# Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries

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October 2015

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September 2015

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**Acknowledgement**

ICF received and considered data or commentary from numerous stakeholder organizations, including oil and gas producers, industry associations, pipelines, equipment vendors, service providers, NGOs, and governments. No information in this report should be attributed to any single organization, as all data is aggregated from multiple sources and often uses average values. Furthermore, acknowledgement of participation does not imply their agreement with the study assumptions or conclusions, which reflect the professional judgment of ICF.

We thank all of the stakeholder organizations for providing input to this study, and specifically acknowledge the following entities: the Government of Alberta, the Alberta Energy Regulator (AER), the British Columbia Oil and Gas Commission, and Enbridge Inc.

# Acronyms and Abbreviations

| Acronym / Abbreviation | Stands For |
|---|---|
| AEO | Annual Energy Outlook |
| AER | Alberta Energy Regulator |
| AGR | Acid Gas Removal |
| ANGA | America's Natural Gas Alliance |
| API | American Petroleum Institute |
| AR | Assessment Report |
| BAMM | Best Available Monitoring Methods |
| bbl | Barrel |
| Bcf | Billion Cubic Feet |
| BCF | Billion Cubic Feet |
| BEA | Bureau of Economic Analysis |
| BTEX | Benzene, Toluene, Ethylbenzene, and Xylenes |
| CAC | Criteria Air Contaminant |
| CAD | Canadian Dollars |
| CapEx | Capital Expenditures |
| CAPP | Canadian Association of Petroleum Producers |
| CBM | Coal Bed Methane |
| CCR | Coal Combustion Residuals |
| CEPA | Canadian Energy Pipeline Association |
| CGA | Canadian Gas Association |
| $CH_4$ | Methane |
| $CO_2$ | Carbon Dioxide |
| $CO_2e$ | Carbon Dioxide Equivalent |
| CPI | Consumer Price Index |
| CSAPR | Cross-State Air Pollution Rule |
| DI&M | Directed Inspection and Maintenance |
| DUC | Drilled but Uncompleted Wells |
| EDF | Environmental Defense Fund |
| EIA | U.S. Energy Information Administration |
| EPA | U.S. Environmental Protection Agency |
| ESD | Emergency Shutdown |

| Acronym / Abbreviation | Stands For |
|---|---|
| EUR | Estimated Ultimate Recovery |
| FERC | Federal Energy Regulatory Commission |
| GDP | Gross Domestic Product |
| GGFR | Global Gas Flaring Reduction |
| GHG | Greenhouse Gas |
| GHGRP | Greenhouse Gas Reporting Program |
| GMM | Gas Markets Model |
| GRI | Gas Research Institute |
| GWP | Global Warming Potential |
| HAP | Hazardous Air Pollutant |
| hp | Horsepower |
| IEA | International Energy Agency |
| IMF | International Monetary Fund |
| IPCC | Intergovernmental Panel on Climate Change |
| IR | Infrared |
| LDAR | Leak Detection and Repair |
| LDCs | Local Distribution Companies |
| LNG | Liquefied Natural Gas |
| MAC | Marginal Abatement Cost |
| MATS | Mercury & Air Toxics Standards Rule |
| Mcf | Thousand Cubic Feet |
| MMcf | Million Cubic Feet |
| $MMTCH_4$ | Million Tonnes Methane |
| $MMTCO_2e$ | Million Tonnes CO2 equivalent |
| MRR | Mandatory Reporting Rule |
| NEB | National Energy Board |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NGL | Natural Gas Liquid |
| NPV | Net Present Value |
| NSPS | New Source Performance Standards promulgated under the Federal Clean Air Act |
| OECD | Organization for Economic Co-operation and Development |
| OpEx | Operating Expenditures |
| OVA | Organic Vapor Analyzer |

| Acronym / Abbreviation | Stands For |
|---|---|
| PRO | Partner Reported Opportunity |
| PRV | Pressure Relief Valve |
| psig | Pounds per Square Inch – Gauge |
| RECs | Reduced Emission Completions |
| SAGD | Steam Assisted Gravity Drainage |
| scf | Standard Cubic Feet |
| scfd | Standard Cubic Feet per Day |
| scfh | Standard Cubic Feet per Hour |
| scfm | Standard Cubic Feet per Minute |
| SME | Subject Matter Expert |
| TEG | Triethylene Glycol |
| TSD | Technical Support Document |
| UNFCCC | United Nations Framework Convention on Climate Change |
| USD | U.S. Dollars |
| VOC | Volatile Organic Compound |
| VRU | Vapor Recovery Unit |
| WCSB | Western Canadian Sedimentary Basin |

# 1. Executive Summary

Methane is an important climate change forcing greenhouse gas (GHG) with a short-term impact many times greater than carbon dioxide. According to data from Canada's United Nations Framework Convention on Climate Change (UNFCCC), oil and gas methane accounted for approximately 6% of Canada's total GHG emissions, using the 100 year GWP of methane[1]. Recent research also suggests that mitigation of short-term climate forcers such as methane is a critical component of a comprehensive response to climate change[2].

Methane is the primary component of natural gas. As a result, methane emissions occur throughout the oil and gas industry, and are the largest anthropogenic source of Canadian methane emissions[3]. There are effective methods readily available to reduce emissions of fugitive (leaked) and vented (intentionally emitted) methane from the oil and gas industry and, because of the value of the gas that is conserved, some of these measures could potentially increase revenue (e.g. reduce lost product), or have limited net cost. The Canadian Government has discussed reducing these emissions as part its commitment to international GHG reduction efforts[4] and key provinces including Alberta are also looking at these emissions as a way to reduce province-wide emissions[5]. Provinces including Alberta and British Columbia already have policies in place that require reductions in methane emissions and this study highlights the additional opportunities for further reductions.

International nonprofit organization Environmental Defense Fund (EDF) commissioned this economic analysis of methane emission reduction opportunities from the Canadian oil and natural gas industries to identify the most cost-effective approaches to reduce these methane emissions. This study is solutions-oriented and builds off a similar study ICF undertook for EDF on oil and gas methane reductions in the United States.[6] This study attempts to project the estimated growth of methane emissions from Canada's oil and gas industry through 2020. It then identifies the largest emitting segments and estimates the magnitude and cost of potential reductions achievable through currently available and applicable technologies and practices. The key conclusions of the study include:

- **124.8 Bcf of Emissions in 2020.** – Methane emissions from oil and gas activities are projected to remain stable from 2013 to 2020 at around 60.2 million tonnes $CO_2e$ (125 Bcf of methane[7]).

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1 National Inventory Report – Greenhouse Gas Sources and Sinks in Canada, 6% derived using the 100 year GWP. The percentage value of Canada's total GHG emissions would be higher if the 20-yr GWP were used. https://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/8812.php

2 Shoemaker, J. et. al., "What Role for Short-Lived Climate Pollutants in Mitigation Policy?". Science Vol 342 13 December 2013

3 Part 3 of the 2015 inventory, Table A9-3.

4 Government of Canada announces 2030 emissions target http://news.gc.ca/web/article-en.do?nid=974959

5 http://alberta.ca/climate-leadership.cfm

6 Available at: https://www.edf.org/energy/icf-methane-cost-curve-report

7 All values of $CO_2e$ in this study are calculated using 100-yr GWP values of Methane according to the AR-4 report unless stated otherwise. Example calculations using the 20-yr GWPs can be found in Appendix D

  - This relatively constant emissions mask sub-national changes including decreased gas and conventional oil production in Alberta and emissions growth in the Gathering and Boosting and Transmission segments, as a result of increased unconventional gas production in British Columbia and newly constructed pipelines, respectively.
  - The emissions estimate in this study is slightly higher than Canada's UNFCCC submitted values.
  - Existing 2013 emissions sources account for over 90% of emissions in 2020.
  - This assessment does not account for all possible methane emissions from oil sands production. The only emissions included related oil sands are flared and vented volumes and tank emissions from Steam Assisted Gravity Drainage (SAGD). Offshore emissions, while included, are small and are not a significant part of this study. This study also does not account for some insignificant emissions from oil transportation and refinery operations.
- **Concentrated Reduction Opportunities** - 35 of the over 175 emission source categories account for over 80% of the 2020 emissions, primarily at existing facilities.
- **45% Emissions Reduction with Existing Technologies** - This 45% reduction of oil and gas methane is equal to 27 million tonnes $CO_2e$ (56 Bcf of methane) and is achievable with existing technologies and techniques. This reduction:
  - Comes at a net cost of $2.76 CAD / tonnes $CO_2e$ reduced. If the natural gas is valued at $5 CAD/Mcf, the methane reduction potential includes recovery of gas worth approximately $251.1 million CAD[8] ($200.8 million USD) per year.
  - Equals $1.33 CAD /Mcf methane reduced ($1.06 USD/Mcf reduced)[9] or for less than $0.01 CAD/Mcf of gas produced nationwide[10], taking into account savings that accrue directly to companies implementing methane reduction measures (Figure 1-1).
  - Is achievable at a net annualized cost of $74.5 million CAD per year ($59.6 million USD) if the full economic value of recovered natural gas is taken into account and not including savings that do not directly accrue to companies implementing methane reduction measures[11]. If the additional savings that do not accrue to companies are included, the 45% reduction is achievable at a net savings to consumers and the Canadian economy of $2.3 million CAD ($1.8 million USD).
  - Is in addition to regulations already in place as well as projected voluntary actions companies will take by 2020.

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[8] Value is calculated based on whole gas and not just methane, excluding flaring.

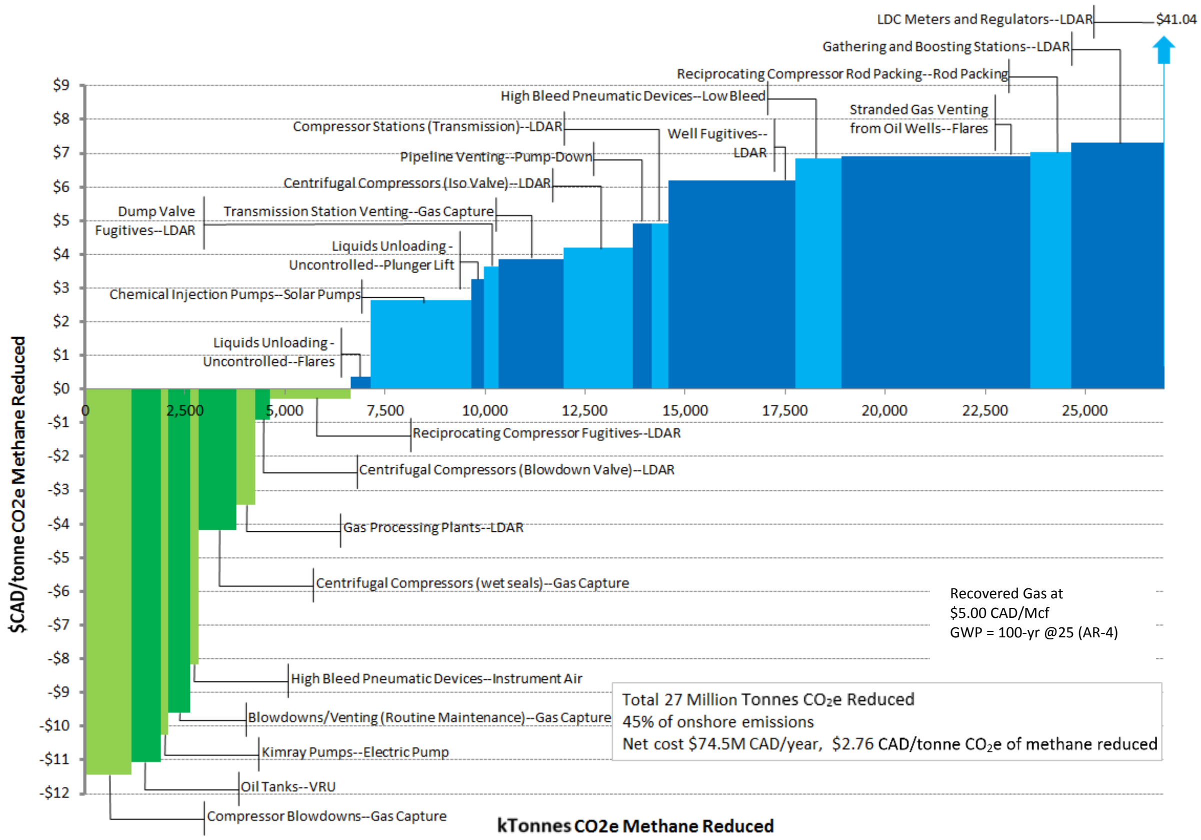
[9] All costs in this report are on a Canadian Dollar basis (CAD) unless where specifically expressed as U.S. Dollars (USD). A 2015 monthly average was used to calculate an exchange rate of 1.25 CAD to 1 USD. https://research.stlouisfed.org/fred2/series/EXCAUS/downloaddata

[10] Based on average natural gas production numbers across Canada

[11] Does not include or take into account potential social cost of methane emissions. As discussed later, typically reduction benefits do not accrue to Transmission and Distribution companies.

- **Capital Cost** - The initial capital cost of the measures is estimated to be approximately $726.3 million CAD ($581 million USD).

**Figure 1-1 - Marginal Abatement Cost Curve for Methane Reductions by Source**




- **Largest Abatement Opportunities**[12] – In 2020, the Gas Production segment makes up 26.8% of total oil and gas methane emissions, followed by Gathering and Boosting (21.8%) and Oil Production (19.9%). 35 of the over 175 emission source categories[13] account for over 80% of the 2020 emissions, primarily at existing facilities. By volume, the top five largest sources of Canadian oil and gas methane emissions are:
  - Stranded gas venting from oil wells – opportunity to reduce emissions by 78% by installing flares.
  - Fugitives from gathering and boosting stations – opportunity to reduce emissions by 60% by implementing leak detection, and repair (LDAR).
  - Chemical injection pumps - opportunity to reduce emissions by 60% by replacing gas-driven pumps with a non-natural gas driven variety.

[12] Economic analysis in this study does not include carbon costs unless otherwise stated

[13] For example, fugitive emissions from reciprocating compressors or vented emissions from liquids unloading.

- Reciprocating compressor rod packing seals - opportunity to reduce emissions by 22% by replacing rod packing at a higher frequency.
- Fugitives from centrifugal compressors - opportunity to reduce emissions by 60% by implementing leak detection, and repair (LDAR).

- **Provincial Results**: **Cost Effective Reductions Possible in Alberta and BC** – Alberta and British Columbia (Upstream only) make up 58% (32.6 Bcf) and 9% (4.8 Bcf) respectively of total Canadian oil and gas methane emissions reductions in 2020 and reductions are projected to be achievable in both provinces with existing technologies for less than $0.01/Mcf of gas produced[14].
  - Alberta - a 15.7 million metric tonne of $CO_2$e reduction (32.6 Bcf) is projected to be achievable with existing technologies and practices at a net total cost of $2.57 CAD/tonne $CO_2$e or $1.24 CAD /Mcf reduced which is less than $0.01 CAD/Mcf of gas produced in Alberta.
  - British Columbia - a 2.3 million metric tonne of $CO_2$e reduction (4.8 Bcf) is projected to be achievable with existing technologies and practices at a net total cost $1.69 CAD/tonne $CO_2$e or $0.81 CAD /Mcf reduced, which is less than $0.01 /Mcf of gas produced in British Columbia.
- **Co-Benefits Exist** – Reducing methane emissions will also reduce - at no extra cost - conventional pollutants that can harm public health and the environment. The methane reductions projected here would also result in a reduction in volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) associated with methane emissions from the oil and gas industry.

There are several caveats to the results:

- This study used as much Canadian-specific data as possible and modeled emissions by resource type, Canadian province, and by using Canada-specific activity data, where possible. Various assumptions across each segment were utilized in conjunction with Canadian-specific data (e.g. CAPP, Environment Canada, Alberta Energy Regulator, etc.) in order to develop equipment and segment specific activity estimates for the Canadian oil and gas industry. Where no Canadian data existed, supplementary data from U.S. studies was used.
- Data from the Subpart W[15] of the U.S. EPA GHG Reporting Rule (GHGRP) was analyzed in conjunction with regional proxies (based on geology) to develop emission factors that apply to the Canadian case. Source-specific emissions factors from U.S. data are not expected to be significantly different vs. Canadian operations. For example, a pneumatic device made by the same company can reasonably be assumed to operate the same in Canada as it would in the U.S.
- Emission mitigation cost and performance are highly site specific and variable. The values used here are estimated average values.

[14] Approximately 20% of emissions come from the midstream (e.g. Transmission, Distribution, etc.) which are not broken down provincially, but rather represented in Canada on a National level. Other provinces account for the remaining emissions.
[15] Subpart W – Petroleum and Natural Gas Systems
http://www.epa.gov/ghgreporting/reporters/subpart/w.html

- The emission reduction analysis addresses emissions from SAGD tankage and flaring and venting sources from oil sands, but due to the limited data on other sources (e.g. mining, tailings ponds, bitumen processing, etc.), these other oil sands sources have been excluded from the analysis.

# 2. Introduction

Methane emissions have an enhanced effect on climate change because methane has a climate forcing effect 25 times greater on a 100 year basis than that of carbon dioxide, the primary greenhouse gas (GHG). Methane's impact is 72 times greater than carbon dioxide on a 20 year basis[16], illustrating that methane reductions made today can have a real and tangible impact on reducing impacts of climate change tomorrow. Recent research also suggests that mitigation of short-term climate forcers such as methane is a critical component of a comprehensive response to climate change[17].

Methane emissions from the oil and gas industries are the largest anthropogenic sources of Canadian methane emissions according to UNFCCC reporting, using Canada's latest submission in April 2015[18]. At the same time, there are many ways to reduce emissions of fugitive and vented methane from the oil and gas industries and, because of the value of the gas that is conserved, some of these measures actually increase revenue or have limited net cost.

Several Canadian provinces have taken some leadership on this issue and have implemented some policies requiring methane reductions. Since many of these policies are based on performance-based and best-management practices that leave discretion to the companies as to how often they are performed, this analysis postulates that there may still be opportunities for additional reductions. For example, while companies in Alberta are required to look for and repair leaks, the frequency of inspections is left to company discretion. More frequent inspections typically yield greater reductions[19], but since the current Alberta policies do not require companies to disclose how often they are screening for leaks, there are likely additional reductions to be captured. The topic of the Canadian regulatory landscape is discussed further in Section 2.5.

Companies in the oil and gas industries have also made voluntary reductions in methane emissions, which were included in this analysis, but the statistics on the specific efforts undertaken are unclear given the lack of publicly available data sources. The reductions projected here are additional to projected voluntary actions taken until 2020. Overall, methane emissions remain a significant component of the Canadian GHG inventory and there is a sizeable potential for additional cost-effective reduction opportunities.

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[16] Based on AR-4 values for GWP. See section 2.3 of this report for further discussion of GWP and AR-5 values for 20-yr and 100-yr.

[17] Shoemaker, J. et. al., "What Role for Short-Lived Climate Pollutants in Mitigation Policy?". Science Vol 342 13 December 2013

[18] UNFCCC, "National Inventory Submissions". April 17th, 2015. https://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2015-nir-17apr.zip

[19] Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9) http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820

## 2.1. Goals and Approach of the Study

Environmental Defense Fund (EDF) commissioned this economic analysis of methane emission reduction opportunities from the Canadian oil and natural gas industry. This study's analysis is solutions-oriented and complements EDF's ongoing work on global methane emissions in the oil and natural gas sectors. This study also references and implements a similar approach and methodology to the U.S. marginal abatement cost curve study performed by ICF International in 2014[20]. The approach of the Canadian study was to:

- Define a baseline of methane emissions from the oil and gas sectors according to segments defined further in Section 2.2 below. The baseline was established for 2013 and projected to 2020 as a conservative estimate of a point when existing mitigation technologies could be fully installed throughout the supply chain.
- Review existing literature and conduct further analysis to identify the largest reduction opportunities and validate and refine cost-benefit estimates of mitigation technologies.
- Conduct interviews with industry, oil and gas experts, and equipment vendors with a specific focus to identify additional mitigation options.
- Use this information to develop marginal abatement cost (MAC) curves for methane reductions in these industries.
- Document and present the results.

The final outputs of the study include:

- The projected 2020 emissions baseline. (Chapter 3 and Appendix B)
- Inventory of methane mitigation technologies. (Chapter 3)
- Emissions abatement cost curves across a range of scenarios (Chapter 4 and Appendix C)
- Conclusions (Chapter 5)
- Additional sensitivity cases (Appendix D)

## 2.2. Overview of Gas Sector Methane Emissions

There are many sources of methane emissions across the entire oil and gas supply chain. These emissions can be characterized as:

- Fugitive emissions – methane that "leaks" unintentionally from equipment such as from flanges, valves, or other equipment.

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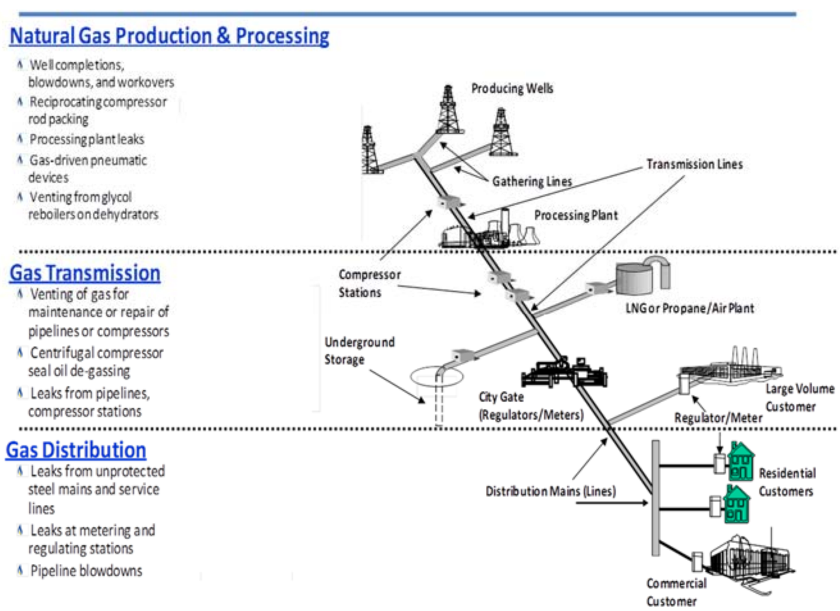
[20] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf

- Vented emissions – methane that is released due to equipment design or operational procedures, such as from pneumatic device bleeds, blowdowns, or equipment venting.
- Incomplete combustion – methane that passes through a combustion device, such as an engine or flare, without being combusted due to less than 100% combustion efficiency of the device.

Although 'leaks' or 'fugitives' is sometimes used to refer to all methane emissions from the oil and gas industry, we use the more narrow technical definitions in this report.

Figure 2-1 illustrates the major segments of the natural gas industry and examples of the primary sources of methane emissions as gas is produced, processed, and delivered to consumers. Natural gas is produced along with oil in most oil wells (as "associated gas") and also in gas wells that do not produce oil (as "non-associated gas"). Up until the past few years, most of the Canadian natural gas supply came from the Alberta region. More recently, significant shale plays in British Columbia have been a growing source of gas supply.

**Figure 2-1 - Natural Gas Industry Processes and Example Methane Emission Sources**




**Sources:** American Gas Association; EPA Natural Gas STAR Program

***Gas Production***

Raw gas (including methane) is vented at various points during the production process. Gas can be vented when the well is "completed" at the initial phase of production. Further, because gas wells are often in remote locations without electricity, 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 or "bleed" small amounts of gas during their operation.

In both oil and gas production, water and hydrocarbon liquids are separated from the product stream at the wellhead. The liquids release entrained 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. In some cases, the gas released by these processes and equipment may be flared rather than vented, to maintain safety and to relieve over-pressuring within different parts of the gas extraction and delivery system. Other times the gas cannot always be routed to pipelines or used beneficially onsite and sometimes due to safety or infrastructure reasons, etc., and it is flared.

Flaring produces $CO_2$, a significant but less potent GHG than methane, but no flare is 100% efficient, and some methane (uncombusted) is emitted during flaring. In addition to the various sources of vented emissions, the many components and complex network of small gathering lines have the potential for fugitive emissions.

Although some gas is pure enough to be used as-is, most gas is first transported by pipeline from the wellhead to a gas processing plant. The gathering system has pneumatic devices and compressors that vent gas as well as having potential fugitive emissions. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including $CO_2$, in order for the gas to be pipeline-quality and ready to be compressed and transported. Such plants are another source of fugitive and vented emissions.

From the gas processing plant, natural gas is transported, generally over long distances by inter-provincial pipeline to the "city gate" hub and then to consumers. The vast majority of the compressors that pressurize the pipeline to move the gas are fueled by natural gas, although a small share is powered by electricity. 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 from seals and during operations and maintenance. Compressor stations constitute the primary source of vented methane emissions in natural gas transmission.

Some power plants and large industrial facilities receive gas directly from transmission pipelines, while others as well as residential and commercial consumers have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some methane emissions do 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, however these are not common in Canada.

***Oil Production***

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 and the gas is separated from the oil stream at the wellhead and can be captured for sale, vented, or flared. Venting or flaring are most common in regions that do not have gas gathering infrastructure ("stranded gas").

The oil sands region in Alberta is a segment of oil production that differs from conventional oil production. Methane emissions occur from the mine face and during the processing of oil sands in open pit mining operations. Small amounts of methane may evolve when crude oil is extracted from SAGD operations and stored in storage tanks. Both open pit mine and SAGD operations use natural gas as fuel and leaks occur from piping and meters, and associated components. Finally, methane may be biogenically produced from tailing ponds in open pit mining operations. For the purposes of this study and based on the availability of data from ICF's GMM model, tank emissions from SAGD production were included in the emissions estimates. Also included, based on Alberta's ST60B report, were flared and vented volumes from crude bitumen facilities. The Alberta report might include some SAGD vented emissions from tank, however this is expected to be minimal. Other oil sands-related emissions were not included due to lack of data and mitigation options.

Oil is taken from the wellhead in electric-powered pipelines and more recently by rail, to refineries for processing. Petroleum products are then taken to consumers by pipeline, truck, rail, or barge. The downstream methane emissions in the petroleum sector are much smaller than in the gas sector as most of the methane has been removed from the oil by this point. The oil transportation and refining segments are not included in the emissions analysis of this report.

***Oil and Gas Operations and Shale Developments***

For the last 100 years, domestic oil production has been primarily in the Alberta region of Canada, both conventional and oil sands operations. Domestic gas production has historically been mostly concentrated in the Alberta region, but more of the focus of new natural gas development has been in the extraction of gas from shale formations in British Columbia. Shale is a sedimentary rock composed of compacted mud, clay and organic matter. Over time, the organic material can produce natural gas and/or petroleum, which can slowly migrate into formations where it can be recovered from conventional oil and gas wells. The shale rock itself is not sufficiently permeable to allow the gas to be economically recovered through conventional wells; that is, gas will not flow sufficiently freely through the shale to a well for production.

Gas and oil from shale formations is recovered by hydraulically fracturing the shale rock to release the hydrocarbons. This involves pumping water and additives at high pressure into the well to "fracture" the shale, creating small cracks that allow the gas and/or oil to flow out. When the water "flows back" out of the well, methane is entrained and may be vented. Due to the high global warming potential of methane, this can be a large source of GHGs. For these reasons, the increased production of shale gas is a potential source of increased GHG emissions (e.g. if flowback emissions are not controlled).

***Offshore Operations***

In Canada, relatively insignificant amounts of both oil and gas are produced from offshore facilities. Thus, while emissions were estimated and included for these offshore facilities based on reports and other data, the reports do not have the detail and specificity of the rest of the methane inventory and therefore cannot be included in the same methodology applied to the rest of the inventory for this analysis.

Therefore, while this report includes offshore emissions in the baseline inventory model, offshore emissions are not analyzed as part of the marginal abatement cost curve reductions going forward to 2020.

## 2.3. Climate Change-Forcing Effects of Methane

Different greenhouse gases persist in the atmosphere for different lengths of time and have different warming effects, and thus have different effects on climate change. In order to compare them, the scientific community uses a factor called the global warming potential (GWP), which relates each GHG's effect to that of $CO_2$, which is assigned a GWP of 1. The science and policy communities have historically looked to the Intergovernmental Panel on Climate Change (IPCC) assessment reports as the authoritative basis for GWP values. The currently accepted values are from the IPCC Fifth Assessment report[21] (AR-5).

$CO_2$ emissions are the primary driver for climate change over the long term, due to their long lifetime in the atmosphere. Because stabilizing climate will require deep cuts in GHG emissions, GWP values are most commonly expressed on a 100-year time horizon. The 100 year GWP is the standard value used by Environment Canada and other federal, provincial, and international agencies to measure GHG emissions. On a 100-year basis, methane is assigned a GWP of 34 by the AR-5. This means that one tonne[22] of methane has the same effect as 34 tonnes of $CO_2$ over 100 years. However, the Canadian GHG inventory uses a 100 GWP of 25, as specified by the UNFCCC inventory protocol.

Some GHGs, including methane, have a stronger climate-forcing effect than $CO_2$ but a shorter lifetime in the atmosphere (12 years for methane). In order to evaluate the short-term effects, the GWP is also calculated on a 20 year basis. On a 20 year basis, the AR-5 assigns methane a GWP of 86. In summary:

- Most countries, including Canada and the EPA Greenhouse Gas Reporting rule as of 2013 use the AR-4 100 year GWP of 25 for methane. The AR-4 20 year GWP for methane is 72.
- The GWPs for methane per the AR-5 are 34 for 100 years and 86 for 20 years.
- This study uses the AR-4 100 year GWP of 25 for methane except where otherwise noted.

## 2.4. Cost-Effectiveness of Emission Reductions

It is common in discussing emission reductions to describe "cost-effective" emission reductions. However, there are three different concepts of cost effectiveness that must be understood and differentiated.

**<u>The Company Perspective</u>** - The first concept is cost-effectiveness for the company implementing the measure. In this case, "cost-effective" means that the value of gas that is recovered through a methane

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[21] IPCC. Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.
https://www.ipcc.ch/report/ar5/wg1/

reduction measure exceeds the incremental capital and operating cost of the measure sufficiently to create a payback or rate-of-return that meets the company's investment criteria. Measures that meet these criteria might be described as having a positive net present value (NPV), a short payback period, or an internal rate of return that exceeds a certain threshold. In order for a measure to meet this cost-effectiveness criterion, the measure must recover the methane emissions and be able to recover their monetary value. Flaring of methane emissions does not meet this criterion, for example. In addition, the company must be able to monetize the value of the recovered methane. For example, if a producer reduces methane losses, it will have more gas to sell and will receive an economic benefit.

**<u>Economy Perspective</u>** - The second concept is cost-effectiveness at the economy-wide scale. In segments in which the company owns the gas, such as oil and gas production, the company can clearly monetize the value of reduced gas losses. This is also true in some other segments. Most midstream companies (gathering, processing, and storage) are paid a fixed fee for gas lost and consumed during their operations. If they can reduce their losses then they will benefit directly from the reduced losses.

Transmission and local distribution companies typically do not own the gas they transport and they are usually required by regulators to return the value of reduced losses to their customers, so they cannot recover the benefit of reduced methane losses. Methane reductions in these segments of the industry will not have a positive return to the company or be "cost-effective" in this sense. That said, the value of reduced losses will accrue to other parts of the economy. If a pipeline or LDC reduces its losses, the benefit will eventually flow through to the customers and to the economy overall. Reduced losses will eventually flow through as lower prices for gas delivery and delivered cost of gas to consumers. Thus, even when the entity implementing a reduction cannot directly benefit from reduced losses, there is a broader benefit and that full economic benefit can be calculated and allocated against the cost of the methane reduction, the second kind of cost-effectiveness.

**<u>The Regulatory Perspective</u>** - The last concept of cost-effectiveness is in the context of pollution control programs. In conventional pollution control programs the control technology rarely results in a cost reduction to the company that is required to implement it. That is, the cost-of-control is almost always positive and the net present value is negative and there is no payback for the investment. Nevertheless, these programs incorporate the concept of cost-effectiveness, meaning that the cost is acceptable to society as a means of meeting public health and environmental goals. The cost-effectiveness varies for different pollutants and different regulatory programs. In this context, methane reductions can be considered cost-effective even if they have a net cost to the company or society overall. Where methane reductions do create a net value to the implementing company, the cost-of-control will be negative, i.e., the company is reducing emissions and saving money rather than spending money.

In this study, the value of recovered gas is included in calculating the cost-effectiveness of mitigation measures where the gas can be recovered and where it can be monetized by the company. Therefore, the same measure may have different costs for different segments, e.g., reducing compressor emissions will have a lower net cost in the production segment than in the transmission segment because the savings can be monetized in the former but not that latter. This reflects the net cost to the company to implement the measure. However, where gas can be recovered through a mitigation measure, it will have value to the broader economy, even if it is not recognized by the company that must make the investment. The cost-of-control, whether positive or negative, can be also evaluated in the regulatory sense and compared to other available emission reduction options. Finally, there are additional social and environmental benefits of methane reductions that are not captured in these calculations, including the broader economic value of reduced climate risk and co-benefit reductions of conventional pollutants such as ground-level ozone and hazardous air pollutants.

## 2.5. Canadian Regulatory Landscape

The regulatory structure in Canada is such that each province has an overarching set of regulations that apply to the oil and gas industry. For the purposes of this report, the following main regulations were reviewed when evaluating methane emissions across industry segments:

- Alberta – Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting[23], and ST60B: Upstream Industry Flaring and Venting Report[24]
- British Columbia – Flaring and Reduction Guideline[25], and Industrial Facility Greenhouse Gas Emissions Report Summaries[26]
- Saskatchewan – Directive S10: Upstream Petroleum Associated Gas Conservation[27]

Although there are differences across provinces in Canada regarding the approach to regulating emissions from oil and gas activities, the core methodology of each province is essentially the same, and can be characterized by a few key principles, such as:

- Flaring and venting must first be evaluated for *elimination*
- If the emissions source cannot be eliminated, then the flaring and venting must then be evaluated for *reduction*
- If the emissions source cannot be reduced, then the flaring and venting source shall meet specified *performance standards*

In all three scenarios above, Canadian regulations typically employ a decision tree style approach with a mandatory economic analysis (e.g. NPV) to determine what category an emissions source falls into. Due to the similarity of regulations across provinces, only the Alberta Directive 60 regulations are discussed here to provide some further insight. Developed as a draft in 1999 and revised multiple times from that point, Directive 60 applies to all upstream oil and gas industry wells and facilities as well as pipeline installations that convey gas. One of the main focal points of the directive is the conservation of associated

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[23] Alberta Directive 060 - https://www.aer.ca/rules-and-regulations/directives/directive-060

[24] ST60B - https://www.aer.ca/data-and-publications/statistical-reports/st60b

[25] British Columbia Flaring and Venting Reduction- https://www.bcogc.ca/content/flaring-and-venting-reduction-guideline

[26] Industrial Facility Greenhouse Gas Emissions Report Summaries - http://www2.gov.bc.ca/gov/content/environment/climate-change/reports-data/industrial-facility-ghgs

[27] Saskatchewan Directive S-10 - http://www.publications.gov.sk.ca/details.cfm?p=69502

gas, or solution gas, as it's referred to in the regulation. This is demonstrated by the fact the directive has set a province-wide solution gas flaring limit of 670 million cubic metres per year. If solution gas flaring exceeds the 670 million cubic metre limit in any year, the Alberta Energy Regulatory (AER) will impose reductions that will stipulate maximum solution gas flaring limits for individual operating sites based on analysis of the most current annual data so as to reduce flaring to less than the target.

Beyond the focus on sources such as solution gas, well testing, dehydrators, and compressor stations as specific emissions sources, Directive 60 does not lay out prescriptive requirements for emissions reductions across Alberta. Rather, the regulations are performance-based, allowing operators to identify sources that meet the requirements of the directive. For example, where the U.S. NSPS Subpart OOOO[28] regulation specifically identifies wet seal centrifugal compressors as an emission source that must be controlled, Directive 60 does not make mention of specific sources such as wet seal compressors. Thus, it is unclear whether all sources that emit methane are being captured and analyzed across Canadian oil and gas activities.

Further research reinforces this uncertainty. The AER enforces Directive 60 and releases a historical monthly enforcement report, ST108. A historical review was performed of all enforcement actions published from AER's ST108 report from 2008 to 2014. The majority of non-compliance events for Directive 060 came in the form of performance issues (e.g. improperly functioning flares, exceeding flaring limits, not completing decision tree analysis, etc.) or proximity issues (e.g. emissions source too close to a residential area). No instances of missed or uncharacterized emissions sources were found in the public domain, leading to the uncertainty on whether or not all methane emissions sources are being captured across Canada. There is also no publicly available data on what control measures have been implemented by oil and gas operators and the reductions in methane emissions as a consequence, which also leads to uncertainty regarding existing methane reduction efforts.

As another example, Alberta requires leak detection and repair but the required protocol leaves the frequency of the inspections to the discretion of the company[29]. Since effectiveness of these programs highly correlated to frequency, this structure leaves uncertainty as to the effectiveness of the program and the potential for additional reductions.

