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ECONOMIC AND ENVIRONMENTAL IMPACTS OF METHANE EMISSIONS REDUCTION IN THE NATURAL GAS SUPPLY CHAIN

ECONOMIC AND ENVIRONMENTAL IMPACTS OF METHANE EMISSIONS REDUCTION IN THE NATURAL GAS SUPPLY CHAIN

Economic and Environmental Impacts of Methane Emissions Reduction in the Natural Gas Supply Chain

Readers Note: This is a revised report to correct several data sources.

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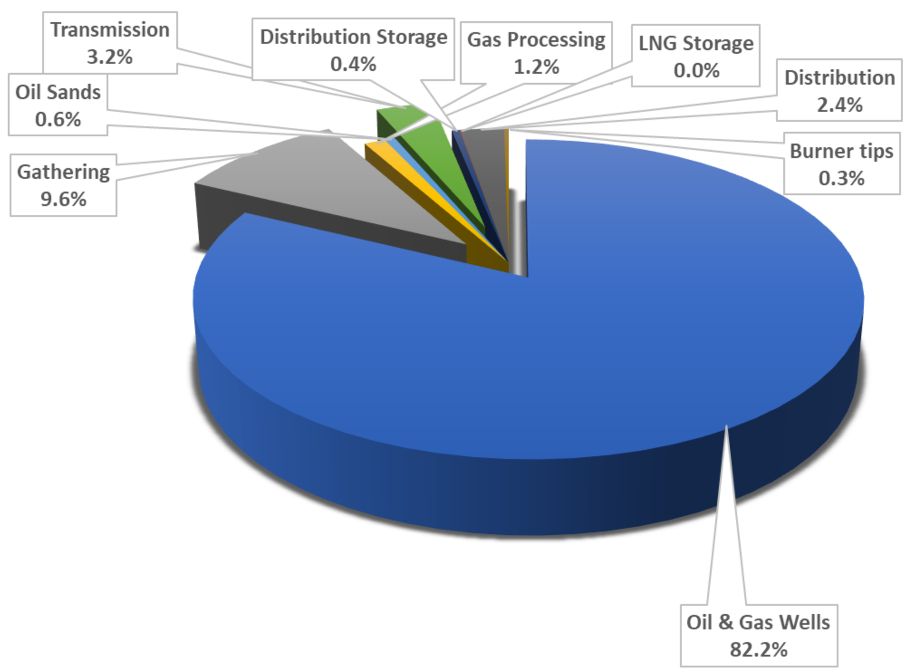
Executive Summary

The Canadian government, along with some provincial governments, have set policies to cut methane emissions from between 40-45% of baseline value by the year 2025. Baselines might differ between governments, but the overall targeted reductions by Canada are about 25 Mt CO_2e of methane emissions by 2025. The gas supply chain can be broadly divided into upstream, midstream and downstream sectors where sources of methane emissions are identified, and mitigation technologies are assessed from wellhead to burner-tip. Methane emissions from the sectors can be further grouped into source categories such as fugitives,[i] flared,[ii] vented,[iii] line heating,[iv] and burner-tip.[v]

In line with the ongoing debate on the economic and environmental impacts of methane emissions from natural gas supply chains, the Canadian Energy Research Institute (CERI) developed a modelling tool, the Integrated CH_4 Emission Reduction Model (ICERM), with the objective to quantify methane emissions and assess reduction opportunities covering end-to-end of the Canadian natural gas supply chain. CERI used ICERM to quantify methane emissions from the Canadian natural gas supply chain in 2017 to be 40.4 Mt CO_2e. Figure E.1 details the emissions along the entire value chain for natural gas.

Figure E.1: Overall Canadian Methane Emissions from Natural Gas Supply Chain Sources



[i] A leak or unintentional release of methane emissions
[ii] Undestroyed methane at upstream sector from gas flaring due to incomplete combustion
[iii] Methane released intentionally to the atmosphere at upstream, midstream or downstream sector
[iv] Undestroyed methane at midstream sector from stationary combustion due to incomplete combustion
[v] Undestroyed methane at downstream end-user burners due to incomplete combustion

Western provinces with more upstream oil and gas activities generate more emissions than eastern provinces where natural gas demand may be high but supplied from other provinces. Alberta contributes more emissions than other provinces with an estimated total in 2017 of about 24.5 Mt CO_2e, of which the upstream sector is responsible for up to 97% of this number. These emissions are mainly from oil and gas wells and gathering facilities. The oil and gas wells emissions include methane emissions from all equipment at the wellhead and field operations. Like Alberta, the other western provinces (British Columbia, Saskatchewan and Manitoba) have higher upstream emission footprints with total estimated values of 2.2, 11.7, and 0.8 Mt CO_2e, respectively.

The optimization module in ICERM combines emission quantification and abatement cost data to evaluate emission reduction and economic impacts of various policy scenarios. This study evaluated three different hypothetical policy scenarios to achieve emission reductions by adopting various combinations of mitigation technologies. These scenarios are:

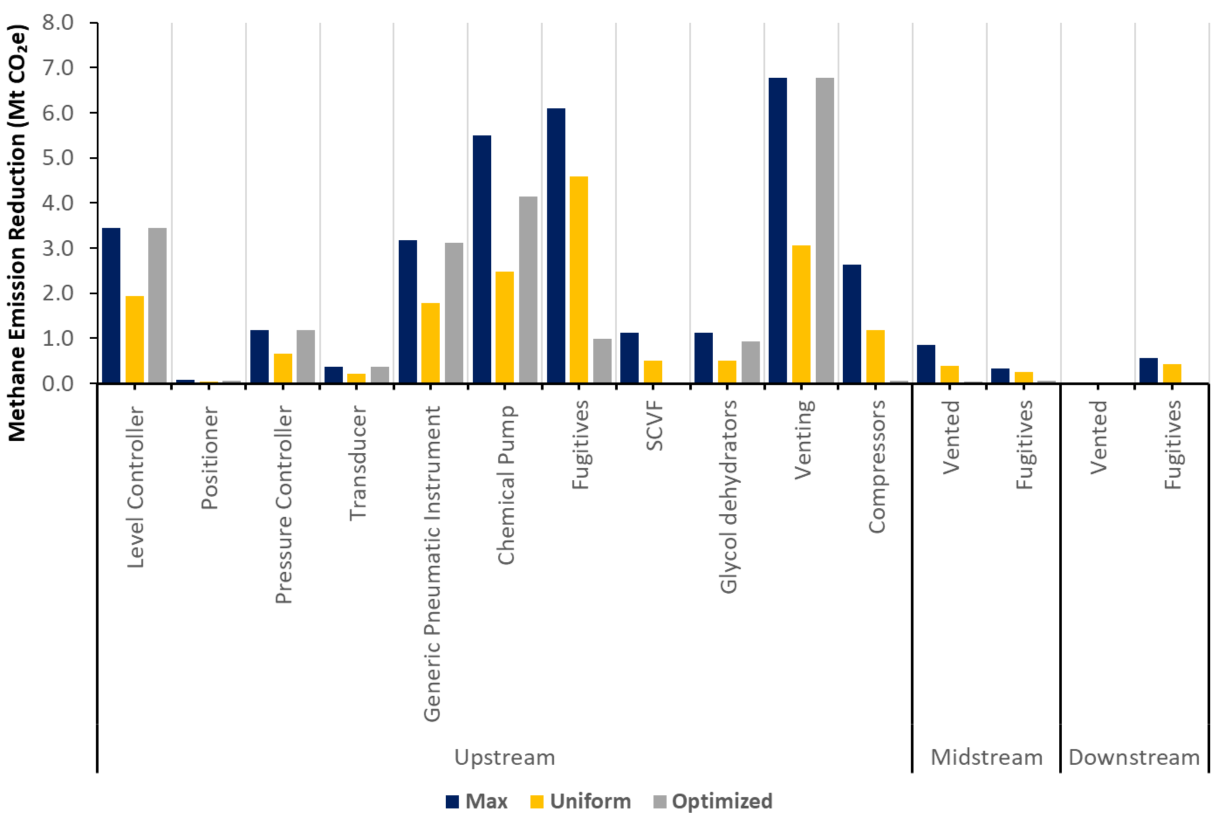
- **Maximum reduction**, which evaluated the economic cost and the maximum amount of emission reduction that can be achieved using the mitigation technologies assessed in this study.
- **Uniform reduction**, which evaluated the economic cost and emission reduction achieved if a 45% reduction target is assigned to each emitting device in the supply chain (except burner-tip emissions).
- **Optimal reduction**, which identifies a cost-effective mitigation pathway to reduce emissions to 45% of baseline levels as reported in the National Inventory Report (this scenario is created to mimic methane regulations in Canada).

These scenarios are applied to the entire Canadian natural gas supply chain. This contrasts with the existing federal and provincial regulations which place methane emission reduction targets mainly in the upstream sector. Figure E.2 shows methane emission reductions from each supply chain sector and emitting devices for the entire Canadian natural gas supply chain under the three hypothetical policy scenarios. In order to realize the most economic reductions in the optimal scenario, some of the emission source categories are omitted when choosing where mitigation should be deployed. These include emissions from midstream venting, upstream fugitives, compressors and surface casing vent flow. Optimal emission reduction is calculated from the average of the results obtained using the lower and upper ranges of the abatement costs. This scenario does not arbitrarily specify what emission sources should be controlled but uses linear programming to determine the cost-effective mitigation to meet expected reduction at both federal and provincial levels. For provinces with existing methane emissions regulations (such as British Columbia, Alberta, and Saskatchewan), the optimal scenario specifies methane emission reduction targets according to provincial baselines as reported in the National Inventory Report. For other provinces, federal methane regulation baseline year (2012) emissions are adopted.

Reductions in the maximum and uniform scenarios are predominantly from upstream venting, fugitives and pneumatic pumps. In the optimal scenario, reductions are mainly from upstream venting and pneumatic devices including pumps, controllers and generic instrumentation. Figure E.2 allows close comparison of emission reductions from each emission source category under the hypothetical policy scenarios. At the provincial level, optimal (45%) reduction of emissions is based on contributions to total Canadian methane emissions during 2012.

According to Figure E.2, mitigation of emissions from surface casing vent flow (SCVF) and compressors are not done in the optimal adoption scenario due to their higher abatement costs. Most emission reduction opportunities are identified from pneumatic, venting and fugitive sources under each mitigation scenario. Also, in line with the distribution of overall emissions across supply chain sectors, the upstream sector is the major source of the emissions where significant mitigation efforts are to be channelled to achieve deeper cuts in emission reductions.

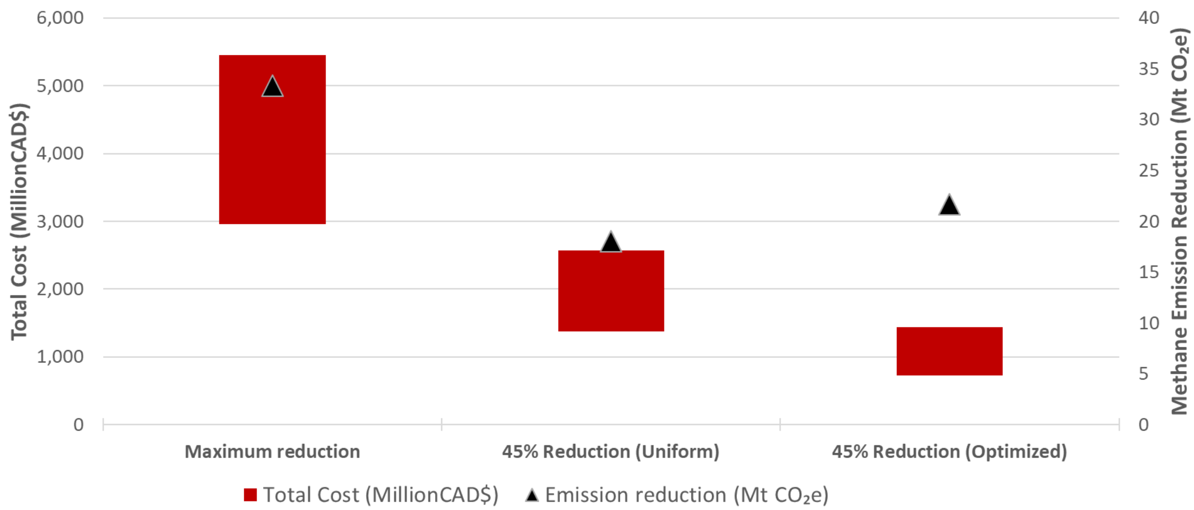
Figure E.2: Methane Emission Reduction from Various Emission Source Categories under the Three Hypothetical Policy Scenarios for Canada



Notes:
1) Each colour represents a hypothetical policy scenario. 2) Venting in this figure refers to non-routine, whereas routine venting is presented in terms of the emitting devices.

Figure E.3 presents a results summary showing total emission reductions and cost of achieving those reductions under the various abatement analysis scenarios for the entire Canadian natural gas supply chain. The provincial breakdown of these costs, along with the emission reductions, is presented in Chapter 4. For the three abatement scenarios, total cost of emissions reduction in the maximum reduction scenario is in the range of \$3.0 to \$5.5 billion,[vi] for a total methane emission reduction of about 33 Mt CO_2e. For the uniform scenario, the cost is in the range of \$1.4 to \$2.6 billion and total reduction of 18 Mt CO_2e, whereas the optimal reduction scenario achieves about a 22 Mt CO_2e emissions cut for a total cost range of \$0.7 to \$1.4 billion. We note that these do not include costs of administration, measurement and reporting which are required by existing methane regulations in Canada.

Figure E.3: Emission Reduction and Ranges of Total Cost of Abatement under the Three Hypothetical Policy Scenarios for the Entire Canadian Natural Gas Supply Chain



In comparison to existing methane regulations, Canadian federal regulation has a target of 40-45% reduction below 2012 levels by 2025. Canadian national inventory report data indicate that total methane emissions in that baseline year (2012) was 107.5 Mt CO_2e, of which about 51% (55 Mt CO_2e) was from oil and gas. Therefore, if the regulation covered all sectors of the natural gas supply chain for a reduction target of 45%, that would amount to about 25 Mt CO_2e. If our optimal reduction scenario applies the 2012 baseline reduction target across all provinces, the total cost of emissions reduction would be in the range of \$0.9 to \$1.7 billion. However, the federal regulation aims to achieve reductions from the upstream sector and transmission (midstream), so if the 45% reduction is applied to these components alone, the reduction target would be slightly below 25 Mt CO_2e given that most of the emissions are from upstream sector.

CERI acknowledges that more accurate data for modelling will become available over time as new field measurements are reported. Hence, future versions of ICERM will incorporate updated information in order to improve the accuracy of results.

[vi] All values throughout the report are in 2017 Canadian dollars.

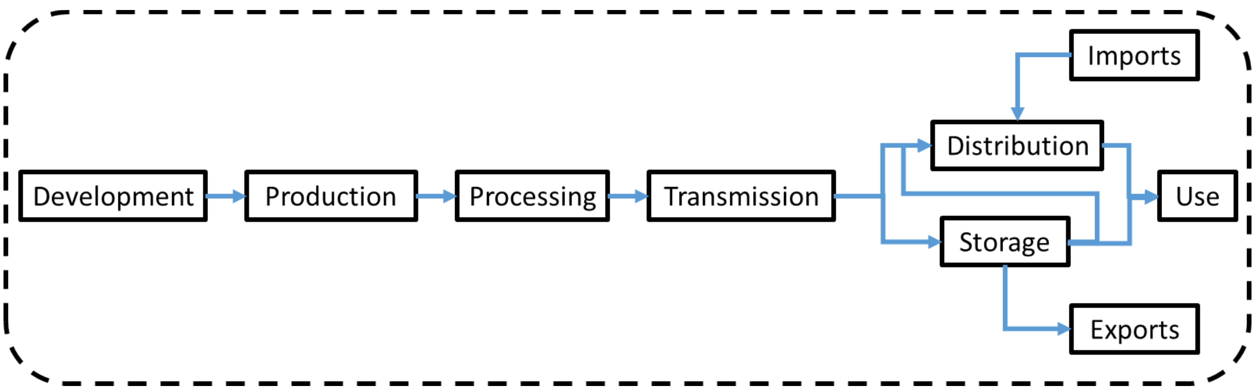
Chapter 1: Introduction

Background

In 2016, the Government of Canada along with its US and Mexican counterparts proposed new regulations to reduce methane emissions from the oil and gas sector in their respective countries by 40-45% below 2012 levels by 2025. In like manner, Canadian provinces harbouring most of the oil and gas industry activities are also proposing regulations to combat methane emissions. Methane is the primary constituent of natural gas, with compositions that can vary from below 50% to almost 100% depending on the source and the handling stage along the supply chain.

Methane is also a potent global warming gas with a current climate forcing potential over a 100-year period estimated in the range of 28 and 36 times above that of CO_2, dependent on the estimation method (EPA, 2018). Methane releases can happen during development, production, supply and use of natural gas. The supply chain can be broadly divided into upstream, midstream, and downstream segments. The upstream segment comprises production, gas gathering, and processing units. The midstream segment includes transmission and storage, while the downstream segment comprises of the gas distribution and consumption. Figure 1.1 highlights the major segments of the natural gas supply chain.

Figure 1.1: Segments of a Typical Natural Gas Supply Chain



Source: Umeozor et al. 2018

There is a consensus about a knowledge gap in the amount of methane emitted from the natural gas supply chain (Umeozor et al. 2018). Recent Canadian oil and gas emission inventories reported to the UNFCCC are 1.7 Tg CH_4 per year for Canada. In 2015, ICF International estimated Canadian oil and gas methane emissions to be 2.4 Tg per year, which is 30% higher than the estimate by Environment Canada (Sheng et al. 2017). A recent study by Zavala-Araiza et al. (2018) used ground-based measurements to quantify emissions from oil and gas facilities in the Red Deer region of Alberta concluding that actual emissions from the area could be 15 times more than what is reported in the national inventory. Johnson et al. (2017) performed aerial methane emission measurements over the same region and reported that emissions could be at least 25-50% more than current official estimates. In fact, emissions information collected and published by Environment and Climate Change Canada (ECCC) represent only a portion of industrial emitters in Canada because facilities (including natural gas pipelines) whose total annual GHG emissions are less than 50,000 tonnes CO_2e are not required to report.

Reported emissions are usually from casing gas venting, waste associated gas flows, treater and stabilizer off-gas and gas volumes discharged during process upsets and equipment depressurization events, whereas unreported sources are often equipment leaks, unreported venting, and routine emissions from pneumatic devices. Total measured emissions are often many times more than reported emissions, suggesting that unreported sources might contribute a majority of emissions (Sheng et al. 2017). However, current studies based on direct or aerial measurements of equipment or facility emission rates focus on specific segments of the supply chain. It is known that the majority of the emissions come from a few so-called super-emitters which could be easily missed due to low sampling occasioned by the limited budget for quantification studies. Now and then, process offsets create super-emitters. Any facility could become a super-emitter when/if abnormal operating conditions (like equipment malfunction, damage, etc.) occur leading to large, unintended releases. Normal operations are usually not considered a trigger for high-emitting situations, although routine emissions are known and different.

Due to the nature of the devices used and the activities involved in natural gas production and supply, some of the gas may be vented or flared as part of normal operation of gas supply networks. This can happen when fuel gas is used for actuating pneumatic devices for pumping and flow control applications. Some gas may also leak from the system because of the limitations/failures of the devices in use in the supply chain. An example could be gas leakage due to compressor seal failure. Canada's emission inventory indicates that the oil and gas infrastructure – from production to distribution components – constitute a major source of methane emissions, accounting for up to 50% of total methane emissions (Sheng et al. 2017). At upstream operations, oil producing sites have been observed to have more emissions than gas producing sites, and this can be ascribed to the higher economic value of oil relative to gas driving a preference for liquid hydrocarbons by some producers especially where there is no immediate use for the gas in remote locations. The intensity of emissions could also be higher at older facilities (Zavala-Araiza et al. 2018).

The challenge to quantify emissions from gas networks is better appreciated when considering the extensive nature of gas networks with various kinds of equipment, different types of facilities, and often many operators with possibly unique operational philosophies. There is also diversity in natural gas hydrocarbon composition across the chain, in addition to other peculiarities related to the characteristics of resource deposition, development, production, processing, transportation, and end-use applications. Moreover, events that occur in natural gas systems often have various timescales; with irregular frequencies of occurrence and in some cases are accidental in nature. They may depend on the components, design and operation of the gas supply chain in consideration. These events include the normal activities performed during development, production, processing, distribution and use which trigger routine emissions.

Although normal operations are subject to operator decisions, random events can occur as conditions change at various points in the system leading to non-routine emissions. For instance, methane venting by pneumatic systems depends on how often such systems must be actuated – a function of the normal operating requirements and other random disturbances on the gas supply systems. These issues make the task of quantifying emissions from the systems through modelling or measurement sampling a challenging and controversial one.

Methane Emission Reduction Policies in Canada

The US-Canada joint statement on March 10, 2016 aims to reduce methane emissions by 40-45% below 2012 levels by 2025 from the oil and gas sector by:

- Regulating methane emissions from new and existing oil and gas sources
- Working collaboratively on programs, policies and strategies, and sharing experiences
- Improving data collection, transparency, and R&D and sharing knowledge of cost-effective methane reduction technologies and practices
- Supporting the World Bank's initiative on "zero routine flaring by 2030"

Canada annexed the methane emission reduction target under the Canadian Environmental Protection Act (CEPA), with the regulation focused on achieving the reductions from upstream oil and gas, and the gas transmission systems (midstream sector). The regulation is designed for onshore and offshore upstream oil and gas facilities with the hydrocarbon gas flows of 60,000 m^3/hr or more. At the same time, individual provinces have also announced methane emission regulations. The Alberta Government aims to reduce methane emissions from oil and gas operations by 45% below 2014 levels by 2025 targeting upstream sector emissions – excluding oil sands (Government of Alberta 2018). British Columbia also announced a methane regulation for the upstream oil and gas sector to reduce the emissions by 45% by 2025 below 2014 level (BCOGC 2019). Saskatchewan recently released a new methane regulation designed to reduce methane emissions from the upstream oil and gas sector venting and flaring by 40-45% below 2015 level by 2025 (Government of Saskatchewan, 2019).

Natural Gas Systems, Methane Emissions and Regulations in the US and Canada

Upstream natural gas operations in Canada are exclusively located in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba and a few areas in eastern Canada. Gas processing in Canada is concentrated in Alberta, British Columbia and Saskatchewan. Previous studies indicate that gas production and processing (upstream) emissions account for the larger part of overall oil and gas emissions. Gas transmission is the second major source and is mainly in western Canada. Gas distribution in the downstream segment of the gas supply chain is often seen as the smallest contributor to overall emissions, although most studies never go beyond the meter to quantify combustion efficiencies at the burner-tips, where final hydrocarbon destruction is rarely 100%.

Emissions in the US include a much larger contribution from gas transmission and distribution than Canada and are therefore more spread out across the country (Sheng et al. 2017). The US has more extensive inter- and intra-state transmission pipelines with a total length of nearly 500,000 km (EIA 2007a,b) – five times that of Canada (NRCan 2014). Longer transmission pipelines require more compressor stations. There are more than 1,200 compressor stations in the US (EIA, 2007a, b), compared to about 200 in Canada (ArcGIS online 2015). The US also uses more natural gas and has much larger distribution systems – about 2 million km (the American Gas Foundation, 2012) compared to Canada's 450,000 km (Natural Resources Canada, 2014). Furthermore, the US distribution systems have more, high-emitting cast iron and bare steel pipes (9% of the total distribution system) than Canada (0.2%) (the American Gas Foundation 2012).

Canadian facilities emitting above stipulated thresholds report their emissions individually to the National Greenhouse Gas Reporting Program. For the 2016 reporting year, individual facilities that emitted 50,000 tonnes of carbon dioxide equivalent (CO_2eq) GHGs or more were required to submit their GHG emissions information (from all sources) to Environment and Climate Change Canada. The 2016 GHG Emissions Inventory includes all direct emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O) and CO_2eq emissions from the operations of participating companies (NIR 2016).

About 35% of methane emissions in the US come from the oil and gas sector (Ravikumar and Brandt 2017). The US methane regulation covers the natural gas supply chain up to the transmission and storage segments (Ravikumar and Brandt 2017). Under the regulation, periodic leak detection and repair is required to mitigate fugitive emissions by performing surveys semi-annually at production well pads and quarterly at larger facilities including midstream compressor stations (Ravikumar et al. 2018). Based on EPA estimates, leak detection and repair (LDAR) implementation at well-pads and compressor stations should be able to reduce fugitive emissions from these sites by up to 60% and 80%, respectively (Ravikumar et al. 2018). Alberta's current regulation specifies annual or triannual LDAR survey frequency for various facility types as shown in Table 1.1. Facilities designed to vent all received and produced gas do not require fugitive emission surveys (AER 2018). Canadian federal regulation requires triannual surveys for all specified emitting sources.

Table 1.1: Frequency of Fugitive Emission Surveys by Equipment/Facility Type

Equipment or Facility Type	Frequency
Sweet gas plants	Tri-annually
Compressor stations (<0.01 mol/kmol H_2S in inlet stream)	
Liquid hydrocarbon storage tanks and produced water storage tanks with vent gas control	
Gas plants	Annually
Straddle and fractionation plants	
Compressor stations (≥0.01 mol/kmol H_2S in inlet stream)	
Battery and associated satellite facilities	
Custom treating facilities	
Terminals	
Injection/disposal facilities	

Source: (AER 2018)

Ravikumar and Brandt (2017) proposed four policy measures for effective methane emission mitigation as:

- The use of performance targets to regulate the emissions
- Policy mechanisms that account for regional variations
- Technology-blind regulations to drive cost-effective mitigation
- Integrated implementation framework accommodating other GHG mitigation policies

Recent regulations enacted by the federal government pursuant to controlling methane emissions will impact Canadian upstream oil and gas facilities. Most of the impacted facilities are in three Canadian provinces – British Columbia, Alberta and Saskatchewan. The Canadian government has stated that unless provincial regulations achieve equivalent or more conservative emissions reductions to federal ones, the provinces will be required to comply with the proposed federal regulations. Consequently, federal regulations will duplicate or conflict with the respective provincial regulations that are not as equally comprehensive. This drives the need to understand actual amounts of methane released from various segments of the gas supply chain in order to reliably estimate economic and environmental implications of the new methane regulations.

