Ontario's Emissions and the Long-Term Energy Plan

Phase 1 - Understanding the Challenge

Final Report

Marc Brouillette

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STRATEGIC POLICY ECONOMICS

Executive Summary

This study informs the Ontario Long-Term Energy Plan (LTEP) consultation with background analyses that relate to emission reduction targets, the costs of emission reducing technologies, the carbon price within Ontario's Cap and Trade (C&T) program, and the supply mix choices being developed for the next LTEP.

Since the global community of nations emerged from the COP21 Paris Climate Conference and its ratification at COP22 (Nov 2016), the urgency to combat climate change is now fully acknowledged by all key actors. To reverse the impacts of global warming, deep decarbonization of the global economy is now a priority for government action. Electrification across all economic sectors is considered a critical enabler for a pathway to a low carbon energy future. Beyond Ontario's electricity sector, transportation and the heating of buildings comprise the largest sources of emissions, creating an intersection of policy challenges for the environment, the economy, and Ontario's three energy systems: petroleum, natural gas, and electricity.

Ontario's next LTEP consultation process is underway, and the province's climate change strategy is a key driver. Ontario has legislated the province's greenhouse gas (GHG) emissions to drop to 37% below 1990 levels by 2030, or from the business as usual forecast of 176 Mega-tonne (Mt)/year to 111 Mt/year. The mandate to achieve these reductions falls under: (1) the C&T program that will establish the carbon price; and (2) the Climate Change Action Plan (CCAP) that will administer the use of the C&T proceeds. The LTEP's role, on the other hand, is to provide for the energy to enable Ontario's transition to a low carbon economy. However, publicly released reference materials do not draw an explicit connection between the LTEP and the legislated emission targets and the cost required to achieve them.

The Ontario Planning Outlook (OPO) prepared by the IESO identifies increased cost to the electricity system of $8B/year by 2035, and the Fuels Technical Report (FTR) prepared for the Ontario Ministry of Energy identifies $20B/year additional fuels costs. The relationship of these costs to the 2030 emissions targets is not clearly expressed.

This study comprises two phases.

1. Phase 1, *"Defining the Challenge"*, quantifies the costs of Ontario's climate actions and identifies the factors that the LTEP consultation process must address.
   - This report documents emission targets for each sector, identifies 45 emission reduction options posited by Ontario stakeholders, estimates the costs of each, and summarizes the aggregated cost to Ontarians and the implications for market carbon pricing, C&T program, CCAP implementation, and the LTEP.

2. Phase 2, *"Meeting the Challenge"*, will examine the cost and economic implications of options for Ontario's electricity supply mix in the 2017 LTEP.
   - The next report will examine the implications on supply arising from the new electricity demand, assess the costs and implementation considerations of the supply mix options put forward in the OPO as well as alternatives, and describe the cost and economic implications to Ontarians associated with those choices.

Although the primary focus of this study is the province of Ontario and its LTEP process, the detailed analyses within this report are potentially relevant for other similar jurisdictions in the Great Lakes-St. Lawrence Region, or more broadly, that may be contemplating aggressive emission reductions, deep decarbonization, and government mandated carbon pricing schema.

Key Findings: Phase 1

An LTEP process focussed on the province's climate change objectives is critical to lowering costs, meeting emission targets in a timely manner, and to allow the transition of Ontario to a low carbon economy. The LTEP should seek out the lowest cost incremental new electricity solution for Ontario that includes the integrated costs of generation, transmission, and distribution.

Four recommendations for the LTEP process are:

1. 90 TWh of new demand requires a decision at the earliest stage in the LTEP process for commitment to low-cost, emission-free generation options.
   - Forecast new demand for electricity is primarily for home heating and industrial baseload applications. This is 80% greater than the 50 TWh presented in the OPO Outlook D and 60% more than is consumed today.
   - Meeting 2030 emission targets depends on supplying this new demand with new generation. The timing for this consideration is not reflected in the OPO. Maximizing the safe economic life of the Pickering Nuclear Generating Station (PNGS) can support the transition.

2. Low cost electricity choices should be prioritized by the LTEP to reduce the cost of carbon emission reduction initiatives. Low cost electricity choices could reduce this cost by up to 25% or $7B/year.
   - With OPO Option D1, adoption of carbon emission reduction initiatives could potentially add costs of up to $27B/year to how Ontarians use energy, depending on the cost of electricity and the effectiveness of administrating the use of C&T proceeds. This cost could be reduced by the above mentioned 25%. The components contributing to the additional costs are:
     - Expected required carbon pricing within the C&T program would account for 60% or $16B/year of these costs which are to be directed towards subsidizing emission reduction initiative adoption;
     - As Ontarians make low emission choices, they will invest $9B/year to cover the unsubsidized portions of such things as new building heating equipment; and
     - Another $2B/year could be incurred by the administration and implementation of the C&T processes and dispensation of C&T proceeds.
   - The estimated carbon price required to achieve the 2030 targets ranges from $120/tonne to $210/tonne, also depending on the cost of electricity and the effectiveness of administrating the use of C&T proceeds.
     - Low cost electricity supports a carbon price of $120/tonne. The IESO has identified nuclear as the lowest cost option in the OPO.

3. Ontario's climate strategy initiatives should be integrated with the LTEP to match the pace of C&T emissions caps with the pace at which new electricity generation capacity can be built and alternative fuels provided.
   - Aligning emission targets to the availability of electricity and/or alternative fuels will minimize the likelihood that provincial targets will be missed.

- Missed emission targets caused by lack of generation could cost ~$1.2B/year in C&T allowance purchases from other jurisdictions.
- The integrated LTEP and climate strategy should consider the pathway to 2050 for deep decarbonization.
- The LTEP process should fully and transparently integrate emission targets, climate actions, electricity planning, and fossil fuels strategies.

4. Rigorous attention should be paid to the effective and efficient management of C&T proceeds use.
   - An effective program can accelerate emission reductions, get the carbon price much below $210/tonne, minimize the cost to Ontarians through effective subsidization programs. There is the potential of a $10B/year risk associated with ineffective policies.
   - A transparent evidence based process that considers all potential emission reduction technologies, such as hydrogen and nuclear, could lead to significant economic and competitive advantages for Ontario. Hydrogen generated with the lowest cost nuclear energy has emerged as among the most economical emission reduction options assessed in this study.
   - The effective use of C&T proceeds could make options economic at $120/tonne that would otherwise require a carbon price of $800/tonne.

Next Steps: Phase 2

The next report will examine the implications on supply that the new electricity demand necessitates, assess the costs and implementation considerations of the supply mix options put forward in the OPO, as well as alternatives, and describe the cost, schedule achievability, and economic implications to Ontarians associated with those choices.

Table of Contents

List of Figures

List of Tables

1.0 Introduction

This study informs the Ontario Long-Term Energy Plan (LTEP) consultation with background analyses that relate to emission reduction targets, the costs of emission reducing technologies, the carbon price within Ontario's Cap and Trade (C&T) program, and the supply mix choices being developed for the next LTEP.

Since the global community of nations emerged from the COP21 Paris Climate Conference[1] and its ratification at COP22 (Nov 2016), the urgency to combat climate change is now fully acknowledged by all key actors. To reverse the impacts of global warming, deep decarbonization of the global economy is now a priority for government action. Electrification across all economic sectors is considered a critical enabler for a pathway to a low carbon energy future. Beyond Ontario's electricity sector, transportation and the heating of buildings comprise the largest sources of emissions, creating an intersection of policy challenges for the environment, the economy, and Ontario's three energy systems: petroleum, natural gas, and electricity.

Ontario's next LTEP consultation process is underway, and the province's climate change strategy is a key driver. Ontario has legislated the province's greenhouse gas (GHG) emissions to drop to 37% below 1990 levels by 2030, or from the business as usual forecast of 176 Mega-tonne (Mt)/year to 111 Mt/year, a 65 Mt reduction. The mandate to achieve these reductions falls under: (1) the C&T program that will establish the carbon price; and (2) the Climate Change Action Plan (CCAP) that will administer the use of the C&T proceeds. The LTEP's role, on the other hand, is to provide for the energy to enable Ontario's transition to a low carbon economy. However, publicly released reference materials do not draw an explicit connection between the LTEP and the legislated emission targets and the cost required to achieve them.

The Ontario Planning Outlook (OPO) prepared by the IESO identifies increased cost to the electricity system of $8B/year by 2035, and the Fuels Technical Report (FTR) prepared for the Ontario Ministry of Energy identifies $20B/year additional fuels costs. These costs are additive for a total of $28B/year of new energy supply costs to Ontario. The relationship of these costs to the 2030 emissions targets is not clearly expressed. The absence of some key facts and analyses suggests that the anticipated outcomes of Ontario's climate change strategy actions may be optimistic.

This study comprises two phases.

1. Phase 1, *"Defining the Challenge"*, quantifies the costs of Ontario's climate actions and identifies the factors that the LTEP consultation process must address.
   - This report documents emission targets for each sector, identifies 45 emission reduction options posited by Ontario stakeholders, estimates the costs of each, and summarizes the aggregated cost to Ontarians and the implications for market carbon pricing, C&T program, CCAP implementation, and the LTEP.

[1] 21st Conference of the Parties, the 2015 Paris Climate Conference, http://www.cop21paris.org/about/cop21

2. Phase 2, *"Meeting the Challenge"*, will examine the cost and economic implications of options for Ontario's electricity supply mix in the 2017 LTEP.
   - The next report will examine the implications on supply that the new electricity demand necessitates, assess the costs and implementation considerations of the supply mix options put forward in the OPO as well as alternatives, and describe the cost and economic implications to Ontarians associated with those choices.

Although the primary focus of this study is the province of Ontario and its LTEP process, the detailed analyses within this report are potentially relevant for other similar jurisdictions in the Great Lakes-St. Lawrence Region, or more broadly, that may be contemplating aggressive emission reductions, deep decarbonization, and government mandated carbon pricing schema.

Methodology

This first phase of the study developed an estimate of the future cost of reducing Ontario's emissions, the associated dynamics impacting carbon pricing, and the implications that LTEP choices for the electricity system may have on these total costs. The five objectives of this study are to:

- Identify the emissions reductions in required in each sector to meet the 2030 targets;
- Investigate available emissions reduction options and estimate the emission benefits, the amount of electrification required, and the costs of the options compared to existing technology;
- Aggregate the provincial level demand for electricity and identify the implications this represents regarding new generation;
- Estimate the carbon price required to enable emission reduction options as economic choices for Ontarians; and
- Estimate the total cost to Ontarians of achieving the emission reductions and the sensitivity of that cost to both the incremental cost of electricity as well as to the government's policy choices for implementing the Cap and Trade (C&T) program.

For validation purposes, the directional findings of this study are compared to the assumptions in the IESOs Ontario Planning Outlook (OPO) and the Fuels Technical Report (FTR) prepared for the Ontario Ministry of Energy (MoE) in support of the LTEP consultation process.

Document Structure

This report provides a comprehensive description of the drivers, assumptions, and outcomes regarding Ontario's 2030 emission reduction targets, and their potential implications for the LTEP and the energy related costs Ontarians could pay.

Section 2.0 provides background for Ontario's emissions targets, the C&T program and Climate Action Plan and the degree to which these programs are expected to be successful. Illustrations of the sector specific emissions, Ontario's energy supply mix, and their relationship to the Buildings, Transportation, and Industry sectors provide context for the research priorities addressed in this study.

Section 3.0 of this document describes the methodology underpinning this assessment: the approach and assumptions used to characterize emissions, electrification, and costs including the premise upon which effective carbon prices have been calculated.

The findings are presented in four sections:

- Section 4.0 characterizes the emissions reduction targets that relate to alternatives that may require electrification;
- Section 5.0 estimates the demand for electricity that may arise from electrifying these emission reduction opportunities;
- Section 6.0 looks at the cost of the emission reduction options and estimates the carbon price that would enable implementation; and
- Section 7.0 considers the implications for provincial level management and governance required to cost effectively achieve the province's emission targets, including the importance of the associated prerequisite low-cost electricity.

Section 8.0 provides several recommendations to be incorporated into the 2017 LTEP consultation process and also identifies further work that could better inform it, including the second report from Phase 2 of this study.

Acknowledgements of those who supported this study are provided following the recommendations. The sources consulted during the research for this study are listed in Appendix A. A list of acronyms can be found in Appendix B.

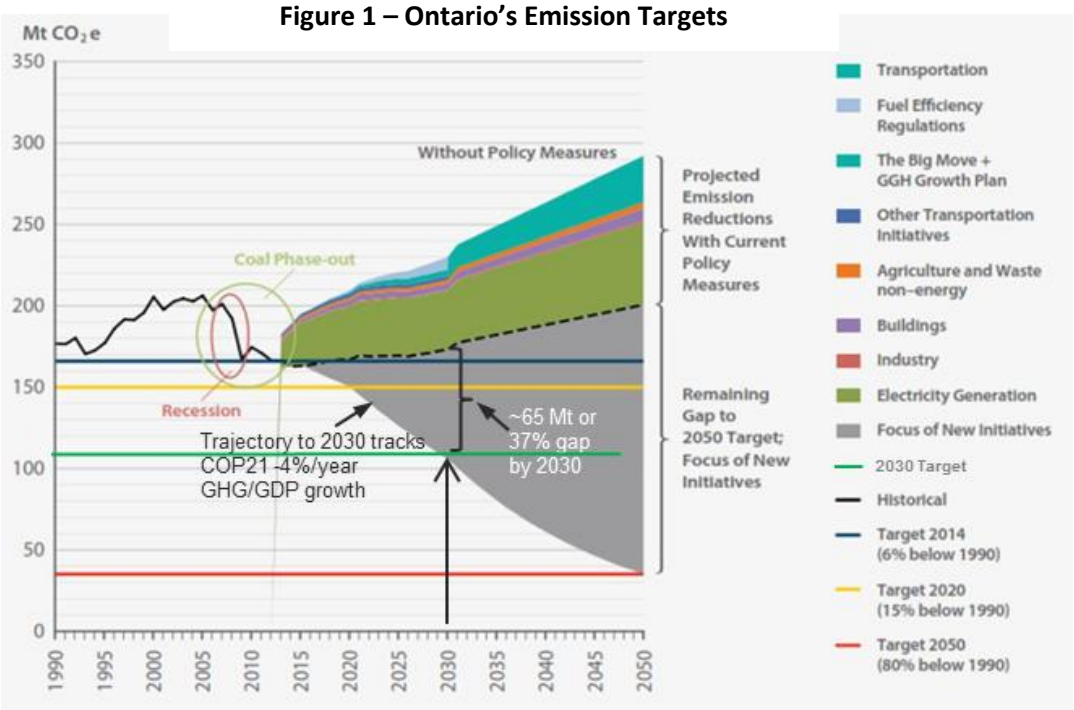
2.0. Background

To set the context under which the emission reduction initiatives have been identified and evaluated in this report, this section provides background on the emissions targets set by Ontario's Ministry of Environment and Climate Change (MOECC), the expectations of the C&T Program and the CCAP, and how energy is used in Ontario.

2.1. The MOECC's Climate Targets

The MOECC issued Ontario's Climate Change Strategy in the fall of 2015 prior to the COP21 meeting in Paris, France. Ontario's climate strategy identified the emission reduction targets shown in Figure 1. This included a new 2030 target to achieve emission reductions to 37% below 1990 levels.

Figure 1 – Ontario's Emission Targets



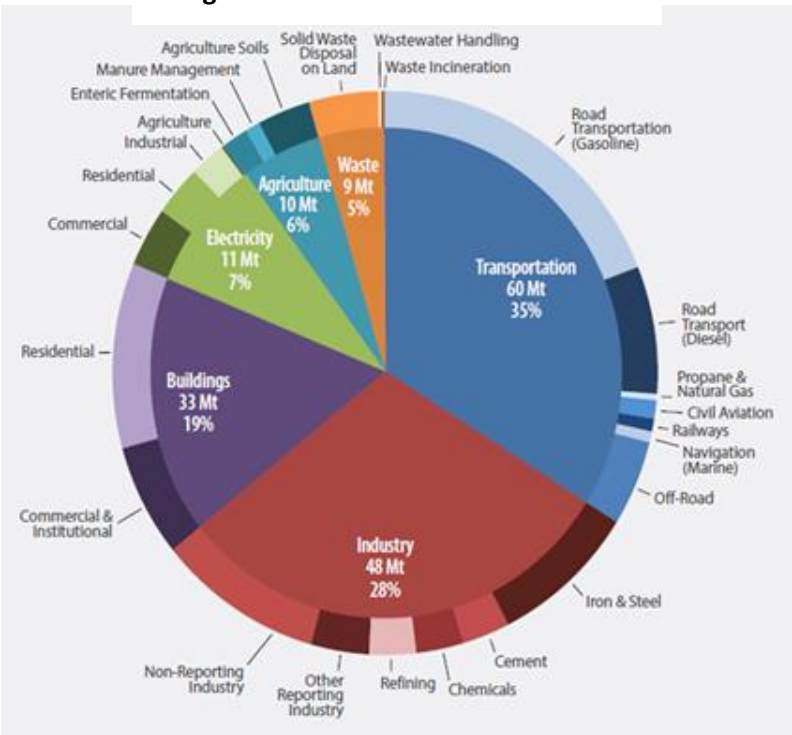
The Ontario Government's participation in the COP21 discussions was underpinned by these provincial targets. The COP21 event resulted in a global agreement on the approach to greenhouse gas emission (GHG) reductions. An annual GHG/GDP growth ratio of -4%/year to 2030 is a primary criterion used to set global emission reduction targets. At the global level, this criterion leads to an emissions target in 2030 that remains above global 1990 levels. Intended Nationally Determined Contribution (INDC) efforts

communicated in Paris are recognized as being insufficient to avoid global disaster[2]. These post-2020 climate actions or INDCs were developed by each country following the COP21 agreement in 2015.

Since the COP21 agreement, Ontario has legislated a 2030 provincial emission reduction target to achieve 37% below 1990 levels[3]. This objective appears to be more aggressive than most of the INDCs, but aligns with the globally required target to maintain a ratio of GHG emissions growth divided by GDP growth of -4%/year to 2030.

Figure 2[4] shows the summary of provincial emission levels in 2013 for each sector of the economy as presented in the MOECC's Climate Strategy. The Transportation, Industry, and Buildings sectors are the largest contributors to this province's emissions.

Figure 2 – Ontario's 2013 Emissions



Heating and transportation are generally viewed as the low hanging, near-term fruit. The Building and Transportation sectors are also candidates for efficiency improvements and technology substitutions.

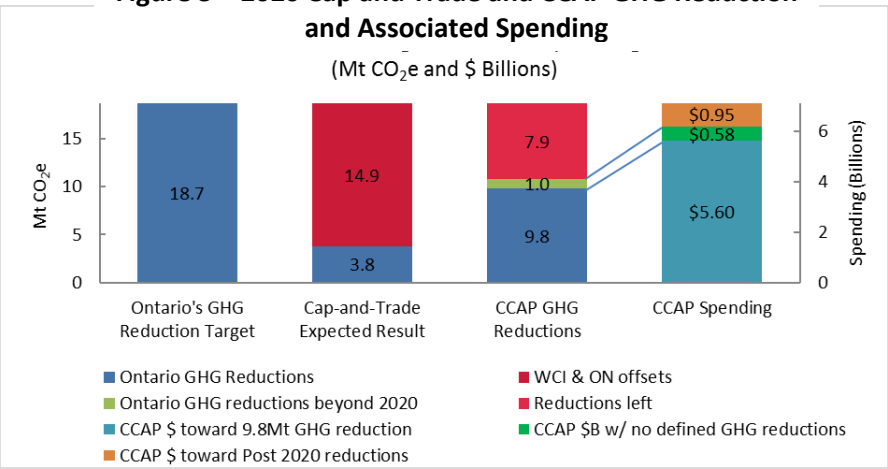
[2] Werksman, EU Climate Policy, 2016
[3] Bill 172, Climate Change Mitigation and Low-carbon Economy Act, 2016
[4] MOECC, Ontario's Climate Change Strategy, 2016

2.2. Expectations of the Cap and Trade Program and the Climate Change Action Plan

Both the C&T and CCAP programs currently focus on achieving the 2020 emission targets, while the post 2020 objectives do not appear to be addressed in any of the materials researched for this study. Ontario's 2020 emissions reduction target is 18.7 Mt. The MOECC initiatives outlined to date are not expected to achieve this near-term target.

For example, the MOECC's economic study[5] shows that Ontario's C&T program is expected to achieve only 3.8 Mt of emission reductions within Ontario by 2020 (20% of the target). As Figure 3 illustrates, this leaves 14.9 Mt of emission allowance to be purchased from other jurisdictions. The expected cost of these purchase allowances by Ontario GHG emitters is $250-$300M per year[6]. It is expected that Ontario's natural gas and gasoline distributors will be the primary buyers of these allowances as they manage the majority of the emitting fuels in the province. Consumers will pay these costs at the pump and on their natural gas bills.

Figure 3 – 2020 Cap and Trade and CCAP GHG Reduction and Associated Spending



The CCAP[7] sets out to use $5.6 billion from the Greenhouse Gas Reduction Account (GGRA) to achieve approximately half (9.8 Mt out of 18.7 Mt) of the required emission reductions by 2020, as shown in Figure 3. CCAP spending of $0.95 billion is expected to contribute to emission reductions beyond 2020. An additional CCAP spending of $0.58 billion has no defined GHG reduction target. Assuming this budget can achieve the same $/tonne emission reduction as the first $5.6 billion in spending, this analysis suggests an additional 1 Mt of emission reductions may be achievable by effectively using the GGRA funds by 2020. The implication is that Ontario will need an additional 7.9 Mt of emissions reductions to meet the 2020 target.

[5] Dillon Consulting, Impact Modelling and Analysis of Ontario Cap and Trade Program. 2016
[6] ICF International, Ontario Cap and Trade, 2016
[7] MOECC, Ontario's Five Year Climate Change Action Plan, 2016

This suggests that the C&T and CCAP initiatives will not achieve the desired emissions reductions within Ontario by 2020. It is not clear if Ontario intends to reduce emissions within the province, or if policy makers consider that the purchase of allowances from other jurisdictions in support of their emission reductions is an acceptable way to meet the 2020 reduction target.

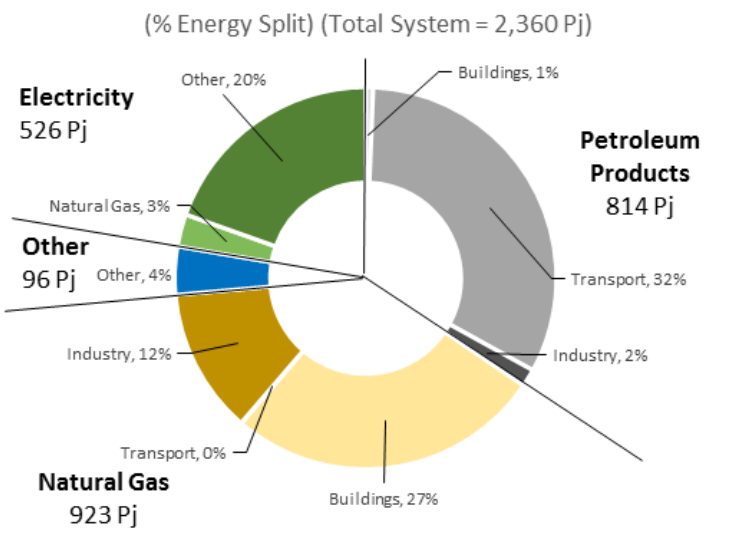
Given these uncertainties within the current MOECC climate initiatives, this study has been commissioned to help inform how the 2030 emission targets can be achieved, the costs of doing so, and any implications relating to Ontario's current LTEP process.

2.3. Ontario's Energy Use

Sector emissions are primarily driven by the fossil fuels each consumes. Assessing the nature of the fuel use in each sector can help with the evaluation of the potentially available technology option for reducing emissions. There are various sources of energy used in Ontario, each leveraged differently by the respective sectors. Figure 4[8] shows that there are three main sources of energy used in Ontario:

- Electricity (23%) – 20% of the 23% is from non-carbon emitting sources;
- Petroleum products (35%); and,
- Natural Gas (39%) – note an additional 3% of primary energy is used in natural gas-fired generators to produce electricity.

Figure 4 – Primary Energy Use in Ontario



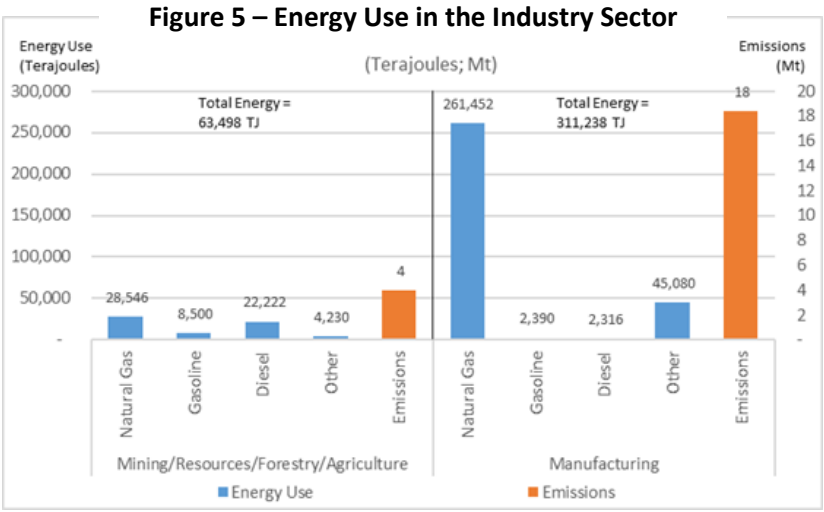
The total primary energy of 2360 Petajoules (PJ) includes the use of fossil fuels where 923 PJ (plus 71 PJ for electricity) are provided by natural gas and 814 PJ are provided by petroleum products.

[8] Statistics Canada, Report on Energy Supply and Demand in Canada, 2014

Petroleum products (gasoline and diesel) are mostly used in the Transportation sector, which represents 34% of Ontario's emissions. Natural gas supplies most of the energy to buildings and industry which in turn represent 19% and 28% respectively of the emissions in Ontario (shown in Figure 2).

Figure 5 illustrates the breakdown of energy consumption within the Industry sector and that natural gas is this sectors largest source of energy, with 90% of it being used in manufacturing. However, the 18 Mt of fuels related emissions represent only ~35% of the emissions from Industry. The remaining 30 Mt are related to emissions from industrial processes.

Figure 5 – Energy Use in the Industry Sector



Focussing on the largest sources of emissions, this study has prioritized the following areas for assessment:

- Buildings, where emissions are primarily related to the use of natural gas for heating;
- Transportation (gasoline/petroleum); and,
- Natural gas options that may also impact manufacturing, agricultural and waste sector emissions.

2.4. Summary

Ontario has legislated that provincial emissions must decrease to 37% below 1990 levels by the year 2030. The largest sources of emissions in Ontario in 2013 are the Transport, Buildings, and Industry sectors. These sectors are the focus for emission reduction opportunities in this study. The source of emissions stems from the use of (1) natural gas, primarily by Buildings and Industry, and (2) petroleum used primarily in Transportation.

3.0. Methodology

To better characterize Ontario's climate change challenge, this first phase of the study developed an estimate of the future cost of reducing Ontario's emissions, the associated dynamics impacting carbon pricing, and the implications that LTEP choices for the electricity system may have on these total costs. To provide these results, this study focused on the following five objectives:

- Identify the emissions reductions in each sector that are required to meet the 2030 targets;
- Gather insight on options to reduce emissions that may require electrification, and estimate the emission benefits, electrification required, and costs of those options;
- Aggregate the provincial level demand for electricity and implications on new generation;
- Estimate the carbon price required to enable options as an economic choice for Ontarians; and,
- Estimate the total cost to Ontarians of achieving the emission reductions and the sensitivity of that cost to the incremental cost of electricity.

To achieve these objectives, several assumptions, data gathering, and analytical methods were employed. The assumptions and methods were heavily influenced by the options identified for reducing emissions. The source for identifying emission reduction options forms the main content of this section. The methodology applied by this study is described through the following topics:

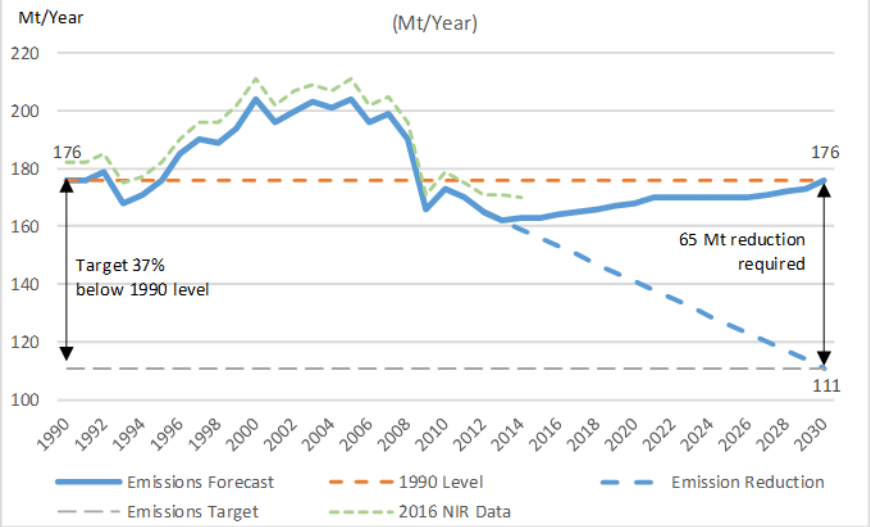
a) Overview of future emissions expectations, those addressed by this study, and relationship with the FTR;
b) Energy efficiency improvement assumptions not requiring electrification;
c) Emission reduction alternatives in Buildings, Transportation and Industry, and the electrification estimation approach;
d) Assumptions for costing of alternatives;
e) Method for calculating carbon price; and,
f) Approach to characterizing the C&T related economic implications for consideration by the LTEP.

3.1. Overview of Future Emission Expectations

The overall 2030 emissions expected for Ontario under a BAU case are based on the MOECC's 2014 Ontario Climate Change Update (based on 2012 data, the most recent which was contained in the 2014 National Inventory Report). In the Climate Change Update, the MOECC provided emission projections to 2030 that were based on the 2012 data actuals. The analysis in this study used this 2030 forecast as the reference case. The MOECC's forecast has been replicated in Figure 6[9], with the targeted emission reductions identified.