Finally, looking ahead at the regulatory landscape across Canada, according to Intended Nationally Determined Contributions (INDC) to the UNFCCC[30], Canada is continuing to develop and implement measures to reduce emissions from key greenhouse gas sources. The Canadian Government announced

[28] Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.oooo

[29] CAPP Best Management Practice for Fugitive Emissions Management http://www.capp.ca/publications-and-statistics/publications/116116

[30] Canada's submissions to the UNFCCC http://www4.unfccc.int/submissions/INDC/Published%20Documents/Canada/1/INDC%20-%20Canada%20-%20English.pdf

its intentions to develop regulations to address methane emissions from the oil and gas sector through a responsible sector-by-sector regulatory approach as part of this effort.

# 3. Approach and Methodology

## 3.1. Overview of Methodology

This section provides an overview of the methodology applied for this study. The major steps were:

- **Establish the 2013 Baseline Inventory for Canada**– upstream and midstream operations in Canada were divided into two categories based on the presence of hydrogen sulfide ($H_2S$) ("sweet" or "sour" gas). $H_2S$ is poisonous and its presence sometimes requires systems that are less prone to leak. The determination of whether or not to classify production as sweet or sour was made based on data extracted from IHS Accumap®. The data structure and taxonomy of the U.S. EPA GHG Inventory was then used as a starting point to generate the list of source categories for the Canadian baseline. Emissions were segregated by Canadian province, specifically Alberta, British Columbia, Manitoba, and Saskatchewan.

  Canadian-specific data were used wherever possible. This was particularly true for the activity data (the characterization of the number and type of facilities) such as provincial well counts, miles of Transmission pipeline, number of gathering stations, etc. Canadian emissions data were less available in this case, and some U.S. emission factors were used, such as Subpart W data. This was estimated to be an appropriate approach because the types of equipment and operating procedures are very similar between the U.S. and Canada. That said, surrogate locations were identified in the U.S. to help generate these estimates for select emissions sources based on geological and operating criteria. The following analogs were identified specifically for oil and gas activity from production through processing segments of the industry based on SME input:

  - Alberta – Rocky Mountain
  - British Columbia – Rocky Mountain
  - Saskatchewan – Midwest Continent
  - Manitoba – Midwest Continent

  To further clarify the approach above, on a very basic level, emissions in this study are estimated by the following equation:

  $$Emissions = \sum_{i=1}^{n} (AF_i \times EF_i)$$

  Where n is the total number of emissions sources and AF and EF stand for activity and emissions factor, respectively, for each source. Canadian-specific data was mainly used to estimate the AF portion of the equation, while some Canadian data as well as proxy data and detailed analysis of Subpart W, external reports, etc., was used to estimate the EF portion.

Additionally, the Canadian analysis was developed using publicly available reports from the Canadian oil and gas industry[31], support from Canadian oil and gas experts, and the evaluation of the most recent U.S. EPA inventory of methane emissions in the EPA Inventory of U.S. GHG Emissions published in 2015 with data for 2013[32]. The Canadian inventory was then reviewed and revised to account for additional, more recent information such as information from the EPA GHG Reporting Program[33] and recently published studies such as the University of Texas/EDF gas production measurement study and the Prasino et al BC study[34] and other recent studies sponsored by EDF. These changes were applied to develop a 2013 Baseline, which was used as the basis for projecting onshore methane emissions to 2020. The baseline inventory includes methane emissions by source for the onshore and offshore exploration and production, gas processing, gas storage, gas transmission, LNG import / storage, and distribution segments of the industry.

Finally, routine checks were made in the development of the baseline with external sources as points of comparison in the analysis.

- **Projection of emissions to 2020**– the analysis then used the baseline inventory to project emissions to the year 2020 based on various drivers such as growth in gas production, pipeline mileage, etc. Data for projections were obtained mainly from ICF’s Gas Markets Model™ (GMM) model and are discussed in Appendix B. Potential reductions were based on regulatory analysis and input from subject matter experts. The year 2020 was chosen as a realistic date by which control technologies could be installed.
- **Identification of major sources and key mitigation options** – the next step was to identify the largest emitting sources in the projected 2020 inventory and the emissions with associated mitigation technology that would be most effective and cost-effective for these sources.
- **Characterization of emission reduction technologies** – a key part of the study was to review and update information on the cost and performance of the selected mitigation technologies. Information was gathered from equipment manufacturers, oil and gas companies, and other knowledgeable parties and then applied to the volume of associated emissions.
- **Development of Marginal Abatement Cost curves** – the technology information was applied to the emissions inventory to calculate the potential emission reduction volume and cost. The results were displayed in a series of marginal abatement cost curve to highlight which options are considered most cost-effective.

[31] Examples include Canadian Association of Petroleum Producers (CAPP), Environment Canada, and Alberta Energy Regulatory

[32] U.S. EPA, “Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990-2013”, http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

[33] http://www.epa.gov/ghgreporting/

[34] Allen, David, et. al., “Measurements of Methane Emissions at Natural Gas Production Sites in the United States”. 10.1073/pnas.1304880110

The UNFCCC Canadian national inventory in addition to the Alberta and British Columbia inventories (referenced above in section 2.5) were considered as part of this process. However, after communicating with provincial experts from the agencies responsible for those inventories, it was established those inventories do not include the component-level data needed to undertake the type of analysis this study performs. ICF used its model to develop that detailed data, which differs from the public inventories. Not surprisingly different methods will yield different results. However, the baseline developed for this study is within 15% (higher)[35] of the emissions estimate from the UNFCC Canadian inventory, suggesting that while the methods may be different, the results are comparable.

The key steps are discussed further in the following sections.

## 3.2. Development of the 2013 Baseline Inventory

The first step in this analysis was to develop a baseline inventory of fugitive and vented methane emissions from each oil and gas segment. The inventory serves as a basis for identifying existing sources and associated quantities of emissions with potential for mitigation. The following approach was used:

- **Develop estimates for equipment-specific activity and/or drivers –** This study relied on publically available information to estimate activity data for each emission source. While detailed information and sources are described in Appendix A, some examples include:
  - Technical Report on Canada's Upstream Oil and Gas Industry Volumes 1-4[36]
  - A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulfide (H2S) Emissions by the Upstream Oil and Gas Industry[37]
  - $CH_4$ and VOC Emissions from the Canadian Upstream Oil and Gas Industry[38]

  Organizations such as the Canadian National Energy Board (NEB), U.S. EIA (Energy Information Agency), International Energy Agency (IEA), and the Canadian Energy Pipeline Association (CEPA) also provide information on historic and projections of oil and gas activity. This study has well-level data for Canadian provinces from DI Desktop[39] in addition to other data sources. CAPP and companies such as TransCanada also publish or present specific equipment level data. This study extracted Canadian activity data when available, mainly production volumes for the production segment, natural gas and

[35] Calculated from page 18 of PT3 of 2015 Canadian Submission to the UNFCCC using total methane emissions in Energy sector https://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/8812.php

[36] [EC] Environment Canada. 2014. Technical Report on Canada's Upstream Oil and Gas Industry. Vols. 1 - 4. Prepared for Environment Canada. Calgary (AB): Clearstone Engineering Ltd. June 2014.

[37] Canadian Association of Petroleum Producers - A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry. 2004. http://www.capp.ca/publications-and-statistics/publications/86220

[38] Canadian Association of Petroleum Producers - CH4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry Volume. 1999. http://www.capp.ca/publications-and-statistics/publications/84180

[39] Drilling Info Basic – Provides historical well information, historical production, and other data http://info.drillinginfo.com/

condensate volumes for processing facilities, miles of transmission pipeline for transmission, LNG import/ export volumes for the LNG facilities, and natural gas end use volumes for the distribution segment or used relevant U.S. specific counts and expert judgment to estimate provincial level Canadian specific equipment counts. Detailed steps for developing both activity and emissions factors can be found in Appendix A.

Finally, data from the U.S. EPA's mandatory Greenhouse Gas Reporting Rule (GHGRP) subparts C (combustion from stationary sources) and W (methane emissions from petroleum and natural gas systems) were used to provide supplemental information for Canada's baseline inventory.

- **Develop equipment-specific activity data based on activity drivers -** Once activity drivers for 2013 and 2020 were established, the next step was to estimate activity for equipment without available specific public information. For example, a well count was used to establish the number of separators, and the miles of transmission pipelines to determine the count of compressors. This study used expert judgment and data from reports and publications to determine the most appropriate drivers for existing activity. By doing so, it was possible to fill in the data gaps identified by research efforts on equipment activity. Some examples include:
    - Oil and gas production volumes – this activity driver was used to estimate equipment-specific activity data for production and gathering and boosting segments that are correlated to production volumes, such as storage tanks and glycol dehydrators. This study's modeling approach allowed for the development of additional activity drivers that represent the specific Canadian oil and gas operational characteristics. Production volumes were used to estimate volume of gas processed.
    - Well count – this activity driver was used to estimate equipment activity data that are correlated to well count, such as separators and pneumatic devices.
    - Residential/commercial gas demand – this was used to determine the growth in the distribution segment, if any.
    - LNG import and export volumes –was used to determine the number of new LNG facilities that will come online in 2020.
- **Establish relevant emission factors -** After establishing Canadian specific equipment counts, emission factors were used to determine the volume of methane being emitted by source. Methane emissions for approximately 200 sources were calculated using the developed activity factors (e.g., equipment counts) multiplied by emission factors (average emissions from each source) to estimate the total emissions. These factors were developed either from Canadian literature cited in this study, the EPA Inventory, or calculated using available GHGRP data[40] and regional proxy data specific to each particular emission source.

[40] Envirofacts Customized GHG Search – Subpart W Petroleum and Natural Gas Systems
http://www.epa.gov/enviro/facts/ghg/customized.html

- **Establish current control measures** - The next step was to establish current control measures in place and develop a scenario for expected penetration of control measures in the future, i.e. whether the proportion of control measures is expected to remain the same or accelerate in the future. This study primarily relied on the library of technologies and practices identified in the Natural Gas STAR and Global Methane Initiative Programs and utilized in the earlier ICF/EDF MAC[41] work as control measures for this project. U.S. proxy data is reasonable in these instances because equipment such as pneumatic devices, compressors, and pumps are on-average likely to perform similarly whether located in Canada or the U.S. There are typically two options to develop current control measure penetration estimates: 1) Research and utilize all reported country-specific control measures, or 2) Research all publicly available data on facility, segment and source specific implementation of control measures in the countries. Companies often report their reduction measures to organizations like the Global Methane Initiative, United Nations Clean Development Mechanism, and Carbon Disclosure Project. These sources provide some information on control measures. For Canada, the information was pieced together by company and province depending on the availability of data. When there were any data gaps, this study relied on using expert judgment and U.S.-specific data combined with regional proxies. ICF worked with EDF to determine the future scenario of control measure penetration.
- **Calculate emissions from the baseline inventory model -** The baseline inventory model calculates emissions estimates by source and segment. The inventory identifies the portion of emissions by source that is controlled versus uncontrolled emissions that provide the potential for reductions. The study also projected the baseline to 2020 based on the oil and gas activity forecast. Table 3-1 below summarizes emissions by segment from the baseline inventory in 2013. As a point of comparison, this study contrasted the inventory estimates against the various industry and governmental sources (e.g. CAPP, Environment Canada, UNFCC, etc.) and found the estimates to be reasonable.

[41] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf

**Table 3-1: 2013 Baseline Inventory Emissions by Segment**

| Segment | Million tonnes $CO_2e$ | Bcf $CH_4$ |
|---|---|---|
| **Natural Gas** | | |
| Gas Production | 17.4 | 36.3 |
| Gathering and Boosting | 12.4 | 25.8 |
| Gas Processing | 6.9 | 14.4 |
| Gas Transmission | 7.1 | 14.8 |
| Gas Storage | 1.1 | 2.4 |
| Gas Distribution | 1.2 | 2.4 |
| LNG-Storage | 1.1 | 2.3 |
| LNG-Import | 0.2 | 0.4 |
| **Petroleum** | | |
| Oil Production | 13.0 | 27.0 |
| **Offshore** | | |
| Gas Offshore Production | 0.01 | 0.01 |
| Oil Offshore Production | 0.03 | 0.06 |
| | | |
| **Total Emissions** | 60.5 | 125.9 |

## 3.3. Projection to 2020

The 2020 forecast of natural gas and petroleum systems methane emissions starts with the 2013 Baseline described in Section 3.2. Using quantities such as gas production, gas consumption, or pipeline miles as drivers, emission estimates from the baseline inventory were projected to 2020. Figure 3-1 shows the results for estimated methane emissions for both the 2013 baseline inventory and for the 2020 projections. Data from ICF's GMM model was used to estimate future data such as production volumes, pipeline mileage, number of completions, etc., while sources such as the National Energy Board[42] and the U.S. EIA's Annual Energy Outlook (e.g. Canadian import/exports to/from the U.S.) were utilized to supplement the projections. In addition, expected emission reductions from sources such as high bleed pneumatic devices and wet seal centrifugal compressors as a result of voluntary control efforts are included in the forecast. Other sources were assumed to have no additional control measures applied. Emissions are projected to be relatively flat over this period: 125.9 Bcf in 2013 to 124.8 Bcf in 2020. Growth is observed in the Gathering and Boosting and Transmissions segments, mostly due to increased unconventional production in British Columbia and new pipeline projects, respectively. Much of the offsetting decline in emissions can be attributed to the decrease in conventional production across Alberta, driven mainly by economics and geology. Given the relatively flat emissions projection profile, more than 90% of the emissions in 2020 come from existing sources (sources in place as of 2013) as shown

[42] National Energy Board – Statistics and Analysis
https://www.neb-one.gc.ca/nrg/sttstc/index-eng.html

in Figure 3-2. The projection also disaggregated the national level upstream emissions estimate of the 2013 inventory to Canadian provinces in this study. The details of the analysis are discussed in Appendix A.

**Figure 3-1 – Emission Projections to 2020 – (Including Offshore and Excluding Oil Sands)**

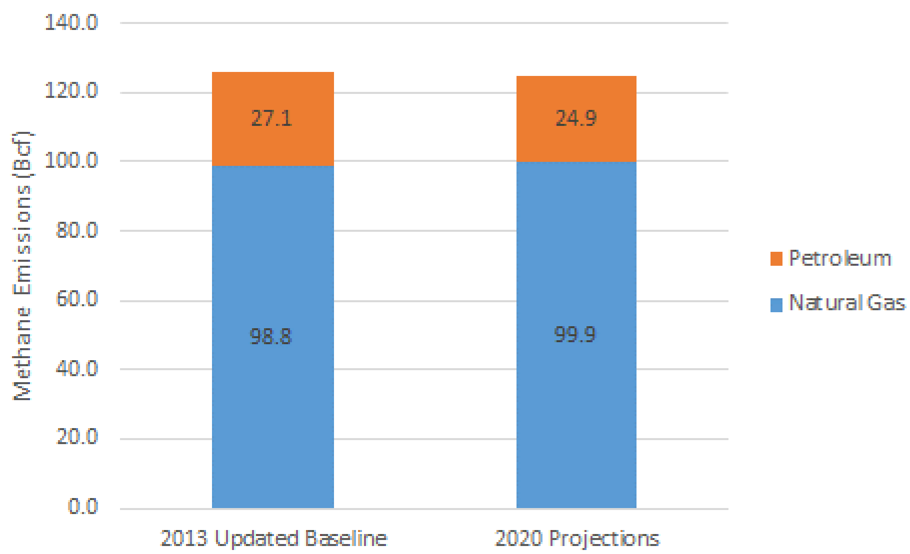
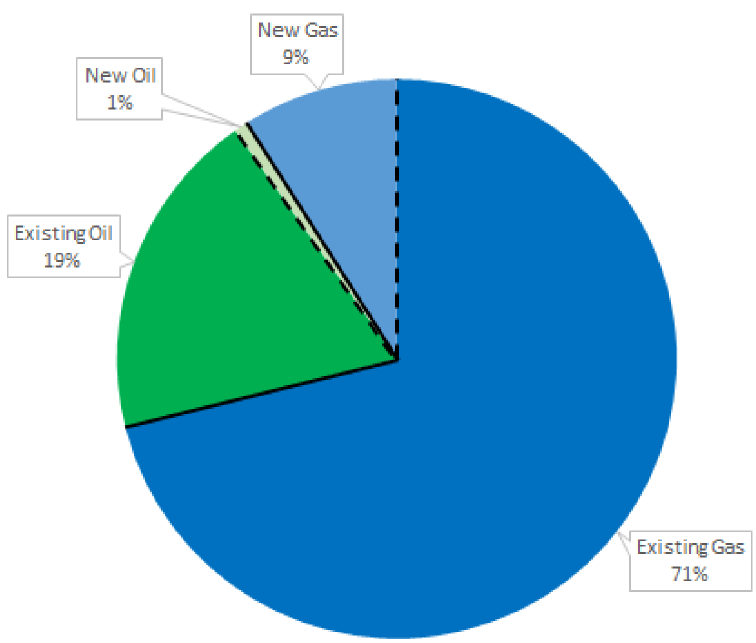



**Figure 3-2 - Distribution of Emissions in 2020**



## 3.4. Identification of Targeted Emission Sources

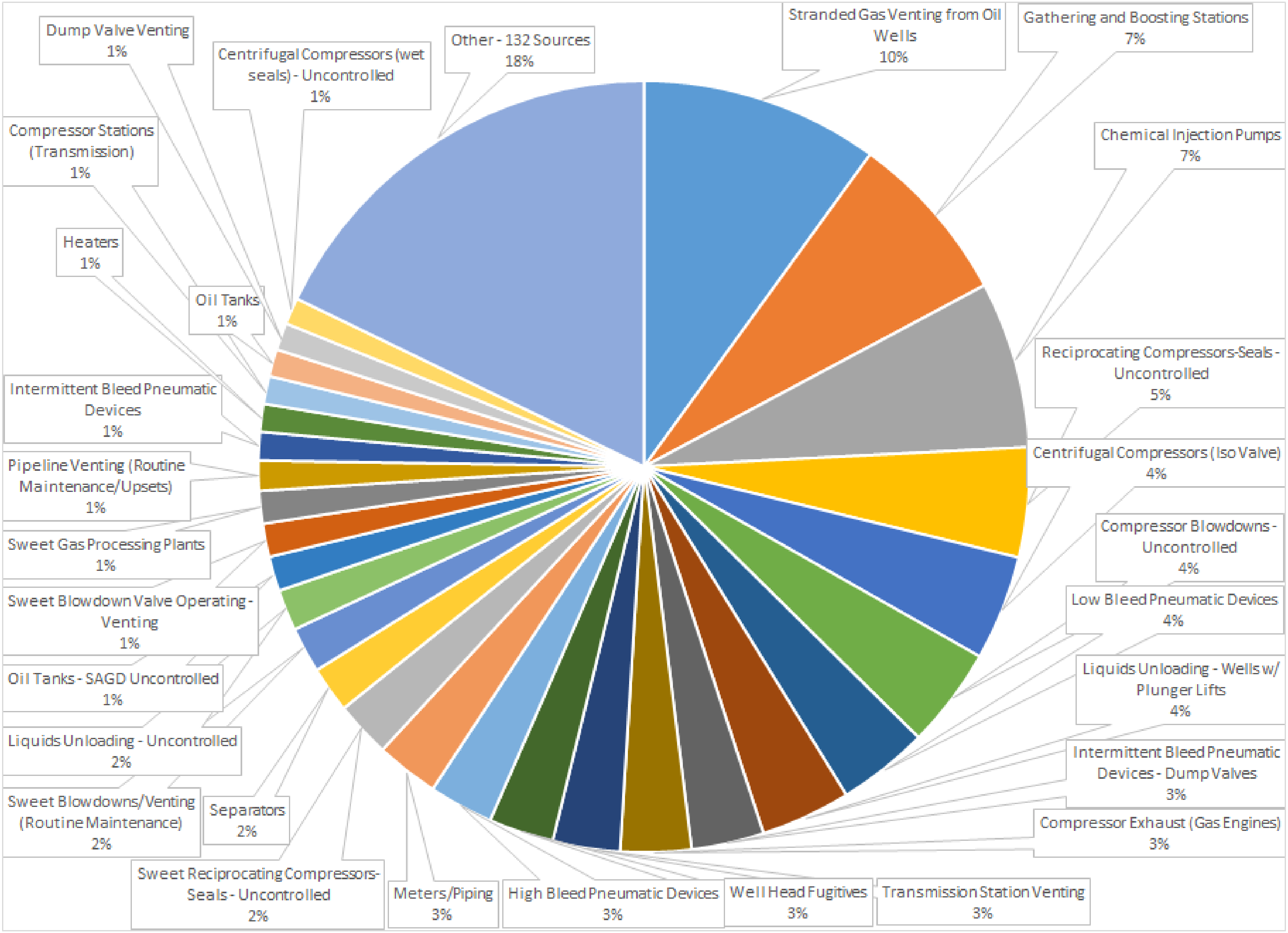
Table 3-2 summarizes the largest emitting source categories in the projected 2020 emissions for the oil and gas sectors by major source category. The top 35 source categories account for approximately 80% of the total 2020 methane emissions of 124.8 Bcf and the remaining 100+ categories account for 0.7% or less of the total emissions each individually. Although these source categories were not included in this specific table due to their small size, there are demonstrated methane reduction technologies that can provide cost-effective reductions for many of them on a selective case-by-case basis. Figure 3-3 shows the distribution of sources graphically. Vented emissions are the largest emission source category overall, with stranded gas venting, reciprocating compressor seals, blowdowns, pneumatic controllers and pumps being among the significant sources. Fugitives as a collective source across segments is a significant emissions category.

**Table 3-2 - Highest Emitting Onshore Methane Source Categories in 2020**

| Segment | Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|---|
| Oil Production | Stranded Gas Venting from Oil Wells | Vented | 12.5 | 10.0% | 12.5 | 10.0% |
| Gathering and Boosting | Gathering and Boosting Stations | Fugitive | 8.0 | 6.4% | 20.5 | 16.4% |
| Gas Production | Chemical Injection Pumps | Vented | 7.7 | 6.1% | 28.1 | 22.5% |
| Gathering and Boosting | Reciprocating Compressors-Seals - Uncontrolled | Vented | 5.7 | 4.6% | 33.8 | 27.1% |
| Gas Transmission | Centrifugal Compressors (Iso Valve) | Fugitive | 5.5 | 4.4% | 39.3 | 31.5% |
| Gathering and Boosting | Compressor Blowdowns - Uncontrolled | Vented | 5.0 | 4.0% | 44.3 | 35.5% |
| Gas Production | Liquids Unloading - Wells w/ Plunger Lifts | Vented | 4.7 | 3.8% | 49.0 | 39.3% |
| Gas Transmission | Transmission Station Venting | Vented | 3.5 | 2.8% | 52.5 | 42.1% |
| Gas Production | Well Head Fugitives | Fugitive | 3.1 | 2.5% | 55.6 | 44.6% |
| Gas Production | Meters/Piping | Fugitive | 3.0 | 2.4% | 58.6 | 47.0% |
| Gas Processing | Sweet Reciprocating Compressors-Seals - Uncontrolled | Vented | 2.9 | 2.3% | 61.5 | 49.3% |
| Gas Processing | Sweet Blowdowns/Venting (Routine Maintenance) | Vented | 2.4 | 1.9% | 63.9 | 51.2% |
| Gas Production | Low Bleed Pneumatic Devices | Vented | 2.2 | 1.8% | 66.2 | 53.0% |
| Gas Production | Separators | Fugitive | 2.2 | 1.7% | 68.3 | 54.7% |
| Oil Production | Low Bleed Pneumatic Devices | Vented | 2.2 | 1.7% | 70.5 | 56.5% |

| Segment | Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|---|
| Gas Production | Liquids Unloading - Uncontrolled | Vented | 2.1 | 1.7% | 72.6 | 58.2% |
| Oil Production | Oil Tanks - SAGD Uncontrolled | Vented | 1.8 | 1.5% | 74.4 | 59.6% |
| Oil Production | Intermittent Bleed Pneumatic Devices - Dump Valves | Vented | 1.8 | 1.4% | 76.2 | 61.1% |
| Gas Production | Intermittent Bleed Pneumatic Devices - Dump Valves | Vented | 1.8 | 1.4% | 78.0 | 62.5% |
| Gas Processing | Sweet Blowdown Valve Operating - Venting | Fugitive | 1.7 | 1.4% | 79.7 | 63.9% |
| Gas Processing | Sweet Gas Processing Plants | Fugitive | 1.7 | 1.4% | 81.4 | 65.2% |
| Gas Production | High Bleed Pneumatic Devices | Vented | 1.6 | 1.3% | 83.0 | 66.5% |
| Gas Transmission | Pipeline Venting (Routine Maintenance/Upsets) | Vented | 1.6 | 1.3% | 84.6 | 67.8% |
| LNG-Storage | Compressor Exhaust (Gas Engines) | Combusted | 1.5 | 1.2% | 86.1 | 69.0% |
| Gas Transmission | Compressor Stations (Transmission) | Fugitive | 1.4 | 1.2% | 87.5 | 70.1% |
| Oil Production | Oil Tanks | Vented | 1.4 | 1.1% | 88.9 | 71.2% |
| Gas Production | Dump Valve Venting | Fugitive | 1.4 | 1.1% | 90.3 | 72.4% |
| Gas Transmission | Centrifugal Compressors (wet seals) - Uncontrolled | Vented | 1.4 | 1.1% | 91.7 | 73.5% |
| Gathering and Boosting | Isolation Valve - Venting | Fugitive | 1.4 | 1.1% | 93.1 | 74.6% |
| Gathering and Boosting | Compressor Exhaust (Gas Engines) | Combusted | 1.3 | 1.0% | 94.4 | 75.6% |
| Oil Production | High Bleed Pneumatic Devices | Vented | 1.1 | 0.9% | 95.5 | 76.5% |
| Oil Production | Chemical Injection Pumps | Vented | 1.1 | 0.9% | 96.5 | 77.4% |
| Gathering and Boosting | Blowdown Valve Standby - Venting | Fugitive | 1.0 | 0.8% | 97.6 | 78.2% |
| Gathering and Boosting | Gathering and Boosting Stations | Fugitive | 1.0 | 0.8% | 98.6 | 79.0% |
| Gas Production | Heaters | Fugitive | 1.0 | 0.8% | 99.5 | 79.8% |

**Figure 3-3 – Top 2020 Projected Methane Emissions Sources**



## 3.5. Selected Mitigation Technologies

The following sections describe the mitigation measures included in this analysis to address the high-emitting source categories. Much of the cost[43] and performance data for the technologies is based on information provided by industry and equipment vendor sources consulted during this and the earlier ICF study, which has been updated and augmented with Canadian-specific information as well as updates from the EPA Natural Gas STAR program[44] and other data sources. The costs have also been adapted to emissions profiles estimated for Canada, specifically for leak detection and repair practices. The discussion is organized according to the emission source and mitigation option. All costs in this section are listed in Canadian dollars unless otherwise stated and already reflect a 120% cost escalation across all of Canada from base U.S. costs, which is discussed further in Section 4 of this report. In addition to this global Canadian cost escalation, the model also adjusts for regional price differences across the provinces, which is also discussed in Section 4.

This analysis attempts to define reasonable estimates of average cost and performance based on the available data. The costs and performance of an actual individual project may not be directly comparable to the averages employed in this analysis because implementation costs and technology effectiveness are highly site-specific. Costs for specific actual facilities could be higher or lower than the averages used in this analysis.

**Fugitive Emissions** – Fugitive emissions are the unplanned loss of methane from pipes, valves, flanges, and other types of equipment. Fugitive emissions from reciprocating compressors, compressor stations (transmission, storage, and gathering), wells, and LDC metering and regulator equipment are one of the largest combined emission category.

Leak Detection and Repair (LDAR) is the generic term for the process of locating and repairing these fugitive leaks. There are a variety of techniques and types of equipment that can be used to locate and quantify these fugitive emissions. Extensive work has been done by EPA and others to document and describe these techniques, both in the Gas STAR reference materials and in several regulatory analyses. In some instances and in this study, LDAR has been found to be amongst the most cost-effective options to reduce methane emissions.

The potential size and nature of these fugitive emissions can vary widely by industry segment and even by site. While there are some provincial requirements for leak detection, as noted above, frequency of inspection is left to the discretion of the operator which suggests additional reductions are achievable with companies all consistently performing more regular screening. Despite multiple efforts to identify Canadian costs for leak detection, they are not available publicly. Therefore, this study relied on data available from U.S. studies and regulations, but modified for the Canadian context. Other than labour, the cost of equipment for locating leaks will not be different. This is because there are only two vendors who

[44] http://www.epa.gov/gasstar/

supply the primary leak detection equipment, the infrared camera capable of detecting methane emissions from the oil and gas industry.

LDAR programs have been analyzed for several recent U.S. regulatory initiatives, including for the EPA's NSPS Subpart OOOO[45] and the Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9)[46]. This study used both the Colorado regulatory analysis and the EPA Technical Support Document (TSD)[47] for NSPS Subpart OOOO and OOOOa as the basis for cost structure and reduction effectiveness calculations. This study took the average emissions per facility type from the Canadian baseline developed in this study to establish emission reductions from implementing a LDAR program.

The key factors in the analysis are how much time it takes an inspector to survey each facility (or alternatively how many facilities can be surveyed in a day), how many inspections are required each year, how much reduction can be achieved, and how much time is required for repairs. According to the recently published NSPS OOOOa Technical Support Document, the EPA indicates that more frequent inspections result in greater reductions[48], summarized as approximately:

- Annual inspection = 40% reduction
- Semi-Annual inspection = 60% reduction
- Quarterly inspection = 80% reduction

Although this analysis assumes quarterly emission surveys for all facilities, the reduction was assumed to be only 60%. This measure was taken to account for the fact that some Canadian operators are already implement regular LDAR programs per CAPP Best Management Practices (BMPs).

This study adapted the EPA and Colorado analysis to the Canadian context, which calculates the capital and labour cost to field a full-time inspector, including allowances for travel and record-keeping (Table 3-3). This study added additional time for training. The capital cost includes an infrared camera (which is used to locate fugitive emissions) a truck and the cost of a record-keeping system.  The combined hourly cost was the basis for the cost estimates. This estimate is on the high-end of the range of costs suggested by discussions with Canadian oil and gas experts.

**Table 3-3 - LDAR Hourly Cost Calculation**

| Labour | | | Capital and Initial Costs | |
|---|---|---|---|---|
| Inspection Staff | $150,000 | | Infrared Camera | $183,300 |

[45] http://www.epa.gov/airquality/oilandgas/

[46] http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820

[47] U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards". http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf

[48] NSPS OOOOa Technical Support Document http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-5021

| Labour | | | Capital and Initial Costs | |
|---|---|---|---|---|
| Supervision (@ 20%) | $30,000 | | Photo Ionization Detector | $7,500 |
| Overhead (@10%) | $15,000 | | Truck | $33,000 |
| Travel (@15%) | $22,500 | | Record keeping system | $21,750 |
| Recordkeeping (@10%) | $15,000 | | Total | $245,550 |
| Reporting (@10%) | $15,000 | | | |
| Fringe (@30%) | $45,000 | | Training Hours | 80 |
| **Subtotal Costs** | **$292,500** | | Training Dollars | $12,447 |
| | | | | |
| Hours/yr | 1880 | | Amortized Capital +Training | $68,058 |
| **Hourly Labour Rate** | **$155.6** | | Annual Labour | $292,500 |
| | | | **Annual Total Cost** | $360,558 |
| | | | **Total Cost as Hourly Rate** | **$191.8** |

Many analyses have used facility component counts and historical data on the time required to inspect each component to estimate facility survey times. However, the use of the infrared camera technology allows much shorter survey times.[49] The estimates here are based on experience with the infrared camera and are shorter than the estimates that are based on the older leak detection approach using hand-held devices, such as the organic vapor analyzer (OVA).

This study then established the average fugitive emission values per facility for production, gathering and boosting, transmission, processing, and LDCs from the baseline developed in this study. For the purposes of implementing LDAR, "facility" in production is defined as a single well which may include basic process equipment such as separator, heaters, and glycol dehydrators. In gathering and boosting, transmission, and processing the facility is defined as the station, without the pipelines included. And finally LDCs are defined as metering and regulator stations/ vaults. For each segment the average fugitive emissions value is the total fugitive emissions from the segment divided by the total number of facilities in that segment.

Table 3-4 summarizes the assumptions for the overall LDAR calculation. In addition to the surveys, the estimate includes one initial visit to each site to inventory the equipment (equivalent hours to two inspection visits for each site with cost averaged over five years) and additional visits for repairs. Assumptions were made for estimating the hours for each inspection based on SME input and review of the NSPS. A large number of the entire population of wells are expected to have only the well without

[49] Robinson, D, et. al., "Refinery Evaluation of Optical Imaging to Locate Fugitive Emissions". Journal of the Air & Waste Management Association. Volume 57 June 2007.

any substantial equipment on site. The time required to survey the “christmas tree”/well and associated piping is minimal. When the time required to survey these wells is averaged with other sites that have process equipment it is reasonable to assume that it takes 0.33 hours per site across an 8 hour work workday, on average, or 24 wells per day. As a conservative measure, this study assumed only 20 wells per day could be inspected by car using an IR camera, or 0.4 hours per well.

Some repairs can be made at the time of the survey, such as tightening valve packing or flanges but others will require additional repair time. This analysis assumes repair time equivalent to three survey visits for each facility for repairs each year. The capital cost of larger repairs is not included on the assumption that these repairs would need to be made anyway and the LDAR program is simply alerting the operator to the need. The time for repairs is consistent with the low end of the Colorado analysis that was derived based on component counts and leak rates. This lower repair estimate takes into account that:

- These are average values across facilities – not every facility will require repairs.
- These are average values over time – not every facility will need repairs every year while being monitored on a continuing basis.
- Some or all of cost of major repairs is assumed to be part of regular facility maintenance. The LDAR process allows operators to pinpoint these leaks that are fixed during regular shutdown cycles.

**Table 3-4 – Cost Calculation – Quarterly LDAR**

| | Wells | Gathering | Processing | Transmission | LDC |
|---|---|---|---|---|---|
| Methane Mcf/yr | 117 | 2,900 | 9,370 | 20,086 | 114 |
| % Reduction | 60% | 60% | 60% | 60% | 60% |
| Reduction Mcf | 70 | 1,740 | 5,622 | 12,052 | 7 |
| Hours each Inspection | 0.4 | 10.7 | 16.0 | 16.0 | 0.7 |
| Frequency (per year) | 4 | 4 | 4 | 4 | 5 |
| Annual Inspection Cost | $307 | $8,183 | $12,274 | $12,274 | $639 |
| Initial Set-Up | $31 | $818 | $1,227 | $1,227 | $51 |
| Repair Labour Cost | $230 | $6,137 | $9,206 | $9,206 | $384 |
| Total Cost/yr | $568 | $15,138 | $22,708 | $22,708 | $1,074 |
| | | | | | |
| Recovered Gas Value* | $536 | $13,250 | $42,817 | $80,077 | $455 |
| Net Cost | $32 | $1,888 | ($20,109) | ($57,369) | $619 |
| | | | | | |
| Cost of Reduction ($/Mcf methane reduced) | | | | | |

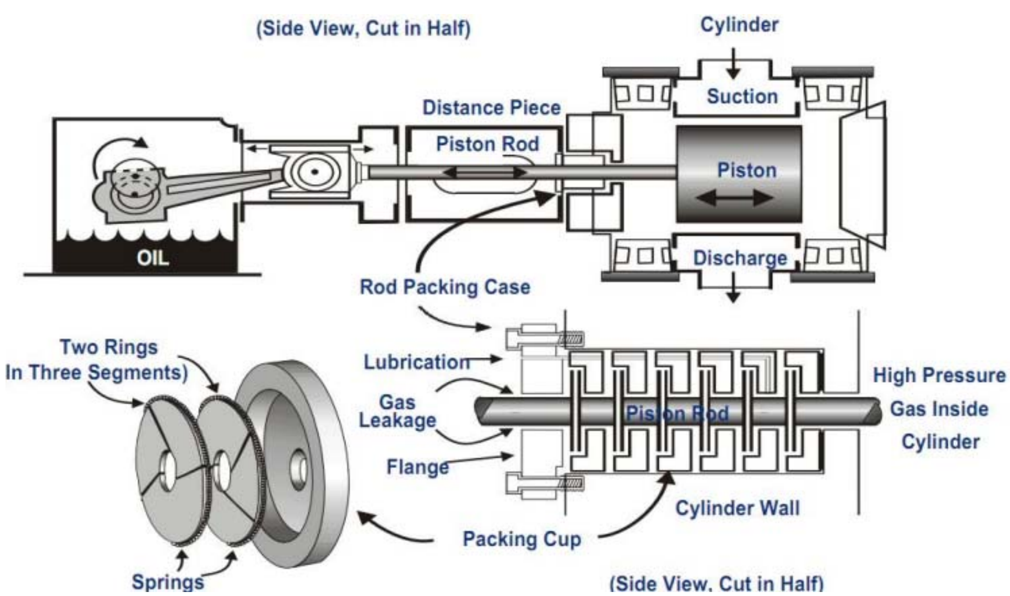
| | Wells | Gathering | Processing | Transmission | LDC |
|---|---|---|---|---|---|
| Without Gas Credit | **$8.07** | **$8.70** | **$4.04** | **$1.88** | **$15.69** |
| With Gas Credit[50] | **$0.45** | **$1.09** | **$(3.58)** | **$(4.76)** | **$9.05** |

*Gas at $5 CAD/Mcf

The value of reduced gas losses is credited to the program for the upstream segments. These final reduction cost values were used for the analysis.