Previous Inventory and Emission Quantification Studies

In 1996, the Environmental Protection Agency (EPA) conducted an inventory study on pneumatic devices to assess greenhouse gas emissions in the US using 14,000 oil and gas wells data (EPA, 2015). The study found that 65% of the pneumatic controllers were low-bleed, while the rest were high-bleed controllers. Based on the study, the EPA developed emission factors for various pneumatic systems which are still being used today. Allen et al. (2013) studied the methane emissions from pumps and pneumatic controllers in the production sites of different regions including the Appalachians, the Gulf Coast, Midcontinent, and the Rocky Mountains in the US. The study showed that the emissions for intermittent and low-bleed controllers were 29% and 270% higher than the ones reported in the EPA national emission projections, respectively. Emissions from pumps, however, were in the range of 10% of the values obtained using EPA-generated emission factors.

In a similar study, Prasino Group investigated the bleed rates for pneumatic controllers and pumps at upstream oil and gas facilities across Fort St. John, in British Columbia (Prasino Group 2013). The study observed lower emission rates for high and intermittent bleed controllers relative to EPA estimates. The observed differences in the estimates are often ascribed to differences in the measurement conditions between the two studies. In another work, Allen et al. (2014) measured methane emissions directly from 377 pneumatic controllers (85% intermittent vent and 15% continuous vent) over a wider region across the US. The study showed that 95% of the emissions were due to a small portion of level controllers operating on compressors and separators, which had emission rates of 6 scf/h and above. Low bleed devices are usually defined as those emitting 6 scf/h or less.

In 2016, GreenPath Energy performed a study to generate methane emission modelling data from the upstream oil and gas sector in Alberta and British Columbia. They developed a matrix to classify device types (such as level controllers, positioners, etc.) against facility types such as batteries and gas processing plants (GreenPath 2016b). In another project, GreenPath Energy collaborated with the Alberta Energy Regulator (AER) to conduct a survey to develop equipment inventory and quantify methane emissions from various sources across 395 facilities with 676 oil and gas wells within six regions including Red Deer, Grand Prairie, Medicine Hat, Drayton Valley, Bonnyville, and Midnapore (GreenPath, 2016a). A total of 1,688 pneumatic devices including 469 pumps and 1,218 controllers were involved, which are mainly operated with natural gas. Table 1.2 shows a breakdown by power source for the pneumatic systems surveyed. In terms of function of the total pneumatic devices, 41% were level controllers, 18% were pressure controllers, 15% were high-level shutdown, 13% high-pressure shutdown, 10% were transducers, and 1.8% were positioners.

Table 1.2: Pneumatic Devices by Power Source

Natural Gas	Electric	Instrument Air	Propane
1608	59	20	1

Source: (GreenPath 2016a).

An ICF International study in 2016 used information on likely major sources of methane emissions from the Canadian oil and gas industry to project the emission profile into 2020. They concluded that methane emissions from Canadian oil and gas activities would remain stable at 2013 levels through 2020 and estimated the capital cost of mitigation measures to be approximately C$726.3 million. Delphi Program (2017) used publicly available data to examine the range of costs required for methane emission mitigation under five focus categories including LDAR, pneumatic devices, compressors, dehydrators, and oil and gas site venting. Cap-Op Energy (2018a) used Alberta data to generate a methane emission profile for pneumatic devices in the province. Cap-Op Energy also collaborated with Environmental and Climate Change Canada to assess other sources of methane emissions in the upstream oil and gas industry in Canada (Cap-Op Energy 2018b). The objective of the latter study was to:

- identify less-known methane emission sources,
- highlight the level of activity of these sources, and
- quantify the emissions if the level is high.

Spartan Controls (2018) presented a procedure to improve the accuracy in the quantification of methane emissions from pneumatic devices under static, transitory, and dynamic operating modes. GreenPath Energy (2018) examined vent gas reduction potentials for the two most commonly used level controllers in Alberta (Fisher L2 and Norriseal 1001a). The controllers were replaced with their low-emission equivalents. From about 200 samples measured and replaced, they observed methane emission reduction capability of 80% and above.

Lastly, a joint study by Clearstone Engineering and the Alberta Energy Regulator in 2018 investigated uncertainties in methane emission measurements from pneumatic devices, reciprocating rod-packings, and fugitive equipment leaks in the Alberta upstream oil and gas sector. The study data were collected in 2017 from 333 locations, 241 production accounting reporting entities, and 440 unique well identifiers (UWIs). The results were used for the development of an emission inventory model for predicting an inventory of equipment/components, uncertainties, and air emissions associated with upstream facilities and wells.

There are other ongoing field studies to address some of the data and quantification methodology challenges limiting current understanding of the economic and environmental impacts of gas supply chain emissions (e.g., the Fugitive Emissions Management Program Effectiveness Assessment - FEMP EA). Such programs and other regulatory requirements on emission measurement, monitoring and reporting are expected to provide new field data and additional insights to enhance current knowledge.

Why This Study?

As presented in the literature review, several studies have investigated methane emissions from a few sources and sites in Canada, with the majority of them focused on pneumatic devices. Some of the studies have been limited in their use of Canada-specific emission and activity factors to quantify the emissions. This study uses a holistic approach considering the entire gas development, production, supply, and end-use methane emissions across Canadian provinces.

In this study, CERI developed a modelling tool, the Integrated CH_4 Emission Reduction Model (ICERM), with the objective being to quantify methane emissions and assess reduction opportunities covering the entire Canadian natural gas supply chain. ICERM prioritizes the use of Canadian data in all cases. The gas supply chain is broadly divided into the upstream, midstream and downstream sectors where sources of methane emissions are identified, and mitigation technologies are assessed from wellhead to burner-tip. Emissions from the sectors are further grouped into five source categories including fugitives,[1] flared,[2] vented,[3] line heating,[4] and burner-tip.[5] ICERM has three modules for emission quantification, abatement cost estimation and optimizing selection of mitigation technologies to meet emission reduction targets in a cost-effective way.

By combining the emission quantification results and abatement cost data, CERI evaluated impacts of various policy scenarios on methane emission reduction opportunities in the supply chain along with the total cost of achieving the reductions. Previous studies did not assess reduction opportunities and their economic implications from end-to-end of the supply chain. The tools developed in this study can be used to evaluate economic and emission reduction impacts of methane regulations.

Report Structure

This study is divided into five chapters. Chapter 1 provides background and defines the scope of the project. Chapter 2 discusses the natural gas supply chain; identifying the various components and sources of methane emissions from each sector, as well as the opportunities for reducing methane emissions through various mitigation technologies. Chapter 3 presents the modelling methodology and assumptions. Chapter 4 discusses the results presented at both provincial and national levels. Chapter 5 provides conclusions and policy implications of the results. Additional information is provided in Appendices A through E.

[1] A leak or unintentional release of methane emissions
[2] Undestroyed methane at upstream sector from gas flaring due to incomplete combustion
[3] Methane released to the atmosphere at upstream, midstream or downstream sector
[4] Undestroyed methane at midstream sector from stationary combustion due to incomplete combustion
[5] Undestroyed methane at downstream end-user burners due to incomplete combustion

Chapter 2: Natural Gas Supply Chain

Overview

The natural gas supply chain is an integrated and complex network of market participants that all play a key role in delivering natural gas to industrial, commercial and residential users. Natural gas is currently considered the third most important source of fuel after oil and coal (Statista 2017), having supplied one-third of Canada's energy needs in 2017 with a combined consumption of 9.1 billion cubic feet per day (Bcf/d) (CAPP 2018a). End-uses of natural gas span from that of space heating, transportation fuel, electrical power generation to that of synthesizing industrial products. Global demand for natural gas is expected to increase by 45% by 2040 (CAPP 2018), primarily due to its clean burning characteristics; superior to that of other fossil fuels in power generation, and its abundant and relatively inexpensive production and ease of use. The production and use of natural gas are vulnerable to fugitive emissions across the transportation and distribution nodes of its supply chain and has prompted extensive research and technological studies.

The natural gas supply chain consists of 4 key nodes: production, gathering and processing, transmission and distribution, each with its own subsystems and complex set of regulations, facilities, and operators. Connectivity and integration within the natural gas industry are important in order to allow access between the supply basins and demand centers, market gas economically, and allow the industry to be malleable with supply and demand changes. It is also important to understand the full system dynamics in order to properly account for the GHG footprint of natural gas use versus other energy types.

Production

Canada is currently the fifth largest producer of natural gas in the world, having produced over 16.1 Bcf/d in 2017 (NRCan 2017). Natural gas in Canada is largely produced from the Western Canadian Sedimentary Basin (WCSB) in British Columbia, Alberta, and Saskatchewan, whose production accounts for 97% of all Canadian gas produced as of 2017 (NRCan 2017). Conventional production accounts for most of the Canadian natural gas production, representing 91.7% in 2017 (AER 2018c) and forecasted to remain the biggest producer source over coalbed methane and shale gas.

The production node of the natural gas supply chain includes the exploration, development, drilling, and extraction phases of natural gas from either onshore or offshore reservoirs. Several drilling and extraction methods exist, depending on the resource. Coalbed methane is traditionally extracted by depressurizing coal seams through pumping water from the reservoir to reduce pressure and allow natural gas to flow up to the wellhead. Shale and tight gas are extracted by injecting water and chemical mixtures to release natural gas pocketed in isolated pores within dense rock/shale, a process made easier with hydraulic fracturing.

Conventional gas reservoirs are naturally pressurized, and when accessed with vertical/horizontal wells, push natural gas to the wellhead. There are three main types of wells from which natural gas is recovered – crude oil, gas, and condensate wells. Gas and condensate wells contain little to no crude oil, and gas recovered from such wells is called non-associated gas. Natural gas produced from oil wells as a by-product when light-gas-carbon chains are depressurized during oil production is known as "associated gas." Previously, unwanted/by-product natural gas during oil production was flared/burned off at the well site, but now, with an integrated and well-developed natural gas supply chain, this gas can be added to well-connected natural gas gathering systems.

Gathering and Processing

The gathering and processing node of the natural gas supply chain is responsible for collecting natural gas from wellheads and gas producing facilities and transporting them to processing sites for producing user-ready natural gas. The gathering and processing node consist of the gathering, compressing, dehydrating, treating, conditioning and processing of raw natural gas. Natural gas developed at the wellhead contains varying amounts of impurities, water vapour, and natural gas liquids (NGLs) that will need to be separated to provide methane-rich/"dry" gas to the end-users. Natural gas gathering consists of aggregating natural gas from different wellheads, through small diameter low-pressure gathering lines. A network of complex gathering lines transport natural gas from the wellhead to the processing facilities and are usually 4-12 inches in diameter.

Natural gas processing consists of separating oil condensates, NGLs, water vapour and impurities such as carbon dioxide and hydrogen sulphide from methane – the primary component of natural gas. Oil condensates and free water are typically separated from raw natural gas by conventional separators at wellhead sites. Raw gas from gathering systems is transported to processing facilities where it is first stripped of acid gases (hydrogen sulphide and carbon dioxide) either through amine treating or newer technologies based on polymeric membranes that are attractive for their non-reagent use. Acid gases are stripped from natural gas and processed in sulphur recovery units to produce sulphuric acid or elemental sulphur. Water vapour is then removed from natural gas through separation processes such as pressure swing adsorption, triethylene glycol dehydration or dehydration through deliquescing desiccants such as calcium chloride. Mercury is removed through adsorption processes that typically use activated carbon or molecular sieves. Nitrogen, an inert and non-flammable gas, is removed from natural gas to maintain the high heating value of methane. Nitrogen rejection follows mercury removal and is carried out either through cryogenic distillation or absorption processes using lean oil or special absorbing solvents. Nitrogen removal through adsorption is also possible with molecular sieves or activated carbon but is not often chosen since it causes the loss of butanes and heavier hydrocarbons.

Once the impurities and water vapour are removed, NGLs are recovered from natural gas. Typically, liquids found in natural gas include ethane, propane, butane, iso-butane, and natural gasoline. Although those liquids are not natural gas pipeline quality, they are valuable products in the petrochemical industry. Most modern gas processing facilities use low-temperature cryogenic distillation that cools the gas mixture and condenses hydrocarbons heavier than methane. Upon their recovery, NGLs are separated into their pure components through fractionation columns. Sweet and dry natural gas is then on-spec for pipeline quality and is compressed to transmission lines for distribution.

Transmission

Transmission pipelines are generally 20-48 inches in diameter and deliver user-ready natural gas to distribution hubs/city gates to be distributed among end-users. Transmission pipelines that cross provincial borders are regulated by the federal government whereas those confined to one province are regulated by the respective provincial government. In Canada, there are up to 117,000 km of transmission pipelines (NRCan 2016) operated by pipeline companies including Enbridge, TransCanada, ATCO and TransGas. Natural gas transmission pipelines are characterized as either interstate or intrastate pipelines, with the former being long-distance, high capacity pipelines that transport gas throughout the nation, whereas the latter links natural gas production facilities to local markets.

Transmission pipelines consist of several installations to allow natural gas transport, including compressors, filters/scrubbers, control valves, and control stations. Compressor stations are located 40-70 miles along transmission pipelines to provide enough pressure and optimal flow of natural gas against pipeline frictional losses and elevation changes. Pipeline operators respond to demand fluctuations by raising and lowering gas pressures along pipeline segments. Natural gas pipelines and utility systems are highly automated, and operators model customer demand through hourly/daily consumption trends with seasonal and environmental factors to ensure reliable delivery.

The transmission node of the natural gas supply chain also includes storage. Natural gas is stored underground in three types of reserves: depleted natural gas reservoirs, aquifers, and salt caverns. Storage facilities are typically located near distribution hubs and pipeline gathering systems for easy access. Natural gas can also be stored and transported as liquefied natural gas (LNG) which enables more gas storage per unit volume since LNG has about 1/600th the volume of natural gas.

Distribution

Natural gas from transmission pipelines is transported to city gates that process natural gas before distribution. Gate stations receive natural gas from several transmission pipelines where they are all aggregated at the gas station prior to delivery. City gates are key market centers for natural gas pricing and are where utility companies take ownership of the gas. Natural gas pressure is reduced from the transmission pipeline operating pressure of (200 - 1,500 psi) to enough distribution pressures of (0.25 – 200 psi). Distribution pipeline pressures are not required to be as high as those transmission pressures since there are lower pressure losses due to relatively shorter distances. A harmless and non-toxic chemical known as mercaptan is added at gas stations due to its poignant odour characteristic that facilitates natural gas leak detection. Only a small concentration of mercaptan is needed to perceive the smell of a natural gas leak, as natural gas is colourless and odourless without mercaptan. Natural gas flowrate from transmission pipelines is also measured at the city gates to provide utility companies with gas rates and inventories.

Generally, distribution lines are 2-24 inches in diameter and have their operating pressures automatically regulated by utility companies. The closer the end-user is to the gas station, the lower the operating pressure and the smaller the pipe size. Natural gas flow rates and pressures across distribution lines are continuously monitored by utility companies to ensure gas is delivered at adequate flow rates and pressures. Distribution system grids are all fitted with shut-off valves for maintenance activities and emergencies.

Distribution lines are split into service lines that are smaller pipelines for servicing individual homes or businesses. Flow meters are installed at service lines which is where the responsibility of the system is passed from the utility company to the end-user. Regulators downstream of the flow meters further reduce gas pressure to levels appropriate for home/business use, typically under 0.25 psi.

Distribution systems are made up of a complex network of distribution lines and service lines that cover a wide geographical area. This transportation infrastructure is the reason why distribution costs make up about half of the natural gas costs and why natural gas distribution is usually monopolized by utility companies. Local government agencies regulate utility companies to ensure their efficient operation and reasonable gas costs amid the natural monopoly.

Structure of the Canadian Natural Gas Supply Chain

The Canadian gas supply chain has a vast network of upstream, midstream and downstream components. Figure 2.1 illustrates the supply chain, from extraction to the point of delivery, including the key elements of each sector. The following sections describe each sector of the supply chain, focusing on what operations are involved, why they are required and how they occur.

Upstream Sector

Pre-production activities

Once an economically feasible reservoir is identified, wells are drilled at a variety of depths (1 km to over 10 km). Every well, regardless of the type of formation, undergoes completion after drilling. This consists of several operations such as inserting the casing, cementing and perforating the well-casing. This is also the stage where hydraulic fracturing is carried out when the well needs to be stimulated for production (EPA 2011). Once the fracturing is complete, a period of 'flowback' ensues for between three and ten days, where some of the fluid returns to the surface, alongside large slugs of gas and oil. The flow increases up to the initial production rate, where completion ends, and production begins.

Production activities

Once the well is completed and connected to downstream gathering equipment, production begins. The production stage involves collecting the raw, and associated gases from a variety of wells, gathering the gas flows together using piping manifolds while controlling the flow rate and pressure using compression and flow regulation.

Workovers

The gas flow from a well decreases over time because, as the quantity of gas in the well decreases, so does the well pressure that forces the gas up to the surface. To re-stimulate the gas well, the well may require a workover, or recompletion. During a workover, there are several processes that may occur, all for the purpose of increasing the flow of gas from the well. Such processes include repairing leaks, perforating new parts of the well bore or cleaning existing perforations. For unconventional gas, this may involve hydraulically fracturing the well again to release more gas (Skone 2011). Liquids unloading is not considered to be part of workover operations, but instead, a separate set of processes described below.

Liquids unloading

A number of times during the lifetime of the well extraction, the well flow may become impeded due to the accumulation of liquids within the well. At the early stages of well production, gas velocity is high, which allows liquids to be brought to the surface. However, as the well matures, the flow and velocity of gas decreases preventing the entrainment of these liquids. Thus, liquids may accumulate at the bottom of the well and as the liquid level increases this further impedes gas flow. Liquids unloading is a set of processes that are carried out to remove the flow restriction and increase production (EPA 2014). Liquids unloading may be required for any gas well, conventional or unconventional. It has been suggested previously that shale gas wells do not require liquids unloading because the liquids are unloaded during the workover process instead (Skone 2011) and that CBM does not require liquids unloading. However, this has since proved to be incorrect (Shires and Lev-On 2012).

Processing

The processing sector includes plants (e.g., batteries, gas gathering network, field plants, and straddle plants) that treat gas to pipeline quality standards. Some produced gas is close to pipeline quality standards and may bypass the processing sector and instead undergo minor treatments in the production or gathering sectors. Depending on the quality of the raw gas, it may be necessary to remove contaminants to meet the gas sales specification. Common contaminants are water, heavy hydrocarbons, CO_2, hydrogen sulphide (H_2S) and nitrogen. Water is normally removed using a glycol absorption column. It is also possible to flash separate the water by boiling off lighter compounds but this is generally less economically efficient (Speight 2011). The removal of H_2S and CO_2 is also usually by absorption, with amines such as monoethanolamine (MEA) or diethanolamine (DEA). Solid adsorbents such as iron oxide (sponge) can also be used to remove H_2S and CO_2. Within the processing stage, compression systems are usually installed to increase gas pressure to the transmission pipeline.

Midstream Sector

Transmission

Once processed, the gas is sent through long-distance pipeline networks, either nationally or transnationally. Gas may travel distances of hundreds or thousands of kilometres. Therefore regular compression stations are required throughout the network to drive the gas and overcome pipeline friction. Transmission lines operate at up to approximately 1,450 psig (Tobin 2007; INGAA 2010).

Storage

The demand for gas varies throughout the year, with winter in the northern hemisphere causing a surge in demand. As supply rates tend to be relatively inelastic, most countries have underground storage reservoirs that can be called upon to meet spikes in demand. According to the Energy Information Agency (EIA 2015), the 2013 US storage capacity comprised 77% depleted gas reservoirs, 16% depleted aquifers and 7% salt caverns. A small percentage of the gas that is injected underground for storage cannot be recovered again later and is known as base gas. Stored gas often picks up water during underground storage and therefore requires dehydration prior to being released back into the distribution network. It is therefore common for storage facilities to have both dehydration and compression facilities.

LNG liquefaction, storage and distribution (transport)

A significant percentage of the world's natural gas reserves are geographically isolated from energy markets. Transportation by pipeline is efficient for high volumes of consistent demand and shorter distances but lacks flexibility in demand and location. Instead, natural gas can be compressed and shipped. To make shipping economically feasible, it is liquefied so that the energy density is much higher. Large quantities of natural gas are found in Australia, Algeria, Qatar, Iran, Malaysia, Brazil, Trinidad and Tobago, and Indonesia. Without LNG, all these gas fields would be stranded from markets by either politically bureaucratic or regulatory difficulties with transnational transmission or extremely large distances.

The liquefaction process involves cooling the gas to a temperature of approximately -160 ºC and then maintaining that temperature by storing the liquefied gas in cryogenic containers. Prior to cooling, the gas must be processed to remove any impurities that will freeze, such as water, CO_2, H_2S, N_2 and heavy hydrocarbons. LNG is typically in the range of 95 to 100% methane; small quantities of impurities such as N_2, ethane and butane will not cause problems to the liquefaction process.

Downstream Sector

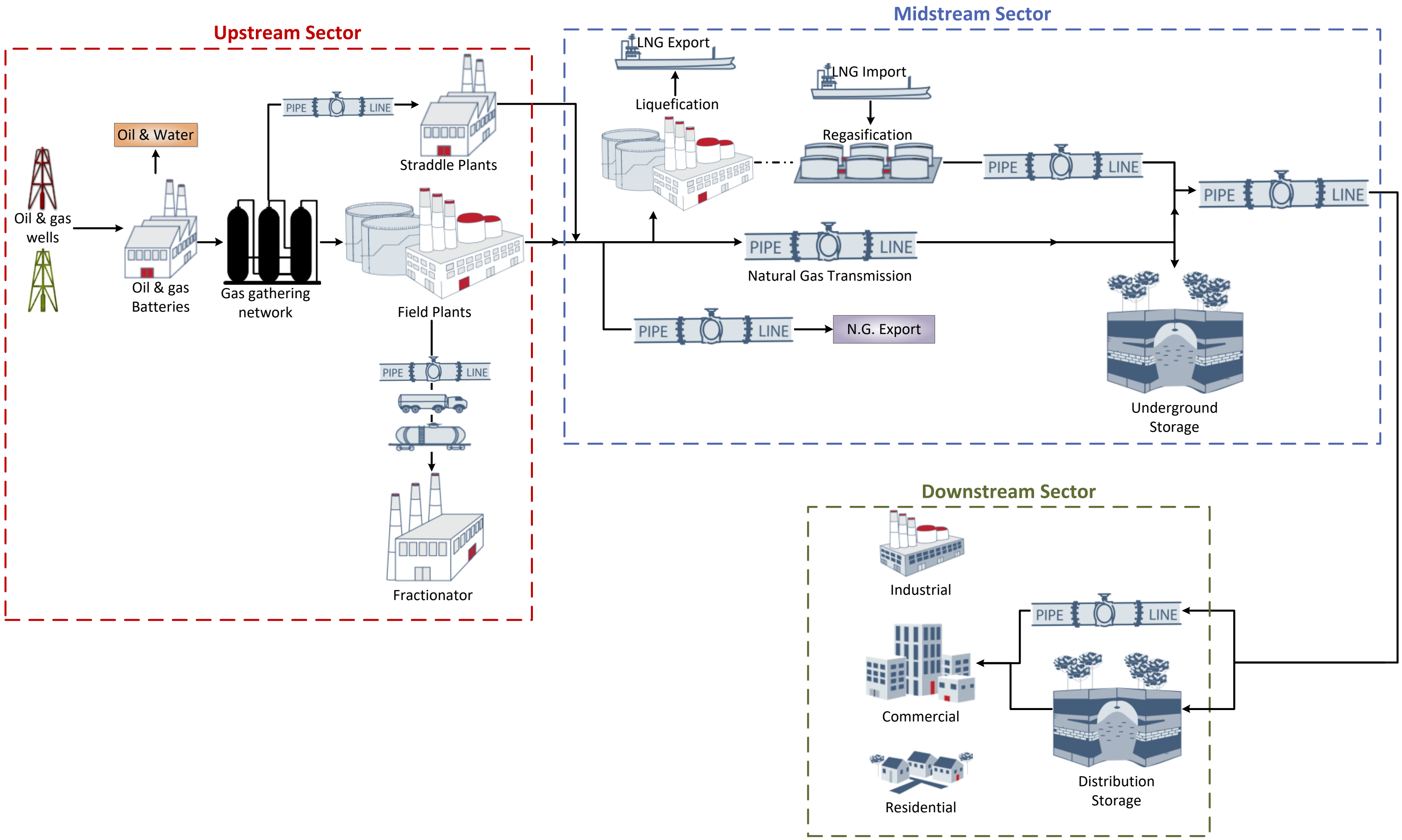
Distribution

The domestic distribution system begins at the city gate stations where gas from the transmission network is reduced in pressure to approximately 0.4 psig to feed into the domestic consumer pipeline system, where it will primarily be used for space heating and cooking. Alternatively, the gas may be sent from higher pressure pipelines to commercial users such as chemical production facilities.

