Wellhead to Waterline

Opportunities to limit greenhouse gas emissions from B.C.'s proposed LNG industry

Adam Goehner and Matt Horne

February 2014

PEMBINA institute

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The Pembina Institute
219 19 Street NW
Calgary, AB
Canada T2N 2H9
Phone: 403-269-3344

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- promoting pragmatic policy approaches for governments to avoid dangerous climate change, such as increasing the amount of renewable energy plugged into our electricity grids;
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1. Introduction

British Columbia is attracting and promoting extensive liquefied natural gas (LNG) development, including the shale gas extraction and processing needed to produce the LNG. Its 2012 LNG strategy targets three export terminals in operation by 2020.[1] More recently, the province has published revenue and jobs estimates for LNG development that would require five to seven plants to be in operation on a similar timeline.[2,3]

Greenhouse gas emissions (GHGs) would be released across the LNG supply chain. The processes of extracting, processing, transporting, liquefying and eventually burning natural gas produce GHGs. While three-quarters of GHGs come from end use combustion, the scope of this report is extraction through liquefaction. These processes occur in B.C., where the provincial government and industry have direct influence over the amount of GHGs produced.

The province has estimated the greenhouse gas emissions that could accompany different levels of development, but to date has not made details of that analysis publicly available. The Pembina Institute and Clean Energy Canada (CEC) have both published estimates of the GHGs that could result from processes across the supply chain.[4] At the scale of development the province is using for its revenue and jobs estimates (five to seven LNG terminals), the GHGs from B.C. LNG could be on par with emissions from the oilsands by 2020.[5] Based on summary information released through Freedom of Information requests, the province's internal estimates are similar in scale.[6]

Those GHG estimates are not fixed. They depend in large part on the actual level of LNG development realized, but also depend upon choices about the source of gas extraction and the specific technologies employed along the supply chain. This report is intended to describe the different sources of GHGs along the LNG supply chain from wellhead to waterline (Section 2), and the range of opportunities to limit GHGs from these sources (Section 3 and 4).

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[1] British Columbia Ministry of Energy and Mines, *Liquefied Natural Gas: A Strategy for B.C.'s Newest Industry*, 3. http://www.gov.bc.ca/ener/popt/down/liquefied_natural_gas_strategy.pdf

[2] Grant Thornton, *Employment Impact Review*, prepared for B.C. Ministry of Energy, Mines and Natural Gas (2013). http://www.empr.gov.bc.ca/OG/Documents/Grant_Thornton_LNG_Employment_Impacts.pdf

[3] Ernst & Young, *Potential Revenues to BC Government from Potential Liquefied Natural Gas Development in BC*, prepared for B.C. Ministry of Energy, Mines and Natural Gas (2013). http://www.empr.gov.bc.ca/OG/Documents/Ernst_and_Young_LNG_Revenue.pdf

[4] Pembina's calculations equal 0.8 tonnes of carbon dioxide equivalent per tonne of LNG; CEC's calculations equal 0.9 tonnes of carbon dioxide equivalent per tonne of LNG.

[5] At 80 million tonnes of LNG exported per year (roughly five terminals), the Pembina Institute estimates that LNG would result in 73 million tonnes of GHGs, while CEC's estimates would result in 82 million tonnes of GHGs. In Environment Canada's 2013 Emissions Trends report, they estimate that the oilsands will be responsible for 101 million tonnes of GHGs in 2020.

[6] *Ministry of Environment Transition Binder*, June 2013, available as FOI Request: MOE-2013-00154 Response Package, Part 2, 324. http://www.openinfo.gov.bc.ca/ibc/search/detail.page?config=ibc&P110=recorduid:4743903&title=FOI%20Request%20-%20MOE-2013-00154

In characterizing the range of opportunities, this report is limited by the availability of data that is specific to Canadian natural gas operations; data from available U.S. studies were used when necessary. As a result, the potential reductions from different technologies were obtained in a variety of different units, making it difficult to easily compare or sum all reduction opportunities. Additional studies into B.C. practices and operations are needed to fully understand the level of reductions that are feasible in B.C., and which technologies are best for reducing GHGs.

This report does not assess the financial costs and savings associated with different technologies, or the specific policy actions that government could take to encourage or require industry to act. In general, however, the province has options for building on the initial steps in the Climate Action Plan to address the GHGs that will accompany LNG development. It could increase or broaden the base of the carbon tax, use a technology fund or offsets to incentivize improvements, set GHG standards for different elements of the LNG supply chain, or require the use of specific technologies. The degree to which the B.C. government and the gas industry act on those opportunities to limit GHGs will determine the overall climate impact from B.C.'s nascent LNG industry.