**Reciprocating Compressor Rod Packing** – Reciprocating compressors are used in most segments of the natural gas and oil industry, though rarely in local gas distribution than in other segments. Rod packing systems are used to maintain a seal around the piston rod, minimizing the leakage of high pressure gas from the compressor cylinder, while still allowing the rod to move freely (Figure 3-4). However, some gas still escapes through the rod packing, and this volume increases as the packing wears out over time, potentially to many times the initial leak rate. There is no standard optimum interval to replace the rod packing, but the NSPS Subpart OOOO requires rod packing in new reciprocating compressors in the production and processing sectors to be replaced every 26,000 hours of operation (approximately every three years).

Figure 3-4 - Reciprocating Compressor Rod Packing




Industry reports that the rod packing for compressors at gas processing plants and some transmission stations is routinely replaced at least that frequently as part of routine maintenance. However, it is believed that rod packing in the production and gathering and boosting sectors is replaced less frequently. This is due, in part, to several factors, including the remote location of these compressors, the lack of a

[50] With Gas Credit – Operator is able to monetize the methane recovered, thus reducing overall reduction cost.

back-up compressor for use during compressor downtime, and because many of the compressors in these sectors are leased rather than owned. This analysis assumes a requirement to replace rod packing for all reciprocating compressors every 26,000 hours of operation.

Gas STAR data[51] indicates that rings (the compressor packing) cost between $450 and $900 per cylinder and $1,500 to $3,750 per compressor to install. Industry sources from the previous U.S. MAC Curve study[52] put the cost at $7,500 per cylinder, which was adopted for this analysis. Across a 15-year period, replacing a cylinder every 3 years costs approximately $22,500, while replacing a cylinder every 5 years costs approximately $37,500. The incremental difference between the 5-year and 3-year case is $15,000 total or $3,000 if annualized over the 5-year case. Assuming 3.3 cylinders per reciprocating compressor yields a total incremental cost of $9,900 per reciprocating compressor.

The Technical Support Document (TSD) for NSPS Subpart OOOO provides a detailed analysis of rod packing replacement. The emissions from new rod packing are estimated in the TSD at 11.5 standard cubic feet per hour (scfh). Baseline emissions for rod packing are estimated at approximately 57 scfh, however the age of the packing at that time is not stated. There is little data on the emissions from rod packing over time but reductions for this mitigation option come from replacing the rod packing at a shorter interval than currently being practiced at a given facility.

For this analysis it was assumed that the facility currently replaces the rod packing every five years and that the interval is reduced to three years (26,000 hours). It was assumed that the new rod packing emits 11.5 scfh and the emissions increase linearly to 57 scfh after three years and increase linearly thereafter. Comparing the emissions under this scenario for 15 years, the three year replacement schedule would emit 31% less than the five year replacement schedule. In addition, the cost of rod packing replacement would be 67% greater for the three year replacement schedule than the five year schedule. As noted above, it was assumed that rod packing is already changed on this schedule in many processing plants and some transmission stations, so the applicability was reduced to 25% for processing and 70% for transmission, storage and LNG. The assumptions are summarized in Table 3-5.

**Table 3-5 - Assumptions for Rod Packing Replacement**

| Capital Cost per Compressor | Percent Reduction | Mcf Reduced/year | Lifetime (years) | Cost w/o Gas Credit |
|---|---|---|---|---|
| $9,900 | 31% | 438 | 3 | $9.09/Mcf |

[51] "Reducing Methane Emissions From Compressor Rod Packing Systems" http://www.epa.gov/gasstar/documents/ll_rodpack.pdf

[52] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf

**Centrifugal Compressors (wet seals)** – The seals in a centrifugal compressor perform a similar function to the rod packing in a reciprocating compressor – allowing the rotating shaft to move freely without allowing excessive high pressure gas to escape. Centrifugal compressors with wet seals use circulating oil as a seal against the escape of high pressure gas, and the oil entrains some of the gas as it circulates through the compressor seal. This gas must be separated from the oil to maintain proper operation (called "degassing the seal oil"), and the gas removed from the seal oil is typically vented to the atmosphere, and in some cases capture and rerouted to beneficial use or sent to a flare.[53] These emissions can total 30,000 Mcf/year or more. There are two options to mitigating emissions from wet seal systems. The first is the replacement of the wet seals with dry seals that do not use oil and do not vent significant amounts of gas. The dry seal technology also provides additional benefits in terms of reduced operational and downtime costs. Most new centrifugal compressors are being fitted with the dry seal as a standard option.

The second option is to capture and use the entrained seal oil gas rather than venting it. Typically, this recovered gas is either injected back into the compressor suction, injected into a low pressure fuel line, or sent to the sales line. In some cases, the captured gas may be sent to a flare for combustion. This retrofit technology currently exists at several compressor stations that had such systems installed as original equipment, but it has not been applied commercially as a retrofit. However, the equipment needed for a retrofit is commercially available.

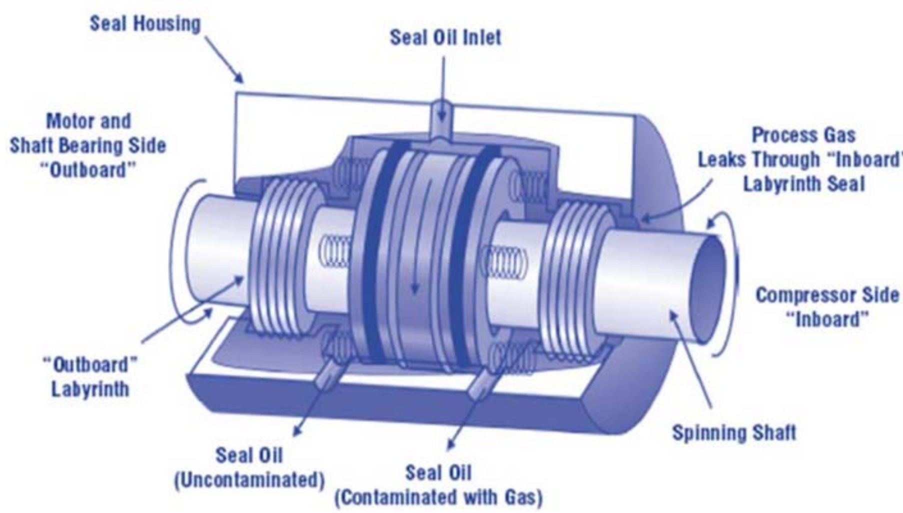
Both technologies are commercially available. The choice on whether to use a dry seal or wet seal retrofit depends on several factors, such as size and life expectancy of the compressor, wet seal emissions rate, and whether there is a place to put the captured gas. In either case, it is quite likely that an operator will implement the option that provides the most benefit specific to the particular operators situation (e.g. operations, location, economics, safety, etc.).

Although the gas can be re-captured, it may be difficult to use it productively, as this depends on both the pressure of the captured gas and whether a need for the gas exists. The applicability is therefore discounted by 10% to 25% depending on the industry segment. The dry seal retrofit has large upfront capital cost, anywhere from $375,000 to $750,000, depending on compressor size. However, it does provide operational efficiency over the long run, because it does not require seal oil replenishment and touts lower maintenance than a wet seal. The wet seal capture system has a much lower up front capital investment of approximately 75,000 to $150,000 depending on the size of the compressor and the efficiency of capture. However, the maintenance cost of a retrofit do not change. For this study, it was assumed that the operator will either replace the wet seal with a dry seal at $675,000 with a maintenance cost reduction of $75,000 or they will retrofit the wet seal with a capture system at a cost of $105,000.

[53] Replacing Wet Seals with Dry Seals in Centrifugal Compressors http://www.epa.gov/gasstar/documents/ll_wetseals.pdf

Both options result in an equivalent cost-effectiveness of $0.4/Mcf without a gas credit and -$5.94/Mcf with a gas credit.

**Figure 3-5 - Wet Seal Compressor Schematic**




**Pneumatic Devices** – Pneumatic devices use the pressure of the natural gas stream to operate various control functions, such as adjusting valves to maintain proper pressure, actuating liquid level and temperature controllers, etc. Some devices require a continuous small discharge of gas as part of the controller function. These types of devices are designated as either low bleed devices (emitting < 6 scf/hr) or high bleed devices (emitting ≥6 scf/hr, but typically much more – often more than 30 scf/hr). In addition to these two categories, there are intermittent devices that are designed to discharge gas only when they are actuating. These types of pneumatic devices can have emissions anywhere between high and low bleed controllers. One common device is an intermittent level control device ("dump valve") that emits gas only when actuated and typically has emissions similar to low bleed controllers. The level of emissions from an intermittent device is highly variable and depends on the process it is located on and the function it performs.

Although studies exist with Canadian specific emissions factors for pneumatics, there is not a consolidated dataset for each province or broken down by segment.  To generate the necessary factors, this study supplemented Canadian specific information with proxy data.  The EPA GHG Reporting Program Subpart W provides information on pneumatic controllers that can be used to estimate the distribution of these devices in each segment of the Canadian oil and gas industry. This analysis is discussed in Appendix A and, for example, yields a rough distribution of 10% high bleed, 60% intermittent, and 30% low bleed devices for the Production segment. Further analysis was performed to estimate the distribution of higher-emitting intermittent devices vs lower-emitting dump valves, also discussed in Appendix B. For the Production segment, it was estimated that 75% of the intermittent bleed devices are of the dump valve variety.

The two mitigation options considered in the study are:

- Replace high bleed controllers with low bleed controllers.
- Install instrument air systems where grid power is available.

Some components require high bleed controllers for operational reasons, primarily for fast-acting valves associated with compressors, so the measure was applied to only 60% of the inventory of high bleed controllers in transmission, storage, and LNG, 80% in processing and 90% of the high bleed controllers in other segments. Although there are lower cost estimates from Gas STAR and vendors, this measure assumed a cost of $4,464 per replacement based on industry comments. Both options yield a greater than 90% reduction. This yields a reduction cost of $1.45/Mcf of methane for replacement of high bleed pneumatics and $9.07/Mcf of methane for replacement of intermittent bleed pneumatics with instrument air systems, including a credit for recovered gas, where applicable.

Instrument air systems directly replace natural gas that is used by pneumatic devices as a source of power with air. This requires the installation of an air compressor, compressed air tank, and dryer. The instrument air can be compressed to the same pressure as the existing natural gas pressure used in the pneumatic devices. Therefore, there are no operational limitations on what high bleed devices can be converted to instrument air, i.e. they can achieve the same level of fast-action as natural gas. However, not all facilities have access to grid power. Hence, this study assumes that 30% of gathering, 50% of processing, and 30% of transmission high bleed devices can be converted to instrument air, resulting in a 100% reduction in methane emissions. Implementation of instrument air at facilities that only have low bleed (with possibly a few high bleed devices for operational consideration) is usually not feasible economically and have not been considered in this study.

**Chemical Injection Pumps** – These are small pumps used to inject various chemicals, most commonly methanol, into gas wells to prevent well freeze-up during cold weather. They are typically driven by gas pressure and vent gas when they operate. The suggested mitigation measure is to replace the gas-driven pumps with electric pumps driven by solar energy or grid power. (Well pads and many gathering/boosting stations typically do not have electricity.) This technology has been demonstrated by Gas STAR Partners and industry respondents indicated that it is gaining broader acceptance. Replacement results in elimination of the methane emissions, and the gas-driven pump could be left in place as a back-up. The cost of the measure was estimated at $7,500 per pump, yielding an annual reduction of 180 Mcf/year and a cost-effectiveness of -$0.32/Mcf of methane reduced with the recovered gas credit. Local conditions or operational considerations including hours of sunlight may limit the applicability. The U.S. study assumed 80% applicability however this measure was reduced to 60% for this study to account for higher latitudes.

**Oil and Condensate Tanks without Control Devices** – Crude oil and liquid condensate production at wells and gathering facilities is stored in fixed roof field tanks and dissolved gas in the liquids is released and collects in the tank space above the liquid. Ultimately, this gas is often vented to the atmosphere or occasionally sent to the flare. Vapor recovery units (VRUs) collect and compress this gas, which can then be re-directed to a sales line, used on-site for fuel, or flared.

The sizing of the VRU depends on the vapor volume, which in turn depends on the upstream separator pressure, API gravity of the oil or condensate, and the throughput of the tank. For this study, this study assumed a distribution of tanks, and thereby VRUs, by size which is representative of the industry where fewer tanks are large and located in gathering systems and most of the tanks are at the wellheads and smaller in size. Table 3-6 shows the distribution assumed for VRU sizes applicable in this study. Data was adapted from the EPA Natural Gas STAR lessons learned – Installing Vapor Recovery Units on Storage Tanks[54] and this data was supported in conversations with provincial experts.

**Table 3-6- Assumptions for Vapor Recovery Units**

| Design Capacity (Mcfd) | Population Distribution Weighting | Installation & Capital Costs ($) | O&M ($/Year) | Value of Gas Internal Rate of ($/Yr), Payback (months), Return (%) | | |
|---|---|---|---|---|---|---|
| 25 | 25% | $53,607 | $11,051 | $45,450 | 19 | 58 |
| 50 | 45% | $69,110 | $12,629 | $90,900 | 11 | 111 |
| 100 | 15% | $83,286 | $15,155 | $182,040 | 6 | 200 |
| 200 | 10% | $111,638 | $17,681 | $364,088 | 4 | 310 |
| 500 | 5% | $155,939 | $25,259 | $910,215 | 3 | 567 |

Based on Gas STAR and industry data, the weighted average capital cost of this measure is assumed to be $75,954 with an operating cost (electricity) of $ 13,749 per year and a reduction of 9,232 Mcf per year. This yields a reduction cost of -$4.78/Mcf if the gas is recovered for sale or $2.83/Mcf if it is flared. Some facilities already have VRUs and they may not be effective where the liquid volume is small or the methane content is low. Also VRUs require electricity, which is not available at all sites. For these reasons, the measure is applied to 50% of the remaining oil and 25% of the remaining condensate tank emission inventory.

**Kimray Pumps** – Kimray pumps are gas-powered pumps used to circulate glycol in gas dehydrators. They are larger than the chemical injection pumps and vent larger amounts of gas. In the facilities that have electricity, these could be replaced by electric motor-driven pumps. The replacement cost is estimated at $15,000 per pump based on vendor and Gas STAR data. Unlike the solar pumps, these pumps will require grid electricity, estimated to cost $3,000 per year. Based on a 5,000 Mcf emission reduction, the cost-effectiveness is -$6.25/Mcf of methane with credit for gas recovered and it is applied to 50% of the inventory.

**Liquids Unloading** – Liquids unloading is the process of removing liquids from the bottom of gas wells when the accumulation is impeding the gas production. The liquids must be removed in order to allow effective production from the well. Historically this has been practiced on older, vertical wells whose pressure has declined.

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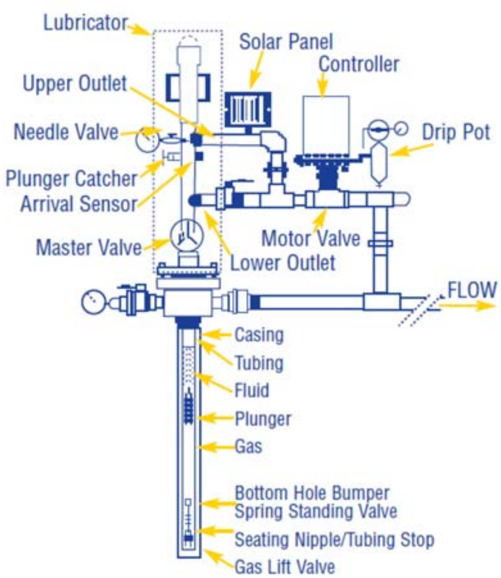
[54] EPA Lessons Learned: Vapor Recovery Units
http://www.epa.gov/gasstar/documents/ll_final_vap.pdf

While there are a variety of methods of removing this liquid, one method is by venting or “blowing” the well to the atmosphere, using the pressurized gas in the reservoir to lift and blow the liquids out of the well. The frequency and duration of liquids unloading depends on the well and reservoir conditions, however, venting is not a very effective method of removing the liquids. Further, since the well is vented to the atmosphere, it results in large methane emissions and losses of gas. There are multiple methods of removing liquids without venting, but in standard practice, the primary goal of liquids unloading is to improve well performance, not reduce emissions. The choice of method is normally a function of the cost versus the value of improved well performance. The previous U.S. MAC curve contains case studies on this topic[55].

Figure 3-6 - Plunger Lift Schematic




Plunger lifts are devices that fit into the well bore and use the gas pressure to bring liquids to the surface more efficiently while controlling and limiting the amount of venting (Figure 3-6). If there is sufficient reservoir pressure, the gas can be directed to the sales line with no venting. If there is insufficient pressure to direct the gas to the sales line and the gas must be vented, the emissions can still be reduced by 90% compared to uncontrolled venting. Plunger lifts are a relatively low cost option and can be implemented in a relatively simple manual control method or more complex automated installations. That said, the technology does have limitations. The well must have sufficient pressure to operate the plunger and older wells may require clean-outs or work-overs to allow the plunger to operate. Further, not all well types can use a plunger lift for liquids removal.

Gas STAR estimates for plunger lift installation range from $3,750 to $15,000[56] but industry commenters on the U.S. study cited costs in the range of $22,500 and pointed out that well treatments and clean-outs may be required before plunger lifts can be installed. This analysis assumes a cost of $30,000, including the allowance that some wells may need clean-outs or other work. Gas STAR Partners report reductions of venting emissions of 90% for plunger lifts that do not go to the sales line. In addition, they report that liquids unloading can increase production by anywhere from 3 to 300 thousand cubic feet per day (Mcf/day). The increased productivity of the well is the primary goal of liquids unloading and the higher gas production can pay for the cost of plunger lifts many times over. However, the subsequent increase in well productivity is difficult to predict and is not included in this analysis. Without credit for the

[55]Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf

[56] Installing Plunger Lift Systems In Gas Wells http://epa.gov/gasstar/documents/ll_plungerlift.pdf

productivity increase, the cost-effectiveness breakeven point is at about 1,200 Mcf/year of venting, estimated here as a reduction cost of -$0.07/Mcf reduced.

If the well does not have sufficient pressure or cannot support a plunger lift, there are a variety of mechanical pumping technologies that can be employed to remove liquids. However, these are much more expensive and while they may have a positive payback for increasing well production, they most often do not purely for the methane emission reduction. Moreover, the methane reduction value only applies if the well would otherwise be vented. As the well pressure declines, venting becomes a diminishingly effective option. In addition, it is not clear how effective venting will be at removing liquids from long horizontal wells that are now being drilled. It may be that venting for liquids removal will continue to be primarily focused on older, vertical wells.

There is no Canadian data set, so a proxy was used but with Canadian specificity included as described below. The GHG Reporting Program Subpart W provides extensive data on wells that are venting for liquids unloading with and without plunger lifts. The data for 2013 shows over 25,000 wells venting an average of 352 Mcf per year without plunger lifts and over 28,000 wells with plunger lifts venting an average of 362 Mcf per year. Wells that use plunger lifts and send the gas to the sales line do not have any venting emissions and do not report to this part of Subpart W. While it seems counterintuitive that wells with plunger lifts that vent would be emitting more than those without plunger lifts, this study interprets this information to indicate that most of the wells with the largest venting emissions have already installed plunger lifts while most of the remaining wells are venting infrequently or venting small volumes that do not justify the cost of installing plunger lifts. That said, there are a small number of wells without plunger lifts that report larger venting emissions and account for a disproportionate fraction of the venting emissions for wells without plunger lifts, approximately 36% of total venting emissions. Installing plunger lifts on these wells could be cost-effective and create significant emission reductions. Because plunger lifts are not applicable to all wells, the measure was applied to 30% of this emission segment for the analysis. The costs of plunger lifts were also increased based on conversations with provincial experts.

As noted above, wells with plunger lifts also report significant emissions from venting. Operation of a plunger lift is complex and its effectiveness as an emission reduction technique depends on many factors to operate the plunger at the optimum time to maximize production and minimize emissions. Approaches to plunger lift operation range from ad hoc manual operation, to fixed mechanical timers, to programmable “fuzzy logic” automated controllers. Specific data on the potential reductions from optimized plunger lift operation is not available but it is clear from industry experience that an integrated program of training, technology, and automation can improve the performance of plunger lifts for both productivity and emission reductions. Consequently, there may be an opportunity for significant emission reduction through optimization of plunger lifts, which is not included here and would be additional to the reduction estimates this analysis provides for installation of new plunger lifts.

Finally, another option to reduce methane emissions from liquids unloading is to use a portable or temporary flare system to burn vented emissions, which is required by law in some jurisdictions like British

Columbia if there is sufficient volume. Although this still results in the emissions of GHGs ($CO_2$) and other air pollutants, a portable flare would be used to flare gas from venting events, thus avoiding the release of a gas with a higher global warming potential. A temporary flare would be used to flare gas from manual unloading of the well. Estimated costs for purchasing a trailer-mounted flare system ranging from 20 – 50 ft. in height, designed to handle gas flow rates of 1 - 10 MMscfd is approximately $45,000. Based on data for liquids unloading vented emissions, the 1-10 MMscfd capacity flare should be adequate across most oil & gas facilities and is used as such.

**Stranded Gas Venting from Oil Wells and Venting of Oil Completion Gas** – Oil contains some amount of natural gas, which is separated at the wellhead. Where there is a gas sales line available, the gas is sent to sales. When no nearby sales line exists, the gas is either vented or flared. This can occur during the short period after the well is completed or it can continue throughout the life of the well, depending on the access to gathering infrastructure. While flaring creates $CO_2$ emissions from combustion and some unburned methane, the total greenhouse gas emissions are much lower than venting the methane, with its higher global warming potential.

The measure modeled here is flaring of the gas on the assumption that the gas would be sent to sales if the infrastructure were available. While Gas STAR and vendor information cite relatively low-cost flares, industry cited more expensive flaring equipment that is being required to meet regulatory requirements. This study adopted an even higher estimate based on input from Canadian experts, assuming a capital cost of $93,750 and a fuel cost of $9,000 for ignition. The flare is assumed to be 98% effective. The cost-effectiveness depends on the amount of gas flared, which is lower for completion emissions than flaring of associated gas on a continuous basis. The cost-effectiveness is estimated at $2.78/Mcf of methane for completion gas.

**Pipeline Venting (Routine Maintenance/Upsets)** – These emissions occur when companies take sections of pipeline out of service for maintenance and vent the gas that is in the pipeline. These emissions can be reduced for planned shutdowns (not emergency shutdowns) by first using the pipeline inline compressors located at compressor stations to pump down the gas in the affected section to a pressure that is within the compression ratio of the compressor. Often this still leaves a significant amount of gas that can further be captured using a leased mobile compressor unit. This mobile unit captures the remaining gas and injects it into the pipeline upstream or downstream of the pipe section being blowndown. In cases where the pipe section to be blowdown is not in close proximity to the inline compressor then only the portable unit may be an effective option. The analysis in this study assumed a combination of both measures applied to 10 mile sections of pipeline, based on a Gas STAR analysis[57]. We also assumed that only 1 in 4 pipeline pumpdown activities were able to use both portable and inline compression, and the rest used only inline compression. Using the pipeline compressor requires no capital cost but only the fuel cost to pump down the line. The second option was to lease a portable compressor and pay for the delivery and

[57] "Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance". http://www.epa.gov/gasstar/documents/ll_pipeline.pdf

fuel consumption. Capital costs are zero while operating costs are $590,226/yr, yielding a cost-effectiveness of $2.05 with no gas recovery credit.

**Transmission Station Venting** –Transmission station venting is characterized as a single emissions source characterized as routine blowdowns/maintenance. Compressors may be blowndown to the atmosphere for maintenance or upset conditions multiple times a year, releasing methane to the atmosphere, or in some cases to the flare. Capture of this gas is possible and can be routed to the fuel system or other low pressure gas stream.

There is no Canadian dataset, but Subpart W has two distinct tables with emissions data on blowdown emissions. One table contains data on physical volumes that were blown down more than once during the reporting year, while the other table has unique physical emission volumes that were blown down only once during the reporting year. Both tables were considered when characterizing emissions factors and reduction opportunities across the Transmission and Gas Processing segments. For performing pipeline capture of gas from other routine blowdown emissions, assumptions were made based on SME input. Capital costs vary between $30,000 and $75,000 whether performed on a per compressor or per plant basis, respectively. The cost effectiveness is estimated at $0.80/Mcf and $1.62/Mcf on a per compressor or per plant basis, respectively.

**Summary**

Table 3-7 summarizes the mitigation measures applied in the analysis for each major emission source. Table 3-8 summarizes the characteristics of the measures modeled. The cost-effectiveness ($/Mcf of methane removed) was calculated with and without credit for any recovered gas[58]. The Canadian annual cost was calculated as the annual amortized capital cost over the equipment life plus annual operating costs. This was divided by annual methane reductions to calculate the cost-effectiveness without credit for recovered gas. Where gas can be recovered and monetized by the operating company, the value of that gas was subtracted from the annual cost to calculate the cost-effectiveness with credit for recovered gas. The costs shown here are the baseline costs, which are adjusted for regional cost variation in the analysis. As noted earlier, these are average costs that may not reflect site-specific conditions at individual facilities.

[58] The price of natural gas was assumed to be $4/Mcf for the main portion of analysis in this report.

**Table 3-7 - Summary of Mitigation Measures Applied**

| Source | Mitigation Measure |
|---|---|
| Oil/Condensate Tanks w/o Control Devices | Vapor Recovery Units |
| Liquids Unloading - Wells w/o Plunger Lifts | Plunger lifts and Portable Flares |
| High Bleed Pneumatic Devices | Replace with low bleed devices or instrument air |
| Intermittent Bleed Pneumatic Devices | Replace with instrument air systems |
| Chemical Injection Pumps | Solar electric pumps |
| Kimray Pumps | Electric pumps |
| Pipeline Venting (Routine Maintenance/Upsets) | Pipeline pump-down |
| Centrifugal Compressors (wet seals) | Wet seal gas capture or Dry seal retrofits |
| Transmission Station Venting | Gas capture and route to fuel system or lower pressure gas stream |
| Stranded Gas Venting from Oil Wells | Flaring |
| Reciprocating Compressor Rod Packing | Rod packing replacement |
| Reciprocating Compressor Fugitives | Leak detection and repair (LDAR) |
| Compressor Station Fugitives | Leak detection and repair (LDAR) |
| Well Fugitives | Leak detection and repair (LDAR) |
| Gathering Station Fugitives | Leak detection and repair (LDAR) |
| Large LDC Facility Fugitives | Leak detection and repair (LDAR) |

**Table 3-8 - Summary of Mitigation Measure Characteristics**

| Name | Capital Cost | Operating Cost | Percent Reduction | $/Mcf w/ Credit | $/Mcf w/o Credit |
|---|---|---|---|---|---|
| Early replacement of high-bleed devices with low-bleed devices | $4,500 | $0 | 97% | $1.46 | $9.07 |
| Replacement of Reciprocating Compressor Rod Packing Systems | $9,900 | $0 | 30.7% | $1.47 | $9.09 |
| Install Flares-Stranded Gas Venting | $94,050 | $9,000 | 98.0% | $3.17 | $3.17 |
| Install Flares-Portable | $45,000 | $0 | 98% | $0.17 | $0.17 |
| Install Plunger Lift Systems in Gas Wells | $30,000 | $3,600 | 95% | -$0.07 | $7.54 |
| Install Vapor Recovery Units | $75,955 | $13,750 | 95% | -$4.79 | $2.83 |
| LDAR Wells | $257,997 | $292,500 | 60% | $1.25 | $8.87 |
| LDAR Gathering | $257,997 | $292,500 | 60% | $1.95 | $9.56 |
| LDAR LDC – MRR | $257,997 | $292,500 | 60% | $9.63 | $17.24 |
| LDAR Processing | $257,997 | $292,500 | 60% | -$3.18 | $4.44 |
| LDAR Transmission | $257,997 | $292,500 | 60% | -$5.54 | $2.07 |
| Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps | $7,500 | $113 | 100% | -$0.33 | $7.28 |
| Replace Kimray Pumps with Electric Pumps | $15,000 | $3,000 | 100% | -$6.25 | $1.36 |
| Pipeline Pump-Down Before Maintenance | $0 | $591,468 | 80% | -$5.55 | $2.06 |
| Wet Seal Degassing Recovery System for Centrifugal Compressors | $105,000 | $0 | 95% | -$7.13 | $0.48 |
| Wet Seal Retrofit to Dry Seal Compressor | $675,000 | -$75,000 | 95% | -$7.13 | $0.48 |
| Blowdown Capture and Route to Fuel System (per Compressor) | $30,000 | $0 | 95% | -$6.81 | $0.81 |
| Blowdown Capture and Route to Fuel System (per Plant) | $75,000 | $0 | 95% | -$5.99 | $1.62 |
| Replace with Instrument Air Systems - Intermittent | $90,000 | $26,655 | 100% | -$5.75 | $1.86 |
| Replace with Instrument Air Systems - High Bleed | $90,000 | $26,655 | 100% | -$5.75 | $1.86 |

## 3.6. Source Categories Not Included in MAC Analysis

Several source categories with emissions were not addressed in the analysis. The sources and the reasons for their treatment are summarized below.

- **Oil Sands Production** – As noted in this study, the following sources from oil sands operations have been included as part of the emissions inventory:
  - Stranded Gas Flaring and Venting – covers sources contributing to flared and vented volumes from in situ bitumen facilities based on Alberta's ST60B report.
  - SAGD Tankage - covers vented volumes from tanks emissions operating in steam assisted gravity drainage production operations.

  Beyond these characterized sources, some entities across Canada have made additional efforts to estimate fugitive oil sands emissions, with one such estimate found on the Alberta Environmental Monitoring, Evaluation, and Reporting Information Service website[59]. The report only focuses on oil sands mining production. According to their estimates, methane emissions from oil sands mining operations are roughly in the 4 Bcf range, with emissions broken down as follows:

  - Tailings Pond – 74%
  - Mine Faces – 24%
  - Other Sources- 2%

  However, even with preliminary studies and data on this topic, oil sands mining emissions have been excluded from this report as an emissions source due to the high level of uncertainty and relatively low level of source characterization. Furthermore, there are no mitigation options currently implemented to capture much of these emissions. Thus, this is an area in which further analysis could yield additional opportunities for reduction.

- **Cast-iron gas mains** – Cast-iron mains have been identified as a significant emission source in the distribution segment in the United States. In the United States, these cast-iron mains are primarily located in congested urban areas where replacement or repair is very expensive, reported as $1 million to $3 million (US) per mile. This makes for a very expensive control option based purely on emission reduction. In addition, LDCs are making increasing efforts to replace miles of cast iron each year for safety reasons, so the emissions are gradually declining. New technologies could reduce the cost of reduction in the future. That said, research indicated that cast-iron mains are not common in Canada and this option was not included.

- **Engine exhaust** – The exhaust from gas-burning engines and turbines contains a small amount of unburned methane from incomplete combustion of the fuel. While it is a small percentage, it is

[59] Fugitive Emissions for SGER Oil Sands Facilities: 2011 – 2014
http://aemeris.aemera.org/library/Dataset/Details/263

significant in aggregate. Oxidation catalyst devices are used to reduce unburned emissions of other hydrocarbons in the exhaust but they are not effective at reducing emissions of methane due to its lower reactivity. However, new catalysts are being developed, in part for natural gas vehicles, which may be applicable to these sources. This is a topic for further research and technology deployment.

- **Other sources** – There are additional cost-effective measures for methane reduction that have been identified by the EPA Gas STAR program and others. They are not included here because this report focuses only on the largest emitting sources. However, their omission should not be taken to indicate that the measures listed here are the only cost-effective methane reduction measures.

# 4. Analytical Results

## 4.1. Development of Emission Control Cost Curves

With the 2020 Projected Baseline established and mitigation technologies identified and characterized for the major emitting sectors, emission cost reduction curves were calculated for a variety of scenarios. The model developed for this task includes the individual source categories for each segment of the oil and gas industry by region. Mitigation technologies can be matched to each source by region and/or individual source applied. The model can also specify what portion of each source population the measure applies to and whether it applies to new (post-2013), existing (as of 2013), or all facilities. The model calculates the reduction achieved for each source and calculates the cost of control based on the capital and operating costs, the equipment life, and where appropriate, the value of recovered gas. Key global input assumptions include: whether a particular segment is able to monetize the value of recovered gas, the value of gas, and the discount rate/cost of capital. Individual instances of cost adjustments were applied across provinces to account for U.S./Canada cost differences in addition to provincial cost differences. The Rocky Mountain region in the U.S. was used as a proxy to represent cost in Canada on a national level. This was chosen as a conservative estimate because based on the U.S. EDF MAC curve study, Rocky Mountain costs were roughly 20% higher than base costs in the Gulf Coast[60]. Provincial costs were then further adjusted up or down based on regional consumer price index (CPI) fluctuations between provinces reported by the NEB[61]. CPI adjustments ranged from a 6% increase in cost in Alberta to a 3% cost decrease in British Columbia. These estimates were considered to be conservative, as a report for the Alberta Department of Energy[62] on Alberta's natural gas and oil investment competitiveness indicated that Alberta was 12-14% more expensive than the U.S. on comparable oil and gas activities.

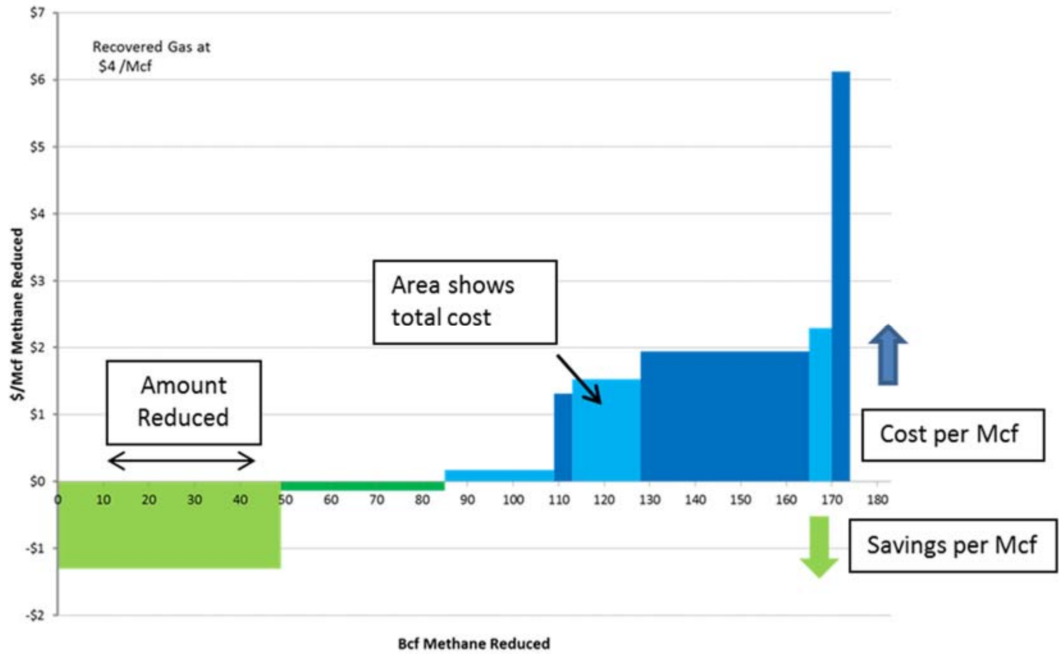
The results are presented primarily as a Marginal Abatement Cost Curve (MAC curve), shown in Figure 4-1. This representation shows the emission reductions sorted from lowest to highest cost-of-reduction and shows the amount of emission reduction available at each cost level. The vertical axis shows the cost per unit in $ CAD/Mcf of methane reduced. A negative cost-of-reduction indicates that the measure has a positive financial return, i.e. saves money for the operator. The horizontal width of the bars shows the amount of reduction. The area within the bars is the total cost per year. The area below the horizontal axis represents savings and the area above the axis represents cost. The net sum of the two is the total net cost per year. All costs in this section are in Canadian dollars (CAD) unless otherwise stated.

[60] The costs listed in this report are the Canadian baseline values, i.e. escalated by 20% from Gulf Coast values and converted to Canadian dollars.

[61] Statistics Canada – Consumer Price Index Tables
http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/ind01/l3_3956_2178-eng.htm?hili_cpis01

[62] Technical Report Appendices to Project Committee Final Technical Report to the Alberta Department of Energy on Alberta's Natural Gas & Conventional Oil Investment Competitiveness
http://www.energy.alberta.ca/Org/pdfs/CRSierraTechReportApp.pdf

**Figure 4-1 - Example MAC Curve**




## 4.2. Emission Reduction Cost Curves

This section presents the results of the cost curve analysis. The curves represent different views of a potential emission control scenario in 2020 based on measures installed between 2013 and 2020. The emission reduction costs are the annual costs per Mcf of methane reduced. This should not be confused with cost per Mcf of natural gas produced, which is an entirely different metric. In the cases shown here, the total annual cost of reductions divided by total Canadian gas production is less than $0.01/Mcf of gas produced in all cases.