Consumption

Unburnt hydrocarbons are among the major sources of emissions from combustion systems. Most studies and analysis do not explicitly indicate what portion of efficiency losses in combustors are due to unburned hydrocarbons. Most natural gas heating systems have reported efficiencies of around 70-90%. However, efficiency losses are often lumped together for both heat losses (via flue gas and containers) and any unburned portion of fuel feed to the combustion system. Ideally, all hydrocarbons should be destroyed during combustion, but conditions are hardly ideal in practice. Complete combustion requires optimal combinations of the fuel and air. Too much air results in more heat losses in the flue gas, inadequate air results in more unburnt hydrocarbons.

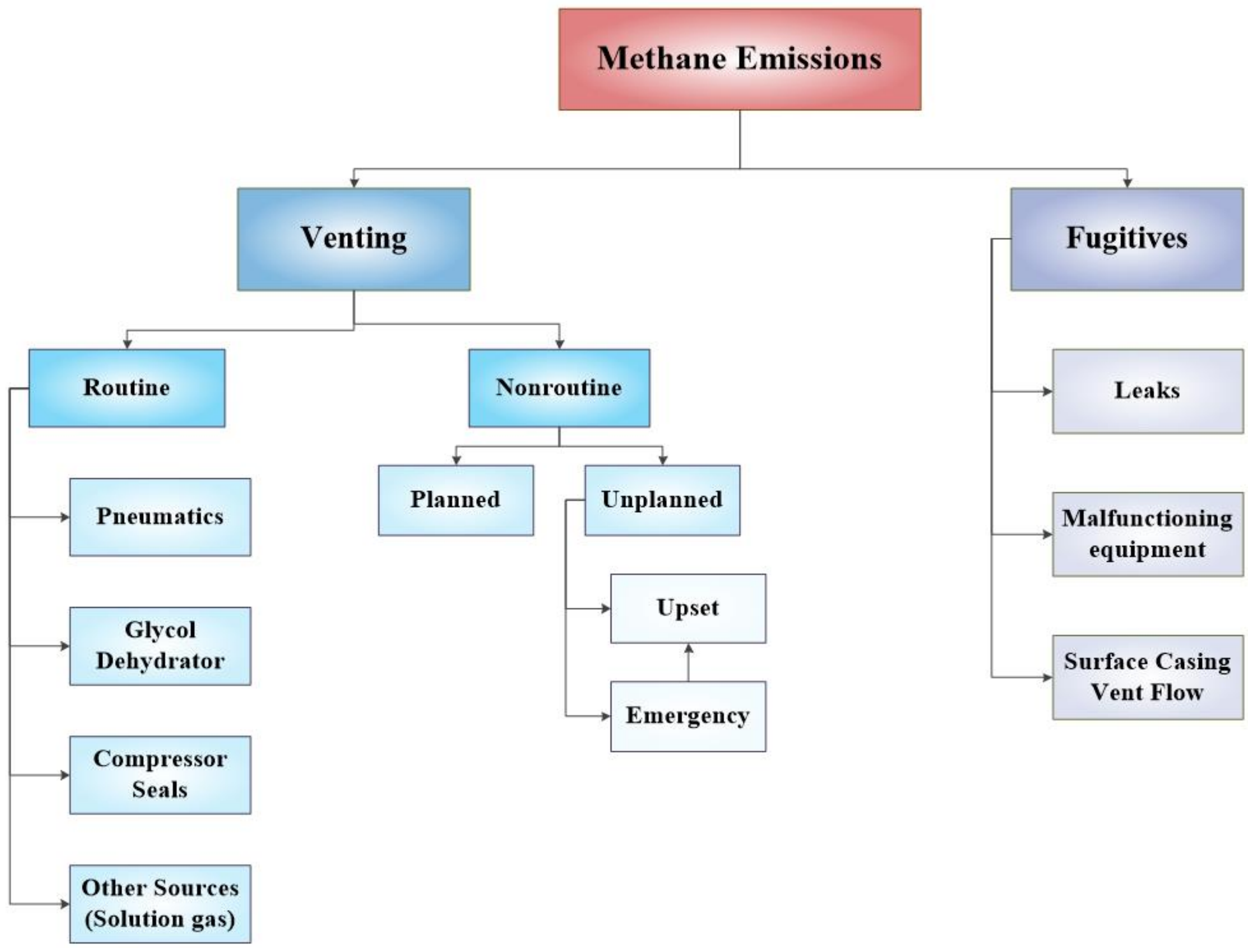
Figure 2.1: The Natural Gas Supply Chain Components and Segments



Sources of Methane Emissions in the Supply Chain

As illustrated in Figure 2.1, there are two distinct sources of methane emissions – venting and fugitives. Routine venting is considered a continuous or intermittent event occurring on a regular basis as part of a normal operation. This is typical for the equipment listed under routine venting in the diagram as they are usually operating continuously. Non-routine venting is usually intermittent and infrequent and can be categorized into two types; either planned or unplanned. Planned non-routine venting is typically associated with maintenance, shutdown, or pipeline depressurizing. Unplanned non-routine venting is either due to an upset in the facility such as pressure buildup requiring blowdown or an emergency. A fugitive emission is defined as a leak and is considered an unintentional release.

Figure 2.2: Categories of Methane Emissions



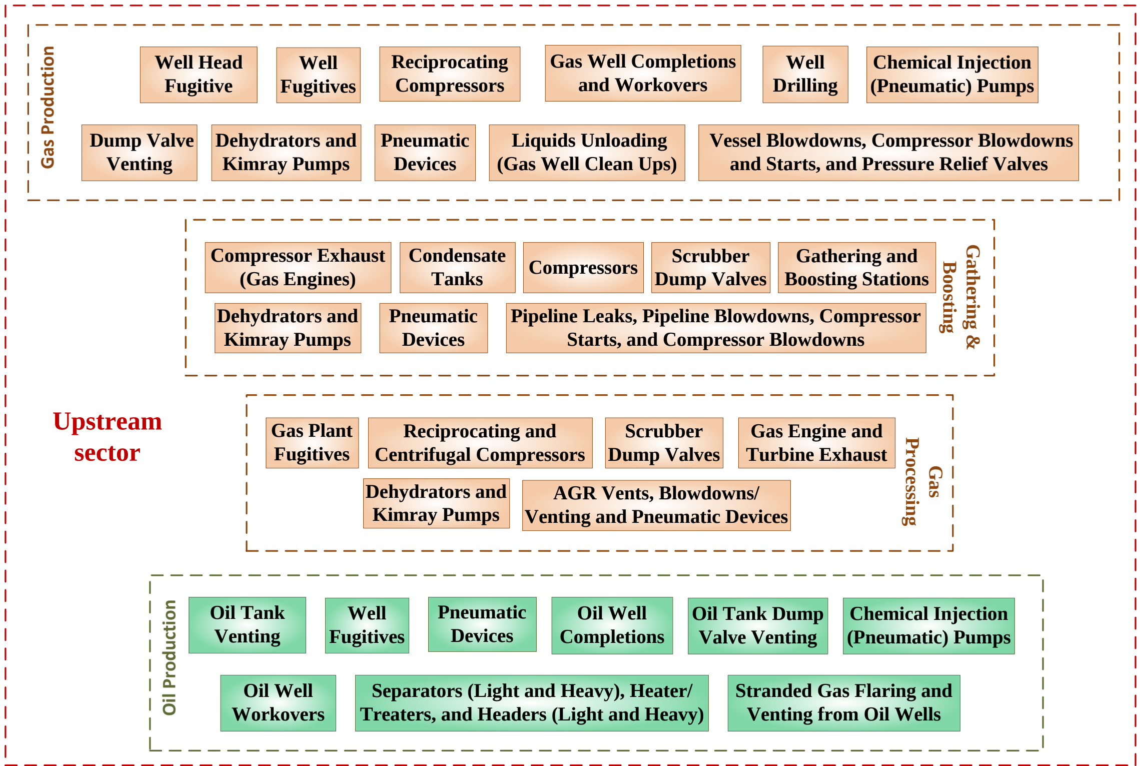
Source: (AER 2018b)

Figures 2.3 to 2.5 provide a breakdown of potential sources of methane emissions from the upstream to downstream sectors, respectively. Itemized descriptions of these sources are provided below.

Sources of Emissions in the Upstream Sector

- Gas can be vented when a well undergoes completion at the initial phase of development.
- Because gas wells are often in remote locations without electricity, the gas pressure is used to control and power a variety of control devices and on-site equipment, such as pumps. These pneumatic devices typically release ("bleed") small amounts of gas during their operation.
- Water and hydrocarbon liquids are separated from the product stream at the wellhead. The liquids release gas, which may be vented from tanks unless it is captured.
- Water is removed from the gas stream by glycol dehydrators, which vent the removed moisture and some gas to the atmosphere.
- Flaring produces CO_2, a significant but less potent GHG than methane, but no flare is 100% efficient, and some methane is emitted during flaring. Based on the new Alberta methane regulation, conversion efficiencies of upstream combustors cannot be less than 20 MJ/m^3 for new systems and 12 MJ/m^3 for existing stacks. Using the common natural gas LHV of 38.2 MJ/m^3, these represent about 50% and 30% hydrocarbon conversion efficiencies, respectively, of which a considerable amount of the energy content may be lost in the form of undestroyed hydrocarbons – which can result in significant methane emissions from upstream combustion systems.
- Many of the emission sources from domestic oil production are similar to those in gas production – completion emissions, pneumatic devices, processing equipment and engine/compressors. Crude oil contains natural gas (either associated or in solution) and the gas is separated from the oil stream at the wellhead and can be captured for sale, vented, or flared. Venting or flaring is most common in regions without gas gathering infrastructure.
- The many components and complex network of small gathering lines have the potential for fugitive emissions. The gathering system has pneumatic devices and compressors that vent gas as well as potential fugitive emissions.
- Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from raw gas to make it pipeline-quality and ready to be compressed and transported.

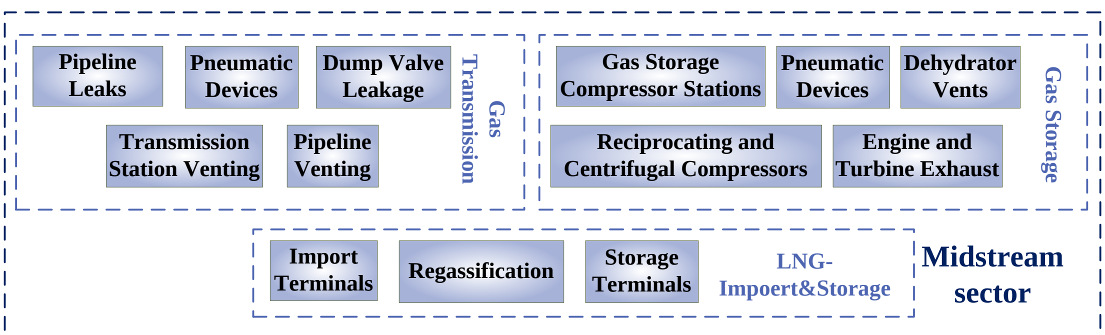
Figure 2.3: Emission Sources in the Upstream Sector



Sources of Emissions in the Midstream Sector

- Most of the compressors driving the gas through pipelines are fueled by natural gas. Compressors emit CO_2 and methane emissions during fuel combustion and are also a source of fugitive and vented methane emissions through leaks in compressor seals, valves, and connections, and through venting that occurs during operations and maintenance. Thus, compressor stations are the primary source of vented methane emissions in natural gas transmission.
- Line heating combustion systems in the midstream sector are also not 100% efficient in terms of their hydrocarbon destruction capacity. However, destruction efficiencies of midstream combustors are known to be higher than those of upstream combustors.

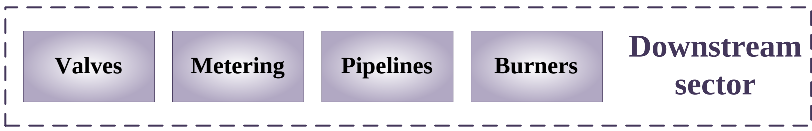
Figure 2.4: Emission Sources in the Midstream Sector



Sources of Emissions in the Downstream Sector

- Some methane emissions occur due to leakage from older distribution lines and valves, connections, and metering equipment. This is especially true for older systems that have cast iron distribution mains.
- Combustion efficiency of end-use burners vary. Relative to upstream and midstream combustors, end-use burners downstream typically have higher efficiencies reaching up to 99.9% (Environment Canada, 2000).

Figure 2.5: Emission Sources in the Downstream Sector



Mitigating Technologies for Methane Emissions from Natural Gas Systems

Field measurement studies have observed that the largest sources of emissions in the oil and gas sector are pneumatic devices, fugitive emissions, compressors, glycol dehydrators, and venting (Cap-Op Energy 2018a; Clearstone Engineering 2018; AER 2018b; CAPP 2018b). Mitigating the emissions may require changing the design of processing systems, substituting equipment or replacing a component within the equipment. When a source of methane emissions is already known, it can be easily and quickly controlled either based on the facility operator’s interest or in the interest of regulatory compliance. Fugitive emissions from unintentional leaks can pose a major challenge to first discover them before repairs can be implemented. Nevertheless, methane leakage can occur in all sectors of the gas supply chain. Table 2.1 summarizes the mitigation measures assessed in this study for various methane emission source categories.

Table 2.1: Summary of Applied Mitigation Measures

Category	Mitigation
Wells	Fugitives – LDAR
Batteries	Fugitives – LDAR
Gathering	Fugitives – LDAR
Compressor Stations	Fugitives – LDAR
Processing (Gas plants)	Fugitives – LDAR
Transmission	Fugitives – LDAR
Pneumatic devices	Replace with Instrument Air Systems
	Replace High-Bleed Devices with Low-Bleed Devices
	Replace High-Bleed Devices by Installing Retrofit Kits
	Replace Pneumatic Pumps with Electric or Low/No-Bleed Pumps
	Electrification of Pneumatic Devices
	Install Vapour Recovery Units
Compressors and Engines	Conversion of Gas Starter to Air Start
	Starter Vent to Flare
	VRU Vent Capture to Inlet
	Capture Blow Down to Inlet
	Capture Atmospheric Vents with SlipStream®
	Replacement of Rod Packing
	Centrifugal Seal Build
	Metering Seals
Dehydrator	Install Flash Tank Separators
	Optimize Glycol Circulation Rates
	Replace Gas Powered Glycol Pumps with Electric Glycol Pumps
	Glycol Dehydrator Optimization
	Stripping Gas Elimination
Oil and Gas Site Venting	Plunger Lift Instead of Well Venting for Liquids Unloading
	Reduce Liquids Unloading Venting Flaring/Incineration/Destruction Device
	Install Vapour Recovery Units on Storage Tank
	Recover Casing Vent and Use as Fuel
	Casing Gas Recovery Compressors (CHOPS)
	Casing Gas Combustor/Incinerator (CHOPS)

Leak detection and repair is the primary way to mitigate fugitive emissions which are the most unpredictable of all the methane leakage categories. The current standard for LDAR implementation is based on the EPA's requirement for the use of optical gas imaging (OGI) to identify and subsequently repair leaks (Ravikumar, Wang, and Brandt 2017). Of the OGI technologies, infrared (IR) imaging is the most widely used. Depending on the minimum detectable limit of an LDAR system in use, it can be implemented in such a way that it selectively identifies "super-emitters" thereby minimizing the resources needed to significantly cut down the emissions (Ravikumar and Brandt 2017).

Parameters like the minimum detectable leak rate (MDLR) of an LDAR program can be tailored to be able to capture large numbers of small leaks (with a low MDLR) or the fewer sources of large amounts of leaks (with high MDLR) (Ravikumar and Brandt 2017; Ravikumar et al. 2018). Mean leakage is found to generally reduce with higher survey frequencies (Ravikumar and Brandt 2017). However, with better leak detection sensitivity (lower MDLR), marginal effectiveness of mitigation through periodic surveys have been observed to diminish (Ravikumar et al. 2018).

Generally, the effectiveness of LDAR implementation has been found to be related to a number of factors, including:

- Imaging distance
- Size distribution of the leaks
- Weather conditions including; wind speed/direction, temperature (plume and surrounding), humidity, emissivity (plume and surrounding), gas plume composition
- Expertise level of the camera operator
- Number of surveys (frequency)

Changes in any of the above variables influence what can be detected or not during a leak detection survey. Depending on effects of these variables, field studies observe that between 5 to 80% of leaks can be detected using between single annual to quarterly annual surveys. This implies that surveys need to be designed for specific execution and weather conditions. The EPA expects a semiannual survey to yield about 60% emission mitigation (Ravikumar and Brandt 2017). Other emerging LDAR technologies are required to demonstrate equivalency to the standard OGI-based methods (AER 2018b). There is also an established Method 21 technology which uses concentration measurements to detect leaks where local methane concentrations exceed a design threshold. Although more sensitive than OGI, it requires proximity to the emission source in order to detect leaks.

Detected leaks are required to be fixed within a specific time period. Under Alberta's recently approved regulation, leaks must be fixed within 24 hours when there are health and safety concerns. Otherwise, leaks must be repaired within 30 days in all cases except when the methane emission is less than 10,000 ppm, or the repair requires a shutdown of the facility (AER 2018b). Alberta's regulation also expects OGI technology to detect methane leak rates of 1 g per hour at an imaging distance of 6m. However, recent field studies suggest that the technology will be able to find leaks of not less than 20 g CH_4 per hour at this specified imaging distance, with only 50%

detection probability (Ravikumar et al. 2018). Alberta's regulation is also silent on what the detection likelihood of the LDAR technologies needs to be at the specified imaging condition.

Ravikumar and Brandt (2017) divided the actual cost of fugitive emission mitigation into 3 parts: one-time capital investment and cost to develop compliance plans, the annual recurrent cost associated with continuous survey programs, and cost of repair and resurvey. Apart from the effect survey frequency has on the cost of implementation, the LDAR mitigation cost is often captured in terms of the number of leaks rather than the size of leaks – which does not capture the effect of leak size on abatement cost (Ravikumar et al. 2018). For this reason, these ballpark estimates of cost may not mirror actual field implementation cost of individual LDAR programs.

Data on CAPEX, OPEX and emission reduction attributes of each mitigation technology considered in this study is presented in Appendix D (Table D.1). We capture the ranges of data values reported by various vendors and previous studies. However, our current results are mainly based on cost data from the Delphi Program (2017) study. This study did not use ICF cost data (ICF 2016) in the calculations, but we have included them for comparison and reference purposes. It should be noted that the data from the ICF report are in 2015 Canadian dollars, whereas the Delphi data are in 2017 Canadian dollars.

Renewable Natural Gas and Hydrogen Addition to the Supply Chain

One of the avenues to reduce the environmental impact of more gas in the energy system is through Renewable Natural Gas (RNG) and Power-to-Gas (P2G) integration with the conventional natural gas supply chain. This section discusses the opportunities and challenges for RNG and hydrogen to complement petroleum-derived natural gas as an environmental impact mitigation strategy. Economic assessments of these complementary technologies are not performed in this report.

RNG is the methane gas derived from organic materials and waste streams which must be processed in order to meet current natural gas pipeline specifications or natural gas vehicle fuel standards. There are three main sources of inputs or "feedstocks" suitable for producing RNG:

- Agricultural and agri-food sources such as unused crop residues, animal manure and food processing waste;
- Forestry bi-products such as wood waste generated during harvest operations;
- Municipal solid waste and bio-solids from wastewater.

Hydrogen produced from renewable sources (such as wind, solar and biomass energy) can be utilized in a variety of applications including power-to-power, power-to-gas, power-to-mobility, power-to-fuels, and power-to-industry. Enriching natural gas with hydrogen is one of the pathways considered for P2G. Hydrogen produced from water electrolysis by large-scale electrolysers could be blended with natural gas and carried through transmission/distribution networks to end-user systems. The accepted level of hydrogen gas is dependent on the inherent design and operation of all the participating elements of the natural gas system: piping materials, storage systems, and end-use equipment.

When produced for injection into the grid, renewable hydrogen bridges electricity networks with gas utilities under the vast existing natural gas infrastructure to provide a fossil-free fuel through which electricity is transported indirectly. This envisioned Power-to-Gas calls for detailed evaluations of the allowable hydrogen levels in the natural gas grid. There are risks of using hydrogen in gas systems related to the existing piping, storage systems, and product end-users, along with fitted equipment such as gas detection devices. Existing knowledge suggests that a significant portion of the natural gas grid can accept up to 10% hydrogen volume concentration, although there remain some concerns about the impacts on underground storage systems, compressed natural gas tanks, gas turbines and the applicability of current gas detection devices.

In summary, the following have been highlighted as benefits of adding hydrogen to the natural gas network:

- Overall benefits: significant reduction of greenhouse gas emissions if hydrogen is produced from renewable sources.
- Hydrogen in automotive applications: potential benefits from reducing petroleum consumption and improving air quality by reducing sulphur dioxide, oxides of nitrogen, and particulate emissions.
- Greening natural gas: when a hydrogen/natural gas mixture is used in existing appliances for heat and electricity generation. This benefit is like increasing the mix of renewable generation on the electricity grid in that it does not require significant changes in end-use equipment.

However, pipelines used in the natural gas grid have not been designed to withstand some specific properties of hydrogen such as the potential for increased permeation and corrosion of piping materials. Originally it was thought that no more than 5% hydrogen could be injected. Depending on the pipeline engineering and downstream uses, ratios up to 12% have been achieved. According to ongoing work on European standardization of power-to-hydrogen applications, most of the European natural gas infrastructure can withstand a volume concentration of 10% hydrogen (Dodge 2014). There have been calls for more investigations to assess the tolerance to hydrogen at several gas grid components, including storage caverns, surface facilities, storage tanks, gas flow monitors and gas analysis instruments (AESO 2014). Some studies have argued that most pipeline materials cannot withstand hydrogen-induced failures (Melaina, Antonia, and Penev 2013).

Hydrogen blends, even at low levels, can be a problem for appliances that are not properly maintained. As the blend level increases from 1% to 12%, additional precautions must be taken to minimize the impact on end-use systems. High blend levels might be safe in transmission lines, but additional risks are posed from the city gate through distribution lines. Older cast iron and steel pipes can become brittle when exposed to hydrogen. Modern plastic pipes are known to be more effective for hydrogen transport and can handle higher concentrations, but the end-use systems need to be compliant and compatible with such gas compositions. End-use applications of gas may impose constraints on the hydrogen level in the gas. For instance, compressed natural gas (CNG) vehicles and gas turbines are mainly designed for fuel gas containing less than 2 or 3% hydrogen in volume (SBC Energy 2014).

Other specific challenges of hydrogen addition to the gas supply are briefly discussed below.

Leakage Rates

Hydrogen has a permeation rate that is 4-5 times higher than that of methane, raising the concern for leakage from pipeline and piping walls. Literature suggests, however, that hydrogen concentration volumes up to 20% maintain the same order of leakage as pure natural gas (NEB 2017a).

Leak Detection

Another concern for hydrogen addition in natural gas networks is the accuracy of existing gas detection devices, where some devices are more sensitive to hydrogen presence, and some will only react with diluted methane. Most gas detector devices used for natural gas grid inspections are flame ionization detection (FID) devices that are specified for hydrocarbon detection and can accept low hydrogen levels. Research shows that they can accept up to 5% hydrogen levels in a natural gas product.

Natural Gas Transmission Pipelines

Pipeline integrity is a concern with the addition of hydrogen in the natural gas product due to faster degradation from hydrogen embrittlement. Transmission pipelines operate at high pressures of 600 – 2,000 psig, which further elevates concern of fatigue and fracture. Hydrogen concentration volumes up to 10% do not cause concern for hydrogen embrittlement in high-pressure transmission pipelines (NRCan 2016).

Hydrogen additions in natural gas were also tested for the initiation and growth of existing defects in pipelines. It was shown that hydrogen concentrations up to 50% did not cause any catastrophic failures (NEB 2017a).

Natural Gas Distribution Network

Hydrogen embrittlement in distribution and service piping is not a major concern since those lines operate at low pressures of 0.5 psig to 100 psig. Moreover, many of the branching distribution piping and service piping are made of materials that are compatible with hydrogen, such as ductile iron, cast, and polyethylene (NEB 2017a).

Research studies show concern for hydrogen concentration volumes higher than 20% in distribution networks due to increased risk of ignition. With a hydrogen flammability range of 4-75% gas-to-air volume compared to that of natural gas (5-15% gas-to-air volume), hydrogen has a wider range of ignition than natural gas. This wider ignition range poses a higher risk of ignition for hydrogen. Distribution and in-house piping systems are of concern due to their proximity to urban areas and presence in confined spaces.

Gas Metering

Three different gas meters with polymer membranes were tested, and results showed discrepancies of less than 2% for all tested meters (NEB 2017a). Testing was carried out with a controlled sample of 100% natural gas and other samples comprised of 50% methane/50% hydrogen. As such, the discrepancy is expected to be smaller for lower hydrogen concentrations.

Underground Storage

Studies have shown difficulty in recommending a reliable concentration of hydrogen in underground storage systems (Natgas 2013b, 2013c; AGA 2018). Research studies have only investigated the effect of hydrogen on the inner reservoir (Natgas 2013c; AGA 2018), although for a thorough understanding of the effects, well conditions and interactions between wells and reservoirs should be evaluated. The biggest issue identified was the potential growth of bacteria. Hydrogen is a good substrate for sulphate and sulphur-reducing bacteria – a potential for hydrogen sulphide (H2S) formation. This can consume the stored hydrogen, plug the reservoir rock or wellhead and pose safety concerns due to its toxic, flammable and corrosive properties. Previous researchers were unable to identify a safe operating hydrogen concentration, hence, highlighting the need for advanced studies (Natgas 2013b, 2013c; AGA 2018).