2. Sources of greenhouse gas emissions

The processes of extracting, processing, transporting, liquefying and eventually burning natural gas produce GHGs. While three-quarters of the GHGs come from end use combustion, this report focusses on the processes of extraction through liquefaction. They occur predominantly within B.C., where the province and industry have direct influence over the amount of GHGs produced.

That said, the end use GHGs are a very important part of the overall LNG picture. While those GHGs do contribute to climate change, the contribution should be assessed against energy sources that could be displaced. If the alternative is coal, LNG likely represents a decrease in GHGs. If the alternative is nuclear or renewable energy, then LNG represents an increase in GHGs. If the alternative is another source of natural gas, or LNG, the net impact on GHGs would depend on how emissions-intensive the different sources of gas are, because end use GHGs would be identical. The Pembina Institute is examining the global GHG and climate change implications of B.C. LNG exports in a forthcoming paper.

The GHGs that accompany the LNG supply chain in B.C. consist primarily of methane (CH_4), which is the predominant component of natural gas itself, and carbon dioxide (CO_2). There are five main sources in this supply chain.

Combustion — natural gas is burned to power equipment to process and transport the gas, releasing CO_2. In addition to sources that already exist in B.C.'s natural gas sector, future LNG terminals could be a major new location of natural gas combustion if they are powered with natural gas.

Formation carbon dioxide venting — CO_2 that is found in natural gas (referred to as formation CO_2) is separated from the gas at processing plants and vented to the atmosphere.

Methane venting — methane is vented from process equipment such as pneumatic controllers, gas driven pumps, dehydrators and compressors or during operations such as pipeline blowdowns, where gas is removed and vented from a section of pipeline for repair or maintenance.

Fugitive emissions — methane leaks or is unintentionally released to the atmosphere at valves or fittings, along pipelines and at storage tanks.

Flaring — natural gas is flared in order to control pressure, to maintain a flare pilot light at a facility or during well testing and completion.[7]

[7] Flaring in B.C. is regulated to limit the amount that occurs, especially in close proximity to communities and when infrastructure is present to capture the gas. This source also includes gas needed to fuel pilot lights for flare stacks, which must remain burning for safety reasons.

The relative magnitudes for these five sources from B.C.'s oil and gas sector in 2012 are outlined in the figure below. A more detailed breakdown of specific sources is available in Appendix A. This breakdown does not include any GHGs from LNG terminals as LNG terminals do not yet exist in B.C. Implementing technologies to limit GHGs will also change the size of each source relative to others.

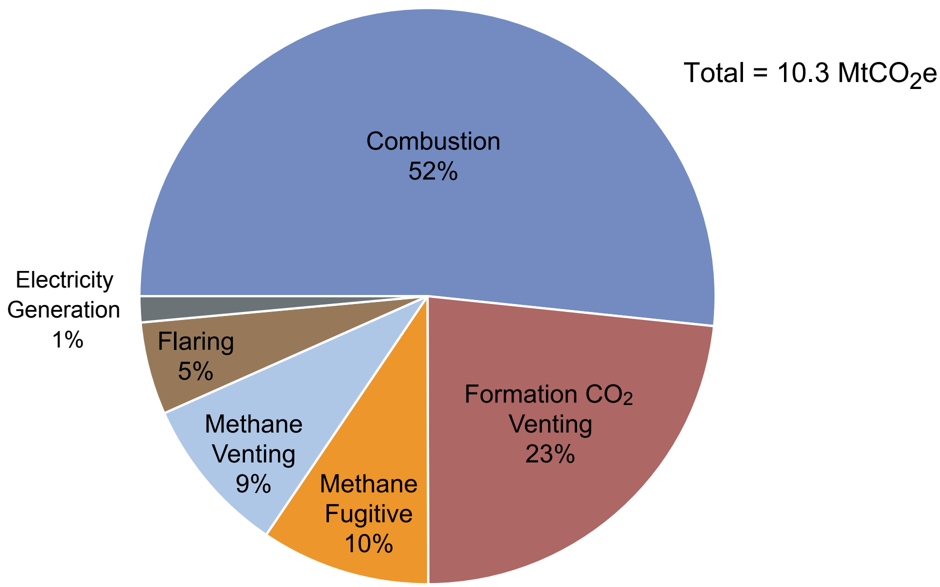

Figure 1. Current breakdown of GHGs from B.C.'s natural gas sector[8]

