Methane Mitigation Pathways

Part II: Future Drive to 75

Prepared For: Alberta Innovates

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Final Report

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Executive Summary

This is the second of two reports completed under the Methane Mitigation Pathways work product. The report contemplates key factors influencing Canada's oil and gas sector's journey to a 75% reduction in methane emissions by 2030. Using historical data from the 2014-2021 timeframe, the analysis contained in this report identifies pathways industry, government, regulators, and other stakeholders may consider to support the emissions reduction target. The report further identifies knowledge gaps that, if bridged, may further improve the assessment completed here. Plus, the report provides recommendations for new programs and other options that may prove helpful to ensuring the oil and gas sector is able to cost-effectively support government ambition. Further summary notes are below:

- The Government of Canada has committed to achieve a 75% reduction in upstream oil and gas methane emissions, from 2012 levels, by the year 2030.
- As of April 2023, the Government of Alberta (GoA) indicates that their upstream oil and gas sector has achieved a 44% methane emissions reduction from 2014 levels at year-end 2021. The GoA is currently assessing potential pathways to achieving a 75-80% reduction from 2014 levels by the year 2030.
- Modern West Advisory (MWA) created an emissions estimation model that pulls publicly available data on methane emissions reported by the Government of Alberta between 2014 and 2021 (the latest year with full data). The modelled emissions profile in 2021 is shown in the table below.

Table 1. Breakdown of modelled upstream oil and gas methane emissions in Alberta in the year 2021. Total may not add due to rounding.

Emissions Source Category	Methane Emissions in 2021 (Mt CO_2e)
Pneumatics	5.5
Routine Venting	2.8
Methane Slip – Fuel Combustion	2.7
Fugitives	1.6
Surface Casing Vent Flow/Gas Migration	0.9
Methane Slip – Flaring	0.8
Compressor Seals	0.4
Spills & Ruptures	0.3
Glycol Dehydrators	0.2
Total	**15.3**

- The 2014 75% reduction target is equal to a total of 6.8 Mt CO_2e of methane emissions in 2030. This represents a further 8.5 Mt CO_2e reduction from 2021 emission shown in Table 1.
- The largest emissions source in 2021, Pneumatics (5.5 Mt), is well placed to achieve significant reductions via existing technologies, regulations and offset

programs.

- Knowledge and technology barriers may prevent Routine Venting (2.8 Mt) from being completely eliminated as an emission source, particularly for tank vents.
- Methane slip (3.5 Mt, fuel and flaring combined) is an unregulated source of methane emissions, meaning there are not currently any policy tools in place to drive reductions from this source. This source lags behind other categories in terms of baseline assessment, detection techniques, and commercially available mitigation technology. New technologies may need to be developed and deployed to address methane slip from reciprocating engines.
- Fugitives (1.6 Mt) and Surface Casing Vent Flow (SCVF, 0.9 Mt) have recently been subject to leak detection and repair (LDAR) requirements. It is anticipated that LDAR requirements will become more stringent in updated regulations. New and innovative altFEMP methodologies continue to emerge (truck and fence mounted sensors, aerial LiDAR, continuous monitors). As more data is collected through these initiatives, fugitive and vent emissions may see continued improvement in tracking and mitigation.
- Alberta's existing funding and incentive program framework has been essential to achieving a 44% methane reduction in Alberta by 2021. New programs, designed and implemented for the 2023 to 2030 timeframe should leverage the expertise of current program administrators, accounting systems, resource configurations, and data platforms. These programs could be enhanced to target the hardest to abate emission sources at the most vulnerable facilities, with an emphasis on tank venting, methane slip from engines, and surface casing vent flows.

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1. Report Objectives

This is the second of two reports which are developed to inform a stakeholder working group session, where participants will contemplate past and future methane emissions reduction activities in Canada's upstream oil and gas industry. The first report, titled "The Path to 45", provides a historical review of emissions reductions achieved within the oil and gas sector between 2014 and 2021. The second report, contained herein, is titled "The Drive to 75" and focuses on pathways and barriers to achieving a 75% reduction in oil and gas methane emissions by 2030. This second report builds off the first report. As a result, some historical context and content relating to Alberta's emissions profile and the regulatory landscape will not be repeated here. There is an assumption that the reader has completed a review of The Path to 45 report and/or has baseline knowledge of the oil and gas sector's methane emissions sources, regulations, and mitigation solutions.

The "Drive to 75" report is designed to assess the latest available methane emissions profile in Alberta and provide an assessment of opportunities where the sector in Canada may achieve further emissions reductions, the technologies and solutions that will enable success, potential pathways forward, and an assessment of barriers. The Report also provides an analysis of the gaps in knowledge and associated risks to the sector's ability to meet this ambitious 75% target.

It is important to note that these reports evaluate publicly available data to analyze the methane emissions profile of the oil and gas sector. Our recommendations are intended to be subjective assessments of past pathways and applying those learning to potential opportunities in the future. At no point do we intend to make any consideration for policy or regulatory changes. We understand and appreciate that each stakeholder will have their own view of the data and different experiences with past and ongoing programs and compliance obligations. We did our best to rely on the data and our own experiences with the programs when completing the analysis. Finally, we note that time was not available to test our assumptions and insights with key stakeholders. We are open to future discussion with any interested parties.

2. Introduction and Background

The Government of Alberta (GoA) introduced the Methane Emission Reduction Regulation (MERR) in 2018 with the commitment to reduce conventional upstream oil and gas methane emissions by 45%, from 2014 levels, by the year 2025 (Government of Alberta, 2018). The latest modelling by the GoA, released in April 2023, indicates that Alberta achieved a 44% reduction in methane emissions by 2021, and is on track to exceed the 45% target by 2025 (Government of Alberta, 2023a).

In October 2021, the federal government announced new plans to commit to a 75% reduction from the baseline year[1] by 2030 (Government of Canada, 2021).

[1] Federal regulations use 2012 as the baseline year, while Alberta is using 2014.

Amendments to the existing federal methane regulations are currently under development to achieve this new target[2]. In April of 2023 the Government of Alberta released the Emission Reduction and Energy Development Plan. This plan indicates that Alberta Environment and Protected Areas will engage stakeholders, Albertans, and Indigenous organizations to assess potential pathways to achieve a provincial 75 to 80 per cent methane emissions reduction target from the upstream oil and gas sector by 2030 (from 2014 levels) (Government of Alberta, 2023b).

Figure 1 below shows the historical methane emissions for the upstream oil and gas sector in Alberta. Both the GoA and the Federal government's National Inventory Report (NIR) model results and targets are shown for comparison purposes.

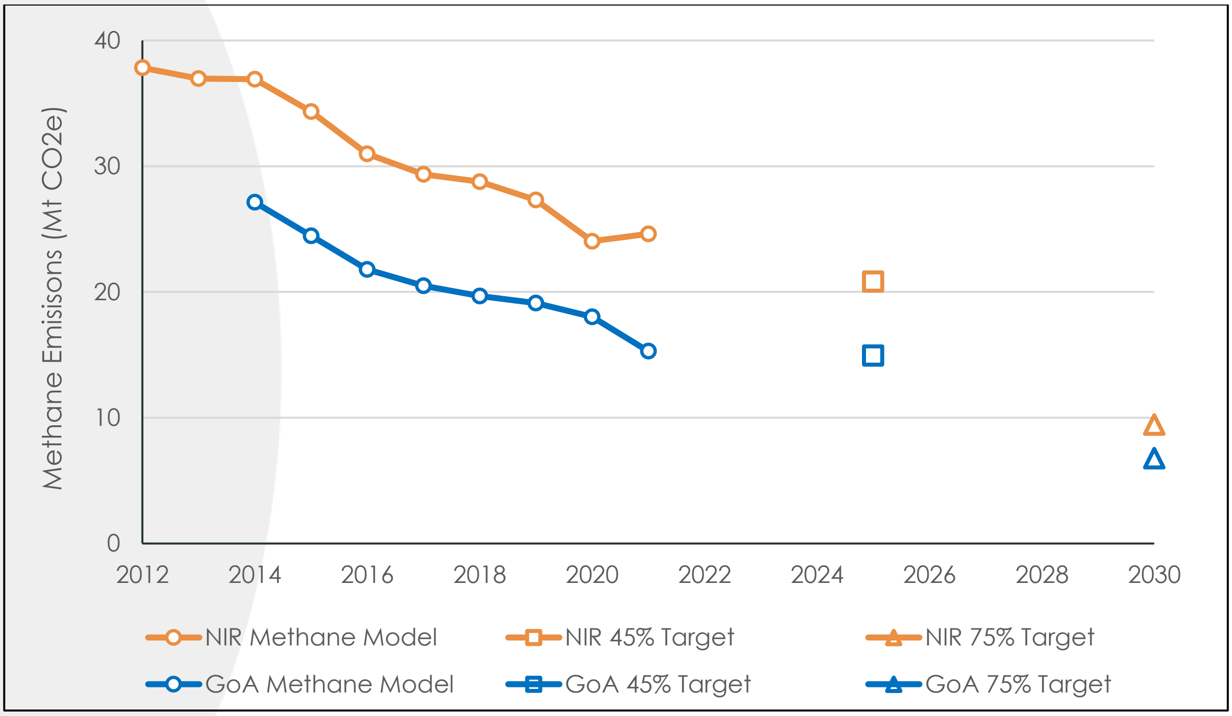

Figure 1. *Historical methane emissions and reduction ambitions for Alberta's upstream oil and gas sector. Note that the National Inventory Report (NIR) model includes emissions from oil sands mining and upgrading, while the Government of Alberta (GoA) does not*[3]. Sources: *(Environment and Climate Change Canada, 2023)*, ***(Government of Alberta, 2023a)***

[2] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reducing-methane-emissions/proposed-regulatory-framework-2030-target.html

[3] Other differences between the GoA and NIR methodologies include sources (abandoned wells, unreported venting) and emission factors (pneumatics, equipment fugitives).