Compressed Natural Gas Steel Tanks, Metallic and Elastomer Seals

Severe restrictions are already in place for hydrogen presence in compressed natural gas steel tanks, where even small quantities can pose serious concerns due to hydrogen embrittlement. According to UNECE Regulation 110 for compressed natural gas (CNG) vehicles, hydrogen gas concentration is limited to 2% by volume (if the tank is made from steel with an ultimate tensile strength higher than 950 MPa). Moreover, gas-carrying components in CNG vehicles are only tested for a hydrogen gas content of 2% by volume (Natgas 2013a), probing further research into their ability to withstand higher hydrogen levels. Concerns also exist for leak tightness of metallic and polymer seals in the CNG vehicles.

Gas Engines

Hydrogen enriched natural gas increases flame speed and reactivity that result in increased in-cylinder peek pressures (AER 2018c). This can cause several concerns in combustion gas engines, including:

- Increased combustion and end-gas temperature which leads to higher NOx emissions and sensitivity to engine knock
- Increased engine wear
- Reduced power output
- The unreliability of lambda sensors leading to inaccurate lower oxygen measurement in exhaust gas. Lower oxygen readings in exhaust gas cause the engine to run on a leaner air/fuel mixture which affects performance and emissions.

Some research suggests hydrogen addition levels of up to 2-5% (AER 2018c). This recommendation is to be considered with caution since different engines can have different allowance limits, especially those operating at the higher emissions range.

Gas Turbines

Many gas turbines have fuel specifications that restrict hydrogen levels below 5% by volume. For most installed base gas turbines, hydrogen level specifications are below 1% by volume. Hydrogen levels in natural gas fuel for gas turbines affect the performance of the turbine combustion system, and acceptable levels should be evaluated for different types of turbines. Syngas turbines, for example, can accept hydrogen levels as high as 50% by volume.

Renewable Natural Gas and Power-to-Gas in Canada

As of 2016, up to 30 power-to-gas projects were in service in Europe (Beez 2018) and global awareness has recently been on the increase, including the launch of the Canada-US P2Gas Taskforce to examine hydrogen blending in the natural gas network. Canadian based companies such as ATCO and Enbridge are both spearheading hydrogen electricity-storage facilities. Enbridge recently cooperated with Hydrogenics and started the operation of a P2G facility in Ontario that stores hydrogen during off-peak electricity generation and utilizes the stored fuel for hydrogen fuel cell applications, injection into the natural gas grid or converting back to electricity when needed. Although currently operating at 1 megawatt, the future of the project is to scale up to 100 megawatts by 2020. Enbridge currently estimates hydrogen blending concentrations up to 5% in the natural gas grid and can store up to 100 billion cubic feet of hydrogen gas (Hamilton 2012).

FortisBC also has a Long-Term Gas Resource plan that is investigating hydrogen blending in natural gas grids, estimating that the process would account for up to 15% of annual demand by 2036. Other projects include collaboration between BC Hydro and ITM Power, Chiyoda Corporation, and Mitsui, for renewable hydrogen export.

Hydrogen Tolerance in Canada

According to the current consensus of international projects and studies investigated for hydrogen injection into natural gas pipelines, it seems that most parts of the natural gas system can be tolerant of the gas mixtures of up to 10% by volume of hydrogen. The minimum threshold for requiring no action or limited action would be around 2% of hydrogen by volume in natural gas. It is also possible to mix up to 5% of H2 by volume with natural gas, but this tolerance calls for further investigation and could be a driver for innovation of end-use appliances.

It's expected to be challenging to increase the allowable hydrogen concentration up to 20 vol.% without the generation of extensive performance and safety information for end-use appliances and gas analysis methods. In general, the natural gas grid would be tolerant for 1%-5% hydrogen blending by volume at any point of the network, and up to 20% in distribution pipelines with no critical downstream appliances (SBC Energy Institute 2014b). In case of underground porous rock storage, hydrogen blending with natural gas may induce bacterial growth forming hydrogen sulphide and consuming hydrogen. Steel tanks in natural gas vehicles have a limit value for hydrogen of 2%. Most currently installed gas turbines were specified for a hydrogen fraction in natural gas of 1 vol.% or even lower and 5-15 vol.% may be attainable by using new or modified types of gas turbines. It is recommended to restrict the hydrogen concentration to 2 vol.% for gas engines, but higher concentrations up to 10 vol.% may be possible for dedicated gas engines with sophisticated control systems (Altfeld and Pinchbeck 2013). However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must, therefore, be assessed on a case-by-case basis.

In Canada, Alberta-based TransCanada Pipeline's (TCPL) natural gas quality specifications do not directly limit the amount of hydrogen that can be injected into TCPL's pipeline; however, the lower limit on the heating value of 36 MJ/m^3 implicitly limits hydrogen content to around 5 vol.% in a TCPL pipeline at any point. Natural gas can be stored in depleted oil or gas reservoirs, aquifers, salt caverns, LNG or CNG units, and pipeline networks as line pack. In the case of underground gas storage, a 2007 survey specified Canadian underground natural gas storage capacity as 583.8 billion cubic feet (Bcf), consisting of 44 depleted reservoirs, and 8 salt caverns. Salt caverns being used for storing natural gas could be suitable for much higher hydrogen concentrations in natural gas or even pure hydrogen but require modification of equipment such as injection wells or compressors at gas storage facilities. However, since these major storage assets are linked to the existing natural gas grid, their practical capacity for hydrogen would be limited by existing pipeline standards/specifications, to around 5% (vol.).

Chapter 3: Modelling and Analysis Approach

Methodology

A hybrid method based on emission and activity factors and material balance is used to quantify methane emissions along the natural gas supply chain. Emission factors for various equipment and events at the supply chain segments are multiplied by the activity factors to estimate total emissions in 2017. Where 2017 activity factors are not available, the most recent data is scaled following the segment of the supply chain which is affected, using either relative raw natural gas production for upstream activities or the relative gas demand for downstream activities. Material balance is applied using reported data on gas flows and handling at oil batteries or gas gathering facilities for the upstream segment in each province. Material balance is also used to quantify burner-tip emissions using end-use demand data.

Considering that climate mitigation goals and emission reduction targets are often set for specific locations or geographical areas (e.g., regions, provinces, whole countries), the material balance can be performed in terms of the molar quantities of unaccounted for gas (UFG) resolved to the annual basis so that yearly environmental conservation performance can be benchmarked against policy targets. UFG quantification is common practice among gas utilities who use it for a general assessment of losses in their network or subnetworks. Regulatory filings by Canadian gas distribution companies reveal that average distribution level losses for most companies have been observed at around 1%; this is outside losses beyond customer metering (OEB 2017). The geography of focus can be regarded as a System Control Area – SCA (Umeozor 2018). Potential elements of the gas supply chain within an SCA is represented in Figure 1.1, covering the various segments of the chain. Total emissions over the area during a period of time (Δt) can be estimated using a discrete form of the molar balance as:

$$Q_{\Delta t} = Q(N) - Q(s) = \sum_{k:N\to s} [I_{C1}(k) - E_{C1}(k) + S_{C1}^{W}(k) - S_{C1}^{I}(k) + P_{C1}(k) - U_{C1}(k)]$$

where I_{C1} is the total molar flows of methane into the SCA, E_{C1} accounts for all out-flows, S_{C1} represent storage injection and withdrawals, P_{C1} is the production, and U_{C1}, is the utilized amount during this period. Each term in the extreme right-hand side of the above equation is evaluated over the timeframe of the analysis using discrete calculus as follows:

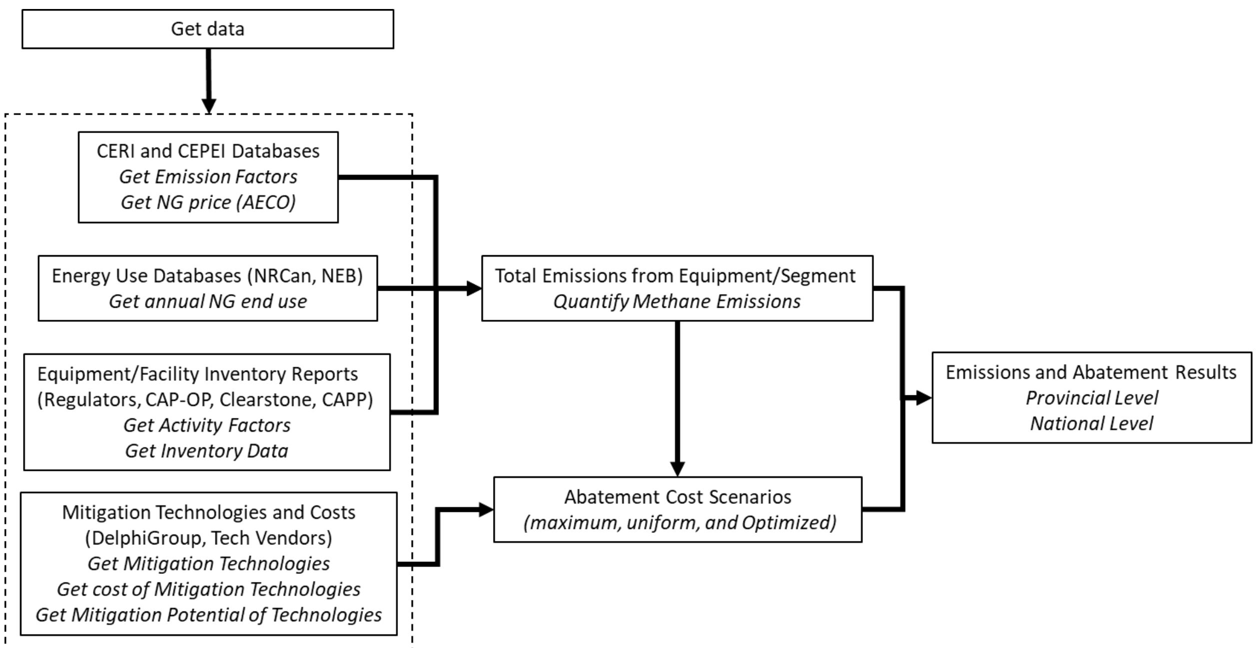
$$\sum_{k:N\to s} X(k) = X(N) + X(N-1) + \cdots + X(s-2) + X(s-1)$$

When and where there is insufficient data along the supply chain to implement the UFG approach, the quantification can be performed using emission and activity factors as:

$$q(X_k) = Emission\ factor(X_k) \times Activity\ factor(X_k)$$

This structure of the model accommodates both spatial and temporal variabilities of the input data, in terms of the supply chain (SCA) and the discrete time (k), respectively. Ignoring such variabilities have been shown to introduce pitfalls in methane emission estimates (Vaughn et al 2018). Data on province-specific methane content of natural gas is obtained from CEPEI and CERI databases for both raw natural gas and post-processing marketable gas. CERI's database consists of Canada-specific data reported by industry or academic publications through actual field measurement studies. Figure 3.1 shows the modelling workflow for emission quantification and mitigation cost analysis. Most recent equipment and facility inventory data is obtained along with activity factors from provincial regulators, CAP-OP Energy study (Cap-Op Energy 2018a), Clearstone Engineering study (Clearstone Engineering 2018), and CAPP reports (CAPP 2018b).

Figure 3.1: Modelling Workflow for Methane Emission Quantification and Abatement Cost Analysis



Emission reduction potentials and costs (CAPEX and OPEX) of mitigation technologies are obtained from vendors and a recent pneumatics abatement cost study by the Delphi Program (2017). Mitigation cost is calculated on a net cost basis using an average 2017 (AECO) natural gas price of C$2.25 per GJ. Costs of each mitigation technology are spread over the lifetime. For equipment or components that are likely to be replaced more frequently, a 3-year lifetime is used. For others not changed as often, a 10-year lifetime is assumed for all. All calculations of CO_2 equivalent emissions are based on a GWP of 25, consistent with both federal and provincial environmental and regulatory agencies in Canada. We further evaluate overall global warming impacts of emissions using the upper range of the most recently updated methane GWP value of 36.

Datasets for the upstream segment include a production well to outflows from processing plants and straddle plants to pipelines for transmission. Midstream segment datasets start from transmission pipelines to the city gate (gas metering and regulation station). Figures 3.2 to 3.4 show the upstream, midstream and downstream emission sources including the data sources for gas volumes, emission and activity factors.

Figure 3.2: Upstream Methane Emission Sources

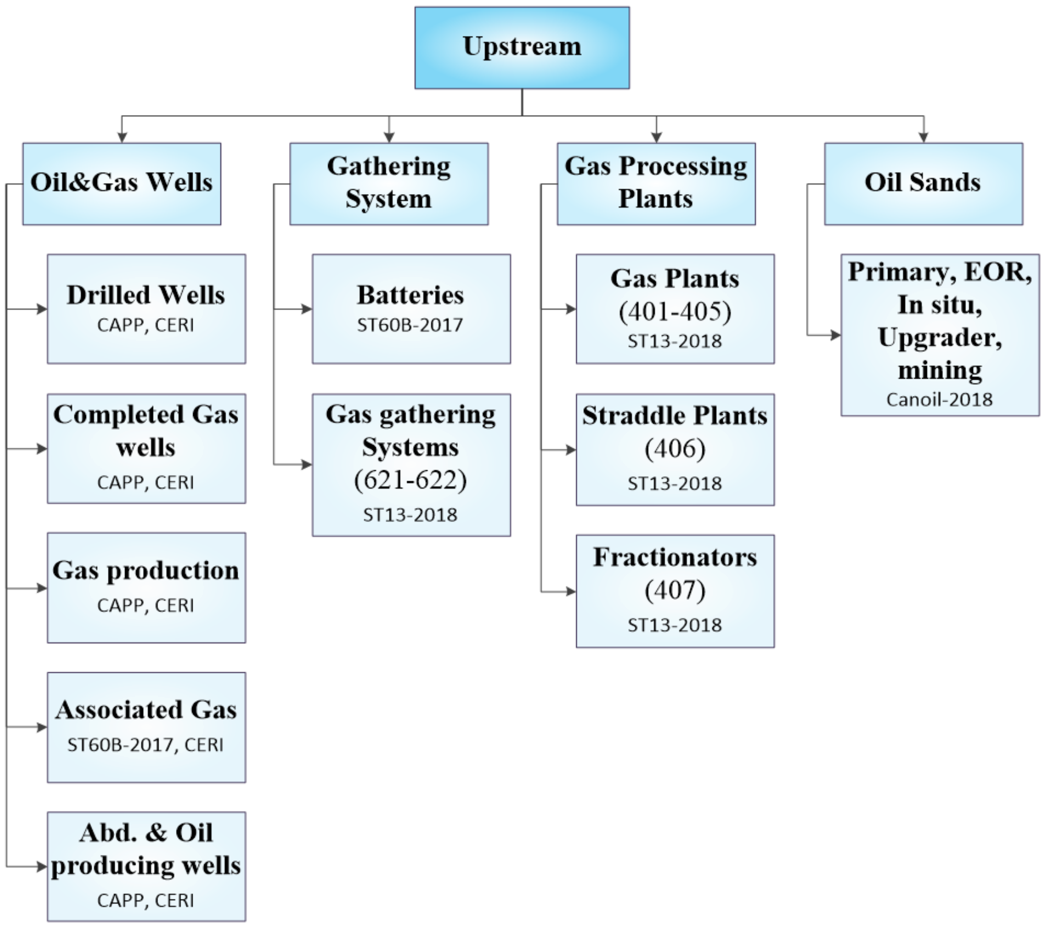


Figure 3.3: Midstream Methane Emission Sources

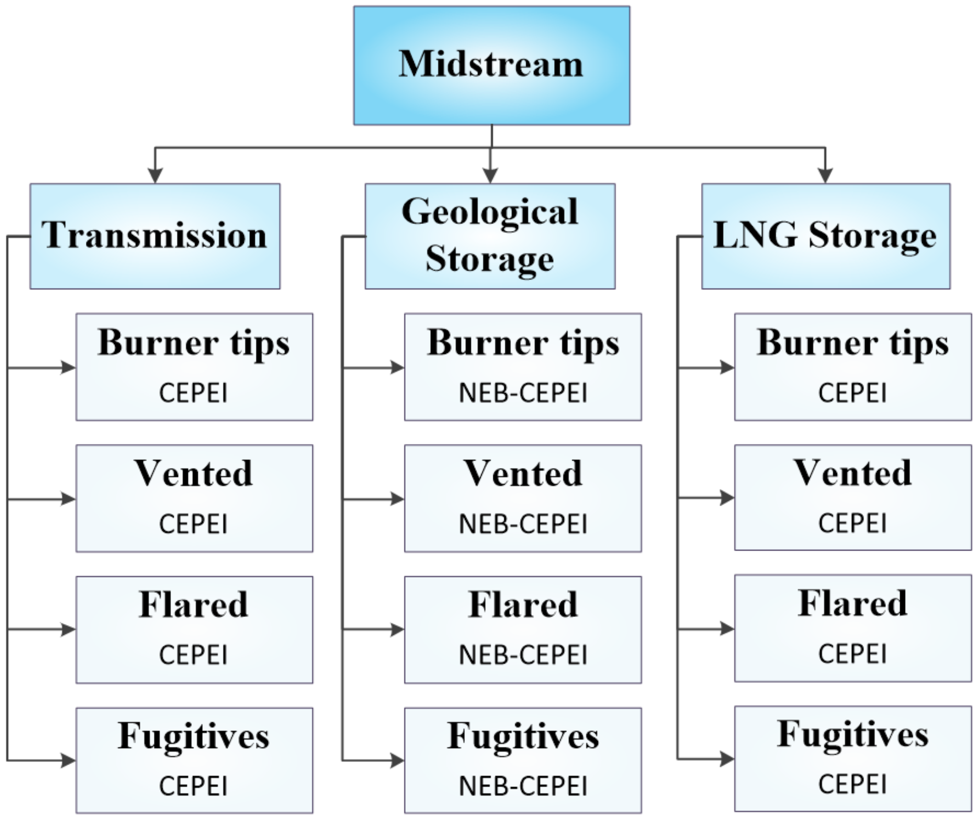
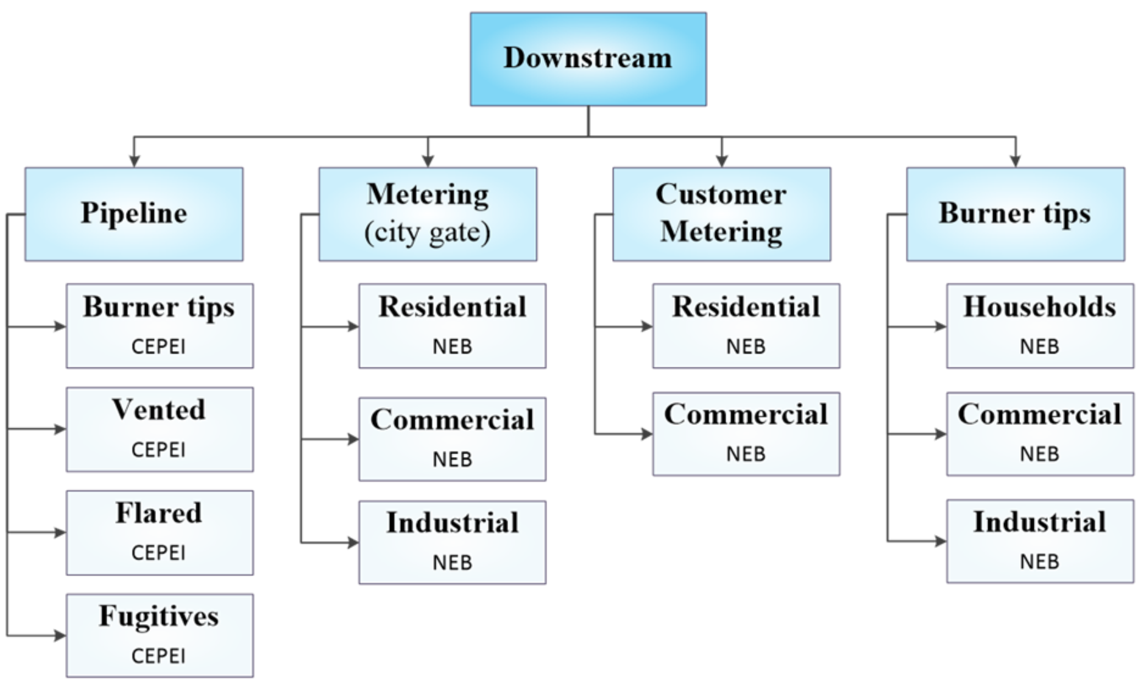
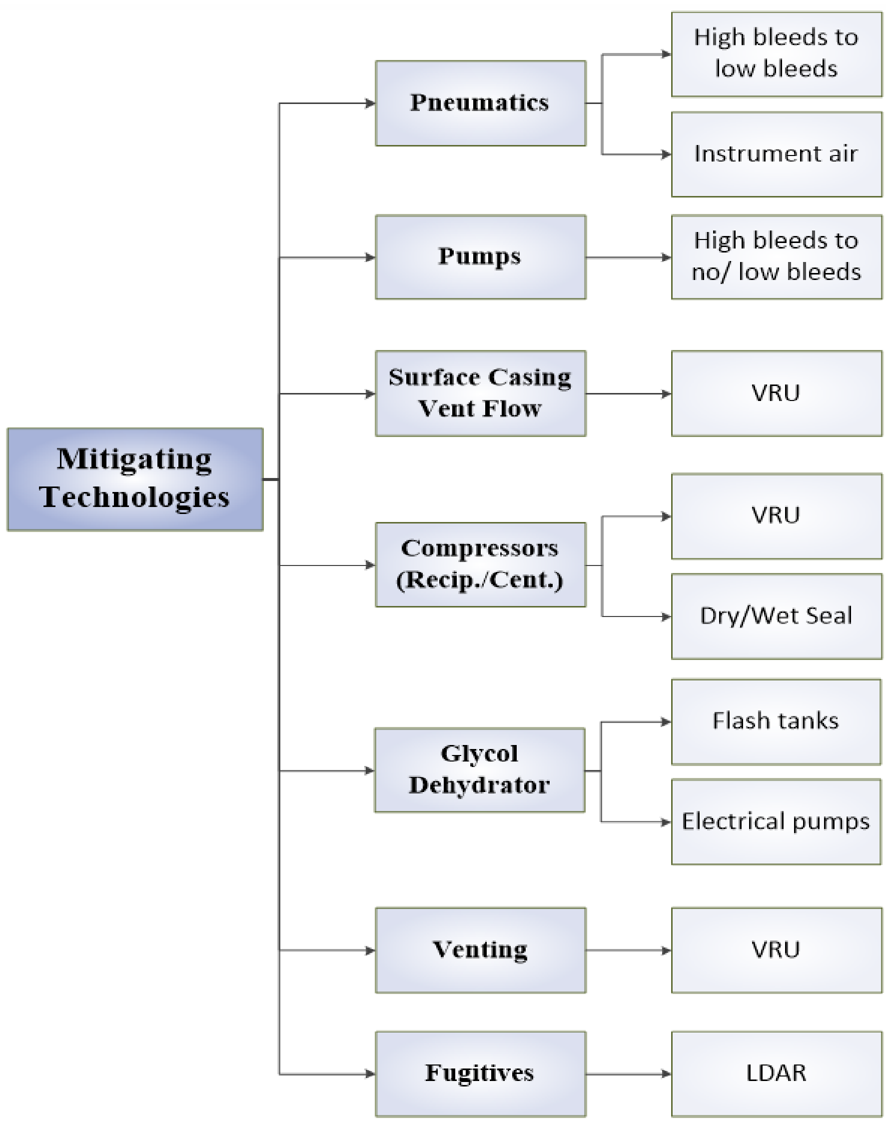


Figure 3.4: Downstream Methane Emission Sources



Abatement cost calculations do not include carbon credits for saved gas, although it is done on a net cost basis using the value of captured gas. Figure 3.5 shows the emission source categories and mitigation technologies applied in each case. Fugitive emissions are divided into surface casing vent flow emissions to which vapour recovery unit (VRU) can be deployed and others for which LDAR can be used to reduce the emissions. Venting emissions are divided into routine venting (from pneumatics, pumps, compressors and dehydrators) and non-routine venting for which VRUs can be used to recover vented gas. Undestroyed methane during combustion is categorized differently from fugitive and vented emissions, and also separately for each supply chain sector as flared (upstream), line heating (midstream) and burner-tip (downstream) emissions. Mitigation of undestroyed methane during combustion is not treated in this study.

Figure 3.5: Mitigation Technologies Applied to Various Emission Source Categories



By combining the methane emission estimation model and abatement cost information for the various emission source categories and mitigation technologies, emission reduction opportunities and their economic implications can be evaluated. This study evaluated three different hypothetical policy scenarios to achieve emission reductions by adopting various combinations of mitigation technologies. These scenarios are:

- **Maximum reduction**, which evaluated the economic cost and maximum amount of emissions reduction that can be achieved using the mitigation technologies assessed in this study.
- **Uniform reduction**, which evaluated the economic cost and emissions reduction achieved if a 45% reduction target is assigned to each emitting device in the supply chain (except burner-tip emission).
- **Optimal reduction**, which identifies cost-effective mitigation pathways to reduce emissions to 45% of baseline levels as reported in the National Inventory Report (this scenario is created to mimic methane regulations in Canada).

The maximum reduction scenario is used to assess potential mitigation cost to control all emissions from every release source in the supply chain, whereas the uniform reduction scenario considers the impact of indiscriminate application of 45% reduction policy goal across all emission source categories. To determine the optimal emission reduction portfolio required implementation of a linear programming model defined as follows: considering the set of mitigation technologies to reduce emissions from various source categories in the gas supply chain, the objective of the optimization model is to select the group of technologies and reduction targets from each emission source so that the total cost of methane regulation is minimized. For provinces with existing methane regulations (such as British Columbia, Alberta, and Saskatchewan), the provincial baseline years are adopted, whereas for the other provinces the federal baseline year (2012) emissions are applied. Further details of the modelling approach are given in Appendix B.