[9] MOECC, Ontario's Climate Change Update, 2014

Figure 6 – MOECC Ontario Emissions Forecast



Ontario's forecasted emissions for 2030 are similar to those realized in 1990. To meet the 2030 reduction target, Ontario must reduce its total forecast 2030 emissions by that same 37%, which represents a 65 Mt future reduction in annual emissions.

The 2016 National Inventory Report[10] (NIR) highlights differences in the data used in the MOECC's Update. The 2016 NIR contains data to 2014 and restated 2012 data. The 2013 data is now reflected in the current Ontario Climate Strategy materials, which are available on the Ontario government's website. These 2013 values are consistent with the 2016 NIR. Although the 2012 data has been restated, MOECC's emission forecast has not been updated.

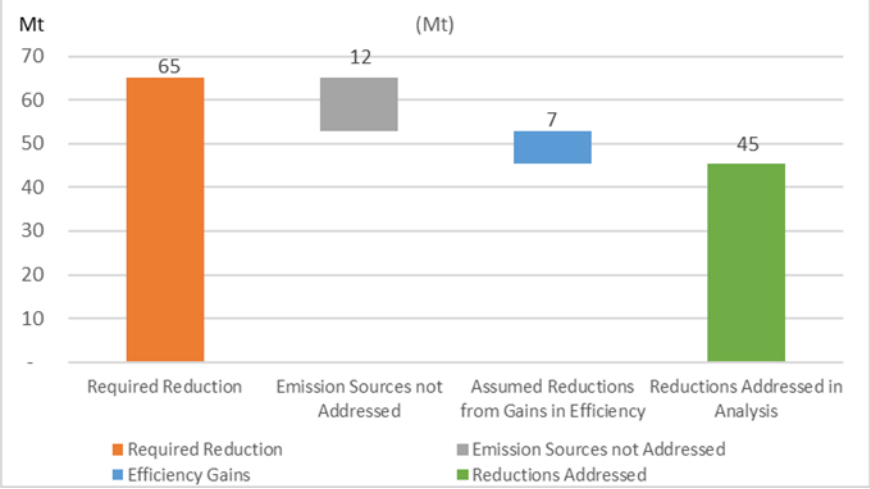
For the purpose of this study, the 2030 forecast obtained from the original 2012 data used by the MOECC has been adopted as the reference from which emissions must be reduced. This is likely a conservative assumption, given that Strapolec's analysis suggests that, had the higher 2012 restated emissions data been used in the 2014 MOECC Update, the future BAU emissions would now be higher than previously forecast. This means the forecasted electrification contained in this report may be marginally lower than what is potentially needed.

Emissions sources were analyzed to identify potential electrification needed to achieve the emission targets. The targeted emissions for Buildings and Transportation were determined using a top down assessment requirement to achieve 37% below the 1990 emission levels in each sector. For Industry, the approach was based on opportunities and ideas identified through the literature reviews conducted by Strapolec. Figure 7 illustrates the overall scope of this analysis. The targeted 65 Mt of emission reductions are categorized as either not addressed (12 Mt), addressed by efficiency improvements through actions such as the introduction of additional codes and standards (7 Mt), or emission reductions that may be

[10] Environment Canada, National Inventory Report, 2016

achieved via alternative technologies that can potentially increase the demand for electricity (45 Mt). The latter is the focus of the following analysis.

Figure 7 – Emissions Addressed in Study



With the focus on Buildings, Transportation, and Industry use of natural gas, 12 Mt of the required emissions reductions are not assessed by this study. It is assumed that this gap can be addressed by other strategies, as discussed in Section 3.1.1. Seven Mt of reductions are assumed to be achieved through additional efficiency improvements in Buildings and Transportation beyond the BAU assumptions. These innovations in efficiency improvements are assumed to not have electrification implications.

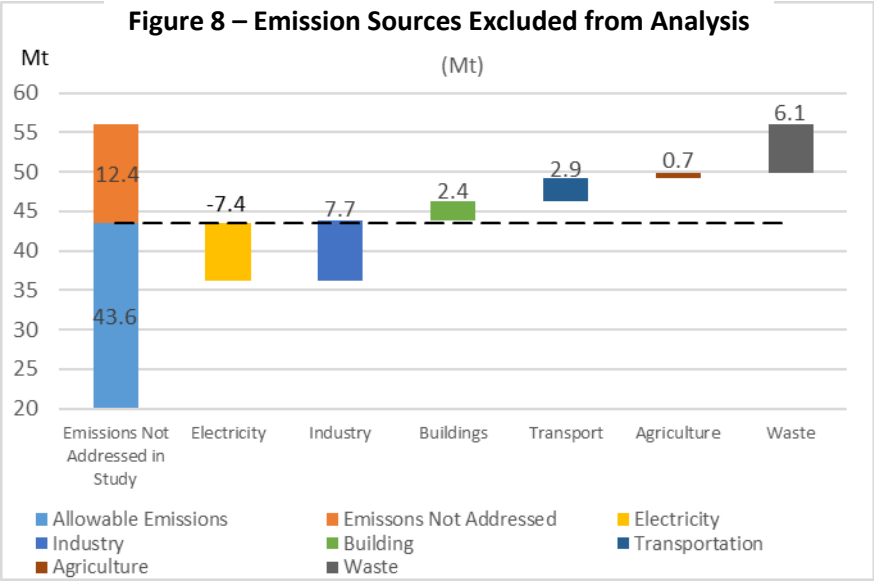
3.1.1. Excluded Emission Areas

Figure 8 illustrates the emissions excluded from this study's scope:

- Agriculture, industry, and waste sectors;
- Air, rail, marine and other transport fuels beyond gasoline and diesel;
- Buildings use of oil, propane etc.; and,
- Electricity production.

Of particular note is the benefit that is accruing to the province from the reduction in emissions that have come from the coal generation phase out enabled by the return to service and the increased performance of Ontario's nuclear fleet[11]. The 7.4 Mt of reduced electricity system emissions can be used to offset emission reductions required from the remaining sectors. Achieving further reductions from the electricity sector may be challenged by new demand for electricity, and the time that that it may take to secure new sources of low-carbon electrical generation. This topic will be addressed in the Phase 2 report from this study.

[11] Strapolec, Extending Pickering Nuclear Generation Station Operations, 2015



The category "Allowable Emissions" is the cumulative level of emissions allowable in these sectors after removing the 12.2 Mt required to meet the provincial emission target. Adding the 43.6 Mt of allowable emissions to the post-reduction emission levels of the sectors analyzed yields the provincially mandated 111 Mt of remaining emissions in 2030.

It is possible that additional electrification implications could result from emission reduction strategies for the sectors not assessed. Electrification forecasts in this study may be conservatively low.

3.1.2. Assessment of the Fuels Technical Report Emission Forecast

According to the 2016 NIR, the 1990 emissions level from energy fuels was 107 Mt. Applying the 37% target reduction criteria suggests the 2030 emissions target for energy fuels should be approximately 67 Mt.

The FTR projects a relatively flat BAU annual emissions forecast of approximately 120 Mt/year out to 2035. This profile is similar to that included in the MOECC's 2014 Climate Update. By 2035, which is the planning horizon for the FTR and the OPO, the most aggressive FTR emission reduction scenario, Outlook F, projects a 39% reduction to achieve 75 Mt from the forecasted BAU 2035 emission level, 10 Mt short of the 2030 target implied by the assumptions of this study.

In 2030, the FTR forecasts emissions for Outlook F of 87 Mt from fuel use. This is ~ 20 Mt higher than the ~67 Mt target inferred from a 2030 fuel sector target of 37% below 1990 levels.

A shortfall of 20 Mt at a carbon price of $100/tonne could cost Ontario ~$2B/year in externally purchased emission allowances, unless the reduction gap is made up from agriculture, waste, the electricity system, and industrial processes. This would be a difficult added challenge to these sectors which have their own

emission growth forecast in the 2014 MOECC Update and hence must work to achieve their own reductions.

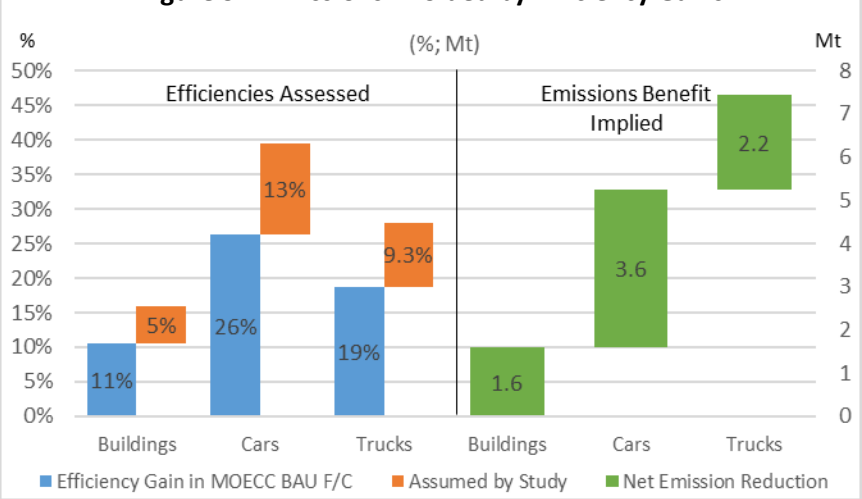
In contrast to the FTR, the unaddressed emissions described earlier in this study are 12 Mt.

3.2. Energy Efficiency Improvement Assumptions Not Requiring Electrification

The BAU efficiency improvements are based on the forecast from the MOECC's Update, in combination with the economic assumptions in the 2013 LTEP data tables and the recent 2016 OPO data tables. Efficiency improvement assumptions appear to be optimistic and aggressive.

Prior to assessing emission reduction solutions that may involve electrification, assumptions about what plausible energy efficiency initiatives could achieve have been applied to the Buildings and Transportation sectors. A simple approach has been adopted that involves assessing the status quo efficiency assumptions that are inherent in the BAU forecasts and then increasing these trended values by an additional 50%. Figure 9 illustrates the results of this approach.

Figure 9 – Emissions Avoided by Efficiency Gains



Based on the resulting trend analysis, the emissions model developed for this study assumes that 7.4 Mt of emissions will be removed though efficiency improvements: 1.6 Mt from the building sector, 3.6 Mt from passenger vehicles, and 2.2 Mt from trucks.

This is premised on optimistic efficiency induced emission reduction achievement forecasts, so as to provide a conservatively low electrification forecast. The objective of these assumptions is not to be "exact" but to identify areas that warrant serious consideration during the LTEP consultation process. Aggressive efficiency assumptions underscore the importance of considering the remaining options.

3.3. Identifying Alternatives and Electrification

Research was conducted to identify the concepts and ideas being put forward by Ontario stakeholders to achieve emission reductions. Table 1 represents a list these from major stakeholders and categorizes them as either energy solution providers, consumers, or interest groups. These organizations were chosen based on their involvement in Ontario's electricity sector and their size and the availability of recent publications regarding Ontario's C&T program, the MOECC's CCAP, and the 2017 LTEP.

Table 1 – Organizations Used as Sources for Ideas in this Study

Energy Solution Provider /Transmitters/ Distributers	Energy Consumers	Interest Groups
Association of Power Producers of Ontario (APPrO)	Association of Major Power Consumers of Ontario (AMPCO)	Canadian Environmental Law Association (CELA)
Canadian Biogas Association (CBA)	Association of Municipalities Ontario (AMO)	Clean Economy Alliance (CEA)
Canadian Electricity Association (CEA)	Building Owners and Managers Association of Canada (BOMA Canada)	Clean Energy Canada
Canadian Energy Efficiency Alliance (CEEA)	Business Council of Canada (BCC)	Environmental Defence
Canadian Gas Association (CGA)	Canadian Manufacturers and Importers (CME)	Greenpeace Canada
Canadian Nuclear Association (CNA)	Canadian Vehicle Manufacturers' Association (CVMA)	Ontario Clean Air Alliance (OCCA)
Canadian Solar Industries Association (CanSIA)	Ontario Chamber of Commerce (OCC)	Ontario Sustainable Energy Association (OSEA)
Canadian Wind Energy Association (CanWEA)	Ontario Home Builders' Association (OHBA)	Ontario Society of Professional Engineers (OSPE)
Electricity Distributors' Association (EDA)	Ontario Road Builders' Association (ORBA)	Ontario Trucking Association (OTA)
Decentralized Energy Canada (DEC)	Toronto Atmospheric Fund (TAF)	Pembina Institute
Energy Storage Ontario (ESO)		Pollution Probe
Ontario Energy Association (OEA)		Toronto Environmental Alliance (TEA)

Ontario Petroleum Institute (OPI)		
Ontario Waterpower Association (OWA)		

Materials on their websites were reviewed to identify their ideas regarding climate change in Ontario. Specific attention was given to energy consumers and their ideas for reducing emissions. As illustrated in Figure 10[12], energy consumers were found to be interested in topics such as GHG emissions, climate policy, C&T, the economy, costs of energy related solutions, investments needed, and sectors such as Transportation, Buildings, and Manufacturing. Stakeholders materials also contained options and ideas for reducing emissions in Transportation, Buildings, and through the use of alternative fuel options. These are summarized in Table 2.

Figure 10 – Energy Consumer Communicated Priorities

[12] Graphic was made by conducting a scan of what key energy sector players discuss in their publications and creating a word cloud based on the number of times each word was mentioned in their documents. The larger the word appears, the more it was mentioned.

Table 2 – Ontario Stakeholder Emission Reduction Ideas		
Transportation	**Buildings**	**Alternative Fuels**

• Biofueled vehicles
• Cycling and walking
• Electric vehicles
• Hydrogen fueled vehicles
• Natural gas fueled vehicles
• Increasing efficiency
  ○ Hybrids
  ○ Plug-in hybrids
  ○ Replacing old vehicles
	• Increasing efficiency through retrofits:
	  ○ New boilers
	  ○ Insulation
	  ○ Lighting
	  ○ Smart thermostats
	  ○ Stoves
	• Heat pumps (air & ground)
		• Biofuels
		  ○ Cellulosic
		  ○ Non-cellulosic
		• RNG
		• Power to Gas

In the Transportation sector, energy stakeholders are interested in the use of cleaner fuels such as electricity, hydrogen, biofuels and natural gas to replace conventional fuels used in compact cars, trucks, buses, and rail. In addition, there is interest in efficiency improvements via the replacement of old vehicles with newer, more energy efficient models, and by increasing the number of hybrid and plug-in hybrid vehicles (PHEVs).

In the Buildings sector, stakeholders focussed on increasing efficiency through retrofits such as improving insulation, installing newer and more efficient boilers, lighting, stoves, and smart thermostats to allow for better temperature control and demand management. It is also expected that switching from fossil fuel sourced space heating to air source heat pumps (ASHP) and ground source heat pumps (GSHP) will contribute to emission reductions in both residential and commercial buildings.

Another emission reduction option is to use alternative fuels for energy production. This includes Renewable Natural Gas (RNG) and mixing it with the current natural gas supply, cellulosic and non-cellulosic biofuels, and Power to Gas (P2G) solutions involving hydrogen that can be stored and used when needed.

The outcomes of this literature scan guided the scope of this project in selecting alternatives whose emissions, electrification, and costs could be quantified to provide a perspective on how climate change initiatives may impact the 2017 LTEP.

Specific ideas pursued in this study are discussed in the following sections.

3.3.1. Buildings

Research by the Ontario Society of Professional Engineers (OSPE)[13] was used to identify available applications for reducing emissions in the Buildings sector. Alternative technologies include electric resistance heating, ASHP and GSHP, and electric water heaters. Data on the characteristics of these devices, primarily the efficiency ratings, were obtained from Natural Resources Canada (NRCan) and the U.S. Energy Information Administration (EIA), as were the characteristics of new and existing natural gas furnaces and water heaters. The EIA also maintains forecasts for the efficiencies of future equipment. The Strapolec team integrated these future estimates with the NRCan data to produce the results used in this study.

NRCan household data on the existing use of devices in Ontario was used to calculate the electrification and emission reduction benefit. It was assumed that the incremental electricity generation created to meet the new decarbonisation driven demand will itself be zero emission. Both of the OPO Outlook Scenarios, D1 and D3, include the development of new clean generation[14].

3.3.2. Transportation

There are a number of pathways that may contribute to achieving emission reduction targets in the transportation sector in Ontario. These include:

- Improving the efficiency of vehicles, including hybrids;
- Introducing alternative fuel vehicles: Natural Gas Vehicles; Electric Vehicles (EVs); Hydrogen Fuel Cell Electric Vehicles (FCEVs); and
- Introducing alternative fuels such as renewable diesel.

There are two distinctly different segments within the transportation sector.

a) Light duty or passenger vehicles
b) Heavy duty (HD) trucks

a. Light Duty or Passenger Vehicles

Three passenger vehicle options are evaluated in this study: Natural gas conversions; Electric vehicles; Hydrogen vehicles.

The U.S. Department of Transportation statistics on emission differences between vehicle types were used to estimate the potential emission reduction benefits of natural gas vehicles.

[13] OSPE, Ontario's Energy Dilemma, 2016
[14] IESO, Ontario Planning Outlook, 2016

Data on EVs was obtained from Plug'N Drive, which has collected a substantial catalogue of information about available vehicles and their characteristics, including average emissions saved and electricity consumed. These sources provided the foundation for this emissions and electrification analysis.

The analysis also used information on hydrogen vehicles from the U.S. National Renewable Energy Laboratory (NREL). As the FCEV technology and hydrogen production are both developmental technology pathways, the NREL forecasts of future efficiencies and costs enabled the cost comparisons for what may be relevant by the late 2020s when the new electricity generation may be available.

b. Heavy Duty/Trucks

The HD vehicles segment consists of two types:

- Short range vehicles such as off road, busses, local delivery and refuse vehicles which represent the rest of the diesel transportation emissions; and
- Class 8 long distance road transport vehicles (tractor trailers), which are assumed to represent 20% of the road emissions.

The HD vehicle sector is considered to be a significant emission reduction challenge. Four options are evaluated in this study for heavy vehicles: Renewable diesel; Natural gas conversions; Hybrid vehicles; and Hydrogen vehicles.

The FTR places significant emphasis on bio and renewable diesel to support emission reductions. However, the FTR states that bio-diesel's primary role is as a blending additive. The current plans to increase the additive requirements from 2% to 4% are considered in this study to part of the overall emissions reduction goals of ICE vehicles which are discussed in Section 4.0. The 4% goal will require about 500 million liters per year by 2035, which according to the Canadian Canola Growers' Association, is all of Canada's total potential production of both bio or renewable diesel from tallow, yellow grease, canola, and soy[15]. Current and planned production capacity in Ontario for bio-diesel is about 300 million litres/year[16]. This study has assumed no electrification implication from bio-diesel and therefore does not consider it further.

Renewable diesel, on the other hand, is more of a direct substitute for current diesel consumption and as such may have the potential for greater emission reductions than bio-diesel. As with bio-diesel, there are concerns regarding the availability of available feedstock for the production of renewable diesel. There are no existing renewable diesel plants in Canada. The FTR report assumes it will be imported primarily from the U.S.

Research shows that natural gas, plug-in hybrid trucks, and hydrogen powered trucks may all be options to achieve a lower emission short-range fleet. The impetus for identifying plug-in hybrids as a potential

[15] Natural Resources Canada, Study of Hydrogenation Derived Renewable Diesel as a Renewable Fuel Option in North America, 2012.; Strapolec analysis
[16] Navigant Consulting, Fuels Technical Report, 2016

option has arisen from research on a company called WrightSpeed, that offers such solutions[17] commercially. Hydrogen fuel cell buses, fork lifts, and rail applications are being adopted today.[18]

The Class 8 fleet options include natural gas, conventional hybrids being developed in the U.S. SuperTruck program, and hydrogen vehicles. Hydrogen vehicles are deemed to be potentially impractical and expensive, but are evaluated in this study as sufficient cost data is available to illustrate the carbon price implications for making this option economic.

A Discussion of Hydrogen in Transportation

The recent FTR did not mention any substantive benefits of hydrogen use. The primary reason cited by the FTR is that hydrogen is currently produced from natural gas and as such offers no emissions reduction benefit. This study examines the potential for hydrogen manufactured in Ontario through electrolysis. Given Ontario's carbon-free supply mix of hydroelectric, nuclear, wind and solar. Using electricity for hydrogen production is therefore a real possibility for the province and Canada as it represents a unique and significant potential emission reduction strategy. The opportunity that hydrogen vehicles present for Ontario is not addressed in the FTR.

The production process for making renewable diesel requires hydrogen. The FTR assumes that renewable diesel would be imported, e.g., from the United States. Given the emissions profile of the energy system in the United States, renewable diesel will not be emission-free. If renewable diesel is manufactured in Ontario, it will require electricity to produce the necessary hydrogen, unless natural gas is used in the Steam Methane Reforming (SMR) process. Using natural gas to produce hydrogen feedstock for renewable diesel would decrease emission reductions.

Finally, there are unaddressed emission reductions in both this study and the FTR. Hydrogen production and renewable diesel may be synergistic, particularly in the long-term as emissions reductions must continue to accelerate to meet Ontario's targets.

3.3.3. Industrial Sector

Several emission reduction opportunities related to natural gas were identified that are not specific to buildings. They have been grouped under the general classification of Industry. This grouping enables the targeted emissions and business cases for the building emission reductions to be done in isolation without incurring any double counting of emissions reduction estimates.

Four innovations were identified during the research phase that relate to the potential reduction of emissions from natural gas applications:

- RNG production from waste streams;

[17] Wrightspeed Powertrains, The Route Powertrain, 2016
[18] Hydrogenics interviews

- Hydrogen blending into the natural gas pipeline delivery system, referred to as P2G;
- Using electrolysis to displace the SMR process currently used to produce hydrogen from natural gas; and,
- Substitution of electricity for some natural gas applications in the industrial sector.

Renewable Natural Gas

RNG production reduces GHGs emitted to the atmosphere from several waste sectors in Ontario, primarily agricultural (manure & crop residues) and landfills but also includes source separated organics (SSO), municipal solid waste (MSW), and waste water treatment plants (WWTP). The literature has identified two distinct processes for the creation of RNG: Anaerobic Digestion (AD); and Gasification[19].

Only AD processes are addressed in this study. AD technology is available and is already used in North America. The technology for gasification is not included in this study as it is not well established and requires further development. Interviews with agricultural stakeholders also suggest that the gasification process may involve accessing carbon sources that have already been sequestered and/or could be used in alternative ways such as for fertilizer.

Research for this study surfaced several concepts related to synthetic natural gas; however, no costing information was available. The processes for gasification and synthetic natural gas both require the availability of low emission production and process capabilities for hydrogen and carbon capture[20]. These are expected to require electrification and incur additional costs to reduce emissions.

These opportunities have not been fully explored in this study due to lack of available data but may be relevant to Ontario's emission reduction future, particularly if a low emissions hydrogen economy develops. These options could be among the potential solutions to Ontario's long term emission reduction path to 2050.

Hydrogen blending into the natural gas system, also referred to as P2G

The P2G concept is designed to produce hydrogen for the purpose of blending it into the natural gas pipeline delivery system. P2G has two benefits:

- Reduces the emission content of the natural gas system; and,
- Uses hydrogen as an energy storage mechanism that stores electrical energy in hydrogen gas that can then be delivered by the natural gas pipeline system when needed.

The intent is to utilize electrical energy at optimum times, i.e. when relative demand and the cost of the electricity is lower, store the energy in the form of hydrogen and then deliver that energy through the natural gas network at periods of high natural gas demand, such as for meeting winter heating demand.

[19] Alberta Innovates, Potential Production of Renewable Natural Gas from Ontario Wastes, 2011

[20] Synthetic Natural Gas (SNG): Technology, Environmental Implications, and Economics, Climate Change Policy Partnership, Duke University, January 2009

Conceivably, this function could offer daily, weekly and seasonal smoothing benefits for meeting electricity system demand.

Electrolysis alternative to the SMR process for hydrogen production in refineries

SMR is currently used in Ontario's refineries to produce hydrogen from natural gas. Hydrogen is a necessary feedstock for many processes at a refinery. Substituting lower emitting technologies for hydrogen production can reduce the emissions from this non-energy use of natural gas. In this study, electrolysis is examined as an alternative.

Industry electrification of 10% of natural gas use

As with buildings, it is assumed that some of the industrial natural gas applications may be candidates for electrification.

3.3.4. Approach to Estimating Provincial Electricity Demand and Implications

The potential incremental provincial level demand for electricity arising from a range of electrification options can be computed by allocating a proxy market share for each of the various sectors. For example, if all electrical heating options envisioned for commercial buildings were assumed to be introduced in equal proportion until the targeted emissions were achieved, the total amount of required electricity could be estimated for that scenario. This is the approach employed for this electrification implication analysis.

3.4 Assumptions and Sources for Costing Alternatives

Data from the U.S. EIA was utilized for the estimated installed costs of all the devices examined for the electrification of building space and water heating. The dollar values were converted to Canadian currency based on an historical long-term exchange rate of 1.15[21].

The study assumes that all capital expenditures by residential consumers are financed over the expected life of the device using a 5% interest rate. A pre-tax interest rate of 14% was assumed for commercial investments.

The cost of electricity was assumed to be $180/MWh, all in, for class B consumers and $65/MWh for transmission (Tx) connected Class A industrial users. These values are based approximately on the OPO average unit cost of electricity of $140/MWh for 2030[22], for all scenarios, and the average cost of electricity today. Residential and commercial rate payers (Class B) pay more per MWh due to the process for calculating the Regulated Price Plan (RPP) and the additional costs for distribution that direct Tx connected customers do not incur. The use of common pricing assumptions for all options reflects a

[21] Strapolec analysis prepared for "Extending PNGS Operations: Emissions & Economic Assessment"
[22] IESO, Ontario Planning Outlook, 2016

presumption that, at the aggregated provincial level, the total costs of new generation obtained for the purpose of supplying emission reduction initiatives should be recovered by the economics of those aggregated initiatives. This is a simple "matching principle" inherent in accounting practices. Special pricing alternatives that cause some Ontarians to subsidize others are not addressed in this study.

The cost of natural gas delivered to homes and businesses was assumed to be $10.50/mmBtu, reflecting a Henry Hub price of $5 US per EIA forecast to 2030[23], a US to Canadian dollar exchange rate of 15%, a 9% DAWN premium[24], and today's Enbridge delivery costs to residential consumers[25]. Note that gas distribution rates on a per mmBtu basis could increase with declines in volume. This has not been modelled in this study.

RNG parameters have been acquired from Ontario Energy Board (OEB) submissions by Enbridge and Union Gas[26].

Hydrogen production costs have been obtained from NREL[27]. A number of sources were referenced to obtain SMR costs[28].

Costing has nominally used 2016$ as the base. Some imperfections in alignment of the assumptions from different years have introduced small errors (eg. 2015 vs 2016). These deviations are not deemed material to the directional outcomes pursued by this study, given the low inflation rate environment that has been assumed.

3.5. Calculating Carbon Price

The effective carbon price is defined in this study as the price of carbon required to render the costs of alternatives as an economic choice for Ontarians. This effective carbon price is calculated from the difference in the total cost of installing and operating new devices/processes compared to the existing alternative or new fossil based devices/processes. The difference in cost is divided by the emissions saved to identify the effective carbon price that make the costs equivalent.

3.6. Emission Reduction Costs, C&T, and Economic Implications for LTEP Consideration

The economic implications addressed by this study are focused on the degree to which electricity generation choices may impact the cost of emission reduction. The objective is to assess the total cost to

[23] U.S. EIA, Annual Energy Outlook, 2016
[24] Strapolec analysis prepared for PNGS Report
[25] OEB, Estimated Monthly Gas Bill, 2016
[26] Union Gas, Renewable Natural Gas Applications, 2011
[27] Ainscough, Hydrogen Production from PEM Electrolysis, 2014
[28] Miller, 11.0 Hydrogen Production Sub-Program Overview, 2015; Stoll, Hydrogen – What Are the Costs, 2000; Simbeck, Hydrogen Supply, 2002; NextHydrogen

Ontarians of achieving provincial emission reductions and the sensitivity of that cost to both the C&T program's use of proceeds, as well as the incremental cost of electricity.

Two areas of investigation were pursued to determine the total cost and timing of the emission reductions:

- The cost of new generation; and,
- The effectiveness of managing the use of the C&T proceeds.

With a detailed cost and emissions build up based on individual alternatives for carbon emissions, it is possible to adjust electricity costs to illustrate the impact on effective carbon price required to make the options economic. This can be aggregated to provide a provincial total.

The proceeds of a C&T program can be beneficial if investing these proceeds to reduce emissions ultimately lowers the market price of carbon and makes the consumer investments economic. Alternatively, the proceeds can act as subsidies for otherwise uneconomic options. This study calculates the sensitivity of the market carbon price costs to the reinvestment of the proceeds.

3.7. Point of Clarification on Outcomes Produced by this Report

The objective of this study is to establish a framework for estimating the broad implications of emission reduction on electrification and the price of carbon. It is not intended to provide guidance or opinion on the merits of individual solutions, nor which solutions may/should be adopted to a higher degree than others. In general, options have been assumed to be adopted by the market place in some proportional balance. Presenting the possible outcomes is intended to illustrate this "balanced" adoption. This includes the:

- Possible implications on the demand for the electricity system; and,
- A framework for assessing carbon price implications.

On balance, Strapolec has observed that the aggregated impacts on either the demand for electrification and/or the economic impact of the carbon price are relatively insensitive to specific assumptions regarding the market penetration of individual technologies. In other words, deciding how to price or cap carbon emissions matters more than deciding what technologies to favour.

3.8. Summary

In order to meet Ontario's 2030 emissions target of 111 Mt, 65 Mt of forecasted emissions need to be eliminated. Seven (7) Mt of emission reductions are expected to come from increased efficiencies in Ontario's main sectors. Another 45 Mt are expected to come from emission reduction technologies in the Transport, Buildings, and Industry sectors. Twelve (12) Mt of emissions have not been addressed in this study, and must be achieved from Ontario's remaining sectors.

The characteristics of the emission reduction options presented in this study are consistent with those in the OPO, FTR and associated source references. However, the FTR Outlook F emission reductions are 8 to 20 Mt short of the 2030 emission reduction target of 67 Mt for energy fuels (as compared to the 1990 level of 107 Mt).

- The FTR relies upon extensive penetration of renewable natural gas (RNG) as well as bio- and renewable diesel into Ontario's energy system. This study has modelled more modest expectations for RNG and bio and renewable diesel, primarily due to lack of readily available data on these fuels. The assumptions are not a comment on the potential viability or suitability of these options in supporting emission reductions.
- In contrast, this study evaluates several hydrogen-based alternatives not considered in the FTR. The FTR did not classify hydrogen as an emission reducing technology because it is currently produced from natural gas. This study includes several hydrogen options as hydrogen can be a 100% carbon free fuel if produced from Ontario's emission-free electricity generation.

