($90/MWh) difference between the minimum levelized costs. The solar PV results from the LRP I are within the lower part of the LUEC band in the OPO, demonstrating a high degree of competitiveness within the procurement. The large difference in LUEC estimates for solar PV suggests that continued price decreases are possible in the Ontario market given experience in other jurisdictions. These comparisons are illustrated in Figure 10 below.

Figure 10: Comparison of OPO LUEC, US LCOE, & LRP I Results by Fuel Type



Other analyses have also forecasted continued cost declines for solar PV, as well. While these analyses have differing views on the pace of cost reductions for solar PV into the future, there is unanimous consensus that costs will continue to decline.

- NREL projects 0.4 - 4.7% annual system cost decline 2014-2025
- IEA projects 4.2% annual system cost decline 2015-2020
- Green Tech Media Research projects 5.6% annual module cost decline 2012-2017
- Tracking the Sun VIII – LBNL Sunshot (expects a 9% 2015 reduction)
- ITNPV projects 3.5% average annual system cost decline 2015-2025[7]

In making a forward looking assessment of installed costs in Ontario it is useful to compare against current and forecasted installed costs for similar sized projects in the United States. Figure 11 below includes CanSIA's installed cost data in CAD and USD as a comparison between in-Ontario costs and US 2015 costs and forecast 2020 costs. CanSIA's installed cost forecasts are in all cases lower than US data for similar sized systems in 2015 and come close to US installed costs in 2020. It is important to note that the US Sunshot forecasts for 2020 are both aggressive as well as backed by multi-million dollar government cost reduction initiatives focused on research/analytics and

[7] ITRPV 2015 Roadmap – Relative System Cost Development for Systems 2014 – 2025.

deployment strategies. The US market also benefits from massive economies of scale in comparison to Ontario. That costs in Ontario will be so close to the Sunshot forecasts in and around 2020 is a remarkable achievement.

Figure 11: Comparison of Installed Cost Forecasts

Renewable Fuel	Project Capacity (kW)	CanSIA Installed Cost ($/W CAD)	CanSIA Installed Cost ($/W USD)	NREL Installed Cost 2015 ($/W USD)*	NREL Installed Cost 2020 ($/W USD)*
Rooftop	6	2.84	2.16	3.10	1.60
Rooftop	10	2.75	2.09	3.10	1.60
Rooftop	100	2.58	1.96	2.20	1.30
Rooftop	500	2.40	1.83	2.20	1.30
Non-Rooftop	10	2.58	1.96	3.10	1.60
Non-Rooftop	500	2.27	1.73	2.20	1.30

*Source: NREL/TP-6A20-65872

As discussed above, the Bruce NGS refurbishment agreement includes off-ramps if more economic supply options materialize before nuclear refurbishments commence. If solar PV (by itself or in conjunction with other technologies like wind and storage) can provide lower cost power than refurbishments at Bruce Power, the LTEP should explicitly allow for that option. To that end, the LTEP should commit to full transparency on nuclear refurbishment off-ramps and cost thresholds that trigger them.

The Cost of Electricity in Ontario

Where is Ontario Relative to Other North American Jurisdictions?

While Ontario's electricity rates have increased since 2008, studies completed by both the Ontario Financial Accountability Office and Hydro Quebec have shown that Ontario's residential rates rank in the middle of the pack when compared against other Canadian Provinces and major North American cities.[8] Figure 12 below illustrates where Ontario falls compared to other Canadian provinces while Figure 13 shows where Toronto falls compared against other major North American cities.

[8] Financial Accountability Office of Ontario, Home Energy Costs in Ontario, http://www.fao-on.org/en/Blog/Publications/home_energy, and, Comparison of Electricity Prices in Major North American Cities, Hydro Quebec, http://www.hydroquebec.com/publications/en/corporate-documents/comparaison-electricity-prices.html.

Figure 12: Financial Accountability Office of Ontario - Average Household Home Energy Cost (2014)

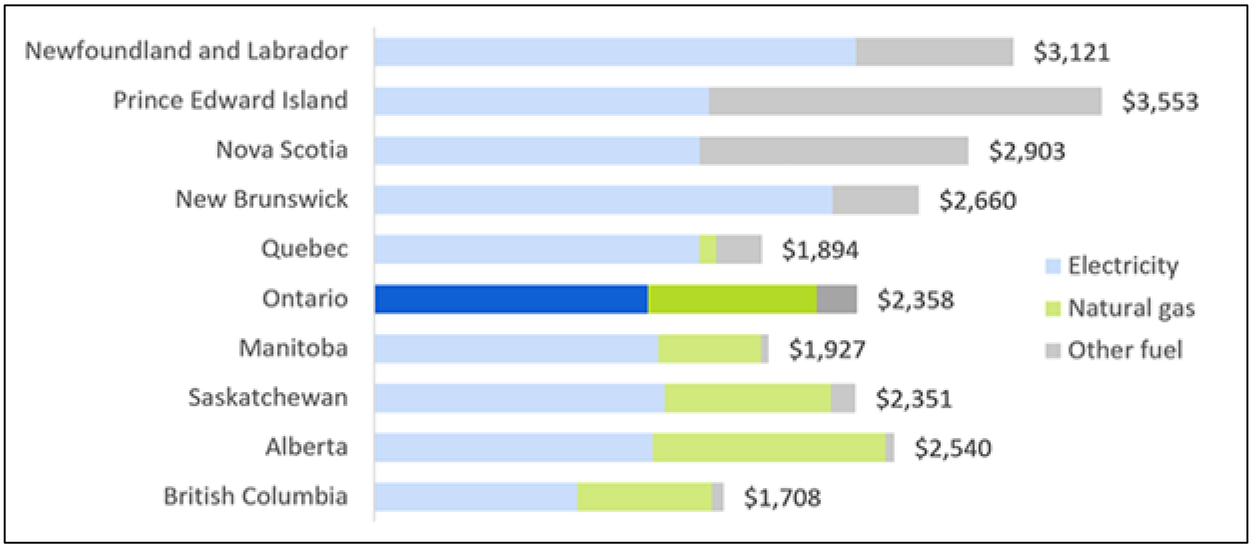
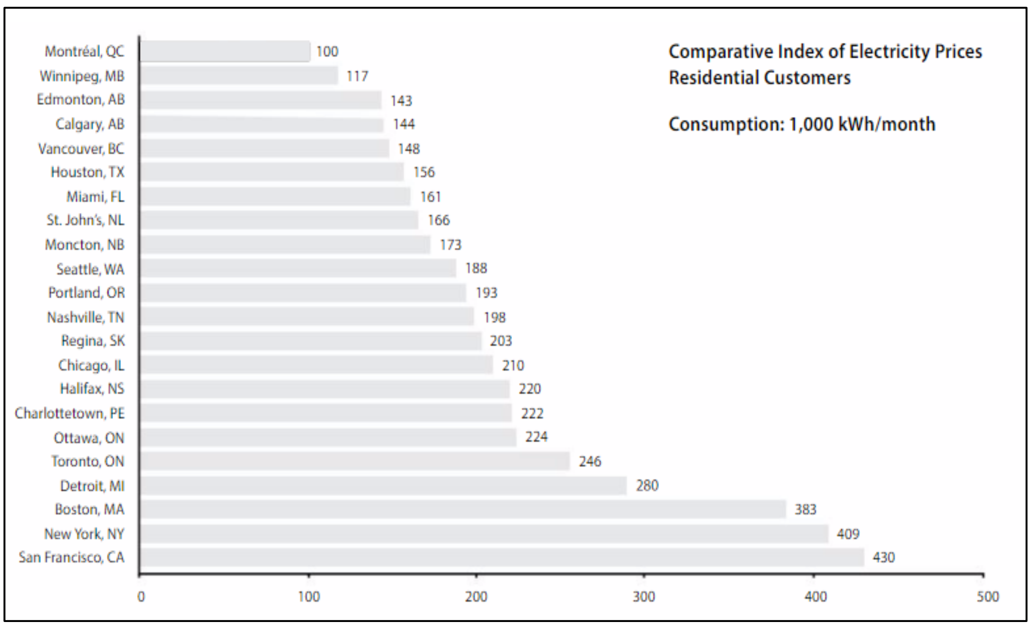


Figure 13: Hydro Quebec – Comparative Index of Residential Electricity Costs (2016)



For Figure 13 it is important to note that while Toronto is towards the higher end of the spectrum when compared against other major North American cities, many of the cities that have lower electricity costs are either much smaller in both population and geographic footprint, or, benefit from large quantities of very inexpensive waterpower.

Solar's Contribution to the Cost of Electricity in Ontario

As aforementioned, Ontario has experienced increases in the cost of electricity over the past decade. Many stakeholders, however, make the incorrect assertion that the majority of these increases are due to adding renewables (wind, solar, waterpower, and bioenergy) to the grid. Natural gas and nuclear contracts, transmission and distribution system reinforcement and expansion, and conservation programs have all contributed to rising electricity rates and renewables make up a relatively small portion of the cost of electricity overall.

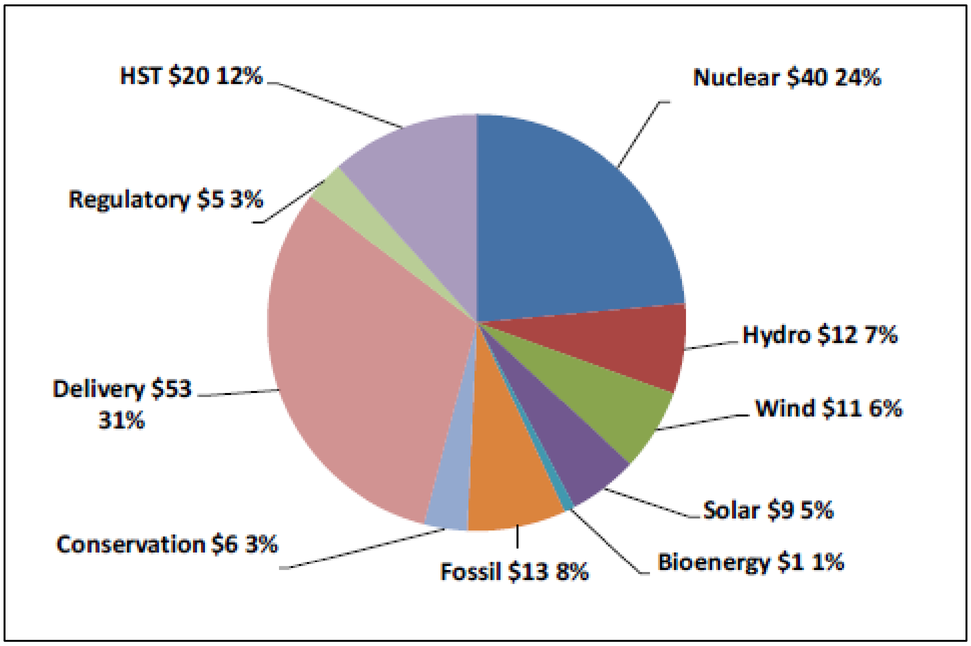
Research conducted in 2016 by Power Advisory LLC on the components of the Ontario residential electricity bill shows what these components are and their relative contribution to the cost of electricity for an average residential consumer. The component pieces include:

- Market energy (Hourly Ontario Electricity Price (HOEP) plus distribution losses)
- Global Adjustment (GA) (which is further subdivided into sources of electricity supply)
- Transmission and distribution (combined into a single component)
- Regulated charges (wholesale market service cost and debt retirement charge)
- Harmonized Sales Tax (HST and the Ontario government's planned rebate of the provincial portion of HST

The GA pays for the difference between Ontario's contractual commitments to electricity generators (including CDM suppliers), and the value on the short-term wholesale market of the electricity generated under these contracts. The great majority of the cost impact of adding renewables to the grid are accounted for within the GA. Some technologies like natural gas and utility scale renewables make a portion of their revenues through the wholesale market and so their cost impacts are a function of the two (i.e. market revenues and GA). If the cost impacts of market revenues and GA is broken down into its component pieces (i.e. the various different electricity supply sources), and the other component pieces of the residential electricity bill are added, we arrive at Figure 14 below.