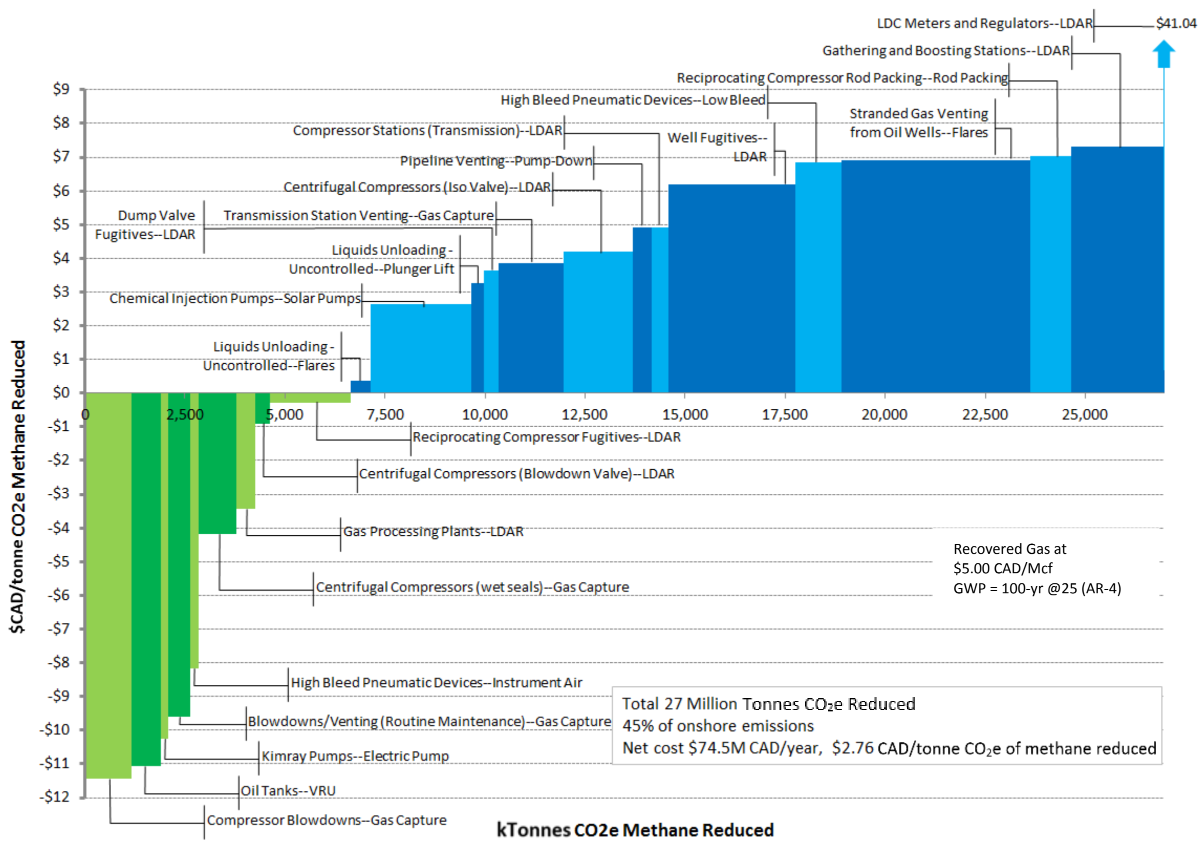
There are several caveats to the results:

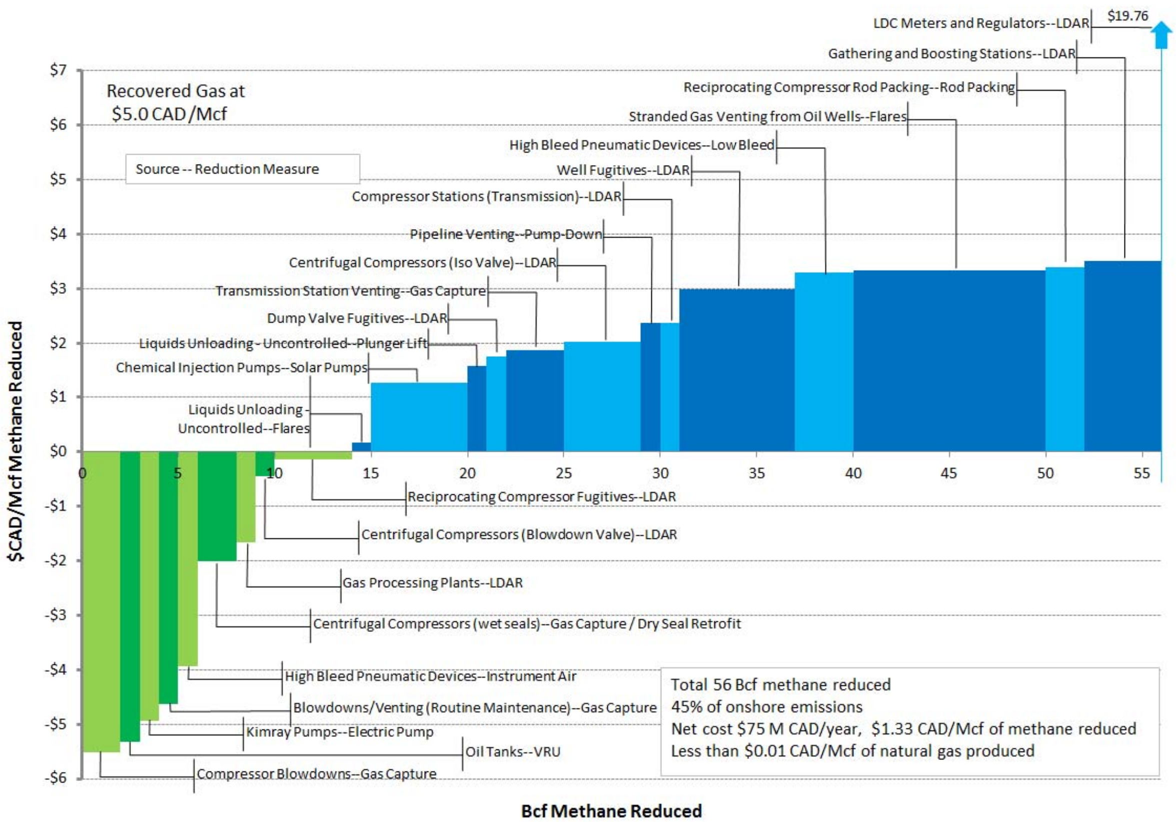
- Canadian data sources/reports and other U.S. sources are the best starting points for this analysis, but each is based on many assumptions and some older data sources. Although these reports and the inventory are improving with new data, aspects of the methodology are imperfect, especially at the detailed level, for a granular analysis of this type.
- Emission mitigation cost and performance are highly site-specific and variable. The values used here are estimated average values.
- The analysis presents a reasonable estimate of potential cost and magnitude of reductions within a range of uncertainty.

The base case assumption for the results in this section assumes a $5 CAD/Mcf ($4 USD/Mcf) price for recovered gas and a 10% discount rate/cost of capital for calculating the cost of control. Additional sensitivity and alternative cases are shown in Appendix C (e.g. Provincial MAC curves and segment emissions breakdowns).

Figure 4-2 shows the national aggregate MAC curve for the baseline technology assumptions by source category for both tonnes $CO_2$e followed by the same chart in Bcf. The Bcf curve is used for much of the analysis and breakdowns in this section. It shows the reductions achievable from each source with the relevant emission control measure. These results are aggregated across industry segments, so the “reciprocating compressor fugitives” block, for example, includes the cost and reductions from the source among all segments. The variations between regions and between segments for a given technology are averaged for each block.

**Figure 4-2 – National Aggregate MAC Curve for Baseline Technology Assumptions**






The total reductions are 56 Bcf of methane per year or 45% of the 2020 emissions from the oil and gas industries. The total annualized cost to achieve those reductions is $74.5 CAD million/year or $2.76 CAD/tonnes of $CO_2$e of methane reduced. This total annual cost is the net of the $36.9 million annual savings (green bars below the axis) and $111.4 million annual cost (blue bars above the axis). The chart shows which sources and technologies have the lowest cost-of-control (height - vertical axis) and the greatest reduction (width – horizontal axis). The results are also summarized in Table 4-1. The cost ranges from -$9.16/tonnes of $CO_2$e methane reduced for Gas Capture of Compressor blowdowns to $41.04/ tonnes of $CO_2$e methane reduced for LDAR at LDC metering and regulator stations. These costs include regional cost adjustments and follow the cost calculations discussed in Section 3 and 4. Credit for recovered gas accrues to all sectors except transmission and LDCs, which are limited by rate regulation from monetizing the emission reductions.

Table 4-1 also shows the estimated annualized costs in addition to reduction potential and cost per Mcf reduced of methane. This is a top-down estimate based on the projected reductions and the capital cost per measure so the costs are less certain than in a bottom-up costing, particularly with respect to differences between segments. The total capital cost is estimated at $726.7 CAD million.

**Table 4-1 – Annualized Cost, Reduction Potential, Cost/Mcf, and Initial Capital Cost**

| Source/Measure | Annualized Cost ($ million/yr) | Bcf Methane Reduced/yr | Cost $/ Mcf Methane Reduced | Initial Capital Cost ($ million) |
|---|---|---|---|---|
| Compressor Blowdowns--Gas Capture | -$13.25 | 2.40 | -$5.51 | $42.5 |
| Oil Tanks--VRU | -$8.13 | 1.53 | -$5.33 | $11.1 |
| Kimray Pumps--Electric Pump | -$2.00 | 0.39 | -$4.94 | $1.3 |
| Blowdowns/Venting (Routine Maintenance)--Gas Capture | -$5.25 | 1.14 | -$4.63 | $18.4 |
| High Bleed Pneumatic Devices--Instrument Air | -$1.75 | 0.43 | -$3.93 | $9.1 |
| Centrifugal Compressors (wet seals)--Gas Capture | -$3.88 | 1.95 | -$2.01 | $13.9 |
| Gas Processing Plants--LDAR | -$1.63 | 1.02 | -$1.65 | $4.1 |
| Centrifugal Compressors (Blowdown Valve)--LDAR | -$0.38 | 0.76 | -$0.44 | N/A |
| Reciprocating Compressor Fugitives--LDAR | -$0.50 | 4.18 | -$0.13 | N/A |
| Liquids Unloading - Uncontrolled--Flares | $0.13 | 1.04 | $0.18 | $85.3 |
| Chemical Injection Pumps--Solar Pumps | $6.63 | 5.23 | $1.26 | $128.4 |
| Liquids Unloading - Uncontrolled--Plunger Lift | $1.00 | 0.61 | $1.57 | $45.4 |
| Dump Valve Fugitives--LDAR | $1.38 | 0.79 | $1.75 | N/A |
| Transmission Station Venting--Gas Capture | $6.25 | 3.35 | $1.86 | $28.3 |
| Centrifugal Compressors (Iso Valve)--LDAR | $7.25 | 3.59 | $2.03 | N/A |
| Pipeline Venting--Pump-Down | $2.38 | 1.00 | $2.36 | $0.00 |
| Compressor Stations (Transmission)--LDAR | $2.13 | 0.87 | $2.37 | N/A |
| Well Fugitives--LDAR | $19.75 | 6.62 | $2.98 | $53.1 |
| High Bleed Pneumatic Devices--Low Bleed | $7.88 | 2.38 | $3.29 | $90.9 |
| Stranded Gas Venting from Oil Wells--Flares | $32.50 | 9.76 | $3.33 | $115.9 |
| Reciprocating Compressor Rod Packing--Rod Packing | $7.25 | 2.15 | $3.39 | $36.1 |
| Gathering and Boosting Stations--LDAR | $16.88 | 4.82 | $3.51 | $42.9 |
| **Grand Total** | **$74.56** | **56.01** | **$1.33** | **$726.7** |

Figure 4-3 shows the emission reductions by major category. Reducing venting and fugitive emissions are some of the main opportunities for reduction. Although also a vented emission source, stranded gas venting is a significant source of methane emissions. Rod packing replacement and wet seal compressors are also significant single equipment type sources with viable mitigation measures.

**Figure 4-3 - Distribution of Emission Reduction Potential**

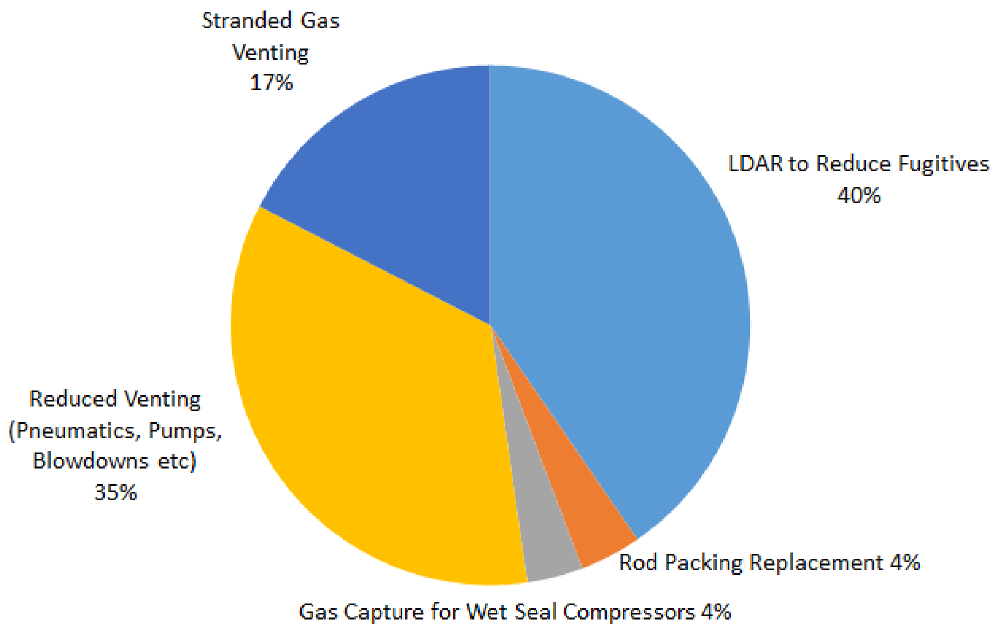


Figure 4-4 shows the reduction in methane emissions by industry segment for the same case. The transmission and distribution sectors are not able to monetize their reductions and therefore will always have a net positive cost. The LDC segment has only one measure and is the highest cost. The costs for the other sectors depend on the particular mitigation options available in each and their aggregate cost. The oil and gas production segments plus gas transmission account for more than 70% of the total reductions.

**Figure 4-4 - Emission Reduction by Industry Segment**

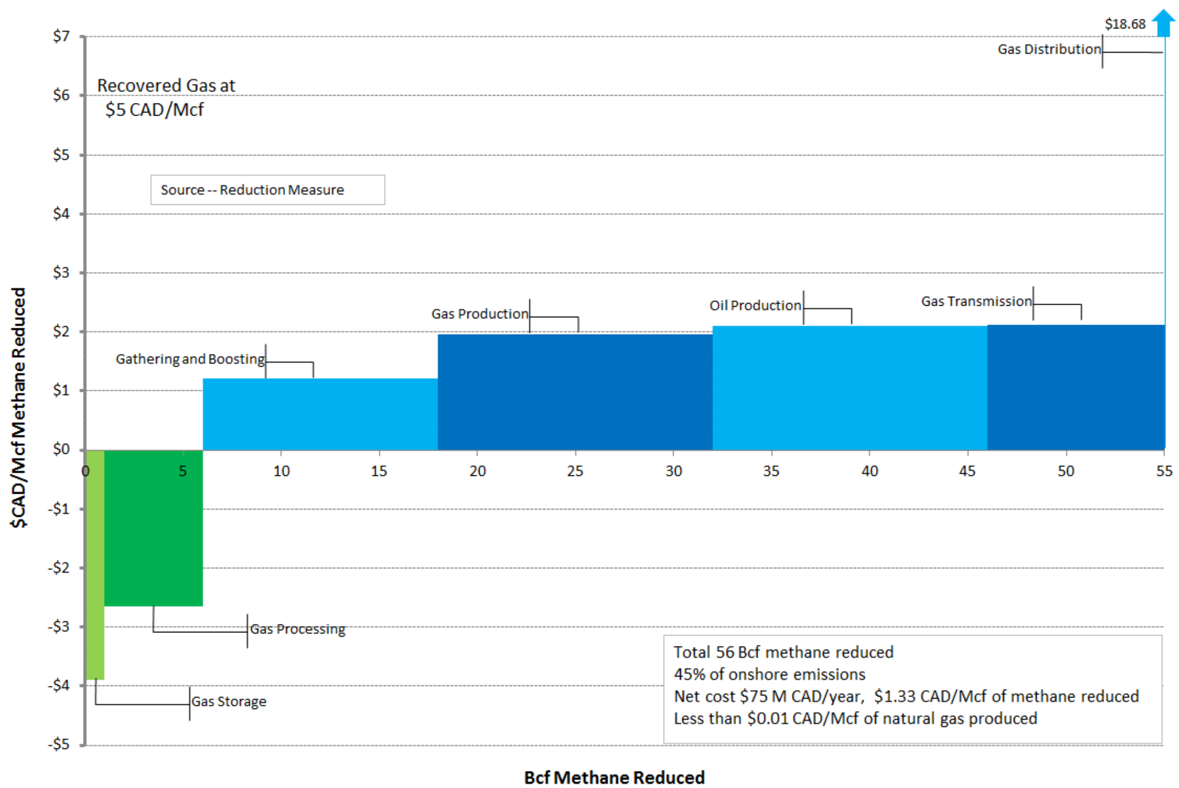


Figure 4-5 shows the breakdown of reduction options for the Gas Production segment. LDAR at wells accounts for almost half of the reductions and can be reduced at roughly $2.98 per Mcf. Chemical injection pumps, liquids unloading, and the replacement of high bleed pneumatics are also significant sources at relatively low positive cost mitigation options. The total reduction opportunity is 14.3 Bcf with a net cost of $1.95/Mcf of methane reduced.

**Figure 4-5 – Emission Reductions for the Gas Production Segment**

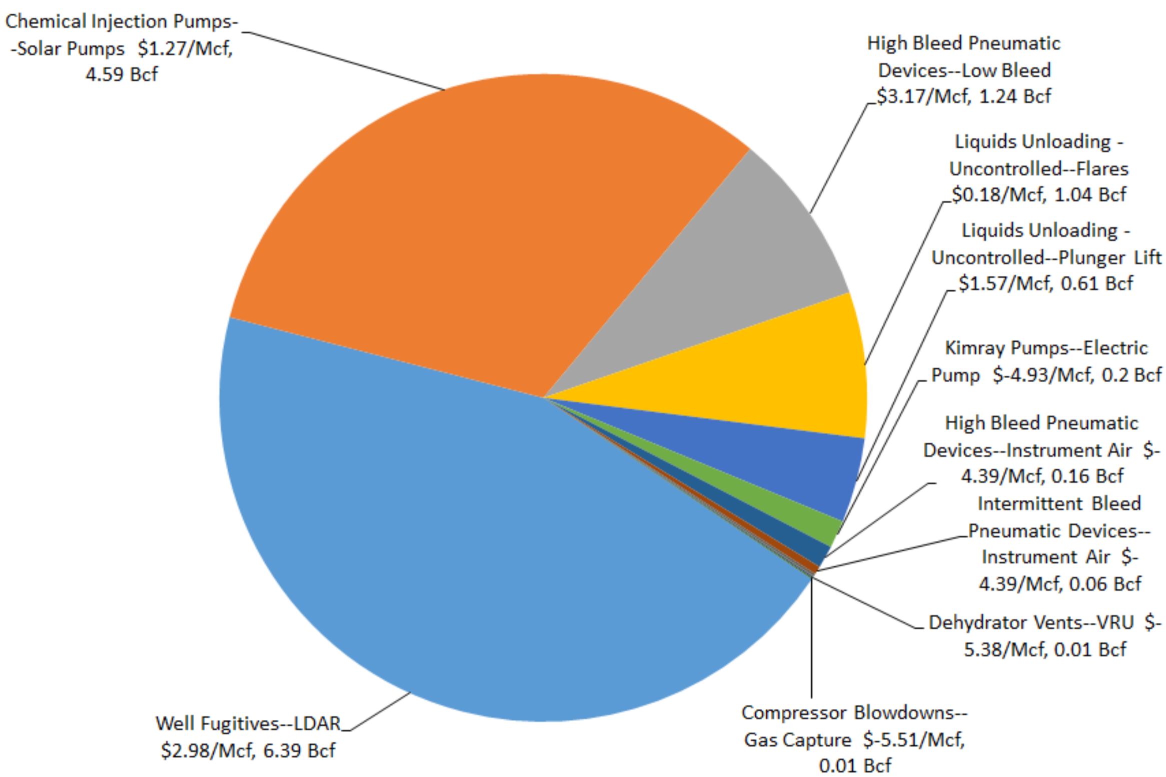


Figure 4-6 shows the reductions for the Oil Production segment. Stranded gas venting is by far the largest source, representing about 10 Bcf of reduction opportunity. Installation of VRU's on oil tanks in addition to the replacement of high bleed pneumatics are significant components as well, accounting for nearly a quarter of the reductions. A handful of other emission sources round out the segment, with the total reduction across oil production being 13.3 Bcf at a cost of $2.10/Mcf of methane reduced.

**Figure 4-6 - Emission Reductions for the Oil Production Segment**

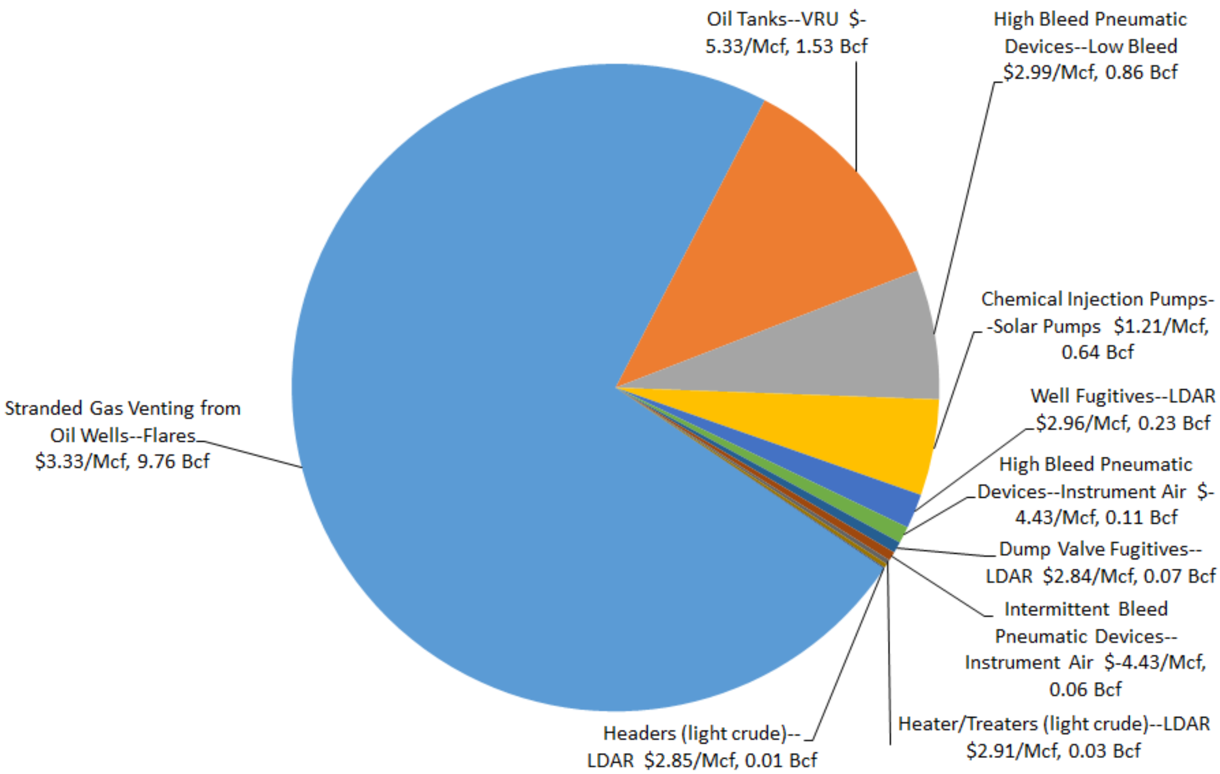


Figure 4-7 shows the reductions for Gathering and Boosting. LDAR to reduce fugitives at stations accounts for almost half of the reductions, while compressor blowdowns and reciprocating compressor rod packing almost account for the other half. The total reduction is opportunity 11.4 Bcf at a cost of $1.22/Mcf.

**Figure 4-7 - Emission Reductions for the Gathering and Boosting Segment**

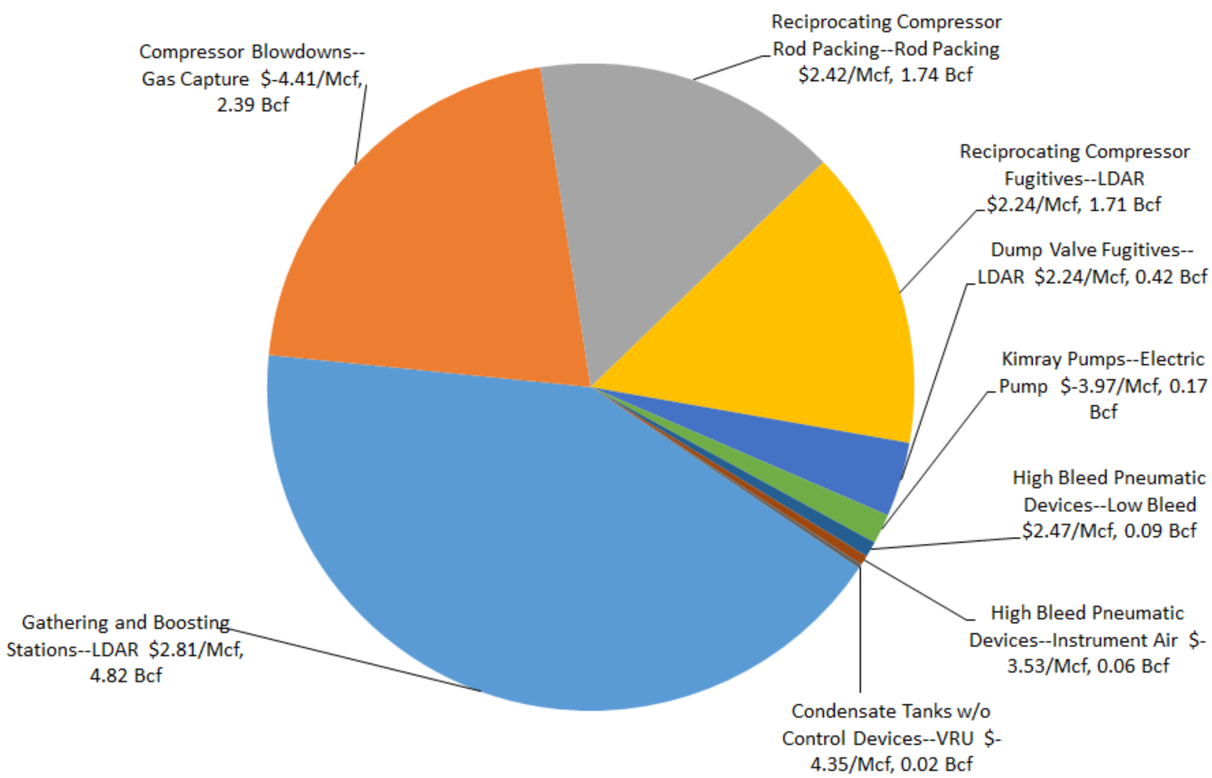


Figure 4-8 shows the reductions for the Gas Transmission segment. Transmission station venting and fugitive emissions from centrifugal compressors represent the two largest opportunities for reduction in transmission. Emissions from these two sources can be mitigated by implementing a gas capture program and LDAR, respectively. Due to regulatory limitations, transmission pipelines are not able to monetize emission reductions, so the cost of reductions is positive for all measures, $2.13/Mcf of methane reduced for 10.6 Bcf of reductions.

**Figure 4-8 - Emissions Reductions for the Gas Transmission Segment**

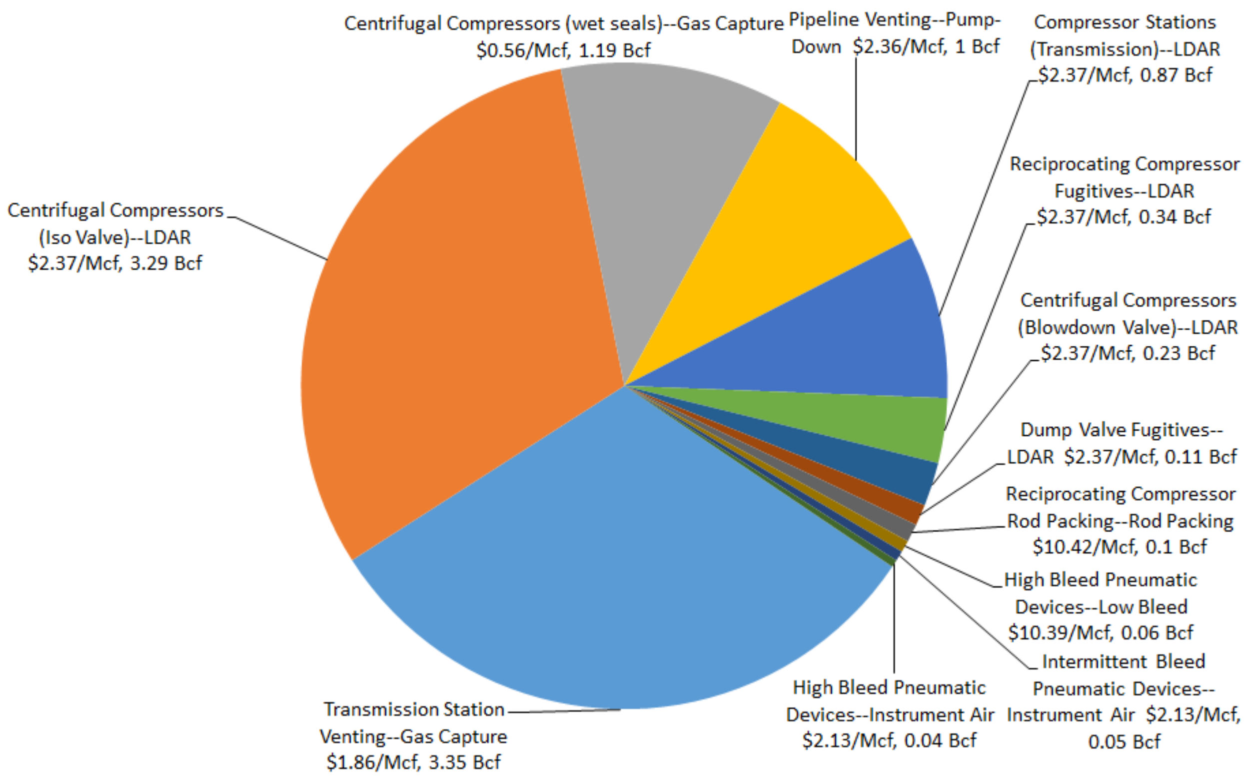
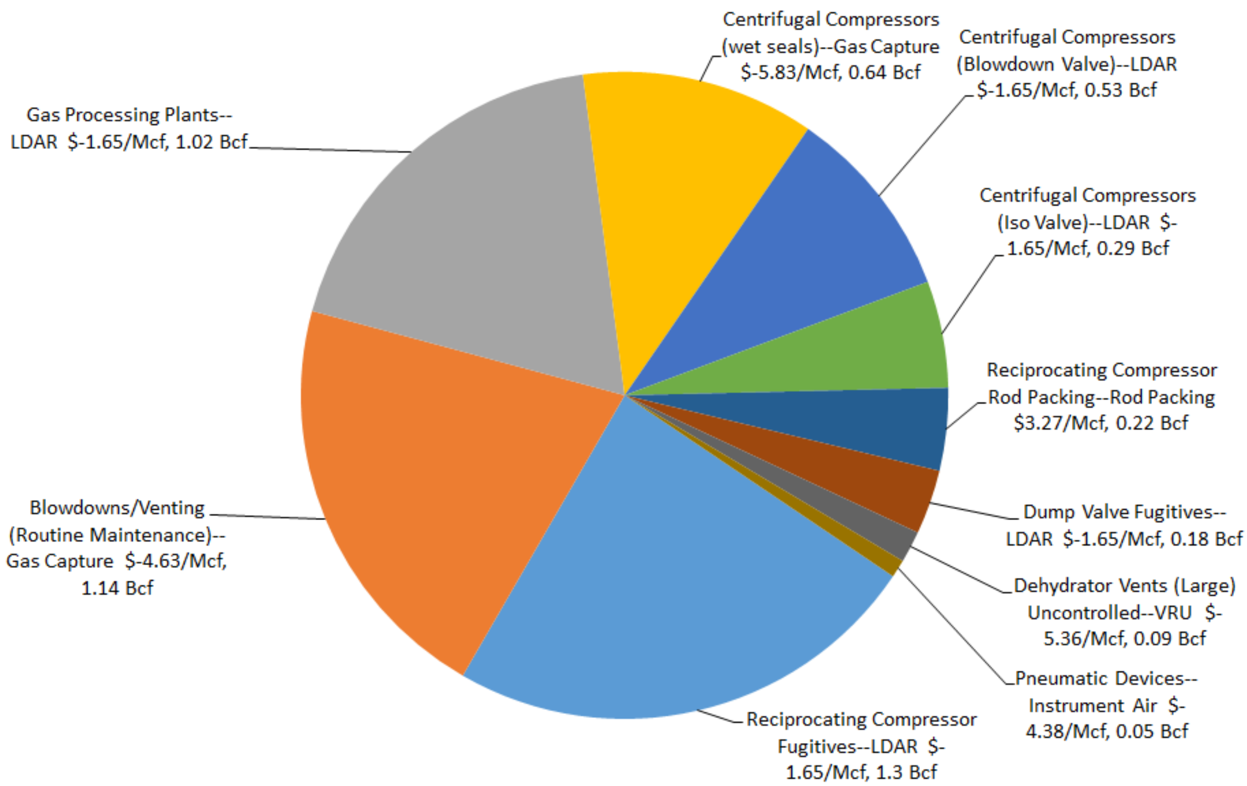


Figure 4-9 shows the reductions for the Gas Processing segment. Fugitives from reciprocating compressors and blowdowns/venting capture are the two largest sources, while processing plant fugitives and wet seal centrifugal compressor emissions are other significant sources. LDAR reduction opportunities exist for other sources, and having a comprehensive LDAR program that targets processing plants will benefit other emission sources as well. The cost of reductions for all measures is -$2.65/Mcf of methane reduced for 5.4 Bcf of reductions.