2.1. Upcoming Policy and Regulatory Targets

2.1.1. Canada

Environment and Climate Change Canada (ECCC) intends to modify the existing federal methane oil and gas regulations with the aim of achieving a 75% reduction in methane emissions by 2030 compared to 2012 levels. Unlike Alberta's target, which excludes methane emissions from bitumen mining and upgrading in the baseline, the federal target includes these sources. In other words, Canada's federal target takes into consideration the non-negligible methane emissions from bitumen mining and upgrading. The proposed amendments involve broadening the range of sources covered by the regulations, eliminating existing exemptions, and pushing certain source categories to zero emissions.

Some selected highlights of the proposed amendments are listed below[4] and are considered key factors that are contemplated in the analysis within this report.

- Increased efficiency requirements for vent gas conservation and destruction equipment.
- Prohibition of flaring at oil sites.
- 5 m^3/day combined flare and vent volume threshold for all facilities
- Conservation or destruction requirements for surface casing vent flows
- Zero emission requirements for all pumps and controllers
- Fugitive Emissions Management Plan (FEMP) required for all facilities and well sites, with monthly inspections.
- Detected leaks must be investigated and repaired immediately, or within 30 days if the repair would require an interruption of operations.
- Annual inspections for non-producing wells, with requirements to measure and report any detected leaks.
- Near-zero emission requirements for glycol dehydrators
- Performance standards for compressor engine exhaust (1 g CH_4/kWh)
- Vent gas destruction/conservation requirements for planned pipeline blowdowns.

2.1.2. Alberta

In 2020, Alberta and the Federal government reached a methane equivalency agreement. This current equivalency agreement runs until 2025. The AER recently conducted a review of Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting in late 2022. It is understood that D060 will likely be amended with updated regulations taking effect in 2025 in order to extend the equivalency agreement with the federal government and to ensure Alberta's 2030 targets can be achieved. Specific details of the regulatory updates are not available at this time.

[4] The full list of proposed amendments is available on ECCC's webpage.

3. Model Analysis and Results

The Modern West Methane Model (MWMM) was constructed to assess where the reported emissions reductions had been achieved between 2014 and 2021 (the last year where methane data was available). The specific reductions achieved in those years are discussed in "The Road to 45" report.

The results of the model for 2021 are explored in further detail in this report to assess what emission source categories may provide further reductions to achieve the 75% target. A summary of the MWMM methodology is provided in Appendix A of this report.

3.1. Alberta's Reduction Targets

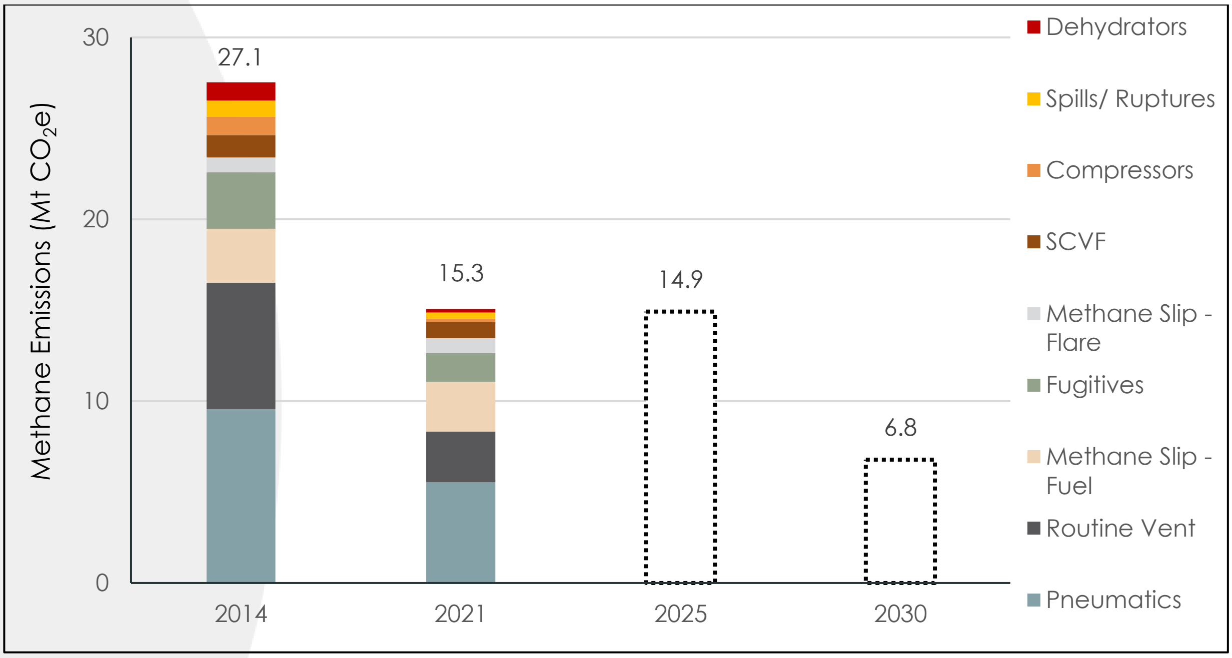

Figure 2. Methane emissions for 2014 and 2021 broken down by source category. A 44% reduction was achieved by 2021 from 2014 levels. A 45% reduction is targeted for 2025 and a 75% reduction is targeted by 2030.

As shown in Figure 2, there were 27.1 Mt CO_2e of methane emissions modelled in the baseline year of 2014. The latest modelled year for methane emissions was 2021. Methane emissions were modelled to be 15.3 Mt CO_2e across the upstream oil and gas sector in Alberta, a 44% reduction from 2014 levels.

The largest sources of reductions came from Routine Venting (4.2 Mt CO_2e), Pneumatics (4.0 Mt CO_2e), and Fugitives (1.5 Mt CO_2e). To reach the 75% reduction target in 2030, an additional 8.5 Mt CO_2e of reductions will need to be achieved from 2021 emission levels. Figure 3 shows a breakdown of the 2021 methane emissions profile. The largest remaining emissions sources are pneumatics (5.5 Mt), routine venting (2.8 Mt), and methane slip from fuel combustion (2.7 Mt).

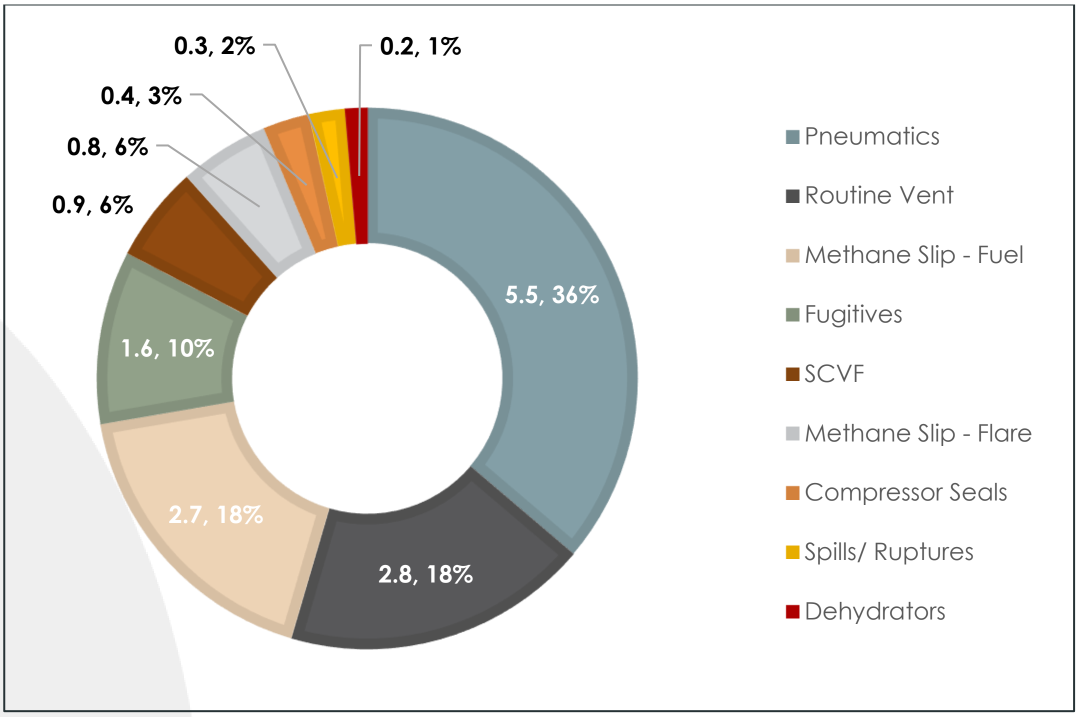

Figure 3. Breakdown of 2021 methane emissions by source category. Each source category shows the absolute emissions in Mt CO_2e and the corresponding percentage of the total 15.3 Mt CO_2e emissions in 2021.