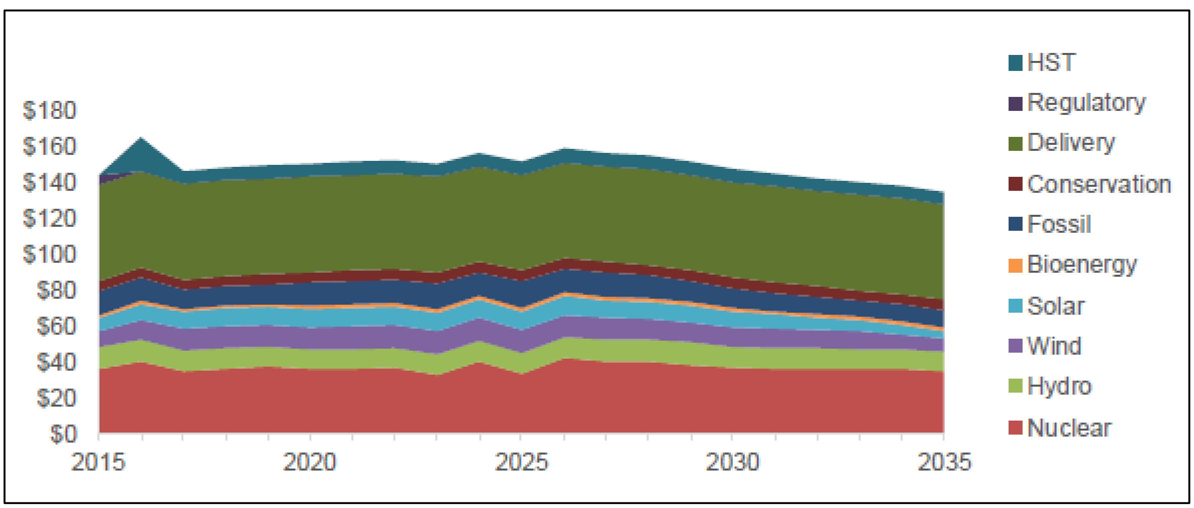
As illustrated here, delivery (i.e. transmission and distribution) make up the single largest share of the electricity bill. Nuclear, HST, and natural gas make up the next largest components. In 2016, solar PV was responsible for just 5% of the average residential electricity bill in Ontario.

Figure 14: Components of the Ontario Residential Electricity Bill (2016)



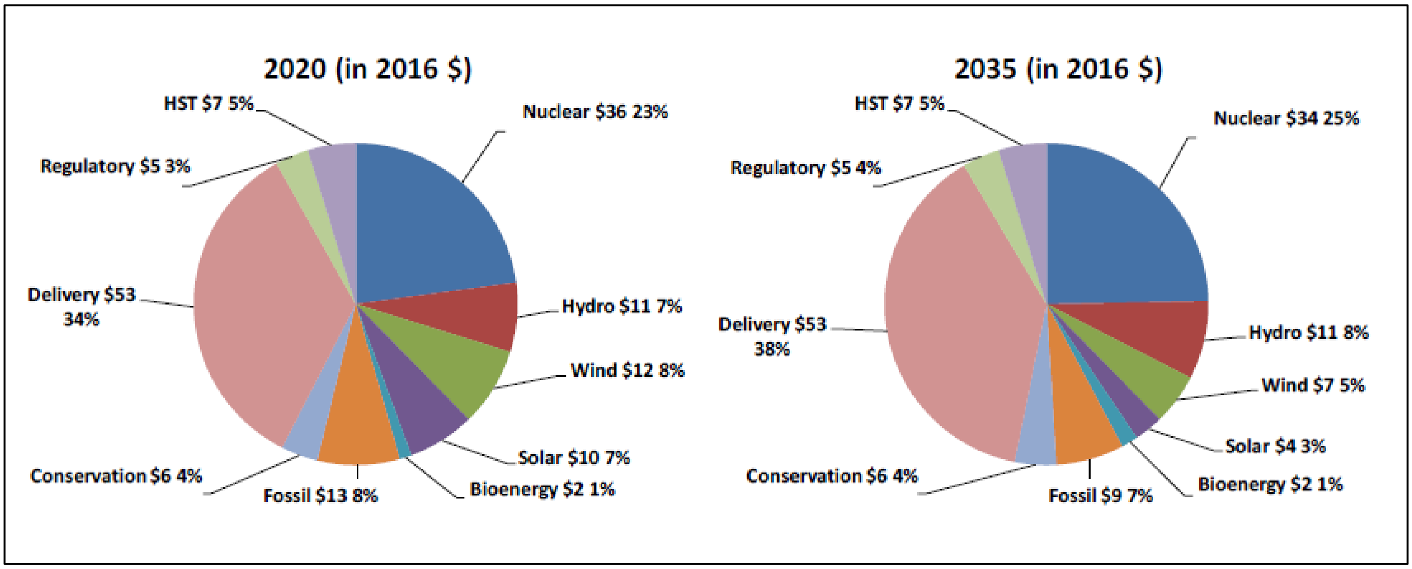
It is also important to analyze how the different component pieces of the residential electricity bill are expected to change over time. Figure 15 below demonstrates how the component pieces will change under the IESO's Outlook B (i.e. no net electricity demand growth and thus very limited build out of any new electricity supply) between 2016 and 2035. Figure 16 then shows snapshots of these component pieces in both 2020 and 2035.

Figure 15: Components of the Ontario Residential Electricity Bill (2016 to 2035)



Nuclear costs are expected to remain more or less constant in real terms, with the volume decreasing due to the retirement of Pickering NGS and the price simultaneously increasing due to the high cost of refurbishment. Hydro costs are also forecast to remain steady, while solar costs will ultimately decline (starting in 2029) as older plants are replaced with newer, less expensive plants. Overall, wholesale supply costs are forecast to increase through 2026, and then to decrease in real terms below current levels.

Figure 16: Components of the Ontario Residential Electricity Bill (2020 and 2035)



Under the IESO's Outlook B (flat demand), solar PV can be expected to continue to contribute a small amount to the electricity bill of the average Ontario resident with only HST, regulatory, bioenergy and conservation coming in with lower impacts.

Distributed Solar Generation

Keeping in mind the supply and demand risks to supply adequacy in Ontario, the resulting GHG risks from decisions made to meet demand, the decreasing cost of solar and solar's small contribution to electricity costs in Ontario, we now turn to how the province can make better use of Distributed Solar Generation (DSG) to mitigate some of these impacts. DSG is a subset of solar PV which is developed at smaller scales on a distribution system (as opposed to larger scales on the transmission system). DSG can be grid-tied (i.e. generate electricity solely for export to the grid) or self-consumption based (i.e. all, or a portion of, the electricity generated is used by a connected customer before any excess is exported to the grid). There is not a set system capacity threshold for distributed solar vs utility scale solar, however, DSG will generally be less than 10 MW. DSG differs from other forms of generation, including utility scale solar PV, and is unique in many respects. DSG thus requires differential consideration as to the policy and regulatory frameworks that must be in place to realize its value.

Attributes and Value of Distributed Solar Generation

DSG is unique renewable energy resource with a diverse set of attributes. Compared to large centralized generation resources such as hydro-electric and nuclear, DSG can be scaled to precisely address power system needs while respecting grid connection constraints. DSG can be located anywhere with access to sufficient sunlight which makes siting DSG highly flexible when compared against other generation with fuel delivery needs. DSG does not require specific geographic features for development and can be sited in varying locations ranging from dense residential housing to commercial rooftops and even low-value land that is not suitable for agriculture.

The output of DSG aligns well with Ontario's electricity demand, with more production during on-peak hours than off-peak. Advances in energy storage, demand response and smart grids are expected to have a significant impact on electricity systems in the near future, and the dynamic controls available to DSG systems work well with these technologies.

DSG provides the following system value and benefits to Ontario:

- Located behind the meter, it is an effective demand reduction measure;
- Regional planning and distribution system planning benefit from having DSG as a grid-responsive and flexible resource option to meet power system needs;
- It gives customers the ability to exercise choice with regards to their energy use and provides an investment option to hedge against the risk of rising electricity rates and increases resiliency;
- It is a supply mix diversification option that reduces peaking natural gas combustion in support of Ontario's climate change objectives; and
- It enjoys strong public support and engages Ontarians in the electricity sector and its evolution.

Net Metering

Ontario's DSG industry is at a crossroads. For the past 7 years the industry has largely focused on building Feed-in Tariff (FIT) and microFIT projects. Since the introduction of these programs Ontario has seen impressive growth in the amount of solar that has been connected to the electricity grid. In total, Ontario has reached over 2,100 MW of installed solar, with roughly another 600 MW in the pipeline.[9] These projects have put Ontario amongst the global leaders for total installed capacity, contributed to job creation, investment, and GHG emission reductions from the electricity sector as a whole.

The future for DSG in Ontario, however, is less than certain. The FIT and microFIT Programs are slated to end in 2018 and at that point the industry must shift its focus to net metering. The government of Ontario has already signaled their intention to transition the DSG industry in this direction, however, the framework for how the transition will work has not yet been finalized.