**Figure 4-9 - Emissions Reductions for the Gas Processing Segment**



## 4.3. Co-Benefits

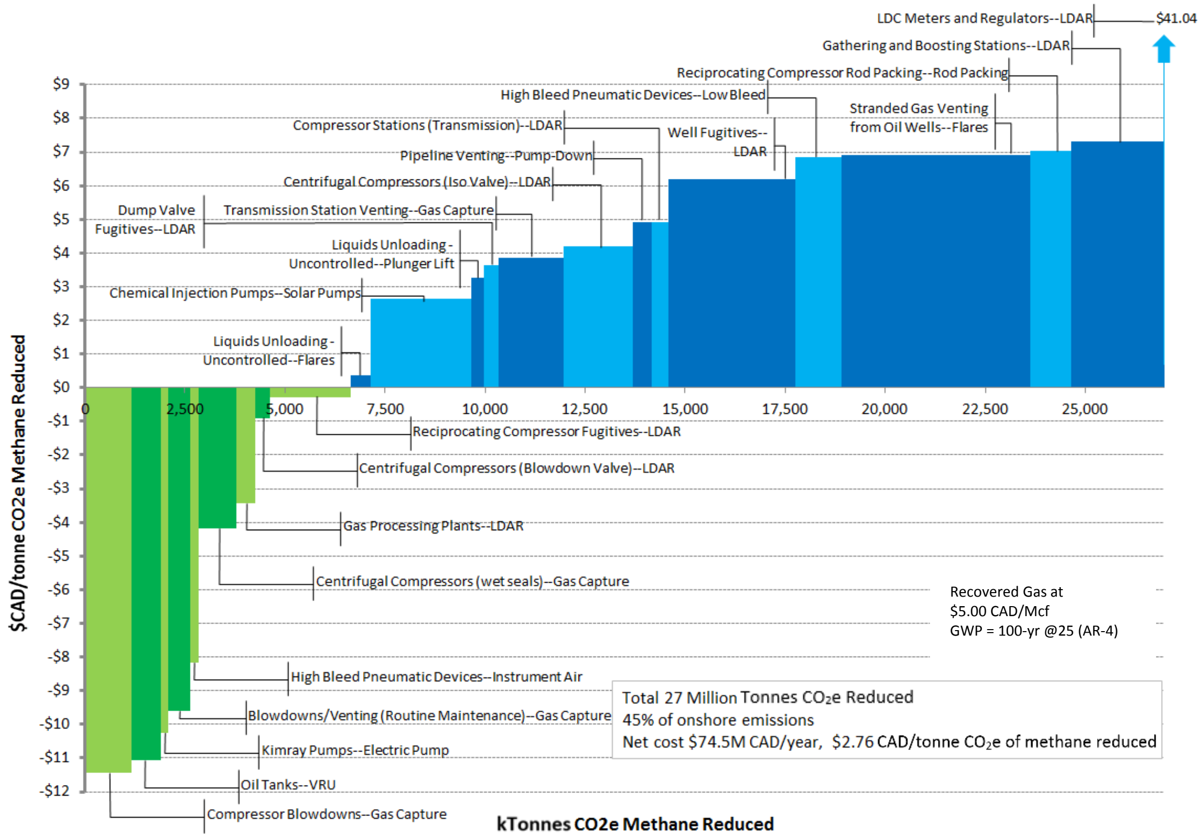
Measures that reduce gas emissions will also reduce the emissions of conventional pollutants - volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) - in the gas as well as methane. Most of these components are removed from the gas at the gas processing stage so the primary co-benefits are at or prior to that stage in the value chain. Although not quantified as part of this report's scope, it can be reasonably anticipated that a reduction of both VOCs and HAPs would result along with actions taken to reduce methane. If the co-benefit of reducing VOCs/HAPs were considered in conjunction with the cost of reducing methane emissions, the overall $/Mcf cost would decrease, essentially yielding a lower cost of control. It should be noted that a control option such as flaring does not avoid all VOCS or HAPs.

# 5. Conclusions

The key conclusions of the study include:

- **124.8 Bcf of Emissions in 2020.** – Methane emissions from oil and gas activities are projected to remain stable from 2013 to 2020 at around 60.2 million tonnes $CO_2e$ (125 Bcf of methane).
  - This relatively constant emissions mask sub-national changes including decreased gas and conventional oil production in Alberta and emissions growth in the Gathering and Boosting and Transmission segments, as a result of increased unconventional gas production in British Columbia and newly constructed pipelines, respectively.
  - The emissions estimate in this study is slightly higher than Canada's UNFCCC submitted values.
  - Existing 2013 emissions sources account for over 90% of emissions in 2020.
  - This assessment does not account for all possible methane emissions from oil sands production. The only emissions included related oil sands are flared and vented volumes and tank emissions from Steam Assisted Gravity Drainage (SAGD). Offshore emissions, while included, are small and are not a significant part of this study. This study also does not account for some insignificant emissions from oil transportation and refinery operations.
- **Concentrated Reduction Opportunities** - 35 of the over 175 emission source categories account for over 80% of the 2020 emissions, primarily at existing facilities.
- **45% Emissions Reduction with Existing Technologies** - This 45% reduction of oil and gas methane is equal to 27 million tonnes $CO_2e$ (56 Bcf of methane) and is achievable with existing technologies and techniques. This reduction:
  - Comes at a net cost of $2.76 CAD / tonnes $CO_2e$ reduced. If the natural gas is valued at $5 CAD/Mcf, the methane reduction potential includes recovery of gas worth approximately $251.1 million CAD ($200.8 million USD) per year.
  - Equals $1.33 CAD /Mcf methane reduced ($1.06 USD/Mcf reduced) or for less than $0.01 CAD/Mcf of gas produced nationwide, taking into account savings that accrue directly to companies implementing methane reduction measures (Figure 5-1).
  - Is achievable at a net annualized cost of $74.5 million CAD per year ($59.6 million USD) if the full economic value of recovered natural gas is taken into account and not including savings that do not directly accrue to companies implementing methane reduction measures. If the additional savings that do not accrue to companies are included, the 45% reduction is achievable at a net savings to consumers and the Canadian economy of $2.3 million CAD ($1.8 million USD).
  - Is in addition to regulations already in place as well as projected voluntary actions companies will take by 2020.
- **Capital Cost** - The initial capital cost of the measures is estimated to be approximately $726.3 million CAD ($581 million USD).

**Figure 5-1 - Marginal Abatement Cost Curve for Methane Reductions by Source**




- **Largest Abatement Opportunities** – In 2020, the Gas Production segment makes up 26.8% of total oil and gas methane emissions, followed by Gathering and Boosting (21.8%) and Oil Production (19.9%). 35 of the over 175 emission source categories account for over 80% of the 2020 emissions, primarily at existing facilities. By volume, the top five largest sources of Canadian oil and gas methane emissions are:
  - Stranded gas venting from oil wells – opportunity to reduce emissions by 78% by installing flares.
  - Fugitives from gathering and boosting stations – opportunity to reduce emissions by 60% by implementing leak detection, and repair (LDAR).
  - Chemical injection pumps - opportunity to reduce emissions by 60% by replacing gas-driven pumps with a non-natural gas driven variety.
  - Reciprocating compressor rod packing seals - opportunity to reduce emissions by 22% by replacing rod packing at a higher frequency.
  - Fugitives from centrifugal compressors - opportunity to reduce emissions by 60% by implementing leak detection, and repair (LDAR).
- **Provincial Results**: **Cost Effective Reductions Possible in Alberta and BC** – Alberta and British Columbia (Upstream only) make up 58% (32.6 Bcf) and 9% (4.8 Bcf) respectively of total Canadian oil

and gas methane emissions reductions in 2020 and reductions are projected to be achievable in both provinces with existing technologies for less than $0.01/Mcf of gas produced.

- Alberta - a 15.7 million metric tonne of $CO_2e$ reduction (32.6 Bcf) is projected to be achievable with existing technologies and practices at a net total cost of $2.57 CAD/tonne $CO_2e$ or $1.24 CAD /Mcf reduced which is less than $0.01 CAD/Mcf of gas produced in Alberta.
- British Columbia - a 2.3 million metric tonne of $CO_2e$ reduction (4.8 Bcf) is projected to be achievable with existing technologies and practices at a net total cost $1.69 CAD/tonne $CO_2e$ or $0.81 CAD /Mcf reduced, which is less than $0.01 /Mcf of gas produced in British Columbia.

- **Co-Benefits Exist** – Reducing methane emissions will also reduce - at no extra cost - conventional pollutants that can harm public health and the environment. The methane reductions projected here would also result in a reduction in volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) associated with methane emissions from the oil and gas industry.

# Appendix A. Development of the 2013 Baseline Inventory

## A.1. Overview

The analysis of methane emission reduction potential uses Canadian-specific research reports from organizations such as CAPP, Environment Canada, and regulatory bodies such as AER. The Canadian data is combined with the structure and emissions sources from the methane portion of the Natural Gas and Petroleum Systems section of EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013* as a basis. The baseline inventory represents a robust, comprehensive data set that utilizes various Canadian specific data resources and applies U.S. inventory methodology to estimate emissions.

## A.2. $H_2S$ Content – Sweet vs. Sour Splits

Oil and Gas activity was divided into two categories based on the presence of $H_2S$- sweet or sour. The determination on whether or not to classify production as sweet or sour was made based on data extracted from IHS Accumap®. The percentage of sweet vs. sour activity (e.g. gas production, gas processing throughput, etc.) for each province was calculated and used to segregate activity accordingly in the baseline inventory.

## A.3. Natural Gas Inventory

The data structure and taxonomy from the U.S. EPA Inventory were used as a starting point to generate the list of sources for the natural gas portion of the baseline. A significant change to the structure of the natural gas segment in the 2013 Baseline was breaking out the Gathering and Boosting segment. This is the segment between onshore Production and either Gas Processing or Gas Transmission. This segment is included in the onshore production segment of the EPA Inventory based on the 1996 GRI measurement study rather than being fully broken out as a separate segment. In this study, some sources were moved from Production to the Gathering and Boosting segment in order to allow them to be analyzed separately for this segment and new emissions estimates, for some sources not represented in the 2013 EPA inventory, were added. For example, emissions from condensate tanks were moved from the Production segment to the Gathering and Boosting segment.

Emissions were segregated by Canadian province, specifically Alberta, British Columbia, Manitoba, and Saskatchewan. Based on geological criteria, surrogate locations were also identified in the U.S. to help generate estimates for activity for select emissions sources when Canadian specific information was not available. Various source estimates (both activity and emissions factors) were driven using data (e.g. Subpart W data, well counts, miles of Transmission pipeline, etc.) from the regional proxies to eventually yield a Canadian specific value. The following analogs were identified:

- Alberta – Rocky Mountain
- British Columbia – Rocky Mountain
- Saskatchewan – Midwest Continent
- Manitoba – Midwest Continent

In subsequent sections, instances where *regional proxies* were used to estimate Canadian activity or emissions factors will be identified as such.

## A.3.1. Gas Production

### A.3.1.1. Natural Gas Well Counts

Well counts were obtained from DI Desktop™, based on the HPDI™ database for Canada. These well counts drive the count of associated well equipment, such heaters, separators, and dehydrators (found in their respective sections below), as well as drive activity estimates for other sources. Well counts were split according to the major Canadian provinces analyzed in this report.

### A.3.1.2. Well Head Fugitives

Gas well counts were split out by province and used as the activity for this source. Emissions factors were generated for each province according to their regional U.S. proxy and work done by the University of Texas for EDF on fugitive emissions from well sites[63]. From this study, any identifiable well head emissions (i.e., emissions from the well itself, not the associated equipment) were grouped together and then divided by the well count at those sites to determine an overall per well emission factor. These emissions factors were then applied to the natural gas well counts for each province.

### A.3.1.3. Heaters, Separators, Dehydrators, and Meters/Piping (Well Fugitives)

Similar to the U.S. EPA Inventory, well counts drive these equipment activities by applying a standard ratio of equipment per well, according to U.S. region. Ratios generated for each U.S. region were applied to each Canadian province based its proxy. An example for Alberta heaters is:

$$HeaterActivity_{Alberta} = \left(\frac{Heaters}{Well}\right)_{RockyMountain} \times Wells_{Alberta}$$

The emission factors used here were provided by the EPA Inventory, and are applied according to the regional proxy specific to each unique Canadian province. Emission factors for heaters, separators, dehydrators, and meters/piping are also from the EPA Inventory.

### A.3.1.4. Reciprocating Compressors

Input from industry experts indicated that the population of small well head compressors may not be as prominent as in the U.S. (e.g. due to electrical codes, etc.). To account for this input and difference between production operations in Canada and the U.S., a total count of compressors was estimated across gas production and gathering and boosting segments by utilizing an internal EDF compressor memo for the U.S. that describes an average compressor count per station. Once a count of compressors was determined, an operating factor of 45.2% was applied per the EPA inventory to arrive at total compressor activity. 75% of the compressor activity was apportioned to the gathering and boosting segment while 25% of total compressor activity was apportioned across the gas production segment as smaller wellhead compressors. Sections 3.2.2 and 3.2.5 provide specific details on the methodology for estimating total compressor and station activity.

An example calculation for Alberta reciprocating compressors is:

$$RCA_{Alberta} = G\&B_{StationCount} \times \left(\frac{Compressor}{Station}\right)_{standard} \times 45.2\% \times 25\%$$

Where RCA is Reciprocating Compressor Activity and G&B is gathering and boosting.

[63] Allen, David, et. al., "Measurements of Methane Emissions at Natural Gas Production Sites in the United States". 10.1073/pnas.1304880110

Emission factors were obtained from the EPA Inventory split according to each unique Canadian province and its regional proxy.

### A.3.1.5. Gas Well Completions and Workovers

Gas well completions are broken out for hydraulically fractured wells and non-hydraulically fractured wells. The emission factors provided were obtained from the EPA Inventory.  For gas well completions with hydraulic fracturing, 50% of the activity was broken out into completions that flare and 50% into reduced emissions completions[64]. For British Columbia, the split was 70% REC and 30% flaring, whoever the emissions are controlled in both cases.

Emission factors from the EPA Inventory are used for both types of completions.  The activity factors for each of these sources were developed using completions data from the ICF Gas Markets Model™. All gas completions with hydraulic fracturing with sour gas are considered being controlled through flaring. Gas well workovers were considered using the same methodology as stated above, with a small fraction of gas wells (approximately 4.35%) requiring workovers.

### A.3.1.6. Well Drilling

The number of wells drilled was estimated from data in the CAPP Volume 3 Inventory report[65]. The report includes a count of wells drilled for the year 2000 and historic EIA Canada gas production was used to extrapolate the count to the year 2013. The emission factor for well drilling was obtained from the EPA Inventory.

### A.3.1.7. Well Testing

This source was not included in the published EPA Inventory, but is included in subpart W of the GHGRP. Activity was obtained by using the total oil and gas well count by province across Canada and assuming each well contributes to well testing.  The emission factor was developed using total emissions reporting under subpart W for each region and the total well count in the U.S. from HPDI for each region.  The regional subpart W factors were then applied to the Canadian provinces according to their U.S. proxy.

### A.3.1.8. Pneumatic Devices

Pneumatic devices in the published EPA Inventory are listed as a single category and use a single emission factor. However, pneumatic devices are reported in subpart W under three categories: low bleed, intermittent bleed, and high bleed devices. In order to break out the devices into the respective categories, the 2013 emissions data in Subpart W was analyzed. From each device type's emissions, the count of each device type was back-calculated using the prescribed standard emission factor in subpart W.  This was done for each regional proxy and applied to estimate Canadian provincial activity, as described further below.  An example calculation for low bleed devices for the regional proxy Rocky Mountain is:

$$LBD\ Activity_{RM} = \left(\frac{\sum RM\ LBD\ Emissions}{Emissions\ per\ device_{standard}}\right)_{SubpartW}$$

[64] Evaluation of Air Emissions Associated with Hydraulic Fracturing: Analysis of Emissions from Drilling, Completions, and Operation of Unconventional Gas Wells in Alberta
http://www.ptac.org/attachments/1389/download

[65] A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry (Volume 3, Methodology for Greenhouse Gas)

Where RM is Rocky Mountain and LBD is low bleed device and the emissions per device is defined in Subpart W.

The "intermittent bleed" category covers a variety of different types of devices with different emission characteristics and is not well-characterized either in the subpart W data or other sources of emission data. Some of these, as characterized in the subpart W emission factors, have a relatively high emission factor, while others are much lower. For this reason, the intermittent devices were further segregated into two categories: dump valves and non-dump valve intermittent devices. The dump valves represent devices that do not have a continuous bleed and generate emissions only when actuating. These types of devices are generally found as level controllers in separators. Assuming that approximately 75% of separators have a lower emitting intermittent bleed dump valve yielded an estimate that approximately 75% of the total intermittent bleed devices were dump valves. The percentage splits were based on SME input.

Then, the activity factors for each type of device were calculated the same way according to province, regional proxy, and well count data (both U.S. and Canada). First, the sum of the total pneumatic device counts (for a particular device) was calculated from Subpart W according to regional proxy and divided by the total number of wells in that U.S. region. An example calculation follows for low bleed devices in the rocky mountain region, utilizing the 'LBD Activity' calculation above.

$$LBD_{PneumaticRatioRM} = \frac{LBD\ Activity}{Total\ Well\ Count_{RM}}$$

The low bleed device example calculation above was further adjusted to account for wells not reported to Subpart W. Once the low bleed device ratio for the rocky mountain region has been calculated it was multiplied by the Alberta gas well count to yield the low bleed device activity for Alberta as follows:

$$LBD_{Alberta} = LBD_{PneumaticRatioRM} \times GasWellCount_{Alberta}$$

Similar calculations are performed for each type of pneumatic device across the remaining Canadian provinces to generate activity factors.

Emissions factors were sourced from a 2013 EDF study with the University of Texas[66]. In the report, bleed rates from low, high, and intermittent bleeds were measured and compiled from multiple sites. Emissions factors were not included from the Prasino study[67] (referenced in the body of the study due to the fact that their emissions factor calculation for high bleed devices included data from low bleed devices. Including data for high bleeds and low bleeds in the same calculation would bias the emissions factor low and thus was not utilized.

### A.3.1.9. Chemical Injection (Pneumatic) Pumps

The count of chemical injection pumps is derived using a subpart W factor of chemical injection pumps per well and applied across provincial well counts in Canada. The emissions factor for chemical injection pumps come from a 2013 Prasino Study[67] performed in British Columbia by calculating a weighted average of the 'generic' diaphragm and piston pump varieties from the Table 1 summary of findings. A 2008

[66] http://www.pnas.org/content/110/44/17768

[67] For Determining Bleed Rates for Pneumatic Devices in British Columbia http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/reporting-regulation/pneumatic-devices/prasino_pneumatic_ghg_ef_final_report.pdf

CETAC-West report[68] was also reviewed as part of characterizing the chemical injection pump emissions factor. The Prasino report references much of the work and data performed in the CETAC-West report.

Both the activity and emissions factors are applied according to the regional proxies.

### A.3.1.10. Dehydrators and Kimray Pumps

Dehydrator counts in the Canadian Inventory were determined using the 2003 CAPP Dehydrator study[69] and scaled from 2003 to 2013 using natural gas production data. The count was split into small and large, with large being considered the dehydrators with a benzene emission rate above 1 tonne per year. In addition to size, dehydrators were also split into controlled and uncontrolled activity based on a subpart W calculated control ratio. The emission factors for large dehydrators, both controlled and uncontrolled, were also based on subpart W derived data. For small dehydrators, the emission factor from the U.S. EPA Inventory was used. The base emission factor was considered uncontrolled, while an adjustment of 95% mitigation for controlled small dehydrators was applied.

Kimray pump activity was estimated using the U.S. EPA Inventory methodology. Kimray pump activity was estimated by taking multiplying dehydrator activity above and EPA's value of average dehydrator throughput (2 million cubic feet per day) multiplied by a 45% capacity factor across an entire year. Finally a fraction of 0.891 is applied to account for the estimate of dehydrators with gas-driven Kimray pumps being present. An example calculation for Alberta is as follows:

$$KP\ Activity_{Alberta} = DehydratorActivity \times \frac{2MMscf}{day} \times 45\% \times 365\frac{days}{year} \times 0.891\frac{KimrayPumps}{Dehydrator}$$

Emissions factors were applied from the U.S. EPA Inventory according to regional proxy.

### A.3.1.11. Dump Valve Venting

Activity was estimated by calculating a dump valve per well count according to subpart W data and reporting oil and gas wells. This ratio was then multiplied by provincial gas well counts according to the regional proxy. Since this source was not included in the published EPA Inventory, but is included in subpart W reporting, the emission factor was also developed using subpart W using total emissions. For production sites, an average emissions per device was calculated according to regional proxy and then applied to each province, respectively. An example for both activity and emissions factor in Alberta is as follows:

$$DV\ Activity_{Alberta} = \left(\frac{DV\ Device\ Count}{OilandGasWells}\right)_{RM} \times GasWells_{Alberta}$$

Where DV is dump valves and RM is Rocky Mountain.

$$DV\ EF_{Alberta} = \left(\frac{\sum DV\ Emissions}{Device}\right)_{RM}$$

Where EF is emissions factor. The emissions factor for each province was supplemented with data on 'malfunctioning devices' from the previous EDF pneumatics device study. SME input determined that the

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[68] Fuel Gas Efficiency BMP - Efficient Use of Fuel Gas in Chemical Injection Pumps (Module 5) http://www.capp.ca/publications-and-statistics/publications/137309

[69] Sep 2003 Pub #:2003-001: This document provides background information on Benzene emissions in the oil and gas industry and what industry is doing to regulate and reduce emissions.

'malfunctioning devices' were stuck dump valves and the accompanying dump valve emissions factor was added to the Subpart W derived dump valve emissions factor.

#### A.3.1.12. Liquids Unloading (Gas Well Clean Ups)

Activity was estimated by calculating a liquids unloading value (both reporting unloadings with and without plunger lifts) per well count according to subpart W data and reporting oil and gas wells. This ratio was then multiplied by provincial gas well counts according to the regional proxy. In a similar fashion, a specific regional subpart W emissions factor was calculated according to region and whether or not the well had a plunger lift present or not. Thus, for production sites, an average emissions per well reporting liquids unloading was calculated according to regional proxy and then applied to each province, respectively. Example calculations are below for both activity and emissions factors in Alberta:

$$LUwoPlungerLiftActivity_{Alberta} = \left(\frac{\#ofWellsUnloading_{woPlunger}}{OilandGasWells}\right)_{RM} \times GasWells_{Alberta}$$

Where LU is liquids unloading and woPlunger is without plunger lifts.

$$LUwoPlungerLiftEF_{Alberta} = \left(\frac{\sum Emissions_{woPlunger}}{WellsUnloading}\right)_{RM}$$

Where EF is emissions factor. Activity and emissions factors for wells with plunger lifts is calculated in a similar manner to wells without plunger lifts above.

#### A.3.1.13. Vessel Blowdowns, Compressor Blowdowns and Starts, and Pressure Relief Valves

Activity for compressor starts is equal to the number of small production compressors (a separate emissions source) estimated according to the methodology in 3.1.4. Activity for vessel blowdowns is assumed to be the summation of activity for heaters, separators, and dehydrators at well sites. The number of pressure relief valves was estimated by taking the ratio of pressure relief valves in the U.S. EPA inventory to total wells and then applying that ratio to provincial gas well counts according to regional proxies.

All emissions factors for each emissions source are from the U.S. EPA Inventory region according to regional proxy.

### A.3.2. Gathering and Boosting

According to U.S. EPA Inventory methodology, the gathering and boosting segment was previously included as part of the Production sector, but has been broken out in this analysis so that it could be separately analyzed. This sector in the 2013 Canadian Baseline contains emissions from large reciprocating compressors, compressor stations, pneumatic devices, and pipelines, amongst other sources. Some other supporting equipment types were left in their respective segment, as found in the EPA Inventory and will be noted.

#### A.3.2.1. Condensate Tanks

Activity data for condensate tanks in Gathering and Boosting is based on lease condensate production specific to each province according to the HPDI™ database for 2013. Data reported to subpart W was used to update the U.S. EPA Inventory emission factors for condensate tank venting. The data pulled from subpart W was on a regional basis and included average API gravity, separator pressure, and separator temperature. This data was then used to run simulations through API's E&P Tank™ software in order to develop new emission factors. The emission factors for each region were then applied to Canadian provinces according to regional proxies. Based on SME input and to stay consistent with the EPA Inventory methodology, it was assumed that on average 50% of the tanks had control measures in place, although this could mean higher or lower percentages in different jurisdictions. For example, British Columbia is assumed to be 70% controlled based on O&G expert input.

#### A.3.2.2. Compressors

The initial estimate of the compressor count comes from a ratio of compressors per gathering and boosting station[70] based on a previous internal EDF compressor memo. An average of 2.75 compressors per station was established from an analysis performed on the U.S. gathering and boosting system validated by and an EDF study of gathering systems, while a 45.2% operating factor was applied from the U.S. EPA inventory.

As mentioned in the small reciprocating section above for Gas Production, input from industry experts indicated that the population of small well head compressors may not be as prominent as in the U.S. (e.g. due to electrical code, etc.). To account for this input and difference between production operations in Canada and the U.S., a total count of compressors was estimated across gas production and gathering and boosting segments by utilizing an internal EDF compressor memo for the U.S. that describes an average compressor count per station. 75% of the compressor activity was apportioned to the gathering and boosting segment while 25% of total compressor activity was apportioned the gas production segment.

For this source and similar sources in other segments, there are two sources of reciprocating compressor emissions. Fugitive emissions (non-seal) from sources such as open-ended lines, flanges, and valves, in addition to vented rod packing seal emissions. To account for fugitive sources, the emission source was separated into blowdown valve operating, blowdown valve standby, and isolation valve activity. To drive the activity for each of these sources, the total compressor count was used since subsequent emissions take into account operating modes and % of time operating in those modes.

Emission factors for each fugitive source were derived from subpart W according to regional proxies, including data from both measured and non-measured compressors and applied across provinces. Vented emissions were calculated using total compressor count per reporting facility and subpart W derived emission factors, specific to rod packing.

In addition to splitting out fugitive sources on compressors, both seal and non-seal emission sources were further split between controlled and uncontrolled. The split was derived from an Alberta Energy Regulator flaring and venting report[71]. The control percentage was the percentage of solution gas being flared rather than vented, and is unique per industry segment. The respective emissions factors for the controlled sources were assumed to be going to a flare and thus a control factor of 98% was applied.

#### A.3.2.3. Scrubber Dump Valves

According to input from SMEs, the baseline inventory assumes one scrubber dump valve per compressor. The activity factor for scrubber dump valves is the sum of individual activity factors for controlled and

[70] Two independent sources of data were used to determine the count of Gathering and Boosting Stations. 1) The Oilfield Atlas (Tenth Edition, 2014-2015), and 2) ST102: Facility List formerly Battery Codes and Facility Codes from the AER.

[71] ST60B: Upstream Petroleum Industry Flaring & Venting Report https://www.aer.ca/data-and-publications/statistical-reports/st60b

uncontrolled reciprocating compressors. The emission factor was derived from subpart W data according to regional proxy and applied to each province.

### A.3.2.4. Compressor Exhaust (Gas Engines)

The exhaust from compressor engines and turbines contains some unburned methane. The activity factor for these two emissions sources in the derived from analysis of the EPA Inventory which has total horsepower hours of the equipment. Additionally, the U.S. EIA publishes the amount of natural gas used as "Lease Fuel," which is fuel burned at natural gas production sites. A new fuel volume was calculated for small reciprocating, gathering and boosting reciprocating, and gathering and boosting centrifugal compressors, respectively, according to typical horsepower ratings of each compressor type. This fuel volume was used as the new activity factor for compressor exhaust. The analysis assumed 70% of the lease fuel was consumed in engines and turbines and the breakdown between engines and turbines was determined to be 96% to 4%, respectively, using the breakdown of compressors according to count of U.S. compressors from the EDF Compressor Analysis report.

The emissions factors were updated using emissions factors from the EPA's manual of emission factors ("AP-42"). Since AP-42 lists 3 separate emission factors for engines (two stroke lean-burn, four stroke lean-burn, and four stroke rich-burn), a combined emission factor was developed based on the data obtained from U.S. state energy agencies. This data set, which contained nearly 10,500 compressors/engines across all sectors of the industry, was used to determine the breakout of engine types: 10% two stroke lean-burn, 34% four stroke lean-burn, and 56% four stroke rich-burn. These ratios were used to give an overall emission factor for engines. The emission factor for turbines, was listed directly in AP-42 and used as-is.

### A.3.2.5. Gathering and Boosting Stations

Formally called "Large Compressor Stations" in the EPA Inventory, the count of stations was determined from two independent sources as described in 3.2.2. The emission factor for this source is derived from subpart W data for transmission stations by taking the average emissions per station and applying it according to regional proxy in Canada. An example calculation for the gathering and boosting station emissions factor is:

$$G\&BStationEF_{Alberta} = \left(\frac{\sum Emissions_{TransmissionStation}}{\#ofTransmissionStations}\right)$$

### A.3.2.6. Dehydrators and Kimray Pumps

Dehydrators and Kimray pumps were handled in a similar fashion as described in Gas Production (3.1.10)

### A.3.2.7. Pneumatic Devices

The pneumatic device methodology is split in a similar to fashion as in Gas Production (3.1.8). The activity count is driven by an API/ANGA[72] ratio of device per gathering station multiplied by the ratios established in gas production according to the type of device (e.g. High-bleed, low-bleed, intermittent bleed, etc.). The emission factor methodology is the same as described in the Gas Production section.

[72] Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf

### A.3.2.8. Pipeline Leaks, Pipeline Blowdowns, Compressor Starts, and Compressor Blowdowns

These emissions were moved from Production to Gathering and Boosting to better represent the breakout of emissions in the industry. Pipeline leaks and blowdowns are based on a gathering miles estimate from a 1992 CAPP study[73], which breaks out gathering lines by province. Gathering miles are scaled up to 2013 according to Canada's natural gas production growth from 1992 to 2013, broken down by province. The units of pipeline blowdowns is also in miles and follows the same methodology.

For compressor starts, activity is based on the total number of compressors in the Gathering and Boosting segment as detailed in section 3.2.2. Since the units of activity for compressor blowdowns is "stations", the activity factor for compressor blowdowns (controlled) is the count of gathering and boosting stations multiplied by the Alberta Energy regulator's flaring and venting percentage for the gathering and boosting segment[74]. Activity for uncontrolled compressor blowdowns is simply the venting portion of from the AER flaring and venting analysis. An important assumption is that these ratios are also applied across the remaining Canadian provinces to estimate their respective counts of compressor activity.

Emissions factors for pipeline leaks, pipeline blowdowns, and compressor starts are sourced from the U.S. EPA Inventory, while the emissions factor for compressor blowdowns was calculated using subpart W data. Specifically, emissions the subpart W table for transmission station venting was used as a proxy for compressor blowdowns in Gathering and Boosting and applied across each Canadian province.

## A.3.3. Gas Processing

### A.3.3.1. Gas Plant Fugitives

Activity for currently operating Gas Plants across Canada was obtained by an internal data source from the ICF Calgary Office. The source provides a 2013 list of gas processing facilities according to province and whether the plant is considered a sweet or sour processing plant. This count by province drives much of the activity for the Processing segment. The emissions factor for gas plant fugitives is obtained from the U.S. EPA Inventory.

### A.3.3.2. Reciprocating and Centrifugal Compressors

Reciprocating compressor methodology is split in a similar to fashion as described in the Gathering and Boosting segment. The only difference is that centrifugal compressors now are included and have similar pieces of its activity broken out into separate sources (e.g. blowdown operating value, isolation valve, etc.). The overall activity count is driven by a subpart W ratio of compressors to gas plants according to regional proxy and applied across provinces with respect to their specific gas plant count. An example calculation for centrifugal compressors in Alberta is:

$$CentrifugalActivity_{Alberta} = \left(\frac{CentrifugalCompressors}{GasProcessingPlant}\right)_{RM} \times GasProcessingPlants_{Alberta}$$

[73] Gas Pipelines in Canada at Year-End 1992.
http://statshb.capp.ca/SHB/Sheet.asp?SectionID=8&SheetID=111
http://www.capp.ca/library/statistics/handbook/pages/statisticalTables.aspx?sectionNo=8
[74] ST60B: Upstream Petroleum Industry Flaring & Venting Report
https://www.aer.ca/data-and-publications/statistical-reports/st60b

The emissions factor for each of the sources are also mainly derived from subpart W. For centrifugal compressors, subpart W ratios of compressor emissions per compressor are used for blowdown operating and isolation valve modes, while the EDF memo[75] on compressor seal emissions was used as the seal-only emissions factor. Reciprocating compressor emissions factors were strictly sourced from subpart W analysis with minor supplements from the U.S. EPA Inventory. For example, subpart W provides emissions data on blowdown and isolation valves, which can produce provincial emissions factors, but subpart W does not have data on emissions from reciprocating compressor PRVs and miscellaneous components. The respective emissions factors from the U.S. EPA inventory are used here to supplement the emissions factor for completeness.

### A.3.3.3. Scrubber Dump Valves

This emissions source followed a similar methodology as in gathering and booster, whereby it is assumed that there is one scrubber dump valve per compressor. The activity factor for scrubber dump valves is the sum of individual activity factors for controlled and uncontrolled reciprocating & centrifugal compressors. The emission factor was also derived from subpart W data according to regional proxy and applied to each province.

### A.3.3.4. Gas Engine and Turbine Exhaust

The activity factor for these two emissions sources in the Canadian Baseline Inventory are driven by U.S. EIA published values for gas processing fuel consumption (the amount of natural gas used as "Plant Fuel") and total U.S. gas processing throughput. The total fuel volume from the EIA was used under the assumption that 80% of the fuel being consumed is for use in engines and turbines in a typical processing plant. Furthermore, fuel consumption splits between engines and turbines was assumed to be 46% to 54%, respectively, using the current horsepower-hour ratios in the published U.S. EPA Inventory. These estimates for both engines and turbines were divided by total U.S. gas processing throughput and apportioned according provincial gas processing throughput. The final result of these calculations was a fuel consumption number by province in million standard cubic feet of natural gas burned.

The emissions factors were also updated and followed the same methodology as described in section B.3.2.4.

### A.3.3.5. Dehydrators and Kimray Pumps

Dehydrators and Kimray Pumps followed a similar methodology as in Gas Production (3.1.10).

### A.3.3.6. AGR Vents, Blowdowns/Venting and Pneumatic Devices

Activity for AGR vents is calculated by taking the 1992 ratio of AGR vents to gas processing plants in the U.S. EPA Inventory and multiplying the ratio by gas processing plants in Canada according to province. Pneumatic devices are not split into high, low, or intermittent bleed categories for this segment, but rather follow the U.S. EPA Inventory convention of having just one source. The units of activity for pneumatics using this convention is simply the gas plant count, which is known from the methodology above for gas processing plants across Canada. Blowdowns/venting also follow a similar methodology as pneumatics and also have gas plant count as its activity.

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[75] Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States
http://dept.ceer.utexas.edu/methane/study/

In all three sources, emissions factors from the U.S. EPA Inventory were used for each province according to regional proxies.

## A.3.4. Gas Transmission

### A.3.4.1. Pipeline Leaks

Pipeline leak activity is driven by total mileage of transmission pipeline across Canada. Data was obtained from a 2013 report from the Canada Energy Pipeline Association[76]. This information was summed up for the entire transmission segment across onshore Canada and converted to miles. The emissions factor was obtained from the U.S. EPA Inventory.

### A.3.4.2. Transmission Compressor Stations

Activity for transmission compressor stations was estimated by analyzing internal printouts of transmission pipeline maps and locations of compressor stations across Canada. Based on publicly available company and provincial data, it was possible to generate a ratio of compressor stations per mile of transmission pipeline across each provinces and the merge that data into a national estimate of total compressor stations.

The emissions factor for compressor stations was obtained from the U.S. EPA Inventory.

### A.3.4.3. Reciprocating and Centrifugal Compressors

Activity for compressors were estimated in two distinct steps. First, the transmission compressor station count from 3.4.2 was multiplied by a ratio of U.S. EPA compressor count (both reciprocating and centrifugal) to the number of U.S. compressor stations from the EPA Inventory. Doing so yields a total compressor count across Canada. Secondly, an estimate of the % split between reciprocating vs. centrifugal compressors was obtained by analyzing published data from TransCanada's[77] operations and their splits of reciprocating vs. centrifugal compressors. The resulting splits were 87% centrifugal and 13% reciprocating. For centrifugal compressors, subpart W data for transmission was utilized to determine splits between wet and dry seals. Similar steps were performed in terms of breaking out blowdown and isolation value activity consistent with the methodology found in gathering and boosting.

Emissions factors for both reciprocating and centrifugal compressors were also developed consistently with the Gathering and Boosting segment, namely sourced from subpart W, the U.S. EPA Inventory, and the EDF compressor memo with data on centrifugal seal emissions.

### A.3.4.4. Engine and Turbine Exhaust

Fuel consumption in engines and turbines in the transmission segment was also estimated in two distinct steps. First, as a driver, the ratio of total U.S. pipeline fuel consumption from the EIA to total U.S. transmission pipeline mileage was calculated and applied to the total miles of transmission pipeline across Canada. Secondly, the fuel consumption was apportioned across engines and turbines according to the estimate of Canadian reciprocating and centrifugal compressors and the ratio of million horsepower-hour

[76] About Pipelines – Our Energy Connections
http://www.cepa.com/wp-content/uploads/2013/10/CEPA_Our-Energy-ConnectionsE_Oct04.pdf

[77] Multiple references from TransCanada were used. An example is:
https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92833/92843/665035/711778/718015/772304/B8-35_-_G04_Ontario_-__A2J7T6_.pdf?nodeid=772407&vernum=-2

to reciprocating and centrifugal compressors, respectively, from the U.S. EPA Inventory. Assuming that that 90% of this fuel was used for compression, estimates for total engine and turbine exhaust were then able to be calculated. The emissions factors followed a similar methodology in other segments for engine exhaust.

#### A.3.4.5. Pneumatic Devices

Activity for high, low, and intermittent bleed devices were determined by taking subpart W ratios of each device respectively to the count of reporting U.S. transmission stations. This ratio was then multiplied by the total transmission station count in Canada for each device to arrive at its respective activity.

Emissions factors were applied according to similar methodology as described in other sections, mainly citing EDF studies on measuring device leakage rates.

#### A.3.4.6. Dump Valve Leakage

This emissions source followed a similar methodology as in Gathering and Booster, whereby it is assumed that there is one scrubber dump valve per compressor. The activity factor for scrubber dump valves is the sum of individual activity factors for controlled and uncontrolled reciprocating & centrifugal compressors. The emission factor was also derived from subpart W data according to the transmission segment.

#### A.3.4.7. Pipeline Venting

Activity for pipeline venting was simply the total transmission pipeline mileage as calculated earlier in this segment. The emissions factor was obtained from the U.S. EPA inventory.