Data source: B.C. Ministry of Environment[9]

Of particular note is vented and fugitive methane. Methane has a greater global warming potential than pure CO_2, and the latest guidance from the Intergovernmental Panel on Climate Change (IPCC) suggests that global warming potential assigned to methane will need to be increased, based on most recent findings. The province's GHG inventory currently follows standard international practice in applying a global warming potential of 21 for methane. If that guidance increases to reflect the most recent IPCC findings, methane's contribution to GHGs in the gas sector would grow from 19% to 27%.[10]

Another factor in assessing the importance of methane is the timeframe over which its global warming potential is determined. The current convention for timeframe associated with the global warming potential of non-CO_2 related GHGs is 100 years. However, given the urgency of climate change, more studies are considering using a 20-year timeframe instead. If a 20-year timeframe were used in assessing the GHGs from B.C.'s natural gas sector, methane would grow from 19% of the sector to as high as 48%.[11]

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[8] The global warming potential for methane used for this calculation is 21.

[9] B.C. Ministry of Environment, "Facility Green House Gas Emissions Reports Questions and Answers," September 19, 2013. http://www.env.gov.bc.ca/cas/mitigation/ggrcta/reporting-regulation/emissions-reports-qa.html

[10] Calculated using 100 year global warming potential for methane of 34 from 2013 IPCC AR5 p714. This value includes climate-carbon feedbacks.

[11] Calculated using 20-year global warming potential for methane of 86 from 2013 IPCC AR5 p714. This value includes climate-carbon feedbacks.

In addition to the debate about how significant a given amount of methane is, there is also a debate about the exact volume of fugitive and vented methane across the gas supply chain. This debate mainly centres on the uncertainty between modelling that is done to estimate the volumes of methane released and how this compares to actual field emissions. Modelling is required to quantify emissions that occur in places where there is no physical measurement device. Many of the field-level efforts to date indicate actual levels of methane could be either higher or lower than modelled estimates.

For example, a recently released study from the University of Texas looked at field level emissions of activities such as well completions and liquid unloading.[12] The study found the emissions from well completions were lower than estimated by the U.S. Environmental Protection Agency (EPA), but emissions for liquid unloading were higher than the most recent EPA estimates. In this case, the net effect of their findings was that the overall emissions from the studied activities were close to the EPA estimates.[13] There are a number of U.S. studies currently underway to quantify the emissions along the entire supply chain that should help to reduce the uncertainty surrounding this debate.

[12] Liquid unloading is when liquids, such as produced water, are removed from a gas well to facilitate further flow of gas from the well.

[13] David T. Allen et al., "Measurements of methane emissions at natural gas production sites in the United States," *Proceedings of the National Academy of Sciences*, 110 no. 44 (2013). http://www.pnas.org/content/early/2013/09/10/1304880110.full.pdf+html

3. Reduction opportunities

There are numerous opportunities to reduce GHGs from the various sources described in the previous section. This section describes 13 technologies that could be deployed at different locations across the LNG supply chain in B.C. and that would serve to reduce GHGs. It is not intended to be an exhaustive list of options, nor does it provide a detailed assessment of the viability of these technologies in all possible applications. The technologies are ordered based on the categories of emission sources they apply to, as described in the previous section.

Combustion

3.1 Electrification of LNG terminals

Compressors used to process and liquefy natural gas require a large amount of energy. This demand can be met either from the combustion of natural gas or with electricity from the grid. There are challenges with both options, but natural gas powered compressors are the current technology of choice for operating LNG terminals. Two Norwegian projects — an operational LNG terminal and one under construction — are exceptions.

An alternative to using natural gas driven compressors at liquefaction terminals is to use electric drives, the electricity from which could be supplied through a mix of local and grid-connected renewable energy sources. Analysis done by CEC indicates that replacing the LNG terminals' natural gas direct drive compressors with electric drive (powered by a mix of gas-fired electricity, local renewables and grid power) could reduce emissions by 0.11 tonnes of CO_2 equivalent (tCO_2e) for every tonne of LNG processed.[14] While these represent potentially significantly reductions in GHGs, the electricity generation requirements would be significant and would be accompanied by impacts of their own.

Most B.C. LNG project proponents are currently planning to use direct drives for the liquefaction process, but are contemplating using grid power for auxiliary power demands.