The following subsections explore each emissions source category in more detail and discuss their remaining methane mitigation potential. The emissions source categories are ordered from largest to smallest emissions based on our 2021 model results. Based on our knowledge of the sector, we have also provided some high-level commentary on forward-looking opportunities to mitigate methane emissions. When possible, we have tested some of our assessments with relevant stakeholders within our network, including technology providers. This assessment is categorized into three sub-sections listed here. It is important to note that the options and information presented in these categories is not exhaustive, particularly in the case of Technology Options and Knowledge Gaps. Further analysis could be completed to build a more comprehensive list.

- **Technology Options** – Provides information on readily available technologies to mitigate methane emissions from the source category. Some discussion about emerging technologies is included, where available.
- **Incentive Options** – Discusses where incentive programs or other alternatives may be helpful to improve category data quality and/or emissions mitigation activities.
- **Knowledge Gaps and Barriers** – Identifies where additional information/data is required within the source category to improve understanding of the emissions profile and, where appropriate, defines other limitations and challenges that affect the analysis. This sub-section attempts to identify unintended

consequences of certain activities and highlights potential new challenges that may arise as a result of new regulations or technology implementations, etc.

3.2. Pneumatics

Pneumatic devices (pumps and controllers) are powered by pressurized gas (natural gas or compressed air). There were 5.5 Mt CO_2e of methane emissions all pneumatic devices in Alberta in 2021, making this the largest source of methane emissions for that year. The majority (72%) of pneumatic device emissions are at natural gas wells and batteries. The geographic distribution on methane emissions modelled in 2021 are shown below in Figure 4.

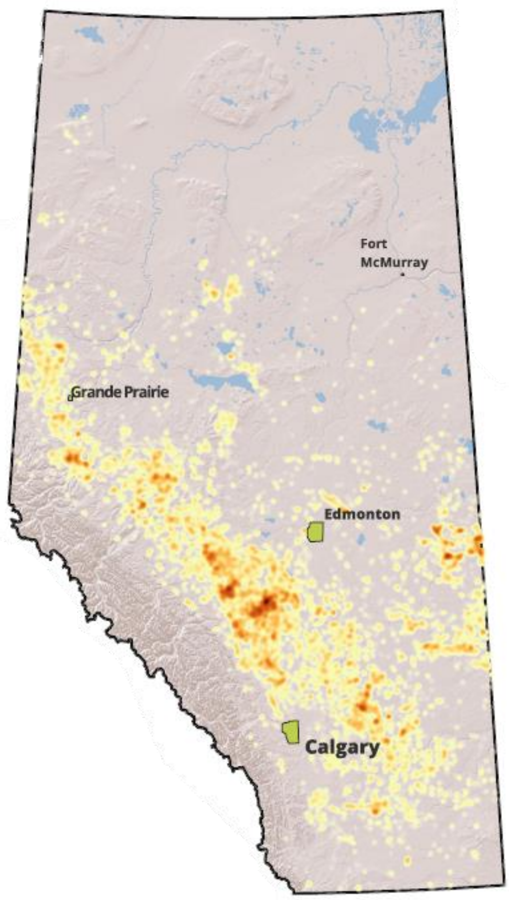

Figure 4. Heatmap showing the distribution of methane emissions from pneumatic pumps and instruments in 2021, as modelled by the MWMM. Map developed by MWA, data from AER ST60b.

As of January 1st, 2023, pneumatic devices are regulated under Directive 060 in the following manner (Alberta Energy Regulator, 2022a):

- No venting from pneumatic *instruments* installed after January 1, 2022
- No venting from pneumatic *pumps* installed after January 1, 2022

- Pneumatic instruments installed prior to January 1, 2022, must be zero vent or low bleed (< 0.17 m^3/hr)[5]

These requirements were not in place for the 2021 modelled emissions profile shown in Figure 3. It is expected that these regulations will drive large reductions from this source from 2022 to 2025. ECCC has proposed requiring non-venting solutions for all pneumatic devices in the updated methane regulations. Many operators in Alberta have recently retrofitted their pneumatic instruments to low-bleed versions to meet Directive 060 requirements. Consequently, there will be additional cost associated with a second round of retrofits in the case where low-bleed devices can be converted to zero-bleed with an instrument air package.

Technology Options

Some examples of available technology options to reduce methane emissions from pneumatic devices are listed below:

- Alternative energy sources for pneumatic devices includes electrification, compressed air or nitrogen, and fuel cells. Since 2018, 6.1 Mt CO_2e of pneumatic offsets have been registered in the province ("Alberta Carbon Registry," 2022)[6].
- Importantly, high bleed conversion to zero bleed using instrument air will benefit from conversion to low-bleed devices first, thereby reducing the size of the instrument air package. For those sites that have converted from high to low bleed pneumatic devices for D060 compliance, small instrument air packages, or supplied nitrogen, will be the likely technology option.

Incentive Options

Conversion of brownfield pneumatic pumps and low-to-zero pneumatic instruments are still eligible to generate offset credits under the latest D060 requirements. The current pneumatic offset protocol can continue driving emissions reductions from this source.

- Pneumatic chemical injection pumps have an offset potential of 40 - 400[7] tCO_2e per year (Petroleum Technology Alliance Canada, 2023). However, low-bleed pneumatic devices[8] can have an offset potential of just 5 – 30 tCO_2e per year. By 2025, it is possible that most companies have identified and retrofit their pneumatic devices where the offsets economics make sense to do so.

[5] There are specialized requirements for level controllers based on the device's actuation frequency under normal operating conditions.
[6] Data aggregated from an MWA analysis of the AEOR database.
[7] This range depends on a number of site and pump specific factors such as operating hours, injection rate, and fuel gas methane composition. While 400 tonnes per year is technically possible, the average electric pump will offset closer to 100 tonnes per year.
[8] Low-bleed devices have vent rates less than 0.17 m^3/hr.

Knowledge Gaps and Barriers

Some knowledge gaps in the pneumatic devices' methane emissions category and ways to reduce the remaining emissions from this emission category may benefit from the following questions:

- What impact would new zero-vent regulations have on the mitigation costs at facilities where retrofits have recently occurred (I.e.: high to low bleed devices)? Is there a risk of stranded low-bleed assets? What proportion of remaining pneumatic emissions can be considered "hard to abate"? How close to zero can this emissions source be squeezed?
- Will producers be incentivized enough to pursue new offset projects from pneumatic retrofits if the crediting period is cut short by the phasing in of new regulations?
    - Is there sufficient rationale to extend the MTIP[9] program beyond its current timeframe to capture these marginal retrofit projects with constrained economics under the offsets system?

3.3. Routine Venting

Routine venting covers several emission sources which occur on a regular basis as a part of normal operations, most notably associated gas venting, tank vents, and purge vents (Alberta Energy Regulator, 2020). There were 2.8 Mt CO_2e of methane emissions resulting from routine (direct) venting in 2021. This was the second largest source of emissions in the sector in 2021. The distribution of routine vent emissions is shown below in Figure 5.

[9] Alberta's Methane Technology Implementation Program (https://www.carbonconnectinternational.com/mtip?gclid=Cj0KCQjwnMWkBhDLARIsAHBOftogbkamXqycspbxDk94hcAwmlXMKAxF33lYkFlkheBu8lOS1qxovisaAnGcEALw_wcB)

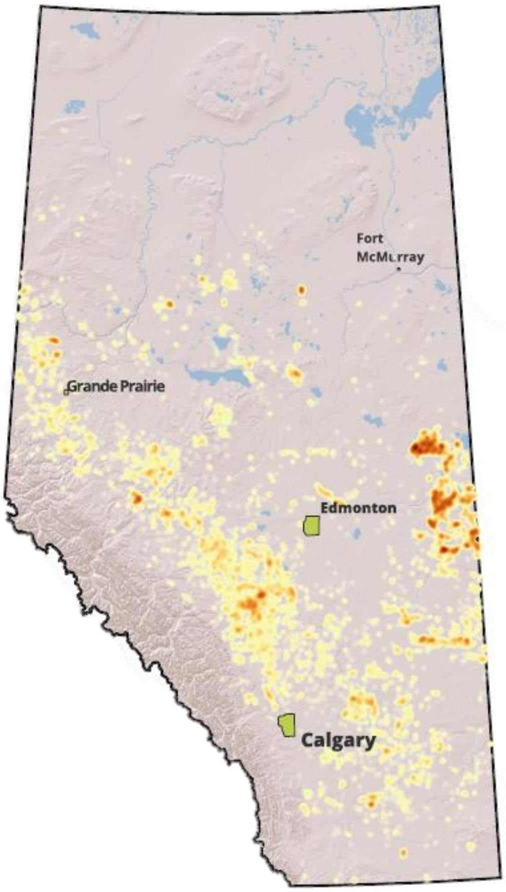

Figure 5. Heatmap showing the distribution of 2021 methane emissions from routine venting modelled by the MWMM.

Figure 5 shows that there is a high intensity of venting occurring in the Lloydminster/Cold Lake region, where there is a large number of closely located crude bitumen and crude oil batteries. This is aligned with a 2021 study that found that the Lloydminster region had the highest methane emissions intensity in Alberta (MacKay et al., 2021)[10].

"The Road to 45" report indicated that there have been significant reductions in this source from the 2014 baseline, when routine vent emissions were estimated to be 7.1 Mt CO_2e. Directive 060 currently regulates routine venting through the site level Defined Vent Gas (DVG) Limit of 3.0 10^3 m^3 of vent gas or 1.8 10^3 kg of methane per month, per site. Alternatively, crude bitumen batteries can choose to be regulated under a fleet average limit of 1.5 10^3 m^3 of vent gas per battery.