#### A.3.4.8. Transmission Station Venting

The total count of transmission stations from Canada was used as the activity for transmission station venting. The emissions factor was obtained from subpart W by calculating blowdown emissions and reporting station count from the transmission segment across 2011-2013 and averaging the resulting emissions factor. The resulting value was implemented as the emissions factor for transmissions station venting in Canada.

### A.3.5. Gas Storage

#### A.3.5.1. Gas Storage Compressor Stations

#### A.3.5.2. Pneumatic Devices

The activity and emissions factors for pneumatic devices follow the same methodology as described in the Gas Processing segments.

#### A.3.5.3. Reciprocating and Centrifugal Compressors

Both reciprocating and centrifugal compressors were driven off of U.S. EPA Inventory gas storage capacities between 1992 and 2013. A ratio of compressors, by type, was taken as a ratio to gas storage in 1992 and multiplied against the obtained gas storage capacity value for Canadian gas storage in 2013 according to CGA statistics[78].

[78] Canadian Gas Association
http://www.cga.ca/resources/publications/fact-sheets-and-bulletins/

Development of emissions factors for both compressor types followed a methodology similar to other segments, utilizing data from subpart W, the U.S. EPA Inventory, and external reports.

#### A.3.5.4. Engine and Turbine Exhaust

The activity factor for these two emissions sources in the Canadian Baseline Inventory are driven by U.S. EIA published values for pipeline fuel consumption (the amount of natural gas used as "Pipeline Fuel Consumption") and million horsepower-hour values from the U.S. EPA inventory for engines and turbines. The total pipeline fuel volume from the EIA was used under the assumption that 80% of the fuel being consumed is for use in engines and turbines in a gas storage station. The values from the EPA Inventory were then used to calculate a composite MMscf/MMHPhr conversion factor and a typical "consumption rate" for reciprocating and centrifugal compressors, respectively. Once the consumption rates for each compressor type were know, it was possible to multiple these rates by the estimated reciprocating and centrifugal compressor counts as described in its section in Gas Storage. The final result of these calculations was a fuel consumption number by in million standard cubic feet of natural gas burned.

Emissions factors for engine and turbine exhaust were calculated according to the same methodology in other exhaust sections.

#### A.3.5.5. Dehydrator Vents

Dehydrator vents, both activity and emissions factors, follow a similar methodology as in the compressor section of Gas Storage.

### A.3.6. Liquefied Natural Gas (Import and Storage Terminals)

Besides import and storage terminals below, other sources LNG followed similar methodology as described in other segments of this appendix. This study's analysis relies on GMM predictions for potential future completions of LNG terminals. Based on model outputs, this study assumes most major LNG installation activity will occur post-2020 and thus will not have a major impact on the results.

#### A.3.6.1. Import Terminals

There is not significant activity across Canada for LNG import terminals. However, there was one identified active import terminal according to research performed for the year 2013[79]. The import terminal, Canaport[80], represents the only activity for emissions for import terminals. Emissions from import terminals were estimated using an emissions factor sourced from the U.S. EPA inventory.

#### A.3.6.2. Storage Terminals

Activity for LNG important terminals was obtained by analyzing data from data publicly available from Westport Power[81]. According to analysis of the available map, it was determined that approximately 13 LNG storage stations were present in Canada in 2013 and was used as the basis for emissions estimate for this source. The emissions factor was obtained from the U.S. EPA Inventory for LNG import terminals.

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79 LNG Import Terminals
http://www.globallnginfo.com/world%20lng%20plants%20&%20terminals.pdf

80 Canaport LNG Import Terminal
http://www.canaportlng.com/

81 Westport Power LNG Station Map
http://www.westport.com/is/natural-gas/lng-infrastructure

## A.3.7. Gas Distribution

Gas Distribution in the Canadian Baseline Inventory follows the U.S. EPA Inventory methodology with three key differences. First, each source is driven by residential gas consumption or mains mileage specific to Canada. Total distribution mileage was obtained from the Canadian Gas Association[82], while residential gas consumption was obtained from Statistics Canada[83]. The final main difference between the Canadian methodology and the U.S. EPA Inventory was the implementation of emissions factors from an EDF study on leaks from distribution systems[84]. The resulting emissions factors from the EDF study are significantly lower than U.S. EPA Inventory values. It's important to note these factors applied to all sources except: Residential, Commercial/Industry, Pressure Relief Valves, Pipeline Blowdowns (Maintenance), and Mishaps (Dig-ins).

## A.3.8. Oil Production

### A.3.8.1. Oil Tank Venting

Activity data for oil tanks is based on oil production specific to each province according to the HPDI™ database for 2013. Additionally, data reported to subpart W was used to update the emission factors for condensate tank venting. The data pulled from subpart W was on a regional basis and included average API gravity, separator pressure, and separator temperature. This data was then used to run simulations through API's E&P Tank™ software in order to develop new emission factors. The emission factors for each region were then applied to Canadian provinces according to regional proxies. Based on SME input and to stay consistent with the EPA Inventory methodology, it was assumed that 50% of the tanks had control measures in place.

SAGD tankage from oil sands production were obtained as outputs from ICF's GMM model and used as activity for estimating emissions from SAGD tankage. It was assumed 50% of the production was due to steam assisted gravity drainage and 50% due to surface mining. It was also assumed that 50% of the activity was controlled and 50% uncontrolled. The emissions factors developed above for generic oil tanks were applied across the SAGD activity to estimate emissions.

### A.3.8.2. Oil Tank Dump Valve Venting

Activity and emissions factors for dump valve venting were estimated using a similar methodology as described in the Gathering and Boosting segment.

### A.3.8.3. Pneumatic Devices

Activity and emissions factors for pneumatic devices (high, low, and intermittent bleed) were estimated using a similar methodology as described in the Gathering and Boosting segment. Data from the oil production segment of subpart W was used according to regional proxies.

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[82] CGA Distribution Mileage.
http://www.cga.ca/wp-content/uploads/2011/02/Chart-16-Natural-Gas-Distribution-System.pdf
http://www.cga.ca/wp-content/uploads/2015/06/Chart-16-Natural-Gas-Distribution-System.pdf
[83] Statistics Canada.
http://www.statcan.gc.ca/pub/57-003-x/57-003-x2015002-eng.pdf
[84] Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.
http://pubs.acs.org/doi/abs/10.1021/es505116p

### A.3.8.4. Chemical Injection (Pneumatic) Pumps

Activity for chemical injection pumps in the oil production segment were sourced according to the U.S. Inventory Petroleum model, which is based on a 1999 Radian report[85]. The only difference is that a count of Canadian oil wells is used to drive chemical injection pump activity instead of U.S. oil well counts.

The emissions factor for chemical injection pumps come from a 2013 Prasino Study[86] performed in British Columbia by calculating a weighted average of the 'generic' diaphragm and piston pump varieties from the Table 1 summary of findings.

### A.3.8.5. Oil Well Completions

Activity on completions data was mainly sourced from ICF's proprietary GMM model for 2013. Oil well completions were not broken out for hydraulically fractured wells and non-hydraulically fractured wells in the published U.S. EPA Inventory. However, these two categories were broken out in subpart W, so this was also implemented in the Canadian baseline. The data reported to subpart W was used to develop new emission factors use in Canada for both emissions sources.

### A.3.8.6. Oil Well Workovers

The same methodology for oil well completions was used to develop activity and an emissions factor for workovers with the one additional assumption of 4.35% of wells requiring workovers.

### A.3.8.7. Stranded Gas Flaring and Venting from Oil Wells

Stranded gas flaring and venting emissions in the Canadian baseline are estimated by directly incorporating known information from Alberta Energy Regulator reports on solution gas for 2013. The ST60B report contains volumes of vented and flared gas for 2013 in Alberta and the volumes from that report were imported into the baseline inventory. Thus, no explicit activity or emissions factor were implemented for this source, but reported emissions were directly used. A study by the Canadian Energy Research Institute references this data in their February 2015 report, "The Associated Gas Sector in Alberta" [87]. Emissions are estimated by using the flaring volume of 495 million cubic metres, an assumed methane content, and considering 2% uncombusted methane. Vented volumes are simply the reported 403 million cubic metres of reported vented solution gas. Stranded gas flaring emissions are only considered in Alberta and British Columbia, where sour gas is present. Finally, a "vented ratio" in scf/bbl was calculated (i.e. total crude oil production in Alberta to total reported vented volume in 2013 according to ST60B) and extrapolated across other provinces according to their local crude oil productions. This allowed for estimates across other provinces for their flared and vented volumes of stranded gas from oil wells.

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[85] Methane Emissions from the U.S. Petroleum Industry
http://www.epa.gov/climatechange/pdfs/radian-petroleum-1999.pdf

[86] For Determining Bleed Rates for Pneumatic Devices in British Columbia
http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/reporting-regulation/pneumatic-devices/prasino_pneumatic_ghg_ef_final_report.pdf

[87] AER ST60B-2014, "Upstream Petroleum Industry Flaring and Venting Report, 2013". November 2014
http://www.ceri.ca/images/stories/Associated_Gas_Sector_in_Alberta_-_February_2015.pdf

### A.3.8.8. Separators (Light and Heavy), Heater/Treaters, and Headers (Light and Heavy)

Activity for all sources were calculated according to the U.S. EPA Inventory for petroleum systems. Much of this activity follows the 1999 Radian report[88], which characterizes each of these emissions sources and drives activity based mainly on whether production is light (i.e. API gravity greater than 20°) or heavy (API gravity less than 20°). ICF assumed that 90.1% of oils wells across Canada are considered producing light crude, while the remainder of oil wells are producing heavy crude[89]. These percentages drive the light vs. heavy splits for separators and headers. Heater/treaters are assumed to be present for both light and heavy crude wells.

The emission factor for all three sources were originally sourced from the U.S. EPA Inventory and then were updated to the emission factors published in subpart W.

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[88] Methane Emissions from the U.S. Petroleum Industry
http://www.epa.gov/climatechange/pdfs/radian-petroleum-1999.pdf

[89] The Canadian emissions inventory does not consider oil sands production, which may have significantly heavier crude production. Estimates are for light/heavy splits are for conventional crude only.

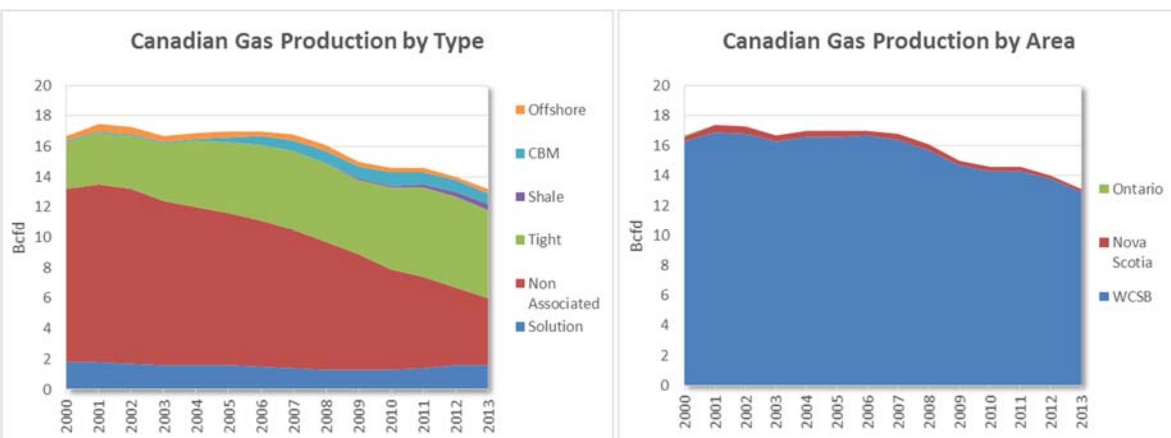
# Appendix B. Emission Projection to 2020

## B.1. Canada's Oil and Gas Production

### B.1.1. Gas Production

Canada produces most of its natural gas in the Western Canadian Sedimentary Basin (WCSB), although there is some limited production in Ontario and in offshore Nova Scotia. The decline of conventional gas production in WCSB and stagnant associated gas production has led to Canadian's overall gas production decline over the last decade from 16.7 Bcfd in 2000 to 13.2 Bcfd in 2013 (see Figure B-1). However, this trend is expected to reverse with the expected acceleration of shale gas development across North America. Two major shale gas plays in the WCSB are the Montney and Horn River Shales, which are primarily located in British Columbia. Increasing demand for natural gas in oil sands production, as well as LNG exports from British Columbia are expected to drive the development of shale gas in Western Canada. Eastern Canada's offshore production is relatively small and largely supplies local demand in the Maritimes provinces and the U.S. Northeast. The figure below shows Canada's historical gas production.

**Figure B-1 – Canadian Historical Gas Production**



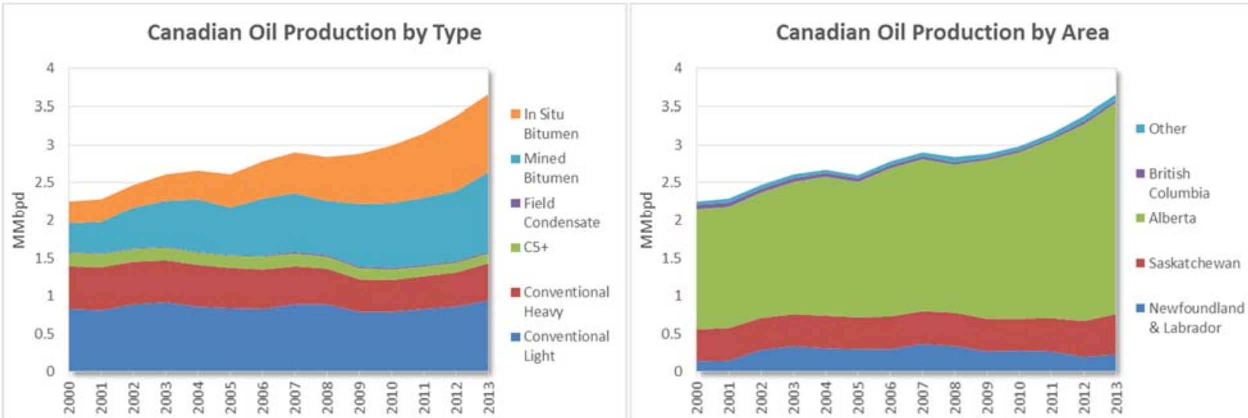

**Source: NEB Canada's Energy Future 2013**

### B.1.2. Oil Production

Western Canada accounts for 93 percent of Canadian oil production, which consists of both conventional oil and oil sands production.[90] Oil sands has driven Canadian oil production growth in recent years, whereas conventional production has remained flat. In Eastern Canada, oil production comes from offshore fields such as the Hibernia, White Rose and Terra Nova. These fields account for a small portion of the total production (7% in 2013), and offshore oil prospects in Canada is likely to remain uncertain in the future. Figure B-2 below summarizes Canadian oil production by type and area.

[90] Canadian Association of Petroleum Producers. "Crude Oil Forecast, Markets & Transportation". CAPP, June 2014. Available at: http://www.capp.ca/publications-and-statistics/crude-oil-forecast

**Figure B-2 – Canadian Historical Oil Production**




**Source: NEB Canada's Energy Future 2013**

## B.2. Overview of ICF's GMM Model

In order to develop projections of future production levels of natural gas and oil in Canada, this study has used ICF's proprietary Gas Market Model (GMM®). The GMM® is a nationally recognized, comprehensive, detailed supply and demand equilibrium model of the North American gas market. The Canadian gas market is integrated with the U.S., and therefore production projections in Canada require an understanding of the full North American market. The GMM operates by equilibrating supply and demand across the pipeline network on a monthly basis for a forecast period. The model generates gas production and gas consumption forecasts, shows pipeline utilization and flows, and storage operations. The GMM® forecasts gas supply, consumption, and prices at over 120 supply and demand market nodes. The GMM forecasts the marginal (or incremental) value of natural gas (i.e., natural gas prices) by balancing supply and demand in each of the market nodes. GMM develops a forecast for dry pipeline-quality gas, and a separate vintage production model is used to develop estimates of well completions and liquids (crude oil and lease condensate) production from various basins.

This study's Base Case forecast incorporates the following key underlying assumptions:

- Historical U.S. GDP growth rates are based on the U.S. Bureau of Economic Analysis's (BEA) estimates. This study uses recent Wall Street Journal's Survey of Economists for the 2015 U.S. GDP rate of 2.9%, in order to capture potential near-term swings in economic activity. From 2016 forward, this study assumes a U.S. GDP grows at 2.6% per year. Historical Canadian GDP growth is based on estimates published by Statistics Canada; for the forecast, this study assumes that Canadian GDP grows at 2.5% per year from 2014 forward. This study's assumptions are consistent with projections from other institutions such as the EIA, OECD, and IMF.
- Long term oil price (refiner's average cost of crude) is assumed to stabilize around $75 per barrel (in 2014$).
- Demographic trends are consistent with trends during the past 20 years. U.S. population growth averages about 1% per year. Future Canadian demographic trends are consistent with historical trends, and based on information from Statistics Canada.

- Future weather pattern is assumed to be consistent with averages over the past 20 years.
- Electric load growth averages 1.2% per year.
- This study's Base Case reflects EPA's current rules for Mercury & Air Toxics Standards Rule (MATS), water intake structures (often referred to as 316(b)), and coal combustion residuals (CCR, or ash). It also includes the Cross-State Air Pollution Rule (CSAPR), which was reinstated in January 2015. CSAPR has replaced the CAIR program, imposing regional and state caps on emissions of NOX and SO2.
- Current U.S. and Canada gas production is from over 400 trillion cubic feet of proven gas reserves.
- The substantial North American natural gas resource base, totaling over 4,000 trillion cubic feet of unproved plus discovered but undeveloped gas resource, can supply the U.S. and Canada gas markets for over 100 years (at current consumption levels).
- Shale gas accounts for over 50 percent of remaining recoverable gas resources.
- No significant restrictions on well permitting and fracturing beyond current restrictions (e.g., banning of hydraulic fracturing in New York State).
- GMM forecasts well completions, not wells drilled. Inventory of drilled but uncompleted wells (DUC) could be large in some producing areas (mostly in the U.S) and is not considered in this analysis.
- Projections of oil sands development is based on GMM's estimate derived from CAPP and NEB estimates. It is an exogenous input into the model. Oil well completion estimates do not include any wells developed for oil sands development.
- No significant hurricane disruptions to natural gas supply. Modest disruptions assumed, consistent with the average disruption over the past 20 years.
- Arctic projects (specifically Alaska and Mackenzie Valley gas pipelines) are not included in our projection.
- Near-term midstream infrastructure development is aligned with project announcements. Unplanned ("generic") projects are included when the market signals need for capacity (i.e., projected basis covers the unit cost of expansion). This study assumes that there are no significant delays in permitting and construction of pipelines.

## B.3. Projected Canadian Production

Over the next seven years, production growth in Canada will be driven by shale gas development in western Canada. Conventional and tight well completions in Alberta and Saskatchewan are expected to see the largest declines. This reflects the ongoing decline in conventional oil and gas extraction. This study expects no new gas wells in eastern Canada in 2020 due to the uncertain outlook for offshore development.

Figure B-3 shows the annual well completions in 2013 and 2020, as well as cumulative and average well completions between 2013 and 2020. The annual gas well completions in the Montney and Horn River plays increase over time, with an average annual well completion of 500 and 180 wells respectively. These two plays are expected to serve the LNG export and oil sands production demand. This study's forecast of

2,250 new gas well completions in 2020 is in line with the NEB's estimate of roughly 2,200 new gas wells drilled in Western Canada in 2020[91].

New annual oil well completions in Canada are expected to decrease between 2013 and 2020 due to the decline in new conventional oil well drilling and completions. EURs for the conventional oil wells will decline slowly over time, as sweet spots are running out leading to more expensive resources and declining well productivity. Although, conventional oil production will decline over time, overall oil production in Western Canada will increase over time due to the growth of oil sands.

**Figure B-3 - New Annual Oil and Gas Well Completions in Canada**

| | Alberta/Saskatchewan | | | British Columbia | | Eastern Canada | Canada | U.S. |
|---|---|---|---|---|---|---|---|---|
| | Conventional & Tight | CBM | Shale | Conventional & Tight | Shale | Offshore / Other | Total | Total |
| **Gas Well Completions** | | | | | | | | |
| 2013 | 1,080 | 400 | 410 | 95 | 640 | 40 | 2,670 | 9,250 |
| 2020 | 890 | 70 | 340 | 160 | 780 | 0 | 2,250 | 9,080 |
| Cumulative 2013-2020 | 7,990 | 1,630 | 3,150 | 1,150 | 5,480 | 70 | 19,460 | 71,770 |
| Average Annual 2013-2020 | 1,000 | 200 | 390 | 140 | 680 | 10 | 2,430 | 8,970 |
| **Oil Well Completions** | | | | | | | | |
| 2013 | 8,730 | 0 | 0 | 95 | 0 | 0 | 8,820 | 31,980 |
| 2020 | 5,920 | 0 | 0 | 140 | 0 | 0 | 6,060 | 21,940 |
| Cumulative 2013-2020 | 56,430 | 0 | 0 | 1,050 | 0 | 0 | 57,480 | 212,010 |
| Average Annual 2013-2020 | 7,050 | 0 | 0 | 130 | 0 | 0 | 7,180 | 26,500 |
| **Total Well Completions** | | | | | | | | |
| 2013 | 9,810 | 400 | 410 | 190 | 640 | 40 | 11,490 | 41,230 |
| 2020 | 6,820 | 70 | 340 | 300 | 780 | 0 | 8,310 | 31,020 |
| Cumulative 2013-2020 | 64,420 | 1,630 | 3,150 | 2,200 | 5,480 | 70 | 76,940 | 283,780 |
| Average Annual 2013-2020 | 8,050 | 200 | 390 | 270 | 680 | 10 | 9,620 | 35,470 |

**Source: ICF International. Other Western Canada shale includes smaller shale plays excluding Montney and Horn River. Note that oil well completions are only for conventional and tight oil production, and does not include any wells associated with oil sands production.**

Figure B-4 below shows total gas production from gas wells and oil wells (associated gas production) in Canada. Total gas production is expected to reach nearly 16 Bcfd in 2020, which is a 7.6% increase over 2013 production. This is driven by growth in shale gas particularly in the Montney and Horn River Shales. The growth in shale gas more than offsets the 3.8 Bcfd decline in other sources including Eastern Canada Offshore, CBM, conventional and tight plays. This study forecasts total Canadian gas production to be higher than the NEB's forecast of 11.7 Bcfd by 2020[92] in its 2013 report: Canada's Energy Future.[93] However, NEB's estimate of 2013 production in Canada (13.2 Bcfd) was lower than actual marketable

[91] National Energy Board. "Canada's Energy Future 2013 - Crude Oil Production". NEB, 2013. Available at: https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/ppndcs/pxlprdctn-eng.html

[92] National Energy Board. "Canada's Energy Future 2013 – Natural Gas Production". NEB, 2013. Available at: https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/ppndcs/pxgsprdctn-eng.html

[93] https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/index-eng.html

production in 2013 (14.0 Bcfd).[94,95] Furthermore, the NEB's 2013 forecast is different from this study's forecast due to different assumptions about North American gas demand, gas use for oil sands production, and quality of natural gas resource base in Canada.

**Figure B-4 – Gas Production Outlook**

| Year | Eastern Canada Offshore/ Other | Alberta CBM | Alberta and Saskatchewan Conventional and Tight | Montney Shale | Horn River Shale | British Columbia Conventional and Tight | Other Western Canada Shales | | U.S. | Canada |
|---|---|---|---|---|---|---|---|---|---|---|
| **Gas Production From Gas Wells (Bcfd)** | | | | | | | | | | |
| 2013 | 0.2 | 0.8 | 7.1 | 2.4 | 0.5 | 1.3 | 0.9 | | 56.3 | 13.1 |
| 2020 | 0.1 | 0.5 | 4.1 | 4.5 | 1.5 | 1.0 | 2.7 | | 66.4 | 14.4 |
| **Gas Production From Oil Wells (Bcfd)** | | | | | | | | | | |
| 2013 | 0.0 | 0.0 | 1.6 | 0.0 | 0.0 | 0.1 | 0.0 | | 11.3 | 1.6 |
| 2020 | 0.0 | 0.0 | 1.4 | 0.0 | 0.0 | 0.0 | 0.0 | | 17.9 | 1.5 |
| **Total Gas Production (Bcfd)** | | | | | | | | | | |
| 2013 | 0.2 | 0.8 | 8.6 | 2.4 | 0.5 | 1.4 | 0.9 | | 67.6 | 14.7 |
| 2020 | 0.1 | 0.5 | 5.6 | 4.5 | 1.5 | 1.0 | 2.7 | | 84.3 | 15.9 |

**Source: ICF International. Other Western Canada shale includes smaller shale plays excluding Montney and Horn River.**

Canadian liquids production is expected to increase through 2020 (Figure B-5 below). Western Canada shales are rich in NGL and lease condensates. Alberta and Saskatchewan conventional and tight plays are primarily oil, while shale plays in British Columbia are relatively dry. Liquids production from Canada includes both production from the shale and bitumen production from oil sands. Oil and lease condensate production is anticipated to grow by over 20% from 3.4 MMbpd in 2013 to 4.1 MMbpd by 2020, driven primarily by oil sands production, which is expected to reach 2.9 MMbpd by 2020 from 2 MMbpd in 2013.

This study's forecast of oil production is more conservative than those of CAPP (4.6 MMbpd by 2020[96]) and NEB (4.8 MMbpd by 2020[97]) due to oil price assumptions. NGL production increases by 200 Mbpd. These volumes largely come from Western Canada shales such as the Montney and others. Areas expecting a drop in liquids production include Eastern Canada and conventional plays in Western Canada.

[94] https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/stt/archive/mrktblntrlgsprdctn2013.xls

[95] Note that marketable production does not include pipeline losses and gas use for lease and plant. ICF's production estimate includes total dry gas production, including pipeline losses and lease and plant use.

[96] Canadian Association of Petroleum Producers. "Crude Oil Forecast, Markets & Transportation". CAPP, June 2015. Available at: http://capp.ca/publications-and-statistics/publications/264673

[97] National Energy Board. "Canada's Energy Future 2013 - Crude Oil Production". NEB, 2013. Available at: https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/ppndcs/pxlprdctn-eng.html

**Figure B-5 – Liquids Production Outlook**

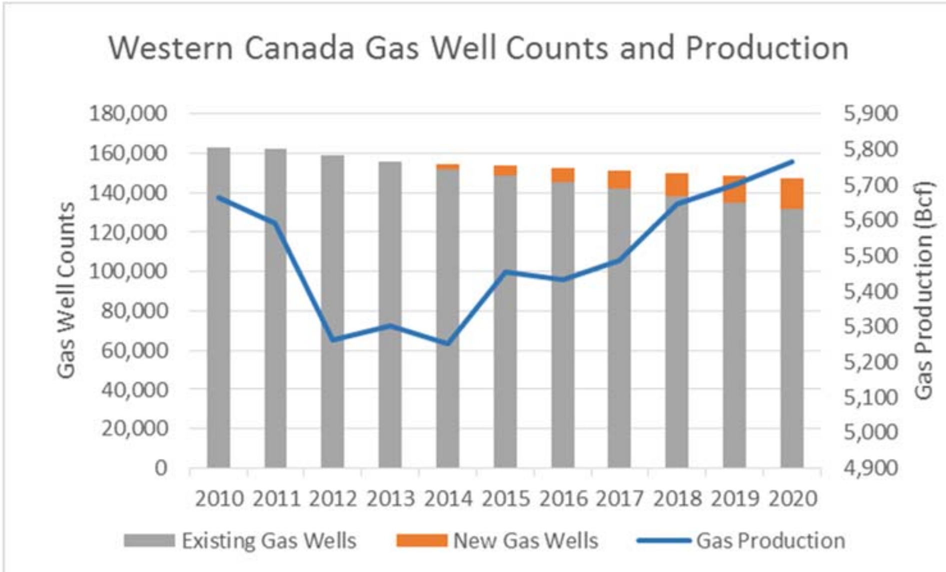
| | Eastern Canada Offshore/ Other | Alberta CBM | Alberta and Saskatchewan Conventional and Tight | Alberta Oil Sands Production | Montney Shale | Horn River Shale | British Columbia Conventional and Tight | Other Western Canada Shales | | U.S. | Canada |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Oil and Lease Condensate Production (MBbl/d)** | | | | | | | | | | | |
| 2013 | 240 | 0 | 1,150 | 2,030 | 10 | 0 | 30 | 190 | | 7,040 | 3,440 |
| 2020 | 210 | 0 | 960 | 2,890 | 10 | 0 | 20 | 520 | | 8,870 | 4,070 |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| **NGL Production (MBbl/d)** | | | | | | | | | | | |
| 2013 | 10 | 0 | 350 | | 140 | 0 | 40 | 100 | | 2,610 | 640 |
| 2020 | 0 | 0 | 220 | | 250 | 0 | 30 | 330 | | 4,880 | 840 |

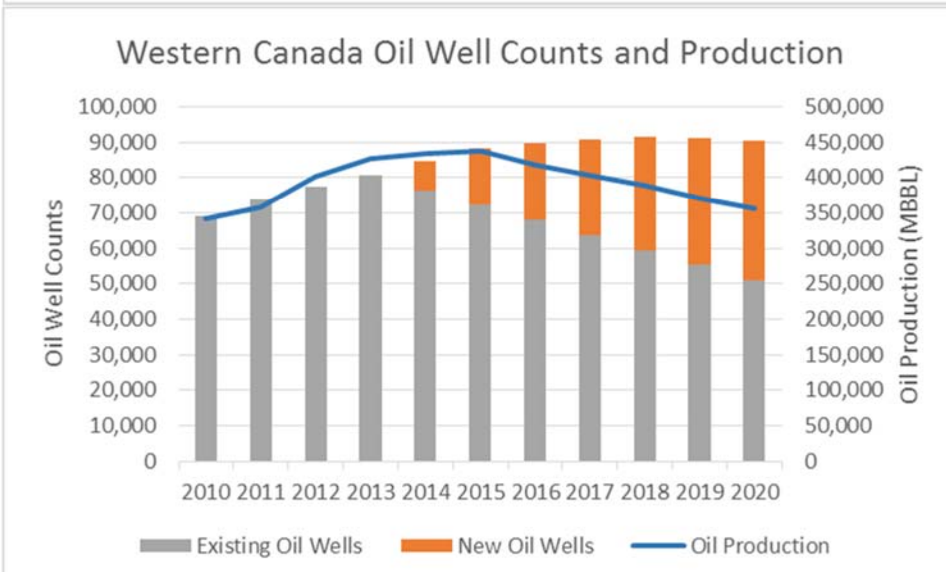
**Source: ICF International. Note that oil sand production is separately listed in the table above.**

## B.4. Summary Tables and Projection Charts for Western Canada

Figure B-6 through Figure B-9 describe ICF's projections from Western Canada in more detail at the provincial level. Total gas wells in Western Canada decline slightly from almost 163,000 wells in 2010 to over 147,000 wells in 2020. However, gas production grows to nearly 5,800 Bcf/year due to higher EUR and well productivity, particularly for production out of British Columbia's shale plays. Figure B-6 shows a 32% increase in conventional oil wells from 67,000 in 2010 to 89,000 in 2020. Despite this increase in well counts, producers are running out of sweet spots and facing lower oil well productivity, and therefore, conventional oil production is expected to decrease to approximately 356,000 Mbbl by 2020. Oil production is also impacted by lower oil prices, which reduces the incentives for growth in oil production. Note that production of oil (bitumen) from oil sands is excluded in all of the figures below.

**Figure B-6 - Western Canadian Oil and Gas Well Count and Production Projections**

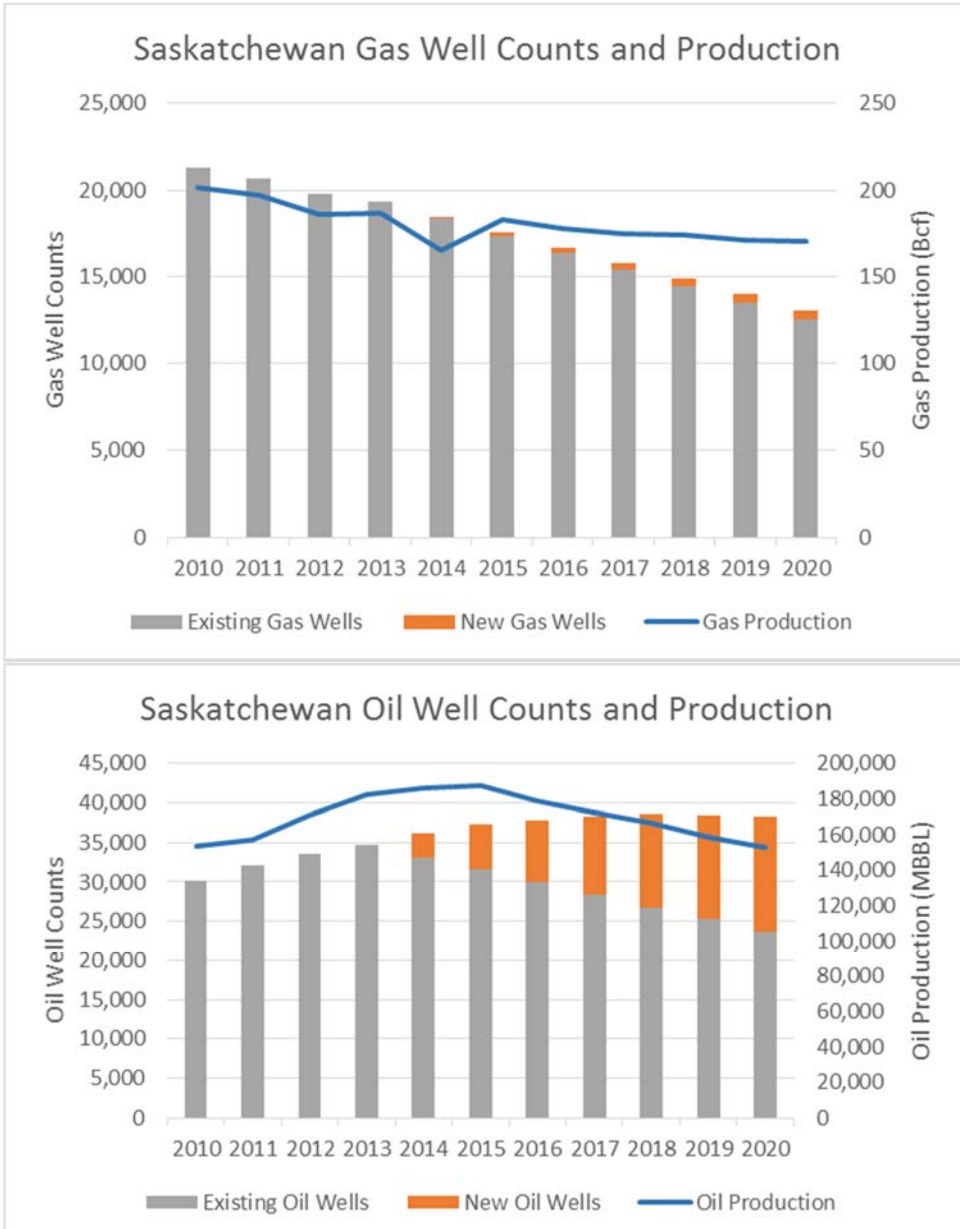



**Source: Canadian GMM Model Well Count and Production Predictions. Does not include oil sands production.**

Saskatchewan is not a major gas producer, and most of the production is from conventional wells. Gas production follows the decline in gas well count over the next 5 years. This study does not anticipate significant new well drilling and completions in the province, although the new wells have slightly higher productivity due to technology improvements. The province is expected to produce 170 Bcf of gas by 2020, with gas well counts declining to roughly 13,000 wells by 2020. Conventional oil production is expected to peak at around 187,000 Mbbl in 2015, and decline thereafter due to decreased drilling activity as well as decline in EURs (as new wells have to be drilled in less productive areas).