Ontario currently has a net metering regulation which allows customers to install solar PV and use the generation to offset their own electricity consumption. Net metering is currently available to renewable generation facilities with a nameplate capacity of 500 kW AC or less. Customers are only charged for the net electricity consumption between their total output and total gross consumption over the course of the billing period. Customers are still responsible for charges not calculated on the basis of the customer's energy consumption (ex., monthly fixed charges or peak

[9] Independent Electricity System Operator, A Progress Report on Contracted Electricity Supply, http://www.ieso.ca/Documents/Supply/Progress-Report-Contracted-Supply-Q22016.pdf, Pg. 11, and Independent Electricity System Operator, Contracts Offered for FIT 4, http://fit.powerauthority.on.ca/newsroom/newsroom-2016/June-29-2016-Contracts-Offered-for-FIT-4.

demand based charges). Excess renewable generation greater than consumption in a month creates a credit for the customer that can be carried forward for up to a rolling 10 – 11 month period. After a positive credit balance has been carried for that period, any excess generation credit is reduced to zero and lost by the customer.

Consultation on a new net metering regulation occurred during the fall of 2016 with the new regulation slated to be released in 2017. This new regulation, however, has several pieces missing – pieces that are necessary to implement if net metering is going to act as a viable new market for the DSG industry to reduce customer's electricity bills and reduce GHGs. As relayed previously through our Distributed Generation Task Force (DGTF)[10], CanSIA envisions a transition for the Ontario DSG industry to move away from the current microFIT and FIT regime and into a net metering based framework. This transition, and the resultant net metering framework, will be more responsive to electricity customer demand and shift more of the investment and performance risk to the market. Making this transition will allow the private sector to design and deliver projects efficiently within a timeline driven by economics and investment decisions rather than centralized procurement cycles.

The revised net metering regulation due out in 2017 is one of the central pillars to implementing this transition. The Ministry of Energy's proposed changes represent an improvement on the existing regulation, however, additional modifications both to the regulation, as well as to other supporting systems and legislation, are required in order to establish a robust and successful net metering framework in Ontario that supports customer choice and the ability to access net metering projects at a reasonable cost. Those additional changes are described below.

Time of Use Rates

One of the largest barriers to net metering project uptake from a financing and system economics perspective is transitioning the current use of tiered rates for net metered customers to Time of Use (TOU) rates.

Currently if a load customer installs a net metering system they are required to move to tiered rates for both their electricity use as well as for the calculation of credits for exported generation. This is largely due to IT infrastructure issues between the IESO's Meter Data Management and Repository (MDMR) system, smart meters, and LDCs data input and billing systems. Tiered rates do not account for the difference in value between on-peak, mid-peak, and off-peak electricity. Under TOU, the higher price periods tend to align with the production curves of solar generation. Evolution of the TOU structure in the future is also likely to see a larger separation between the on-peak and off-peak price, which would benefit solar generation. The possible inclusion of a fourth time period for critical peaks (i.e., 1 or 2 hours a day during the summer price period) would further enhance the value of solar generation. The fixed price periods of TOU also allows for strong predictability of the benefits of solar generation for customers.

Using tiered rates for the calculation of consumed electricity and excess generation undervalues the generation of a solar system and lowers the revenue available to system owners due to that undervaluation. This undervaluation can be between 7 – 23% depending on the electricity demand of the net metering customer (ex. Whether the majority of their consumption falls within tier 1 rates or tier 2 rates).

[10] CanSIA, Distributed Generation Task Force Recommendation Report, http://www.cansia.ca/uploads/7/2/5/1/72513707/cansia_dgtf_recommendation_report.pdf.

Making the necessary IT and billing structure investments to allow the LDCs to settle net metered customers at TOU rates will:

- Accurately value generation and consumption of the customer in the period in which it materializes;
- Encourage net metering and thus encourage electricity generation close to load which allows LDCs to reduce distributions system costs over time;
- Encourage electricity generation close to load which should allow ratepayers to reduce impacts of line losses on their bill;
- Encourage electricity generation close to load which should allow LDCs to reduce transmission and distribution expenditures, going forward;
- Encourage net metering customers to respond to price signals based on the cost of peak energy;
- As net metering continues to expand in Ontario, switching to TOU rates makes use of the investment that the province has already made in smart meters, rather than reversing it, for this group of customers (which is expected to grow over time).

If net metering is to serve as a viable regulatory framework for the DSG industry and electricity customers, access to TOU rates for net metering customers is absolutely essential.

Community Net Metering

Another crucial addition to the net metering regulatory framework in Ontario is to implement the required legislative and regulatory changes to facilitate community net metering.

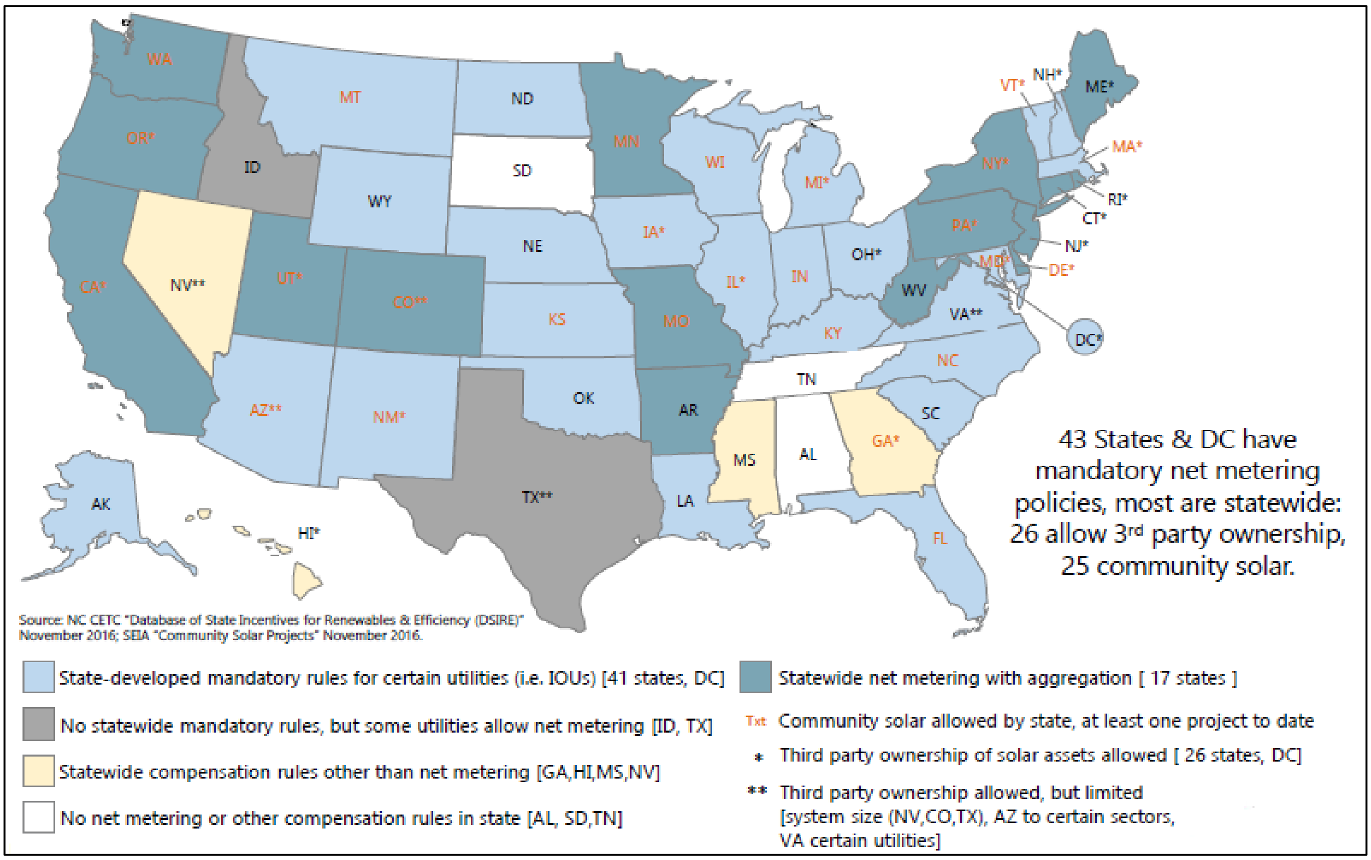
Community net metering allows the sharing of credits generated by the output of a solar system to be allocated to other electricity customers based on percentage of ownership or of subscriptions. It offers a way for those who cannot, or do not want to, install solar panels on their own properties to go solar. Community net metering also allows the customers and the solar industry to capture the benefits of economies of scale by building systems at larger scales. This allows for the installed cost of solar to go down and thus creates greater savings and shorter payback periods for customers and generators.

Community net metering also has the benefit of providing a backstop against the loss of a load customer by permitting the generator to sign-up a new load customer to transfer excess generation credits to. In the event that a customer's load decreases, or, for example, a business closed down, the generator could then find a new customer to buy the excess generation credits. This provides a risk hedge for the generator which will assist in any financing arrangements with lenders by providing more certainty that the asset will not be stranded in the event of the loss of a load customer.

Community net metering is currently not practiced widely in Canada, however, is becoming a more established practice in the United States. At least 100 community solar projects are online in 25 states. State approaches in the United State vary from opening this option to all customers (ex. Massachusetts and Delaware) to making it the utilities choice to offer the option (ex. Illinois). Figure 17 below illustrates the full range of states that permit community net metering across the US. Since establishing a community solar program in 2015 (via PSC 15-E-0082), New York State has committed to community solar in its REV process. To maximize locational benefits utilities are required to identify Opportunity Zones and initial projects were limited to those areas. Access is also a central component with provisions for low/moderate income customers and the establishing of a Low-Income Customer Collaborative to identify barriers to participation.

It is noted that Section 7(1)(a) of the net metering regulation would likely require modification if the Ministry of Energy incorporates community net metering. This section currently specifies that the generator must generate electricity primarily for their own use. In a community net metering framework, the generator would be a different entity than the associated load accounts and the generator would be generating electricity primarily for use by others.

Figure 17: Community Net Metering and Third Party Ownership in the United States



Meter Eligibility

Permitting community net metering arrangements would help make the new net metering regulation more permissible for new and different business models. Allowing new business models, and associated economies of scale, is important given the economic gap between the revenue requirement of solar systems and the available revenue from net metering that CanSIA's DGTF has forecasted in our past Recommendations Report. This economic gap is further exacerbated by the Ontario Energy Board's (OEB) decision to fix distribution system related charges on residential bills (an approach to these charges that the OEB may replicate for commercial and industrial customers at the conclusion of their EB 2015-0043 process).

The already challenging economics of net metering requires the solar industry to deliver solutions that drive greater efficiencies including improved economies of scale. A framework that permits a broader pool of eligible load accounts permits this cost saving model to lower project development costs (which can also be passed down to customers). Community net metering (as well as virtual net metering) should thus allow the generator to generate credits for any customer located within the same LDC service territory as the generator. Ruling out the ability of a net metering generator to pass on savings to the accounts billed by the same LDC would severely limit the feasibility of a virtual net metering business case/value proposition.