Surveyed stakeholder materials have identified forty-five (45) opportunities for emission reductions in buildings, transportation and the natural gas system. These have been modelled as a sample portfolio to achieve 45 Mt of the legislated 65 Mt of emission reduction by 2030.

- The analysis presented here addresses only 75% of the required reductions. The remaining emission reductions are assumed to be achieved through efficiency gains (over 7 Mt) or some other means not assessed by this report (over 12 Mt).

Carbon prices are derived based on industry sourced cost estimates for the timeframe leading up to 2030 timeframe. The effective carbon prices are used in the context of the C&T program to estimate the cost of emission reductions to the provincial economy.

4.0 Characterizing Emissions Reduction Targets for Electrification Implications

This section describes the emission reductions objectives relevant to each sector being assessed. The first subsection starts with an overview of the emission reduction objectives for each sector and the criteria applied to establish them. The Buildings, Transportation, and Industry sectors are then each described in the ensuing subsections.

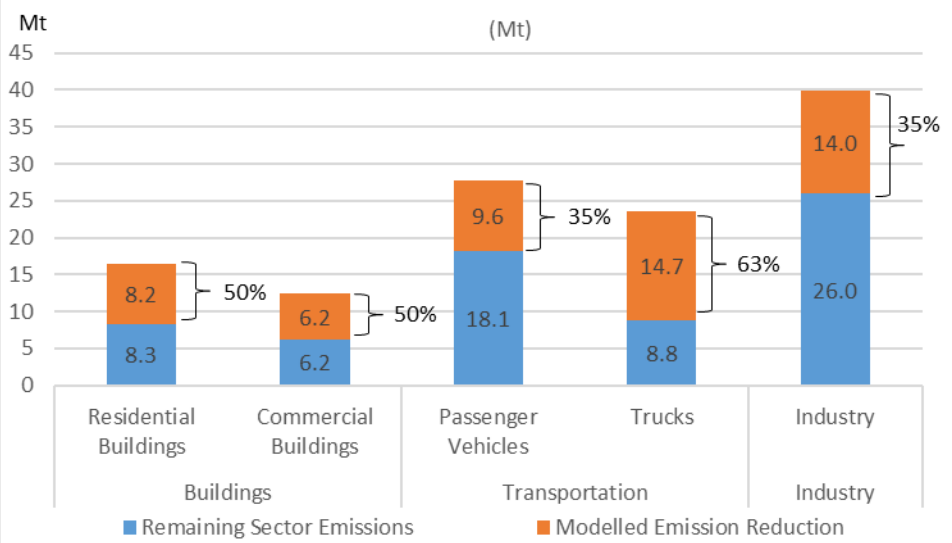
For each sector, the rationale for and the expectations assumed for emission reduction from efficiency improvements are provided. For each of the identified emission reduction options identified in section 3.0, the emission reductions objectives associated with electrification are defined.

This section closes with a summary of the key findings.

4.1 Overview of Emission Reduction Objectives

Figure 11 illustrates the emissions reduction objectives that are modelled to be achieved by the considered alternatives. Figure 11 summarizes the reductions required and the allowable emissions that can remain after the 65 Mt province level reduction objective is met.

Figure 11 – 2030 Target Emission Reduction by Sector



Two approaches were adopted for establishing the emission reduction objectives for this analysis.

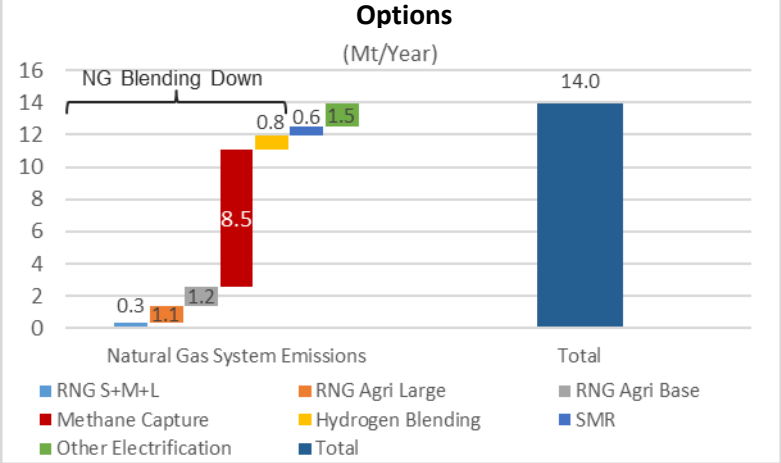
It is assumed the Buildings and Transportation sectors must each achieve by 2030 an emission level that is 37% below their respective 1990 levels. Since the BAU emissions are forecast to grow for these sectors, the future reductions required are greater than 37% from the BAU forecast:

- Buildings must reduce emissions by 50%; and,
- Trucks must reduce emissions by 63%.

The "Industry" category in this study pertains primarily to opportunities that reduce natural gas use in the province. Natural gas system emissions reductions were not derived from a target, but were examined based on the industry stakeholder ideas discussed earlier in Section 3.3.3. While it appears that the modeled emission reduction of 35% for Industry aligns with the 2030 target of 37% below 1990 levels, most of the emission reductions not assessed by this study are also required from the Industrial sector as described in Section 3.1.1. This "Industry" descriptor is loosely applied to recognize that none of the fuel "blending" assumptions for the natural gas system have been reflected in the Building assumptions. These emission reduction opportunities have all been credited in this study to the "Industry" targets, which should be interpreted to apply to all sectors where natural gas is used other than Buildings and Transportation.

The emission reduction potential for the natural gas displacement options attributed to industry are summarized in Figure 12.

Figure 12 – Natural Gas System Emission Reduction Options



Opportunities for emission reductions include:

- RNG production could reduce emissions from the following sources (up to 2.6 Mt):
  - Landfills (small, medium and large)
  - Large Agricultural operations (including large, aggregated and co-operative farms and also WWTPs)
  - Typical or Base reference agricultural operations (also includes SSOs, Industrial, and very small landfills)
- Methane capture from the production of RNG reduces emissions (~8.5 Mt)
- Blending Hydrogen into the natural gas system (<1Mt)
- Transitioning from the SMR process for hydrogen production to electrolysis (<1 Mt)
- Assuming that 10% of the use of natural gas in industry can be electrified (~1.5 Mt)

There are significant potential emission reductions associated with RNG. It should be noted that most of the emission reductions result from methane capture, and not from the displacement of natural gas with

RNG in the distribution system. While all of the methane capture related emission reductions are potentially achievable, some of them may be achieved through other initiatives that are independent of RNG.

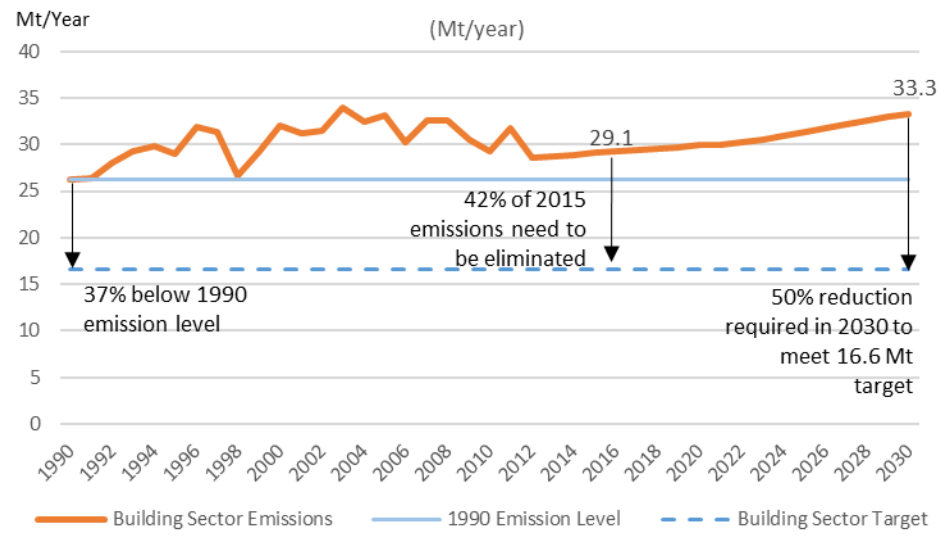
Clearly, there are different options for the sectors to reduce their emissions at different rates. The targets are an assumption made in this study to facilitate electrification estimates. As a result, these assumptions should not be interpreted as guidance on what will or should take place for any particular alternative discussed.

The following subsections address the specific emission reduction assumptions derived for each of the priority sectors, including the assumptions for emissions reductions achieved by efficiency improvements.

4.2. Building Efficiency and Alternatives Emission Reduction Objectives

Figure 13 shows the 2014 MOECC Update emissions forecast for Buildings. It indicates that a 50% reduction in emissions is required from the buildings sector in order to meet the target as a sector.

Figure 13 – MOCC Building Sector Emission Forecast



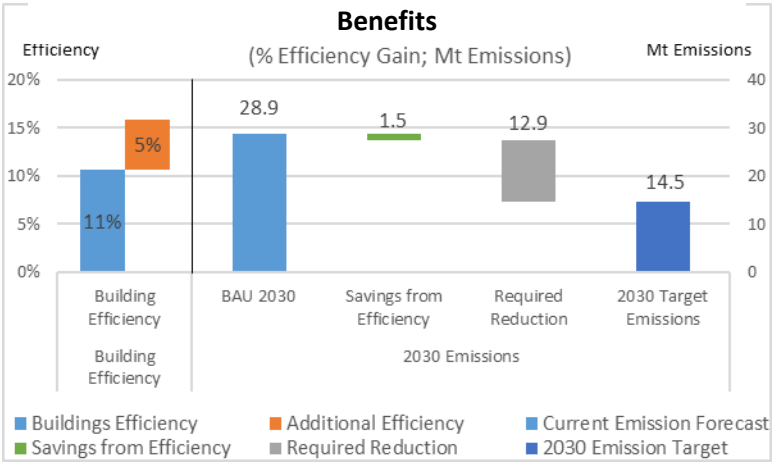
For the purpose of this analysis, it is assumed that the 50% reduction applies equally to both future residential and commercial building emissions. Such a target could be met in several ways:

- Improving the energy efficiency of all applications within buildings by 50%; or
- Replacing 50% of natural gas appliances and devices with electrical devices; or
- Reducing by 50% the CO_2 content of natural gas; or
- Some combination of the above.

These are very aggressive ambitions to achieve in 13 years.

The approach taken in this study allocates a provision for efficiency gains from alternatives that do not require electrification, and then assumes that the remaining reduction objectives must be met by substituting natural gas use with low carbon electricity. Figure 14 summarizes the results.

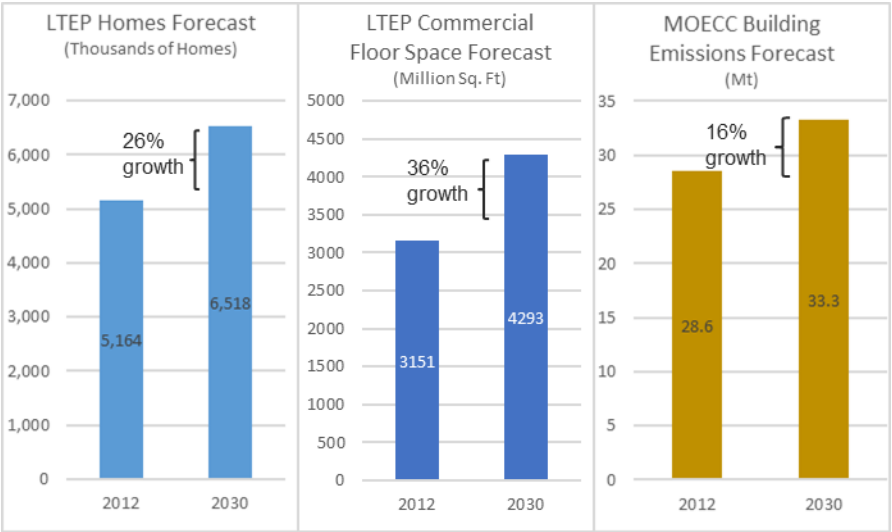
Figure 14 – Building Efficiency Gains & Emissions Benefits



4.2.1. Derivation of Building Efficiency Emission Reduction Target Assumptions

For the purpose of this study, emissions reductions have been estimated based on a comparison of the MOECC emission forecast to a forecast for building growth. IESO 2013 and 2016 data sets were used to develop building growth assumptions. It is assumed that these two data sets are reliable and mutually consistent. Figure 15 compares the various trends suggesting that a 10% per household emission reduction is embedded in the BAU forecast (26% growth in number of household less 16% growth in emissions). When combined with the 36% growth in commercial floor space, the effect of the differences in compound annual growth rate leads to an 11% net building efficiency BAU assumption.

Figure 15 – Building BAU Trends



In other words, it is assumed that within the MOECC BAU emissions forecast, Buildings have an embedded 11% energy efficiency improvement by 2030. The FTR also demonstrates that buildings have improved energy efficiency on average by 11% since 2005. This historical trend is consistent with the 11% forecast BAU trend assumed by this study.

An assessment of provincial building efficiencies indicates that Ontario is leading Canada[29]. Most Ontario homes have recently invested in efficiency improvements. There is not much obvious room for further improvement. The IESO OPO says 95% of assessed potential energy savings are already accounted for in Ontario's conservation program.

Notwithstanding these leading energy efficiency statistics for Ontario, this study assumes that an additional half of the existing efficiency assumption will be realized on top of the existing efficiency assumption, the equivalent of an additional 5.5% province wide average efficiency improvement above the BAU. This assumption requires a total of 16.5% of additional home energy efficiency improvements from today. This outcome will be dependent on the degree of penetration or rate of adoption of these new initiatives. Or example, it could mean that 25% of the homes in Ontario would have to find 66% energy efficiency improvements, or, equivalently, that 50% of the homes in 2030 would each achieve a 33% natural gas energy efficiency improvement over today.

The 5.5% efficiency assumption translates into a reduction in emissions of 1.5 Mt from natural gas use in the home. The FTR was consulted to assess the reasonableness of this assumption. The FTR allocated 6% efficiency improvement for commercial buildings and only 2% for residential homes by 2030. The net effect of the two FTR assumptions is a lower assumption regarding future building energy efficiency improvements than assumed here. This suggests the assumptions made by this study are conservative with respect to the remaining emissions that must be addressed through electrification.

The Natural Gas Conservation Potential report prepared by ICF International for the OEB[30] forecasts greater BAU emission growth in the Buildings sector than reflected in the 2014 MOECC Update assumed by this study. The BAU forecast in that report is 16% emission growth from 2015 to 2030, for a total of 32.5 Mt of emissions expected from natural gas use by 2030. This is in contrast with the 14% emission growth embedded in the model used here by Strapolec that projects future emissions of 28.8 Mt from natural gas. The difference between these values suggests a projected 3.7 Mt lower emission level than reflected in the OEB's BAU assumptions.

Adding the future efficiency emission benefit of 1.5 Mt assumed by Strapolec implies 5.2 Mt of emission reductions relative to the OEB's achievable potential savings case. This assumption is also double the OEB constrained achievable savings amount of 2.5 Mt, which is assumed to be based on existing programs (budgets), but less than the higher unconstrained potential savings options of 5.8 Mt in reductions. The FTR uses this higher unconstrained potential savings in their Outlook F.

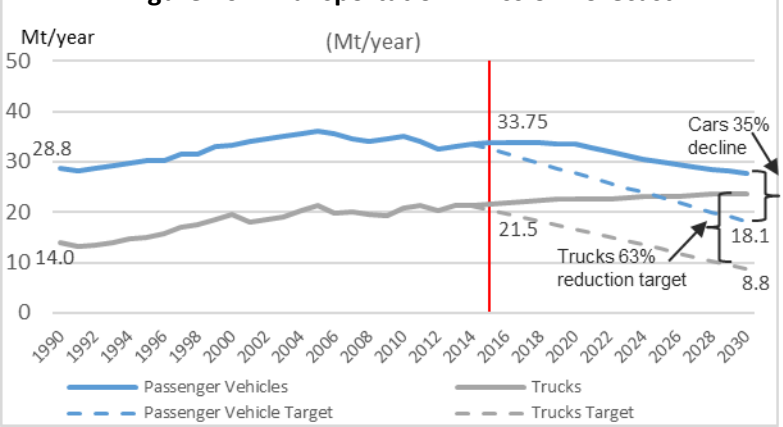
[29] NRCan, National Energy Use Database, 2015
[30] ICF International, Natural Gas Conservation Potential Study, 2016

The emission reduction target for buildings in this study is 10.7 Mt beyond these compared efficiency improvement levels. The targeted reduction in this study is 16 Mt below the ICF forecast. The 16 Mt target assumed in this study approaches the ICF reported technical limit of 19.4 Mt of reductions from the Building sector, but remains within it. Given the higher growth forecasts and the expected technical limitations of reducing building emissions, there is little room for the Building sector to accommodate emission reduction shortfalls from other sectors that may be challenged to achieve their own respective 2030 targets.

4.3. Transportation Emission Targets

For this study, the Transportation emissions forecast is split into two segments: passenger vehicles and trucks. The historical and forecast emissions for these two segments and their 2030 emission targets are illustrated in Figure 16.

Figure 16 – Transportation Emission Forecast



The passenger vehicle segment aligns with the emissions framework in the MOECC's climate strategy document, and is defined as all light duty vehicles that use gasoline. To also align with the MOECC framework, the truck segment is defined as all heavy-duty vehicles that use diesel. This includes short-range vehicles such as garbage trucks, busses, delivery vehicles, and off-road construction vehicles. It also includes the heavy transport fleet for shipping freight. This facilitates a comparison of the two sectors on a fuel basis: gasoline vs diesel, as used in the FTR report.

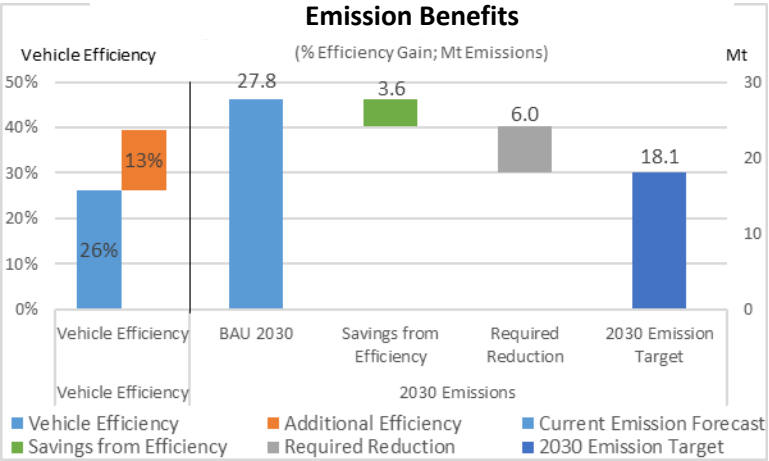
The emission reduction targets for these two sectors differ in magnitude. This is because, for 2015 to 2030, emissions from light vehicles are anticipated to decline, while emissions from trucking and off-road vehicles are expected to climb.

Strapolec assumes that both sectors must achieve emission reductions of 37% below the 1990 emissions levels. The passenger fleet must drop emissions from the forecast level of 27.8 Mt to 18.1 Mt, a drop of 35% or 9.7 Mt from BAU 2030 levels. The truck sector must drop emissions more dramatically from 23.5 to 8.8 Mt, a drop of 63% or 14.7 Mt from BAU 2030 levels.

4.3.1. Passenger Vehicles Efficiency Assumptions

For passenger vehicles, the splits of emission reduction expectations for efficiency improvement versus other alternatives are shown in Figure 17. The target for passenger vehicle emissions reductions is 6 Mt after accounting for 3.6 Mt in assumed efficiency improvements.

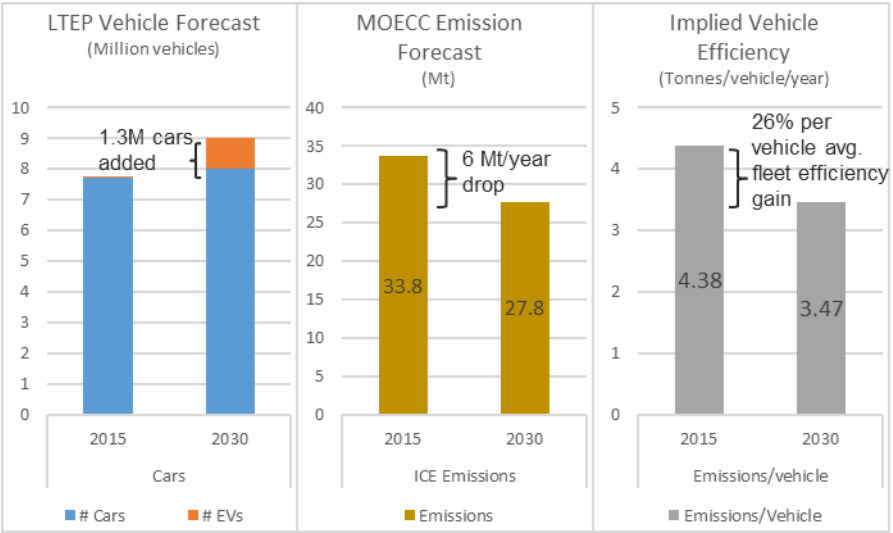
Figure 17 – Passenger Vehicle Efficiency Gains & Emission Benefits



As with the building efficiency forecast, the MOECC data was combined with the 2013 LTEP data tables to estimate the BAU efficiency assumptions made for the passenger vehicle fleet. The analysis is illustrated in Figure 18.

Assuming the OPO Outlook B forecast is similar to the 2013 LTEP forecast, of the estimated 9 million vehicles that will be on the road in 2030, 1 million of them will be EVs. This means 8 million Internal Combustion Engines (ICE) vehicles will produce the forecast emissions. The analysis demonstrates that the MOECC's data already includes a 26% passenger vehicle efficiency improvement within the BAU emissions forecast.

Figure 18 – Passenger Vehicle BAU Trends



The forecast 1 million EVs represent an important consideration for identifying the additional electricity that may be required. Electrification implications derived in this study assume that the electricity required for these first 1 million vehicles is already in the OPO Outlook B forecast.

Strapolec assumes that an additional 50% efficiency improvement will be achieved through climate change motivated innovations, for a total of a 13% increase in additional emission reductions. New emission regulations being introduced in both the US and Canada will require a 50% emission reduction for new vehicles sales across the fleet.[31]

- The "fleet" includes the use of hybrids and other vehicles
- It will take time for the fleet to "turn over" which has typically been at a rate of 7% per year[32].

It is further assumed that the introduction of additional fuel blends such as ethanol, as discussed in the FTR, will also contribute to the forecast for the overall efficiency improvement of the fleet that does not entail additional electrification loads.

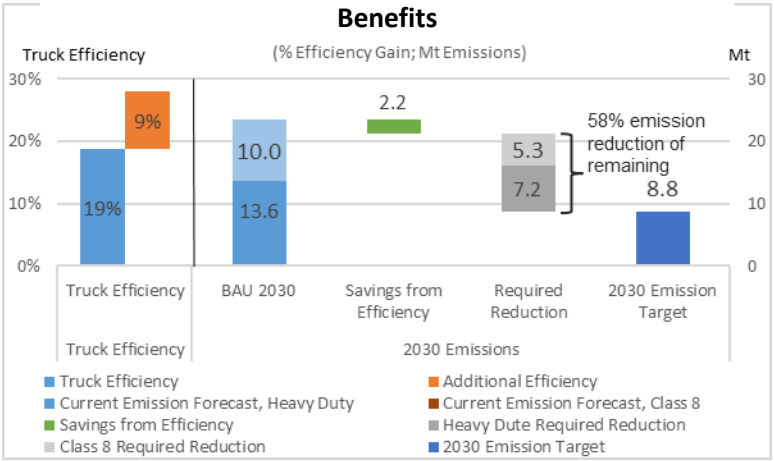
These additional efficiency improvements are anticipated to account for 3.6 Mt of emission reductions. This assumption facilitates the calculation of the emission reductions that must be generated by alternative vehicle options. These vehicle options will have to address 6.0 Mt of additional emission reductions.

[31] Atkinson, The Automotive Industry to 2025, 2016; GM, OEA Energy Conference, 2016
[32] GM, OEA Energy Conference, 2016

4.3.2. Efficiency Assumptions for Trucks

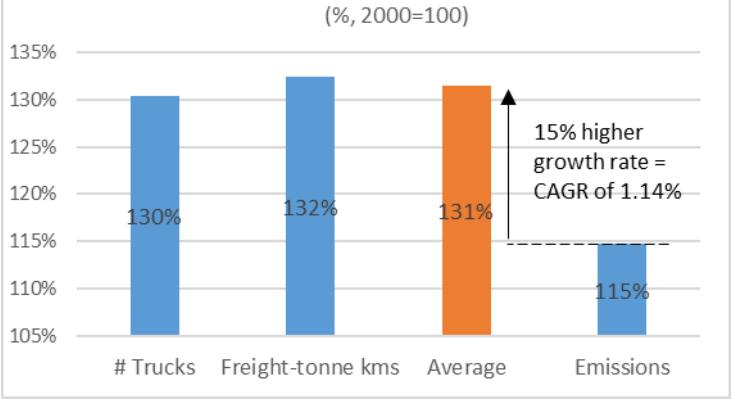
Figure 19 illustrates the efficiency and alternative emission reduction targets for trucks assumed in this study.

Figure 19 – Trucks Efficiency Gains & Emissions Benefits



Efficiency improvements of 18% from trucks appear to be reflected in the BAU forecast. Using MOECC data to assess the trucking efficiency improvements is more difficult as LTEP forecast data is not available for trucking. The opportunity for efficiency improvements in trucks are also less than for passenger vehicles (e.g. A lighter weight truck cab doesn't change the payload where all the weight is). This study assumes that the efficiency gains observed in the past will continue in the future. Figure 20 summarizes the efficiency analysis conducted based on the MOECC Update data.

Figure 20 – % Growth in Trucking Statistics



Trucking efficiency gains from 2000 to 2012 were estimated based on two methods:

- Trend in number of trucks
- Trend in freight-tonne kms

When these trend averages are compared to the trend in emissions, a compound annual growth rate (CAGR) difference of 1.14% is observed.

As Figure 20 illustrated, the MOECC emissions forecast tracks the emission trend from 2000 to 2012 and therefore it is assumed that ongoing efficiency gains are included in the freight forecast as well. For the period to 2030, extrapolating these CAGRs suggests an average efficiency gain of 19% can be assumed to be part of the BAU. Presuming an additional 50% incremental improvement on that trend would add a 9% fleet efficiency improvement resulting in an expected efficiency induced emissions reduction of 2.2 Mt off the trucking fleet emissions target.

The U.S. Department of Energy (DOE) SuperTruck Program anticipates that additional efficiency gains for ICE vehicles can be expected. The goal of the SuperTruck program is to develop and demonstrate a wide range of state-of-the-art, commercially feasible efficiency technologies for Class 8 long-haul tractor-trailers.[33]

Results from Phase I of the SuperTruck program[34] show an 80% improvement in mileage performance (40% emission reduction) as compared to 2009 emission performance. A new SuperTruck II program will focus on a 100% mileage performance improvement (50% emission reduction against 2009 standards). The SuperTruck II program also includes hybrid vehicle options that may provide an additional 20% fuel efficiency for tractor trailers.

As these are developmental programs, applying this efficiency assumption to the entire diesel fleet, including off-road vehicles, should be done with caution. One of the major areas of efficiency improvement aerodynamics, which does not dramatically affect slow moving vehicles like garbage trucks.

As indicated in Figure 19, the trucking segment has been split into two categories, short-range trucks and Class 8 tractor trailers. The emissions split has been estimated based on U.S. statistics that show Class 8 trucks represent 20% of diesel emissions. The target for emission reductions from alternative options from the truck fleet is 12.5 Mt, 60% or 7.2 Mt from the short-range trucks, and 5.5 or 50% from the Class 8 tractor trailer fleet.

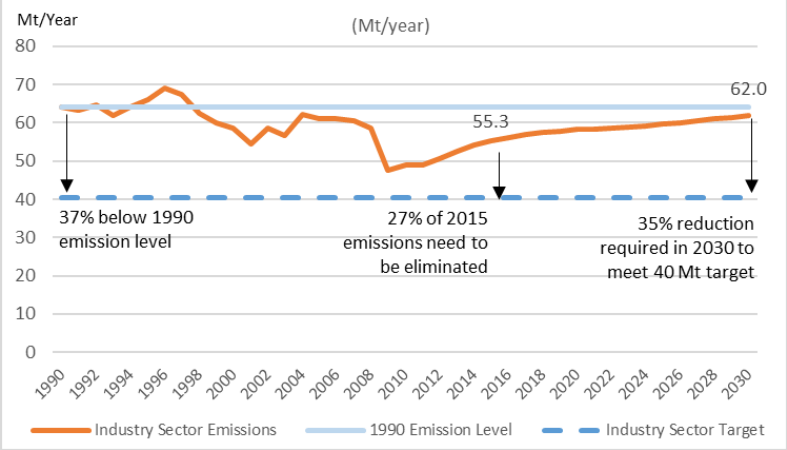
4.4. Industry Emission Targets

The Industry sector emission reduction targets are based on the concepts and ideas surfaced during the research phase of this study. Several opportunities exist to reduce emissions associated with natural gas use that are outside the heating objectives for buildings. The emission reduction potential is derived from an assessment of the market potential of the applications which are collectively referred to, and accounted for as being part of the emission reduction strategy for the industrial sector.

[33] TA Engineering, DOE SuperTruck Program Benefits Analysis, 2013
[34] U.S. DOE, SuperTruck Success, 2016

Figure 21 shows the MOEECC emission targets for the Industry sector. A 35% reduction in emissions, or 22 Mt of emission reductions are required. This study examines the options that could achieve 14 Mt, or 70%, of these reductions.