3.2 Upstream electrification

Energy is also required to produce, process and transport gas to the LNG terminals. Standard practice in industry is to combust natural gas to generate this energy. These activities currently result in over 50% of the emissions from the oil and gas sector.[15] Switching the energy demands from these upstream facilities from natural gas to electricity is also a key area where emission reductions are possible.

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[14] James Glave, Jeremy Moorehouse, *The Cleanest LNG in the World? How to Slash Carbon Pollution From Wellhead to Waterline in British Columbia's Proposed Liquefied Natural Gas Industry* (Clean Energy Canada at Tides Canada, 2013), 12. http://cleanenergycanada.org/wpcontent/uploads/2013/09/CEC_Cleanest_LNG_World.pdf

[15] "Facility Green House Gas Emissions Reports Questions and Answers."

The Pacific Carbon Trust provides a number of example projects where electrification has been implemented in the field:

- The Septimus gas processing plant was electrified resulting in a reduction of 42,963 tCO_2e per year.[16]
- ARC Resources electrified a well pad resulting in an estimated reduction of 10,000 tCO_2e per year.[17]
- The Arc Resources gas processing plant in Dawson Creek was electrified resulting in a reduction of 56,332 tCO_2e per year.[18]

Similar to the opportunity of electrifying LNG terminals, the electricity generation requirements for upstream electrification would be significant and would be accompanied by other environmental impacts of their own.

Formation carbon dioxide venting

3.3 Carbon capture and storage

In northeastern B.C., CO_2 occurs naturally and is produced alongside gas from the Horn River and Montney reservoirs. The Horn River is approximately 12% CO_2 while the Montney is about 1%.[19] The CO_2 is removed from the gas at gas processing facilities and is currently vented directly to the atmosphere. This venting accounts for 23% of the current emissions from the B.C. oil and gas sector.[20]

The only technology option to substantially reduce the emissions from CO_2 venting is to use carbon capture and storage (CCS). Once separated from the natural gas, the CO_2 is injected and stored in selected geological rock formations,[21] typically located several kilometres below the earth's surface. While still a costly technology, the economics of CCS at a gas processing facility are better than potential applications on coal-fired power plants. This is because the CO_2 already needs to be separated from natural gas, whereas separating CO_2 from flue gas at a coal-fired power plant would require an extra step and associated costs.

The proposed Fort Nelson Gas Plant CCS project, which would be situated in the Horn River, is being designed to sequester 2.2 megatonnes (Mt) of CO_2 per year.[22] The Fortune Creek Gas

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[16] Pacific Carbon Trust, "Offset Showcase," January 26, 2014. http://pacificcarbontrust.com/our-projects/offset-showcase/electrification-of-gas-processing-plant-cnrl-taylor/

[17] Pacific Carbon Trust, "Monetizing the value of vented Methane," March 14, 2013. https://www.globalmethane.org/expo-docs/canada13/og_11_D_Antoni_1.pdf

[18] Pacific Carbon Trust, "Offset Showcase."

[19] National Energy Board, *A Primer for Understanding Canadian Shale Gas*, 15. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.pdf

[20] "Facility Green House Gas Emissions Reports Questions and Answers."

[21] A suitable geologic formation for CCS in Northern BC has yet to be proven although work is underway to evaluate the potential of various formations for use near Fort Nelson. http://sequestration.mit.edu/tools/projects/fort_nelson.html

[22] Al Landry, "Spectra Energy Fort Nelson Carbon Capture & Storage Feasibility Project," presented at Carbon Sequestration Leadership Forum, Edmonton, May 19, 2011, 5.

project modelled a reduction of 1.4 Mt of CO_2 per year if CCS were implemented.[23] While it is not yet clear if these projects will go ahead, it demonstrates that CCS is a viable option for achieving significant GHG reductions within the gas sector.

An alternative option to technology, which would achieve a similar result, would be to preference the production of gas from basins that have low CO_2 content, and avoid ones with high CO_2 content, such as the Horn River basin.

Methane venting

3.4 Pneumatic controllers

Pneumatic controllers are used as part of the instrumentation and automation of field operations, such as monitoring fluid levels and controlling valve positions. These controllers use natural gas as a pneumatic fluid because it is readily available in the field. The configuration of devices can vary, including those that vent methane continuously (continuous venting), those that vent methane with each valve movement (snap acting), and those that vent methane to a downstream pipeline instead of to the atmosphere (self-contained).[24] There are also low-bleed devices and high-bleed devices that are differentiated based on the amount of gas that is vented during routine operation of the devices.