These scenarios are applied to the entire Canadian natural gas supply chain. This contrasts with the existing federal and provincial regulations which place methane emission reduction targets mainly in the upstream sector. In order to realize the most economic reductions in the optimal scenario, some of the emission source categories are omitted when choosing where mitigation should be deployed. These include emissions from midstream venting, fugitives, compressors and surface casing vent flow. Optimal emission reduction is calculated from the average of the results obtained using the lower and upper ranges of abatement cost for each source category. This scenario does not arbitrarily specify what emission sources should be controlled but uses the optimization model to determine cost-effective mitigation to meet expected reduction at both federal and provincial levels.

The combined modelling workflow for methane emission quantification, abatement cost estimation, and mitigation adoption scenarios are integrated into a Visual Basic software program which we refer to as the Integrated CH_4 Emission Reduction Model (ICERM). Further details on the ICERM modelling tool is available in Appendix C.

Chapter 4: Modelling and Analysis Results

Methane Emission Quantification

Figures 4.1 and 4.2 show the emission quantification results for each province, indicating the shares of overall emissions at each sector of the natural gas supply chain and the emission sources contributing the total emissions, respectively.

Western provinces with significant upstream oil and gas activities generate more emissions than eastern provinces where natural gas demand may be appreciable but not produced locally. Alberta contributes more emissions than other provinces with an estimated total in 2017 of about 24.5 Mt CO_2e, of which the upstream sector is responsible for up to 97%. These emissions are mainly from oil and gas wells and gathering facilities. Like Alberta, the other western provinces, British Columbia, Saskatchewan and Manitoba, have higher upstream emission footprints with total estimated values of 2.2, 11.7, and 0.8 Mt CO_2e, respectively. Both upstream and midstream emissions from producing provinces are primarily of the fugitive and venting categories. Alberta Government estimated venting and fugitive methane emissions to be 48% and 46% of total upstream emissions, respectively (Government of Alberta, 2019). The downstream emissions are mostly from fugitive and burner-tip sources both representing about 98% of downstream releases in most cases.

Eastern provinces do not have as much upstream oil and gas activity, so their emissions come from the midstream and downstream sectors of the gas supply chain where either imported gas or Canadian gas from other provinces is transported for distribution to various end-users. As such, gas transmission and distribution emissions are the major sources. In these areas, midstream sector emissions are from fugitive sources and venting activities. In Ontario, fugitive and vented emissions accounted for over 90% of their total midstream emissions. Fugitive and burner-tip emissions due to undestroyed hydrocarbons at end-use dominate downstream sector emissions. The fugitive emissions are often from distribution pipelines and customer metering losses. Figure 4.3 shows overall Canadian sectoral emissions according to the source categories. Both upstream and midstream emissions from producing provinces are primarily of the fugitive and venting categories. The downstream emissions are mostly from fugitive and burner-tip source categories both representing about 98% of downstream releases in most cases.

Considering that most of the gas production in Western Canada is consumed in higher population areas in the east, the overall supply chain emissions could be reallocated on a demand basis. Table 4.1 shows the distribution of natural gas demand among Canadian provinces. Alberta and Ontario are the major demand centers for Canadian gas. Alberta's demand is driven mainly by electricity and oil sands operations steam requirements, whereas Ontario's demand is for space, water heating and manufacturing (petrochemical) uses. On this reallocation basis, Ontario and Quebec would be considered major contributors to Canadian gas supply chain emissions, with a combined 2017 impact of 11.56 Mt CO_2e. However, Alberta remains the highest emitter at a total of 20.28 Mt CO_2e.

Figure 4.1: Sectoral Contributions to Overall Methane Emissions Across Canadian Provinces

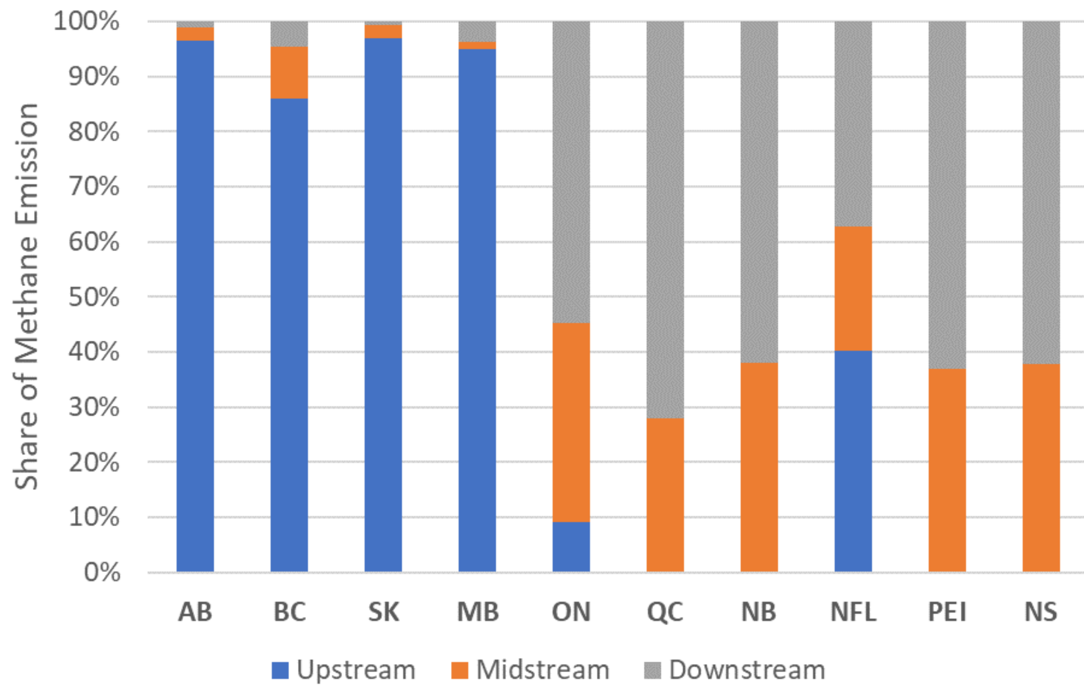


Figure 4.2: Natural Gas Supply Chain Methane Emission Sources Across Canadian Provinces

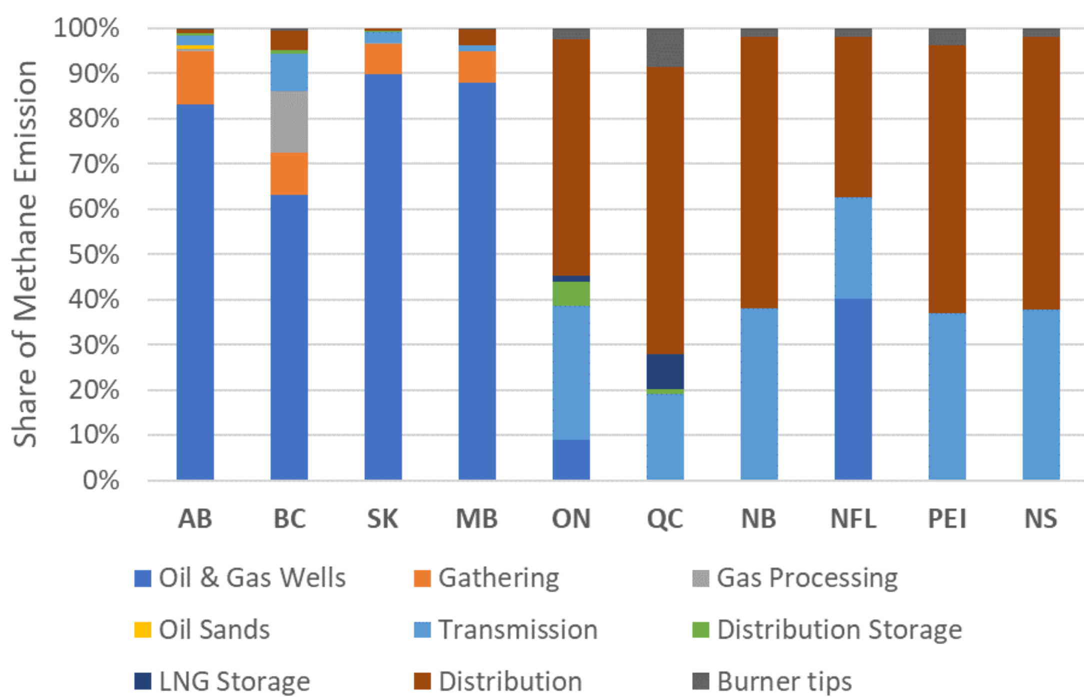


Figure 4.3: Overall Sectoral Methane Emissions by Source Category

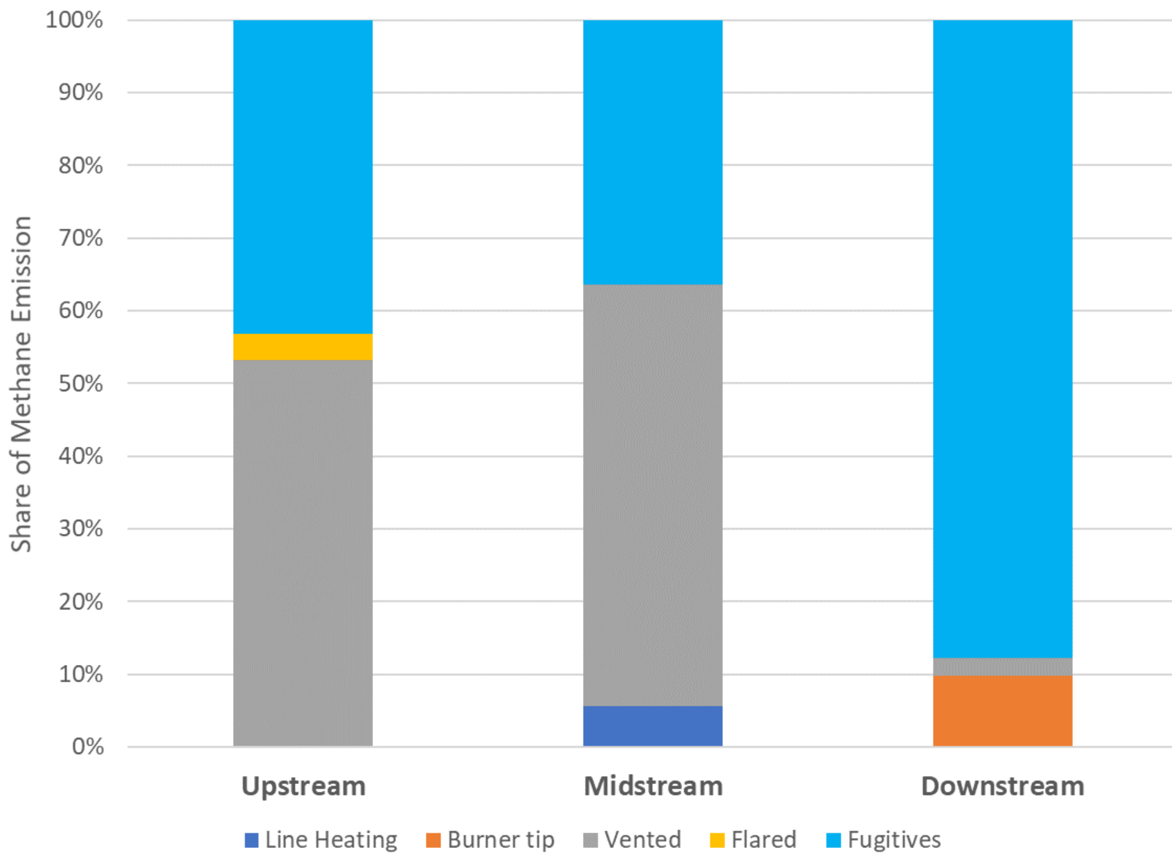


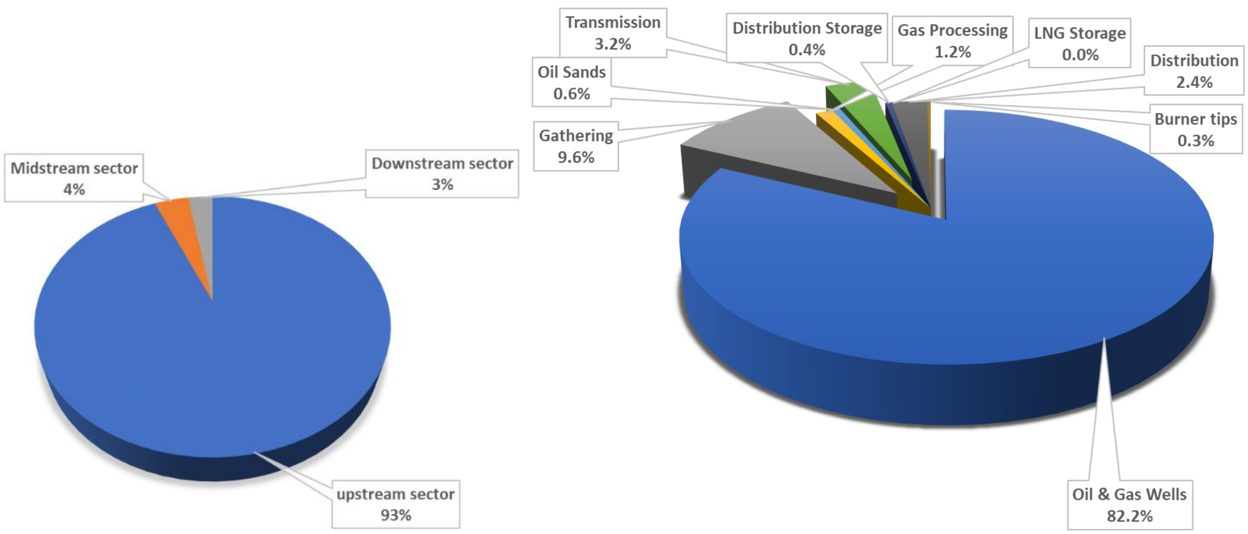
Table 4.1: Provincial Natural Gas Demand and Contributions to Total Emissions in 2017

Description	AB	BC	SK	MB	ON	QC	NB	NL	PEI	NS
Natural Gas Demand (2017)	50%	8%	9%	2%	23%	6%	1%	1%	0%	1%
Based on ICERM Estimation										
Total Emissions (Mt CO_2e)	24.53	2.18	11.74	0.85	0.93	0.08	0.02	0.04	0.00	0.02
Based on Demand Share										
Total Emissions (Mt CO_2e)	20.28	3.27	3.63	0.80	9.27	2.29	0.29	0.30	0.01	0.21

Figure 4.4 shows the distribution of emissions on an overall Canadian basis for 2017. Due to the predominant influence of Alberta's emissions, upstream sources still account for most of the emissions to the tune of 93% from oil and gas wells, gas gathering and processing stations. The midstream segment accounts for about 4% from the gas transmission, LNG and distribution

storage systems, whereas the downstream sector contributes about 3% from distribution and end-use. Total estimated Canadian gas supply chain emissions for the reference year (2017) is 40.40 Mt CO_2e. This dominance of upstream emissions accounts for the current upstream oil and gas focus of methane emissions reduction regulations by Canadian federal and provincial governments.

Figure 4.4: Overall Canadian Methane Emissions from Natural Gas Supply Chain Segments and Source Category



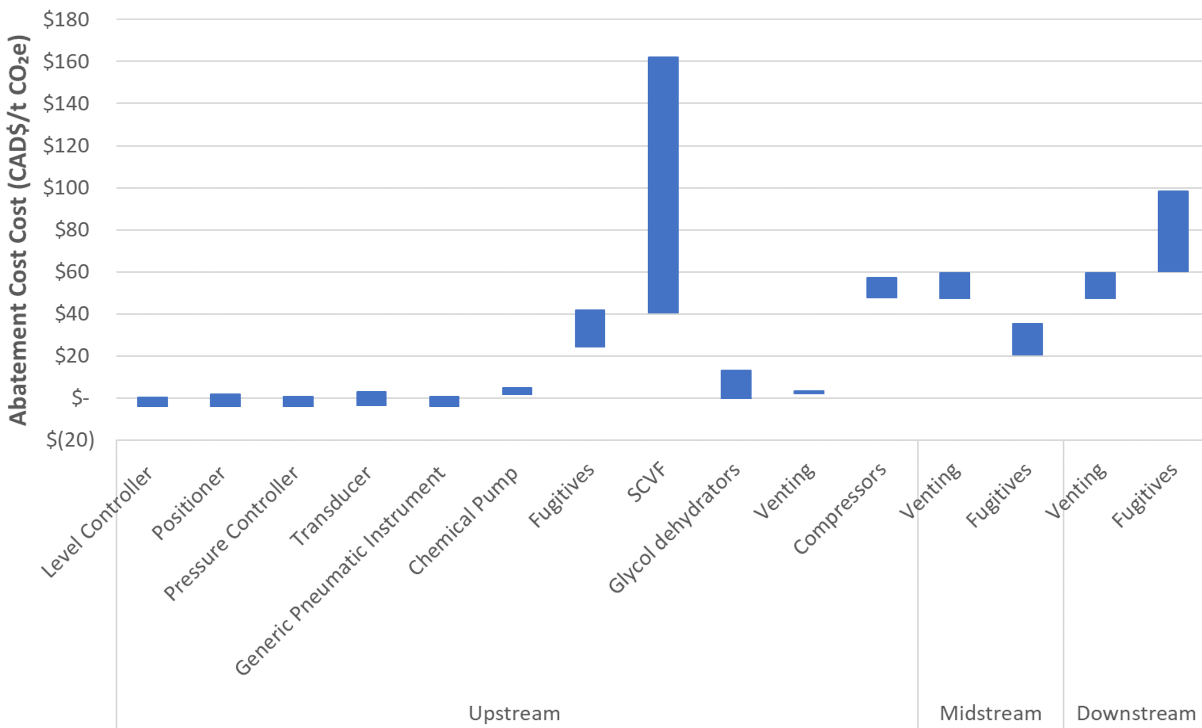
Relative to the total natural gas production in the same year, this amounts to an overall loss of about 1.5% from the entire gas supply chain. Previous studies have estimated that a net environmental benefit of natural gas over coal is maintained when total losses from natural gas systems do not exceed 3% of total production for a 20-year horizon global warming potential or 10% for 100-year horizon global warming potential (Barkley et al. 2017). However, allowable accuracy of measurement equipment by Industry Canada is 2% (Environment Canada 2000). Given that our model utilizes various reported measurement data, it could be argued that the upper limit on our estimate would be about 3.5% of the total gas production.

Moreover, there are also uncertainties on estimates based on emission and activity factors reported by previous studies. Recent analyses have put a bound on the error in fugitive emission estimates to within -16% to 34% (Ravikumar, Wang, and Brandt 2017). Detailed emission quantification results for all provinces are presented in Appendix E.

Abatement Cost Estimates

Figure 4.5 shows the abatement cost for emission reduction from the various source categories in the gas supply chain using the identified mitigation technologies highlighted in Figure 3.5. Leak detection and repair (LDAR) implementation is assumed to be on a triannual survey basis performed by the facility operators (internal inspection) at 60% detection probability. Abatement costs are presented for control of fugitive emissions in each of the three sectors of the network. The range of each estimate depends on the variety of mitigation technologies deployable to each emitting source category and the differences in individual technology vendor and services pricing. The costs are calculated from the CAPEX, OPEX and value of conserved gas over the lifetime of a technology. The venting source category refers to non-routine venting, whereas routine venting is presented in terms of the emitting device. Abatement costs of upstream LDAR range between \$24 to about \$42 per tonne CO_2e. Midstream fugitives are less diffuse with fewer sources than either upstream or downstream since they only occur at specific points along the transmission pipeline systems. Midstream cost is about \$20-\$35 per tonne CO_2e, whereas the downstream fugitive emission abatement cost is in the range of \$60 to \$98 per tonne CO_2e.

Figure 4.5: Abatement Cost for Reducing Methane Emissions from Various Source Categories



Pneumatic devices have the lowest mitigation costs, and in most cases have negative values which indicate net profitability to replace high bleeding pneumatic systems with lower or zero-emission ones and control losses of natural gas from those systems. The abatement costs for pneumatic devices range between -\$4 and \$5 per tonne CO_2e. Cheapest devices to replace are level controllers and the most expensive are the chemical injection pumps. Comparing costs across supply chain sectors, the highest abatement costs are for upstream and downstream fugitives, compressors and surface casing vent flow (SCVF) emissions, in addition to the costs of abating vented methane from mid- and downstream sectors. Venting is the major source of midstream emissions due to releases at compressor stations and undestroyed methane at stationary line heaters. CERI has used actual Canadian field data on hydrocarbon destruction efficiencies at each sector of the supply chain to account for unlit combustion methane in the model.

Assessment of Mitigation Scenarios

Figure 4.6 shows methane emission reductions from each supply chain sector and emission source category for the Canadian natural gas systems under the three hypothetical policy scenarios. The three scenarios are shown together for a closer comparison of the reductions from each source category and under each policy scenario. The reductions in the maximum and uniform scenarios are predominantly from upstream venting, fugitives and pneumatic pumps. In the optimal scenario, reductions are mainly from upstream venting and pneumatic devices including pumps, controllers and generic instrumentation. In order to realize the most economic reductions in the optimal scenario, some of the emission sources are not controlled since the corresponding mitigation technologies are not adopted in this scenario. These include emissions from upstream fugitives, compressors, surface casing vent flow, midstream venting and fugitives, in addition to downstream fugitives.

At the provincial level, optimal (45%) reduction of emissions is based on contributions to total Canadian methane emissions during the baseline year. This scenario does not arbitrarily specify what emission sources should be controlled but uses the linear programming model to determine the cost-effective mitigation satisfying targeted reduction at both federal and provincial levels. For provinces with existing methane emissions regulations (such as British Columbia, Alberta, and Saskatchewan), the optimal scenario specifies methane emission reduction targets according to provincial baselines as reported in the National Inventory Report. For other provinces, federal methane regulation baseline year (2012) emissions are adopted. Furthermore, CERI also evaluated the optimal reduction scenario for a case where the federal methane regulation baseline emissions are used to specify reduction targets for all provinces. Table 4.2 shows oil and gas methane emission data for BC, AB, SK, MB and ON as reported in Canada's National Inventory Report.

As can be observed in Figure 4.6, emissions from SCVF and compressors are not reduced in the optimal adoption scenario due to their higher abatement costs. Most emission reduction opportunities are identified from pneumatic, venting and fugitive sources under each mitigation scenario. Also, in line with the distribution of overall emissions across supply chain sectors, the upstream sector is the major source of the emissions and where most mitigation efforts need to be channelled to achieve deeper cuts in emission reductions. This is in line with the focus of current Canadian federal regulation which targets reductions from upstream oil and gas and transmission, whereas Alberta and British Columbia regulations focus only on upstream oil and gas (excluding oil sands).

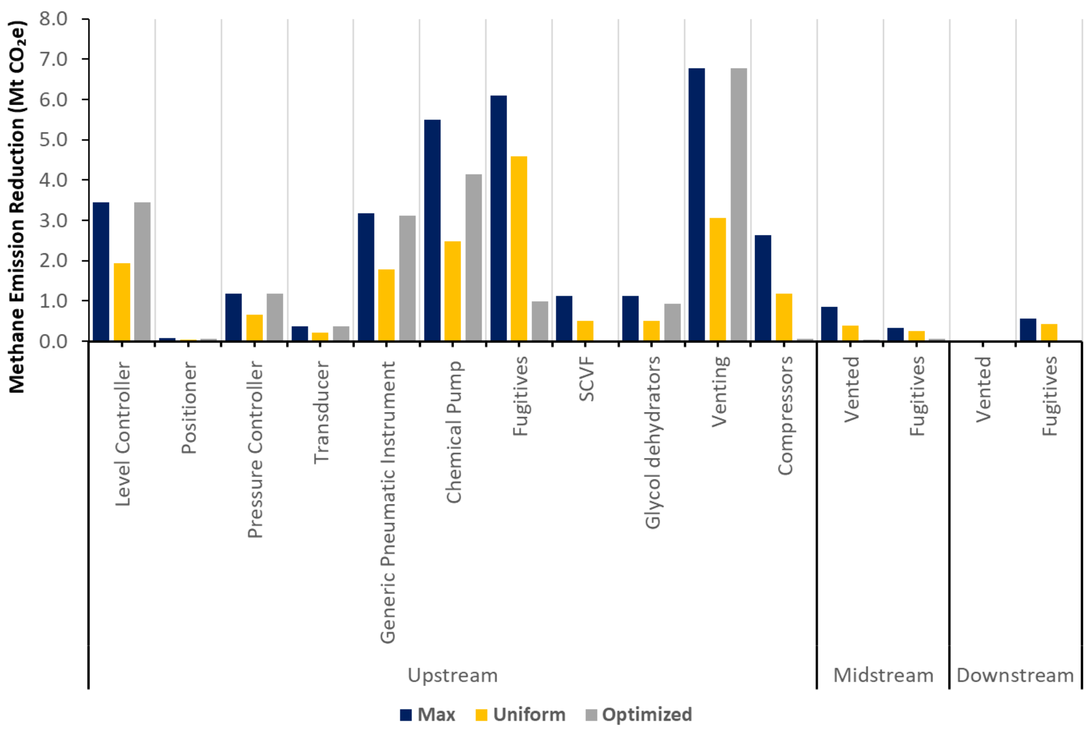
Table 4.2: Provincial Oil and Gas Methane Emissions (Mt CO_2e)

Definition	2012	2014	2015
British Columbia	4.52	3.48	3.13
Alberta	31.56	31.48	31.50
Saskatchewan	17.55	12.11	11.38
Manitoba	0.83	0.31	0.30
Ontario	1.50	1.14	1.23

The range of total abatement costs in the optimized policy scenario corresponds to the results obtained when the lower and upper ranges of abatement costs for each source category are applied in the simulation. In any run of the optimized policy scenario, the reduction target can be constrained to any desired value, and the optimization model determines the combinations of mitigation technologies to satisfy this constraint at the least total abatement cost. When the objective is to determine the maximum amount of reduction that can be achieved if methane emissions from all sources are to be controlled, the ability of each mitigation technology to stop the emissions determines the level of reductions achievable relative to total emissions from all sources in the supply chain.