In terms of an effective policy for implementation and customer participation, the number of potential clients that would have meters within a small area (such as the 3 km restriction proposed by the Ministry of Energy for single entity virtual net metering) would be lower than ones that have meters anywhere within the same LDC service territory. There is a strong possibility that this type of limitation could render community net metering and single entity virtual net metering impractical for the majority of clients who are most likely to invest in and benefit from these frameworks, particularly for the corporate clients that are making sustainability a key corporate objective or that wish to take advantage of incentives arising from the CCAP.

CanSIA recommends allowing community net metering and virtual net metering to occur between two or more eligible meters anywhere within a Local Distribution Company's (LDC) service territory. This treatment has significant precedent in the United States for both virtual net metering and community net metering regulations/programs. For example, programs in Washington, Massachusetts, Colorado, Minnesota, New York, California, Maine, Vermont all allow eligible meters to virtual or community net meter provided those meters are located within the same utility service territory. These programs do not further restrict meter eligibility based on location or distance. A larger pool of eligibility also allows more customers to access net metering projects and creates a more level playing field amongst customers that have facilities that are more ideally configured for the installation of solar and those that do not.

Settlement Provisions

Within community net metering and virtual net metering each of the different customers that are participating with a particular project should have the ability to be settled based on the rate class of their load account (i.e. the load account receiving the credits) rather than based on the rate class of the account where the generation is occurring, or the wholesale rate. For example, under a virtual net metering framework, if a company owns a warehouse and generates electricity there, that warehouse might pay the Industry Rate Class A but its store location, where the credits are being transferred, might pay a higher electricity rate. The net metering customer should have the generation credited based on the rate class of the account receiving the credit. Under a community net metering framework, a kWh generated by the system should translate into a credit at the retail rate for the customer's load account where the credit is being utilized.

Third Party Ownership

Third party ownership arrangements should be facilitated by the new net metering framework. As has been evidenced from experience under the microFIT Program in Ontario and in net-metering based markets in the United

States, third party ownership of systems and third party financing arrangements have resulted in larger amounts of development than direct ownership alone. Allowing third party ownership and financing also results in more options for customers deciding whether to adopt solar to lower their energy bills by facilitating leasing or power purchase agreement (PPA) arrangements for customers with lower access to capital. Increasing consumer choice was identified as the top priority by participants of the OEB's 2015 Energy Leaders Sector Forum and encouraging consumer choice should be a priority for the successor net metering program, as well.

It is noted that Section 7(1)(a) of the net metering regulation would likely require modification if the Ministry of Energy incorporates third party ownership into the net metering regulation. This section currently specifies that the generator must generate electricity primarily for their own use. In a third party ownership framework, the generator would be a different entity than the associated load account and the generator would be generating electricity primarily for use by others.

Virtual Net Metering

CanSIA recommends implementing both single entity virtual net metering as well as traditional virtual net metering within the new net metering framework. While the Ministry of Energy has begun exploring the ability to implement single entity virtual net metering, traditional virtual net metering has thus far not been proposed. Traditional virtual net metering would function very similarly to single entity virtual net metering without the restriction on the two meters belonging to the same entity. Under a traditional virtual net metering arrangement any customer could transfer excess generation credits to any other customer within a single LDC's service territory.

Virtual net metering also has the benefit of providing a backstop against the loss of a load customer by permitting the generator to sign-up a new load customer to transfer excess generation credits to. In the event that a customer's load decreases, or, for example, a business closed down, the generator could then find a new customer to buy the excess generation credits. This provides a risk hedge for the generator which will assist in any financing arrangements with lenders by providing more certainty that the asset will not be stranded in the event of the loss of a load customer.

Similar to the discussion with regards to community net metering, single entity virtual net metering should not place arbitrary distance based restrictions on the distance between meters that can participate. Any two or more eligible meters within an LDC's service territory should be able to participate in virtual net metering. Additionally, and similarly to the recommendations made above with regards to community net metering, virtual net metering customers should have the ability to be settled based on the rate class of the load account receiving the credits rather than based on the rate class of the account where the generation is occurring.

Capital Cost Incentive

CanSIA has provided analysis on the need for an interim capital cost incentive for DSG previously through our DGTF. CanSIA recommends that the Ministry of Energy work with the MOECC to ensure that a capital cost incentive for net metered solar PV is included in the CCAP. This incentive is essential to making a stable and effective transition from the current FIT regime to a net metering framework.

A summary of the recommendations of the DGTF including incentive levels and incentive program structure has been included in Appendix B.

Addressing Other Barriers to Make DSG More Cost Competitive

Beyond shaping a regulatory framework that will support the transition to net metering, there are a number of other actions that government, regulators, and agencies should take in order to help reduce the cost of DSG development. The province has also committed in the CCAP to making Ontario one of the most cost effective jurisdictions to install solar panels in North America. Reducing the cost of DSG development will help achieve a grid parity situation in Ontario more quickly and allow greater numbers of customers to adopt solar without any kind of government incentive. As grid parity is approached and achieved, solar adoption will also become a better and less expensive tool for system operators and LDCs to meet supply adequacy needs, reduce GHG emissions, and provide grid benefits like reducing transmission/distribution costs.

CanSIA recommends that the Ministry of Energy reinitiate the Net Metering/Self Consumption Advisory Working Group and expand the group's mandate to include investigating and addressing the items below.

Connection Threshold Limits

In Ontario, residential DSG is subject to limits on the amount of generation that can be connected on a given feeder. While these limits can differ across LDCs, most LDCs tend to use Hydro One Networks Inc.'s (HONI) limits which are:

- 7% of peak load on a single phase feeder (F class feeder); and
- 10% of peak load on a three phase feeder (M class feeder).

These threshold limits not only present a significant difficulty for the DSG industry by limiting the total market size, they also jeopardize the government's long term net zero home strategy. As outlined within the CCAP, the government of Ontario intends to move new construction towards being net zero between now and 2030.

A net zero energy building is defined as a building that produces as much energy as it consumes over the course of a year. These buildings achieve net zero energy status first through high levels of energy efficiency, and then through the addition of clean, on-site renewable power generation, typically solar PV.[11] From a sustainable development perspective, ensuring as much future building and community development as possible achieves net zero energy status should be one of the most important focuses of governments operating in a carbon constrained environment. In Ontario, approximately 17% of total GHG emissions come from buildings and 9% come from the electricity sector.[12] A building's emissions profile is largely made up of fossil fuel use for heating (space and water), and electricity use that can come from fossil fuel sources (the percentage of which changes depending on the time of day and how much generation is sourced from the natural gas fleet). Additional deployment of solar technology can reduce emissions from both sources.

[11] California Public Utilities Commission, http://www.californiaznehomes.com/#!faq/cirw.
[12] Ministry of the Environment and Climate Change, Climate Strategy, https://dr6j45jk9xcmk.cloudfront.net/documents/4928/climate-change-strategy-en.pdf, pg. 25.

The threshold limits imposed by HONI and other LDCs, however, will severely limit the extent to which buildings can achieve net zero status through the use of solar PV by constraining the amount of solar PV that can be connected on a given feeder.

Connection Requirements

There is currently different treatment by LDCs in Ontario as to the necessity of, and payment responsibility for, various different connection requirements for DSG. For example, some LDCs will require the inclusion of Supervisory Control and Data Acquisition (SCADA) or transfer trip equipment for certain sizes of DSG projects. The sizes that trigger the need for SCADA and transfer trip differ across LDCs as does the LDC's opinion on which entity must bear the cost of the cost of installing the equipment.

The OEB has given high level guidance on the payment responsibility for items such as SCADA and transfer trip within the Distribution System Code (DSC) in Section 3.3.2 on renewable enabling improvements. Renewable enabling improvements are intended to be cost recoverable through the rate base rather than from generators. This section of the DSC specifies that renewable enabling improvements to the main distribution system to accommodate the connection of renewable energy generation facilities include both the provision of protection against islanding (transfer trip or equivalent) and SCADA system design, construction and connection.

These and other connection requirements provide an opportunity for collaborative action between LDCs and the OEB to clarify existing regulatory frameworks as well as investigate potential alternatives to certain connection requirements in order to maintain safety and reliability while reducing the cost of installing solar.

Opportunity Zones

Similar to the process in New York State, the Ministry of Energy and OEB should work with LDCs to identify opportunity zones within their service territory where solar generation would provide them with the best value. The opportunity zones could be aligned with all net metering projects (community, virtual, standard) to provide the maximum value for customers who want to adopt solar. These opportunity zones could also be aligned with the IESO's Regional Planning Process as a way to utilize DSG to meet future supply needs as an alternative to poles/wires solutions.

Distributed Energy Resource Credits

The OEB is currently considering the implementation of Distributed Energy Resource (DER) credits as a part of their consultation on rate design changes for commercial/industrial electricity customers. The fast switching capability of solar generation to react to disturbances in the electricity grid through their inverter connection allows DSG to provide a variety of services to distribution networks. Receiving DER credits would increase the adoption of solar generation by capturing revenue streams beyond simply avoided electricity consumption thereby reducing barriers to adoption.

With the OEB considering DER credits as a part of rate design changes for distribution customers, the new net metering regime should consider how to provide compensation for DER credits, if they are implemented. One option to consider would be to set a fixed rate (either per connection or for excess energy) to reflect the DER credit value. The fixed rate could be set and changed as part of the rate filing of the LDC.

Regional Planning

There are a number of drawbacks with the current approach to regional planning as it relates to opportunities for solar generation. Solar generation uptake to meet regional needs, along with other types of DERs, are only considered in regional planning as part of broader central procurement initiatives (ex. FIT, CHP, etc.) overseen by the IESO. By considering only the uptake of solar generation in a specific region through a central procurement, regional planning is not providing a full analysis of the uptake potential nor of innovative solutions that could be proposed to meet a regional need. This partial assessment of uptake potential for solar generation reduces the perceived capability of solar generation to address potential system needs. To adequately understand the ability for DSG to meet system needs, a specific regional assessment of DSG including a potential regional procurement (or DER credit offering) should be considered. A regional assessment could determine what solar generation projects may be available for development and how well the location of those projects matches with the current connection capability in a distribution or transmission network.

Additionally, regional planning has in recent past only considered the peak capacity contribution of solar generation. There are a number of other benefits (e.g. reactive power compensation, regulation services etc.) that solar generation can provide to power systems (if utilizing the necessary inverter and control technologies) that should be considered as a part of the IRRP. By limiting the comparison of solar generation solutions to other options (ex. Traditional wires options) primarily to meet peak demand needs, solar generation is not able to leverage its full value to the power system.