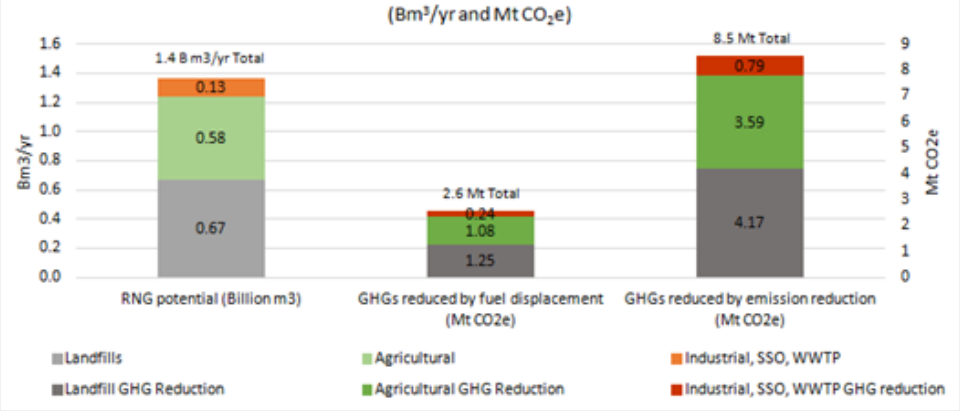
Figure 21 – MOECC Industry Sector Emission Forecast



4.4.1. Renewable Natural Gas

Strapolec's study assumes that processes required to support RNG could reduce emissions by up to 11.1 Mt, as shown in Figure 22. RNG displacement of natural gas could reduce emissions by 2.6 Mt while 8.5 Mt of emissions equivalent could result from the capture of waste methane.

Figure 22 –Annual RNG Potential from Ontario Wastes and Associated GHG Reduction



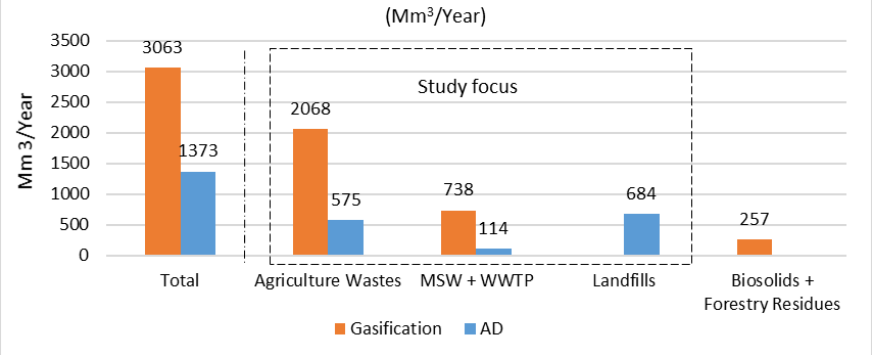
The volume of RNG is derived from the Alberta Innovates Report[35], widely considered a definitive source for potential RNG use in Ontario. The OEB Natural Gas Conservation Potential Report utilized this Alberta data. As shown in Figure 23, waste from the following sectors can be used to produce RNG in Ontario:

- Agricultural wastes (Manure & Crop residues)

[35] Alberta Innovates, Potential Production of Renewable Natural Gas from Ontario Wastes, 2011

- MSW + WWTP
- Landfill materials
- Biosolids + forestry residues

Figure 23 – RNG Potential for Ontario



The 2011 Alberta data indicates that, when combined, Ontario wastes have the potential to produce 4247 M m3/yr of RNG[36]. That represents 14.2% of Ontario's current natural gas supply. Two processes are considered for RNG production:

Anaerobic Digestion (AD)

- 1373 Mm^3/year of RNG can be produced from Ontario wastes representing 4.4% of Ontario's total gas supply
- AD technology is available and already being used in North America.

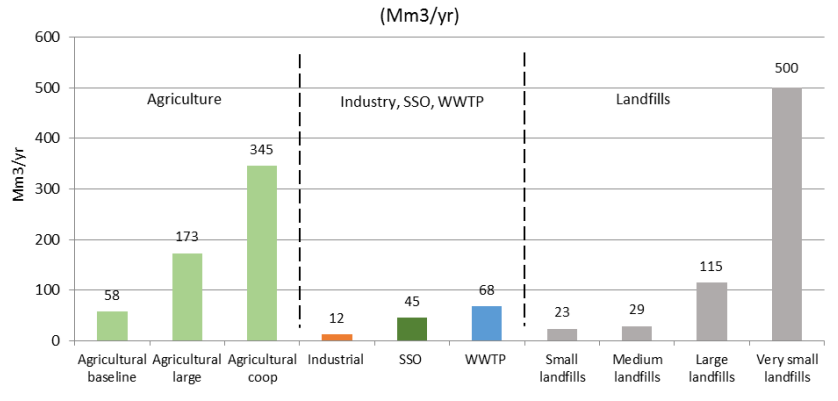
Gasification

- 3063 Mm^3/year or 69% of the RNG potential that is possible from waste streams requires the use of gasification. This represents 9.8% of Ontario's total current gas supply.
- RNG from gasification has limited availability in the short-term. Sources indicate the technology for gasification is not yet well established and requires further development[37]. Gasification potential is not included in the estimate of Ontario's RNG potential in this study as costing data for the production process was not available.

Claims that up to 15% of the natural gas system can be supplied by RNG assume that almost 10% can be derived from the gasification process. In this analysis, the focus is on the use of AD for the purpose of estimating Ontario's RNG potential from the waste sector. Figure 24 summarizes the RNG volume assumed to be available from each waste stream.

[36] Excluding Biosolids and Forestry Residues
[37] Alberta Innovates, Potential Production of Renewable Natural Gas from Ontario Wastes, 2011

Figure 24 – Assumed RNG Potential from Ontario Wastes



Agricultural farms have the potential to produce 575 Mm^3 of RNG, with the largest potential being from co-operative arrangements where the waste (manure and crop residue) is aggregated from several farms for processing at a central digester. The Industrial, Source-Separated Organics (SSO), and WWTP potential for RNG production is small, totalling 126 Mm^3/year. Landfills are the largest potential source of RNG, capable of producing 667 Mm^3/year, representing almost half of the total RNG potential from waste. Very small landfills (<10 kilotonnes/year weight received) are by far the largest potential source of RNG as there are many of these sites compared to small, medium, and large landfills.

The economics of obtaining RNG from the very small landfills has not been validated. Economic data is based on an Electrigaz report[38] used by Union Gas in an OEB submission, in which the economics for harvesting the potential from small landfills was not estimated. The amount of RNG available from very small landfills was limited to materials available from the 850 sites[39]currently open in Ontario. Based on an RNG production potential of 0.27 Mm^3/year per landfill[40] for 850 sites and using a multiplier observed in the Electrigaz report volume assumptions, 500 Mm^3/year of total RNG is assumed available from very small landfills.

AD related processes reduce GHGs emissions via two mechanisms: (1) fuel displacement; and (2) methane capture.

- Fuel displacement reflects all of the methane extracted from the waste sector is converted to RNG and injected into the natural gas delivery system to eventually become a fuel.
- Methane reduction is achieved by preventing the emission of methane into the atmosphere that would otherwise be naturally occurring absent an RNG process. Methane is a GHG with 21 times the warming potential of CO_2. By capturing that methane, the GHG emissions of that methane are

[38] Electrigaz, Economic Study on Renewable Natural Gas Production, 2011
[39] Government of Ontario, Small Landfill Sites List, 2016
[40] Alberta Innovates Technology Futures, Potential Production of Renewable Natural Gas from Ontario Wastes, 2011

avoided. The total GHG reduction potential from methane capture is 3.3 times the fuel displacement benefit or 8.5 Mt CO_2e.[41]

By displacing up to 1.4 billion m^3/year of natural gas, 2.6 Mt CO_2e can be eliminated per year.

The total RNG potential of 1.4 billion m3/year determined by this study is lower than the 4.3 billion m3/year presented by ICF International, Enbridge Gas Distribution, and Union Gas[42]. This is partially due to the discounting by this study of RNG potential from small landfills, but primarily because this analysis has excluded consideration of RNG potential from gasification due to the previously noted challenges.

While there is the potential to reduce methane emissions, it remains questionable as to whether these emission reductions can be attributed to the RNG process for the following four reasons:

1. There are regulations that require the capture of this methane, particularly for large landfills.
2. Once methane is captured, it can be flared. Using it for RNG may therefore only provide the smaller benefit of fuel displacement emission reductions.
3. Costs for capturing the methane have not been included in this report.
4. These methane emission avoidance benefits have similarly not been accounted for in the FTR either.

It is important to recognize that emissions reductions from these sources will result if RNG options are pursued, as the process relies on the capture of methane.

4.4.2. Hydrogen Blending Power to Gas

With proper natural gas network maintenance, hydrogen blends of 20% could exist. Higher blends are limited by safety margins and regulations. In Ontario, there is currently a technical limit on how much hydrogen can be injected into the natural gas system. This limit is estimated to be only 5% of the natural gas volume that can be replaced by hydrogen[43]. The limits arise from blend level restrictions in end use appliances[44]. For some appliances, no hydrogen blending would be acceptable. Higher blend rates may be possible over time as old appliances are changed out for new ones.

This study assumes a 5% blend for the next decade. The benefits of blending are further limited by the fact that the heat content by volume of hydrogen is only 30% of the heat content of natural gas. Blending hydrogen as 5% of the natural gas in the system only replaces 1.5% of heat content, thereby diluting the overall heat content of the system. To maintain system heat capacity, 3.5% more natural gas volume is required, resulting in only a 1.5% drop in the natural gas volume.

[41] To avoid double counting, we remove the methane used for fuel displacement when tallying the GHGs reduced by preventing the direct emission of methane into the atmosphere
[42] ICF International, Results from Aligned Cap & Trade Natural Gas Initiatives Analysis, 2015.
[43] Industry interviews; OSPE, Ontario's Energy Dilemma, 2015
[44] Melaina, Blending Hydrogen into Natural Gas Pipeline Networks, 2013

As a result, only 1.5% of the natural gas volume, or 15.2 BCF, can be displaced. Hydrogen blending is assumed in this study to reduce emissions by 0.8 Mt from the production of 110 million kg of hydrogen.

In the long run, if hydrogen becomes a technology of choice and end use applications are adjusted to the new burn characteristics, the hydrogen offset of natural gas could increase four-fold to reduce 3.2 Mt of emissions or 15% of currently required industrial emission reductions.

4.4.3. Displacing Steam Methane Reforming

Hydrogen is a product refineries use for their production processes. Currently, Ontario's refineries are estimated to use approximately 140 million kg of hydrogen annually[45].

SMR is the most commonly used production process for hydrogen. The SMR process uses natural gas as a feedstock to produce hydrogen and a CO_2 bi-product. Typically, Ontario refineries vent the CO_2 into the air[46]. The SMR production process potentially generates 1.4Mt of CO_2 emissions or 7% of the 22 Mt of required industry emission reductions.

Air Products Canada has recently commissioned a new plant in Sarnia to produce 80 million standard-cubic-feet-per-day (MMSCFD) of hydrogen for two nearby refineries—Shell and Suncor[47]. This equates to 74 million kg of hydrogen per year. Ontario has two other major refineries that are estimated to require an additional 68 million kg of hydrogen for a total of approximately 140 million kg.[48]

This study assumes that 50% of the existing hydrogen production can be converted to an electrolysis process. This is for two reasons: 1) not all SMR is from raw natural gas feedstock[49], some may be from waste products within the refineries which would still have to be addressed. 2) The remaining 50% is assumed to be an opportunity for post 2030 emission reductions in support of the 2050 targets.

Assuming 70 million kg of hydrogen is produced (50% of existing market production), and 8.29 kg of CO_2[50] avoided per kg of hydrogen produced, this equals 0.59 Mt of emissions that could be avoided by this process.

[45] Canadian Hydrogen Survey – 2004-2005, for Natural Resources Canada, June 2005
[46] Industry interviews
[47] Air Products, Air Products' Sarnia, Ontario, Canada Hydrogen Plant Now On-Stream and Supplying Suncor and Shell Refinery Operations, 2006
[48] Dalcor Consultants Ltd, Canadian Hydrogen Survey – 2004-2005, 2005; Strapolec analysis
[49] Nyboer, A Review of Energy Consumption in Canadian Oil Refineries, 2010
[50] Hydrogen Analysis Research Center, Hydrogen Production Energy Conversion Efficiencies, 2016; Ruether, Life-Cycle Analysis of Greenhouse Gas Emissions for Hydrogen, 2005; Collodi, Hydrogen Production via Steam Reforming with CO_2 Capture; Linde Group, Hydrogen; Strapolec analysis

4.4.4. Industrial Natural Gas Use Displacement

Finally, Strapolec assumes that 10% of the natural gas used by Ontario's industry will be replaced by some form of electrification. This is consistent with the OPO. The Industrial sector in Ontario uses approximately 290,000 TJ of natural gas energy annually. Displacing 10% of this would represent approximately 29,000 TJ avoiding approximately 1.45 Mt of emissions.

4.5. Summary

This section outlined the emission forecast for Buildings, Transportation and Industrial use of natural gas, the required 2030 emission level, the BAU efficiency assumptions, and the pathway to reach emission targets through fuel substitution.

For buildings and transportation, the identified target is a 50% reduction in forecasted 2030 emissions. Total required emission reductions assumed in this study are 14.4 and 24.3 Mt respectively. Buildings are assumed to achieve 16.5% greater energy efficiency improvements than today reducing emissions by 1.5 Mt. Passenger vehicles are assumed to achieve 39% less emissions per vehicle than today's performance, saving 3.6 Mt from the BAU forecast and trucks are assumed to improve emissions by 28%, reducing 2.2 Mt from the BAU forecast.

Industry emission reduction expectations are specific to the emissions reduction options identified to displacing natural gas: RNG, SMR, P2G hydrogen blending, and general industrial use of natural gas. Emissions estimates are based on the volume of natural gas displaced which has been established by the actual volumes of alternatives than can be produced. Industry emissions must be reduced by 35% or 22 Mt. The opportunities assessed in this study identify 14 Mt, or 70% of the required Industry emission reductions.

5.0 Electrification Demand Implications

This section details the assumptions and analyses used to estimate the electricity that will be required to implement the identified emission reduction options being assessed by this report.

This section first summarizes the overall results, relating the emissions reduced in each major sector to the associated electricity required to achieve them. The results are compared to the contents of the OPO and FTR. Finally, the projected electricity required in 2030 that would enable meeting the 2030 emissions reductions is illustrated in two ways: (1) comparative forecast with respect to the OPO Outlook D; and (2) by the three types of energy demand – heat, consumer driven demand, and industrial baseload expected. The energy demand is then added to the OPO Outlook B projection to illustrate the total Ontario system demand expected in 2030 if the emissions targets assessed in this study are to be met.

The ensuing subsections then describe the detailed assumptions used to estimate the electricity required for each emission reduction option:

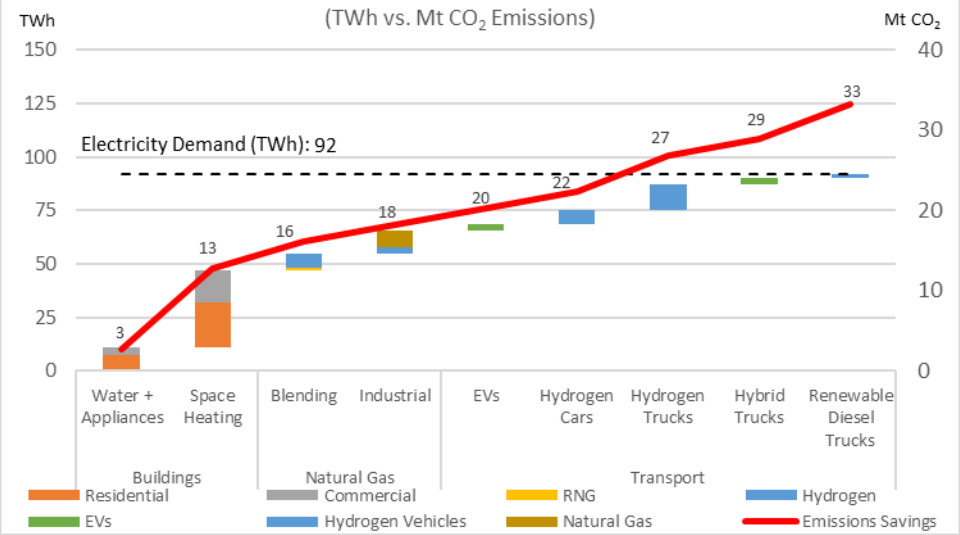
- Buildings, using residential space heating as an example of the methodology deployed for both residential and commercial space and water heating;
- Transportation, the passenger versus trucking segments; and,
- The four Industrial applications that have been assessed.

This section closes with a summary of the key findings.

5.1. Overview

The results of this study estimate that over 90 TWh of new electricity demand will arise from initiatives to reduce emissions to meet the 2030 targets. The correlation of emission reductions with electricity demand by sector is illustrated in Figure 25.

Figure 25 – Electrification Implications of Emission Reductions in 2030



Emission reductions and new electricity supply are highly correlated. Efficiency improvements previously discussed for buildings and vehicles are ongoing and assumed to occur without any implications for the electricity system. Note that the total emissions savings in Figure 25 (33 Mt) does not equal the total emission reductions modelled in the study (45 Mt), as Figure 7 indicated. This is because the figure only illustrates emission savings from technologies that require electrification. Emission savings from technologies such as natural gas vehicles (3.5 Mt) and methane capture (8.5 Mt) are not shown. The relationship between electrification and emissions differs by sector as summarized below with the associated assumption details discussed in subsequent subsections.

Buildings

- 47 TWh, or almost half of the new electricity demand of 92 TWh will result from reducing the use of natural gas for heating in buildings to save ~13 Mt of emissions.

Transportation

- 35% of the transportation fleet is assumed to have converted to natural gas. This assumption helps develop a conservatively low estimate of electrification required in the Transportation sector. As mentioned above, the associated 3.5 Mt of avoided emissions are not shown on Figure 25.
- Passenger vehicles could require 9 TWh for EVs and hydrogen FCEVs to save 4 Mt of emissions.
- Trucks represent the most difficult challenge as there are few options to address the needed sizeable emission reductions in this area. This analysis models 17 TWh to enable the removal of 12.5 Mt.
    - After examining the natural gas and hybrid vehicle options for replacing over half of the fleet, hydrogen and renewable diesel are used as the "plug" to achieve the requisite emission reductions for vehicles not considered as Class 8 tractor trailers. Large hydrogen fueled transport trucks are considered to be cost prohibitive. Nevertheless, there are no known alternatives to this approach.

Industry/Natural Gas System

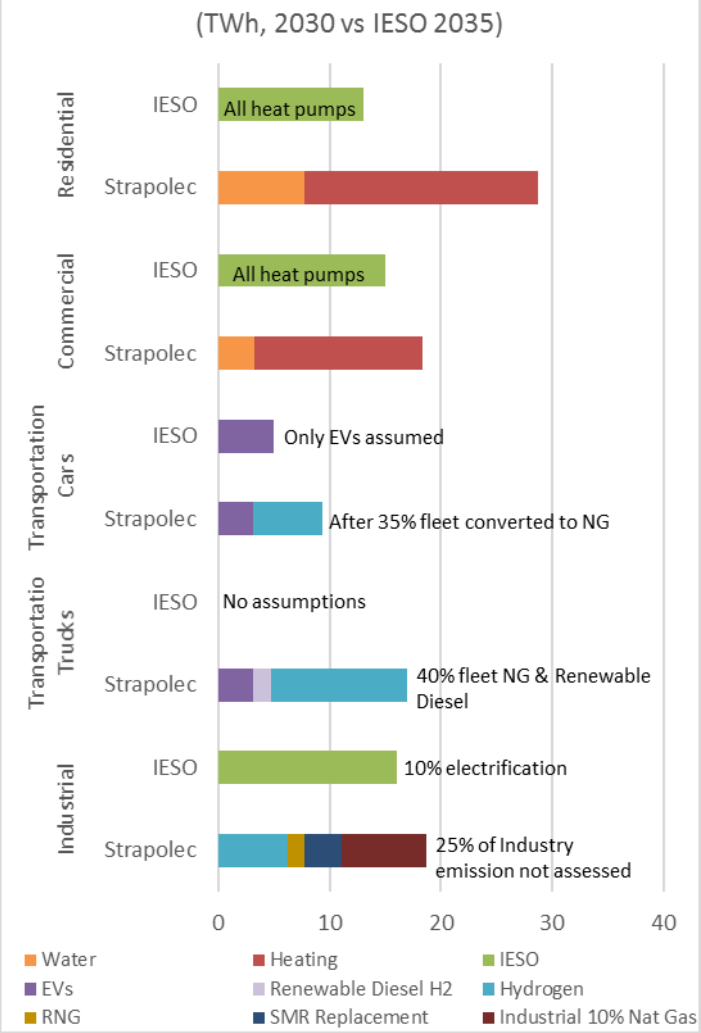
- Collectively, industrial applications related to natural gas substitution require about 19 TWh to achieve ~5 Mt of reductions.
- Approximately 8 TWh of electricity is required to inject RNG or hydrogen blending into the natural gas delivery system, and offer emissions gains of 3.4 Mt.

Other industrial processes, including SMR could require 11 TWh of electricity for 2 Mt of emission reductions.

5.1.1. Alignment of Demand Forecast with OPO Outlook D and the FTR

The results of this analysis forecast a need for over 90 TWh of additional electricity by 2030. This is an 80% greater electrification impact than noted in the OPO Outlook D "high demand forecast". The areas of alignment and differences between the two forecasts are summarized in Figure 26. The notable differences between Strapolec's forecast and the OPO Outlook D are primarily related to residential buildings and trucks.

Figure 26 – Emission Inspired Electrification



Buildings comparison suggest a gap in residential electrification estimates

The OPO reflects assumptions that 30% of the heating and 32% of water heating appliances are electrified by 2035, and all of them are assumed to be replaced by higher efficiency ASHPs. This study targets 44.5% of total future residential consumption switching away from natural gas. This assumption equates to 36% of the heat and 32% of water appliances becoming electrified with low efficiency units being addressed first. In order to meet emission targets, this means converting 15-20% more energy from natural gas applications to electricity than inferred by the OPO. Furthermore, the model assumes that the current market penetration of electric heating appliances carries forward: Electrical Resistance: 68%; ASHP 25%; and, GSHP 7%.

The commercial electrification assumptions are materially similar between the OPO Outlook D and this study. The differences in electricity demand stem from the assumption in this study that an equal

proportion of resistance, AHSP, and GHSP devices are deployed commercially instead of the "all heat pumps" assumption reflected in the OPO.

This study assumed a mix of heating technology choices for both cases for several reasons: (1) Heat pump economics differ for different sized households and businesses; (2) Heat pumps will require a supplementary heat source[51], which may be electricity in some cases; and, (3) Smaller energy consuming locations may not choose the heat pump option. It is thus not an exact science to predict which choice may make the most sense to individual consumers.

Passenger vehicle assumptions are somewhat similar

The BAU Outlook B assumes 1 million EVs will be deployed in Ontario. For Outlook D, the electrification demand above Outlook B is assumed to come entirely from an additional 1.4 million EVs in Ontario's passenger vehicle fleet. Strapolec assumes that to meet the remaining emission targets, it will require a mix of 35% natural gas vehicles and 1.6 million non-emitting vehicles, that have been assumed to be equally split between battery electric vehicles (BEVs) and FCEVs, or 800,000 of each vehicle type. The 50-50 split was arbitrarily chosen so as not to bias the analysis by favouring one technology over the other. This study assumed 600,000 fewer EVs and 800,000 more FCEVs than are contained in the OPO Outlook D. For reference, the FTR assumes 300,000 FCEVs in Outlook F. The electrification load from the FTR Outlook F is not reflected in the OPO Outlook D.

Trucks represent a large challenge not addressed in the OPO

The study assumes a mix of renewable diesel, natural gas, plug in electric, hybrid and hydrogen vehicles. Emissions from the trucking sector form a large part of the reduction targets, and both the FTR and this study have made similar assumptions regarding the increased use of renewable diesel and natural gas in the Transportation Sector.

The OPO has made no provision for the electrification of trucks. This study has identified potential electrification implications for renewable diesel, hybrid electric trucks and hydrogen fuel-cell powered trucks. As stated previously, renewable diesel will require hydrogen for the production process and contribute to electricity demand growth.

Natural Gas/Industry → Emission reduction opportunities are similar with some caveats

The OPO Outlook D includes the assumption that 10% of the industry sector's energy use will be converted to electricity. This study has adopted a similar assumption.

This study further addresses the electrification implications for RNG production and hydrogen P2G blending with the natural gas distribution system. Additionally, switching hydrogen production from electrolysis to replace the SMR process will add an industrial baseload demand. Hydrogen blending and

[51] Energy Solutions Centre, An Evaluation of Air Source Heat Pump Technology in Yukon, 2013

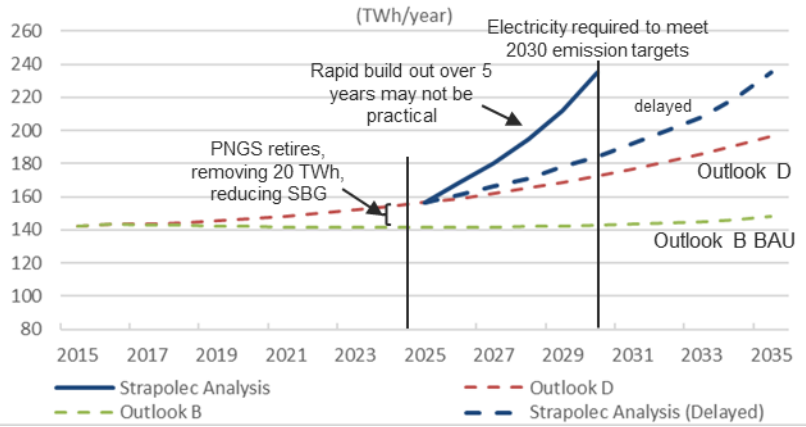
SMR displacement assumptions are unique to this study. The FTR has more significant RNG assumptions in its Outlook F, but no provision for the electricity needed to produce it.

This suggests that the estimates emerging from this study effectively provide an additional scenario, which should not to be compared directly to the OPO Outlook D, but viewed rather as a proxy for the electrification implications of the FTR Outlook F. Outlook F of the FTR appears more aligned with achieving Ontario's emission targets of 37% below 1990 levels, albeit by 2035 not 2030.

5.1.2. Profile of the New Demand for Electricity

Meeting emission reduction targets in 2030 will demand electricity much sooner than provided for in the OPO. If Ontario is to meet its 2030 emission targets, 90 TWh of new low carbon capacity is required by 2030. The 90 TWh is incremental to the BAU OPO Outlook B forecast. Figure 27 illustrates the demand forecast from this analysis compared to the OPO Outlooks B and D.

Figure 27 – Comparison of Annual Net Energy Demands Across Outlooks



The Outlook D forecast is based on electricity demand ramping up gradually to 2035. By 2030 only 30-40% of the energy supply required to achieve the 2030 emission reductions will be available. This suggests that Ontario could miss its 2030 targets by 60%. As noted earlier, the FTR emission forecast shows that a 30% or 20 Mt emission reduction shortfall could occur in 2030. At ICF's forecast carbon price of $100/Mt[52], the 20 Mt shortfall in the fuels report could cost $2B/year in higher costs in the form of externally purchased emission credits.

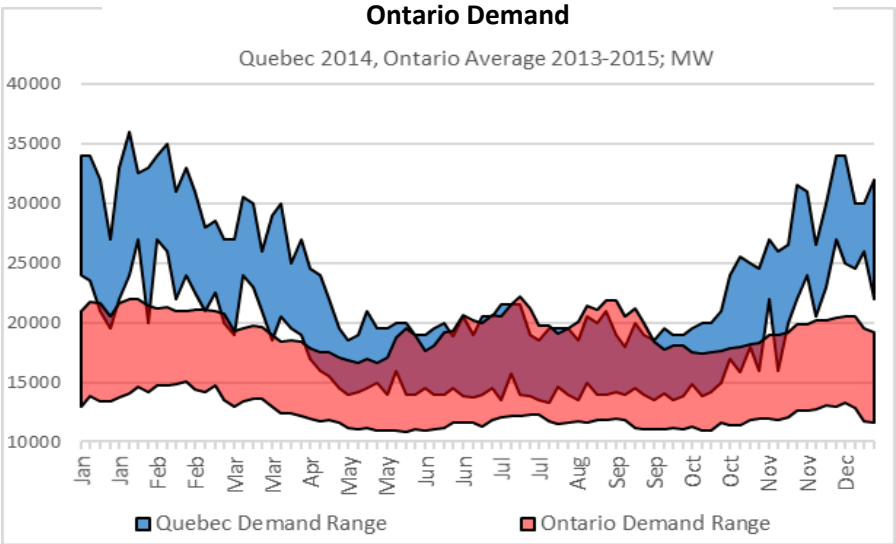
The ability to achieve Ontario's emission targets and the cost of doing so will be driven by the feasible pace at which new electricity generating capacity is developed to meet this demand. Achieving the needed supply in time is particularly important given the anticipated retirement of the Pickering Nuclear Generating Station (PNGS).

[52] ICF International, Ontario Cap and Trade, 2016

By 2025, under the OPO Outlook D assumptions shown in Figure 27, it is conceivable that the province will have 20 TWh greater demand than it has today. Prior to PNGS retirement, Ontario's surplus can provide low cost electrification options to help meet this demand and accelerate decarbonisation. This clean energy asset could also help accelerate Ontario's CCAP objectives for 2020. The expected retirement of the PNGS in 2024 will remove 20 TWh of clean baseload power, effectively eliminating all of the useable low cost carbon-free surplus power[53]. This creates an imperative for developing 20 to 40 TWh of new clean baseload generation by 2025 to provide ongoing support for the emission reduction options.

The LTEP process should consider the need to rapidly make clean electricity generation available to support the 2030 emission reduction pathway. This requires consideration of the type of energy source required. The importance of addressing the heating requirement is central to building emission reductions and will introduce a very different characteristic to Ontario's seasonal electricity demand profile. Figure 28 illustrates how the electricity demand profile in Quebec demonstrates the "face of home heating" as compared to Ontario's current demand profile.

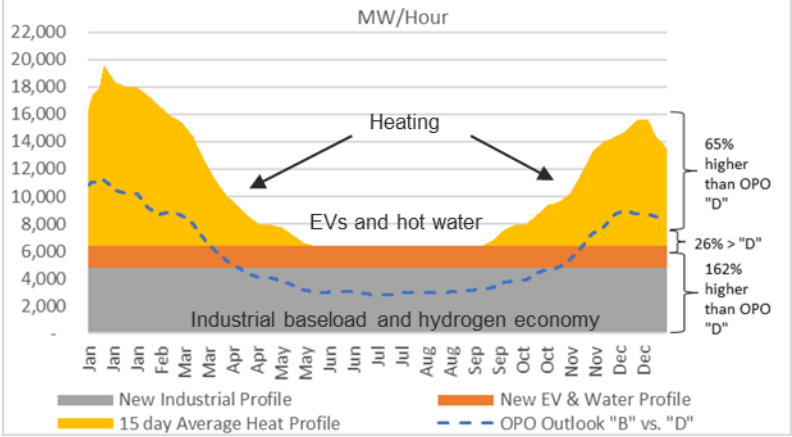
Figure 28 – The Face of Home Heating – Quebec vs Ontario Demand



Not all new electricity demand is the same. Figure 29 shows the nature of the new electricity demand from a seasonal profile perspective.