Technology Options

Some examples of available technology options to reduce methane emissions from routine vent sources are listed below:

- Vapour Recovery Units (VRU) capture and compresses associated gas at the tank headspace. The compressed gas can be used on-site or sent to a sales gas

[10] Based on a production weighted methane intensity.

line. VRUs can be prone to leakage and require regular maintenance. VRUs may not be economical solutions for single tanks with low associated gas production (Sentio Engineering, 2015).

- Incinerators/Enclosed Combustors destroy captured vent gas, with destruction efficiencies greater than 99%, These technologies are smaller and more compact than a flare stack. Also, where flares must be at least 25 m from processing equipment and storage tanks, enclosed combustors can be as close as 10 m from processing equipment and storage tanks (Alberta Energy Regulator, 2022a). Combined, enclosed combustors are a cost-effective option to flares, and considered a good option when gas conservation options are not available.

Incentive Options

The GoA released a *Quantification Protocol for Vent Gas Reduction* in November 2021 (Government of Alberta, 2021). This protocol creates the opportunity for emission offsets generation through the capture of gas that would otherwise be vented to atmosphere. Gas capture activities must be deemed additional to the vent gas limits (OVG, DVG, crude bitumen fleet averages) imposed by D060 in order to generate offset credits. There are two categories of emission reduction activities under this protocol:

- **Conservation:** capture and injection into sales gas pipeline or on-site fuel combustion.

- **Destruction:** capture and route to an incinerator, combustor, or existing flare.

Duration of project eligibility is a critical matter that will determine the success of this incentive option. For example, if the DVG were lowered from 3,000 to 150 m^3/month as per the proposed ECCC regulations, many vent gas reduction projects would no longer be considered additional to requirements, thereby eliminating the carbon offset option.

Knowledge Gaps and Barriers:

Some of the barriers that could potentially impact methane reduction options from the routine vent source category are discussed below.

- Lack of pipeline infrastructure at remote sites. Conserved gas needs to be sent to a gas plant for processing before transmission and distribution. Gas gathering infrastructure may not exist at crude oil sites that were not originally designed to conserve associated gas. Sites without accessible gas infrastructure will be forced to combust or flare the recovered gas on site.

- Variable gas volumes. Associated gas vent rates can be highly variable and inconsistent. Gas production also generally declines over time (Sentio Engineering, 2015). Producers will require a thorough understanding of the emissions abatement potential of their assets before undertaking voluntary emissions reduction projects. Zero-vent requirements at low-venting sites may be cost prohibitive and could result in well shut-ins and stranded assets.

- Initial capital costs of conservation solutions. Vent gas capture technologies require a large initial capital investment. This can be a barrier for smaller to medium size producers employing these technologies at their facilities.

3.4. Methane Slip – Fuel Combustion

Methane slip is the result of incomplete combustion of methane gas. Methane slip is divided into two subcategories, Fuel Combustion and Flaring (discussed in Section 3.7.). The geographic distribution of methane slip from fuel combustion is shown below in Figure 6.

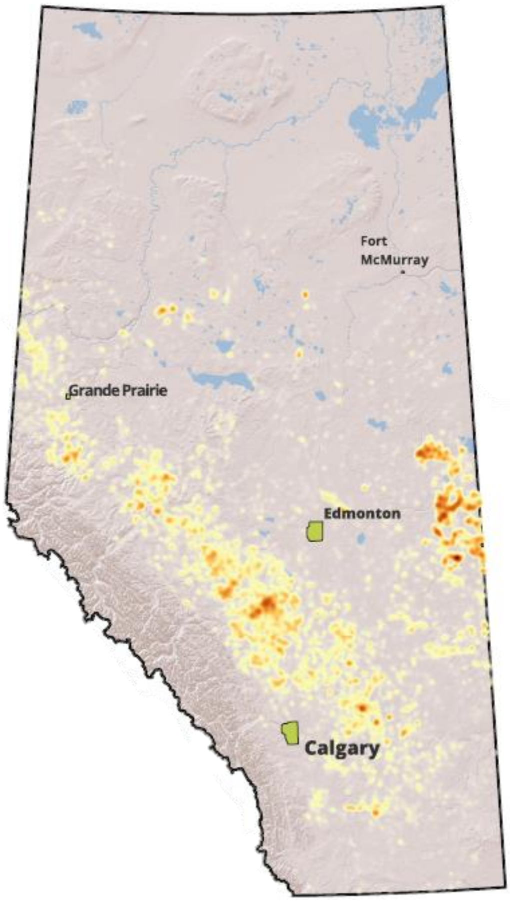

Figure 6. Heatmap of the geographic distribution of 2021 methane emissions from incomplete stationary fuel combustion in Alberta, modelled by the MWMM.

Methane slip from incomplete fuel combustion was a significant source of methane emissions in 2021. This source was estimated to produce 2.7 Mt CO_2e of methane emissions, approximately 18% of the total methane emissions profile for that year. Methane slip from incomplete fuel combustion was the third largest source of methane emissions in the sector in 2021.

Figure 7 below shows the modelled 2021 methane slip form different facility types.

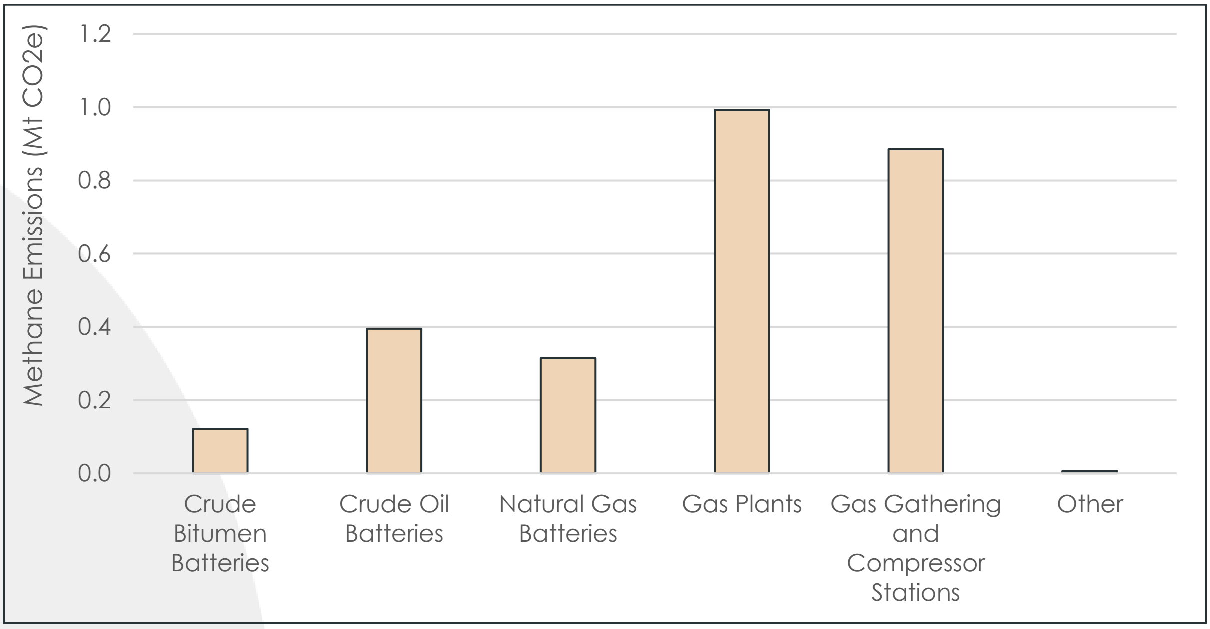

Figure 7. Modelled 2021 methane emissions from incomplete fuel combustion at upstream oil and gas sites in Alberta.

Methane slip is an unregulated methane source in Alberta[11], not currently covered under Directive 060. Regulators may elect to control emissions from this source category in future policy updates. This approach would come with several considerations:

- The vast majority (>98%) of combustion methane slip is produced by reciprocating engines, with the remaining methane coming from turbines, boilers/heaters, or incinerators. Regulations or incentive programs should therefore focus on reducing methane from reciprocating engine exhaust.
- There is a balance between NO_x and CH_4 emissions in engine exhaust. A leaner burn (excess O_2) engine will emit less NO_x but more methane than a rich burn engine (oxygen starved) (Nowak and Beshouri, 2019).
- Generalized emission factors for methane exhaust are shown below in Table 2. Engine manufacturers will have their own factors specific to their engine makes and models. The table also shows the engine performance standard proposed by ECCC.

[11] GHG emissions from stationary fuel combustion are regulated under TIER in Alberta.

Table 2. Methane exhaust emission factors for various natural gas combustion sources. Emission factors are derived from US EPA WebFIRE (United States Environmental Protection Agency, database and ECCC proposed regulations and converted to a common g/GJ unit.

Fuel Destination	Methane Emission Factor ($g\ CH_4/GJ$)
Natural Gas Turbine	3.7
Natural Gas Boiler	0.97
Uncontrolled Natural Gas Engine (4-cycle Rich Burn)	98.9
Uncontrolled Natural Gas Engine (4-cycle Lean Burn)	537.4
ECCC Proposed Engine Performance Standard	277.8

Technology Options

Existing Technologies

- Engine modernization program to reduce unburned methane from engine exhaust (Petroleum Technology Alliance Canada, 2021), (Waukesha Innio, 2023).
- Install engine catalyst and Air Fuel Ratio controllers on uncontrolled rich burn engines.
- Electrification. Convert natural gas fired engines to electric drivers to 100% eliminate combustion slip methane emissions. Specifically target large gas plants and compressor stations, which are responsible for the majority of modelled methane emissions from fuel combustion in the sector, as shown in Figure 7. There are many examples of compressor stations and large gas plants electrifying in northeastern B.C where there is an abundance of locally available hydropower (Ministry of Environment and Climate Change, . Access to reliable grid electricity at remote sites in Alberta is a barrier to the electrification of the provinces fleet of reciprocating engines.