Solar Heating

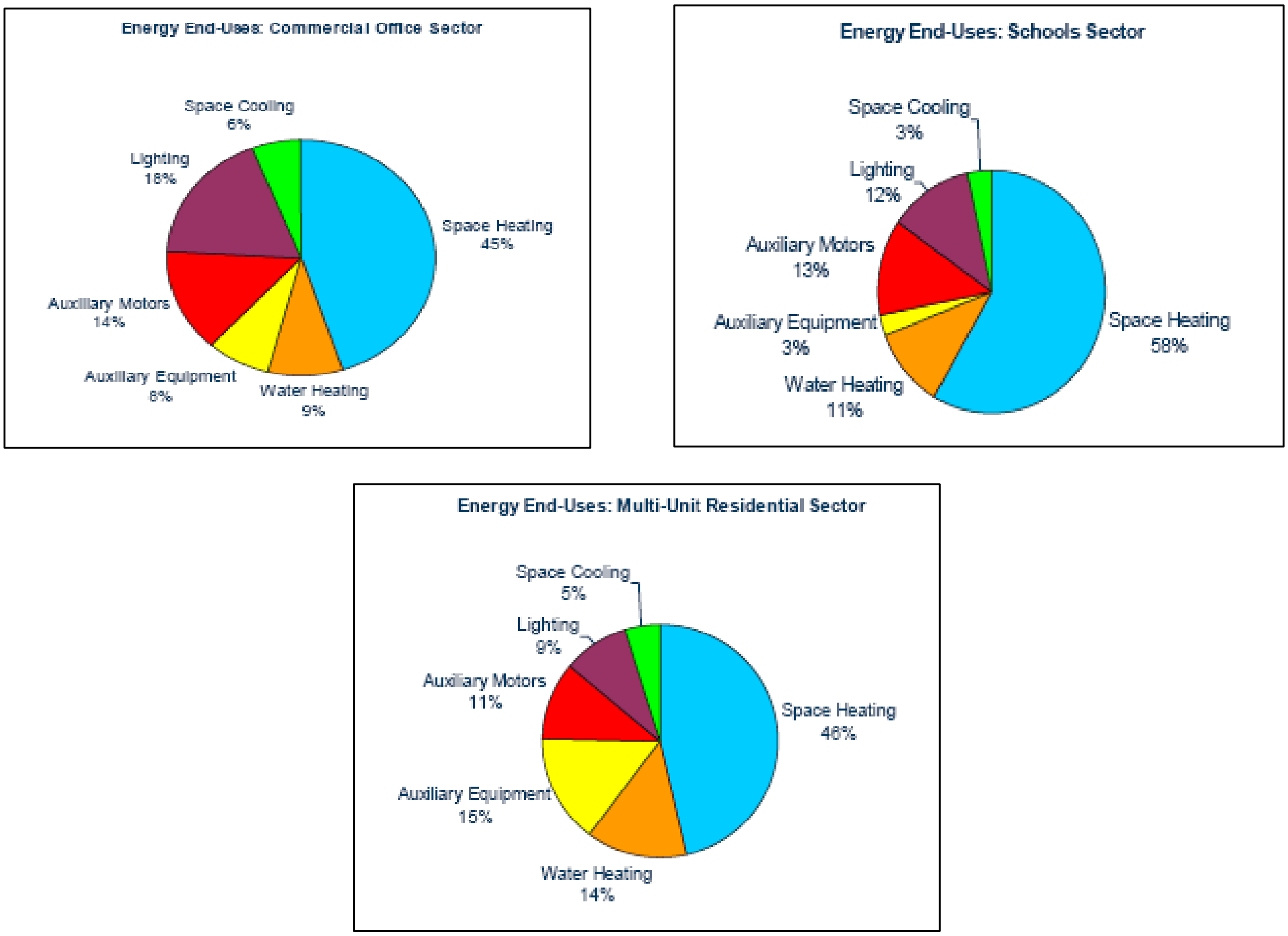
The 2017 LTEP will be the first iteration of the plan to explicitly include policy considerations for the fuels sector, alongside electricity. In conjunction with the province's CCAP, the LTEP should include emissions free sources of heating in order to help achieve GHG emissions reduction goals.

Additionally, the Ministry of Energy should work closely with the MOECC to ensure that the CCAP includes specific funding for solar thermal projects to allow building and homeowners to take advantage of the fossil fuel energy savings these projects produce. The CCAP identified "decarbonizing heating" as a central goal. Given that the majority of heat-related GHG emissions today, and in the future, originate from the existing building stock, it is imperative to focus on retrofitting existing commercial, institutional and industrial buildings with non-emitting sources of heating. The path to mainstream "clean heating" is viable, and solar heating technologies will be an essential component to this strategy.

Solar air heating technologies address the largest usage of building energy in Ontario, which is indoor space and process heating. Heating typically represents over 50-60% of a building's energy load, and currently the majority of this energy is generated using fossil fuels (natural gas and propane).

Solar air heating technologies generate heat energy onsite and displace between 20-50% of a building's heating load, and corresponding GHG emissions. Figure 18 below were developed by PricewaterhouseCoopers LLP for the City of Toronto, and clearly show the potential for meaningful use of solar air systems in Ontario, especially urban and suburban settings.

Figure 18: Energy End Uses in Commercial, School, and Multi-Unit Residential Sectors



Solar Heating Technologies Overview

Solar thermal heating is typically ranked as one of the most cost-effective types of renewable energy technology because of its high energy production and relatively low capital costs. The 2009 report by the C.D. Howe Institute entitled 'Going Green for Less: Cost Effective Alternative Energy Sources' also noted that solar thermal technologies provide the most cost-effective way to reduce greenhouse gas (GHG) emissions.[13] As well, solar thermal systems

[13] C.D. Howe Institute, Going Green for Less: Cost Effective Alternative Energy Sources, https://www.reap-canada.com/online_library/grass_pellets/36%20Going%20Green%20for%20less-Samson%20&%20Bailey%20Stamler-2009.pdf.

provide on-site energy generation, so there are no transmission losses and the integration into the building is relatively straightforward. Solar thermal systems can be used to heat water or to heat air, as described below.

Solar air heating is an Ontario-success story, as it is currently the only renewable energy technology used around the world with its origins in Ontario. It is a mature technology that has been successfully applied in thousands of projects across Canada and the United States, with especially strong uptake in Ontario in the past. There are about 5 million square feet of solar air heating systems in operation in North America alone, representing about 250 MW of thermal energy and 100,000 tonnes of GHG emissions displacement annually.

Solar air heating technologies use sunlight primarily to heat large volumes of ventilation air or for space heating or process heat applications. It addresses the largest use of energy for buildings in Ontario, which is indoor heating. The technology also improves indoor air quality and improves animal health in agricultural applications. The systems are usually wall-mounted and are building integrated, which means they become part of the exterior façade. They are easily applied in retrofit applications over an existing wall, or in new construction systems would double as the exterior wall. Systems can range in size from 1,000ft^2 up to 50,000 ft^2, with most typical systems being between 2,000ft^2-6,000ft^2.

The Canadian solar air heating industry is a world leader, with Ontario having a large percentage of the world's most innovative building-integrated solar air heating projects, in applications such as factories, multi-residential housing, water treatment plants, schools, hospitals, commercial buildings, vehicle maintenance garages, airports, poultry barns, universities and recreation facilities. Systems offset the daytime heating load, which is when most commercial and industrial buildings are occupied.

Solar water heating involves heating water with sunlight that is then used for domestic hot water or commercial applications, such as universities, hospitals, community centres or pools. Solar water heating for commercial and industrial applications was supported by the Ontario Solar Thermal Heating Incentive (OSTHI) Program and projects in Ontario from 2007-2010 received an incentive of about \$50/ft^2. This report does not contain specific data on solar water heating, but CanSIA supports the idea of a solar heating program similar to OSTHI, which would include both heating technologies.

OSTHI Program 2007-2010; the Creation of a World-Class Industry in Ontario

In Canada and Ontario, solar air heating is the most widely used solar thermal technology in the commercial, industrial, and agricultural sectors as a result of its cost-benefit metrics and widespread applicability.

Ontario has a clear success story in solar thermal policy; the Ontario Solar Thermal Heating Incentive Program (OSTHI) ran from 2007-2010 and supported close to 1,000 solar air and solar water heating technologies in the commercial, industrial and agricultural sector.

The program was prescriptive and had a straightforward structure detailed below:

- Incentive were paid up-front to the end user on a per square foot (or per square metre) basis for eligible solar collectors;
- All commercial, industrial, institutional, and agricultural buildings were eligible, in either retrofit or new build;

- A RETScreen® or a SWIFT (Solar Wall International Feasibility Tool) analysis had to be submitted along with the application which would detail the size of the proposed project, the energy performance, and the GHG reductions. (Note: RETScreen® and SWIFT are programs developed by Natural Resources Canada (NRCan) that are based on monitored data);

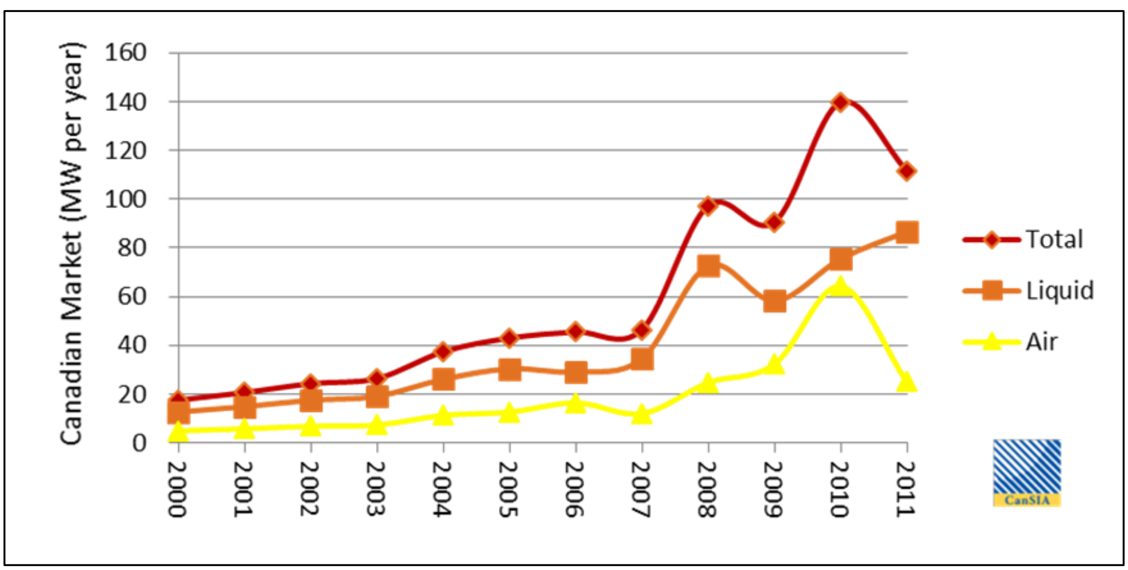
- The end user would receive an acceptance letter from the program, and then they had a certain period of time in which to complete the project; and

- Close out documents included a certification from the end user that the system had been installed and all associated costs had been paid. A commissioning report had to be completed by a P.Eng. verifying the installation and showing the square footage of the project in order to calculate the final incentive that would be paid to the end user.