[53] Strapolec, Extending Pickering Nuclear Generation Station Operations, 2015

Figure 29 – Incremental New Ontario Electricity Demand Profile in 2030



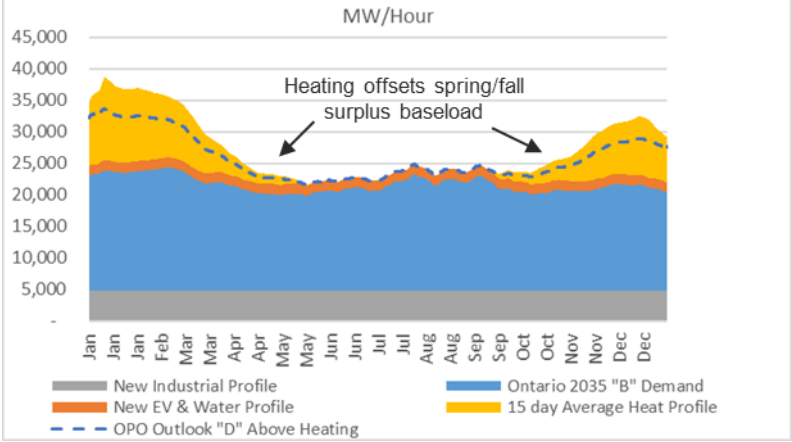
Ontario's current policy direction indicates there will be a significant ramp up of electricity required to supply home heating needs.[54] There are three types of new demand emerging from emission reductions:

- Home heating represents a new seasonal demand load that Ontario currently supplies from its natural gas system. This is considered the largest challenge to the system, particularly the distribution system.
- EVs and water heating represent a daily demand profile driven by consumer behaviors. There is a belief that much of this demand can be accommodated through smart controllers and hence the use of off-peak energy as much as possible.[55]
- The industrial applications and hydrogen economy could conceivably be provisioned by new baseload.

When these new demand profiles are overlaid on existing demand, some of the seasonal variability is smoothed, particularly for the spring and fall. The combined profile is illustrated in Figure 30.

[54] Heating profile based on IESO Outlook D demand, EV profile based on IESO
[55] Haines, OEA Energy Conference remarks, 2016

Figure 30 – Ontario 2030 Demand Profile



The way in which Ontario's electricity system evolves is a critical topic of the LTEP consultation process. Consider should be given to the changing demand profile that is emerging from the emission reduction options. The future may have greater baseload demand and a flatter seasonal spring/summer/fall demand profile. Planning for emission reductions should involve consideration of the costs of this transformation and the associated carbon prices that would incent related emission reduction investments. These subjects are explored in Sections 6.0 and 7.0 of this report.

5.2. Detailed Electrification Assumptions

This section provides a summary of the research conducted to develop estimates of the electricity required by each of the forty-five (45) emission reducing alternative technologies catalogued by this study. The descriptions are provided in three subsections, one for each of the following:

- Building electrification
- Transportation electrification
- Industry electrification, including RNG, SMR, and Hydrogen

5.2.1. Building Emission Electrification

Most Ontario buildings use natural gas for space and water heating applications. Figures 31 and 32 illustrate the use of natural gas for residential and commercial buildings. In 2013, a total of 572 PJ of natural gas was used in the Ontario building sector, with 352 PJ used by residential buildings and 220 PJ by commercial buildings[56].

[56] NRCan, National Energy Use Database, 2015

Figure 31 – Residential Building Natural Gas Use

(PJ)

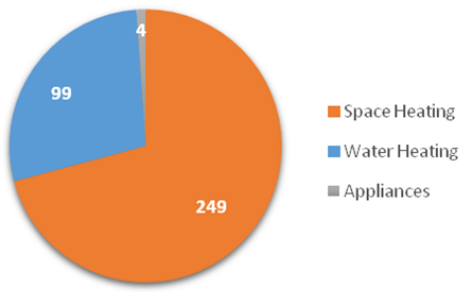
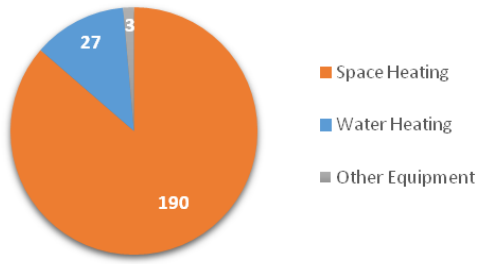


Figure 32 – Commercial Building Natural Gas Use

(PJ)

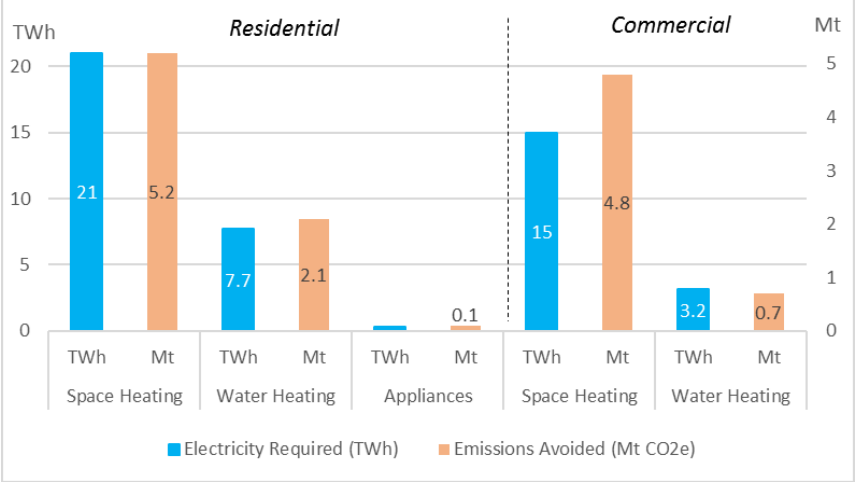


In 2013, residential buildings used 249 PJ of natural gas for space heating, 99 PJ for water heating, and 4 PJ for appliances such as clothes dryers and stoves. Commercial buildings used 190 PJ of natural gas for space heating, 27 PJ for water heating, and 3 PJ for other applications such as auxiliary equipment.

In this study, the target for emission reductions in buildings is 50% below 2030 levels. 5.5% of the reductions are achieved through energy efficiency improvements and the remaining 44.5%. are addressed by electrification options. The focus is on electrifying natural gas space and water heaters as these devices use the majority of natural gas in both residential and commercial buildings. Figure 33 summarizes the electrification implications of emissions reductions from natural gas displacement across these applications in the Buildings sector.

Figure 33 – TWh Required for Building Emission Reduction by 2030

(TWh and Mt CO2e)

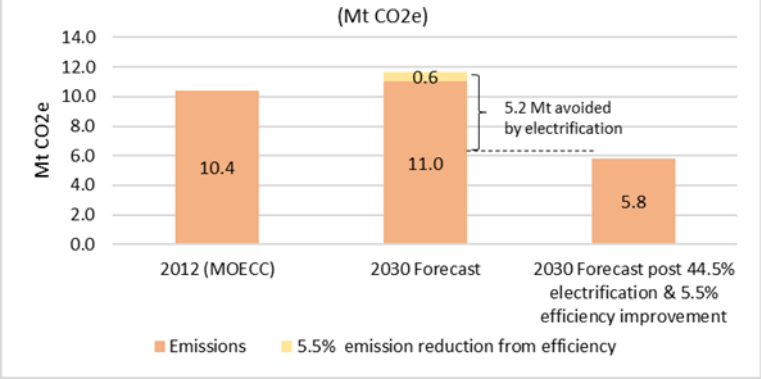


The methodology deployed in this study was common for all natural gas applications in buildings. An example is provided below for residential heating, the largest energy consumer in the Buildings sector.

Electrification scenarios for residential space heating

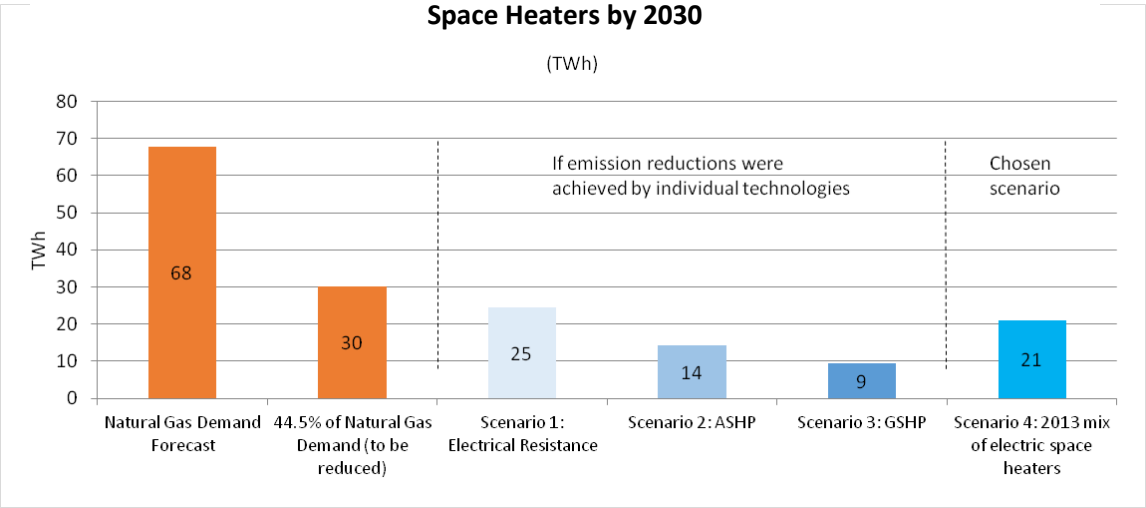
The 2030 energy demand and emissions for natural gas furnaces is based on the MOECC forecast of 2030 building sector emissions. Ontario's residential natural gas furnaces are expected to use 67.9 TWh of energy in 2030 and emit 11.7 Mt CO_2e. An emission reduction from efficiency improvements is assumed prior to estimating the electrification demand as illustrated in Figure 34. As discussed earlier, the efficiency improvement is assumed to be 5.5% which will reduce 2030 forecasted emissions by 0.8 Mt. The remaining gap is 5.2 Mt of emissions that need to be removed through electrification.

Figure 34 – Emissions Forecast for Residential Natural Gas Space Heaters



The analysis, using NRCan data is intended to determine the electrification required based on reducing the equivalent percentage of energy[57]. The energy equivalency model is illustrated in Figure 35 using energy units that have been converted into equivalent TWh's.

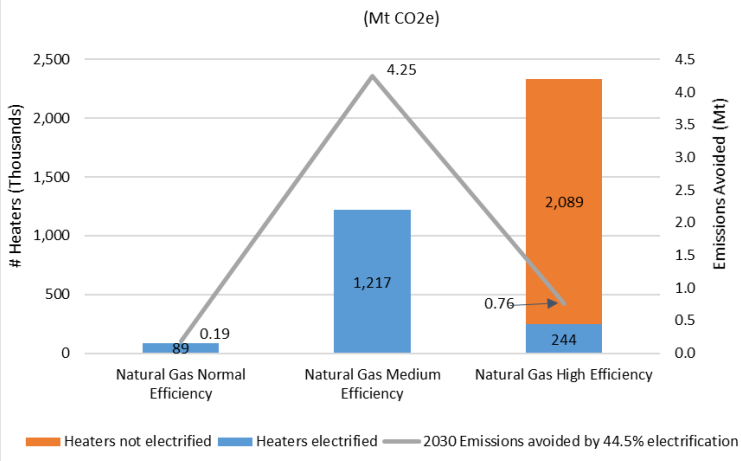
Figure 35 – TWh Required for Electrification of Ontario's Residential Natural Gas Space Heaters by 2030



[57] NRCan, National Energy Use Database, 2015

It will be necessary to remove 30 TWh of natural gas energy use by 2030 in order to reduce natural gas emissions by 44.5%. Strapolec's approach to electrification assumed the least efficient furnaces will be converted first, representing the most optimistic scenario that minimizes the potential electricity required per emissions reduced. The distribution by efficiency rating of residential installations of natural gas furnaces in Ontario is shown in Figure 36. There are very few low efficiency furnaces remaining in Ontario.

Figure 36 – 2030 Emission Reductions Achieved by Electrification of 44.5% of Ontario's Residential Natural Gas Furnaces



Mapping the required emission reductions shows that all low and medium efficiency appliances need to be electrified as well as over 10% of existing high efficiency furnaces. The relative increase in efficiency from switching natural gas heaters to electric for each furnace type is reflected in the assumptions.

Scenarios were developed to determine the electricity required to remove all of the 30 TWh of natural gas energy use and associated emissions. Scenario 1 – electrical resistance heaters, requires 24.5 TWh of electricity to fully displace the natural gas energy. Scenario 2 – ASHPs, requires 14.4 TWh of electricity due to their 1.7 efficiency multiplier[58]. Scenario 3 – GSHPs, requires only 9.4 TWh of electricity due to an almost three-fold increase in energy efficiency.

Scenario 4 is the aggregated model to determine the potential provincial impact. This scenario assumes a mix of electric space heater technologies that mirrors the 2013 installed mix: 68% electrical resistance, 25% ASHPs, and 7% GSHPs. This scenario shows a need for 21.0 TWh of electricity and will avoid 5.2 Mt of emissions.

[58] NRCan, Heating with Oil

5.2.2. Transportation Emission Electrification

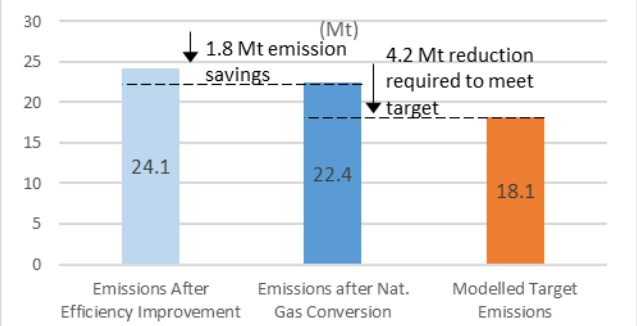
The transportation electrification estimates have been derived separately for the passenger and truck fleets.

Passenger Vehicles

The electrification requirements are driven primarily by an assumption based on the market penetration of the prevailing technology options. Three vehicle options have been modelled to reduce emissions in the passenger vehicle segment: Natural gas vehicles, BEVs and FCEVs. There is much discussion of BEVs in Ontario, with them figuring prominently in the CCAP. Recent market studies suggest there will be 20 million FCEV's globally by 2032[59] which suggests that this vehicle option should be given consideration. The approach to sizing the potential future electricity demand by BEVs and FCEVs is based on the emission reductions required, less the emissions reductions enabled by converting vehicles to natural gas, and then addressing the remaining emissions via equal numbers of BEVs and FCEVs.

The emission balance equation is summarized in Figure 37. It is assumed that 35% of the fleet will convert to natural gas. Based on U.S. Department of Transportation statistics[60], by 2020 Natural Gas vehicles will emit 21% fewer GHG emissions than conventional gasoline. Applying this emission efficiency factor to 35% of the future fleet should reduce emissions by 1.8 Mt, leaving 4.2 Mt to be addressed by the BEVs and FCEVs.

Figure 37 – 2030 Passenger Vehicle Emissions After Efficiencies

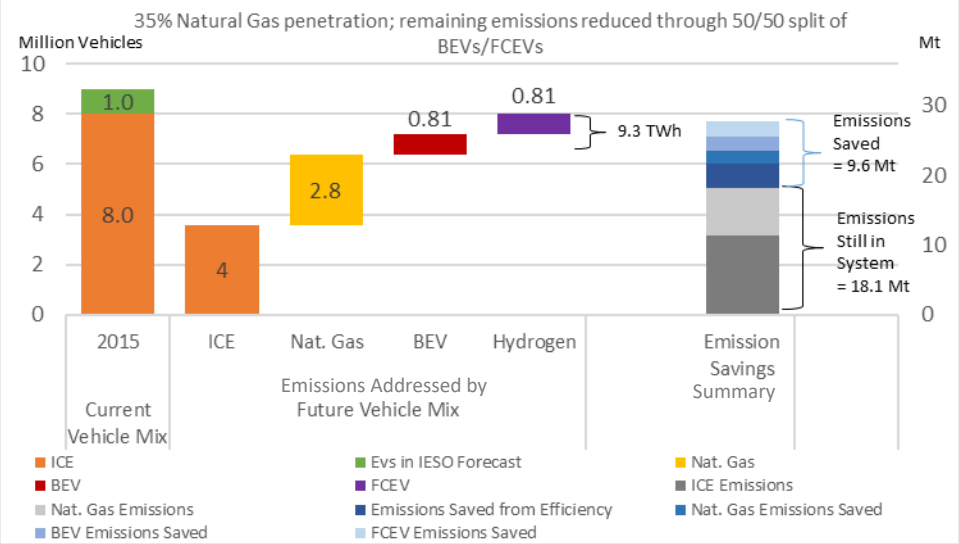


The resulting expected vehicle mix and associated emissions are summarized in Figure 38.

[59] Information Trends, "Hydrogen Fuel Cell Vehicles are Future of the Automobile", www.informationtrends.net/press-release.html regarding "Global Market for Hydrogen Fuel Cell Vehicles", 2016

[60] U.S. Department of Transportation, Transportation Statistics Annual Report 2015, 2015

Figure 38 – Passenger Vehicle Summary



It is assumed that there are no material electrification implications when portions of the fleet convert to natural gas use. To estimate the electrification required for BEVs and FCEVs, the fleet size had to be determined. This was based on forecasting the fuel efficiency assumption of the ICE fleet. It is estimated that average emissions per vehicle in the ICE passenger fleet that may be candidates for electrification will be approximately 2.63 tonnes/year/vehicle. As shown in Figure 37, dividing this value into the 4.2 Mt of emissions to be reduced results in 1.6 million vehicles.

This mix of electric vehicles (EVs) does not account for a mix of Plug in Electric Vehicles (PHEVs) and BEVs. Other studies have shown that when an analysis is based on an emissions reduction target, the number of vehicles may be affected by the vehicle mix, but the TWh/Mt of the fleet is relatively insensitive. Estimates for the EV related electricity demand have been developed from Plug'N Drive data sets and these numbers align well with the IESO's assumptions. Strapolec's model has increased the amount of expected electricity per vehicle, based on the assumption that larger vehicle models will become more common and hence the average electricity needed in the future will be higher than for the smaller vehicles in today's fleet. The assumed electricity required per year is 3.8 MWh/vehicle, based on an average driving distance of 16,000 km for a vehicle mix that would average 11.7 litres/100 kms today.

The electricity required for FCEVs has been obtained from the U.S. NREL studies[61], which show an increasing efficiency factor that should lead to 57 miles/kg of hydrogen by 2025. This is based on the NREL data reflecting expected electrolysis efficiency[62]. On this basis, operating hydrogen vehicles will require about twice the electricity consumed by BEVs, or 7.7 MWh/year. This estimate assumes that hydrogen production takes place at a Class A, Tx-connected industrial facility that avoids the line losses in the distribution system. Toyota estimates of its Mirai[63] vehicle fuel efficiencies and associated demand for

[61] Kurtz, Fuel Cell Electric Vehicle Evaluation, 2016
[62] Kurtz, Fuel Cell Electric Vehicle Evaluation, 2016; U.S. DOE, The Fuel Cell Electric Vehicle
[63] Toyota, The MIRAI Life Cycle Assessment Report, 2015

hydrogen are 76 miles per kg. This suggest 36% less energy required than derived from the NREL forecasts used in this study. This data sample suggests the electrification estimates and costs used in this study to support FCEVs may be high.

Based on 800,000 BEVs and 800,000 FCEVs, it is estimated that in 2030 about 9.3 TWh of electricity may be required to power this fleet.

Trucks

The first step in determining the electrification impact of trucks is to assume the potential market shares of the available emission reducing options. Strapolec's analysis indicates that constraints on the maximum market shares arise for options that emit the least number of emissions, such as the natural gas vehicles, Class 8 hybrids, and PHEVs. The emission-free options of renewable diesel and hydrogen vehicles, in equal proportion, were then used as the plug assumption for achieving the remaining emissions reductions required.

Table 3 summarizes the market share assumptions that were used to estimate the electrification implications. Priority was placed on the short-haul vehicle fleet, based on the assumption that many of the technology solutions would be most suitable to that market, such as the PHEV and hydrogen vehicle solutions. Research has not found cases where PHEVs are suitable for the Class 8 vehicles. While it is generally accepted that hydrogen vehicle solutions for long-haul trucking are not a low-cost alternative, there are specific freight routes where distances are manageable and economic for a hydrogen solution, such as with the ship to rail freight transfer corridor in California[64].

Table 3 - Trucks Emission and Electricity Implications

Heavy Duty Short Range	Natural Gas	Plug-in Hybrid	Hydrogen	Renewable Diesel
% of Fleet	15%	30%	28%	28%
Emission Savings (%)	27%	60%	100%	100%
Emission Savings (Mt)	0.49	2.18	3.43	3.43
Efficiency Gain	0%	20%	20%	20%
Electricity Demand (TWh)	-	3.17	9.72	1.21
Class 8 Tractor Trailer	**Natural Gas**	**Hybrid**	**Hydrogen**	**Renewable Diesel**
% of Fleet	30%	25%	10%	10%
Emission Savings (%)	27%	20%	100%	100%
Emission Savings (Mt)	0.75	0.45	0.91	0.91
Efficiency Gain	0%	20%	20%	20%
Electricity Demand (TWh)	-	-	2.56	0.32

The emission reduction and efficiency improvements for the PHEV options were obtained from the WrightSpeed vehicles. The emissions savings and efficiency gains for the Class 8 hybrids are based on the U.S. DOE Supertruck results and are expressed with respect to the gains the SuperTruck program has

[64] Hydrogenics interviews

reported for the remainder of the ICE fleet. It has been assumed that the SuperTruck program efficiency gains will have penetrated the market by the late 2020s. The assumptions presented here for Class 8 hybrid vehicle penetration are much higher than forecast in the SuperTruck business case assumptions.

In developing the market shares of emission reducing options, the maximum achievable emission reduction estimated for the short-distance truck segment was developed before assigning hydrogen and renewable diesel solutions to the Class 8 vehicle fleet. It has been assumed that the entire short= distance vehicle fleet will have been converted to lower emission options in the future.

The assumed market shares started a 30% natural gas fleet and 30% for either PHEVs for the short-range segment or hybrids for the Class 8 segment. This was subsequently moderated in order to achieve the emission targets. The renewable diesel and hydrogen penetration were used as the "plug" to represent emission-free options to achieve the target. Market shares of the other options were reduced and replaced by hydrogen/renewable diesel options until the targeted emission reductions balanced. Eighty-five percent of the Class 8 fleet will require alternatives.

In order to estimate the electrification implications for hybrid and FCEV truck options, the energy content and emission characteristics of diesel were compared to gasoline. Diesel produces 15% more energy per emission. Using this approach, electricity demand was estimated by scaling up from the PHEV and FCEV TWh/Mt ratios observed for light duty vehicle options. The electrification requirements of renewable diesel were based on research that suggests 33.5 g of hydrogen are required to produce a litre of renewable diesel[65]. Electricity demand was estimated based on this hydrogen electrolysis model.

The market share assumptions are intended to provide a frame of reference for estimating possible electrification implications in the aggregate. As previously noted, the FTR has assumed similar natural gas penetration in the overall transportation sector. To the degree that renewable diesel can become available, for example, the market shares of all the alternatives may be very different.

It may be unrealistic to expect that the entire fleet will convert to new technologies. However, if the trucking sector cannot achieve the emission reduction targets then other sectors will have to make up the shortfall. The purpose of this analysis is to simply identify electrification options. If similar TWh/Mt ratios are realized in other sectors that make up the shortfalls in trucking, the total demand for new electricity could be similar to that illustrated here.

5.2.3. Industry Emission Electrification

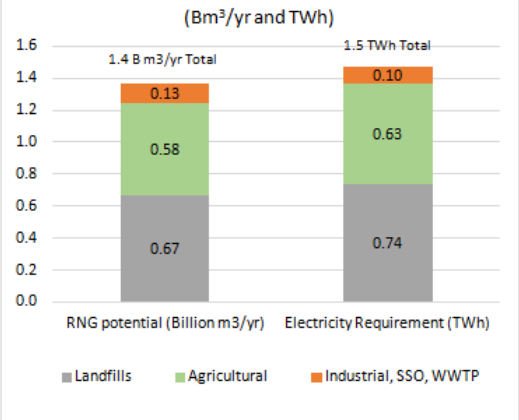
Electrification needed to displace natural gas emissions from the Industry sector are different for each of the four concepts/ideas evaluated in this study: RNG; Hydrogen P2G; SMR replacement; and industry electrification of natural gas use.

[65] Strapolec analysis based on the rapeseed model in: Natural Resources Canada. Study of Hydrogenation Derived Renewable Diesel as a Renewable Fuel Option in North America. March 30, 2012.

Renewable Natural Gas

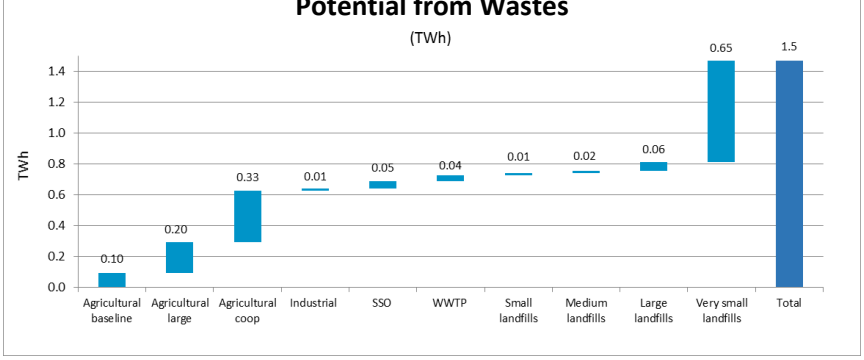
The Electrigaz report provided to the OEB contains business cases for most of the RNG options that have been contemplated for Ontario. Within these business cases, the amount of electricity required for each option is identified. The total expected electricity demand that may arise from RNG production is estimated at 1.5 TWh as summarized in Figure 39.

Figure 39 – Annual RNG Potential from Ontario Wastes and Associated Electricity Required



In proportion to the emissions saved, the greatest need for electricity arises in the production of RNG from landfills and agriculture applications. However, the electrification requirements differ substantially according to the characteristics and scale of the potential RNG sites. The distribution of electrical demand based on potential RNG sites by sector is shown in Figure 40.

Figure 40 – Electricity Required to Produce Ontario's RNG Potential from Wastes



Hydrogen P2G and SMR Displacement

The electrification requirements are estimated based on electrolyser efficiencies forecast by NREL. It is estimated that in the future, 47.7 kWh of electricity will be required to produce 1 kg of hydrogen.

The estimated volume of hydrogen to support P2G and SMR displacement was calculated in Section 3 of this report at 200 million kg. The net electricity required is estimated at 6.3 TWh for P2G hydrogen and 3.3 TWh to displace SMR production of hydrogen.

The combined impact of these two options suggest a need for over 1250 MW of baseload generation to support this hydrogen production requirement.

Industry Use of Natural Gas

It has been assumed that the energy content of natural gas used in Industry, when replaced with electricity will realize a 5% energy efficiency benefit. As a result, 7.6 TWh are assumed to be required to replace 290 Tera Joules of natural gas energy.

5.3. Summary

To reach Ontario's 2030 target emission level using a combination of efficiency savings and electrification, an estimated 90 TWh of new electricity will be required to enable the adoption of the forty-five opportunities assessed in this study for electrification in buildings, transportation, and industry.

The projected growth in electricity demand of 90 TWh is approximately 80% higher than the incremental 50 TWh identified in the OPO Outlook D, and would be needed 5 years sooner than the Outlook D provides for. The new demand arises primarily in the form of winter space heating and industrial level baseload consumption. Electric vehicles represent less than 10% of the expected new demand. Trucks represent the greatest challenge. The use of hydrogen in many applications suggests that hydrogen may be an important pathway to achieving Ontario's emission reduction strategy, a unique Ontario opportunity due to Ontario's virtually zero-emission electricity supply.

The ability to achieve emission reduction targets, and the cost of doing so, will be driven by the pace at which new electricity generation, transmission, and distribution capacity is developed. Developing new generation capacity prior to 2030 will be difficult to achieve.

Deferring compliance with the 2030 emission reduction target may be necessary, as implied by the OPO and FTR 2035 Outlooks, although there is no publicly stated indication that the province intends to be domestically non-compliant with the 2030 target. The pending retirement of the PNGS may further impede the ability to supply mid-term emission reduction initiatives with carbon free energy and could dampen the pace of subsequent progress to meeting the 2030 targets.

6.0 Cost of Emission Reduction Options and Carbon Price

This section provides an estimate of the incremental costs required to achieve the emission reductions and defines this cost in terms of the equivalent carbon price that would enable each option to be economic.

This section first provides an overview of the results of the analysis and then treats each sector individually, examining the incremental costs of each option as compared to the expected future costs of the BAU use of the fossil fuels. A summary of the total cost that can be expected to achieve emission reductions is provided along with a spotlight on the opportunities for natural gas displacement by hydrogen in the industrial sector.

The overview section portrays the electrification relationship with emissions reductions as a portfolio of options. The portfolio view is intended to highlight that collectively the options provide an informative view as to the aggregated emission reduction challenge that is emerging for the electricity sector.

For Buildings, residential space heating is provided as an example for the methodology applied for all buildings options, both residential and commercial. In Transportation, individual attention is given to passenger vehicles and trucks due to the number of alternatives evaluated and to best set out the special challenges that trucking represents.

This section closes with a summary of the key findings.

6.1. Overview

Incremental costs are defined as the change in costs associated with the switch from an existing emitting technology to using a low-carbon alternative.