Emerging Technologies

- Hydrogen slipstream additive into fuel, to help combust methane in piston "cold spots" that otherwise escapes as fugitive emission. Recent research results showed that the addition of 3.5% hydrogen in a pre-combustion chamber reduced hydrocarbon exhaust emissions by 30-40 percent in lean burn engines (Soltic and Hilfiker, 2020).
- Lean-burn post combustion catalyst to increase methane oxidation.

Knowledge Gaps and Barriers

Some of the existing gaps in the technology to reduce methane emissions from combustion methane slip are listed below.

- Detection and quantification techniques for methane in engine exhaust. Optical Gas Imaging (OGI) cameras cannot detect methane slip because the exhaust is too hot. The OGI camera is cryogenically cooled to remove most background IR energy. But engine exhaust temperature overwhelms the camera. Currently, studies may employ aerial and ground-based detection surveys and then assign methane emissions to engine exhaust through the process of elimination (Johnson et al., 2023b).
- Complete combustion catalyst technology for lean burn engines. Natural Resources Canada has developed and patented a robust oxidation catalyst that reduces unburned methane from lean burn engines (Natural Resources Canada, 2022). The U.S. Department of Energy is also funding several low methane slip engine projects, but the technology is not commercially available at this time (Advanced Research Projects Agency - Energy, 2022a, 2022b, 2022c.
.

Other knowledge gaps include:

- Current engine slip emission factors are derived from the U.S. EPA database. Many factors affect fuel combustion in an engine (fuel composition, operating load, atmospheric conditions). Could be beneficial to determine Alberta O&G sector specific EFs through a field program.
- Engine inventory – submitted to ECCC under the Multi-Sector Air Pollutants Regulations (MSAPR), but it would be beneficial to share this database with other stakeholders. Without a complete engine database, assumptions about the makeup of reciprocating engine types must be made for modelling purposes.
- Catalytic heaters are a recognized source of methane slip. It is understood that possibly 50% of the fuel supply is not combusted and is released with the hot heater exhaust. Catalytic heaters are commonly used in industry for building heat. There are thousands in service, ranging from 1,000 to 50,000 Btu/hr. An inventory of both equipment and emissions has not been established.

3.5. Fugitives

Fugitive emissions are the unintentional releases of gas to the atmosphere from equipment components, such as valves, connectors, and meters. Equipment leaks are unpredictable, and the amount of methane released depends on how quickly a leak is detected and repaired. Approximately 1.6 Mt CO_2e of fugitive methane emissions were modelled in Alberta in 2021[12]. Figure 8 shows a heatmap of the distribution of the fugitive emissions reported to the AER in 2021.

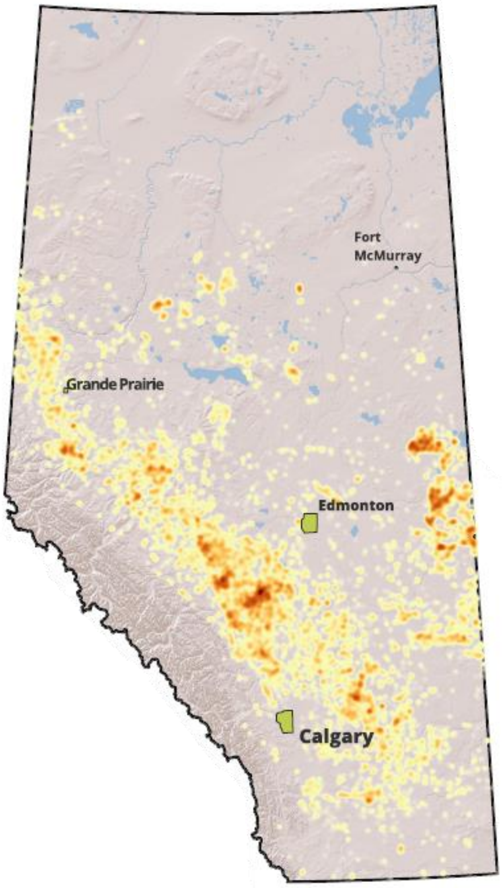

Figure 8. Heatmap showing the distribution of 2021 methane emissions from fugitives modelled by the MWMM.

Directive 060 fugitive survey requirements first began in 2020 but these requirements were eased due to the COVID-19 pandemic, meaning that 2021 was the first full year where LDAR survey and repair activities were mandated. An annual LDAR survey is required at all active facility subtypes, except at compressor stations and sweet gas plants where surveys are required three times per year (Alberta Energy Regulator, 2022a).

- ECCC's proposed methane amendments would introduce monthly survey requirements at all facilities and would impose more stringent conditions for repair timelines.

Technology Options

Many of the technology options for fugitive emission mitigation involve the timely detection and quantification of fugitive releases. These detection and quantification

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[12] For this report, "Fugitives" are considered to be unintentional emissions from equipment or component leaks. Pneumatics are considered their own emissions category.

technologies are also important for the mitigation of other methane sources, such as Routine Venting, Methane Slip, and Surface Casing Vent Flow, as well as improving the overall quality of modelled methane emissions. For this reason, a comprehensive discussion of methane detection and quantification technologies is presented in its own subsection, Section 3.11 of this report.

- A proactive mitigation option is to reduce the occurrence of fugitive releases in the first place by employing ISO 15848-1 (International Standards Organization, 2015) certified "low emissions" valve designs at well sites and facilities[13].

Knowledge Gaps and Barriers

- Under Directive 060, the AER allows for companies to apply to use an alternative Fugitive Emissions Management Program (alt-FEMP). An alt-FEMP program may use long range or remote sensing technologies such as UAVs, aircraft, satellites, truck-mounted sensors, or continuous monitoring technologies. Currently, each alt-FEMP application must be reviewed and approved by the AER.
    - A study evaluating current and emerging emission quantification technologies is currently underway, with an estimated date of completion in December, 2023[14]. Follow-up studies could be designed to compare and ensure the effectiveness of alternative emission detection technologies.
    - Data from approved alt-FEMP technologies is not reported in a transparent way.
- Site-level screening technologies are unable to discern between emissions from fugitive leaks and routine venting, which can lead to "false-positives" (Fox et al., 2019).
- The reliability of fugitive emissions data is often poor; there are many variables, such as camera operator experience and site conditions, that can make fugitive emissions data difficult to reproduce.

3.6. Surface Casing Vent Flow and Gas Migration

Surface casing vent flow (SCVF) and gas migration (GM) are both detected gas flows that occur at the wellhead surface. SCVFs occur from within the well casing annulus, while GMs are detected outside the well casing. The geographic distribution of SCVF volumes reported to the AER in 2021 is shown below in Figure 9. SCVF/GM are prone to occur at older, non-operating or suspended wells, which are more commonly found in the southeast and central/west parts of the province.

[13] https://www.slb.com/valves/valve-applications/low-emission-valves
[14] https://auprf.ptac.org/air/evaluation-of-current-emerging-emission-quantification-tools/

Figure 9. Heatmap showing the distribution of methane emissions from surface casing vent flows reported in 2021. Map developed by MWA, data from AER** (Alberta Energy Regulator, 2023a).**

There were 0.9 Mt CO_2e of modelled methane emissions attributed to surface casing vent flows (SCVF) or gas migration (GM) in 2021. It is important to note that this modelled source category relies on SCVF/GM gas volumes reported annually to the AER (Government of Alberta, 2023a). Recent research shows that there may be significant emissions from this source that go undetected and/or unreported (Johnson and Tyner, 2020).

The AER requires testing, reporting, and repairing[15] requirements for SCVF and GM events under Directive 087 (Alberta Energy Regulator, 2022b). Directive 060 fugitive emission requirements now require an operator to survey surface casing vents and areas around the wellbore for leaks. These measures ensure that data is being captured, however, further consideration for improved data collection and reporting may be helpful in developing future regulations or supporting carbon offsets development for this emissions source.

[15] D087 only requires repair activities for wells with measured flows rates greater than 300 m^3/day.

Technology Options

Emerging Technologies

- Continuous monitoring technologies at remote wells to alert operators of a significant SCVF event. Similar monitoring and detection options as discussed in Section 3.4.
- A catalytic oxidizer to convert SCVF methane to CO_2 is being developed. This technology could be deployed at suspended or non-operating wells to mitigate SCVF emissions (CERIN, 2022).
- Advanced alloy sealing technology to repair and permanently seal vent gas flows at wellhead casings[16].

Knowledge Gaps and Barriers

- Need to increase MMR activities to better understand and quantify this emissions source. Recent research suggests that SCVF is responsible for the majority of measured emissions at Cold Heavy Oil Production (CHOPS) wells in the Lloydminster area (Festa-Bianchet et al., 2022). The accuracy of methane measurement at CHOPS wells could be improved with continuous metering instead of using gas-in-oil ratio estimates (Clarke, 2022).

3.7. Methane Slip – Flaring

This is the second of two subcategories for emissions that arise from the incomplete combustion of methane. This section focuses on methane slip from gas sent to flare stacks. Flares have a destruction efficiency between 95-98 percent, meaning that 2-5% of the flared gas escapes as un-combusted methane. Figure 10 shows the distribution of flared gas methane emissions modelled in 2021.