The program functioned extremely well; it was straightforward and easy to administer, and it was successful in creating significant project uptake. It has been cited as a model by the US Solar Energy Industries Association in discussion with several states on solar thermal programs.

The results from the OSTHI program are clear and illustrative; the solar heating market developed significant momentum and capacity from 2007 to 2010 due to this program. Solar air heating deployment in Canada peaked in 2010 at over 60MW, of which over 40MW was in Ontario. The industry capacity went from around 10 MW in 2007, to over 20 MW in 2008, to close to 40 MW in 2009, and then over 60 MW the peak year of 2010. This growth was the result of the OSTHI program, and when the program ceased to exist in 2011, the industry capacity declined immediately and has remained at a much lower level.

Figure 19: Canadian Solar Heating Market Activity



Other Considerations

Government Objectives	Relevance of Solar Air Heating
Performance	50-60 peak thermal watts/ft^2; or 1.5 - 3.5 GJ/m^2 per year Heats air up to 55° C above ambient for daytime heating Solar energy conversion up to 80% No maintenance and 30+ year lifespan Recaptures building wall heat losses Increases effective insulation value up to R 50 Reduces cost of increased ventilation
Clean Heating	Systems offset 20-50% of conventional heating demand Clean heat energy is generated on-site, thereby reducing reliance on natural gas pipelines / electrical grid Reduce use of natural gas, heating oil & propane
GHG Reduction	Targets large percentage of fossil-based energy required for conventional heating Offsets ~1 ton of CO2 for every 50-70ft^2 of collector per year, or 30 tons of CO2 for every 50-70ft^2 over the system's lifespan.
Job Creation	Local industry for solar air heating in Ontario means that majority of solar air heating systems installed here are made-in-Ontario from components that are also sourced in Ontario, thereby creating local employment. Systems are site-built and create local employment in a cross section of industries including engineering, metal fabrication,

	contracting, installation, sales, components, marketing and distribution
Applicability to Building Stock	Suitable for all types of commercial, industrial, government, multi-residential, military & agricultural buildings Easily integrated in retrofit applications Systems are often specified to remediate older buildings, especially multi-residential buildings Systems are typically wall-mount, but can also be applied to the roof. In new construction solar air heating systems double as the exterior façade

Potential Program Structure under the Climate Change Action Plan

For solar air heating to become commercially viable again in Ontario for retrofit applications, a payback of approximately 5 years is required. This means that an incentive as described in Figure 20 below is required to achieve an average payback range of between 5-10 years in different system applications. CanSIA recommends that all commercial and industrial building types be eligible for funding, as that is the most efficient way to scale a market. Restricting building types would thwart the ability of the industry to expand the quantity of viable applications. The table below represents average values for required incentive level, avoided GHGs and the cost per avoided tonne of GHGs for an average building.

Figure 20: Solar Air Thermal Avoided GHG Emissions

Average Total Installed Cost per square foot (ft^2) in Ontario	Required Incentive per square foot (ft^2)	Average GHG Displacement for Solar Air Collectors Tonnes / ft^2 / year	Cost per Tonne of GHG Avoided
Current Range: \$50-60/ft^2	\$26/ft^2	1 tonne / 50-70 ft^2 / year	\$50

*Assume we can drive some immediate economics of scale with a program in place, we are targeting average installed cost of **\$52/ft2.**
*CanSIA assumes this cost will decline roughly 20% to around \$41/ft^2 in 5 years.

Below are four RETScreen® summaries of typical solar air heating projects in Ontario. These values and the more detailed tables below show more specific examples of building types and the expected paybacks periods, avoided GHGs, and cost per avoided tonne of GHGs for those building types. The incentive level of $26/ft^2 has been maintained for all building types.

- Mid-Performing Commercial - Payback 10.46 Years
- High-Performing Commercial - Payback 8.11 Years
- Mid-Performing Industrial - Payback 6.49 Years
- High-Performing Industrial - Payback 5.02 Years

This illustrates the range of energy production, costs, GHG savings, and the payback metrics assuming the incentive of $26/ft^2.

Figure 21: Solar Air Thermal Project Examples

Mid-Performing Commerical Solar Air Heating System			
COLLECTOR AREA		RATED OUTPUT (kW)	PERCENTAGE OF PROJECT COST
SQF	SQM		
5,000	465	352	50%

INSTALLED PROJECT COST			INCENTIVE COST		
PER SQF	PER SQM	TOTAL	TOTAL	PER SQF	PER WATT
$52	$560	$260,000	$130,000	$26	$0.37

ANNUAL PRODUCTION		30 YEAR PRODUCTION (Industry Standard for Solar Air - NRCan)				
RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	INCENTIVE $ / tC02 REDUCED	INCENTIVE $ / MWh PRODUCED	PAYBACK (YEARS)
428	87	12,836	2610	$50	$10	10.46

ANNUAL PRODUCTION		20 YEAR PRODUCTION				
RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	INCENTIVE $ / tC02 REDUCED	INCENTIVE $ / MWh PRODUCED	PAYBACK (YEARS)
428	87	8,557	1740	$75	$15	10.46

High-Performing Commerical Solar Air Heating System			
COLLECTOR AREA		RATED OUTPUT (kW)	PERCENTAGE OF PROJECT COST
SQF	SQM		
5,000	465	360	50%

INSTALLED PROJECT COST			INCENTIVE COST		
PER SQF	PER SQM	TOTAL	TOTAL	PER SQF	PER WATT
$52	$560	$260,000	$130,000	$26	$0.36

ANNUAL PRODUCTION		30 YEAR PRODUCTION (Industry Standard for Solar Air - NRCan)				
RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	INCENTIVE $ / tC02 REDUCED	INCENTIVE $ / MWh PRODUCED	PAYBACK (YEARS)
552	112	16,560	3367	$39	$8	8.11

ANNUAL PRODUCTION		20 YEAR PRODUCTION				
RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	INCENTIVE $ / tC02 REDUCED	INCENTIVE $ / MWh PRODUCED	PAYBACK (YEARS)
552	112	11,040	2244	$58	$12	8.11

Mid-Performing Industrial Solar Air Heating System						
COLLECTOR AREA		RATED OUTPUT (kW)		PERCENTAGE OF PROJECT COST		
SQF	SQM					
5,000	465	367		46.43%		
INSTALLED PROJECT COST			INCENTIVE COST			
PER SQF	PER SQM	TOTAL	TOTAL	PER SQF	PER WATT	
$56	$603	$280,000	$130,000	$26	$0.35	
ANNUAL PRODUCTION		30 YEAR PRODUCTION (Industry Standard for Solar Air - NRCan)				
RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	INCENTIVE $ / tC02 REDUCED	INCENTIVE $ / MWh PRODUCED	PAYBACK (YEARS)
796	160	23,871	4803	$27	$5	6.49
ANNUAL PRODUCTION		20 YEAR PRODUCTION				
RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	INCENTIVE $ / tC02 REDUCED	INCENTIVE $ / MWh PRODUCED	PAYBACK (YEARS)
796	160	15,914	3202	$41	$8	6.49

High-Performing Industrial Solar Air Heating System						
COLLECTOR AREA		RATED OUTPUT (kW)		PERCENTAGE OF PROJECT COST		
SQF	SQM					
5,000	465	372		46.43%		
INSTALLED PROJECT COST			INCENTIVE COST			
PER SQF	PER SQM	TOTAL	TOTAL	PER SQF	PER WATT	
$56	$603	$280,000	$130,000	$26	$0.35	
ANNUAL PRODUCTION		30 YEAR PRODUCTION (Industry Standard for Solar Air - NRCan)				
RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	INCENTIVE $ / tC02 REDUCED	INCENTIVE $ / MWh PRODUCED	PAYBACK (YEARS)
1029	207	30,857	6209	$21	$4	5.02
ANNUAL PRODUCTION		20 YEAR PRODUCTION				
RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	RENEWABLE ENERGY SAVINGS (MWh)	tCO2 EMISSION REDUCTION	INCENTIVE $ / tC02 REDUCED	INCENTIVE $ / MWh PRODUCED	PAYBACK (YEARS)
1029	207	20,571	4140	$31	$6	5.02

Solar air heating offers a very compelling case in terms of its potential to help Ontario achieve cost-effective displacement of GHG emissions, with an average cost around $50/tonne assuming the government investment of $26/ft^2 of collector area. As can be seen in the figures above, the type of building, the volume of air that requires heating, and the number of times that air is cycled through the building via ventilation systems, affects the payback term at an incentive level of $26/ft^2. CanSIA does not recommend limiting the types of building that could take advantage of the solar heating incentive, however. Allowing all building types to access the incentive allows the market to determine the best applications for solar thermal systems. At first, deployment will likely be focused on high-performing commercial and industrial buildings, as well as applications within the agricultural sector and multi-tenant residential. As costs decline, other building types will deploy the technology with greater frequency.

Deployment Potential and Impacts

$185 Million 5 Year Program: Solar Air Heating & Solar Water Heating

With support mechanisms reinstated for solar air heating, it is reasonable to assume similar rates of growth that were experienced during 2007-2010 with the OSTHI program in place. Potential deployment scenarios over 5 years are detailed below. We assume declining incentives in Years 3-5. Uptake assumptions, associated incentive payments, and associated avoided GHGs are summarized in the table below.

Figure 22: Solar Thermal Program Deployment Impacts

	Solar Air Capacity Potential each Year (MW)	Installed Square Footage of Solar Air Collectors each Year (ft^2)	Solar Air Total Incentive Investment @ $26/ft^2 ($ Million)	Solar Air GHG Offset Estimates (tonnes) Per Year*[14]
Year 1	20 MW	400,000	$10.4 M	5,700 - 8,000
Year 2	40 MW	800,000	$20.8 M	11,428 - 16,000
Year 3[15]	60 MW	1,200,000	$28.8 M	17,142 - 24,000
Year 4[16]	80 MW	1,600,000	$35.2 M	22,800 – 32,000
Year 5[17]	100 MW	2,000,000	$40 M	28,570 – 40,000
Total Solar Air Heating	**300 MW**	**6,000,000 ft^2**	**$135 M**	**~85,000-120,000**
5 Year Program Total			**$185 M**	

*The 5 year program total has been increased by $50 million to account for an associated solar water heating incentive in commercial applications, as was available under the OSTHI Program previously.

It is important to also note that the air heating deployment summarized in the table above is expected to avoid approximately 2.5 – 3.6 megatonnes of GHGs over the life of the systems.

The Pathway to Mainstream Solar Heating After 2021

CanSIA expects that by the end of this programming, the market conditions will be such that the industry can begin to be self-sustaining with average paybacks approaching 5 years in retrofit applications. Below are some key consideration for 2022 and beyond.