A recent study in B.C. found that the average bleed rate for high-bleed and intermittent controllers were lower than the EPA estimates; however, the average bleed rate for low-bleed controllers and pumps were both higher than EPA estimates. These findings align with a similar study that was performed in the U.S. by the University of Texas.[25] Based on the reported emission sources from the oil and gas sector in B.C., venting from pneumatic devices and pump vents currently accounts for approximately 5% of the emissions for the sector, which is equivalent to over 500,000 tonnes of CO_2e per year.[26] The B.C. government recently commissioned a field study of emissions from pneumatic devices. According to the results of the study, GHG emissions from pneumatic devices are about 70% higher than reported currently.[27] This results in an upward adjustment in oil and gas sector's total emissions of about 4% from the current 10 megatonnes shown in Figure 1.

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http://www.cslforum.org/publications/documents/Edmonton2011/Laundry-TG-FortNerlsonProjectOverview-Edmonton0511.pdf

[23] Quicksilver Resources, Memorandum to Climate Action Secretariat and EAO, June 4, 2013. Available at http://a100.gov.bc.ca/appsdata/epic/documents/p379/1370633122202_c6d6c01823dfe2d19c8eac3dd3f8438d5ca5da86be5893b584035f7fa5ff3f14.pdf

[24] The self-contained configurations for pneumatic controllers have limited applicability.

[25] The Prasino Group, *Final Report For Determining Bleed Rates for Pneumatic Devices in British Columbia*, prepared for BC Climate Action Secretariat (CAS), Ministry of Natural Gas Development and Canadian Association of Petroleum Producers (CAPP) (2013). http://www.env.gov.bc.ca/cas/mitigation/ggrcta/reporting-regulation/pdf/Prasino_Pneumatic_GHG_EF_Final_Report.pdf

[26] See Appendix A. This combines emissions from continuous high-bleed device vents, pneumatic pump vents, and continuous low-bleed and intermittent device vents.

[27] Government of British Columbia, "Study Results in Improved Reporting of GHG Emissions," news release, December 20, 2013. http://www.newsroom.gov.bc.ca/2013/12/study-results-in-improved-reporting-of-ghg-emissions.html

Options for reducing emissions from these devices include:

- replacement or retrofit of high-bleed devices with low-bleed alternatives
- installment of instrument air, as opposed to natural gas, devices
- installment of solar powered or grid connected valves activated using electricity instead of natural gas
- improvement and enhancement of maintenance regimes.

A recent study in the U.S. estimates that approximately 80% of high-bleed devices can feasibly be replaced with low- or no-bleed alternatives.[28] Using this estimate, and EPA emission factors for low-bleed devices,[29] this translates to a 77% possible reduction of GHGs from pneumatic controllers in B.C., or approximately 240,000 tCO_2e per year.[30]

3.5 Non-emitting chemical injection pumps

In the natural gas industry, natural gas is often used in injection pumps to inject chemicals into the pipeline network that gathers the gas. The most common chemicals are methanol (used to prevent hydrate formation) and corrosion inhibitors. These chemical injection pumps vent methane to the atmosphere with every stroke. A typical chemical injection pump emits 80–150 tCO_2e per year.[31]

Instead of using natural gas, pumps can be operated via renewable energy either from the BC Hydro grid or using remote power solutions. The most common remote power application is a solar panel configuration. The solar panel configuration has been available commercially for almost a decade, but has not enjoyed wide adoption due to the prevailing low natural gas prices relative to the capital cost of solar solutions. There are also hybrid solutions that employ solar panels and a methanol-based fuel cell.

3.6 Plunger lift systems

Routine well maintenance includes ensuring that the well continues to flow and that liquid buildup is cleaned out of the well so that the gas can flow freely. In order to do this, wells are typically blown down, which means the wells are opened and the gas is vented to the atmosphere.

An alternative to this process is installing plunger lifts, which use the well's own pressure to remove liquid from the well and eliminate the need to open wells and vent methane. There is a large range in the estimated emission reductions from installing plunger lifts, but the EPA

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[28] Allen et al., "Measurements of methane emissions at natural gas production sites in the United States."

[29] U.S. Environmental Protection Agency, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Technical Support Document for Proposed Standards* (2011), 5-12. http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf

[30] Calculated based on outlined assumptions, i.e., that 80% of high bleed devices can be switched to low bleed.