[16] Seal Well Inc. technology that has received funding from Alberta Innovates and ERA

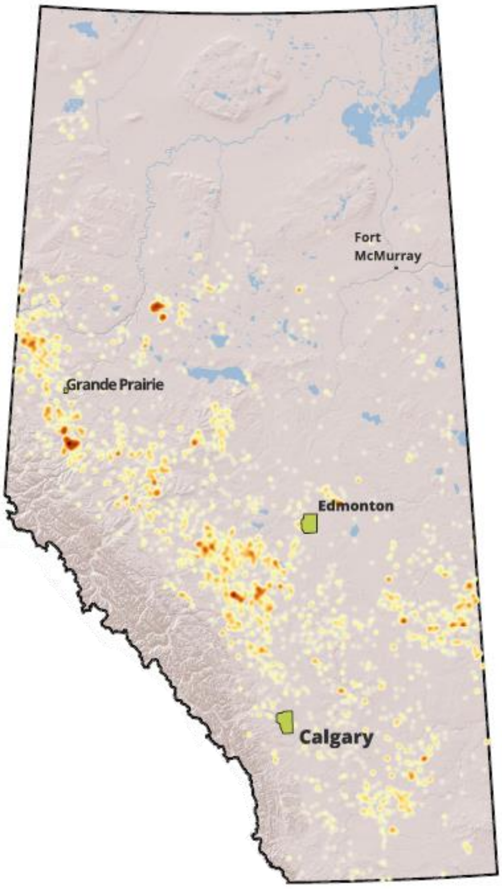

Figure 10. Heatmap showing the distribution of 2021 methane emissions from flare slip, modelled by the MWMM.

There were 0.8 Mt CO_2e of methane emissions from the incomplete combustion of flared gas in 2021. This represents 6% of the methane emissions profile in Alberta. While not a significant source of emissions, this category has available mitigation technology and building a program to improve data quality may prove helpful to mitigation these emissions further.

There has been a general uptick in flared gas volumes across the sector since 2019, as companies adapted to the direct venting limit regulation by tying tank and compressor vents to a site's flare stacks. The distribution of flaring slip emissions facility subtype for 2021 is shown below in Figure 11.

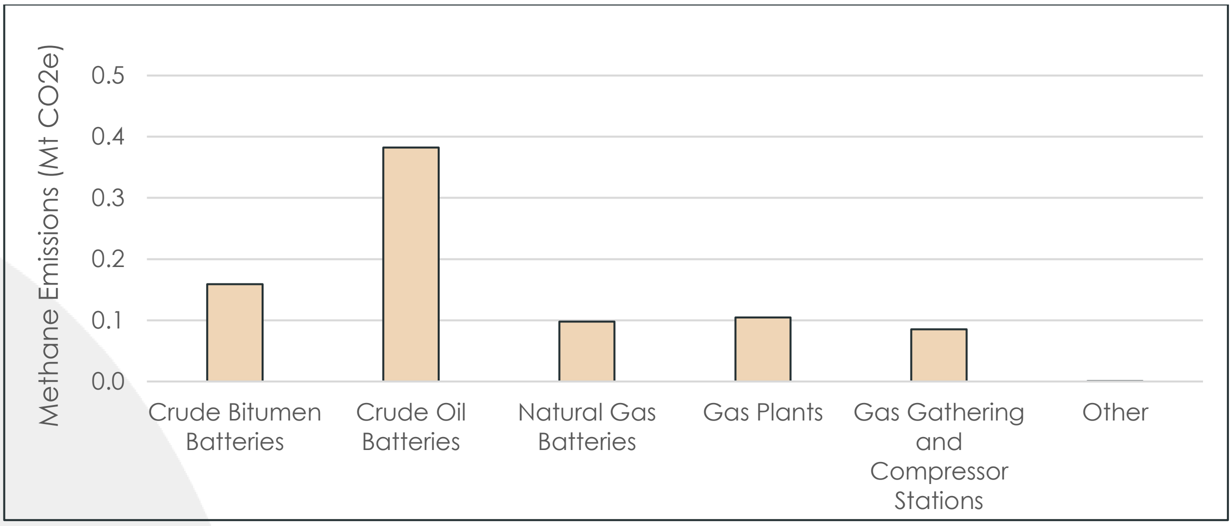

Figure 11. Modelled 2021 methane slip emissions from flaring at upstream oil and gas sites in Alberta, categorized by facility subtype.

Like methane slip from fuel, slip from flares is not currently regulated under D060. However, GHG emissions from flaring are covered under TIER for large emitters and opted-in facilities and will be covered under TIER for aggregate facilities starting in the 2023 compliance year (Government of Alberta, 2023c). The proposed ECCC methane amendments would prohibit all (routine) flaring at conventional oil sites. Vent gas would be flared only during non-routine or emergency events.

Technology Options

Existing Technologies:

- The most effective method to reduce methane slip from flaring is to simply reduce flared gas volume, via gas conservation activities. Various gas conservation technologies are discussed in Section 3.2 of this report.
- When flaring is still necessary, flame-out detection and auto-ignition devices installed at unsupervised flare stacks can ensure a maximum flare combustion efficiency (United States Environmental Protection Agency, 2011).

Emerging Technologies:

- Ultra-high destruction efficiency (> 99.5%) flare technology (Advanced Research Projects Agency - Energy, 2022d, 2022e.

Knowledge Gaps and Barriers:

- Lit flares are assumed to be ~98% efficient at converting methane to carbon dioxide for modelling purposes (Government of Alberta, 2023a). The prevalence of unlit flares in the Alberta O&G sector is still not well understood, however research from other jurisdictions suggests that venting from unlit flares is a more significant source of methane emissions than previously thought (Plant et al., 2022), (Duren and Gordon, 2022), (Tyner and Johnson, 2021).

- Consideration for improving the data from this emissions source may prove helpful. This may be achieved through some sort of baseline data program similar to the current BROA program in Alberta. More details in Section 7.

3.8. Compressor Seals

Compressor seals are designed to reduce vent gas leakage, but leak rates will rise as the seals wear over time. Gas compressors are commonly located at gas batteries, gas plants, gas gathering systems, and compressor stations.

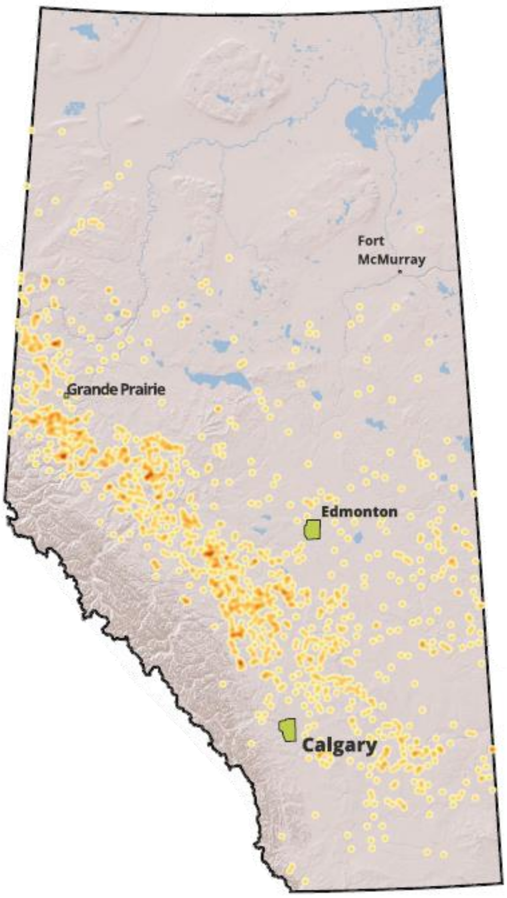

Figure 12. Heatmap showing the distribution of 2021 methane emissions from compressor seals modelled by the MWMM.

There were 0.4 Mt CO_2e of methane emissions were modelled from compressor seals in 2021. Figure 12 shows the geographic distribution of compressor seal emissions reported to OneStop in 2021. Compressor seal emissions are reported most often in the western part of the province, where there are greater number of natural gas batteries and gas plants.

Under Directive 060, compressor seal vent testing and reporting began in 2020. However, compressor seal vent gas limits did not come into effect until 2022.

Technology Options

Existing Technologies:

- Vent gas capture technologies (ex: Slipstream)
- Compressor packing seal replacement/upgrades.

Emerging Technologies:

- Zero-venting compressor technology development currently supported by Alberta Innovates[17].

Incentive Options

- The Alberta *Quantification Protocol for Vent Gas Reduction* allows operators to generate offset credits through vent gas capture activities that are additional to regulatory requirements.
- Compressor vent gas utilization, destruction, and conservation technologies are eligible project types for funding from MTIP[18].

3.9. Spills and Ruptures

There were 0.3 Mt CO_2e of methane emissions modelled in 2021. The average yearly spill and rupture emissions between 2010 and 2021 were 0.4 Mt CO_2e. It is difficult to speculate on the frequency of pipeline release incidents in the future. There are pipeline inspection and maintenance regulations in place. In addition, there are fines, lost revenue, and negative publicity associated with a release incident; plenty of incentive for pipeline operators to maintain their assets.

3.10. Glycol Dehydrators

There were 0.2 Mt CO_2e of modelled methane emissions from glycol dehydrators in 2021. This is a significant decline from the 0.9 Mt CO_2e of emissions modelled in the 2014 baseline year. The modelled emissions reductions for this source are attributed to the AER's *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators* (D039) (Alberta Energy Regulator, 2018). Directive 039 was first published in 2007 and came into effect in 2008 to curtail benzene emissions that were being measured from dehydrator units. Benzene control technologies listed in D039 include flares, incinerators, vapour recovery units, and reciprocating engine emissions control equipment. These technologies all have the added benefit of reducing methane emission from dehydrators.