For New Construction

The Ontario Building Code has moved over time to specify greater and greater levels of energy efficiency for new construction. As the province moves towards the implementation of a it's net zero buildings strategy, eventually it will need to specify a certain percentage of on-site renewable (or non-emitting) energy generation in order to hit its targets. This will mean that clean energy systems will become required on all new buildings and therefore no external financial support would be needed.

Additionally, the costs to integrate any of the solar technologies into new buildings are significantly less than in retrofit, so solar will become an automatic solution to the new codes. The building envelope will become an energy

[14] * Assuming average offset of 1 tonne of CO_2/ 50-70ft^2 of solar collector area
[15] Assume incentive could be declined to $24/ft2 in Year 3
[16] Assume incentive could be declined to $22/ft2 in Year 4
[17] Assume incentive could be declined to $20/ft2 in Year 5

generator; with solar air heating on walls producing heat energy, and solar PV and solar water heating on roofs generating electricity and hot water.

For the Existing Building Stock

Figure 23: Solar Thermal Incentive Reduction Roadmap

YEAR	1	2	3	4	5
Solar Air Heating Materials & Engineering Cost - ($ / SQF)	12	12	11	11	10
Solar Air Heating Installation Cost - ($ / SQF)	14	13	12	12	12
Mechanical Integration & Controls Cost - ($ / SQF)	18	17	16	16	16
Acquisition & Soft Costs Cost - ($ / SQF)	10	8	6	4	3
Total Cost of System Cost - ($ / SQF)	**54**	**50**	**45**	**43**	**41**
Cost of Gas ($ / m^3)	0.3	0.31	0.32	0.32	0.33
Carbon Surcharge to Ratepayer ($ / m^3)	0.033	0.045	0.058	0.070	0.083
Net Cost of Gas ($ / m^3)	0.333	0.35	0.37	0.39	0.41
Incentive Level ($ / SQF)	**26**	**26**	**24**	**22**	**20**
Payback (Years)	7.5	6	5	4.7	4.5
ROI (%)	16.7	20.1	23.6	24.7	25.8

The table above takes the average payback numbers of all 4 system types previously discussed, which is 7.5 years, and then shows the decline in the payback years based on the increasing costs of gas and the decreasing total system cost.

The objective is for the solar air heating industry to scale in a meaningful way under this program in the next 5 years so that market factors such as economies of scale, market awareness, carbon pricing and third party financing can coalesce to create the circumstances under which continued government support will not be required after 2022. The path to self-sufficiency is to be able to achieve average paybacks of under 5 years.

Declining Costs

Most solar air heating systems are made of steel, and therefore follow the world commodity price. With the market scaling contemplated here, mitigation against future price increases in steel will be possible and some economies of scale will be achieved.

Solar heating deployment will also lead to labor efficiencies; the industry knows that installation costs decline once installers have acquired familiarity with systems. This occurs when a market starts to scale, and examples of this exist within the US Military market for solar air heating.

Increased Market Awareness

Consumers and investors will be familiar with solar heating as the technology starts to enter the mainstream (similar to solar PV). Building owners, engineers and architects upgrading their existing energy system or in any new-builds will be aware of benefits of solar heating. This will significantly decrease soft costs associated with selling systems, as is detailed above.

Third Party Financing

Widespread financial support from government agencies across the world encouraged third party investment models and economies of scale which created downward pressure on PV prices. With similar support for solar heating, these third party investment models would become financially viable. This will spur rapid growth and create newfound cost efficiencies in the solar heating market. When the payback period is around 5-6 years, it will start to attract third party financing. Increased exposure to solar air heating projects will decrease the risk profile of the investment and build investor confidence, ensuring a self-sustaining and animated marketplace to continue the growth.

Program Recommendations

To ensure significant immediate uptake, CanSIA recommends establishing a prescriptive program under the CCAP for solar heating systems to drive uptake in the retrofit market for commercial, industrial, institutional, multi-residential, and agricultural buildings. In-line with the timelines of the CCAP, the program is recommended to run for an initial 5 years with a total budget of $135-185 million. The incentive would take the form of an up-front capital contribution to establish market clarity and spur immediate interest again in solar heating.

A solar heating program model previously existed in the province in the form of the very successful Ontario Solar Thermal Heating Incentive (OSTHI) Program and a similar structure could be easily re-implemented under the CCAP. This program operated from 2007-2010 and led to Ontario becoming the solar thermal capital of Canada, with close to 1,000 large solar heating systems installed on a wide variety of buildings. Ontario has a very strong base in solar air heating because of the origins of the SolarWall® technology in the province (the original solar air heating invention that shaped the global industry). Overall solar heating is well established in Ontario, and will provide a strong contribution to bringing carbon-free heating into the mainstream and accomplishing the province's GHG emission reduction targets.

Conclusion and Summary of Recommendations

Ontario has reached an enviable position with regards to the robustness and cleanliness of its electricity supply. There are significant risks, however, to the continuation of those attributes depending on how the supply and demand scenarios evolve over the planning period of the LTEP. The province must ensure that the grid maintains a low level of emissions in order to meet its climate change goals. At the same time, Ontario has the opportunity to modernize its energy system to give consumers a greater degree of choice as to from where and how they consume their energy. Solar PV and solar thermal can help maintain the cleanliness of the grid and offset GHG emissions from both the electricity and the fuels sectors and continue to contribute meaningfully to the expansion of the clean tech sector. These technologies can also offer consumers viable means of controlling their own energy costs while supporting the province's climate goals. In order to do these things the LTEP should take into account the following:

- Demand side risks mean the government should be developing an LTEP which plans for a demand outlook falling between Outlook B and Outlook C.

- Supply side risks mean the government should maintain realistic mechanisms for securing supply, when the need arises. This includes procuring utility scale renewable generation at the lowest possible cost via competitive procurements for long term contracts and ensuring market renewal initiatives support renewables.

- Maintaining low levels of GHG emissions from the electricity sector even in the face of potential risks to supply/demand and increased electrification of other sectors of the economy;

- Committing to full transparency on nuclear refurbishment off-ramps and cost thresholds that trigger them;

- Developing a robust net metering regulatory framework that encourages cost efficiencies, customer choice, and innovative business models including the implementation of Time of Use (TOU) rates for net metering customers, community/virtual net metering, and third party ownership;

- Transitioning the distributed solar industry to a net metering framework in a reasonable fashion using a capital cost incentive administered through the Climate Change Action Plan (CCAP);

- Working with the solar industry, Local Distribution Companies (LDCs), the Ontario Energy Board (OEB) to reduce the cost of solar;

- Modernizing electricity rate models to encourage innovation from utilities while protecting individuals and businesses ability to meet their own electricity needs at a reasonable cost; and

- Utilizing solar thermal technologies to offset natural gas use for space and water heating.

Appendices

Appendix A: Potential Supply Scenarios

Generation Outlook Scenarios

Scenario 1: Outlook B Less CDM

Scenario 1: Outlook B (GW)	Near	Medium	Long
Supply Need	-1.6	-5.8	-11.4
Expired - Gas	0.4	3.1	5.1
Expired - Renewables	0.2	0.3	2.2
Previous Period Renewed or New Supply	0.0	1.1	5.6
Potential Net Supply Need	**-1.0**	**-1.3**	**1.5**
Repowered - Gas	0.40	3.10	3.20
Repowered - Renewables	0.21	0.29	2.15
New Supply	1.0	1.3	0.5
Supply Surplus/Deficit	**0.0**	**0.0**	**0.0**

- In the near-term, there is a supply need due to expired DR and less CDM.
  - The supply need can be addressed by repowering of existing resources gas-fired or contracting new demand responses.
  - The import agreement for 500 MW with Hydro Quebec provides some new supply relief.
  - Expiring renewable generation is expected to continue to operate to reduce total emissions (i.e. reduce the need to operate existing gas-fired generation).
- In the medium-term, supply need is primarily resolved through repowering of existing resources.
  - The import agreement with Quebec is likely expanded to 1 GW. The remaining supply need is addressed through new DR.
  - Renewable generation is expected to repower to continue to assist in emissions reductions. Minor development of new renewable generation (couple hundred MWs) may occur to further reduce emissions.
- In the long-term, the import agreement and repowering of existing assets resolves most of the supply need.
  - Most of the gas-fired generation with contract terms expiring in the long-term will be repowered.
  - To maintain low emissions of the repowered generation fleet, some new renewable generation development may be required.

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Generation Outlook Scenarios

Scenario 2: Outlook B Less CDM Less Nuclear

- The shorter operating life of Pickering NGS results in a significant supply need in the near-term.
  - All expired generation is repowered.
  - The import agreement with Quebec is expanded to 1 GW total.
  - New gas-fired generation, expanded capacity at existing facilities and/or DR is likely developed to meet the supply need in the short-term.

Scenario 2: Outlook B Less Nuclear (GW)	Near	Medium	Long
Supply Need	-4.6	-6.6	-13.0
Expired - Gas	0.4	3.1	5.1
Expired - Renewables	0.2	0.3	2.2
Previous Period Renewed or New Supply	0.0	3.2	6.5
Potential Net Supply Need	**-4.0**	**0.1**	**0.8**
Repowered - Gas	0.4	2.9	4.2
Repowered - Renewables	0.2	0.3	2.2
New Supply	4.0	0.1	0.1
Supply Surplus/Deficit	**0.0**	**0.0**	**0.0**

- New generation developed in the near-term is utilized to meet the medium term supply need.
  - The new generation likely means that some existing generation is retired in the medium term.
  - Renewable generation is expected to repower to continue to assist in emissions reductions. Minor development of new renewable generation (500 MW to 1 GW) over the near-term and medium-term may occur to further reduce emissions.
- Slow demand growth in the long-term along with near-term generation development reduces the need to repower some expired generation.
  - All renewable generation is expected to be repowered to maintain lower emissions.

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Scenario 3: Outlook C Less CDM

- New supply is required in the near-term to meet growing demand under Outlook C.
  - The import agreement with Quebec of 500 MW partially addresses the supply need.
  - All expired generation is likely required, with some gas-fired generation expanding capacity to address the remaining supply need. New DR is also an option.
- Continued demand growth in the medium-term supports further new supply development and repowering of all expiring generation.
  - New gas-fired generation is likely required for peak demand requirements. With additional new gas-fired generation, there is likely support for continued development of new renewable generation (greater than 1 GW) to reduce total emissions growth in the electricity sector.
- In the long-term, the peak demand shifts from summer period to winter period.
  - The shift to winter peaking reduces the availability of imports from Quebec due to the winter peaking need in that jurisdiction.