[31] Energy Resources Conservation Board, *Alberta Fuel Gas Efficiency in the Upstream Gas and Conventional Oil Industry* (2012), 38. http://www.aer.ca/documents/sts/ST110/ST110-2012.pdf

estimates that between 2,263 and 8,789 tCO_2e per year per well are possible.[32] Emission reductions from using plunger lift systems in B.C. may differ from the EPA estimates, as this is very dependent on geology and reservoir characteristics.

3.7 Dehydrator emission controls

Dehydrators are used to remove moisture from natural gas to reduce corrosion, improve quality and to avoid hydrate formation. These dehydrators typically vent methane to the atmosphere, but there are numerous points in the glycol dehydration system where emissions controls can be retrofitted and the system can be optimized, including:

- installing a flash tank separator
- optimizing the glycol circulation rate
- re-routing the skimmer gas
- installing an electric pump to replace natural gas driven energy exchange pump.

In B.C. the reported emissions from glycol vents is 97,100 tCO_2e per year.[33] Depending on how many of the control technologies are applied to reduce methane vents, the potential reduction is estimated to range from 1,760 to 16,650 tCO_2e per unit installed.[34] This range of reductions depends on the size of facility and volume of gas being processed. The largest reduction would only be possible for the largest dehydrators and with a combination of many of the options.

3.8 Desiccant dehydrators

Desiccant dehydrators are an alternative to glycol systems that are applicable in certain operating conditions. They are best suited to applications with low gas flow rates and low temperatures. There are no significant emissions from desiccant dehydrators, so they result in emission reductions if they replace glycol systems that are venting methane. Emissions only occur when the dehydrator is opened to replace the salt. The potential reduction in emissions is estimated to be 482 tCO_2e per year per unit.[35]

3.9 Dry seal systems

Centrifugal compressors are used in the production and transportation of natural gas and can either have wet seals or dry seals. Wet seals use high-pressure oil as a barrier to prevent gas from escaping. When the oil is at high pressure it absorbs methane, which is then released when the oil pressure is released in the system. Dry seal configurations use high-pressure gas to prevent gas escape and have lower vented emissions than wet seals.

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[32] U.S. EPA Natural Gas STAR, *Installing Plunger Lift Systems in Gas Wells, Lessons Learned from Natural Gas STAR Partners*, 2006.; U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2009)*, April 15, 2011.

[33] "Facility Green House Gas Emissions Reports Questions and Answers,"

[34] Susan Harvey, Vignesh Gowrishankar, Thomas Singer, *Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste* (Natural Resources Defense Council, 2012), 18. http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf

[35] Ibid.

Most new compressors use dry seal systems, but there are still a number of legacy compressors in use and repurposed compressors with wet seal configurations. Based on estimates from the EPA, switching from wet seal systems to dry seals has the potential to reduce emissions at individual compressors from 2,796 to 5,065 tCO_2e per year.[36]

3.10 Improved compressor maintenance

Reciprocating compressors are used extensively in the natural gas sector to move gas from the wells to the terminals and eventually to the end user. They primarily leak methane from a component called a rod packing case. A rod packing case is used to maintain a tight seal around the piston rod, preventing the gas from leaking while allowing the rod to move freely. The emissions from the rod packings can be reduced by replacing worn-out rod packings and ensuring all other components are maintained properly. Analysis by the Natural Resources Defense Council suggests that reductions in the range of 409 tCO_2e per year per replaced rod packing can be achieved.[37]

There are other options to improve compressor efficiency and reduce emissions such as engine fuel management systems and vent gas capture.

Fugitive emissions

3.11 Vapour recovery units

Vapour recovery units (VRUs) are used to capture emissions from storage tanks and vessels. Gas evaporates from fluid in storage tanks and vessels and is at near atmospheric pressure. This gas is typically released to the atmosphere but it can be collected with a VRU and rerouted to a gas pipeline, or used on site for fuel. VRUs can typically capture about 95% of emissions that would otherwise be vented to the atmosphere.[38] Optimizing the operating temperatures and pressure can also lead to reduced volumes of gas escaping with minimal capital investment.

3.12 Leak monitoring and repair

There are numerous additional locations along the transmission from wellhead to terminals where leakage of methane and other gases can occur. Examples include valves, drains, pumps, threaded and flanged connections, pressure relief devices, open-ended valves and lines, and sample points. These emissions are generally referred to as fugitive emissions and as a category account for approximately 10% of the emissions from the natural gas sector in B.C.

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[36] *Oil and Natural Gas Sector: Standards of Performance.*

[37] *Leaking Profits*, 18.