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[17] https://albertainnovates.ca/app/uploads/2020/08/Zero-Emissions-Natural-Gas-Compressor-1.pdf
[18] All approved MTIP projects were directed to be completed by March 31, 2023.

Directive 060 introduced vent gas limits for dehydrators starting on January 1st, 2022:

- New units must limit methane emissions to less than 68 kg of methane per day.
- Old units (installed before Jan 1, 2022) must limit emissions to less than 109 kg of methane per day.
- The average dehydrator only vented 17.7 kg of methane per day in 2021 (Alberta Energy Regulator, 2023b).

Technology Options

- A flash tank separates and captures up to 90% of the methane from the rich glycol stream (United States Environmental Protection Agency, 2006).
- Other technological options to further mitigate this source include flares, incinerators and vapour recovery units. Challenges related to these technologies are outlined in Section 3.2.

This source category is an example of where regulations and technology have combined to successfully achieve a greater than 75% reduction in methane emissions from 2014 levels in just seven years.

3.11. Methane Detection and Quantification Technologies

In the last 15 years, there has been tremendous advancements in technologies to detect and quantify methane releases in oil and gas operations.

In the 1980's the US EPA prescribed Method 21 to detect fugitive emissions from industrial components including valves, flanges, connectors, pumps, and compressors (United States Environmental Protection Agency, 2016a). Method 21 required a specialized portable, intrinsically safe VOC analyzer, battery-powered sample pump and a sample probe ¼-inch in diameter. The method is labour-intensive and limited to equipment that was within reach of the operator and the sample probe.

Studies performed by the EPA, API and others in the 1990's determined that Method 21 missed many releases. These studies also introduced the concept of 80/20, where 80% of the emissions are from only 20% of the leaking components. Variations of 80/20 remain today.

In 2005, FLIR introduced the GasFIndIR® optical gas imaging (OGI) camera for leak detection. In 2008, the US EPA promulgated the Alternate Work Practice, dubbed 'Smart LDAR', which allowed LDAR programs to use OGI rather than Method 21. In 2016, the EPA promulgated 0000a (Quad -O) for Upstream Oil and Gas industry, recognizing OGI as the instrument of choice for emissions detection (United States Environmental Protection Agency, 2016b).

3.11.1. Optical Gas Imaging Camera

Today, FLIR's GFx320 has become ubiquitous in the oil and gas sector.

Advantages of the FLIR OGI cameras include:

- Hand-held and portable
- Suitable for hazardous locations
- Detection limits as low as 0.1 m3/day are possible, noting that LDL is dependent on distance and temperature gradients,
- Quantification of releases is possible when paired with FLIR's Qualitative Optical Gas Imaging system (QOGI) or Hi-flow samplers (see next subsection)
- Still the only technology that can truly pinpoint a release, and the only device that can survey inside a building.

Disadvantages of the FLIR OGI Camera include:

- Labour intensive relative to emerging screening technologies
- Single 'point-in-time' measurement, so intermittent releases are challenging to detect.
- Data products include 'free form' description of equipment, presenting challenges to compile and analyze.
- Cannot measure methane slip in engine or heater exhaust due to the high exhaust temperatures.

3.11.1.1. Quantification of Fugitive Emissions with Handheld Devices

The FLIR OGI Camera is widely deployed in Canada for methane detection. However, the camera itself will not quantify[19]. There are 2 common quantification technologies that can be used in conjunction with OGI surveys:

Bacharach Hi Flow® Sampler.

Originally developed in 2001 by Bacharach Inc (now MSA), the Hi Flow ® Sampler is a portable, intrinsically safe, battery-operated instrument designed to determine the rate of gas leakage around various pipe fittings, valve packing, and compressor seals in oil and gas facilities. The gas sample is drawn into the unit through a flexible 1.5" I.D hose. Methane concentration is measured with a low-range catalytic oxidation sensor and a high-range thermal conductivity sensor.

Although still in wide use, Bacharach has not manufactured the Hi Flow Sampler for a number of years, and replacement parts are becoming difficult to find.

[19] Note that FLIR released a new camera at the time of this writing. More details required to ensure statement accuracy.

Providence QL320™

Providence QL320™ is an add-on device to FLIR's GF320 OGI cameras. The QL320 analyzes pixels in the GF320 plume videos and quantifies the release rate. Wind speed, temperature, and distance from the camera to the release are required inputs. A benefit of the QL320 is it can quantify hard-to-access releases that Hi-Flow samplers cannot reach. A drawback of the QL320 is the time required to acquire sufficient plume videos to quantify the release.

A number of new samplers have appeared on the market. One notable example is:

> SEMTECH® HI-FLOW 2 (sensors-inc.com) incorporates a Tunable Diode Laser Absorption Spectroscopy (TDLAS) for accurate concentration measurement, high-volume vacuum sampling fan, and an accurate flow meter, capable of quantifying fugitive emissions between 0.05 to 1000 m3/day.
>
> The SEMTECH HI-FLOW 2 may be a versatile tool beyond fugitive quantification. The accurate TDLAS may be able to measure methane concentrations in tank vents and engine exhaust. Field evaluation can confirm this.

3.11.2. Autonomous, continuous fixed OGI cameras

Two emerging technologies are addressing some of the limitations of handheld OGI cameras by autonomous and continuous installation on fixed towers. Both technologies are designed to monitor large persistent and intermittent releases from tanks, flare systems, and pressure safety valves (PSV's)

Kuva Camera Solutions

The Kuva GCI360 camera is a continuous Optical Gas Imaging (OGI) camera that uses a passive Shortwave Infrared (SWIR) sensor to detect hydrocarbon gas emissions. The system can be permanently installed or can be deployed temporarily. The entire system can be set up in less than two hours and is fully self-contained, cloud connected and autonomous, so it can be left in place to operate indefinitely and remotely. Kuva's camera requires sunlight and detects and quantifies methane during daytime.

FLIR's new Autonomous Detection of Gas Leaks and Emissions (ADGiLE)

FLIR's new system uses the GF77a uncooled camera, pole mounted, with pan and tilt capabilities. Analytics including quantification is powered by Providence. The system can operate day and night. The system is presently being field tested in the US and will be available commercially in Q3 2023.

3.11.3. Ground-based Fixed Sensors

There is growing interest in low-cost fixed sensors installed at the perimeter of a facility for detection, quantification, and localization of methane releases. Qube, Scientific Aviation, Project Canary and others have deployed systems in Canada and continue to use field testing to refine their technologies. The systems typically include a methane sensor capable of measuring methane concentration in the air in parts-per-million (ppm), anemometer for wind speed and direction, solar panels, batteries, and a wireless communications package.

A main benefit of ground-based fixed sensors is the continuous '24/7/365' operation. Future development work includes optimization of the number and location of the sensors. Also, plume dynamics may limit the ability of ground-based sensors to detect and quantify methane slip in hot engine exhaust. This is an area for future studies.

3.11.4. Aerial Screening

The use of small fixed-wing aircraft for methane detection, quantification and localization has grown significantly in the last 5 years. Low speed, low altitude planes with onboard sensors can screen 100 or more facilities a day, identify methane plumes, superimpose images of the plumes on geo-spatially accurate aerial images, and calculate the release rate using modelled wind speed and direction.

> Bridger Photonics Gas Mapping LiDAR (GML) has been deployed commercially in Alberta since 2020. Bridger uses laser light absorption to detect, localize, and quantify methane gas.

> Lidar Services International (LSI) is a new entrant in aerial screening. LSI deploys an optical sensor developed by Telops. LSI is based in Calgary, Telops is based in Quebec City. The optical sensor uses passive infrared hyperspectral imaging to detect and visualize methane release.

Both Bridger and LSI require an estimate of local wind speed and direction to quantify the releases. Commercial weather models are typically used to estimate wind speed at the sites. The ability of the models to accurately predict local wind speed and direction at a O&G facility is unknown, but inaccurate wind speed and direction will generate inaccuracies in release rate calculations. Additional field work is required to compare local wind measurements to modelled wind speed and direction and determine the impact on release quantification.

3.11.5. Predictive Emissions Monitoring Systems (PEMS)

There are tens of thousand of active oil and gas wells and facilities in Alberta, each of which can have hundreds or thousands of equipment and components with the potential to leak methane. This means that mitigation of fugitive emissions is also a "big data" problem. Several companies are attempting to leverage recent advances in Artificial Intelligence (AI) and Machine Learning (ML) to develop and train AI models that can detect and even predict fugitive methane emissions. This is a new and evolving technology space with the potential to help improve the efficiency of LDAR programmes, although the actual impact of PEMS is difficult to forecast at this time.

4. Discussion

Based on the latest methane data released by the GoA, the Alberta UOG sector will need to reduce methane emissions by 8.5 Mt from 2021 levels to reach the 75% reduction target in 2030. This section is intended to contemplate the mechanisms that will enable this 8.5 Mt reduction, again noting that 2022 data is not included in this analysis. We suspect the emissions profile to be lower in 2022 than in 2021.

Figure 13 provides a summary visualization of the state of the methane emissions source categories modelled in 2021. Each source category was assigned a qualitative "mitigation difficulty" that describes the sector's ability to further reduce emissions from 2021 levels using the current regulatory, incentive, and technological framework.