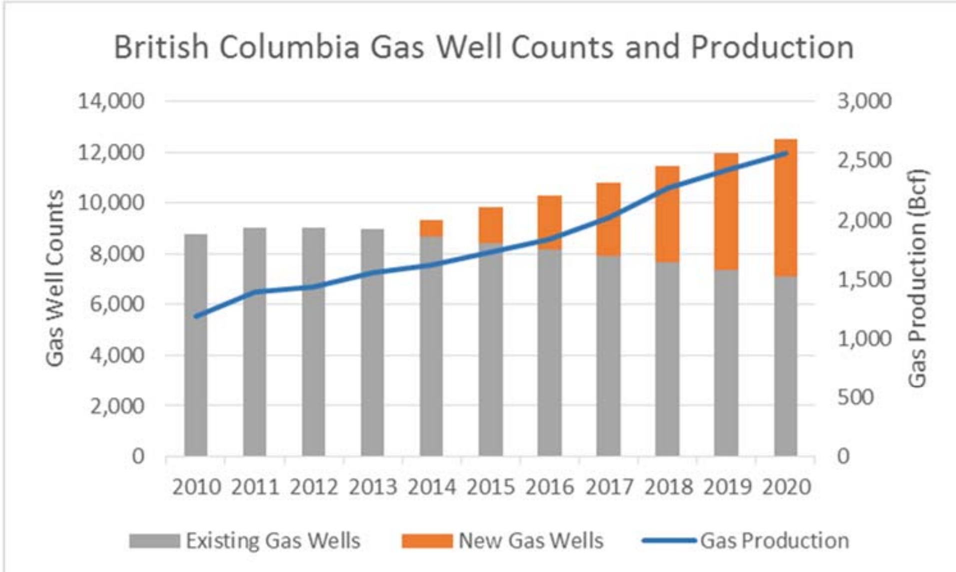
**Figure B-7 - Saskatchewan Oil and Gas Well Count and Production Projections**

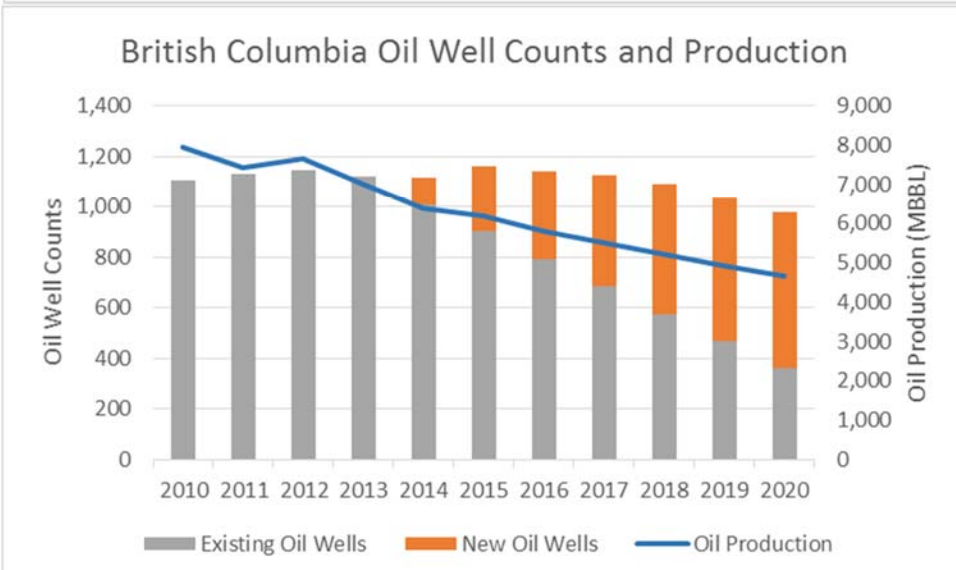



**Source: Canadian GMM Model Well Count and Production Predictions**

British Columbia becomes a larger gas producer in Western Canada, driven by growth in shale plays including the Montney and Horn River/Liard. Production in this area replaces the declining production in Alberta and Saskatchewan. Gas well completions rise to about 12,000 wells, pushing gas production to approximately 2,600 Bcf per year. Furthermore, given that the Montney and Horn River plays are relatively new, this study anticipates greater technology learning effect, such that the average EUR is expected to grow over time. Conventional oil production in the province is expected to decrease over the next 5 years due to lower oil prices, and decline in productivity.

**Figure B-8 - British Columbia Oil and Gas Well Count and Production Projections**

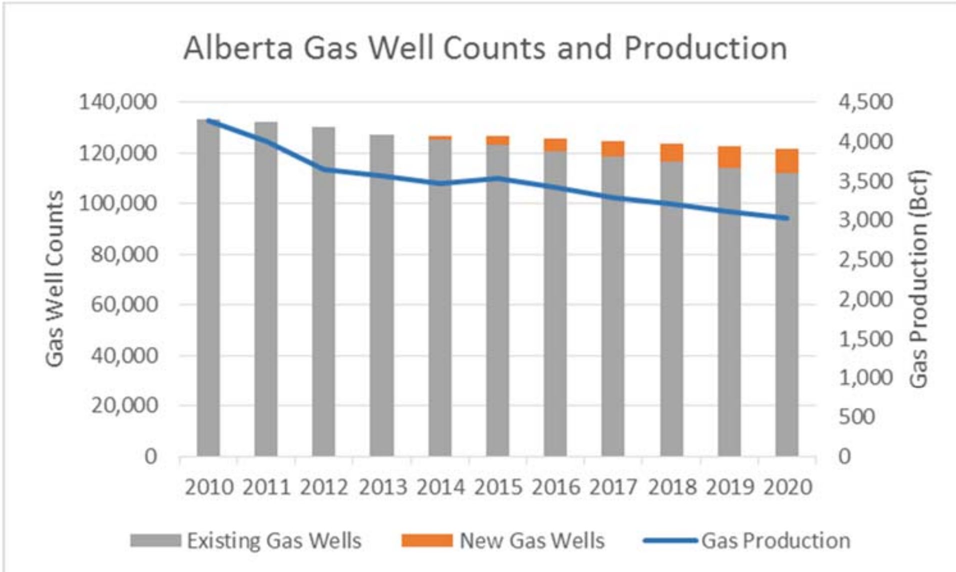


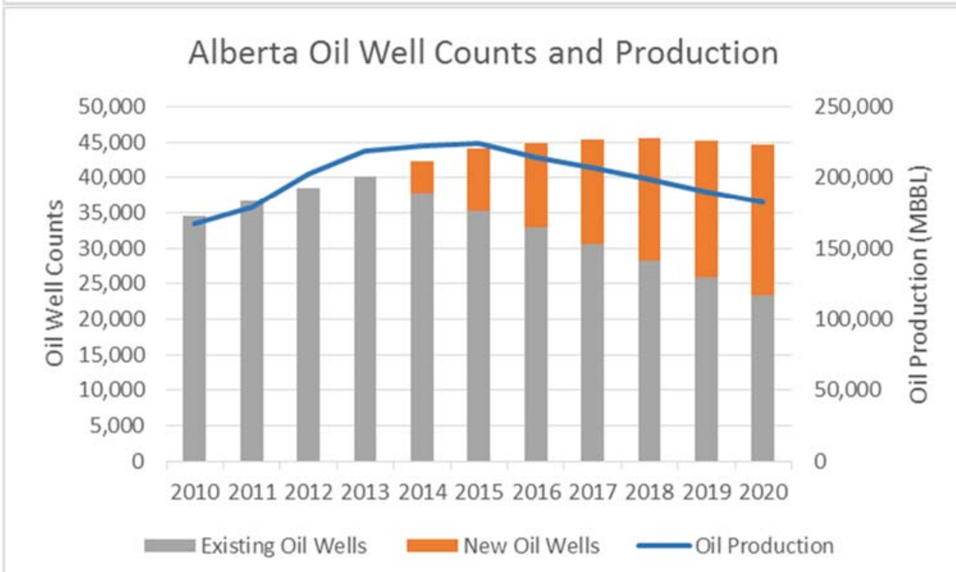




**Source: Canadian GMM Model Well Count and Production Predictions**

Gas production in Alberta declines to approximately 3,000 Bcf by 2020 due to decrease in conventional gas production in the province. The best areas in the conventional plays are already drilled, and the EURs for future wells are expected to decline. Furthermore, increased production from British Columbia's shale plays will limit the growth in Alberta. Therefore, both production and well counts for natural gas are expected to decline. In terms of oil production, conventional production in the province peaks in 2015 and then declines to around 180 million bbls by 2020. Lower oil prices and declining resource productivity result in a flattening total oil well count, but a declining production.

**Figure B-9 - Alberta Oil and Gas Well Count and Production Projections**




**Source: Canadian GMM Model Well Count and Production Predictions**

# Appendix C. Additional Tables and Figures

Additional sensitivity MAC curves for Canada, Alberta, and British Columbia, are developed below, with accompanying tables of top emissions sources within each province. When applicable, these curves only address the upstream segments (production, gathering and process – transmission and distribution are not included. For the subsequent figures, all MAC curves reflect baseline MAC parameters unless otherwise specified. For example, baseline MAC parameters are in Canadian dollars and are set at $5 CAD / Mcf natural gas price and 100-yr GWP at 25.

**Figure C-1 – Total Canadian MAC Curve with 20-Yr GWP in $CO_2e$**

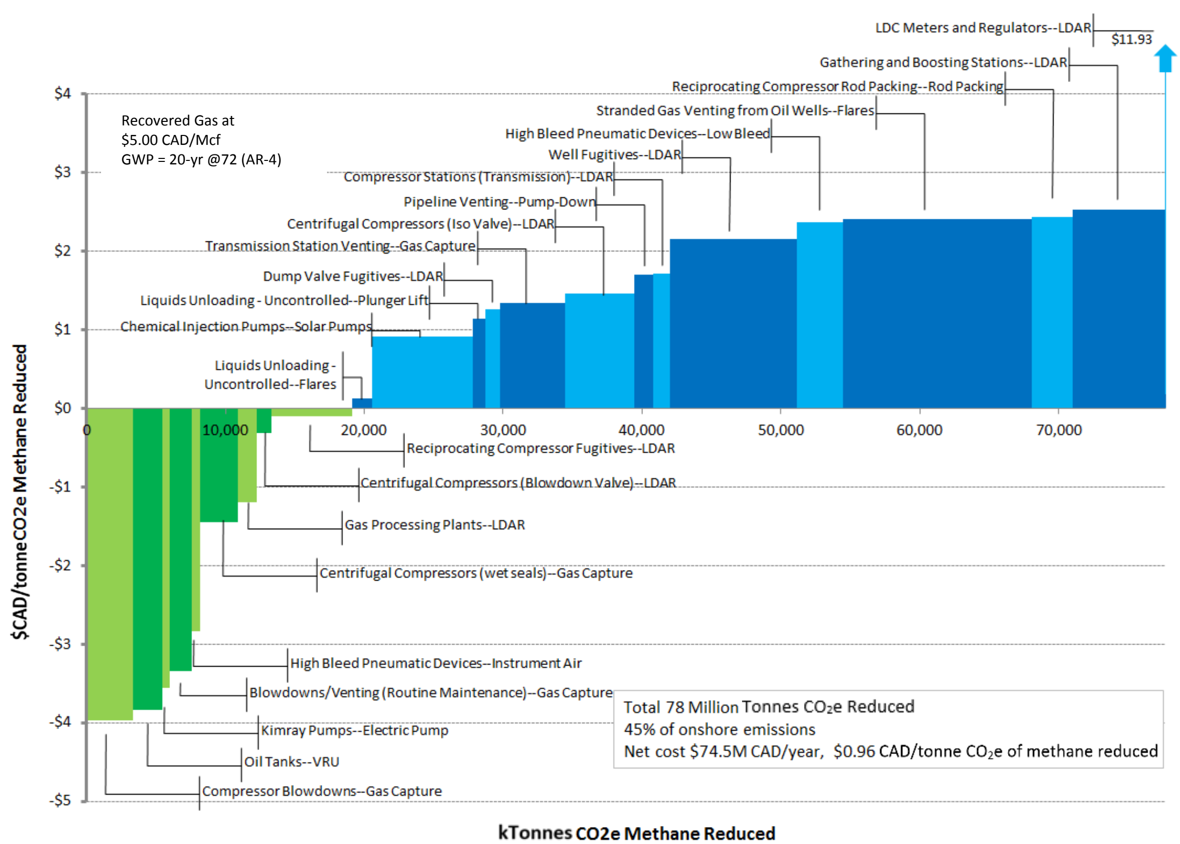


**Figure C-2 – Alberta Upstream MAC Curve with 100-yr GWP in $CO_2e$**

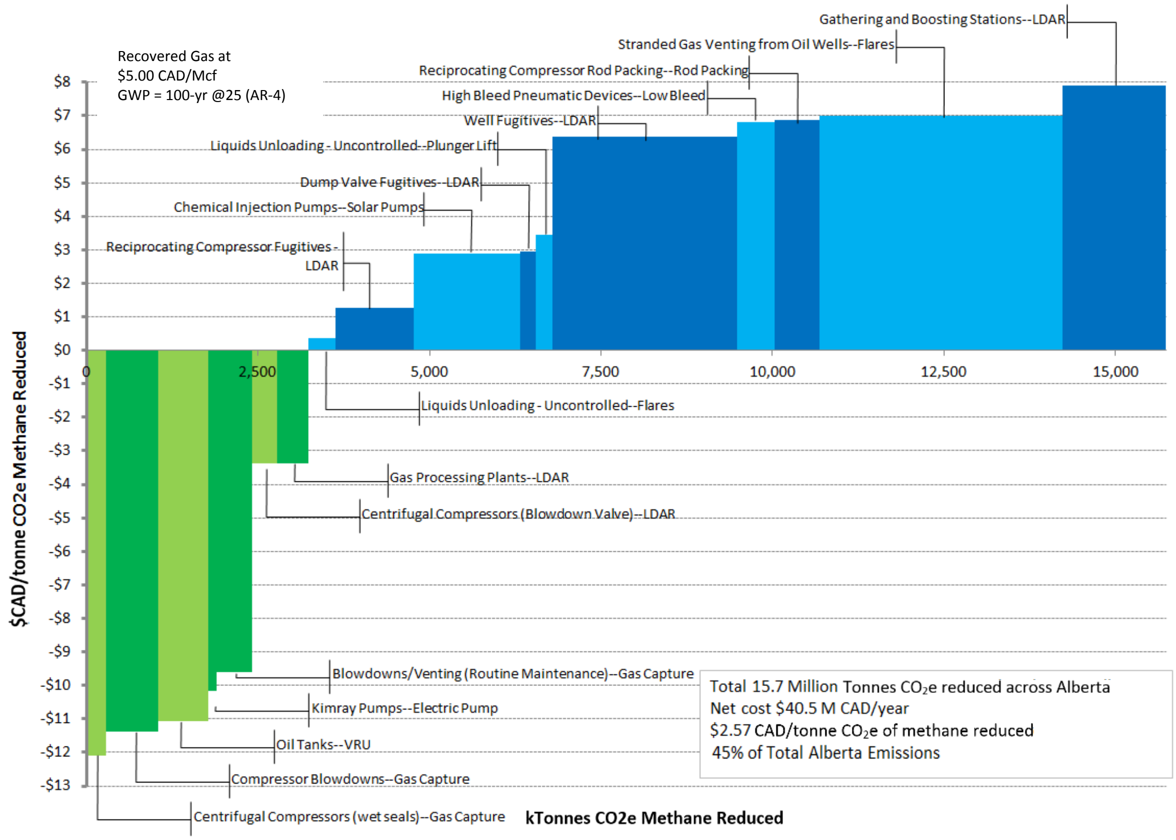


**Figure C-3 – Alberta Upstream MAC Curve with 20-yr GWP in $CO_2e$**

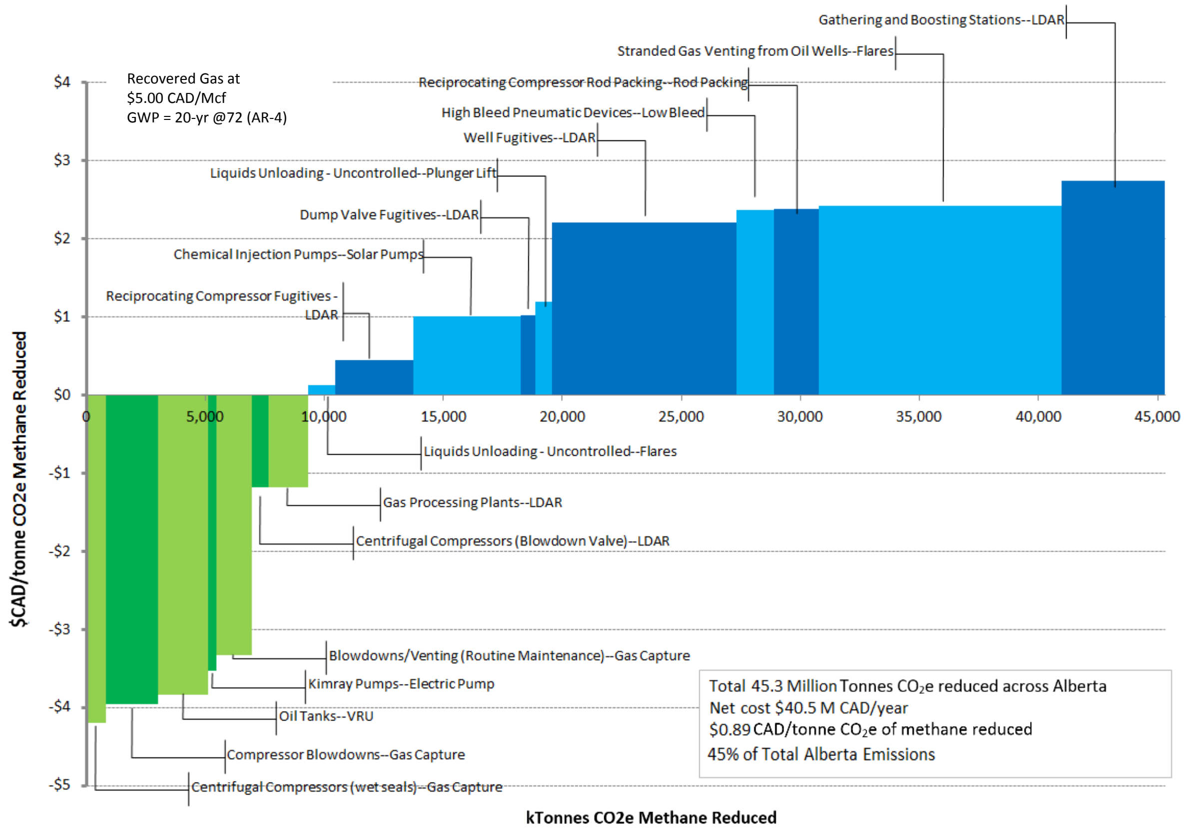


**Figure C-4 – Alberta Upstream MAC Curve for Baseline Technology Assumptions in Bcf**

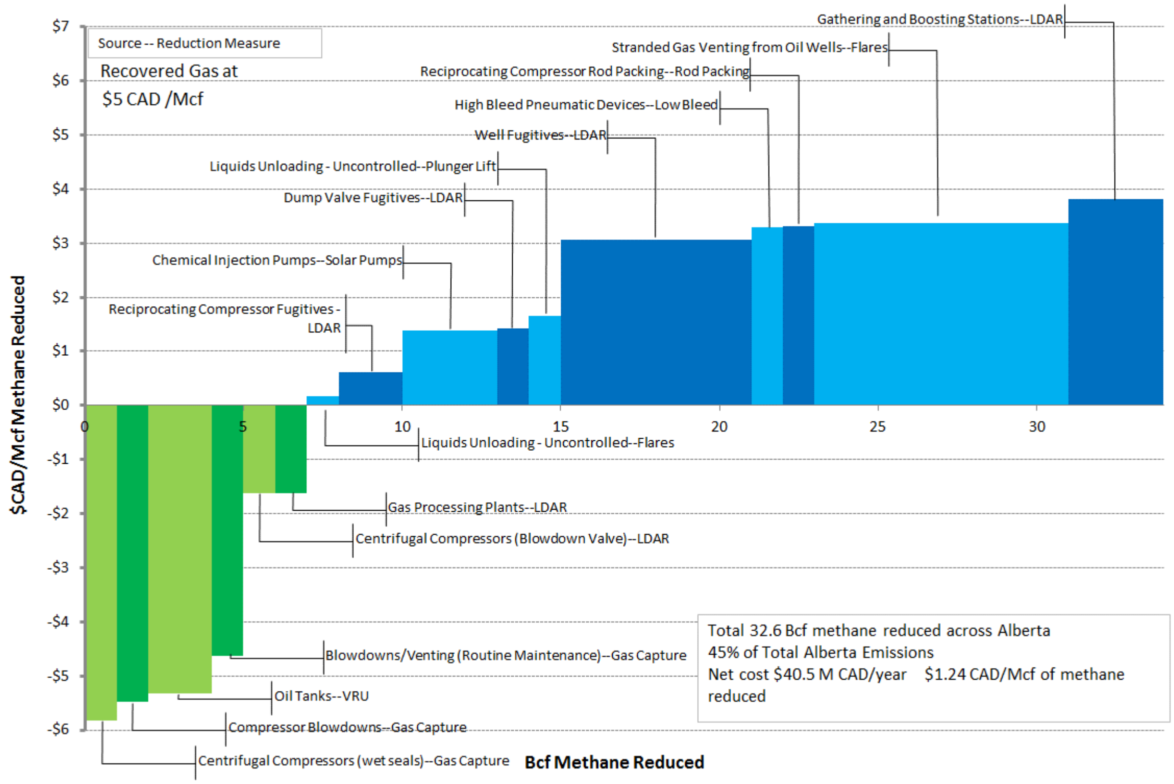


**Table C-1- Top 80% Emitting Onshore Methane Source Categories in 2020 for Alberta Upstream**

| Segment | Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|---|
| Oil Production | Stranded Gas Venting from Oil Wells | Vented | 9.4 | 12.8% | 9.4 | 13% |
| Gathering and Boosting | Gathering and Boosting Stations | Fugitive | 5.2 | 7.2% | 14.6 | 20% |
| Gas Production | Chemical Injection Pumps | Vented | 5.0 | 6.8% | 19.6 | 27% |
| Gas Production | Liquids Unloading - Wells w/ Plunger Lifts | Vented | 4.1 | 5.6% | 23.7 | 32% |
| Gathering and Boosting | Reciprocating Compressors-Seals - Uncontrolled | Vented | 3.7 | 5.1% | 27.4 | 37% |
| Gathering and Boosting | Compressor Blowdowns - Uncontrolled | Vented | 3.3 | 4.5% | 30.7 | 42% |
| Gas Processing | Sweet Reciprocating Compressors-Seals - Uncontrolled | Vented | 2.8 | 3.8% | 33.4 | 46% |
| Gas Production | Meters/Piping | Fugitive | 2.6 | 3.6% | 36.0 | 49% |
| Gas Production | Well Head Fugitives | Fugitive | 2.5 | 3.4% | 38.5 | 53% |
| Gas Processing | Sweet Blowdowns/Venting (Routine Maintenance) | Vented | 2.2 | 3.0% | 40.7 | 56% |
| Gas Production | Separators | Fugitive | 2.0 | 2.7% | 42.7 | 58% |
| Oil Production | Oil Tanks - SAGD Uncontrolled | Vented | 1.8 | 2.5% | 44.5 | 61% |
| Gas Production | Liquids Unloading - Uncontrolled | Vented | 1.7 | 2.3% | 46.2 | 63% |
| Gas Production | Low Bleed Pneumatic Devices | Vented | 1.7 | 2.3% | 47.9 | 65% |
| Gas Processing | Sweet Blowdown Valve Operating - Venting | Fugitive | 1.6 | 2.2% | 49.5 | 68% |
| Gas Processing | Sweet Gas Processing Plants | Fugitive | 1.6 | 2.2% | 51.1 | 70% |
| Oil Production | Oil Tanks | Vented | 1.4 | 1.9% | 52.5 | 72% |
| Gas Production | Intermittent Bleed Pneumatic Devices - Dump Valves | Vented | 1.3 | 1.7% | 53.8 | 74% |
| Gas Production | High Bleed Pneumatic Devices | Vented | 1.1 | 1.6% | 54.9 | 75% |
| Gas Production | Dump Valve Venting | Fugitive | 1.1 | 1.5% | 56.0 | 77% |
| Gathering and Boosting | Isolation Valve - Venting | Fugitive | 0.9 | 1.2% | 56.9 | 78% |
| Gas Production | Heaters | Fugitive | 0.9 | 1.2% | 57.8 | 79% |
| Gas Processing | Sweet Centrifugal Compressors (Blowdown Valve) | Fugitive | 0.8 | 1.1% | 58.6 | 80% |

**Figure C-5 - Distribution of Upstream Emission Reduction Potential in Alberta**

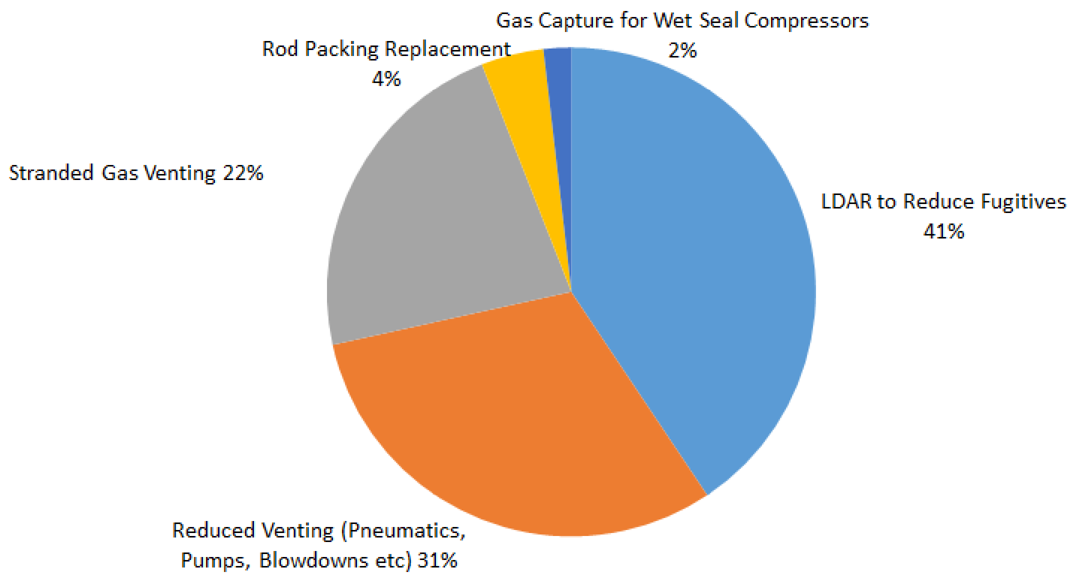


**Figure C-6 – British Columbia Upstream MAC Curve with 100-yr GWP in $CO_2e$**

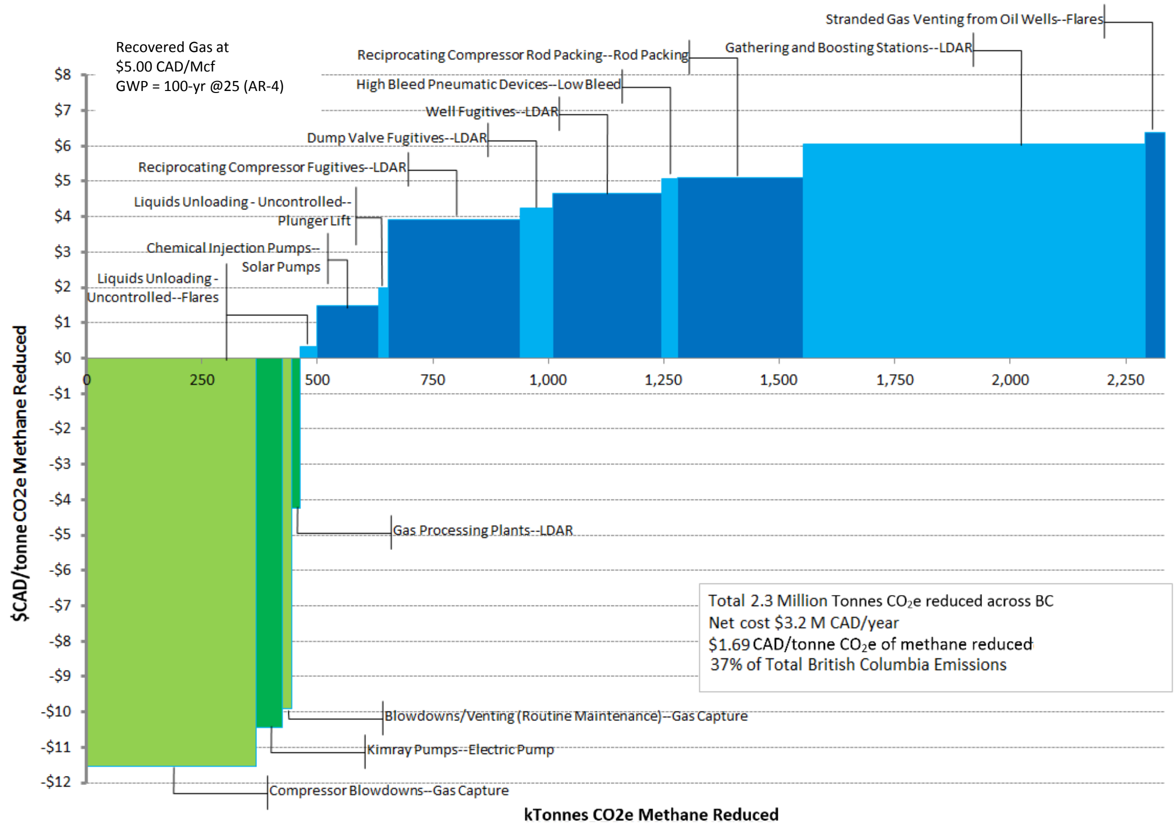


**Figure C-7 – British Columbia Upstream MAC Curve with 20-yr GWP in $CO_2e$**

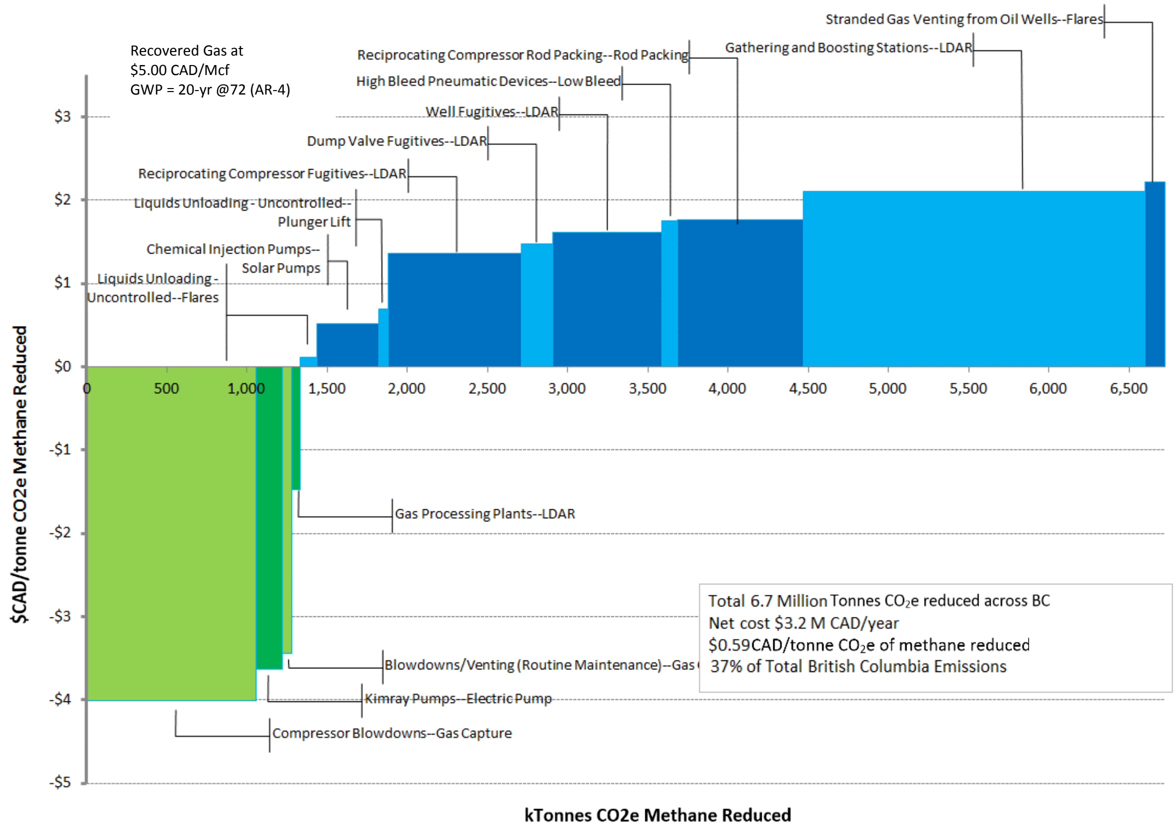


**Figure C-8 – British Columbia Upstream MAC Curve for Baseline Technology Assumptions in Bcf**

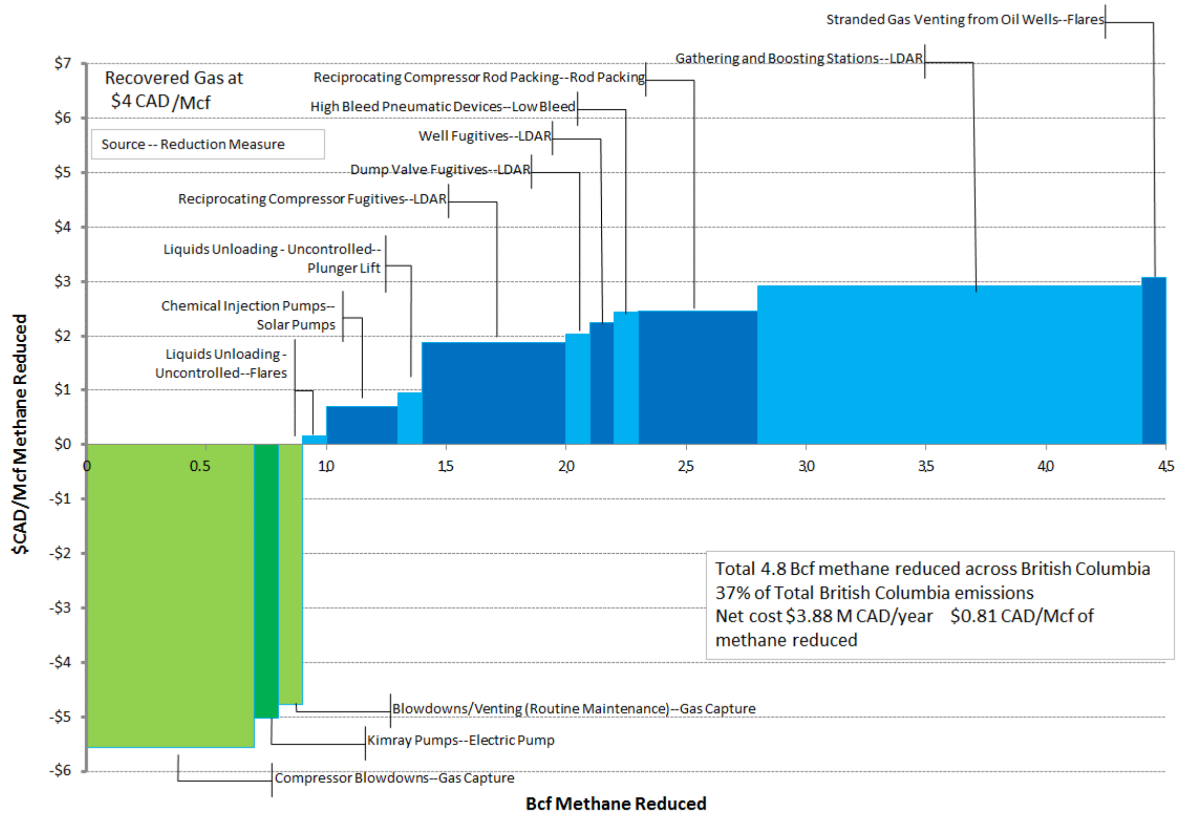
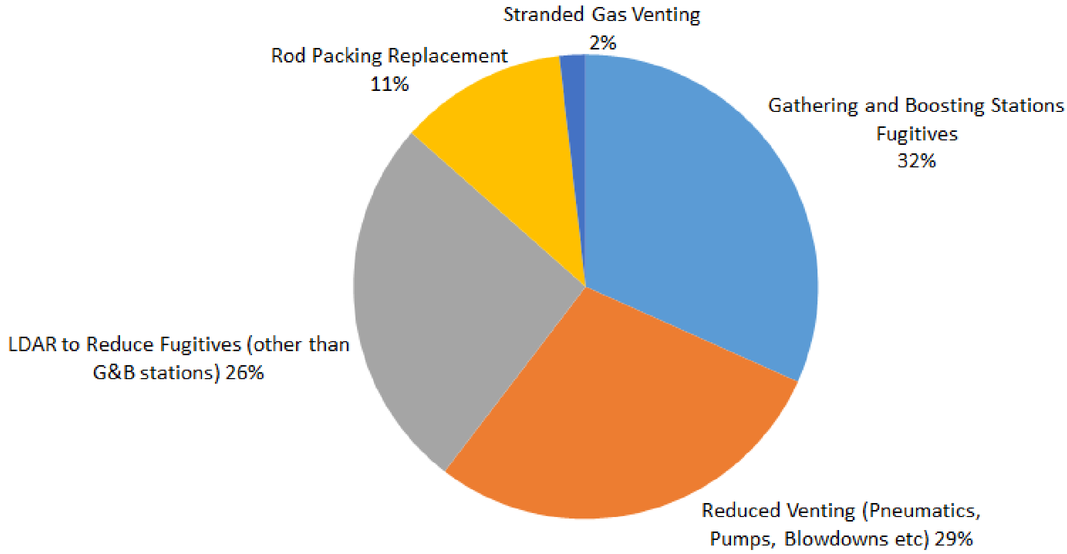


**Table C-2- Top 80% Emitting Onshore Methane Source Categories in 2020 for British Columbia Upstream**

| Segment | Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|---|
| Gathering and Boosting | Gathering and Boosting Stations | Fugitive | 2.6 | 20.4% | 2.6 | 20% |
| Gathering and Boosting | Reciprocating Compressors-Seals - Uncontrolled | Vented | 1.8 | 14.5% | 4.4 | 35% |
| Gathering and Boosting | Compressor Blowdowns - Uncontrolled | Vented | 1.6 | 12.8% | 6.0 | 48% |
| Gathering and Boosting | Compressor Exhaust (Gas Engines) | Combusted | 0.5 | 3.8% | 6.5 | 52% |
| Gas Production | Chemical Injection Pumps | Vented | 0.5 | 3.6% | 6.9 | 55% |
| Gathering and Boosting | Isolation Valve - Venting | Fugitive | 0.4 | 3.5% | 7.4 | 59% |
| Gathering and Boosting | Gathering and Boosting Stations | Fugitive | 0.4 | 3.4% | 7.8 | 62% |
| Gas Production | Liquids Unloading - Wells w/ Plunger Lifts | Vented | 0.4 | 3.0% | 8.2 | 65% |
| Gathering and Boosting | Blowdown Valve Standby - Venting | Fugitive | 0.3 | 2.6% | 8.5 | 68% |
| Gathering and Boosting | Compressor Exhaust (Gas Engines) | Combusted | 0.3 | 2.1% | 8.8 | 70% |
| Gathering and Boosting | Scrubber Dump Valves | Fugitive | 0.2 | 1.8% | 9.0 | 72% |
| Gas Production | Well Head Fugitives | Fugitive | 0.2 | 1.8% | 9.2 | 73% |
| Gas Production | Meters/Piping | Fugitive | 0.2 | 1.6% | 9.4 | 75% |
| Gas Production | Separators | Fugitive | 0.2 | 1.4% | 9.6 | 76% |
| Gas Production | Low Bleed Pneumatic Devices | Vented | 0.2 | 1.3% | 9.8 | 78% |
| Gathering and Boosting | Kimray Pumps | Vented | 0.2 | 1.3% | 9.9 | 79% |
| Gas Production | Liquids Unloading - Uncontrolled | Vented | 0.2 | 1.2% | 10.1 | 80% |

Figure C-9 - Distribution of Upstream Emission Reduction Potential in British Columbia




The tables below present Canada segment breakdowns of emissions across all segments.