Scenario 3: Outlook C (GW)	Near	Medium	Long
Supply Need	-1.9	-7.1	-18.2
Expired - Gas	0.4	3.1	5.5
Expired - Renewables	0.2	0.3	2.3
Previous Period Renewed or New Supply	0.0	1.2	6.4
Potential Net Supply Need	-1.3	-2.5	-4.1
Renewed - Gas	0.4	3.1	5.5
Renewed - Renewables	0.2	0.3	2.3
New Supply	1.3	2.5	4.1
Supply Surplus/Deficit	**0.0**	**0.0**	**0.0**

- In addition to repowered generation, a large amount of new generation is needed in the long-term.
  - Continued development of new renewable generation is likely to occur.
  - The development of large flexible generation (i.e., large hydro, large storage, expanded import agreements) could be supported and provide ability to maximize the value of renewable generation development.

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Generation Outlook Scenarios

Scenario 4: Outlook C Less CDM Less Nuclear

- The shorter operating life of Pickering NGS results in a significant supply need in the near-term.
  - All expired generation is repowered and the import agreement with Quebec is expanded to 1 GW total.
  - New gas-fired generation, expanded capacity at existing facilities and DR are all likely developed to meet the supply need in the short-term.
- Continued demand growth in the medium-term supports further new supply development and repowering of all expiring generation.
  - New gas-fired generation is likely required for peak demand requirements along with development opportunities for new renewable generation.
- In the long-term, the peak demand period shifts from summer to winter, reducing the cost-effectiveness of imports from Quebec.
  - The large supply need supports repowering of all expired generation with possible consideration for expanded capacity at gas-fired generation sites.
  - The long-term offers significant opportunities for new renewable generation development.
  - The renewable generation development can be expanded with investment in flexible capacity (i.e., large hydro, large storage or expanded import agreements).

Scenario 4: Outlook C Less Nuclear (GW)	Near	Medium	Long
Supply Need	-5.0	-7.8	-19.7
Expired - Gas	0.4	3.1	5.5
Expired - Renewables	0.2	0.3	2.3
Previous Period Renewed or New Supply	0.0	3.7	7.9
Potential Net Supply Need	-4.4	-0.7	-4.0
Repowered - Gas	0.4	3.1	5.5
Repowered - Renewables	0.2	0.3	2.3
New Supply	4.3	0.8	4.0
Supply Surplus/Deficit	0.0	0.0	0.0

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Appendix B: Summary of CanSIA's Distributed Generation Task Force Recommendations

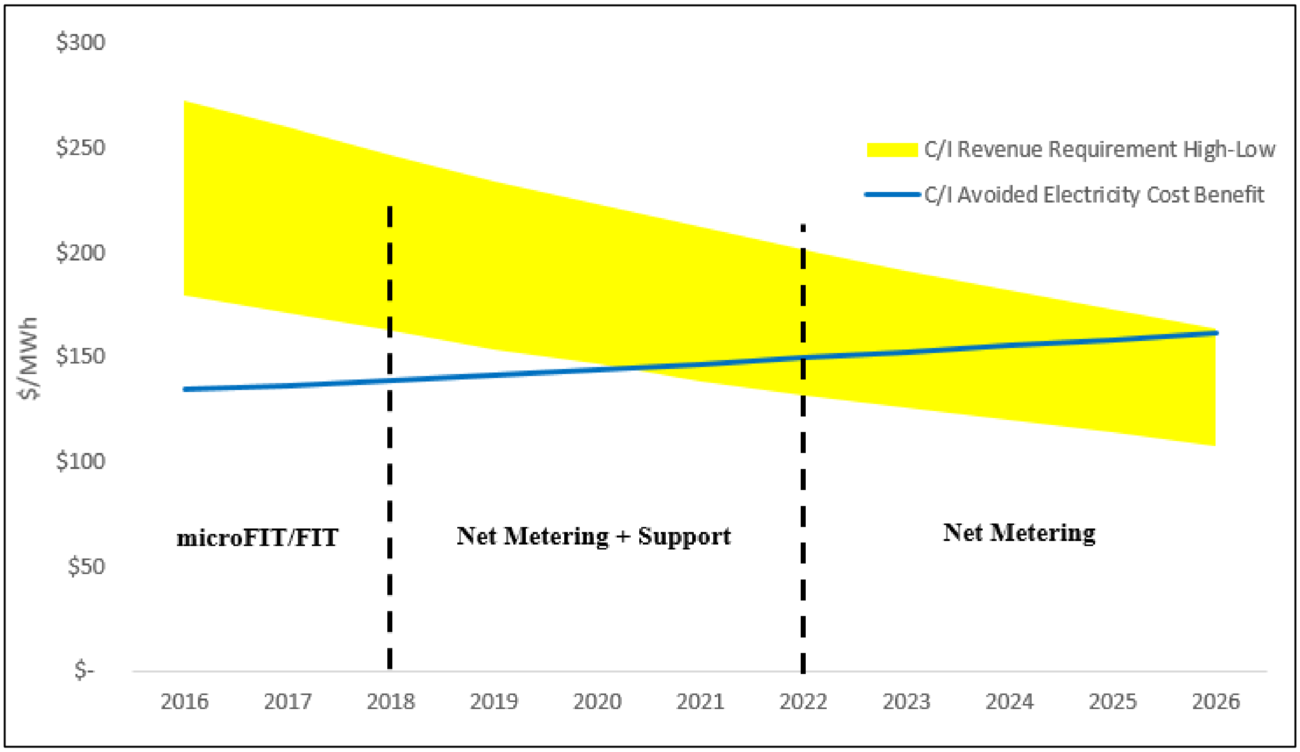
CanSIA created the Distributed Generation Task Force (DGTF) in early 2015 to consult on and design a transition for the Ontario distributed solar industry to move away from the current Feed-in Tariff (FIT) regime and into a net metering based framework. This transition, and the resultant net metering framework, is envisioned to be more responsive to electricity customer demand and to shift investment and performance risk to the market. Making this transition will allow the private sector to design and deliver projects efficiently within a timeline driven by economics and investment decisions rather than centralized procurement cycles.

Distributed Solar Generation (DSG) provides the following system value and benefits to Ontario:

- Located behind the meter, it is an effective Conservation and Demand Management measure
- Regional planning and distribution system planning benefit from having DSG as a grid-responsive and flexible resource option to meet power system needs
- It provides consumers an investment option to hedge against the risk of rising electricity rates and increases resiliency
- It is a supply mix diversification option that reduces peaking natural gas combustion in support of Ontario's climate change objectives
- It leverages strong public support for DSG to engage Ontarians in the electricity sector and its evolution

Ontario is currently capturing many of these benefits via the FIT Program. If the program is transitioned effectively to a net metering based framework, all benefits can be captured. The DGTF has determined that after the conclusion of the FIT program at the end of 2017, modest additional support for net metering projects will be needed for three to five years before net metering is economic without assistance. Figure 24 illustrates the timing of this transition from the conclusion of the FIT Program, through a period of transitionary support, and ending in straight net metering. Net metering is the established DSG policy in 46 of 50 United States and most Canadian provinces.

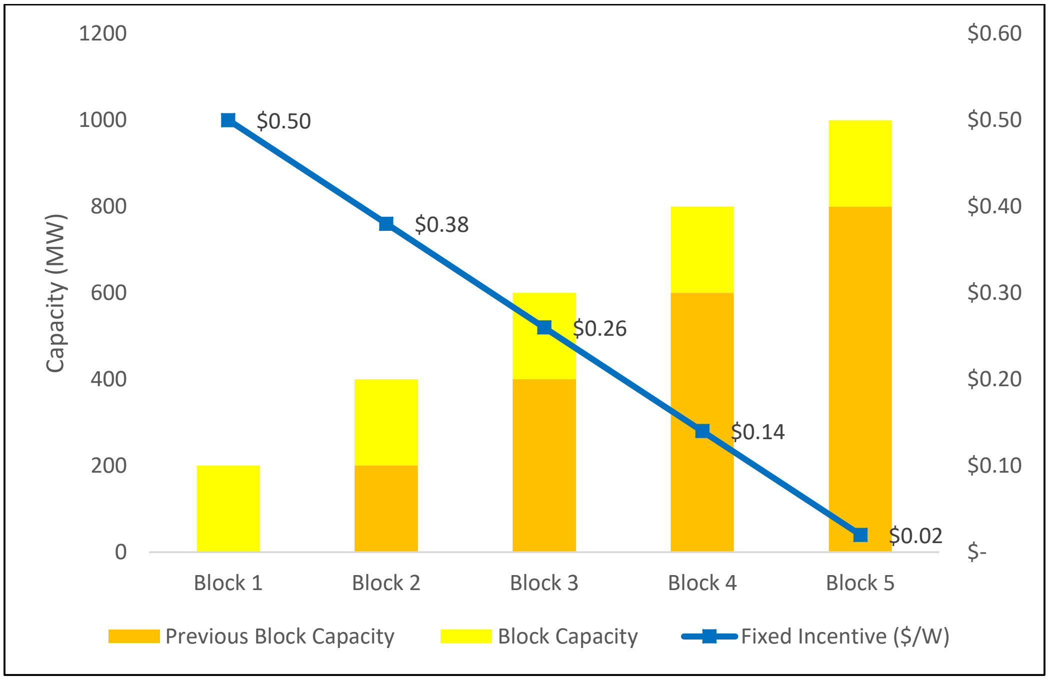
Figure 24: Distributed Solar Generation Cost Curve



Additional financial support will initially be required when a new net metering program is launched after FIT. The majority of revenue under a net metering regime comes from avoided electricity consumption, so additional support will be significantly lower compared to a FIT program. This additional support can decline year over year and will no longer be required post 2022.

- Provide interim support to net metered projects between 2018 and 2022 to bridge the gap to grid parity
- Offer a declining capital cost contribution for a capped quantity of 200 MW and finite budget (see Figure 25)
- Incent projects that support distribution grid need or regional planning system need through existing LDC distribution system planning and rate making processes and IESO regional planning processes
- Continue dialogue with the federal government for improved tax treatment and tax incentives for renewable generation, that could further accelerate reaching grid parity

Figure 25: Proposed Capital Cost Incentive Program



The above annual targets represent a cap on DSG eligible for the specified level of capital incentive, and the years are indicative only. If there is a year with under-subscription then the incentive would continue to be available in the subsequent year, and the schedule could be pushed out.

It is expected that the capital incentive would be needed until 2022, after which net metering at TOU rates would be an adequate incentive for customer adoption of DSG.

The DGTF's recommendations are an off-ramp from the current centralized FIT and microFIT procurement programs. They seek a reasonable balance between ratepayer protection and continued modest and steadily declining support for solar's participation in the supply mix. They harness a Conservation First approach in order to bend the cost curve for ratepayers. Ontario's evolution from FIT through supported net metering to a customer self-consumption model allows for the Province to capture the full value of being an early champion of renewable energy. This balanced approach ensures that Ontario continues to have the support mechanisms and a regulatory environment necessary to enable enhanced energy services for customers and advance toward a collective smart grid future.