[38] Ibid.

Best practice guidelines ensure that proper procedures are in place to detect and repair leaks.[39] Estimates based on implementation of leak monitoring and repair programs suggest that a reduction of 56% to 89% of fugitive emissions is achievable.[40]

Flaring

3.13 Reduced emissions completions

Well completion occurs after a well has been drilled and is the process that facilitates the flow of natural gas from a well. Hydraulic fracturing is one component of the well completion and is the stimulation technique that is used in northeast B.C. The main source of carbon pollution at this stage of operation occurs after hydraulic fracturing when the high-pressure fracture fluid and natural gas return to the surface and the gas is flared instead of being captured and put in a pipeline.

Reduced emission completions (RECs) refers to the practice of capturing the gas that comes to surface during well completions and diverting it to a pipeline instead of venting or flaring. The EPA is phasing in regulations so that all completions by 2015 will be RECs.[41] B.C. currently does not require RECs; however, B.C. regulations do limit the amount of gas that is vented and much of it is flared or captured.

Estimates of the actual emissions that occur as a result of these operations can vary significantly, and there are large ranges of estimates in the literature.[42] Recently a study conducted by researchers at the University of Texas in conjunction with Environmental Defense Fund and industry found that the average methane emissions in the U.S. during well completions are 42.5 tCO_2e per completion.[43] Two-thirds of the completions in this study used RECs and achieved a 99% reduction in methane emissions.[44] The EPA estimates that the potential reduction in emissions by using RECs is 3,976 tCO_2e per event.[45] The data for B.C. suggests that the majority of completions events are either already RECs or the gas is flared; the potential reduction opportunity is therefore not as high. Using the same methodology as the EPA but changing the assumption that the gas is diverted to a flare as opposed to vented directly to the atmosphere, the revised emission reduction potential is 459 tCO_2e per event.

There are many reasons that the variability in estimates is so great but, based on the methodology of the studies and the data analyzed, the prevalence of RECs does appear to contribute to a reduction in GHGs from hydraulic fracturing.

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[39] U.S.EPA, *Leak Detection and Repair: A Best practices Guide* (2007), 7. http://www.epa.gov/compliance/resources/publications/assistance/ldarguide.pdf

[40] Ibid

[41] *Oil and Natural Gas Sector: Standards of Performance*, 4.18.

[42] Allen et al., "Measurements of methane emissions at natural gas production sites in the United States."

[43] Ibid.

[44] Ibid.

[45] Calculated based on data from *Oil and Natural Gas Sector: Standards of Performance*, 4.18.

4. Summary

The following summarizes the 13 opportunities to reduce carbon pollution across the LNG supply chain in B.C. As noted earlier, limited B.C.-specific data and uncertainty about how much development is going to happen and when means that the different reduction opportunities cannot yet be expressed in common units. As a result, the following opportunities for carbon pollution reduction cannot be directly compared, or summed, to estimate the total reduction potential.

The reduced emission completions provide a good example of the limitations of the data. Ideally, it would be possible to estimate the potential reductions per unit of gas produced or per unit of LNG exported. Converting the *tonnes of CO_2e per completion* estimate into a *tonnes per unit of gas produced* estimate would require the average number of completions per unit of gas produced. That information is not currently available.

Table 1. Summary of emission reduction opportunities

Emission reduction opportunity	Reduction	Units	Reduces
Electrification of LNG terminals	0.11	tCO_2e per tonne LNG	Combustion
Electrification of upstream facilities	10 to 56	ktCO_2e per year	Combustion
CCS of formation CO_2	1.4 to 2.2	Mt CO_2e per year per facility	Formation CO_2 venting
Pneumatic controllers	77	% reduction	Methane venting
Non-emitting injection pumps	80 to 150	tCO_2e per year per pump	Methane venting
Plunger lift systems	2,263 to 8,789	tCO_2e per year per well	Methane venting
Dehydrator emission controls	1,760 to 16,650	tCO_2e per year per unit	Methane venting
Desiccant dehydrators	482	tCO_2e per year per unit	Methane venting
Dry seal systems	2,796 to 5,065	tCO_2e per year	Methane venting
Improved compressor maintenance	409	tCO_2e per year per rod packing	Methane venting
Vapour recovery units	95	% of methane captured	Fugitive emissions
Leak monitoring and repair	56 to 89	% reduction	Fugitive emissions
Reduced emissions completion	459	tCO_2e per completion	Flaring

5. Next steps

The following four next steps are recommended to build on this research:

1. ***Refining the information on the different technology options*** so that the estimated potential to reduce GHGs for each technology can be directly compared. This would require extending the current research into a more detailed model of B.C.'s natural gas sector that shows the level of activity across the supply chain under different natural gas and LNG development scenarios.