Although total Canadian supply chain emissions quantified by ICERM for 2017 is 40.40 Mt CO_2e, the maximum reduction achievable using the assessed mitigation technologies is about 33 Mt CO_2e. This calls for improvement in the performance and choices of mitigation technology options, and the need further innovation in the mitigation technology designs. In the uniform reduction policy scenario, it is observed that enforcing the same reduction target (45%) across all source categories may not be as effective in attaining higher emission reduction goals considering that most resources may be dissipated on lower emitting but higher abatement cost source categories. Cost-effective mitigation entails identifying the target supply chain sectors and emission sources with the greatest opportunities for low-cost emission reductions.

Figure 4.6: Methane Emission Reduction from the Various Sectors and Source Categories under the Three Hypothetical Policy Scenarios for Canada



Notes:
1) Each colour represents a hypothetical policy scenario
2) Venting in this figure refers to non-routine, whereas routing venting is presented in terms of the emitting devices.

Putting it All Together

Figure 4.7A presents a results summary showing total emission reductions and cost of achieving those reductions under the various abatement analysis scenarios for the entire Canadian natural gas supply chain. Table 4.3 shows the provincial breakdown of these costs along with the emission reductions. For the three policy scenarios, the total cost of emission reductions in the maximum reduction scenario is in the range of $3.0 to $5.5 billion, for a total methane emission reduction of about 33 Mt CO_2e. For the uniform scenario, the cost is in the range of $1.4 to $2.6 billion and total reduction of 18 Mt CO_2e, whereas the optimal reduction scenario achieves about 22 Mt CO_2e emissions cut for a total cost range of $0.7 to $1.4 billion. It should be noted that these do not include costs of administration, measurement and reporting which are required by existing methane regulations in Canada.

In comparison to existing methane regulations, Canadian federal regulation has a target of 40-45% reduction below 2012 levels by 2025. Canadian national inventory report data indicate that total methane emissions in that baseline year (2012) were 107.5 Mt CO_2e, of which about 51% (55 Mt CO_2e) are from oil and gas. Therefore, if the regulation covered all sectors of the natural gas supply chain for a reduction target of 45%, that would amount to about 25 Mt CO_2e. If our optimal reduction scenario applies the 2012 baseline reduction target across all provinces, total cost of emissions reduction would be in the range of $0.9 to $1.7 billion. Figure 4.7B shows the total cost ranges and emission reductions for all three scenarios when 2012 baseline reduction targets are enforced in the optimal reduction scenario. However, the federal regulation aims to achieve reductions from the upstream sector and transmission (midstream), so if the 45% reduction is applied to these components alone, the reduction target would be slightly below 25 Mt CO_2e, given that most of the emissions are from the upstream sector. To compare with the US reduction target, Sheng et al. (2017) estimated Canadian natural gas supply chain methane emissions to be about 70% lower than that of the US (or about 135 Mt CO_2e). Therefore, under the US-Canada joint agreement, the US reduction target by 2025 would be about 61 Mt CO_2e.

Figure 4.7A: Emission Reduction and Ranges of Total Cost of Abatement under the Three Hypothetical Policy Scenarios for the Entire Canadian Natural Gas Supply Chain

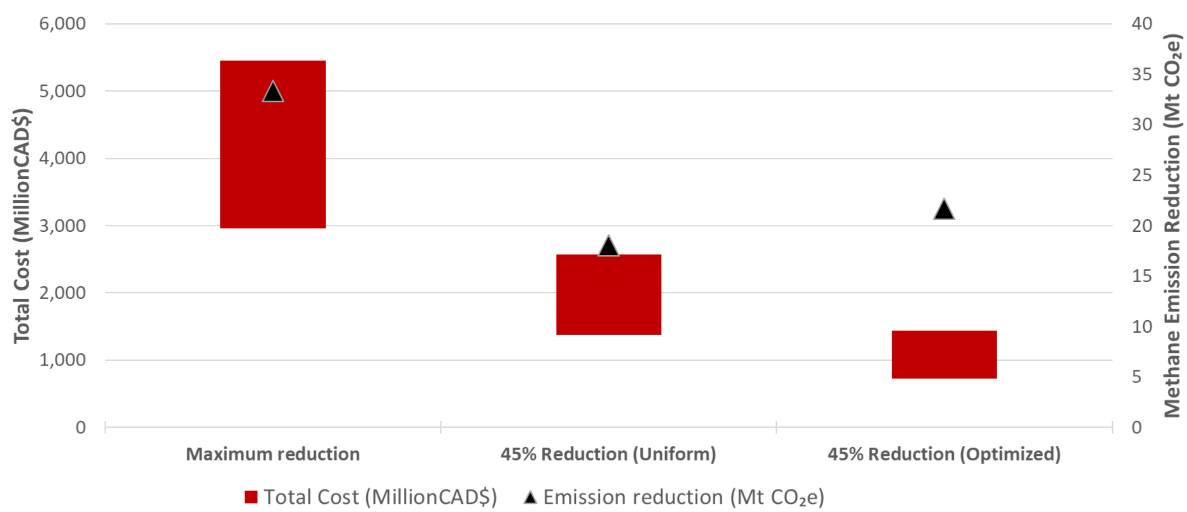
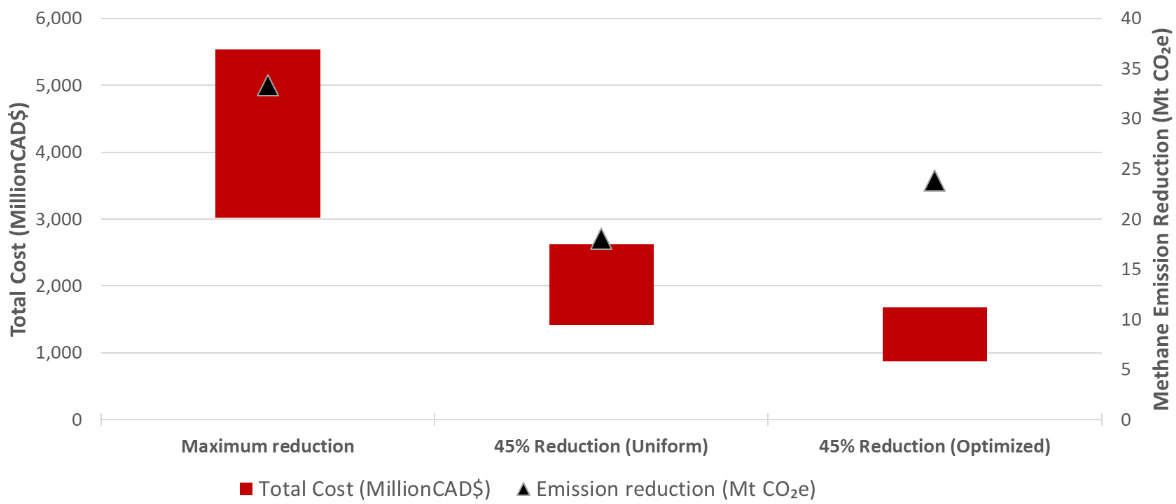


Figure 4.7B: Emission Reduction and Ranges of Total Cost of Abatement when Federal Methane Regulation Baseline Reduction Targets are Applied across all Provinces



As aforementioned, CERI evaluated the optimal policy scenarios in two cases. In the first case, we use the regulation baseline emission for provinces having their own methane regulations and apply the federal baseline to other provinces without existing methane regulation. In the second case, we apply the federal baseline to all provinces. Detailed breakdown of both costs and methane emission reductions in both cases are presented in Tables 4.3 and 4.4, respectively.

Alberta and British Columbia regulations are designed to achieve a reduction in oil and gas methane emissions by 45% below 2014 levels by 2025. Saskatchewan's methane regulation aims to cut between 40% to 45% below 2015 level by 2025. Similarly, if these three regulations covered the entire natural gas supply chain in their respective provinces, Alberta's reduction target would be about 14.16 Mt CO_2e, British Columbia's would be about 1.56 Mt CO_2e, while Saskatchewan's would be 5.12 Mt CO_2e (at 45%). Relative to the federal regulation with 2012 baseline and 45% reduction targets, the numbers would be 14.20 Mt CO_2e, 2.04 Mt CO_2e and 7.90 Mt CO_2e, respectively. However, all three provincial regulations aim to achieve their methane emission reductions from the upstream sector alone. Therefore, their numbers would be slightly below these values given the dominance of upstream emissions.

Table 4.3: Emission Reduction and Ranges (lower and upper values) of Total Cost of Abatement under Various Analysis Scenarios for Implementation in the Entire Canadian Natural Gas Supply Chain

Province	Total Cost (million CAD$)			Emission Reduction (kt CO_2e)		
	Maximum Reduction	45% Reduction (Uniform)	45% Reduction (Optimized)	Maximum Reduction	45% Reduction (Uniform)	45% Reduction (Optimized)
AB	1,824-3,378	846-1,589	462-935	20,442	11,007	14,166
BC	178-310	84-148	103-164	1,778	970	1,564
SK	798-1,527	368-715	104-256	9,773	5,267	5,121
MB	52-109	24-51	(-1)-10	758	381	371
ON	96-122	49-64	49-64	559	358	358
QC	9-11	4-6	4-6	51	33	33
NB	2-4	1-2	1-2	15	10	10
NFL	2-4	1-2	1-2	15	10	10
PEI	0-1	0-1	0-1	0.5	0.3	0.3
NS	2-3	1-2	1-2	11	7	7
Canada	2,962-5,464	1,378-2,576	725-1,440	33,401	18,042	21,639

Table 4.4: Emission Reduction and Ranges (lower and upper values) of Total Cost of Abatement under the Analysis Scenarios using Federal Baseline for all Provinces

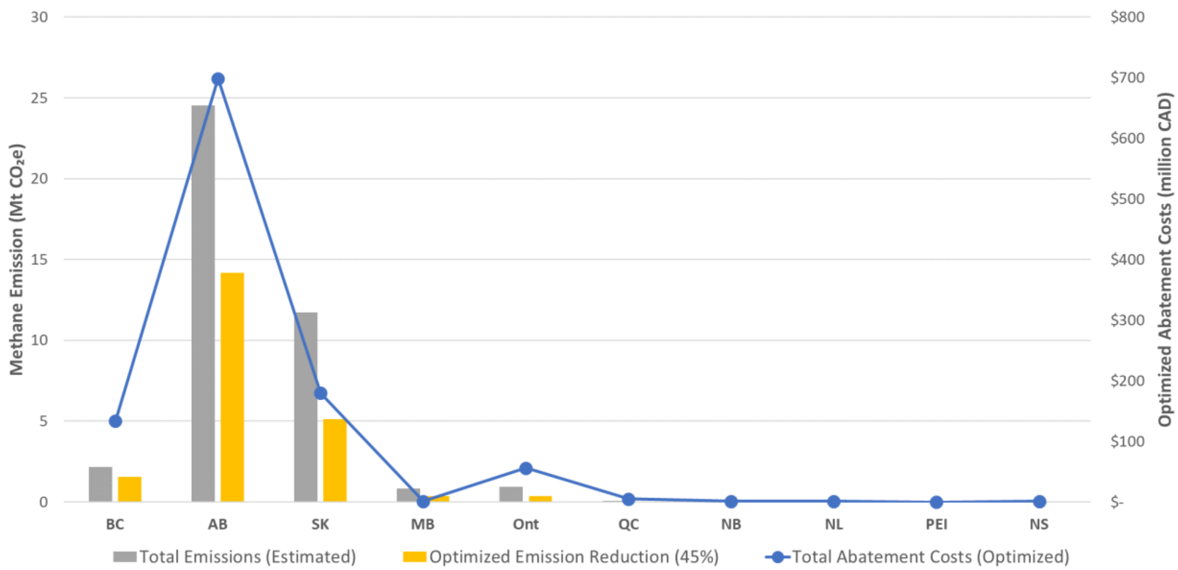
Province	Total Cost (million CAD$)			Emission Reduction (kt CO_2e)		
	Maximum Reduction	45% Reduction (Uniform)	45% Reduction (Optimized)	Maximum Reduction	45% Reduction (Uniform)	45% Reduction (Optimized)
AB	1,824-3,378	846-1,589	462-935	20,442	11,007	14,201
BC	187-321	89-154	89-154	1,778	970	970[12]
SK	855-1,600	398-755	260-506	9,773	5,267	7,898
MB	52-109	24-51	(-1)-10	758	381	371
ON	96-122	49-64	49-64	559	358	358
QC	9-11	4-6	4-6	51	33	33
NB	2-4	1-2	1-2	15	10	10
NFL	2-4	1-2	1-2	15	10	10
PEI	0-1	0-1	0-1	0.5	0.3	0.3
NS	2-3	1-2	1-2	11	7	7
Canada	3,028-5,549	1,413-2,623	867-1,681	33,401	18,042	23,858

[12] Not optimized because estimated reduction for 2017 is less the federal baseline reduction target (based on 2012 level), so uniform reduction result is used here.

Figure 4.8 shows the provincial breakdown of estimated methane emissions, required emission reductions and total abatement cost for an optimal implementation of emission reduction targets at the 45% reduction below 2014 levels (for Alberta and British Columbia), 2015 level (for Saskatchewan), and 2012 levels (other provinces). The estimated total abatement cost for Alberta is $700 million (2017 dollars), for an emission reduction program focusing on upstream oil and gas emissions in line with current regulation, while this cost for British Columbia and Saskatchewan are about $134 and $180 million, respectively. In 2017, British Columbia produced 4.98 Bcf per day of natural gas, whereas Saskatchewan produced 0.51 Bcf per day. Saskatchewan generated more emissions than British Columbia over the same year due to higher oil production activities where associated gas is often emitted from upstream facilities.

In the case of Ontario, baseline oil and gas methane emission in 2012 from the National Inventory report is 1.5 Mt CO_2e. ICERM estimated Ontario's 2017 methane emission to be about 0.93 Mt CO_2e; of which only 0.56 Mt CO_2e can be reduced using the available mitigation technologies assessed in this report. Given that 45% of the baseline emission is 0.675 Mt CO_2e – which is higher than the maximum reduction, there is no room to optimize the reduction scenarios. Therefore, optimization of mitigation options is not performed because of the small number of source categories available in midstream and downstream supply chain sectors where most of the emissions in the province emanate from. The 45% reduction in the optimized mitigation strategy applies to the provincial contribution to overall Canadian methane emissions in the baseline year. Given the fewer source categories for Ontario's emissions, the emission sources to be mitigated in both the uniform and optimized reduction scenarios are essentially the same. Hence, the abatement costs are also the same. Therefore, the total abatement cost of the uniform (45%) emission reduction scenario of $56 million is applied to Ontario. If the maximum reduction is to be achieved, it would cost between $96 to $122 million. Moreover, upstream impacts of US gas imports into Ontario in 2017 of about 2.35 Bcf per day is not accounted for in the current model.

Figure 4.8: Provincial Methane Emission Reduction Opportunities and Economic Impacts under a Cost-Effective (optimized) Mitigation



CERI acknowledges that more accurate data for modelling will become available over time as new field measurements are reported. Hence, future versions of ICERM will incorporate updated information in order to improve the accuracy of results.

Chapter 5: Conclusions

In line with the ongoing debate on the economic and environmental impacts of methane emissions from natural gas supply chains, CERI developed a modelling tool with the objective to investigate methane emission reduction opportunities in Canadian natural gas supply chains. The model, called the Integrated CH_4 Emission Reduction Model (ICERM), is packaged into an open source Visual Basic tool which is designed to provide a more formalized and consistent framework for emission quantification and mitigation scenarios analysis to support analyses of methane emission reduction pathways and the impact of regulatory policy on overall abatement implementation cost. Considering the complexities of the issues involved and current data acquisition and availability challenges, the modelling platform developed in this work provides guidance and sustains the ongoing debates as anticipated improvements in measurement techniques, mitigation technologies and more refined data become increasingly available through further field inventory and measurement campaigns.

ICERM estimated total methane emissions from Canadian natural gas supply chains in 2017 to be 40.40 Mt CO_2e using a methane global warming potential (GWP) value of 25, which is generally adopted by Canadian organizations and governments. On the basis of the most recent 100-year methane GWP upper estimate of 36, total emissions amount to 58.18 Mt CO_2e. Most of these emissions arise from upstream oil and gas sector activities predominantly from venting (routine and non-routine) and fugitive sources. The sources of methane emissions are identified and quantified using the combinations of emission and activity factors along with mass balances to account for the gas flows during 2017. Abatement cost analyses are also performed on a net basis using costs (CAPEX and OPEX) of mitigation technologies and the economic value of avoided emissions based on the average AECO gas price in 2017 of $2.25 per gigajoule (AER, 2017). Three mitigation analyses scenarios are investigated to mirror potential pathways for regulatory compliance. These scenarios are maximum reduction, uniform reduction and optimal reduction. In the maximum reduction case, emission reduction is only constrained to the capacity of a mitigation technology to cut emissions when adopted. Uniform reduction of emissions entails targeting all identified emission sources for the same percentage of reduction (45% reduction), and the optimal reduction case determines the most economic combination of mitigation choices to adopt in order to meet the regulatory target of 45% reduction below the baseline amount (provincial/federal policy dependent) of emissions by 2025.

Of the three abatement scenarios, the total cost of emission reduction in the maximum reduction scenario is in the range of $3.0 to $5.5 billion, but this overshoots the reduction target by about 12 Mt CO_2e. For the uniform scenario, the cost is in the range of $1.4 to $2.6 billion yet undershoots the targeted by 4 Mt CO_2e. The optimal scenario achieves the policy target of about 22 Mt CO_2e at a total cost range of $0.7 to $1.4 billion. An overview of the emission source categories with promise for cost-effective abatement point to upstream operations where transitions from higher bleed to lower or zero-emission pneumatic devices, avoidance of methane venting and integrated LDAR implementation programs will achieve significant reductions in emissions from the natural gas supply chain. This observation supports the current federal and provincial methane emission regulations which focus on meeting reduction targets from the upstream sector. Although federal regulations target oil and gas methane emissions reductions from the upstream sector up to transmission segment, Alberta's regulation is focused only on the upstream sector (excluding oil sands) to cut the emissions – just as Saskatchewan's and British Columbia's regulations are. However, current regulations must clarify the requirements and conditions for detection, measurement and monitoring of fugitive methane emissions.

Fugitive emissions are known to be the most unpredictable source of methane releases from natural gas systems. LDAR is the commonly accepted method to control these emissions, and there are a number of existing and emerging technologies for LDAR implementation. The effectiveness of these technologies depends on a number of factors related to their ability to detect emissions: costs of detection, repair and resurvey, and equivalency criterion of emerging technologies to the standard regulatory ones. Most reports in the literature agree that there is no single suitable LDAR solution to all fugitive emission problems in the gas supply chain. Regulations will require the right blend of specificities and flexibilities that accommodate variabilities in the characteristics of emissions from different source categories, geographical regions, and seasons of the year.

Among the policy measures that have been proposed for effective methane emission mitigation are:

- Coordinated measurements, monitoring, reporting, control and verification,
- Setting performance targets to regulate emissions,
- Policy mechanisms that account for regional and temporal variations,
- Technology-blind regulations to drive cost-effective mitigation, and
- Integrated implementation framework in synergy with other GHG mitigation policies.

The recent regulations enacted by the federal government pursuant to controlling methane emissions will impact Canadian upstream oil and gas facilities. Most of the impacted facilities are in the Canadian provinces of British Columbia, Alberta and Saskatchewan. The Canadian government has stated that unless provincial regulations achieve equivalent or more conservative emissions reductions than federal ones, the provinces will be required to conform to the proposed federal regulations. Consequently, federal regulations will duplicate or conflict with the respective provincial regulations that are not as equally comprehensive. So far, provincial targets by the Saskatchewan, Alberta and British Columbia governments have been introduced, but more detail is needed on how proposed mitigation strategies will yield the desired results, and how that would be assessed and verified in the face of data handicaps for both system operators and regulators.

For this reason, a number of other studies are ongoing to address some of the data and quantification methodology challenges limiting the current understanding of the economic and environmental impacts of gas supply chain emissions. In Canada, the Fugitive Emissions

Management Program Effectiveness Assessment (FEMP EA) is one such study under a collaborative effort by the Petroleum Technology Alliance Canada (PTAC), the Canadian Association of Petroleum Producers (CAPP) and the Explorers and Producers Association of Canada (EPAC). Such programs and other regulatory requirements on emission measurement, monitoring and reporting are expected to provide new field data and additional insights to enhance current knowledge.

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Appendix A: Regulations

Table A.1: Provincial and Federal Methane Emission Regulations

<table>
<tr><th></th><th>British Columbia</th><th>Saskatchewan</th><th>Federal</th><th>Alberta</th></tr>
<tr>
<td>Well Testing</td>
<td>Well Flaring

Flaring for testing, cleanup and completions must not exceed a total of 72 hours.

In-line testing is mandatory for all wells on private/Crown land within 1.25 km of a residence and 3.0 km of a suitable pipeline.

Oil and Gas Well Test Flaring and Venting Durations:
<table>
<tr><th>Well type</th><th>Venting/Flaring Time limit</th></tr>
<tr><td>Crude Oil Wells</td><td>72 hours</td></tr>
<tr><td>Gas Wells</td><td>72 hours</td></tr>
<tr><td>Unconventional Gas Development Wells</td><td>120 hours</td></tr>
<tr><td>Unconventional Gas Non-Development Wells</td><td>336 hours</td></tr>
</table>
</td>
<td>New Oil Wells

- Associated gas testing is required for new non-heavy oil wells and is limited to ten days.
- Associated gas testing is required for new heavy-oil wells and is limited to lesser of 6 months or until combined flaring/venting volumes exceed 900 m3/day on a consecutive 3-month duration. Approval for extension is required.</td>
<td></td>
<td>New oil wells: The solution gas flaring during the test period must not extend beyond the time required to obtain data for the economic evaluation and for sizing conservation equipment.
Existing oil wells: Any flaring for testing, cleanup, and completions must not exceed 72 hours. (See section 3.2 of Directive 060)

The following flaring, incinerating, and venting time limits: crude oil wells/sites: 72 hours
a) Bitumen wells/sites: until flow rates exceed an average of 900 m3/day for any consecutive three-month period, not to exceed six months
b) Gas (non-associated, non-coalbed methane) wells: 72 hours
c) Dry coalbed methane development wells (producing less than 1 m3 of water per operating day): 120 hours
d) Dry coalbed methane nondevelopment wells (producing less than 1 m3 of water per operating day): 336 hours
e) Wet coalbed methane wells (producing more than 1 m3 of water per operating day).

Well test results and information required by flaring and incineration permits must be submitted in accordance with the requirements of Directive 040, the applicable permit, and section 10, Directive 060.</td>
</tr>
</table>

Conservation at Oil and Gas Facilities	**New Oil Facilities** If the Net Present Value (NPV) of the gas conservation project is greater than -$50,000CAD, the wells should be shut in until conservation is implemented. **Existing Oil Facilities** Permit holders should conserve solution gas at all sites where: - Combined flaring and venting volumes are greater than 900 m^3/day per site and the decision tree process and economic evaluation (Chapter 1.8) result in an NPV of greater than -$50,000CAD. - The gas to oil ratio (GOR) is greater than 3000 m^3/m^3. All wells producing with a GOR greater than 3000 m^3/m^3 at any time during the life of the well should be shut-in until the gas is conserved. - Flared volumes are greater than 900 m^3/day per site and the flare is within 500 m of an existing residence, regardless of economics. - For any sites flaring or venting combined volumes greater than 900 m^3/day and not conserving, a review of conservation economics should be done at least once every 12 months - Conserving facilities should be designed for 95 per cent conservation with a minimum operating level of 95 per cent. **Natural Gas Facilities** Facilities should conserve gas when: - Conservation economics are greater than an NPV of $0 CAD - Flared volumes are greater than 4,000 m^3/day and flare is within 1 km of existing residence Economic evaluation should be conducted once a year for facilities not conserving and flaring/venting gas more than 4,000 m^3/day. New facilities with flaring/venting combined volumes greater than 6,000 m^3/day should implement gas conservation unless deemed uneconomic. Gas conservation systems should be designed for 95% conservation.	**(1) Conservation at new oil wells and facilities** - The test period for non-heavy oil wells is limited to ten days or longer where approval is given by ECON. Upon completion of the test period, if test shows that the combined flaring and venting volumes exceed 900 m3/day, the well or the site must be shut-in until associated gas conservation evaluation is completed. - If testing shows that combined flaring and venting volumes do not exceed 900m3/day per site, economic evaluation of associated gas conservation is not required, and the well may proceed to produce without conserving although it may be required by ECON. - If flared volumes are greater than 900m3/day per site and the flare is within 500 metres of an existing residence, regardless of economics, the gas must be conserved. - If a new residence is constructed or relocated within 500 metres of an existing associated gas flare or vent after the effective date of S-10, the licensee must provide information to the new residents about the flaring or venting operations. - New heavy oil well or new heavy oil single well or multi-well battery must be tested in order to obtain data for the economic evaluation or for sizing conservation equipment. The test period is limited to the lesser of 6 months or until combined flared and vented volumes exceed a rolling average of 900 m3/day for any consecutive 3-month period. **(2) Conservation at Existing Oil Wells and Facilities** - Licensee must conserve associated gas at all sites where the combined flaring and venting volumes are greater than 900m3/day (3 month rolling average) per site and it meets the economic criteria (e.g., NPV > –$50,000Cdn) - An oil well producing with a GOR greater than 3500m3/m3 at any time during the life of the well must be shut in until the gas is conserved. - If new residence is constructed or relocated within 500 metres of an existing associated gas flare after the effective date of S-10, the licensee must provide information to the new residents about the flaring operation.	Upstream oil and gas facilities with combined flaring, incinerating or venting volume greater than 40,000 Sm^3/year must not vent more than 15,000 Sm^3 of hydrocarbon gas during a year. Venting from the following events/systems are excluded: - Liquids unloading - Blowdown - Glycol Dehydration - Pneumatic controller, pump or compressor - Start-up/shutdown of equipment - Well completion - Emergency incidents that risk human health/safety Well completion involving hydraulic fracturing with a Gas-to-Oil ratio of at least 53:1 must not vent associated flow-back gas unless gas does not contain sufficient combustion heating value. (does not apply to BC and AB if facility is operating within province's regulations) Hydrocarbon Gas Conservation equipment must be operated such that 95% of the hydrocarbon gas is conserved and is operated continuously other than maintenance periods.	Solution Gas Flaring Limit is 670 million cubic metres (10^6 m^3) per year. Solution gas must be conserved at all sites where: • The combined flaring and venting volume are greater than 900m3/day per site and the decision tree process and economic evaluation result in a net present value (NPV) greater than –Cdn$55 000 • The gas-oil ratio (GOR) is greater than 3000m3/m3. All wells producing with a GOR greater than 3000 m3/m3 at any time during the life of the well must be shut in until the gas is conserved • Flared or incinerated volumes are greater than 900 m3/day per site and the flare or incinerator is within 500 m of a residence, regardless of economics; or • The AER directs the licensee, operator, or approval holder to conserve solution gas, regardless of economics Conserving facilities must be designed for 95% conservation with a minimum operating level of 90%.