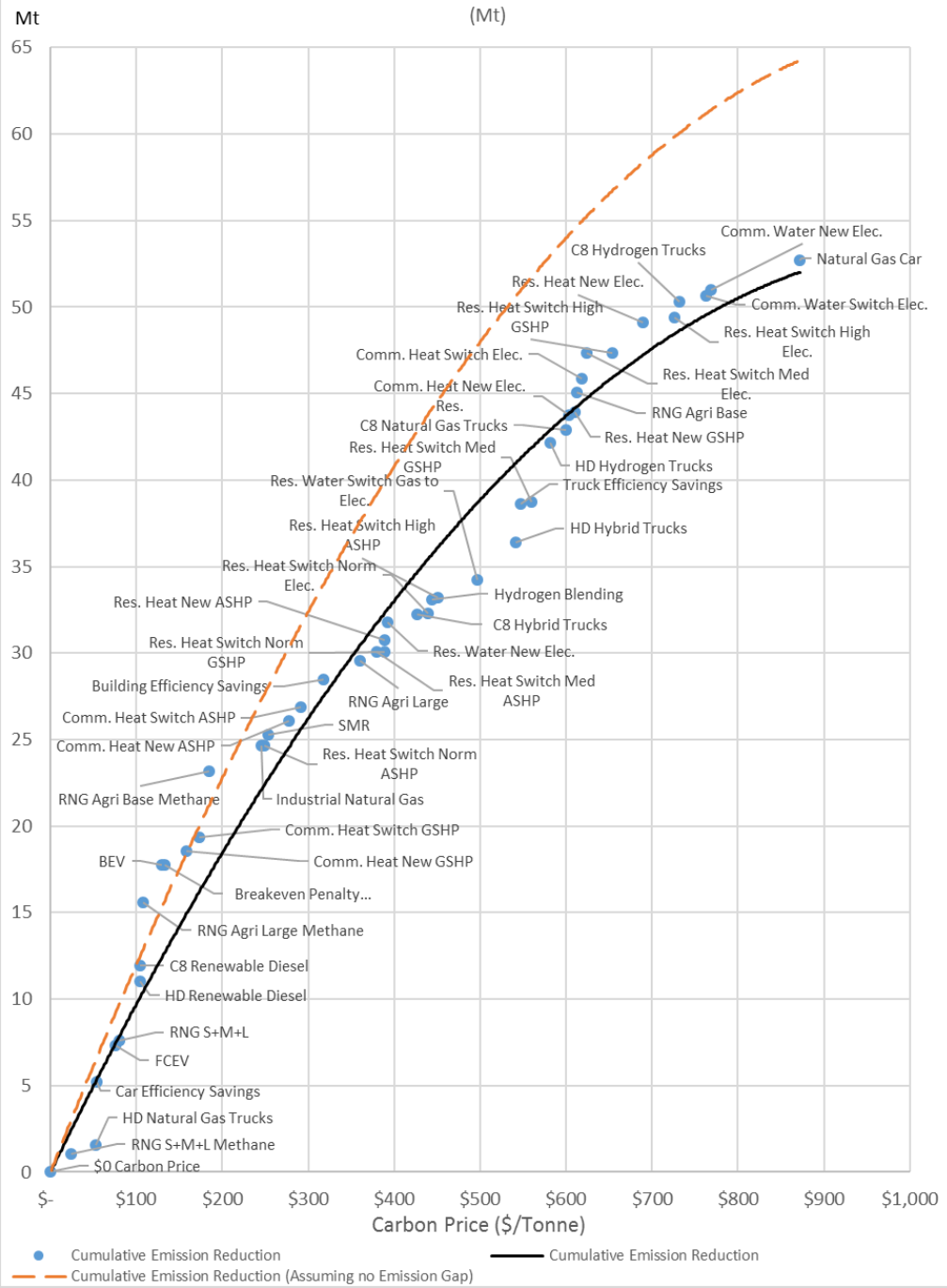
A carbon price provides the framework for estimating the total incremental costs. The carbon price reflects the incremental cost of switching divided by the emissions avoided by the chosen alternative. A carbon price therefore reflects the breakeven market cost that enables user investment to switch to low carbon technologies. Each of the options has been costed to determine the carbon price that makes each technology choice economic for an end user.

Figure 41 illustrates the portfolio of emission reduction options and the associated carbon price implications. This illustrative portfolio is used in this study to develop the cost implications, but may also provide a useful benchmark for evaluating future innovations.

This study has not assessed emission reductions in certain areas. For the purpose of estimating the total cost, a margin has been added to the assessed data to reflect the costs that may arise when solutions to the remaining emissions challenges emerge. A simple percentage multiplier has been applied throughout the range of options consistent with earlier stated assumptions reflecting the expectation that innovations

will occur in an equivalent incremental manner as reflected by the suite of existing options. This adjustment is represented by the dashed red line in Figure 41.

Figure 41 – Cumulative Emissions Reductions vs. Carbon Price



A high carbon price may be necessary before individuals choose the lower emission option. The cost of half of the emission reductions are in the $200/tonne to $600/tonne range, with an increasing potential incremental emission reduction benefit as the price of carbon increases. To fully realize the desired

emission reduction of 67 Mt by 2030, a carbon price in excess of $800/tonne may be required as represented by the natural gas passenger vehicle option illustrated in Figure 41.

In addition to the emission reduction options assessed by this study, provisions have been made for:

- Costs to achieve efficiencies: Building efficiency improvements have been derived from 50% of the MOECC CCAP costs or about $320/tonne. Cars at $50/tonne. Trucks at $550/tonne based on increased capital costs to achieve the D.O.E.'s SuperTruck efficiencies.
- Cost to realize the 12 Mt of emission not assessed by this study have been assumed to be achieved proportionately throughout the cost curve (red dashed line).

The effective carbon prices that enable emission reductions are dispersed across all sectors and over a wide range of options. There is no apparent threshold that represents a magic target. Increasing the carbon price to enable one solution, may also enable the economic viability of several others. For lower cost options, higher carbon prices may also result in greater market penetration than has been assumed.

With this variability in carbon prices, and the innovations that will begin to accelerate as the battle against climate change progresses, these results speak strongly to the need for a transparent, evidence based decision making process to support the adoption of specific emission reduction solutions. Attempting to pick winners in a vacuum comes with significant risk.

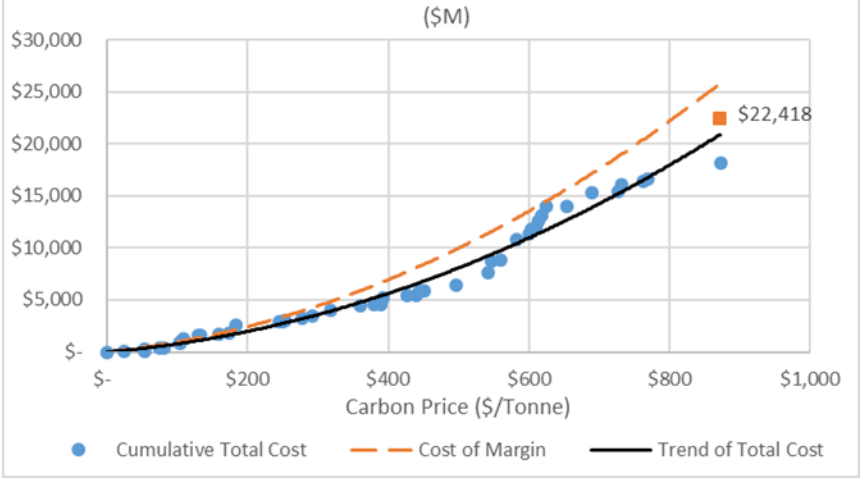
6.1.1 Assessing the Total Cost

A carbon price presents users with a choice between an emitting technology, that has the appropriate carbon price levy on it, versus a non-emitting option that a user would buy at that same net levied cost. This is the essential economic principle behind the C&T concept. In this perfect system, each user pays the cost for switching as it becomes more economic to do so.

When considering the challenge from a societal or total economy perspective, the minimum cost to achieve the emissions can be computed by taking the equivalent carbon price that enables a particular option and multiplying it by the incremental emissions saved by that choice.

When aggregated among all of the options, starting with the lowest cost and proceeding until the emission target is met, a total cost estimate can be developed. The minimum cost to achieve the 2030 emission target is $22B as shown in Figure 42 below.

Figure 42 – Minimum Cost of Achieving Emissions Reductions

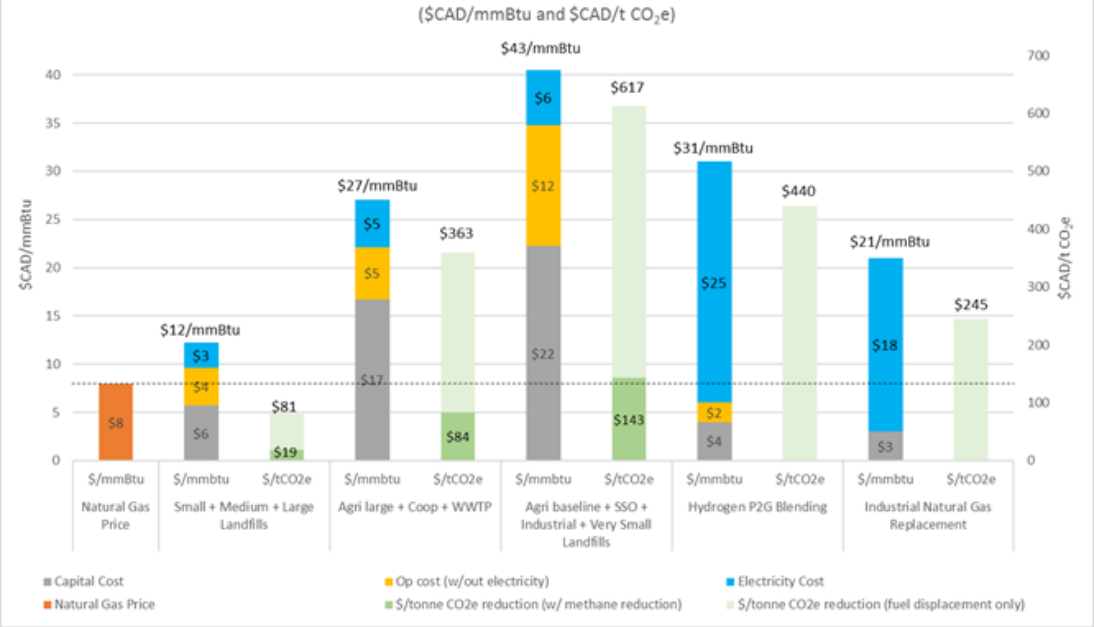


6.1.2 A look at Natural Gas Displacement and Hydrogen

This analysis points to an emerging role for hydrogen that could become important to Ontario's emission reduction strategy.

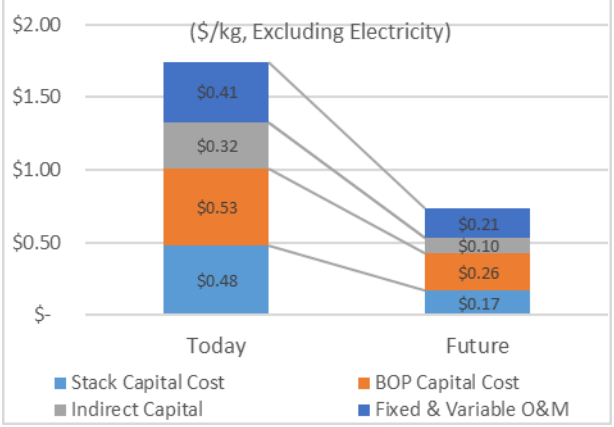
Figure 43 illustrates the incremental costs for the natural gas displacement technologies that have been examined. The RNG costs are based on the Electrigaz report submitted to the OEB by Union Gas. Other than the larger landfill gas RNG sites, most of the emission savings from RNG production will come at a high cost. The blending of hydrogen may be more economic in some circumstances.

Figure 43 – Cost of RNG Production Using Ontario Wastes



The evolving economics of low carbon hydrogen production from electrolysis are being studied by the U.S. NREL[66] and who have forecast the cost of hydrogen electrolysis facilities to decline by 60% over the next 5 to 8 years as shown in Figure 44.

Figure 44 – Cost of Central Electrolysis, Current vs. Future



The implications of this cost reduction will impact the economics for all of the hydrogen applications that have been identified for inclusion in this study. Figure 43 shows a range of carbon prices of $300 to $600 range are required to displace natural gas. In contrast, a $250/tonne carbon price as shown in Figure 45 to make hydrogen electrolysis economic compared to SMR for use in refineries appears modest.

The low cost of hydrogen also extends to FCEVs for the passenger vehicle market as summarized in Figure 46. Hydrogen FCEVs may become the lowest cost, zero-carbon vehicle in the next 10 years if the hydrogen supply is available.

Figure 45 – Future Costs of Hydrogen Production

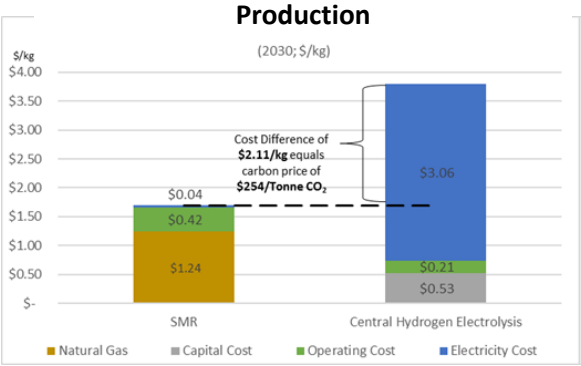
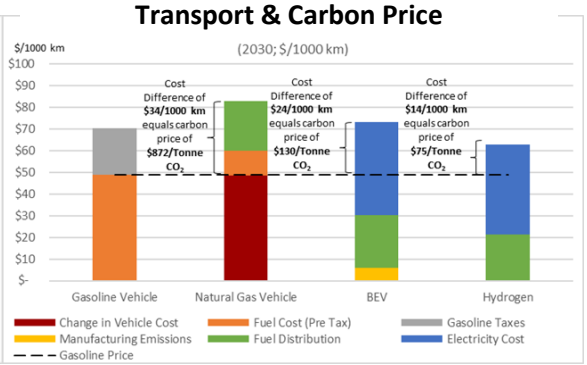


Figure 46 – Future Cost of Passenger Transport & Carbon Price



The detailed cost assumptions for the above findings are provided in the next subsections.

[66] Ainscough, Hydrogen Production Cost from PEM Electrolysis, 2014, FCH JU "Commercialisation of Energy Storage In Europe", March 2015

6.2. Detailed Costing Analysis for Building Options

This section examines the incremental costs for switching to the alternative heat generating equipment in buildings: space heating (electric resistance, AHSPs, GHSPs); water heaters; and, appliances.

Individual analyses were conducted for the residential and commercial building segments. An identical approach was taken for both segments and all the evaluated technologies. The incremental costs are determined by examining:

1. Capital costs to acquire the new equipment
2. Maintenance costs
3. Cost of fuel (natural gas or electricity)

The costing information has been derived from NRCan and EIA[67] sources.

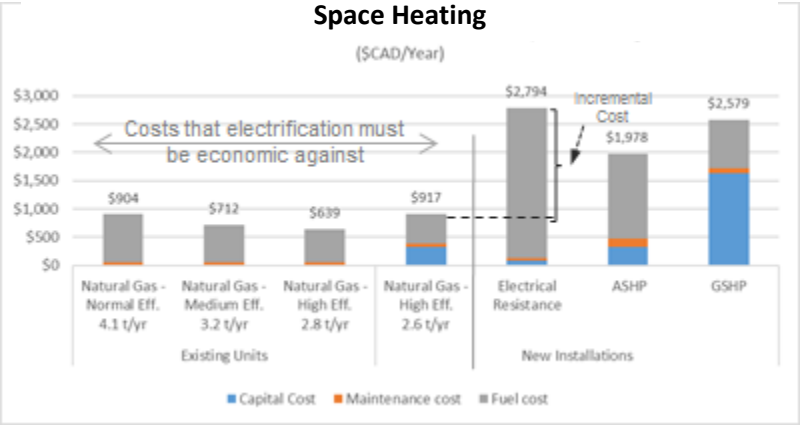
Two scenarios under which a user may choose to switch to a lower emitting technology were considered:

a) An end user is considering *switching* to a new and more efficient technology although the user's existing device may still have a useful remaining lifespan.

b) An end user needs a *new* device because the existing system has reached its end of life, or is being installed in a new building. The user must choose between a new natural gas or electric device.

The residential space heating example illustrates the approach. Figure 47 shows the incremental cost implications for residential space heating. Air Source Heat Pumps (AHSP) are the lowest cost means of electrifying residential heating.

Figure 47 – Cost of Residential Natural Gas vs. Electric Space Heating



The carbon price that makes each option economic differs between the scenarios based on the incremental cost difference and the emissions saved. Computing the incremental cost differences for

[67] Navigant Consulting, Technology Forecast Updates, 2014

each option and dividing it by the emissions saved yields the carbon prices shown in Figures 48 and 49 for both the *switching* and *new* scenarios.

Figure 48 – Carbon Price for Switching to Residential Electric Space Heating

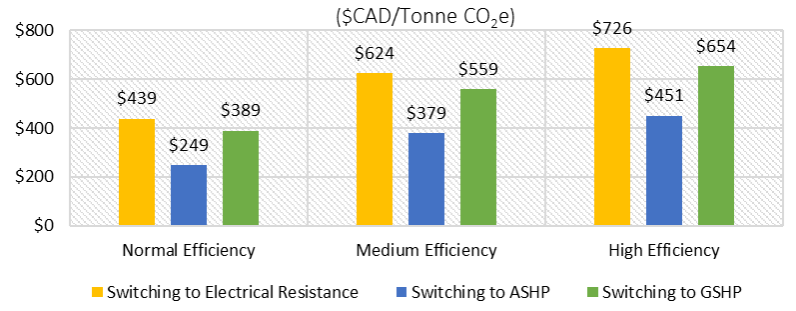
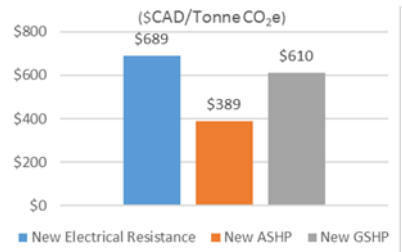


Figure 49 – Carbon Price to Avoid High Efficiency Natural Gas Furnaces



A carbon price of at least $379 per tonne CO_2e would be needed to enable the purchase of an AHSP to replace an existing medium efficiency unit. Subsequently higher carbon prices would facilitate medium and high efficiency natural gas furnaces to be electrified with an AHSP. The estimated carbon prices assume that the full cost of having a natural gas delivery connection has been saved.

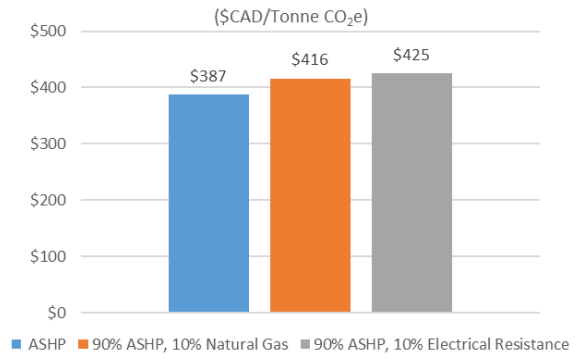
Electrical resistance furnaces are the next most economical option for residential applications with the largest contributor to cost over the product lifecycle being the price of electricity. The Class B consumer rate of $180/MWh is the assumed price of electricity in the illustrations.

Although the fuel cost for running a GSHP is much lower compared to other electric heaters due to the high efficiency of the device, the capital cost of installing a GSHP is significantly higher than other types of heaters. This is a limiting factor in bringing these devices to the residential space heating sector. GSHPs are the most economical for larger commercial applications.

It is generally expected that ASHPs require supplementary heating during very cold days[68]. Figure 50 illustrates the results of a sensitivity analysis conducted to determine the impact on the carbon price for ASHPs if 10% supplementary energy were required from a) natural gas; or b) electricity. The figure represents an aggregated blended average of all scenarios modelled for ASHPs. The natural gas supplementary case assumes the addition of a connection charge for accessing the natural gas supply.

[68] Energy Solutions Centre, An Evaluation of Air Source Heat Pump Technology in Yukon, 2013

Figure 50 – Carbon Price Impact from ASHP Only vs. ASHP with Supplementary Heat



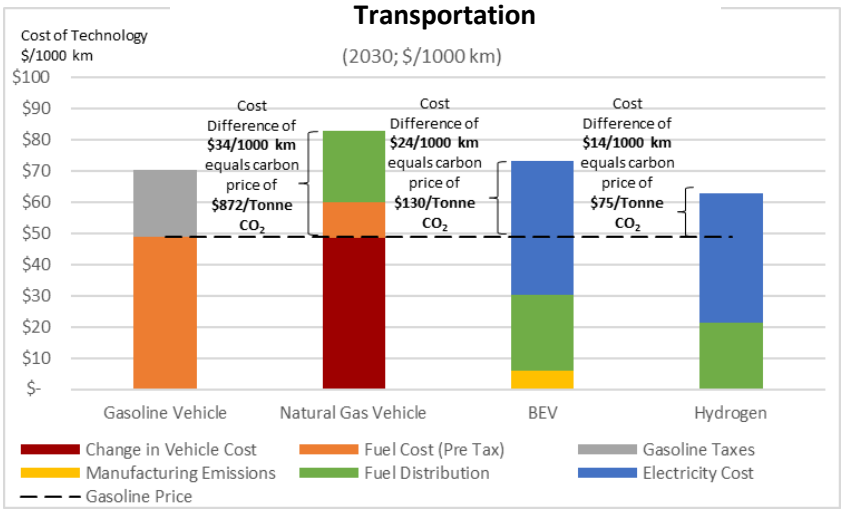
The carbon price for both options increases, with natural gas substitution being marginally less expensive than using electricity as the supplementary heating source. The comparison is sensitive to the natural gas connection delivery charge assumption, which for this scenario was estimated at $5/month. If a 10% supplementary energy is required, the challenge is that a 10% greater market penetration of these devices must be achieved to realize the same provincial level emission reduction.

6.3. Detailed Cost Analysis for Transportation

6.3.1. Passenger Vehicles

This section examines the incremental costs of switching from the future projected ICE vehicles to one of the three alternatives assessed in this study and presents the assumptions that lead to the effective carbon price. The results for passenger vehicles are summarized in Figure 51.

Figure 51 – Effective Cost of Carbon - Transportation



As this study is focused on the time period leading up to achieving the 2030 emission reductions target, costs relevant to that time frame are considered. Understanding the future state of ICE vehicles is a common element for assessing all technology options. Several assumptions have been made regarding the estimation of the cost of these future vehicles:

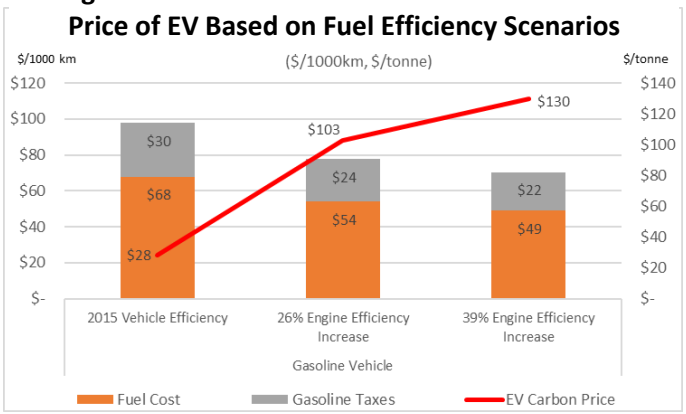
a) Vehicle Costs: According to Bloomberg, the future costs of the different alternative vehicles will converge to an average price[69]. The European Fuel Cells and Hydrogen Joint Undertaking has made a similar statement regarding hydrogen vehicles [70].

b) Cost of Fuel: Gasoline for ICE vehicles is expected to rise approximately 20% from today's levels[71].

c) Gasoline Tax: This tax is removed for comparison purposes as it represents government revenues that will still have to be recovered from somewhere and hence do not impact the incremental cost of the transportation options.

d) Emissions of ICE vehicles: Assumed efficiency improvements will put upward pressure on equivalent carbon prices as illustrated in Figure 52 for the EV scenario. In this scenario EV costs are held constant, just the emissions being offset are changed as the EV substitutes for more and more efficient ICE vehicles. The baseline assumption in this study for emission reductions resulting from efficiency improvement is 39%.

Figure 52 – Cost of Gasoline Vehicle vs. Carbon Price of EV Based on Fuel Efficiency Scenarios



Additional assumptions relevant to each technology option are as follows:

1) Natural gas vehicles
   a. It is assumed that natural gas vehicles will be based on the same platform and engine as ICE vehicles and hence the costs of these vehicles are assumed to be similar.

[69] Bloomberg, Here's How Electric Cars Will Cause The Next Oil Crisis, 2016
[70] European Fuel Cells and Hydrogen Joint Undertaking, A Portfolio of Power-Trains for Europe, 2010
[71] Growth of oil to $55/barrel in future from $47/barrel today (Porter, OEA 2016 energy conference). FTR suggests a similar assumption of slightly over 20% for residential gasoline use.

b. Natural gas vehicles require a compressed natural gas (CNG) tank which is estimated to add about $6000/car.

c. The cost of natural gas is forecast to be $0.56/litre equivalent pre-tax.

- Price of natural gas is split between the commodity cost of the natural gas and the distribution cost.
  1. The commodity price of natural gas is expected to be $0.19/L gasoline equivalent. This is based on double the 2016 price of natural gas, as per the EIA's 2016 Annual Energy Outlook.
  2. The distribution cost of natural gas is calculated based on the difference between the pump cost of natural gas (gathered from a natural gas service station located in Toronto), and the commodity price at the time[72].

2) EVs

a. Additional emissions created during manufacturing[73]

- EV batteries in Canada will either be sourced in the US (giga-factory) or in China and hence have a carbon component that should be subject to the carbon price.
- China is introducing a carbon pricing schema for their economy.[74]

b. Implications on the electricity distribution system

- Cost of charging infrastructure[75]
  1. at home: $2,500 Level-2 Charger
  2. for public use: $50,000 Level-3 charger.
- It is assumed that the local distribution system will need to be enhanced to accommodate the electric vehicles. Represented by allocating a 20% increase in the distribution cost component of a residential bill. This component is so small it is not visible on the chart.

c. Electricity for EV charging.

- Cost of future electricity for Class B consumers is assumed to be $180/MWh.

3) FCEVs

The incremental costs of FCEVs are comprised of three components:

a. Production cost associated with the electrolyser operations

[72] Data taken at two points in time. One in July 2010, the other September 2016. The average of these two dates is used to calculate delivery cost (Canadian Natural Gas Vehicle Alliance, Natural Gas Refueling Stations, 2016; OEB, Natural Gas Rates – Historical, 2016)

[73] 57.94 g/km additional manufacturing emissions above gasoline car (Nealer, Cleaner Cars from Cradle to Grave, 2015)

[74] Cheadle, China cap-and-trade market gives carbon pricing opponents 'nowhere to hide', 2016

[75] Bruce Power, Accelerating the Deployment of Plug-in Electric Vehicle in Canada and Ontario, 2016

- The costs of operating electrolysers, predicted by the NREL[76] as previously discussed, are expected to be approximately $0.74/kg. This equates to ~$8/1000km excluding the electricity inputs.
- The electrolyser operating costs are included in Figure 51 as part of the cost of electricity.

b. Cost of electricity to produce the hydrogen
   - The cost of electricity reflects the efficiency assumptions regarding the electrolysers, which is forecast to be 47.7 kWh/kg.
   - It is assumed that the larger scale central production model of 50 MW electrolysers will be eligible for Tx connected Class A industrial rates.

c. Cost to distribute the hydrogen (central model)
   - The distribution model assumed for hydrogen is to deliver by truck to gas stations with the truck trailer being left at the station as the storage device77. These costs include the dispensing costs of fueling customer vehicles etc..
   - The EU study on FCEVs identified that the distribution system cost for hydrogen is expected to be similar to that of EVs given charging station needs, etc.. The independently derived assumptions in this report is consistent with that observation.[78]

The breakeven carbon price is defined as the effective price of carbon that will make the cost of acquiring and operating an alternative the same net cost to the consumer as purchasing an ICE vehicle. This is calculated by assessing the cost to drive the electric vehicle, subtracting the cost to drive an ICE vehicle, and dividing the difference by the emissions saved. The FCEV has the lowest forecast required carbon price at $75/tonne, just over half the expected carbon price of $130/tonne for future EVs.

6.3.2. Trucks

As noted earlier, reducing emissions from the trucking sector will be challenging. All the options assessed in this report have been met with various levels of skepticism, largely on the basis of that the commercial viability is perceived to be unlikely. The economics of each option are addressed below.

The trucking segment has two distinct categories, each with its own specific cost comparators. Figures 53 and 54 summarize the carbon price calculations that would normalize the economics providing a basis for comparison when choosing between these vehicle options.