   For example, the estimated GHG reduction for reduced emission completions is expressed in terms of tCO_2e per well completion. Extending the research to know how many well completions are required to support different levels of gas production and LNG export would enable the calculation of total GHG reductions for a given amount of gas production and specified LNG export scenario.

   There would be two major benefits to this. First, it would enable an assessment of the total GHGs from B.C.'s LNG supply chain under different technology scenarios. Second, it would enable the relative magnitude of each opportunity to be directly compared on a common basis.

2. ***Assessing the economics of the different technology options*** to understand the likelihood that they will be deployed in B.C. under a range of natural gas price forecasts. The economics of different technologies should be considered in both new and retrofitted applications. This information will be helpful in understanding which improvements are likely without any policy actions by government, and which will require policy action.

   In addition to financial considerations, it would also be useful to have an understanding of other major factors such as how reliable different technologies are in different applications and how long it takes to implement them. For example, even if the economics of a given technology are positive, adoption will be challenging if an operator views them negatively for other reasons.

3. ***Analyzing possible policy options*** that could be used to increase the likelihood that different technology options are deployed in B.C. Policy options should be assessed in terms of anticipated GHG benefit, costs/revenue to industry, costs/revenue to government, alignment with existing policy, transparency and simplicity.

   Options for consideration in a policy scan include: increasing or broadening the base of the carbon tax, complementing the carbon tax with a cap-and-trade system, incentivizing specific technologies with a technology fund or offsets, requiring specified levels of GHG intensity, and designing royalties and the forthcoming LNG income tax in ways that encourage GHG reductions.

4. ***Improving the quality of GHG estimates from B.C.'s natural gas sector*** by conducting additional field studies into specific fugitive and vented methane sources of GHGs. These

sources should be the focus area because they are not currently measured, whereas other sources such as combustion and vented formation CO_2 are.

As discussed, the B.C. government recently completed a field study to understand the GHGs from pneumatic controllers. According to the results of the study, GHG emissions from pneumatic devices are about 70% higher than reported currently. Replicating that study for other fugitive and vented methane sources of GHGs would help to fine-tune the estimates in the province's inventory and provide a better foundation of information when assessing potential GHGs and the opportunities to limit those impacts.

Appendix A. Emission sources from the oil and gas sector in B.C.

Emission source	Category	GHG emissions (tCO_2e)	Percent
Stationary combustion: natural gas	Stationary combustion	5,060,500	49.0
Stationary combustion: other fuels	Stationary combustion	276,100	2.7
Electricity generation	Electricity generation	150,600	1.5
Well testing flares	Flaring	139,500	1.4
Associated gas flares	Flaring	35,200	0.3
Flare stacks	Flaring	362,700	3.5
Continuous high bleed device vents	Venting	311,100	3.0
Pneumatic pump vents	Venting	173,700	1.7
Continuous low bleed & intermittent device vents	Venting	68,900	0.7
Acid gas removal	Venting	2,408,000	23.3
Dehydrator vents	Venting	97,100	0.9
Well venting for liquids unloading	Venting	6,200	0.1
Well venting, with or without hydraulic fracturing	Venting	4,100	0.0
Blowdown vent stacks	Venting	58,900	0.6
Well testing venting	Venting	1,100	0.0
Associated gas venting	Venting	730	0.0
Centrifugal compressor vents	Venting	102,000	1.0
Reciprocating compressor vents	Venting	52,400	0.5
Eor injection pump blowdowns	Venting	-	-
Other venting sources	Venting	40,900	0.4
Storage tanks	Fugitive	16,900	0.2
Gathering pipeline equipment leaks	Fugitive	156,500	1.5
Equipment leaks from valves, connectors, etc.	Fugitive	784,300	7.6
Above-ground meters/regulators at gate stations	Fugitive	5,900	0.1
Below-ground meters/regulators/valves	Fugitive	8,500	0.1
Other fugitive sources	Fugitive	9,400	0.1
Wastewater processing	Wastewater	17	0.0
TOTAL		**10,331,500**	**100**

Source: B.C. Ministry of Environment[46]

[46] "Facility Green House Gas Emissions Reports Questions and Answers."