<table>
<tr>
<td></td>
<td>Permit holder must apply for approval before discontinuing gas conservation system.</td>
<td>- For any sites flaring or venting combined volumes greater than 900 m3/day and not conserving, a review of conservation economics must be done at least once per year, to verify that it is not economically feasible to conserve the associated gas
- ECON may still require economic evaluations for sites flaring or venting combined volumes less than 900 m3 per day and not conserving on a case-by-case basis if it is believed that conservation may be feasible.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-routine/ temporary flaring, incinerating and venting</td>
<td>Frequent Non-Routine Flaring/Venting

Venting/Flaring is not an acceptable alternative to gas conservation

Permit holders are to take reasonable efforts in minimizing and investigating upset events.

Solution/Associated gas must be processed in priority to non-associated gas to minimize flaring/venting.

Permit holder must provide notification to the Commission 24 hours prior to a planned non-routine flaring event and provide a notification 24 hours within an unplanned flaring event.

Operational requirements for non-routine/upset events listed in Table 1.1 of guidelines – specific to shutdown categories and durations

Gas processing plants are not recommended to exceed 6 major non-routine flaring events in a 6-month period. Major flaring events are defined as:

<table>
<tr><td>Inlet Capacity</td><td>Major flaring event</td></tr>
<tr><td>>50*10^4 m^3/d</td><td>> 10*10^4 m^3</td></tr>
<tr><td>15-50 * 10^4 m^3/d</td><td>>20% of daily inlet</td></tr>
<tr><td><15 *104 m^3/d</td><td>>30*10^4 m^3</td></tr>
</table>
</td>
<td>Venting/Flaring is not an acceptable alternative to gas conservation
Site specific emission concentration restrictions may be applied if gas with odorous components is vented
Reasonable level of safety precaution should be taken when continuously venting more than 900 m^3/day
Gas venting complaints made by the public may be investigated and permit holder shall provide acceptable justification
Hydrocarbon products stored in atmospheric tanks at gas plants, compression stations or gas batteries must not exceed a true vapour pressure of 83 kPa at 21.1^{o}C if tanks are vented to atmosphere.
Permit holder must provide notification to the Commission 48 hours prior to a planned temporary/non-routine flaring event.
Permit holders are to minimize non-routine/temporary flaring, incinerating and venting during upsets and outages of gas conservation facilities.
Non-routine or temporary flaring, incineration and venting may be carried out in an emergency, plant turn-around, drilling, well servicing, routine maintenance, etc… under reasonable levels of precaution and environmental/safety considerations.
Non-routine/temporary flaring, incinerating and venting shall not exceed 7 days unless approved.
Temporary venting at wells, facilities and gathering systems must not contain free hydrocarbon liquid and total gas volume must not exceed 2,000 m^3 with duration less than 24 hours. Such incidents are permitted 3 times a month with a total cumulative volume less than 2,000 m^3.
Temporary planned venting is not permitted within 500 m of a residence unless consent/approval is obtained.</td>
<td>Venting volume limits do not include venting during emergency events that are required to avoid human health/safety risk.</td>
<td>Must reduce battery or solution gas plant inlet gas volumes by 50% of average daily solution gas production over the preceding 30-day period for Planned Shut-down.
Must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period
• No flaring from wells that have H2S content greater than 10%
• Production may be sustained at rates that will provide enough throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25% of the average daily solution gas production, a variance must be obtained from the appropriate AER field centre
• Notify residents within 500m at least 24 hours before planned flaring event
• Notify individuals who have identified themselves to the licensee or operator as being sensitive to or interested in emissions from the facility
• The appropriate AER field centre must be notified 24 to 72 hours in advance if the event meets reporting requirements
No reduction in the plant inlet is required

Must investigate causes of repeat nonroutine flaring or venting and take steps to eliminate or reduce the frequency of such incidents

Temporary flaring permit must be obtained to flare:</td>
</tr>
</table>

		Venting must not occur within - 25 m of any flame-type equipment - 50 m of a wellhead - 50 m of a flame stack		• Sour gas containing more than 50 mol/kmol H2S (5%) or sour gas from any well classified as a critical sour well a) If operations result in H2S concentrations that are higher than concentrations at the well (e.g., flaring gas from tanks), the composition of the gas to be burned must be determined in order to establish whether a permit is required. This composition must also be used in any required dispersion modelling. b) If supplemental fuel gas is used, the resulting composition must be used for dispersion modelling. However, the gas composition from the source is still used as the basis for determining whether a permit is required. • If gas well test volumes exceed the volume allowance threshold. See notes 16 and 17. Temporary flaring permit is not required for: • Gas containing 50 mol/kmol H2S (5%) or less and the total volume (for gas well tests) is less than the volume allowance threshold. See notes 16 and 17. • Flaring or incinerating small volumes of sour gas containing more than 50 mol/kmol H2S (5%) provided; a) Maximum sulphur emission rates < 1.0 tonne/day over the duration of the event b) Total flared or incinerated volume < 50 103m3 over the duration of the event. c) Equipment is designed to ensure compliance with the one-hour AAAQO for SO2 or operating procedures are in place to ensure compliance with the AAAQO. Related dispersion modelling evaluations and design information are documented and available to the AER Authorizations Branch upon request. d) Rates and volumes are measured and reported as defined in section 10 of Directive 060. e) Written notification is provided to the AER Authorizations Branch. See note 18. • The use of permanent flares or incinerators installed in AER-licensed

				facilities, including batteries, compressor stations, and gas plants provided that licensees can show, on request from the AER Authorizations Branch or field centre staff, that: a) The flaring or incineration volumes, rates, and gas composition are within the limits of the facility license b) The flares or incinerators are designed to operate safely under the intended conditions in compliance with the AAAQO; and c) The total volumes are less than the volume allowance threshold • Unplanned nonroutine events such as emergencies. See note 19. • Oil and bitumen batteries provided conservation requirements are met as described in section 2, Directive 060
Flared, Incinerated and Vented Gas Reporting	The following must be reported - Flares associated with well drilling, completions and maintenance - All faring and venting of gas at gas plants, gathering systems, compressors, pipelines and all other facilities - Incinerated gas must be reported as flared gas if an incinerator is used in place of a flare stack - All flared and vented gas at the associated reporting facility Flared volumes must be reported to the Commission within 60 days of completion. Permit holders are required to report gas volumes greater than or equal to 0.1*103 m^3/month that are flared, vented or incinerated.	All flared and vented gas must be reported.		Flaring is allowed by the AER when done in accordance with Directive 060. However, parties may agree to zero flaring, as set out in a zero-flaring agreement. The gas plant flaring, incinerating, and venting decision tree must be used to evaluate all new and existing gas plant flares, incinerators, and vents regardless of volume except for intermittent small sources (less than 100 m3 per month) such as pig trap depressurizing Evaluations must be updated annually or when changes at the plant materially change plant operation. See Section 5.1, Directive 060. Gas plants must not exceed six major nonroutine flaring events in any consecutive (rolling) six-month period (6-in-6). See table 3, Directive 060. The pipeline systems flaring, incineration, and venting decision tree must be used to evaluate all new and existing pipeline systems, including compression station flares, incinerators, and vents, except for intermittent small sources (less than 100 m3 per month) such as pig trap depressurizing

				Evaluations must be updated before any planned flaring, incinerating, or venting. See Section 6.1, Directive 060. Gas containing more than 5 parts per million (ppm) H_2S must not be released from a pipeline without the approval of the AER unless the gas is burned such that it meets the requirements in section 7, Directive 060 (flaring or incineration of gas must meet the requirements in section 7 and venting of gas must meet the requirements in section 8 of the same document) Licensees must get an AER temporary flaring/incineration permit in order to use temporary flares or incinerators for the disposal of sour gas containing more than 50 mol/kmol (5%) H_2S, as described above Min. residence time must be 0.5 seconds at max. flow rate or more as required for complete combustion of heavier gases. a) Incinerators must be operated without exposed flame. b) If the gas contains less than 10 mol/kmol (1%) H_2S and the unsupplemented heating value of the gas is 20 MJ/m^3 or more, no minimum residence time is required Minimum exit temperature must be 600°C a) No minimum exit temp. or temp. monitoring is required for combustion of gases with less than 10 mol/kmol (1%) H_2S and an unsupplemented heating value of 20 MJ/m^3 or more. b) For combustion of gases with more than 50 mol/kmol (5%) H_2S, the facility must be designed to automatically shut down if the exit temp. of the incinerator drops below either 600°C or the required temp. to meet the AAAQO, whichever is higher. i. The incinerator must also be equipped with process temperature control and recording.

				ii. All violations, together with measures taken to prevent recurrence, must be immediately reported by the licensee, operator, or approval holder to the appropriate AER field centre.
Flaring, Venting and Incinerating logs	Permit holders must maintain a log of flaring and venting events and are required to respond to public complaints. Logs must be signed, and name printed and kept for a minimum of 12 months. Logs must include information on complaints, description of incident along with contact information, date, time, duration and other relatable information	Permit holder must maintain a log of all flaring, venting and incinerating events along with response to public complaints Logs must include information on complaints, description of incident along with contact information, date, time, duration and other relatable information Logs must be kept for a minimum of 12 months.	Summary of records to be kept: Gas Conservation and Destruction Equipment: Record of the percentage of hydrocarbon gas captured along with flowrate. Operation and maintenance of the equipment Well Completions – Hydraulic Fracturing (does not apply to BC and AB if facility is operating within province's regulations) Record of gas-to-oil ratio Heating value of gas if vented Compressors Compressor details (serial number, make, model, etc…) Gas Conservation/Destruction equipment type Flowmeters/Continuous Monitoring devices Details such as make and model. Manufacturer calibration details Flowrate and date of each measurement and re-measurement Corrective Actions Description of action, date, measurements and gas volumes Venting Limits Volume of gas vented in Sm^3 Volume of gas destroyed in Sm^3 Volume of gas delivered from the facility in Sm^3 Regulatory/Alternative leak detection and repair program: Calibration/Inspection details including date, results, equipment detail, type of leak detection equipment and name, job	Licensees must log and monitor nonroutine flaring events, as required in section 10.1, Directive 060. Major flaring events must be flagged. See Section 5.3.3 for regulation regarding a sixth major flaring event occurring within any consecutive (rolling) six-month period Log of these events must be maintained, and response must be made to public complaints in order to comply with release reporting requirements defined in IL 98-01 and AEP's Release Reporting Guideline. See section 10.1, Directive 060. In situations governed by temporary flaring/incineration permits, a sour gas flaring/incineration data summary report (see appendix 6, Directive 060) must be completed in full and submitted to the AER Authorizations Branch within three weeks of the flaring/incineration completion date

			title and address of the individual who carried out calibration/inspection Pneumatic Controllers Identifier Controller function Design bleed rate and supply pressure Hatches, Pipes, sample systems and pressure relief devices A facility must record if it has a hatch, a pipe with an open end or uses a sampling system or pressure relief device.	
Venting and Fugitive Emissions Management Requirements	Permit holders must burn all non-conserved volumes of gas if volumes and flow rates are sufficient to support stable combustion. The guidelines enforce facility permit holders to have adequate fugitive emissions management program with no further details on the measure of adequacy. Permit holders must develop and implement programs to detect and repair leaks that meet or exceed the CAPP Best Management Practice for Fugitive Emissions Management. New facilities that utilize natural gas to start compressors are required to connect the compressor starter discharge vents to a flare or conservation system, with exemption under acceptable rationale. The Commission enforces the same protocol for existing facilities unless an exemption is approved. Permit holders are referred to the BCOGC Oil and Gas Activity Operations Manual for surface casing vents.	Does not address the management of fugitive emissions	Oil and gas facility operators must establish regulatory leak detection and repair programs that satisfy the below requirements: - Inspect for hydrocarbon release in equipment components at an upstream oil and gas facility at least three times a year with at least 60 days in between each inspection. - Equipment components are to be inspected with eligible leak detection instruments that are operated and maintained in accordance with manufacturer recommendations - Inspections are to be conducted by trained individuals Hydrocarbon emissions from equipment components are considered leaks if they consist of at least 500 ppmv of hydrocarbons. A detected leak from equipment component must be repaired within 30 days of detection if equipment component can remain in operation or until the next planned shutdown if equipment component cannot be operated during repair. Alternative leak detection and repair programs must include: - Leak inspections - Operation, maintenance and calibration of leak detection instruments - Detected leak repairs	Hydrocarbon products stored in atmospheric storage tanks at gas plants, compression stations, and gas batteries must not have a true vapour pressure of more than 83 kilopascals (kPa) at 21.1°C if the tanks are vented to the atmosphere. Temporary, short-term venting is allowed at wells, facilities, pipelines, and batteries where conservation is in place, with the following conditions: a) Gas must contain less than 10 mol/kmol H2S and must not result in exceedances of the AAAQO outside the lease boundary b) Gas must not contain any free hydrocarbon liquid c) All liquids must be separated and contained in accordance with the storage requirements of Directive 055 d) Total gas volume must not exceed 2 103 m3, and the duration must not exceed 24 hours. Notification must be conducted in accordance with section 3.8 and table 2, Directive 060 Vented gas must not constitute an unacceptable fire or explosion hazard and must comply with the spacing requirements listed above. A flame arrester or equivalent safety device, or proper engineering and operating procedures (e.g., sufficient sweep gas velocity) must be used on all

			Hydrocarbon gas emissions from centrifugal compressor seals, rod packings and distance pieces of a reciprocating compressor with rated braking power of 75 kW or higher must be conserved or routed to designated vents that release those emissions to the atmosphere. Pneumatic Controllers A pneumatic controller at an upstream oil and gas facility must not operate using hydrocarbon gas, other than propane, unless bleed rate is less than or equal to 0.17 Sm^3/hour or hydrocarbon gas is conserved/destructed. Pneumatic Pumps Pneumatic pumps that pump methanol must not operate using hydrocarbon gas if the pump has rate higher than 20 L of methanol per day unless hydrocarbons gas is conserved or destructed. Other equipment; pipes, hatches, sampling systems and pressure relief devices Open ended pipes and hatches must be closed unless required. Sampling stations and pressure relief devices must be operated in such a way minimize hydrocarbon gas emission.	vent lines connecting oil storage tanks to flare or incinerator stacks. Gas containing more than 10 mol/kmol H2S or result in off-lease H2S odors. must not be vented to the atmosphere but its pressure-relief valves must be tied into flare systems Venting and/or fugitive emissions must not result in any H2S or hydrocarbon odors outside the lease boundary. Venting must not result in exceedances of the AAAQO outside the lease boundary. Benzene emissions must be controlled such that cumulative emissions from all sources at the facility or lease site do not exceed the limits in table 4, Directive 060. Vented gas from dehydrators must meet all requirements specified in Directive 039 Non-combustible gas mixtures containing odorous compounds including H2S must not be vented to the atmosphere if off-lease odors may result but can be flared or incinerated with sufficient fuel gas to ensure destruction of odorous compounds.
Measurement and Estimating Requirements	Permit holders of oil and natural gas production and processing facilities must report volumes of gas greater than or equal to 0.1 10^3m^3/month that are flared, incinerated or vented Gas that is used for pilot, purge or blanket gas must be reported as either flared or vented. Process gas used to operate instrumentation or as power gas to drive chemical pumps must be included as vented gas. Dilution gas is to be reported as fuel gas. Fugitive emissions are not to be reported as flared or vented gas. Continuous and non-routine flared and vented gases from oil and gas production and processing facilities are required to be measured with	Estimates of flared, incinerated and vented gas is accepted. Volume estimates must be based on measurement and/or engineering calculations performed by a technically knowledgeable person. Estimating systems accounting for gas released through flaring, incinerating and venting must account to the nearest $0.1*10^3$ m^3/month. Measurement systems are not required.	Required measurements: - Flow measurement of hydrocarbon gas - Combusted as a fuel in a combustion system - Released from vents of a compressor - Re-measurement of hydrocarbon flow after corrective actions are taken - Flow measurement of emissions from the seals of a centrifugal compressor - Flow measurement of emissions from the rod packings and distance pieces of a reciprocating compressor Flow meter requirements: Flow meter must be calibrated in accordance with manufacturers	Requirements for measuring and reporting volumes of gas flared, incinerated, and vented are provided in Directive 017.

<table>
<tr>
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<td>appropriate meters designed for the respective flow conditions.

Following vent/flare streams must be measured with meters designed for the appropriate flow conditions:
- Continuous or non-routine flare and vent sources at all oil and gas production and processing facilities where annual average total flared, incinerated and vented volumes per facility exceed 0.5 $10^3 m^3$/day
- Vent sources such as compressor distance piece vents, pumps and valve controllers can be estimated rather than metered.
- Measurement uncertainty must meet the below criteria; single point measurement uncertainty applies when gas volume is only determined from metered volumes.

<table>
<tr><td>Stream</td><td>Max Uncertainty of Monthly Volume</td><td>Single Point Measurement Uncertainty</td></tr>
<tr><td>Fuel Gas > 500 m^3/d</td><td>5%</td><td>3%</td></tr>
<tr><td>Fuel Gas < 500 m^3/day</td><td>20%</td><td>10%</td></tr>
<tr><td>Flare, Incinerator or Vent gas</td><td>20%</td><td>5%</td></tr>
</table>

Estimating systems must account for all gas released through flaring, incinerating and venting to the nearest $0.1*10^3$ m^3/month during routine, emergency and maintenance operations. Volume estimates must be based on engineering calculations with accompanying assumptions, mathematical formulae and methodology.
A flare meter must be considered at all new gas processing facilities that have an inlet capacity greater than $300*10m^3$/day.</td>
<td></td>
<td>recommendations and has a maximum margin error of $\pm$10%

Volume of hydrocarbon gas produced, received vented or destroyed at an upstream oil and gas facility must be determined based on:

- If facility is in BC: Measurement Guideline for Upstream Oil and Gas Operations published by BCOGC
- If facility is in SK: Measurement Requirements for Oil and Gas Operations published by the Government of Saskatchewan
- If facility is in AB: Measurement Requirements for Oil and Gas Operations published by the AER</td>
<td></td>
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</table>

Note that some sections including Minimum Residence Time and Exit Temperature for Incinerators, Smoke Emissions, Ignition, Stack Design, Liquid Separation, Flare and Incinerator Spacing Requirements, Backflash Control and Noise, Flare Pits, Sulphur Recovery Requirements and Sour Gas Combustion in Directive 60 are not covered above for the sake of consistency.

Note that some sections including Ignition, Stack Design, Liquid Separation, Flare and Incinerator Spacing Requirements, Backflash Control, Flare Pits, Sulphur Recovery Requirements and Sour Gas Combustion in Flaring and Venting Reduction Guideline (BC) are not covered above for the sake of consistency.

Table A.2: Requirements for Non-Routine Flaring and Venting During Solution Gas Conserving Facility Outage

Shutdown Category	Duration	Operational Requirements
Partial equipment outages	< 5 days	Shut-in of production is not required for equipment outages lasting less than 5 days that involve small volumes of gas (e.g. storage tank vapour recovery unit repair). This allowance is limited to a maximum of 2 10^3 m^3/day, subject to limitations on venting.
Planned	< 4 hours	Permit holders must make all reasonable efforts to reduce battery or solution gas plant inlet gas volumes by 50% of average daily solution gas production over the preceding 30-day period.
	> 4 hours	Permit holders must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period and meet the following requirements: • Solution gas must not be flared from wells that have an H2S content greater than 5 mole percent. • Production may be sustained at rates to provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. • The Commission also recommends that operators notify individuals that have identified themselves to the permit holder as being sensitive or interested regarding emissions from the facility. • Residents and the Commission must be notified 24 hours prior to the planned event in accordance with Chapter 5.
Emergency	< 4 hours	No reduction in plant inlet is required.
Plant upset	> 4 hours	Permit holders must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period and must meet the following requirements: • Solution gas must not be flared from wells that have an H2S content greater than 5 mole percent. • Production may be sustained at rates to provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. • The Commission also recommends that permit holders notify individuals that have identified themselves to the permit holder as being sensitive or interested regarding emissions from the facility. • Residents and the Commission must be notified within 24 hours of the unplanned flaring event in accordance with Chapter 5.
Repeat non-routine flaring		Permit holders must investigate the causes of repeat non-routine flaring or venting and take steps necessary to eliminate or reduce the frequency of such incidents.

Source: Flaring and Venting Reduction Guideline BC.

Appendix B: Optimal Emission Reduction Model

The objective of the optimization model is to select the group of technologies and reduction targets from each emission source so that the total cost of methane emission control implementation is minimized. We define the objective function and its constraints as follows:

$$Obj.Function = Min\left(\sum_{i=1}^{N} RE_i \times MC_i\right)$$

$Subject\ to$:

$$\sum_{i=1}^{N} RE_i = 0.45 \times ME_{NIR}$$

$Constraints$:

$$0 \leq RE_i \leq RE_{Maxi}$$

Where:

RE_i	The reduced emission for source i (t CH_4)
MCi	Mitigation technology cost for source i (CAD$/t CO_2 eq)
ME_{NIR}	Methane emission for oil and gas sector reported for 2012/2014/2015 by NIR (depending on province and policy scenario simulation case)
RE_{Maxi}	Maximum methane emission reduction using the mitigating technology for source i
i	The identifier for each emission source where a mitigating technology can be deployed

In ICERM, we considered three optimization algorithms where the user has the option to choose one of them:

- *The GRG Nonlinear Solving Method*: This method is used for nonlinear optimization, which uses the Generalized Reduced Gradient (GRG2) method.
- *The Simplex LP Solving Method*: This method is used for linear programming, which uses the Simplex and dual Simplex method with bounds on the variables, and problems with integer constraints use the branch and bound method.

- *The Evolutionary Solving Method*: This method is used for non-smooth (derivative-free) optimization based on varieties of genetic algorithm and local search.

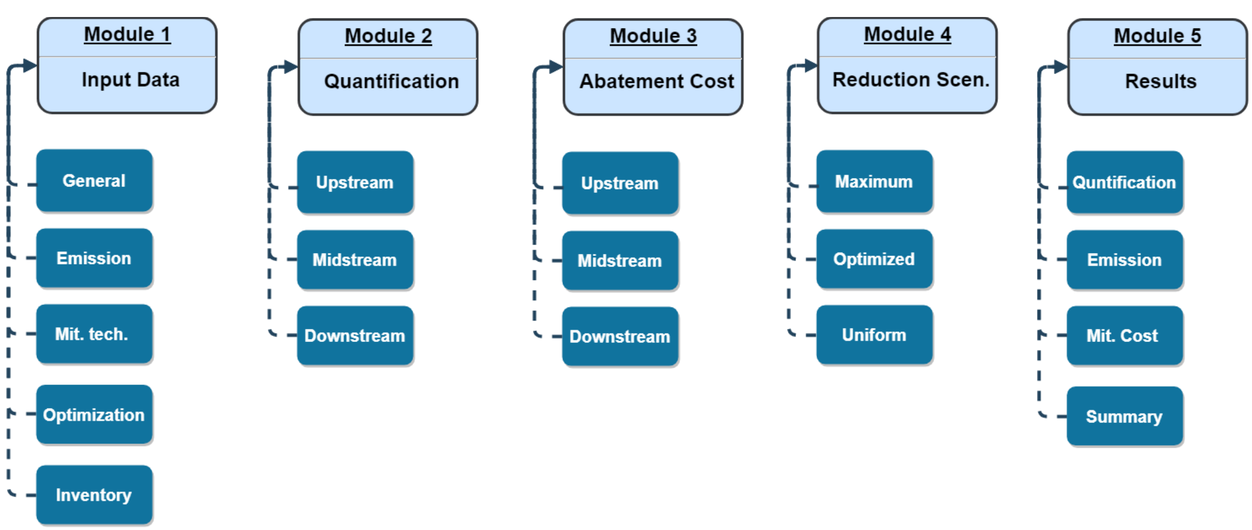
Note that in order to run the optimization module the software will first check if the sum of the maximum reduction by mitigating technologies is less than 45% of ME_{NIR} – which is the target reduction on NIR emission estimate, in order to either skip or run the optimization algorithm. When the sum is less than 45% of ME_{NIR}, it skips and only reports the results of the maximum reduction and uniform scenarios. This may imply that the reduction target is not achievable under the available mitigation technology options or that ICERM under-estimates the emissions for the province in question. Therefore, better performing technologies or new technology options are needed to achieve reduction targets.