Table C-3- Top 80% Emitting Methane Source Categories in 2020 for Gas Production

| Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|
| Chemical Injection Pumps | Vented | 5.0 | 14.9% | 5.0 | 15% |
| Liquids Unloading - Wells w/ Plunger Lifts | Vented | 4.1 | 12.2% | 9.1 | 27% |
| Meters/Piping | Fugitive | 2.6 | 7.8% | 11.7 | 35% |
| Well Head Fugitives | Fugitive | 2.5 | 7.4% | 14.1 | 42% |
| Chemical Injection Pumps | Vented | 2.2 | 6.7% | 16.4 | 49% |
| Separators | Fugitive | 2.0 | 5.9% | 18.3 | 55% |
| Liquids Unloading - Uncontrolled | Vented | 1.7 | 5.0% | 20.0 | 60% |
| Low Bleed Pneumatic Devices | Vented | 1.7 | 5.0% | 21.7 | 65% |
| Intermittent Bleed Pneumatic Devices - Dump Valves | Vented | 1.3 | 3.8% | 23.0 | 69% |
| High Bleed Pneumatic Devices | Vented | 1.1 | 3.4% | 24.1 | 72% |
| Dump Valve Venting | Fugitive | 1.1 | 3.4% | 25.2 | 76% |
| Heaters | Fugitive | 0.9 | 2.6% | 26.1 | 78% |
| Chemical Injection Pumps | Vented | 0.5 | 1.4% | 26.5 | 79% |

| Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|
| Intermittent Bleed Pneumatic Devices | Vented | 0.4 | 1.3% | 27.0 | 81% |

**Table C-4- Top 80% Emitting Methane Source Categories in 2020 for Oil Production**

| Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|
| Stranded Gas Venting from Oil Wells | Vented | 9.4 | 37.7% | 9.4 | 38% |
| Stranded Gas Venting from Oil Wells | Vented | 2.7 | 10.7% | 12.1 | 48% |
| Oil Tanks - SAGD Uncontrolled | Vented | 1.8 | 7.3% | 13.9 | 56% |
| Oil Tanks | Vented | 1.4 | 5.6% | 15.3 | 61% |
| Low Bleed Pneumatic Devices | Vented | 1.3 | 5.1% | 16.5 | 66% |
| Intermittent Bleed Pneumatic Devices - Dump Valves | Vented | 1.1 | 4.5% | 17.7 | 71% |
| High Bleed Pneumatic Devices | Vented | 0.8 | 3.1% | 18.4 | 74% |
| Low Bleed Pneumatic Devices | Vented | 0.7 | 2.7% | 19.1 | 77% |
| Chemical Injection Pumps | Vented | 0.5 | 2.1% | 19.6 | 79% |
| Intermittent Bleed Pneumatic Devices - Dump Valves | Vented | 0.5 | 1.9% | 20.1 | 81% |

**Table C-5- Top 80% Emitting Methane Source Categories in 2020 for Gathering and Boosting**

| Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|
| Gathering and Boosting Stations | Fugitive | 5.2 | 19.2% | 5.2 | 19% |
| Reciprocating Compressors-Seals - Uncontrolled | Vented | 3.7 | 13.6% | 8.9 | 33% |
| Compressor Blowdowns - Uncontrolled | Vented | 3.3 | 12.1% | 12.2 | 45% |
| Gathering and Boosting Stations | Fugitive | 2.6 | 9.4% | 14.8 | 54% |
| Reciprocating Compressors-Seals - Uncontrolled | Vented | 1.8 | 6.7% | 16.6 | 61% |
| Compressor Blowdowns - Uncontrolled | Vented | 1.6 | 5.9% | 18.2 | 67% |
| Isolation Valve - Venting | Fugitive | 0.9 | 3.3% | 19.1 | 70% |
| Compressor Exhaust (Gas Engines) | Combusted | 0.7 | 2.7% | 19.9 | 73% |

| Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|
| Blowdown Valve Standby - Venting | Fugitive | 0.7 | 2.5% | 20.5 | 75% |
| Gathering and Boosting Stations | Fugitive | 0.6 | 2.1% | 21.1 | 77% |
| Compressor Exhaust (Gas Engines) | Combusted | 0.5 | 1.8% | 21.6 | 79% |
| Scrubber Dump Valves | Fugitive | 0.5 | 1.7% | 22.0 | 81% |

Table C-6- Top 80% Emitting Methane Source Categories in 2020 for Gas Processing

| Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|
| Sweet Reciprocating Compressors-Seals - Uncontrolled | Vented | 2.8 | 19.0% | 2.8 | 19% |
| Sweet Blowdowns/Venting (Routine Maintenance) | Vented | 2.2 | 15.4% | 5.0 | 34% |
| Sweet Blowdown Valve Operating - Venting | Fugitive | 1.6 | 11.3% | 6.6 | 46% |
| Sweet Gas Processing Plants | Fugitive | 1.6 | 10.9% | 8.2 | 57% |
| Sweet Centrifugal Compressors (Blowdown Valve) | Fugitive | 0.8 | 5.7% | 9.0 | 62% |
| Sweet Compressor Exhaust (Gas Engines) | Combusted | 0.7 | 5.1% | 9.8 | 67% |
| Sweet Centrifugal Compressors (wet seals) - Uncontrolled | Vented | 0.7 | 4.8% | 10.5 | 72% |
| Sweet AGR Vents | Vented | 0.6 | 4.3% | 11.1 | 76% |
| Sweet Centrifugal Compressors (Iso Valve) | Fugitive | 0.5 | 3.1% | 11.5 | 80% |

Table C-7- Top 80% Emitting Methane Source Categories in 2020 for Gas Transmission

| Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|
| Centrifugal Compressors (Iso Valve) | Fugitive | 5.5 | 32.1% | 5.5 | 32% |
| Transmission Station Venting | Vented | 3.5 | 20.7% | 9.0 | 53% |
| Pipeline Venting (Routine Maintenance/Upsets) | Vented | 1.6 | 9.2% | 10.6 | 62% |

| Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|
| Compressor Stations (Transmission) | Fugitive | 1.4 | 8.5% | 12.0 | 70% |
| Centrifugal Compressors (wet seals) - Uncontrolled | Vented | 1.4 | 8.1% | 13.4 | 79% |
| M&R (Trans. Co. Interconnect) | Fugitive | 0.6 | 3.8% | 14.0 | 82% |

Table C-8- Top 80% Emitting Methane Source Categories in 2020 for Gas Distribution

| Source | Emissions Type | 2020 Emissions (Bcf) | Percent of Total | Cumulative Bcf | Cumulative % |
|---|---|---|---|---|---|
| Residential | Fugitive | 0.8 | 33.6% | 0.8 | 34% |
| Mishaps (Dig-ins) | Vented | 0.3 | 12.1% | 1.2 | 46% |
| Mains - Unprotected steel | Fugitive | 0.3 | 11.4% | 1.4 | 57% |
| Mains - Protected steel | Fugitive | 0.3 | 11.0% | 1.7 | 68% |
| Mains - Cast Iron | Fugitive | 0.2 | 8.4% | 1.9 | 77% |
| M&R 100-300 | Fugitive | 0.1 | 4.3% | 2.0 | 81% |

A provincial breakdown of upstream emissions across Canada in 2013 and 2020 is provided below.

Figure C-10 – Canadian Provincial Methane Emissions Breakdown in 2013

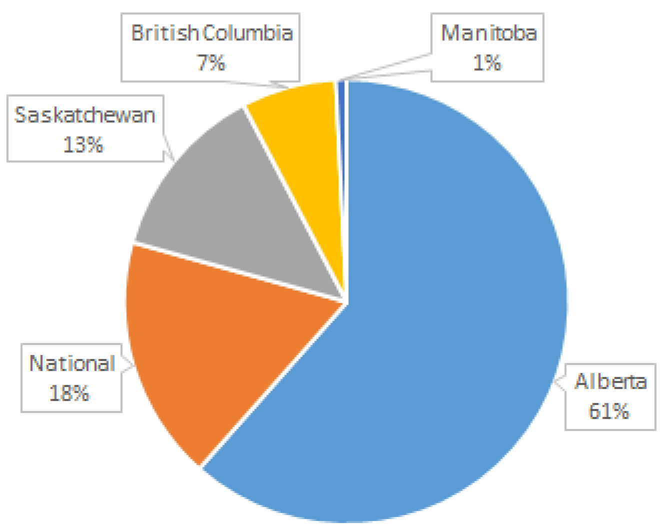


Figure C-11 – Canadian Provincial Methane Emissions Breakdown in 2020

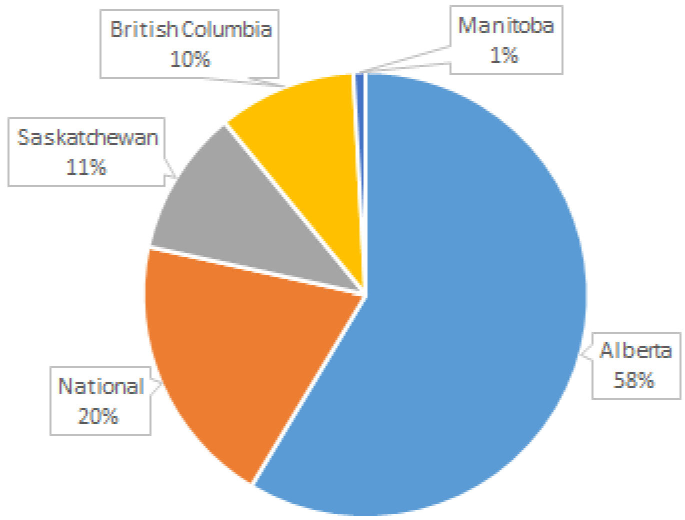



Table C-9 – Baseline Inventory Simple Payback Table for Select Mitigation Technologies

| Mitigation Technology | Simple Payback Period[98] |
|---|---|
| Early replacement of high-bleed devices with low-bleed devices | 6.6 |
| Replacement of Reciprocating Compressor Rod Packing Systems | 3.4 |
| Install Flares-Stranded Gas Venting | 2.6 |
| Install Flares-Portable | 0.1 |
| Install Plunger Lift Systems in Gas Wells | 6.0 |
| Install Vapor Recovery Units | 1.3 |
| LDAR Wells | 5.4 |
| LDAR Gathering | 11.2 |
| LDAR Processing | 0.9 |
| LDAR Transmission | 0.3 |
| Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps | 5.9 |
| Replace Kimray Pumps with Electric Pumps | 0.5 |

[98] Simple Payback Calculated as: Taking the initial investment costs dividing by the annual cash flow (cost). The payback period is measured in years and represents the time to recover the initial investment.

| Mitigation Technology | Simple Payback Period[98] |
|---|---|
| Wet Seal Degassing Recovery System for Centrifugal Compressors | 0.1 |
| Wet Seal Retrofit to Dry Seal Compressor | 0.6 |
| Blowdown Capture and Route to Fuel System (per Compressor) | 2.6 |
| Blowdown Capture and Route to Fuel System (per Plant) | 1.0 |
| Replace with Instrument Air Systems - Intermittent | 2.1 |
| Replace with Instrument Air Systems - High Bleed | 0.8 |

**Figure C-12 – Total Canadian MAC Curve with $3.75 CAD/Mcf Natural Gas Price**

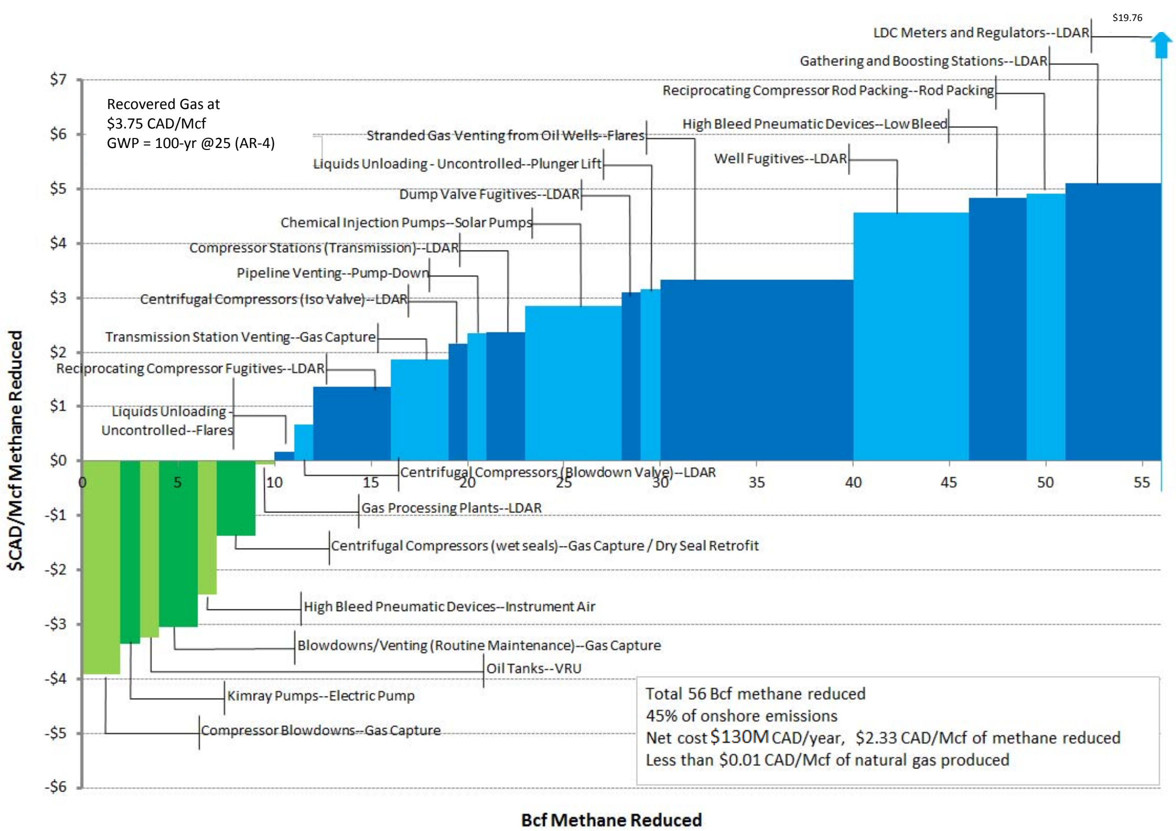


**Figure C-13 – Total Canadian MAC Curve with $6.25 CAD/Mcf Natural Gas Price**

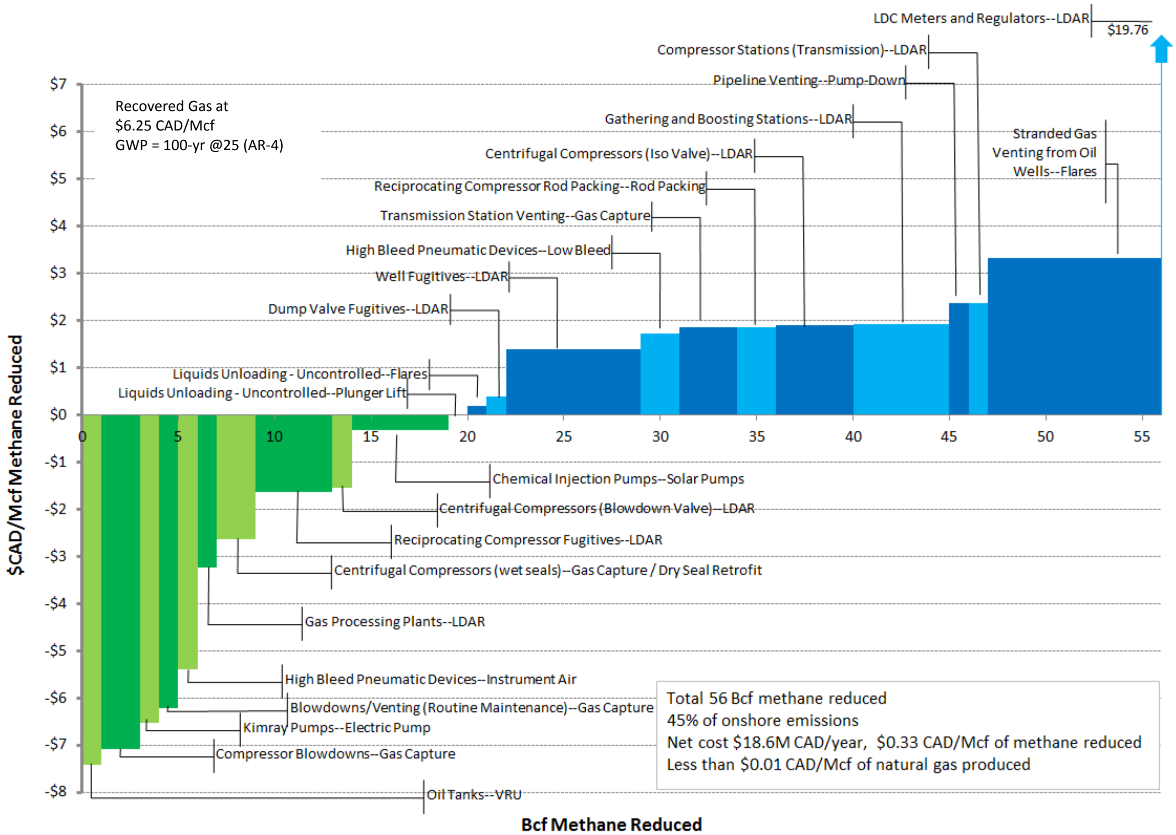


**Figure C-14 – Total Canadian MAC Curve with Base Parameters in Bcf**

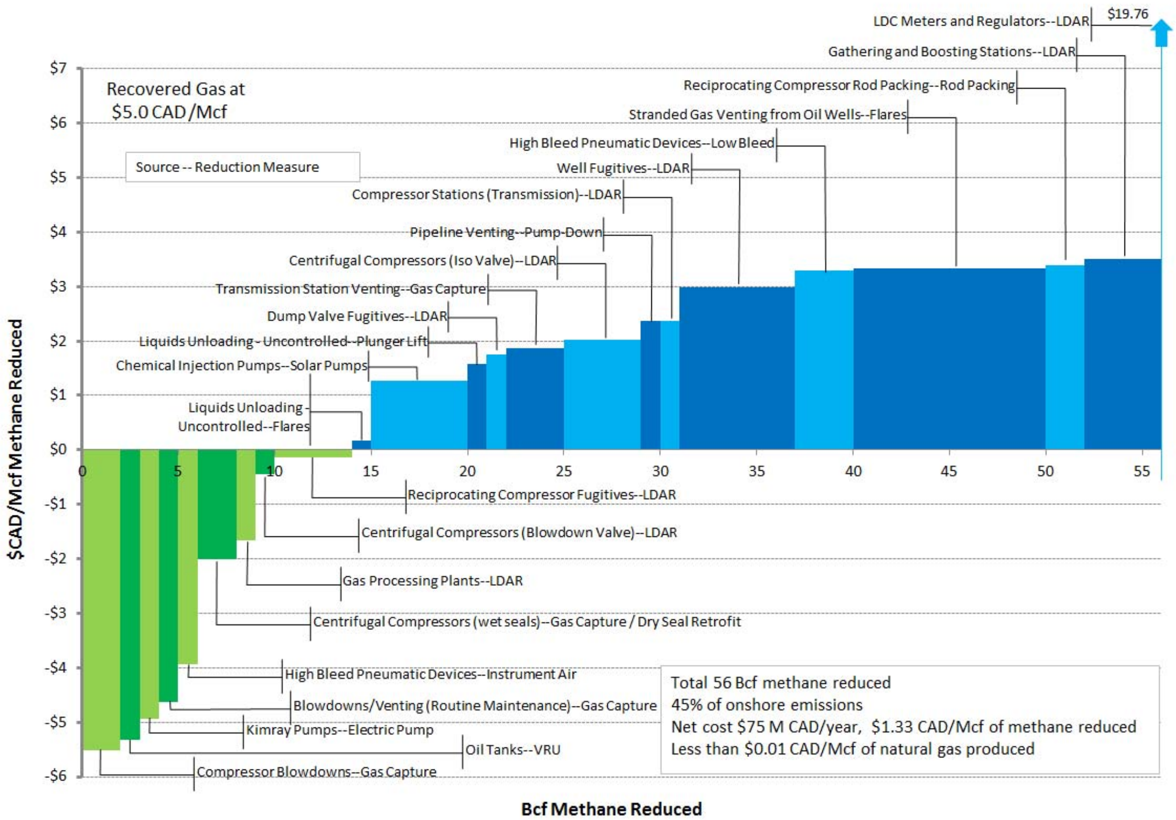
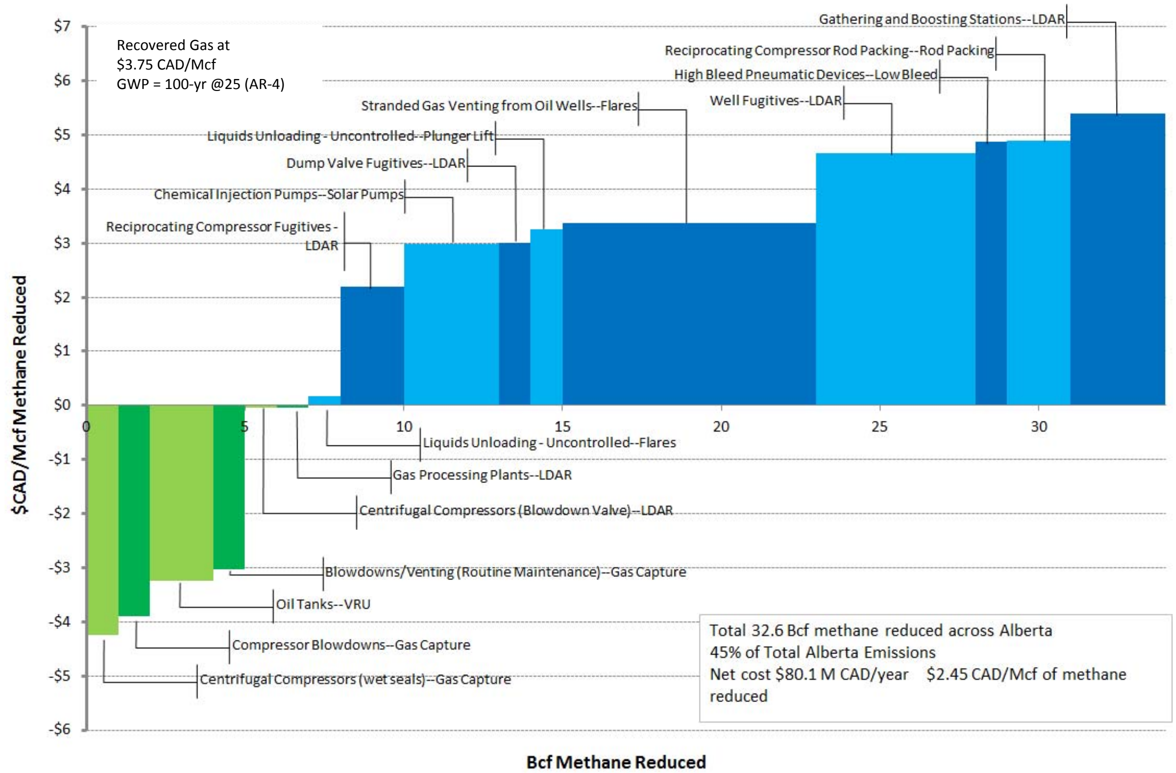
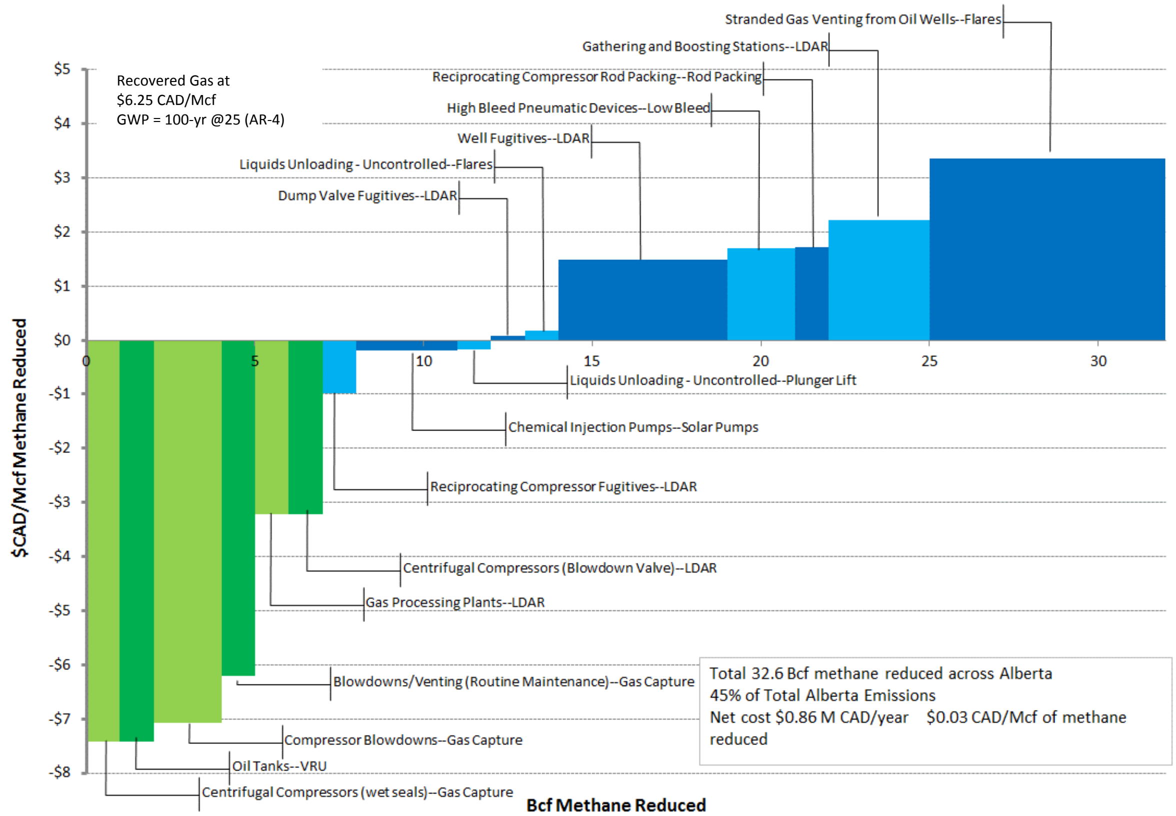


**Figure C-15 – Alberta Upstream MAC Curve with $3.75 CAD/Mcf Natural Gas Price**



### Figure C-16 – Alberta Upstream MAC Curve with $6.25 CAD/Mcf Natural Gas Price



## Figure C-17 – British Columbia Upstream MAC Curve with $3.75 CAD/Mcf Natural Gas Price

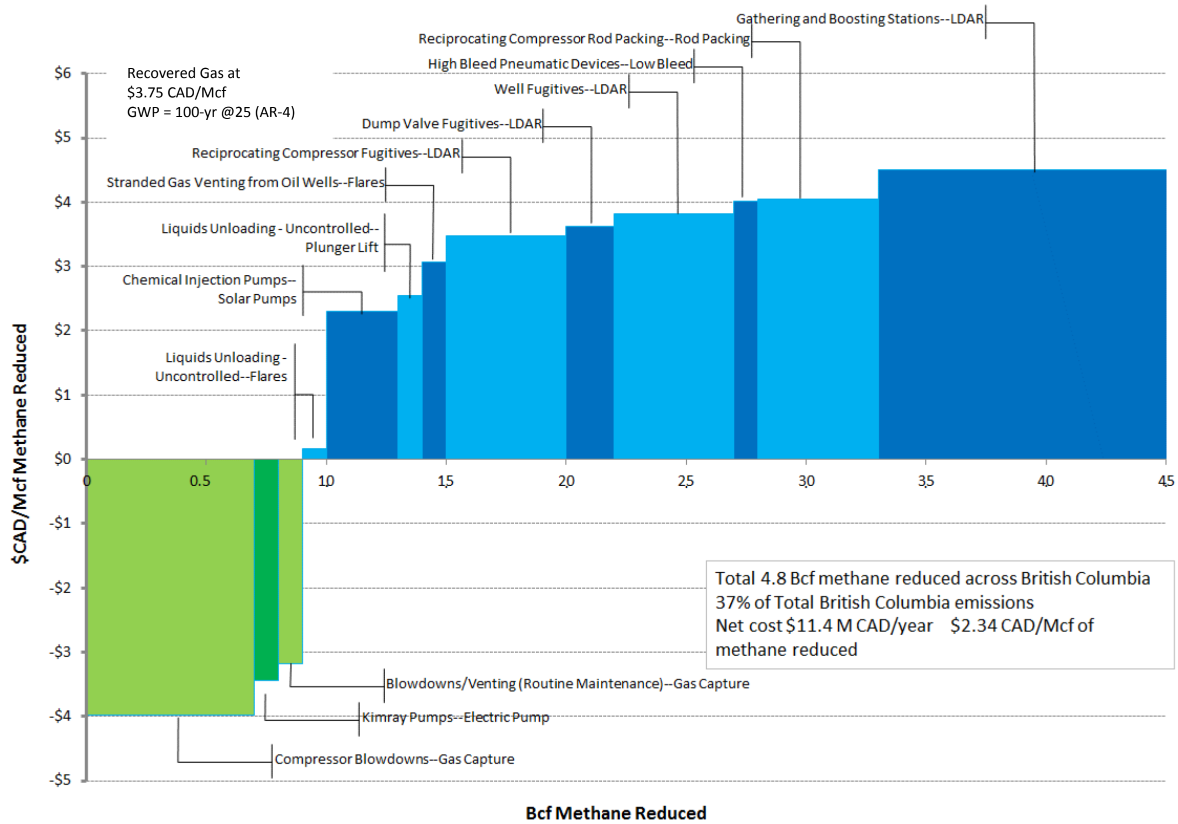
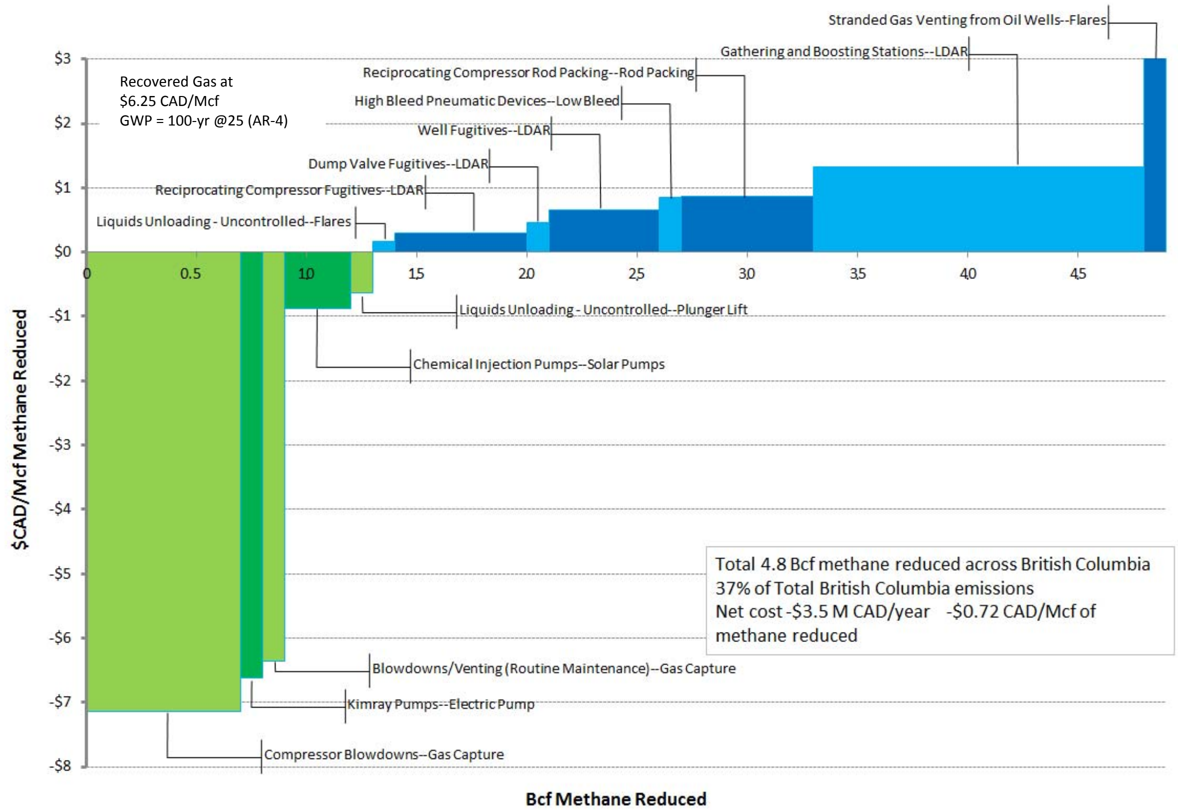


**Figure C-18 – British Columbia Upstream MAC Curve with $6.25 CAD/Mcf Natural Gas Price**



# Appendix D. Emissions Calculations with GWP Sensitivities

Based on the literature cited in this study, Table D-1 below contains the global warming potentials for methane according to the AR-4/AR-5 report and whether it is on a 20 year or a 100 year basis.

Table D-1- Methane Global Warming Potentials

| Assessment Report # | 20-yr Basis GWP | 100-yr Basis GWP |
|---|---|---|
| AR-4 | 72 | 25 |
| AR-5 | 86 | 34 |

As indicated in the main report, the 2020 Canadian Emissions Baseline value of 125 Bcf translates to approximately 60.2 million tonnes $CO_2e$ when using an AR-4 100-yr GWP. Table D-2 demonstrates the GWP sensitivity and recalculates the million tonnes of $CO_2e$ depending on what GWP is used. Table D-3 performs the same calculation but for the total 2020 Canadian reduction opportunity of 56 Bcf. This means that if the AR-5 20 year GWP was used instead of the 100 year, 93 MMTCO2e of reductions could be achieved from the technologies and practices identified in this report.

Table D-2- 2020 Canadian Baseline Emissions with GWP Sensitivity

| Assessment Report # Used in Calculation | Emissions (MMTCO2e) w/20-yr Basis GWP | Emissions (MMTCO2e) w/100-yr Basis GWP |
|---|---|---|
| AR-4 | 173.3 | 60.2 |
| AR-5 | 207.0 | 81.9 |

Table D-3- 2020 Reduction Opportunity with GWP Sensitivity

| Assessment Report # Used in Calculation | Emissions (MMTCO2e) w/20-yr Basis GWP | Emissions (MMTCO2e) w/100-yr Basis GWP |
|---|---|---|
| AR-4 | 77.7 | 27.0 |
| AR-5 | 92.8 | 36.7 |