[76] Ainscough, Hydrogen Production Cost from PEM Electrolysis, 2014
[77] Weil, H_2 Production and Delivery Cost Apportionment, 2012
[78] European Fuel Cells and Hydrogen Joint Undertaking, A Portfolio of Power-Trains for Europe, 2010

Figure 53 – Effective Cost of Carbon – Heavy Duty Short Range Trucks

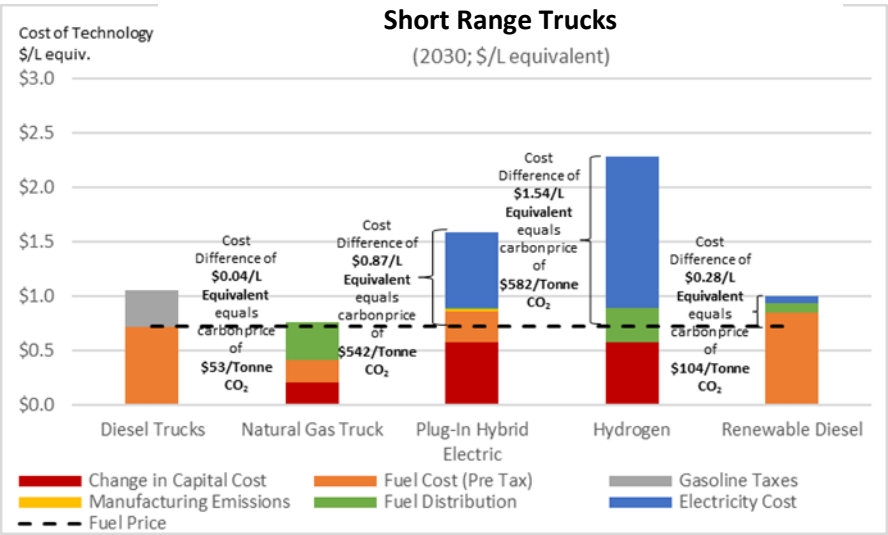
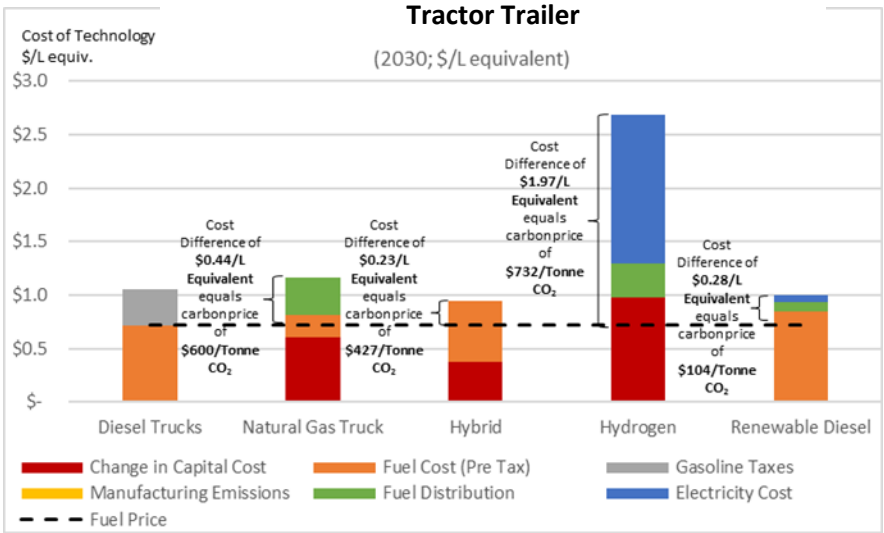


Figure 54 – Effective Cost of Carbon – Class 8 Tractor Trailer



Natural gas trucks appear to be the most economic for short-range vehicles with carbon prices in the $50/tonne range, slightly more economical than renewable diesel carbon prices in the $100/tonne range. As expected, hybrids and FCEV trucks would require much higher carbon prices in the $540 to $580/tonne range. The challenge with the natural gas vehicles is that they cannot, even at 100% penetration, achieve the trucking sector's emission reduction targets. Renewable diesel vehicles cannot achieve reduction targets either, due to real world constraints on the availability of feedstocks. Carbon pricing mechanisms will be required to make other vehicle options economic at some time before 2030.

For the Class 8 tractor trailers, other than renewable diesel, all options have high carbon prices, with hybrids potentially being the earliest adopted option requiring a carbon price just over $400/tonne. As

indicated in the earlier market sizing section, the high cost of the hydrogen vehicles, particularly for Class 8 vehicles, will reduce their market share. However, the reality that the emissions must be reduced somehow may cause carbon pricing policies to ensure hydrogen vehicle options, or other alternatives not yet identified, are enabled.

Assumptions

The assumptions applied to each vehicle type are summarized in Table 4. All HD trucks are assumed to have a life of 450,000 km[79], and an efficiency of 4 km/L[80]. This measure is used to compare capital costs.

Table 4 - Trucking Emission Reduction Option Cost Assumptions

Heavy Duty Short Range	Natural Gas	Plug-in Hybrid	Hydrogen	Renewable Diesel
Costs	$60k	$120k	$60k + $37k	-
Emission Savings (%)	27%	60%	100%	100%
Efficiency Gain	0%	20%	20%	20%
Class 8 Tractor Trailer	**Natural Gas**	**Hybrid**	**Hydrogen**	**Renewable Diesel**
Costs	$60k	$37k	$60k + $37k	-
Emission Savings (%)	27%	20%	100%	100%
Efficiency Gain	0%	20%	20%	20%

Natural Gas Trucks

As with natural gas light duty vehicles, it is assumed that these vehicles have parameters identical to ICE truck vehicles with two caveats:

- For Class 8 vehicles, an additional $60,000 fuel tank with an ICE vehicle equivalent range of 1200 km range between fuelling[81]
- For short-range vehicles, a similar cost assumption is made based on the WrightSpeed findings that natural gas vehicle conversions cost $50,000 US[82].

Plug in Hybrid Electric Vehicle (PHEV) Short Range Trucks

- The costing assumptions for PHEV truck options are based on the research sample for WrightSpeed's after market hybrid vehicles. These are offered as post market upgrade kits that cost approximately $200K, which costs "$150K more than a natural gas conversion". Upgrades are typically done on older, soon to be retired diesel vehicles which makes the choice economic compared to purchasing a new vehicle. The turbine technology deployed can be fuelled with diesel, the assumption used here to make comparisons more direct.

[79] Assumed based on analysis from Canadian vehicle study (NRCan, Canadian Vehicle Survey, 2010)
[80] NRCan, Canadian Vehicle Survey, 2010
[81] Approximate estimate only derived from Canadian Natural Gas Vehicles Association informal discussions
[82] Berg, Wrightspeed's Tantalizing Turbine-Electric Drivetrain, 2015

- The electricity to charge the vehicles is assumed to be available at Class B consumer rates.

Hybrid Class 8 Trucks

- Based on the DOE's Supertruck program results, the hybrids are forecast to incur an additional capital cost of $37k/vehicle[83] and achieve 20% greater emissions reductions than the equivalent SuperTruck ICE vehicles. Part of the emissions reductions are derived from efficiency gains resulting from aerodynamic improvements.

Hydrogen Vehicles

- As with the light duty fleet, it is assumed that hybrid and hydrogen technology capital costs converge. As such, the hybrid capital cost of $37K/vehicle is applied to the hydrogen vehicle along with the assumption that the greater aerodynamic efficiencies will also be realized by FCEV vehicles.
- The compressed fuel tank, as with natural gas vehicles is a technical limit. It is assumed that the hydrogen vehicle cost will reflect this same fuel tank cost.
- Electricity and hydrogen production and distribution costs are assumed to be similar to those for light duty FCEVs.

Renewable diesel

- Costing assumptions for renewable diesel have been extracted from the FTR report using the bio-diesel values as the reference, and they are expected to be 19% higher than the price for diesel fuel.
- The cost of producing 33.5 g of hydrogen per litre has been included.
- A placeholder for distribution costs was set at 25% of the cost of natural gas distribution based on the notes in the FTR that significant infrastructure will have to be built in Ontario to accommodate production.

6.4. Summary

Forty-five carbon saving technologies have been identified to save emissions in the Buildings, Transport and Industry sectors. Carbon pricing is used to measure the incremental costs of switching between emitting technologies and the lower emitting alternatives that have been assessed to help Ontario achieve its emission reductions. A high carbon price may be necessary before individuals choose the lower emission option. The cost of half of the emission reductions are in the $200/tonne to $600/tonne range, with an increasing potential incremental emission reduction benefit as the price of carbon increases. To fully realize the desired emission reduction of 67 Mt by 2030, a carbon price in excess of $800/tonne may be required.

It is estimated to cost over $22B/year to achieve the emission reduction targets by employing these technologies. This cost estimating exercise is best viewed as a portfolio depiction of the potential costs.

[83] TA Engineering, DOE Supertruck Program Benefit Analysis, 2012

No single estimate may be an exact prediction, but in the aggregate the balance of options provides a string signal as to what may be expected. This illustrative portfolio is used in this study to develop the cost implications, but may also provide a useful benchmark for evaluating future innovations.

Air source heat pumps may be the best alternative for most building heating applications, but are expected to require supplementary heating options for extreme cold weather. Even so, carbon prices in the $400/tonne range may be required.

Hydrogen fuel cell vehicles (FCEVs) appear to be emerging as the low-cost passenger vehicle option in the late 2020s. Trucking remains a challenging area with no economical solutions identified that can achieve the required emission reductions. Other than renewable diesel which will be feedstock limited, trucking options appear to require carbon prices in the range of $600/tonne for natural gas conversions to $730/tonne for hydrogen options.

Using hydrogen to displace natural gas is as economic on a carbon price basis as RNG from sources other than landfills. At $245/tonne, producing hydrogen from electrolysis instead of the natural gas fed SMR process, is one of the least costly emissions reductions options assessed.

7.0 Managing Cost of Emission Reduction

This section aggregates the results of the earlier sections of this report to develop the cost and economic implications of the sensitivity of carbon price to electricity costs and administrative effectiveness.

This section first provides an overview of the net cost implications to the province including the sensitivity of carbon price. The relationship between the cost of electricity and emissions achievements and the need to purchase allowance credits for jurisdictions outside Ontario is presented.

A detailed discussion is then provided of how the use of proceeds process would impact the market carbon price within the C&T program. The cost risks associated with government administration of the use of C&T proceeds is then examined and the impact these risks could have on carbon price and total cost is estimated. Finally, an examination of the sensitivity of carbon price and total cost to the costs of the incremental electricity that may emerge from the LTEP is presented.

This section closes with a summary of the key findings.

7.1. Overview of the Cost to Ontario of Emission Reduction

The findings of this study suggest that the total cost of emission reductions may be as high as $27B/year by 2030, but moving the LTEP towards a low-cost electricity solution could save $6.9B/year.

How C&T Reduces Carbon Price

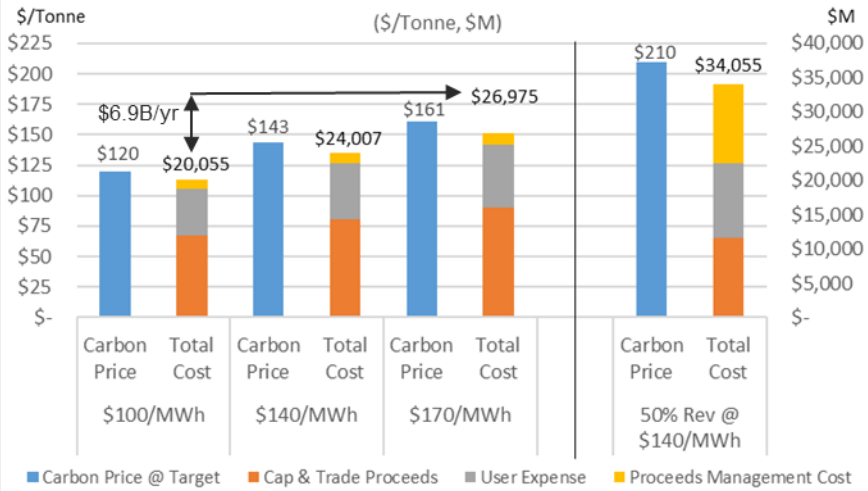
A government C&T or carbon tax program derives proceeds from those who have not yet switched fuels. An effective use of these proceeds would be to employ them to influence the purchase decisions of individual users through subsidies. In a perfectly administered system, the total cost of achieving the emission reduction should be the same as the minimum cost illustrated in Figure 42. The difference, or inherent advantage, is that the government carbon programs can spread the costs of emission reduction among the entire economy not just the individuals making the early decisions to reduce emissions. This can accelerate adoption and enable emission reductions at much lower market carbon prices than may otherwise be required.

Reinvesting C&T proceeds can also subsidize higher cost options to match the revenues obtained at the market carbon price level used to raise the funds. Funds are raised on allowable emissions, which at the outset are quite high. The proceeds can be applied to subsidize technologies that contribute smaller emission reductions towards meeting the target. This process can decrease the highest observed price of over $800/tonne to fully achieve the 2030 emission targets to a range of $120 to $161/tonne depending on the price of electricity.

The Cost of Emission Reduction

Figure 55 summarizes the implications on total cost and carbon price as a function of the cost of electricity and the effectiveness of the "use of proceeds management" scenarios.

Figure 55 – Implications of Different Electricity Cost



It is clear that a lower cost of electricity will drop the cost of carbon emission reductions, potentially by up to $7B, or more if management effectiveness is considered and addressed.

As shown in Figure 55, there are three costs that materialize in implementing an emission reductions program such as C&T.

1. Reinvesting the generated proceeds either as incentives or subsidies
    - Proceeds are either raised through allowances administered in a C&T program or through a tax on emissions. These proceeds can be used as a subsidy to encourage technology switching.
2. The unsubsidized cost paid by a user when choosing to switch.
3. The cost of program administration and the cost implications from government prioritization of CCAP outcomes vis-a-vis the effectiveness of allocating proceeds to emission reductions
    - These costs would be deducted from, for example, the C&T proceeds and represent economic losses in the system.

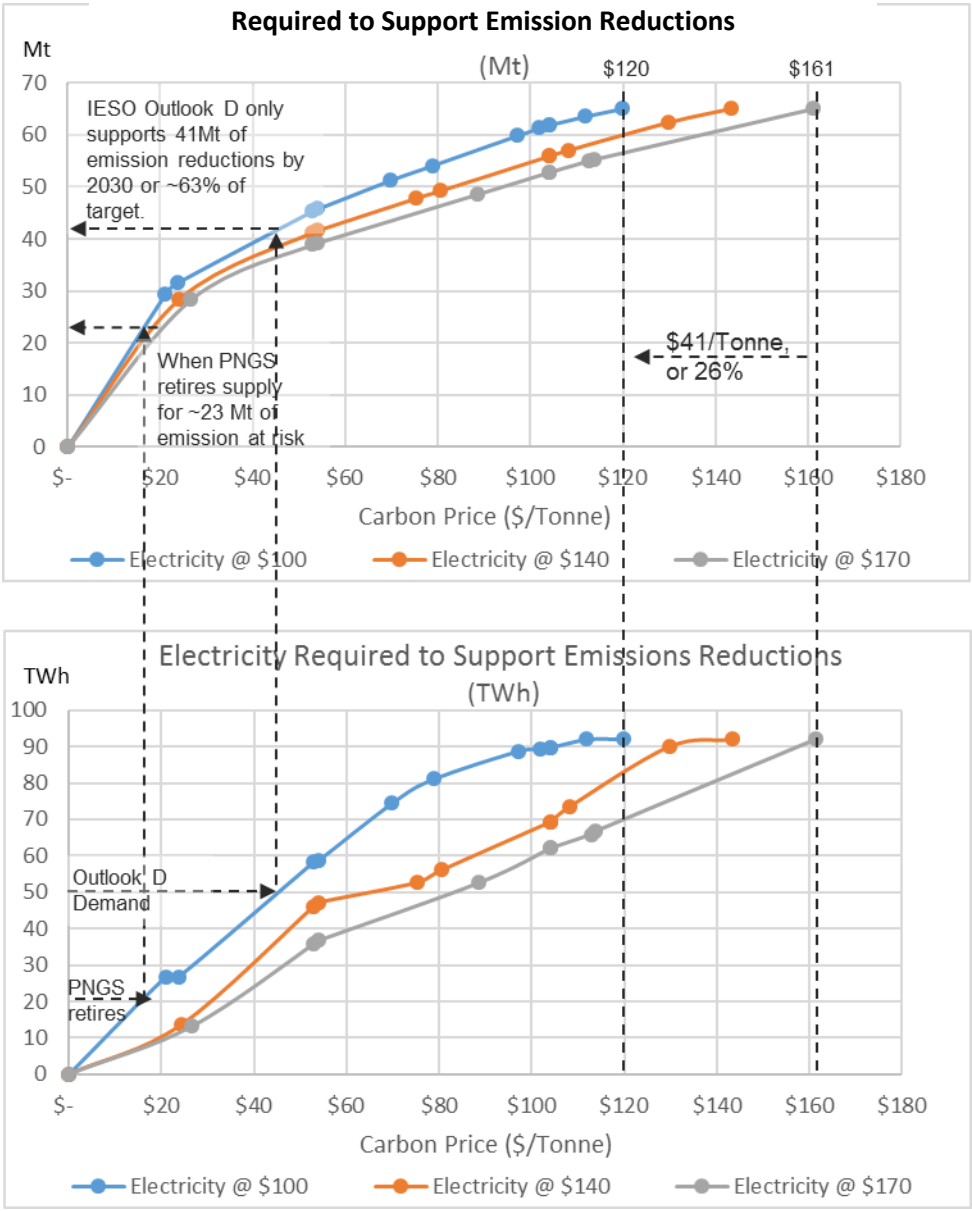
The sum of the C&T proceeds reinvested and the user costs should equal the minimum cost to achieve the emission reduction, if those proceeds are effectively re-invested. The expenses in the administration of the system are a loss to the overall initiative and hence are an additional cost. Ineffective investment of the proceeds and ineffectual administration could result in an increased cost of $10B/year.

Relationship between Electricity Cost and Carbon Price

The cost of electricity can impact the minimum cost required to achieve the emission reductions by reducing the requisite carbon price that makes alternatives economic for users. The cost of electricity can

also affect the success of the emission reduction initiative. The impacts of changing the cost of electricity on electricity supply, emission reductions and the price of carbon is shown in Figure 56.

Figure 56 – Cumulative Emission Savings vs. Electricity Required to Support Emission Reductions



Three scenarios have been modelled to reflect the possible future price of electricity:

1. High cost scenario of $170/MWh
   - This reflects the incremental cost for the large water power projects in Ontario as contemplated by the OPO Outlook D1 scenario.
2. Average cost scenario of $140/MWh

- This reflects both today's average price as well as that forecast average in the OPO Outlook D scenario.

3. Low cost scenario of $100/MWh
   - Reflecting a rounded value below the OPO Outlook D3 nuclear scenario's incremental cost.

Incremental costing is the correct approach for assessing the cost of emission reductions. Incremental costs reflect the matching of costs incurred to the benefits realized. It is the incremental electricity generation capacity that is used to provide the electrification. Other choices can be made but they would reflect pricing strategies not cost recognition.

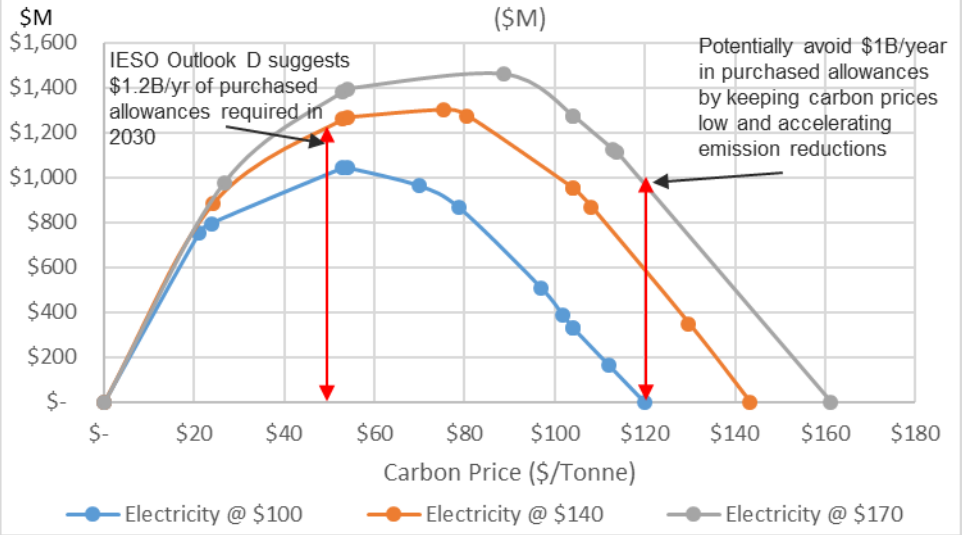
The carbon price and the availability of clean energy are related. With 50 TWh of incremental demand and supply, the OPO Outlook D will only support 41 Mt or ~60% of the targeted reductions, and do so by 2035 not 2030. A $50/tonne carbon price could facilitate the implementation of the required generation.

When PNGS retires, 20 TWh of clean generation will be removed from the system and Ontario's surplus baseload energy will evaporate. Portions of the first 23 Mt of emission reductions achieved by that date may be at risk. New clean generation of similar capacity is required to replace PNGS when it retires in order to support accelerating emission reductions required to achieve Ontario's 2030 target.

The LTEP process should plan to develop the lowest cost generation required to meet 2030 targets.

There is a cost associated with not meeting Ontario's legislated emission targets. This cost results from the need to purchase emission allowances from outside the province. If Ontario fails to reduce its domestically produced emissions, under C&T it can purchase emission allowances from other jurisdictions. It is recognized that Ontario has a greater challenge in meeting emission reductions as it already has a clean electricity system. A clean electricity system is the "low hanging fruit" opportunity in the U.S. and is the focus of their Clean Power Plan. A higher cost of electricity in Ontario will lead to a higher requisite carbon price, making it less likely users will be motivated to switch thereby reducing the emission reduction benefit from the investment of the C&T proceeds. These factors suggest an increasing probability that Ontario's 2030 goals will not be met. Figure 57 illustrates the beneficial impact of lower electricity costs on reducing the cost of purchased allowances from other jurisdictions.

Figure 57 – Carbon Price and Cap and Trade Purchased Allowances



Lower cost electricity could avoid purchasing up to $1B/year of external allowances, a saving that could accelerate the benefit of the use of proceeds towards achieving the targeted emission reductions. Externally purchased allowances of this magnitude are a significant trade balance burden that provides no value to Ontarians. They would represent a potential drain on Ontario's economy and as such are not likely a desired element of a sustainable public policy.

Achieving the Ontario government's legislated emission reduction targets could be advanced by mandating the pace of emissions caps within the C&T program be matched to the pace of the capacity buildout of low cost electricity generation within the LTEP.

7.2. Cap and Trade and the Price of Carbon

In a C&T program, or a carbon tax system, the government has the opportunity to raise funds via a carbon price levy on emitting activities and then to use the proceeds to subsidize desired emission reduction strategies. In a perfectly executed system, the carbon price will be managed to evolve and match the needed subsidies at the time required to achieve the targeted emission reductions. Effectively managing the use of proceeds can optimally reduce the required carbon price.

A C&T system has four cost components:

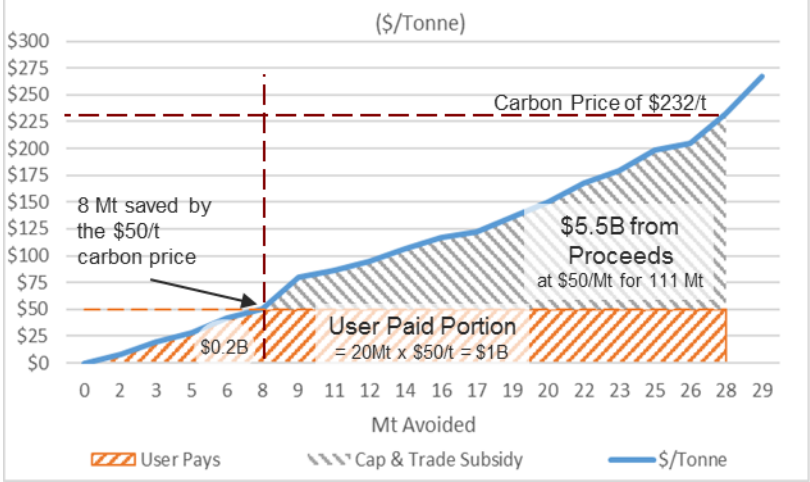
1. C&T proceeds are a cost added to existing energy expenditures.
2. Unsubsidized user costs associated with switching to low emissions technologies.
3. The penalty of not meeting the emission targets, which is manifested as the cost of purchased allowances from outside Ontario. These allowances are not available to subsidize domestic emission reductions.
4. Cost of inefficient government administration.

7.2.1. Cap and Trade Proceeds vs User Cost

C&T proceeds can be reinvested to subsidize the incremental costs of emission reducing technology options that would otherwise require a higher carbon price. C&T proceeds are calculated as the carbon price times the target level of emissions. For an example $50/tonne market carbon price, Figure 58 illustrates the balance between C&T proceeds and user cost. At the targeted 111 Mt of allowed emissions in 2030, a carbon price of $50/tonne will produce $5.5B in proceeds for reinvestment. This assumes no free allowances will be given out in the long run, such as for trade exposed industries. The proceeds would be used to subsidize the technologies that have a breakeven carbon price above $50/tonne.

Technologies will be subsidized until the cumulative required subsidy exceeds the C&T proceeds. In other words, until the proceeds are spent. In the process illustrated in Figure 58, spending of the $5.5B allows for the economic subsidization of any technology that would otherwise require a carbon price of up to $232/tonne.

Figure 58 – Use of Proceeds and Market Carbon Price



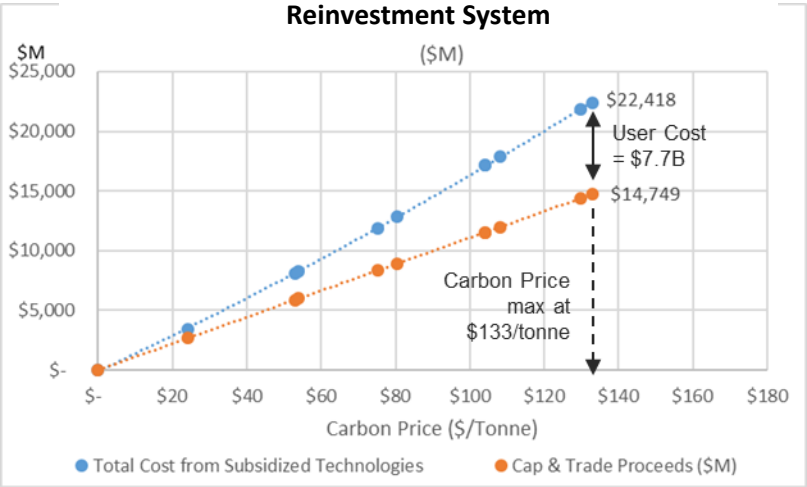
The user paid portion is indicated in Figure 58. The right edge of the grey shaded section reflects the maximum emissions that can be achieved by subsidizing technology options whose equivalent carbon price exceeds the $50/tonne market price level. The maximum achievable emission reduction is limited by the available C&T proceeds, which in this example is $5.5B. By reinvesting the proceeds, the required "Market" carbon price can be reduced, and even high carbon cost solutions can be accelerated.

The market carbon price reflects the cost presented to users. For a given market carbon price, users will make purchase decisions for lowest cost options while also considering of the cost of carbon emissions, e.g. from operating a new gas furnace. As such, options which are economic at, or below the prevailing carbon price will not need a subsidy and the users will effectively be paying for the price of switching away from carbon, and will do so as a matter of course. The orange area in Figure 58 illustrates this user paid portion of emission reduction investments in new technologies. For example, at the market level users will pay $50/tonne x 20Mt, or $1B, plus the amount ($0.2B) for items whose carbon cost is below the market price.

By reinvesting the proceeds to subsidize higher cost options, more emissions reductions can be achieved than at first intimated by the market carbon price.

Applying this methodology to the forty-five identified opportunities for emission reductions in Ontario, the total cost of achievable emission reductions as a function of carbon price is illustrated in Figure 59.

Figure 59 – Cost of Reductions - Perfect Proceed Reinvestment System



For the modelled Ontario situation, the breakeven carbon price for achieving emission reductions is $133/tonne, in lieu of the highest identified required carbon price of over $800/tonne shown earlier. In a perfect system, it would cost Ontario $22B to achieve the emissions target reductions. This total cost cannot be avoided, but the share of the cost is affected by the use of the C&T proceeds:

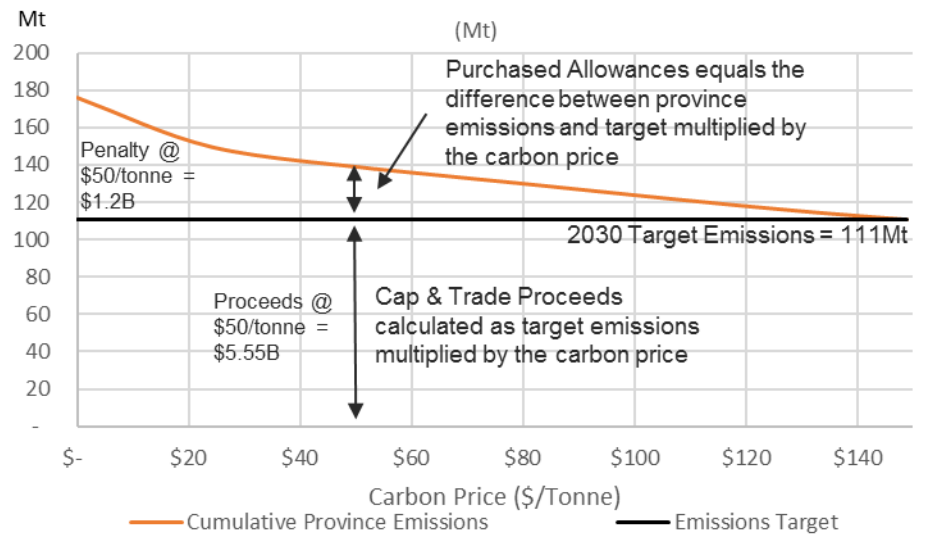
- $14.7B raised through C&T allowances sold at auction, recovered through higher prices charged at the pump or on natural gas energy bills;
- $7.7B in costs borne by consumers choosing to switch to low carbon solutions.

7.2.2. Aligning Targets with Enablers

Aligning targeted emissions with achievable results minimizes the "penalties" that arise in the form of allowances purchased from other jurisdictions. As described in the background section of this document, such purchases are expected by the government until at least 2020.

The "penalty" for not achieving emissions reductions is unique to the C&T program. This mechanism and the relationship to Ontario's emission reduction forecast are illustrated by Figure 60.

Figure 60 – Carbon Price and Purchased Allowances

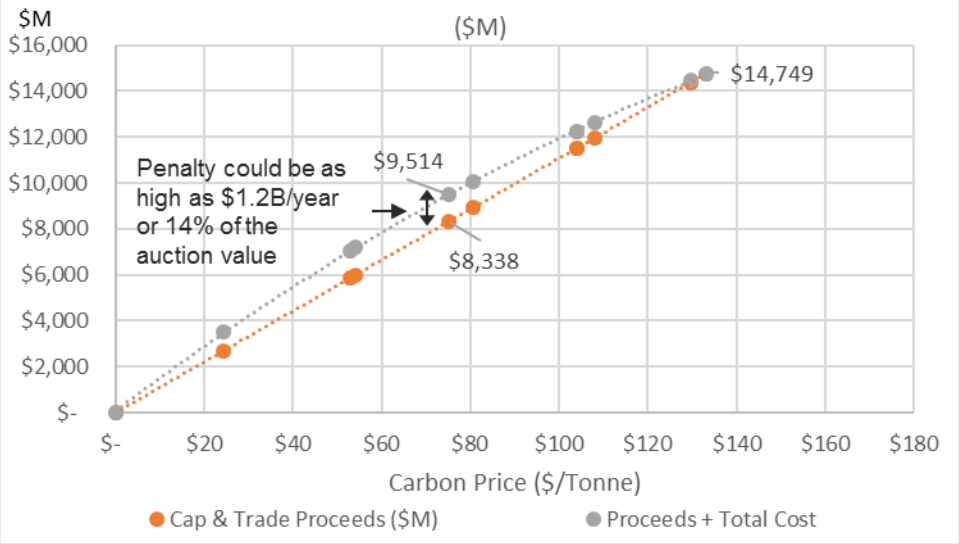


These purchased allowances are a penalty to the provincial economy, in that these costs leave the province in the form of revenues for the other jurisdiction and cannot be used as proceeds to offset further carbon abatement initiatives. Under a carbon tax system, the proceeds would remain in the province for use in abatement strategies. Under this scenario, Ontarians will pay for this economic leakage simply because the government's targets were not met.