Appendix C: Integrated CH4 Emission Reduction Model (ICERM) Manual

As shown in Figure C.1, ICERM comprises five main components in addition to an Inventory List: which contains the most recent publicly available information and estimates of facility and equipment counts across the gas supply chain in each Canadian province. The main components include:

- Input Data: allows assignment of parameter values, emission factors, activity factors, optimization solvers, mitigation technology alternatives and their costs to be selected by the user
- Quantification Module: computes methane emissions from various segments of the gas supply chain considering the input specifications in the Inventory List and Input Data components.
- Abatement Cost Module: identifies the technology options for mitigation of methane emissions at each segment of the chain, along with their costs of implementation and value of conserved gas.
- Optimization Module: uses three mathematical programming algorithms (linear, nonlinear, and evolutionary) to identify the most cost-effective mitigation options to achieve specified emission reduction targets.
- Results Sheets: displays the analyses results at national, provincial, or both levels for the cases of maximum emission reduction, uniform reduction, and optimal reduction. The optimal reduction scenario is the one that identifies mitigation options to achieve reduction targets at the least costs of implementation.

Figure C.1: ICERM Flow Chart



The following pages are intended to briefly describe the assumptions CERI made to prepare the input file for the quantification and abatement cost estimation modules.

- GWP of methane (CH_4) is assumed to be 25 in this study according to (ECCC 2017).
- CH_4 mass composition and CH_4 mol/vol. Composition is considered according to CEPEI Methodology Manual, 2016 (CEPEI 2016). The CH_4 ratio (mass/vol) is calculated by dividing those two numbers (CH_4 mass composition and CH_4 mol/vol). We use this ratio to calculate the leak rate in t CH_4/yr according to the following formula:

$$LR_{CH_4} = \frac{LR_{THC} \times X_{CH_4} \times R_{M/V} \times 24 \times 365}{1000}$$

where

LR_{CH_4}	Leak rate (t CH_4/yr/source)
LR_{THC}	Leak rate (kg THC/h/source)
X_{CH_4}	Composition of CH_4 in the natural gas stream (Vol. %)
$R_{M/V}$	The ratio (mass/vol) (-)

- We estimated GOR based on ST-60B report for 2017 where the Raw Associated gas (mmscf/d) is divided by the produced oil in bpd for different companies and then we get the average from all companies (0.006 mmscf/bbl). Due to the shortage of information for other provinces, we assume the same number for British Columbia, Saskatchewan and Manitoba
- Based on EPA data (EPA 2003), we assumed 6 scf/hr of the emission for low bleed devices, whereas 30 scf/hr for emissions from high bleed devices, which leads to a reduction of 80% in methane emission by replacing high bleed devices with the low bleed ones.
- We assume 95% methane emission reduction for Centrifugal Seal Build - Dry/Wet Seal methane emission reduction.

- Based on PTAC data (CAPP, 2016), the distibution of compressors (reciprocating to centrifugal) is assumed to be 95% to 5% for the upstream, and 78% to 22% for the midstream and downstream sectors.
- The natural gas price and its energy content are assumed to be 2.25 CAD$/GJ (2017) and 53.20 GJ/t N.G based on AER data.
- The methane composition for the upstream sector of AB, BC, SK, and MB are assumed to be 84.41%, 86.26%, 84.41%, and 84.41%, respectively (according to AER, BCOGC, the government of SK). For midstream and downstream sectors, following CEPEI estimate, methane composition is assumed to be 92.87% for Alberta, 96.48% for British Columbia, and 95.71% for Saskatchewan, Manitoba and the eastern provinces.
- The methane emission in the upstream sector is divided into six categories including pneumatics, fugitives, SCVF, glycol dehydrators, venting, and compressors according to the AER website with the following shares (Table C.1). Due to the shortage of data for

other western provinces (BC, SK, and MB), we assume the same methane emission distribution for the upstream sector.

Table C.1: Share of Defined Categories for Methane Emissions in the Upstream Sector

Description	Share
Pneumatics	42%
Fugitives	27%
SCVF	3%
Glycol dehydrators	3%
Venting	18%
Compressors	7%

The pneumatic devices are divided into six categories with the following distribution as presented in Table C.2 according to Clearstone Engineering (2018), Cap-Op Energy (2013), and GreenPath (2016a) studies. Due to the shortage of data for other western provinces (BC, SK, and MB), we assume the same distribution for these provinces.

Table C.2: Share of Defined Categories for Pneumatic Devices in the Upstream Sector

Description	Share
Level Controller	27%
Positioner	1%
Pressure Controller	9%
Transducer	3%
Generic Pneumatic Instrument	25%
Chemical Pump	35%

- The leak rates from pneumatic devices are considered according to Clearstone Engineering (2018) and EPA (2015) docs (Table C.3) and assumed to be the same for other provinces.

Table C.3: Leak Rates for Different Pneumatic Devices

Level Controller	m^3/hr/source	0.3508
Positioner	m^3/hr/source	0.2627
Pressure Controller	m^3/hr/source	0.3217
Transducer	m^3/hr/source	0.2335
Generic Pneumatic Instrument	m^3/hr/source	0.3206
Glycol dehydrators	m^3/hr/source	1117[13]
Chemical Pump	m^3/hr/source	0.9726

[13] 600 Mcf/yr/source

- The facility inventory across Alberta is categorized and considered according to CAPP (2018c) and Cap-Op Energy (2013) as presented in Table C.4.

Table C.4: Facility Inventory Across Canada

Description	AB	BC	SK	MB
Wells	239,918	14,025	80,896	5,503
Compressor Stations	5,931	655	2,144	
Batteries	25,212	2,783	9,114	661
Gas Gathering Systems	3,311	366	1,197	
Gas Plants	673	74	243	

Note that the processing facilities are estimated for other provinces based on the ratio of their raw gas production with respect to Alberta. We also considered 702, 133, and 133 wells for ON, QC, and NL according to CAPP statistical handbook (CAPP 2018a).

- Other statistics with respect to oil and gas wells (number of wells drilled 2017, number of completed gas wells 2017, number of completed oil wells 2017, dry gas production 2017, oil production, GOR, associated gas production, abandoned wells (1998-2017), gas wells, oil wells) and the flared and vented gas from batteries and gathering systems, gas plants, and oil sands are considered based on AER ST-60, 39, 13, BCOGC, Government of SK and Manitoba, and CAPP (2018b).
- The emission factors for oil and gas wells are considered according to CERI as presented in Table C.5.

Table C.5: Considered Emission Factors for Oil and Gas Wells

Description	Unit	Emission Factor	Reference
No. of wells drilled 2017	kg CH4/well	0.8[14]	Umeozor et al. (2018)
No. of completed gas wells 2017	t CH4/well	26.78[15]	Balcombe et al. (2018)
Dry gas production 2017	of throughput	0.18%	Balcombe et al. (2018)
Associated gas production	of throughput	0.18%[16]	Balcombe et al. (2018)
Oil Wells	t CH4/well-yr	4.836	Atherton et al. (2017)
Abandoned wells (1998-2017)	t CH4/well-yr	4.836[17]	Atherton et al. (2017)

[14] Based on the estimated mud gas release

[15] Based on 90% REC (flared - 12.3 t CH4/well) and 10% Non-REC (vented - 157.1 t CH4/well)

[16] Generally, gas produced from oil wells are known to be more likely to be emitted than gas produced at gas wells

[17] Abandoned wells are based on BC OGC well statuses classification. The referenced paper observed that "locations of the majority of well pads and processing facilities appeared to be accurate, but the statuses in the database may not have been up to date. For example, well pads recorded as 'abandoned' in the database occasionally still had infrastructure. During a personal communication with David Risk, who is a co-author of this paper, he could not ascertain the number of the wells classified as abandoned by BC OGC that are actually still active at the time of their field measurements. An abandoned and active well will likely have different emission characteristics than one that is inactive.

- All data for the midstream and downstream sector are considered based on CEPEI manual (2016) where the numbers are adjusted based on the ratio of marketable gas production in 2016 and 2017 in Canada.
- Based on the NEB website we assume the following distribution and emission share for different provinces for geological storage across Canada (Table C.6).

Table C.6: Emission Share for Geological Storage in Different Provinces Across Canada

Province	Geological Storage
Alberta	57.55%
British Columbia	9.96%
Manitoba	0.00%
New Brunswick	0.00%
Nova Scotia	0.00%
Ontario	28.20%
Quebec	0.52%
Saskatchewan	3.77%
NL	0.00%
PEI	0.00%

- The methane emission from geological storage is divided into four categories: burner-tip, venting, flaring, and fugitives according to the CEPEI manual. The share of each category is assumed to be the same as what is reported for Ontario in the CEPEI manual as presented in Table C.7.

Table C.7: Share of Each Emission Source for Geological Storage

Emission Source	CH_4% for UGS (ON)
Burner-tip	0.0004%
Venting	37.0280%
Flaring	0.6022%
Fugitives	62.3694%

- Provincial Gas Consumption at the residential, commercial, and industrial levels are considered based on the NEB (2017b). We use these numbers for estimating the methane emission from meterings and burner-tips in the downstream sector.
- The emission factors for meters and customer meters are shown in Table C.8.

Table C.8: Emission Factors for Meterings

Description	Emission Factor	Unit
Metering and Regulation - Residential	0.00001	of throughput
Metering and Regulation – Commercials	0.00001	of throughput
Metering and Regulation - Industrials	0.00008	of throughput
Customer metering - Residential	0.00025	of throughput
Customer metering - Commercials	0.00025	of throughput

- The burner efficiencies in different sectors are estimated according to the emission factors in g CH_4 / m^3 N.G provided in "Emission Factors and Uncertainties for CH_4 & N_2O from Fuel Combustion" from Environment Canada (20.0, 1.9, 0.037 for upstream, midstream, and downstream, respectively). We convert those numbers to percentages using the following formula according to the CH_4 percentage for all sectors in each province:

$$EF\% = \frac{EF}{\left(1000 \times X_{CH_4} \times \rho_{CH_4}\right)}$$

- Where

EF%	the emission factor (%)
EF	the emission factor (g CH_4 / m^3 N.G)
X_{CH_4}	Composition of CH_4 in the natural gas stream (-)
ρ_{CH_4}	Methane density (0.67 kg CH_4/m^3 CH_4)

The results are presented in Table C.9.

Table C.9: Emission Factor (%) for Burner-Tips in Different Sectors Across Canada

Sector	AB	BC	SK	MB	ON	QC	NB	NFL	PEI	NS
Upstream	3.53%	3.46%	3.53%	3.53%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Midstream	0.30%	0.29%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
Downstream	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%

- For LDAR, we assume three times per year inspection for compressor stations, gas gathering systems, and gas plants (currently proposed ECCC LDAR frequency) (ECCC 2017).
- For venting, we only consider the mitigating technologies for gas gathering systems and gas plants.
- All cost specifications for mitigating technologies are considered according to the Delphi program study (2017).

- The following mitigation technologies with their corresponding emission reduction and the technology life time are considered as follows:

Table C.10: Mitigation Technologies Specifications for Different Sectors

Description	Mitigating Technologies	Emission Reduction Share (%)	Life Time (Years)
Upstream			
Pneumatics	Replace High-Bleed Devices with Low-Bleed Devices (BF)	100%	10
Chemical pump	Replace Pneumatic Pumps with Electric or Low/No-Bleed Pumps (BF)	100%	10
Fugitives	Company Internal Inspection	100%	
SCVF	Install Vapour Recovery Units on Storage Tank	100%	10
Glycol dehyd-Tech1	Install Flash Tank Separators	100%	10
Glycol dehyd-Tech2	Replace Gas Powered Glycol Pumps with Electric Glycol Pumps	100%	10
Venting	SlipStream SS3 standalone (BF)	100%	10
Compressors-Tech1	SlipStream SS3 standalone (BF)	95%	10
Compressors-Tech2	Centrifugal Seal Build - Dry Seal (BF)	5%	3
Midstream			
Venting-Tech1	SlipStream SS3 standalone (BF)	78%	10
Venting-Tech2	Centrifugal Seal Build - Dry Seal (BF)	22%	3
Fugitives	Company Internal Inspection with Repair	100%	-
Downstream			
Venting-Tech1	SlipStream SS3 standalone (BF)	78%	10
Venting-Tech2	Centrifugal Seal Build - Dry Seal (BF)	22%	3
Fugitives	Company Internal Inspection with Repair	100%	-

Appendix D: Economic and Emission Reduction Attributes of Mitigation Technologies based on Previous Studies

Table D.1: Reported Methane Mitigation Opportunities and Costs from Existing Literature

Category	Name	CAPEX		OPEX		Emission Reduction
		Lower	Upper	Lower	Upper	
LDAR	Wells (ICF)	$257,997		$292,500		60%
	Gathering (ICF)	$257,997		$292,500		60%
	Processing (ICF)	$257,997		$292,500		60%
	Transmission (ICF)	$257,997		$292,500		60%
	Wells	$656- $1,875				
	Batteries	$1,313 - $3,180				
	Compressor Stations	$2,625 - $5,556				
	Gas Gathering Systems	$2,625 - $6,657				
	Gas Plants	$3,925 - $8,712				
Pneumatic devices	Replace with Instrument Air Systems W/SOFC (GF)	$54,370		$ 3,000		100%
	Replace with Instrument Air Systems W/SOFC (BF)	$61,784		$ 3,000		100%
	Replace with Instrument Air Systems W/TEG (GF)	$21,370		$50		100%
	Replace with Instrument Air Systems W/TEG (BF)	$24,284		$50		100%
	Replace with Instrument Air Systems W/ Grid (3 km) (GF)	$65,370		-		100%
	Replace with Instrument Air Systems W/ Grid (3 km) (BF)	$74,284		-		100%
	Replace with Instrument Air Systems w/ Solar (GF)	$20,000		$117		100%
	Replace with Instrument Air Systems w/ Solar (BF)	$35,000		$117		100%
	Replace with Instrument Air Systems (ICF)	$90,000		$26,655		100%
	Replace High-Bleed Devices with Low-Bleed Devices (BF)	$1,241	$2,090			

	Replace High-Bleed Devices by Installing Retrofit Kits (BF)	$310	$1,147			
	Replace Pneumatic Pumps with Electric or Low/No-Bleed Pumps (BF)	$9,608	$13,603			100%
	Pneumatic Chemical Injection Solar (ICF)	$7,500		$113		100%
	Kimray Pumps (ICF)	$15,000		$3,000		100%
	Electrification of Pneumatic Devices (GF)	$20,000	$25,000	$117		100%
	Electrification of Pneumatic Devices (BF)	$22,500	$45,500	$117		100%
	VRU to Small Combustor (5000 scf/d) (GF)	$16,500		-		
	VRU to Small Combustor (5000 scf/d) (BF)	$21,000		-		
	Vent Gas Capture to Large Combustor (1.75 Mscf/d) (GF)	$49,500		-		
	Vent Gas Capture to Large Combustor (1.75 Mscf/d) (BF)	$63,000		-		
	Vent Gas Capture to Catalytic Heaters (GF)	$5,000		-		
	Vent Gas Capture to Catalytic Heaters (BF)	$6,000		-		
Compressors and Engines	Conversion of Gas Starter to Air Start (GF)	$235,836		$1,500		
	Conversion of Gas Starter to Air Start (BF)	$293,916		$5,000		
	Starter Vent to Flare - Tie to Existing Flare Stack (GF)	$3,025		$150		
	Starter Vent to Flare - Tie to Existing Flare Stack (BF)	$12,100		$150		
	Starter Vent to Flare - Tie to New Combustor (GF)	$51,425		$650		
	Starter Vent to Flare - Tie to New Combustor (BF)	$60,500		650$		
	VRU Vent Capture to Inlet (GF)	$284,350		$5,000		
	VRU Vent Capture to Inlet (BF)	$447,700		$5,000		
	Capture Packing Vents & Convey to Existing Flare (GF)	$45,980		$5,000		

	Capture Packing Vents & Convey to Existing Flare (BF)	$182,710	$5,000	
	Capture Packing Vents & Convey to New Combustor (GF)	$94,380	$5,500	
	Capture Packing Vents & Convey to New Combustor (BF)	$231,110	$5,500	
	Capture Packing Vents & Convey to Existing Flare-No Vacuum (GF)	$18,150	-	
	Capture Packing Vents & Convey to Existing Flare-No Vacuum (BF)	$76,230	-	
	Capture Packing Vents to New Combustor-No Vacuum (GF)	$66,550	-	
	Capture Packing Vents to New Combustor-No Vacuum (BF)	$124,630	-	
	VRU Vent Capture (ICF)	$75,955	$13,750	95%
	Capture Blow Down to Inlet (GF)	$3,630	-	
	Capture Blow Down to Inlet (BF)	$12,100	-	
	Capture Blow Down to Inlet - Add a combustor (GF)	$52,030	500	
	Capture Blow Down to Inlet - Add a combustor (BF)	$60,500	500	
	Capture Blow Down per Compressor (ICF)	$30,000	$0	95%
	Capture Blow Down per plant (ICF)	$75,000	$0	95%
	Capture atmospheric vents with SlipStream® SS3 (GF) standalone and convey to engine air inlet to blend with fuel gas	$27,500	$800	100%
	Capture atmospheric vents with SlipStream® SS3 (BF) standalone and convey to engine air inlet to blend with fuel gas	$52,250	$800	100%

	Capture atmospheric vents with SlipStream® SS10 (GF) standalone and convey to engine air inlet to blend with fuel gas	$37,400	$800	100%
	Capture atmospheric vents with SlipStream® SS10 (BF) standalone and convey to engine air inlet to blend with fuel gas	$61,050	$800	100%
	Capture atmospheric vents with SlipStream® SS10 in existing REMVue AFR and convey to engine air inlet to blend with fuel gas (GF)	$33,000	$800	100%
	Capture atmospheric vents with SlipStream® SS10 in existing REMVue AFR and convey to engine air inlet to blend with fuel gas (BF)	$57,750	$800	100%
	Replacement of Rod Packing (ICF)	$9,900	$0	30.70%
	Replacement of Rod Packing to OEM Standard (BF)	$25,000	$6,250	
	Packing Upgrade to Low Bleed Packings (GF)	$3,000		
	Packing Upgrade to Low Bleed Packings (BF)	25,000	$6,250	
	Packing Build - Shutdown Seal (GF)	$15,000	$1,500	
	Packing Build - Shutdown Seal (BF)	$35,000	$7,750	
	Centrifugal Seal Build - Dry Seal (BF)	$60,500	$5,000	
	Centrifugal Seal Build - Wet Gas Seal (BF)	$84,700	$6,000	
	Centrifugal Seal Build - Convert Wet Seal to Dry Seal (BF)	$1,452,000	$5,000	
	Centrifugal Seal Build (Wet Seal Degassing Recovery) (ICF)	$105,000	$0	95%

	Centrifugal Seal Build (Wet Seal Retrofit to Dry Seal) (ICF)	$675,000		-$75,000		95%
	Meters - Low Flow Turbine with Flow Computer and Logger (GF)	$15,730		$500		
	Meters - Low Flow Turbine with Flow Computer and Logger (BF)	$24,200		$1,000		
	Meters - Thermal Mass Flow Meter High Cost Range (GF)	$27,830		$500		
	Meters - Thermal Mass Flow Meter High Cost Range (BF)	$36,300		$1,000		
	Meters - Thermal Mass Flow Meter Low Cost Range (GF)	$10,890		$1,500		
	Meters - Thermal Mass Flow Meter Low Cost Range (BF)	$19,360		$2,000		
	Meters - Cost of Periodic Measurement by Positive Displacement with Pressure and Temp Compensation (GF)	$605				
	Meters - Cost of Periodic Measurement by Positive Displacement with Pressure and Temp Compensation (BF)	$3,630		$500		
	Meters - Periodic Measurement with Thermal Mass Flow (GF)	$605				
	Meters - Periodic Measurement with Thermal Mass Flow (BF)	$3,630		$7,500		
Dehydrator	Install Flash Tank Separators	$13,139	$50,835			
Dehydrator	Optimize Glycol Circulation Rates			$540		
Dehydrator	Replace Gas Powered Glycol Pumps with Electric Glycol Pumps	$13,880	$35,429			
Dehydrator	Glycol Dehydrator Optimization	$8,134	$199,273			
Dehydrator	Stripping Gas Elimination			$500		

Oil and Gas Site Venting	Plunger Lift Instead of Well Venting for Liquids Unloading	$4,050	$16,200	$700	$1,300	
	Plunger Lift Instead of Well Venting for Liquids Unloading (ICF)	$30,000		$3,600		95%
	Reduce Liquids Unloading Venting Flaring/ Incineration/Destruction Device	$46,700	$48,700			
	Install Vapour Recovery Units on Storage Tank	$47,711	$185,078	$7,367	$16,839	
	Recover Casing Vent and Use as Fuel	$6,166				
	Casing Gas Recovery Compressors (CHOPS)	$41,685	$203,340	$5,000	$6,400	
	Casing Gas Combustor/Incinerator (CHOPS)	$76,253	$116,921	$277	$1,000	

Source: (Delphi Program 2017; ICF 2016). ICF data is presented for reference only, and not used in our analysis.

Appendix E: Methane Emission Quantification

Table E.1: Provincial Level – Part 1 (tCH_4).

Description	AB	BC	SK
Oil and Gas Wells	816,935	55,007	422,302
Gathering	113,958	8,143	30,900
Gas Processing	5,497	11,829	1,707
Oil Sands	9,482	0	0
Transmission	20,763	7,284	11,330
Geological Storage	4,088	707	268
LNG Storage	0	67	0
Distribution	8,365	3,694	2,593
Burner-tips	2,098	372	349
Total Emissions	981,186	87,105	469,449
Upstream Sector			
Stationary Combustion	0	0	0
Burner-tip	0	0	0
Vented	430,395	44,068	306,137
Flared	31,889	9,163	13,313
Fugitives	483,588	21,749	135,458
Midstream Sector			
Stationary Combustion	629	469	945
Burner-tip	0	0	0
Vented	16,134	4,003	5,547
Flared	29	0	14
Fugitives	8,059	3,587	5,092
Downstream Sector			
Stationary Combustion	1	12	0
Burner-tip	2,098	372	349
Vented	339	54	81
Flared	0	0	0
Fugitives	8,024	3,629	2,511
Upstream Sector	945,871	74,980	454,909
Midstream Sector	24,851	8,059	11,598
Downstream Sector	10,463	4,067	2,942

Table E.2: Provincial Level – Part 2 (tCH_4).

Description	MB	ON	QC	NB	NFL	PEI	NS
Oil and Gas Wells	29,872	3,395	0	0	643	0	0
Gathering	2,419	0	0	0	0	0	0
Gas Processing	0	0	0	0	0	0	0
Oil Sands	0	0	0	0	0	0	0
Transmission	427	11,057	611	349	357	11	252
Geological Storage	0	2,003	37	0	0	0	0
LNG Storage	0	438	253	0	0	0	0
Distribution	1,163	19,529	2,047	549	566	18	401
Burner-tips	96	931	272	18	30	1	13
Total Emissions	33,976	37,353	3,220	916	1,596	30	665
Upstream Sector							
Stationary Combustion	0	0	0	0	0	0	0
Burner-tip	0	0	0	0	0	0	0
Vented	24,237	0	0	0	0	0	0
Flared	988	0	0	0	0	0	0
Fugitives	7,066	3,395	0	0	643	0	0
Midstream Sector							
Stationary Combustion	18	1,207	41	38	39	1	27
Burner-tip	0	0	0	0	0	0	0
Vented	4	7,992	669	200	204	6	144
Flared	0	0	0	0	0	0	0
Fugitives	405	4,298	191	112	114	4	80
Downstream Sector							
Stationary Combustion	0	24	8	1	1	0	1
Burner-tip	96	931	272	18	30	1	13
Vented	32	433	60	14	14	0	10
Flared	0	0	0	0	0	0	0
Fugitives	1,130	19,073	1,979	534	551	18	391
Upstream Sector	32,291	3,395	0	0	643	0	0
Midstream Sector	427	13,498	901	349	357	11	252
Downstream Sector	1,259	20,460	2,319	567	595	19	414

Table E.3: National Level (tCH_4).

Description	Canada
Oil and Gas Wells	1,328,154
Gathering	155,421
Gas Processing	19,033
Oil Sands	9,482
Transmission	52,441
Geological Storage	7,105
LNG Storage	758
Distribution	38,924
Burner-tips	4,181
Total Emissions	1,615,497
Upstream Sector	
Stationary Combustion	0
Burner-tip	0
Vented	804,838
Flared	55,353
Fugitives	651,899
Midstream Sector	0
Stationary Combustion	3,416
Burner-tip	0
Vented	34,903
Flared	44
Fugitives	21,940
Downstream Sector	0
Stationary Combustion	47
Burner-tip	4,181
Vented	1,037
Flared	0
Fugitives	37,839
Upstream Sector	1,512,089
Midstream Sector	60,303
Downstream Sector	43,105

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