The need for purchasing allowances from other jurisdictions arises from the cap setting process. In Ontario, the 2030 emissions "cap" has been legislated to be 111 Mt. In order to comply with this limit, for every tonne of emissions in the province that exceed this cap, allowances will have to be purchased at the prevailing carbon price. The costs of these allowances are inevitably borne by Ontarians as the majority of emissions in the province are associated with heating fuel and gasoline. The recovery of these costs will appear at the pump or on the home natural gas energy bill. For example, the natural gas carbon costs are regulated by the OEB by applying rate increases on the home energy bill. This ensures that the costs are recovered by Ontario's utilities who will be making the allowance purchases.

The cost of this "penalty" is a function of achieving the target as shown in Figure 61.

Figure 61 – Cost of Purchased Allowances When Targets Not Met



At $75/tonne, the purchased allowances could represent $1.2B that leaves the province. If the 2030 emission target is achieved, at the market carbon price of $133/tonne shown in Figure 59, there is no "penalty".

7.3. Cost Risks of Administration of the use of C&T Proceeds

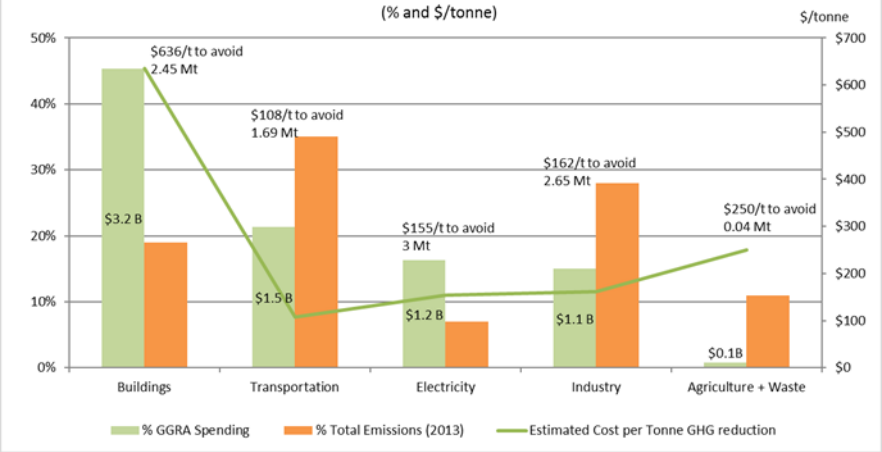
Governments have accountability for the effective administration of the proceeds generated from their programs. Carbon price programs where the government has discretion over the use of proceeds, allows the cost of emission reductions to be spread across the economy and have the inherent potential to lower the market carbon price needed to achieve the objectives.

Achieving the emissions reductions at the lowest cost identified is contingent upon the effective use of the proceeds by the government. The proceeds would have to be exclusively applied as subsidies to the optimal emission displacing solutions to achieve the minimum cost.

By its very nature, the cost of the approach is dependent on the effectiveness of the government at directing the use of proceeds to achieve emission targets for Ontario. The current Ontario CCAP is an example of how the Ontario government may apply the proceeds of the C&T program. Within the CCAP, targeted number of areas and actions have been identified for using the proceeds over the next 4 years. The stated purpose is to encourage emission reduction in various sectors of the economy and to achieve certain emission reduction targets.

Figure 62 compares Ontario's expected CCAP 2020 emissions reductions by sector to the associated portions of the $8.3B in expected GGRA funding dedicated to lowering those emissions.

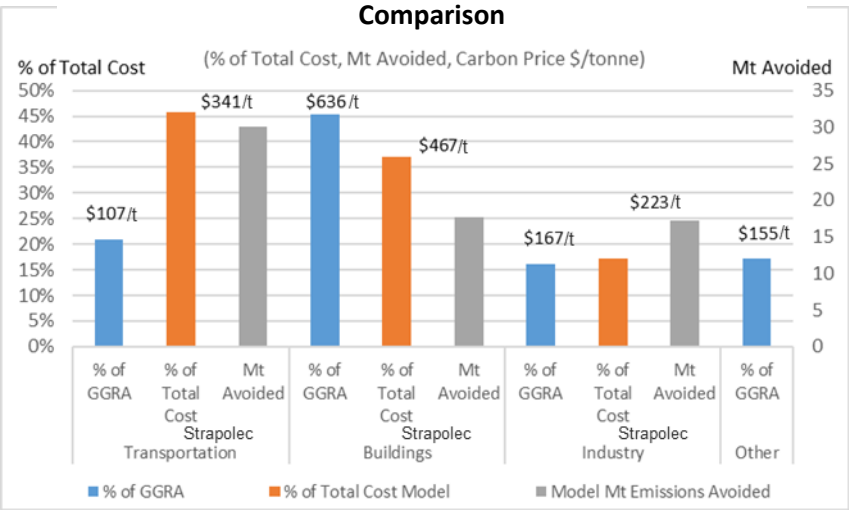
Figure 62 – Ontario 2013 Emissions, GGRA Spending and Cost of GHG Reduction by Sector



Although the building sector is the third largest source of emissions in Ontario, the CCAP dedicates the highest amount of funding to this sector (45% of GGRA funds) to avoid 1.69 Mt of emissions at an expected cost of $636/tonne. Twenty-one percent (21%) of the GGRA funding is dedicated to the transportation sector to avoid 2.45 Mt of emissions at an expected cost of $108/tonne. Sixteen percent (16%) of the GGRA funds have been dedicated to the electricity sector to avoid 3 Mt of emissions at an expected price of $155/tonne. Fifteen percent of the GGRA funds will contribute to avoiding 2.65 Mt of emission in the industrial sector at an expected price of $162/tonne.

Administration costs can arise simply from a misalignment of the optimal solutions. Figure 63 compares the distribution of funds within the GGRA to the priorities suggested by the modelling in this study. The associated implied carbon prices have been noted for the purpose of comparison.

Figure 63 – Sector Emission Saving and Cost – GGRA Comparison



Compared to the findings of this study, the planned GGRA has; (1) Lower than expected spending in transportation at a much lower than required carbon price ($107/tonne vs $341/tonne); (2) A greater share of government spending in the building sector at a higher than necessary carbon price ($636/tonne vs $467/tonne); and (3) An approximately equivalent emphasis on the industrial sector, but with lower than needed equivalent carbon pricing.

An allocation of the costs to electricity bills may not be the most effective tool on its own without a focus on targeted funding for specific initiatives that systemically support fuel switching from fossil fuels to low-carbon electricity. However, the CCAP program must, out of necessity, serve political objectives as well. The example evident in the spending is the use of proceeds to offset the general cost of electricity. This expenditure is defined as "*Keep Electricity Rates Affordable: Use cap and trade proceeds to offset the cost of greenhouse gas pollution reduction initiatives that are currently funded by residential and industrial consumers through their bills*.[84]" While subsidizing electricity costs can be rationalized as an administratively simple mechanism to support electrification, there are two inherent inefficiencies: 1) the benefits are thinly spread resulting in some consumers pocketing the savings instead of using it to reduce emissions; and (2) it offsets costs that are already assumed to be spent in establishing the BAU assumptions. At up to ~$1.2B, this element of the CCAP is ~14% of the expected GGRA funds.

Likewise, funding initiatives to make buildings more energy efficient may reduce GHG emissions, but cannot eliminate them. The more direct and efficient action may be to switch energy sources from fossil fuels to low-carbon electricity. It is reasonable to assume that a perfectly efficient application of the use of proceeds is not likely possible in any system and so scenarios of effectiveness have been developed to illustrate the potential impact.

Two scenarios are created to illustrate the potential impact for Ontarians resulting from the government's performance at directing the use of proceeds:

1. 10% of the proceeds are incurred for administrative purposes
    - There also unavoidable inefficiencies in the system and this scenario is offered as the most reasonable best case assumption.
2. 50% of the proceeds are reinvested
    - This would reflect the directional use of the proceeds towards less effectual policies or investing in solutions that prove to be less cost effective or do not get adopted. A 50% inefficiency assumption could be viewed as an unreasonably high cost outcome and is offered as an upper bound.

The results of these assessments are shown in Figures 64 and 65, respectively. The impact of government effectiveness at directing the use of proceeds carries a 50% cost risk, and could lead to an additional $10B/year in emission reduction costs.

[84] MOECC CCAP

There are two consequences from inefficient administration of the C&T program: (1) The cost of the program would increase proportionately to the inefficiency; and (2) The breakeven market carbon price would drift upwards reflecting less funds being available to subsidize higher cost emission reduction strategies.

The C&T program could cost between $24B/year and $34B/year by 2030 depending on the effectiveness of the governance. By comparison a perfect system cost would be $22B/year. The breakeven carbon price for meeting emissions targets could go up from the perfect system value of $133/tonne to $210/tonne under a misuse of funds scenario. It is the higher carbon price component that drives up the total cost.

Figure 64 – Cost of Cap and Trade with 10% System Inefficiency

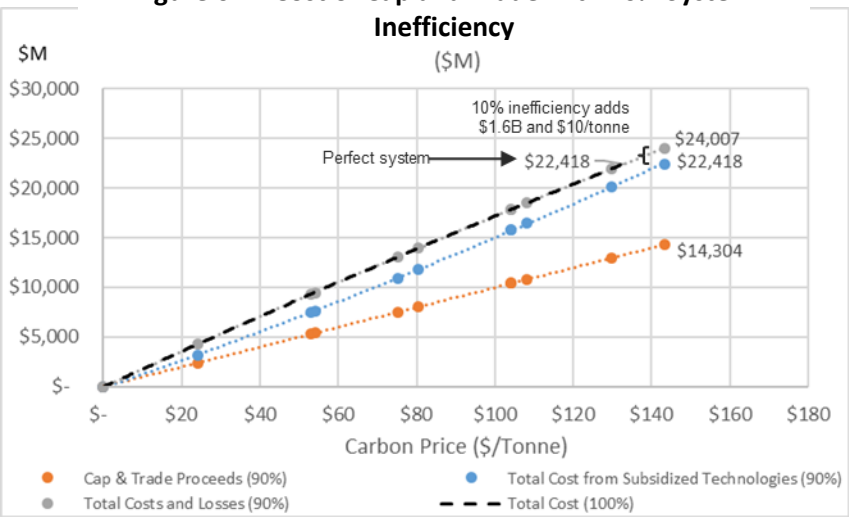
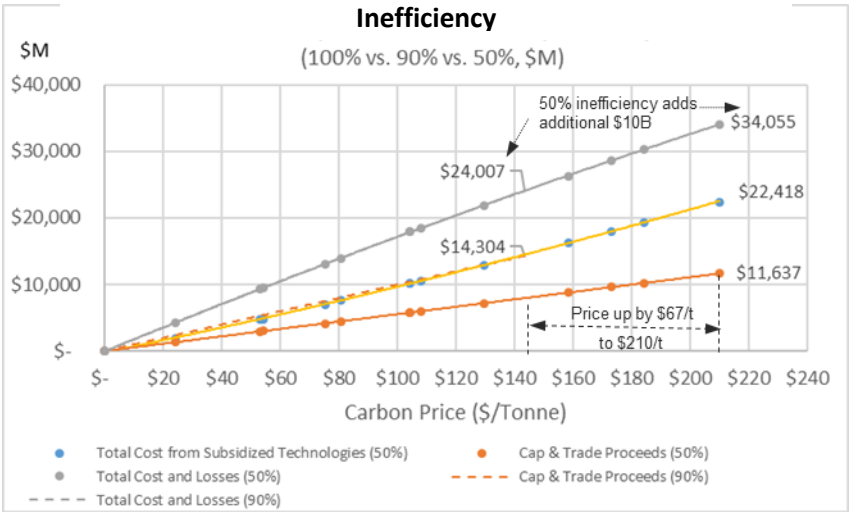


Figure 65 – Cost of Cap and Trade with 50% System Inefficiency



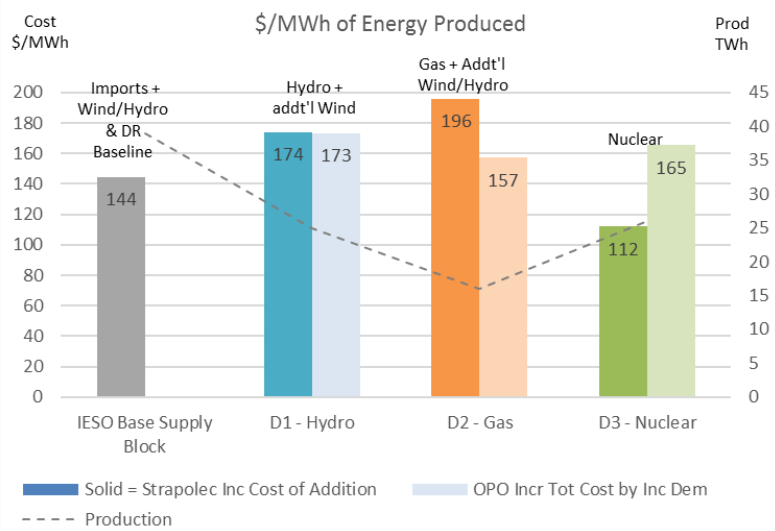
If the jurisdictional realities of Ontario's cost to decarbonize are driven by government policies and these costs become higher than neighboring jurisdictions, Ontario will likely face some difficult economic challenges. The carbon price differential can be a critical factor.

Strapolec suggests that the best mitigation for risks associated with the ineffective application of the C&T proceeds is transparency, fact-based decision making, and establishing an independent, arms-length process for managing the proceeds.

7.4. Low Cost Electricity and the LTEP

The cost of new electricity generation can have a large impact on the market carbon price and emission target achievement. The IESO provided an outlook of future electricity costs for various scenarios in the OPO. While the OPO tables for each scenario suggest similar cost outcomes, a deeper analysis shows that significant incremental cost differences exist among options. There are uncertainties within the data that Strapolec could not resolve in the time available. As a reference for bounding the electricity cost scenarios, Figure 66 illustrates estimates of the incremental costs associated with the capacity options included in the OPO Outlook D.

Figure 66 – OPO Outlook D Incremental Supply Cost



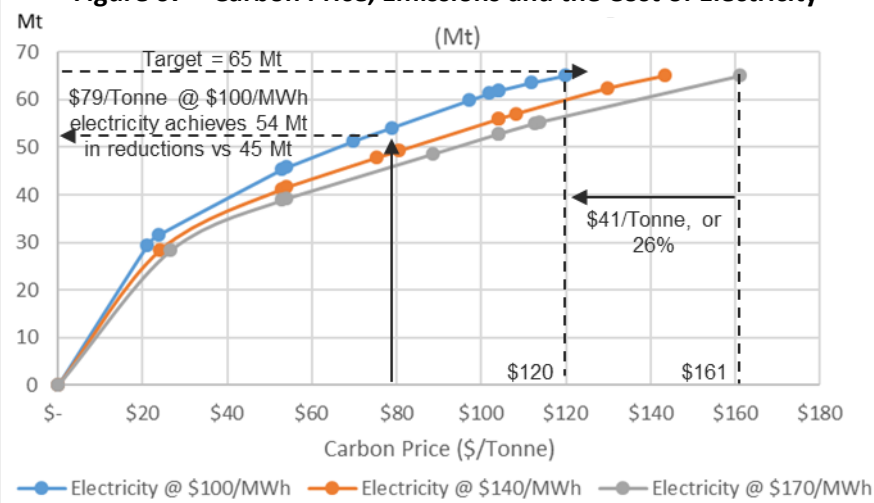
The incremental cost of the new generation has been calculated using two methods:

- OPO Outlook incremental total cost divided by incremental total demand
  - The results of method represents the incremental cost of the total additional supply of each option, including the production costs from the Base Supply Block of the entire electricity system after new capacity costs are added to existing system costs.
- Incremental cost of the capacity differences between the options (as added to the base supply common to all options) divided by the incremental production from that capacity difference

- This method estimates costs for each incremental supply type using the OPO stated cost assumptions for each of the Outlook D scenarios.
- The estimate of $144/MWh for the base supply block is the average cost of the full production from the base supply block capacity that is included in all the OPO Outlook D capacity options shown.
- The cost estimates used in this method consider related incremental transmission costs defined in the OPO, demand response (DR), changes in natural gas-fired generation output from existing assets, and accommodations for a carbon price on natural gas-fired generation.

The resulting estimates of electricity cost range from $112/MWh to $196/MWh for incremental new supply. To assess the impact of electricity cost on the of cost emissions reduction three scenarios were run: (1) Nominal case with expected average electricity costs of $140/MWh; (2) Low case at $100/MWh; and (3) High case at $170/MWh. The results are shown in Figure 67.

Figure 67 – Carbon Price, Emissions and the Cost of Electricity



At an average incremental electricity cost of $100/MWh, meeting the 65 Mt emission reduction target could be achieved with a 26% lower carbon price of $120/tonne as opposed to the $161/tonne needed to achieve the same reduction target at an electricity cost of $170/MWh.

The ability to achieve emission reduction targets is affected by the carbon price relationship to electricity cost. At an electricity cost of $100/MWh, a carbon price of $79/tonne would achieve 85% of the provincial emission reduction target. Conversely, at a higher electricity cost of $170/MWh, a carbon price of $79/tonne would achieve only 70% of the provincial target.

It is clear that the lower the cost of electricity, the lower the required carbon price to achieve emission reductions. This in turn implies that switching to low emission applications will become economic earlier. The sooner these applications are economically switched to low carbon options, the further the use of proceeds can be broadened. It is therefore important to achieve lower electricity costs.

The impact of electricity cost on the purchase of external allowances was discussed at the beginning of this chapter.

7.5. Summary

The analyses conducted in this study suggest that the total cost of emission reductions may be as high as $27B/year, unless low-cost sources of electricity are pursued. C&T proceeds of $16B/year could subsidize many new initiatives, but consumers will also face additional costs of approximately $9B/year for unsubsidized spending on low carbon emitting options. The cost of government administration of the use of C&T proceeds could be $2B/year.

Carbon price is dependent on both the cost of electricity as well as an effective and efficient process for reinvestment of C&T proceeds. A low-cost electricity system can save Ontario an estimated $6.9B/year. Low cost electricity can also save up to $1B/year in externally purchased allowances, accelerating the benefit of the use of proceeds to achieve emission reductions.

Reinvesting the C&T proceeds to fund emission reducing technologies can drastically lower the carbon price required from over $800/tonne to $133/tonne in a perfect system, or $210/tonne in an imperfect system with 50% inefficiency. Accelerating emission reductions with lower carbon prices through the use of C&T proceeds reduces the risk of needing to purchase over $1B/year in emission credits from other jurisdictions.

An inefficient use of C&T proceeds and/or ineffective governance could result in Ontarians paying an additional $10B/year to achieve the reduction goals. Administration of proceeds has the greatest potential for unproductively increasing the costs of emission reductions, a circumstance for which the government is obliged to take accountability and which can be best met by minimizing political influence on the use of the sizable funds that will emerge from the C&T program.

8.0 Recommendations and Further Work

The future demands on Ontario's electricity system resulting from the province's emissions reduction targets, combined with incentives to direct the new demand towards lower cost off-peak hours, will culminate in a need to secure sources of new low-carbon baseload capability and flexible seasonal winter supply.

Six recommendations to effectively achieve Ontario's emission reduction targets and objectives at the lowest cost have emerged from this study:

1. 90 TWh of new demand requires a decision at the earliest stage in the LTEP process for commitment to low-cost, emission-free generation options.
   - Forecast new demand for electricity is primarily for home heating and industrial baseload applications. This is 80% greater than the 50 TWh presented in the OPO Outlook D and 60% more than is consumed today.
   - Meeting 2030 emission targets depends on supplying this new demand with new generation. The timing for this consideration is not reflected in the OPO. Maximizing the safe economic life of the Pickering Nuclear Generating Station (PNGS) can support the transition.

2. Low cost electricity choices should be prioritized by the LTEP to reduce the cost of carbon emission reduction initiatives. Low cost electricity choices could reduce this cost by up to 25% or $7B/year.
   - With OPO Option D1, adoption of carbon emission reduction initiatives could potentially add costs of up to $27B/year to how Ontarians use energy, depending on the cost of electricity and the effectiveness of administrating the use of C&T proceeds. This cost could be reduced by the above mentioned 25%. The components contributing to the additional costs are:
     - Expected required carbon pricing within the C&T program would account for 60% or $16B/year of these costs which are to be directed towards subsidizing emission reduction initiative adoption;
     - As Ontarians make low emission choices, they will invest $9B/year to cover the unsubsidized portions of such things as new building heating equipment; and
     - Another $2B/year could be incurred by the administration and implementation of the C&T processes and dispensation of C&T proceeds.
   - The estimated carbon price required to achieve the 2030 targets ranges from $120/tonne to $210/tonne, also depending on the cost of electricity and the effectiveness of administrating the use of C&T proceeds.
     - Low cost electricity supports a carbon price of $120/tonne. The IESO has identified nuclear as the lowest cost option in the OPO.

3. The nature, breadth, and diversity of emission reduction options available to Ontario oblige the LTEP process to fully and transparently integrate emission targets, climate actions, electricity planning, and fossil fuels strategies.
   - Section 5.1.1 clearly establishes that time is of the essence in developing the electricity system that will allow for fuel switching to occur. The LTEP should prioritize identifying the *quickest route* to available large scale low emission electricity generation. This will enable achieving the maximum emission reductions by 2030 and to facilitate the emission reduction ramp to 2050.
   - Section 7.2 presented several views of the OPO Outlook costs that express which supply options carry the higher costs. To secure the support of Ontarians in bearing the costs of combatting climate change, the

LTEP should establish a publicly transparent evidence base supporting the most reliable, lowest cost electricity solutions, including generation, transmission, distribution, and the integration thereof. Clear full cost decision making could potentially save Ontarians up to $7B/year.

- Section 5.1.1 summarized how the different needs for electricity that will be driven by remission reduction options will point to the need for different types of supply. Some options require greater baseload capacity, some flatten seasonal demand and others create seasonal peaks, while others increase over night energy requirements, flattening the daily profile. The LTEP should explicitly recognize and address how emission reduction options may change the demand profile and best match cost effective supply options to those future needs.
- There are many emission reduction options identified by stakeholders, as summarized in Section 3.3, that may be unique to Ontario's circumstance. These may be opportunities to leverage existing Ontario advantages, such as the interplay between nuclear, hydrogen and demand response, that could enhance Ontario's innovation capabilities and international competitiveness.

4. Ontario's climate strategy initiatives should be integrated with the LTEP to match the pace of C&T emissions caps with the pace at which new electricity generation capacity can be built and alternative fuels provided.
   - Aligning emission targets to the availability of electricity and/or alternative fuels will minimize the likelihood that provincial targets will be missed.
   - This recommendation stems from the observation in Section 5.1.1 that, to meet the legislated emission reductions of 37% below 1990 levels by 2030, more new generation is needed than can likely be supplied by 2030.
   - This recommendation could moderate the pace at which carbon prices increase to reflect realistic emissions objectives, give certainty to Ontario's residents and businesses regarding how their energy costs will rise; and moderate the rise in energy costs until the affordable electricity required by alternatives can be made available. Missed emission targets caused by lack of generation could cost ~1.2B/year in C&T allowance purchases from other jurisdictions. Realistic achievable emission reduction targets will avoid the circumstances causing unnecessary purchases of allowances from outside the province as described in Section 7.0.
5. Rigorous attention should be paid to the effective and efficient management of C&T proceeds use.
   - An effective program can accelerate emission reductions, get the carbon price much below $210/tonne, minimize the cost to Ontarians through effective subsidization programs. There is the potential of a $10B/year risk associated with ineffective policies.
   - Section 7.0 provides an detailed examination of how carbon price, electricity price, and government administration of proceeds can affect the cost to Ontarians. Administration of proceeds has the greatest potential for unproductively increasing the costs of emission reductions, a circumstance for which the government is obliged to take accountability and which can be best met by minimizing political influence on the use of the immense funds that will emerge from the C&T program.
   - A transparent evidence based process that considers all potential emission reduction technologies, such as hydrogen and nuclear, could lead to significant economic and competitive advantages for Ontario. Hydrogen generated with the lowest cost nuclear energy has emerged as among the most economical emission reduction options assessed in this study as described in Section 6.1.
   - The effective use of C&T proceeds could make options economic at $120/tonne that would otherwise require a carbon price of $800/tonne.

6. The integrated LTEP and climate strategy should consider the pathway to 2050 for deep decarbonization.
   - This report has been focussed on assessing what is involved in meeting the 2030 targets. It is unlikely that the infrastructure c an be cost effectively built by 2030 to meet the challenge that has been established. Furthermore, the challenge only continues to rise as double the emissions reductions are needed between 2030 and 2050 to meet the 2050 target of 80% below 1990 levels.
   - The OPO, FTR and Section 5.1.1 of this report clear establish that the 15 years to 2030, or even the 20 years to 2035, is insufficient time to prepare Ontario to achieve the emission reduction objectives set for 2030.
   - Electricity generation options that cannot be implemented by 2030 will still need to be planned for in the current LTEP process to enable the availability of these options after 2030 or after 2035. To meet the electricity demand growth from emissions reduction initiatives that are anticipated in the future, the long lead nature of these significant infrastructure projects obliges the LTEP to consider the longer-term pathway beyond the 20-year window to 2035 that currently defines the LTEP planning horizon.

Further work

The next report to be produced by Phase 2 of this study will examine the implications on supply that the new electricity demand necessitates, assess the costs and implementation considerations of the supply mix options put forward in the OPO, as well as alternatives, and describe the cost, schedule achievability, and economic implications to Ontarians associated with those choices.

Acknowledgements

This study was conceived of and proposed by Strategic Policy Economics to fill a perceived void in transparent evidence based materials. Strategic Policy Economics deemed it fundamental to a successful LTEP consultation that this void be filled to best serve the interest of Ontarians.

Overview of Strategic Policy Economics

Founded by Marc Brouillette in 2012, Strategic Policy Economics helps clients address multi-stakeholder issues stemming from technology based innovations in policy-driven regulated environments. The consultancy assesses strategic opportunities related to emerging innovations or market place conditions and identifies approaches that will achieve positive benefits to affected stakeholders. Strategic Policy Economics specializes in framing strategic market, science, technology and innovation challenges for resolution, facilitating client teams in determining their alternatives, developing business cases and business models, and negotiating multi-stakeholder public/private agreements. Marc has worked directly with federal and provincial ministries, crown corporations and regulators, as well as with the private sector, municipalities, and non-profit organizations.

The Strategic Policy Economics team deployed to develop this report included Marc Brouillette, Scott Lawson, and Andisheh Beiki.

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- Michael Fowler, Professor of Chemical Engineering at the University of Waterloo, specializing in alternative fuels and the hydrogen economy
- Paul Acchione, former chair of the Ontario Society of Professional Engineers (OSPE)
- Paul Newall of Newall Consulting Inc.

The Strategic Policy Economics team hopes this report provides a constructive contribution to the LTEP process.

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Appendix B - List of Abbreviations

AD – Anaerobic Digestion/Digester
AEO – Annual Energy Outlook
ASHP – Air Source Heat Pump
BAU – Business as Usual
Bcf – Billion cubic feet
BEV – Battery Electric Vehicle
C&T – Cap and Trade Program
CAD – Canadian Dollar
CAGR – Compound Annual Growth Rate
CCAP – Climate Change Action Plan
CO_2 – Carbon Dioxide
COP – Conference of Parties
CPP – Clean Power Plan
DOE – U.S. Department of Energy
EIA – U.S. Energy Information Administration
EPA – U.S. Environmental Protection Agency
EV – Electric Vehicle
FCEV – Fuel Cell Electric Vehicle
FTP – Fuels Technical Report
GDP – Gross Domestic Product
GGRA – Greenhouse Gas Reduction Account
GHG – Greenhouse Gas
GJ – Gigajoule (10^9 joules)
GSHP – Ground Source Heat Pump
GW – Gigawatt
GWh – Gigawatt Hour (one billion watts being produced for 1 hour)
HD – Heavy Duty
HVAC – Heating, Ventilation and Air Conditioning
ICE – Internal Combustion Engine
IESO – Independent Electricity System Operator
INDC – Intended Nationally Determined Contribution
Kt – Thousand Tonnes – also referred to as kilotonnes
kWh – Kilowatt hour (one thousand watts being produced for 1 hour)
L – Litre (one thousand mL)
LTEP – Long-Term Energy Plan
mmBTU – million British Thermal Unit
MMSCFD – million standard-cubic-feet-per-day
MoE – Ministry of Energy
MOECC – Minister of Environment and Climate Change

MSW – Municipal Solid Waste
Mt – Megatonne (equal to one million tonnes)
Mt CO2e – Megatonnes Carbon Dioxide equivalent
MW – Megawatt
MWh – Megawatt Hour (one million watts being produced for 1 hour, enough to power ten thousand 100W light bulbs for one hour)
NG – Natural Gas
NIR – National Inventory Report
NRCan – Natural Resources Canada
NREL – National Renewable Energy Laboratory
OEA – Ontario Energy Association
OEB – Ontario Energy Board
OPG – Ontario Power Generation Inc.
OPO – Ontario Planning Outlook
OSPE – Ontario Society of Professional Engineers
P2G – Power to Gas
PHEV – Plug-in Hybrid Vehicle
PJ – Petajoule (10^{15} joules)
PNGS – Pickering Nuclear Generating Station
RNG – Renewable Natural Gas
SBG – Surplus Baseload Generation
SCGT – Simple Cycle Gas Turbine
SMR – Steam Methane Reforming
SSO – Source-separated organics
t – Tonne (1,000 kg)
TJ – Terajoule (10^{12} joules)
TWh – Terawatt hour (one trillion watts being produced for 1 hour)
Tx – Transmission
U.S. – United States of America
WACC – Weighted Average Cost of Capital
WCI – Western Climate Initiative
WWTP – Waste Water Treatment Plant

Contact Information

Strategic Policy Economics

Marc Brouillette
Principal Consultant
(416) 564 - 4185
marc@strapolec.ca
www.strapolec.ca