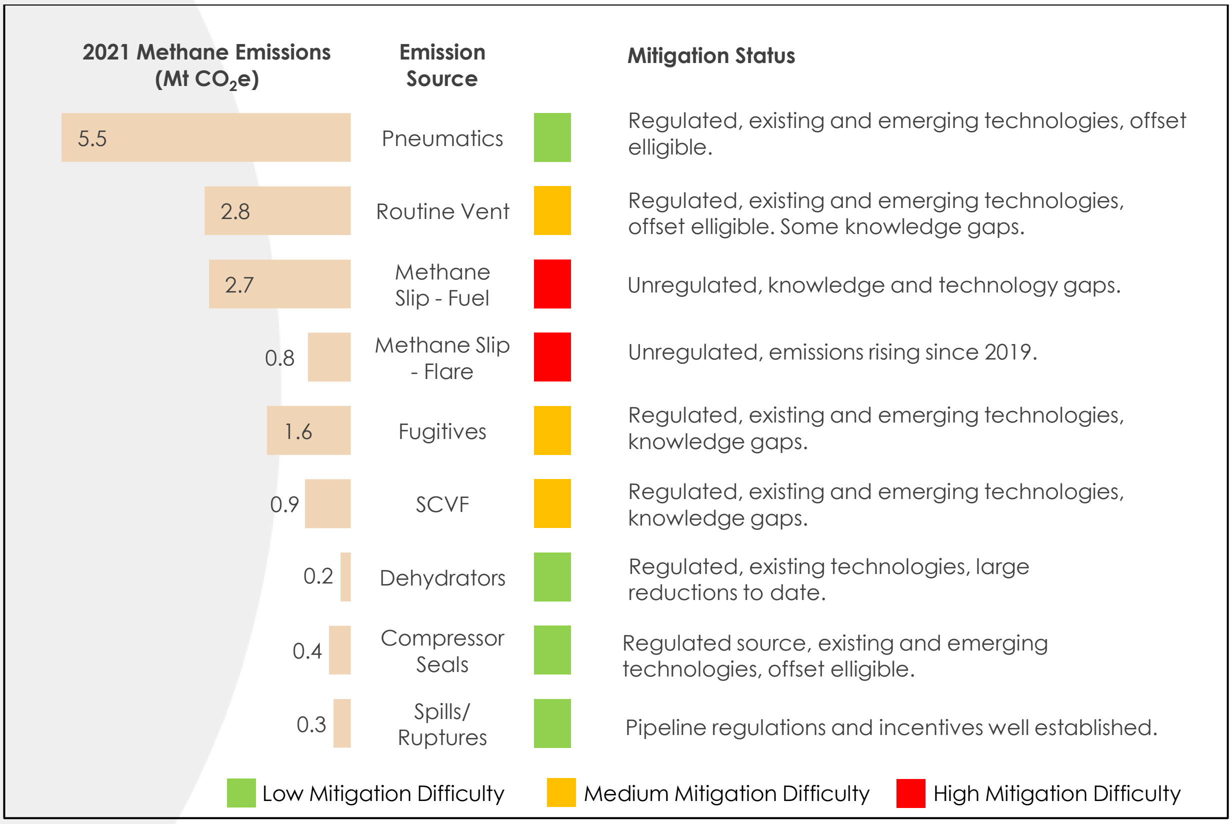

Figure 13. MWMM modelled emissions by source category in 2021 and a qualitative difficulty level for further reductions.

In 2021, the largest methane emissions source was pneumatics (5.5 Mt, 36%[20]). Between 2014 and 2021, we saw a 4.1 Mt drop in the pneumatics emission profile. Recently enhanced regulations should drive further pneumatic emission reductions, and updated regulations will likely require zero-vent alternatives at all facilities at some point between 2025 - 2030. Until then, offsets should continue to drive pneumatic pump retrofits and zero-vent instrument conversions until the new regulations are phased in. However, consideration can be given to the impact offsets ineligibility will have if/when new regulations emerge.

[20] Percentage indicates proportion of total methane emissions in 2021.

Regulations will likely target large reductions in routine venting (2.8 Mt, 18%) and flaring (0.8 Mt 6%) at conventional oil and gas sites by the end of this decade. Gas conservation technologies will need to be implemented at thousands of UOG sites. Capital costs for vent gas capture technologies are a potential barrier to uptake at small to medium size enterprises. There is an opportunity for innovative, low-cost conservation technologies to be developed and deployed to address this source category. Continued uptake of gas destruction technologies may prove beneficial. In this case, consideration for a balance between offsets eligibility and regulatory requirements should be considered. Funding programs promoting both conservation and destruction may also prove helpful in this source category.

As pneumatics and routine venting emissions continue to be drawn down by regulations, fugitives (1.6 Mt, 10%) will become one of the largest emissions categories by 2025. More stringent LDAR requirements may be implemented in the next update of the regulations. Continuous, fixed-place methane detection technologies are currently being developed and field tested. This technology represents a promising solution to more stringent LDAR requirements. There may also be an opportunity to install continuous monitoring devices at well sites, to detect and repair SCVF (0.9 Mt, 6%) emissions as well. Continued testing of these technologies (through programs like NGIF's Emissions Testing Centre) will help promote the development and subsequent implementation in the future.

Methane slip from reciprocating engines is the largest currently unregulated source of emissions in the sector (2.7 Mt,18%). The true size of this emissions source is not well understood at this time, as its estimation relies heavily on engine emission factors. Currently available mitigation technologies are very costly (engine overhauls) or not commercially available (lean-burn catalyst). There is a need for new, innovative technologies for this source category. New funding programs that leverage current program infrastructure may prove helpful to identifying and developing solutions for this source category.

There are stakeholder concerns regarding the level of methane data uncertainty. Some academic research suggests that methane emissions from the upstream oil and gas sector are underestimated by 1.5x - 2.0x in Western Canada.

- Reported methane data is lower than the modelled/estimated volumes, which suggests reporting system challenges. This gap could improve with time, since OneStop is a relatively new program.
- Increased MMR activities are essential to confirm modelled methane values, reduce data uncertainty and enhance the credibility of future modelled methane reductions (Bryant, 2023).
- Many methane emissions sources are estimated using emission factors according to Manual 015. Switching to a measurement-based reporting system would improve the quality of the OneStop dataset, however, cost considerations must be made relative to the incremental value. This change would require the installation of many volumetric meters at oil and gas sites across the province.

- By combining LiDAR measurements and ground-based survey data, Tyner and Johnson developed a new hybrid top-down/bottom-up approach for measuring methane emissions in the upstream oil and gas sector. The new approach showed that 78% of methane emissions were accounted for by measured sources. Compared to traditional bottom-up inventories, the new approach allows faster tracking and verification of reduction efforts. This approach can be applied in jurisdictions with reliable bottom-up data (Johnson et al., 2023a).

4.1. Summary of Identified Gaps

Several knowledge or technology gaps were identified in Section 3 of this report, they are summarized below in Table 3. It should be noted that the methane mitigation technology space is evolving rapidly. Some of the technology gaps identified in Table 3 may already have some emerging solutions that could be included in Table 4. Knowledge gaps may eventually transform into technology gaps once they are better understood.

Table 3. Summary table of knowledge and technology gaps identified in this report.

Emission Source Category	Gap Type	Gap Description
Fugitives	Knowledge	Data sharing and integration from the suite of fugitive emission detection technologies currently deployed or under development. Transparent data sharing could help determine the effectiveness of remote-sensing technologies in comparison to close-range handheld camera surveys, for example.
Methane Slip – Fuel Combustion	Knowledge	OGI surveys often miss this emission source when it is detected by aerial surveys. What is the most appropriate measurement, monitoring and reporting framework for this source?
	Knowledge	Oil and gas sector engine inventory is not available to the public. Estimation of this source category relies on a number of assumptions about engine make and model.
	Knowledge	Methane emission factors from engine exhaust specific to Alberta O&G sector. Currently relying on manufacturer specifications or U.S. EPA emission factors.
	Technology	Detection and quantification techniques to replace estimates from emission factors.
	Technology	Combustion catalyst technology to reduce methane emissions from lean burn engines.
Methane Slip - Flaring	Knowledge	Prevalence of unlit flares in Alberta O&G sector. Current models assume 6% of flares are unlit, recent research from other jurisdictions suggests the actual proportion may be greater than that.
Surface Casing Vent Flow & Gas Migration	Technology	Remote detection and quantification of SCVF/GM volumes at suspended or non-operating wells.
All	Knowledge	For each emissions source category discussed in this report, how much of the 2021 modelled emissions can be considered "difficult to abate"? In other words, how close to zero emission can each source realistically be pushed?

4.2. Summary of Emerging Technologies

A number of emerging technologies were identified in Section 3 of this report. These tools are summarized below in Table 4. Note that this table was completed in limited time. Further work to build out this list would be helpful.

Table 4. Emerging methane mitigation technologies by emissions source category identified in this report.

Emission Source Category	Developer/Funding Source	Technology Description	Comment
Compressor Seals	E3P Technologies/Alberta Innovates	Zero Emission Natural Gas Compressor	Project term ended July 2022
Surface Casing Vent Flow & Gas Migration	Saskatchewan Research Council/Alberta Innovates	SCVF Catalytic Methane Abatement System	Field Testing
Methane Slip – Fuel Combustion	Multiple	Hydrogen fuel additive in natural gas powered engines to improve combustion efficiency	Laboratory testing
	Multiple	Methane Oxidation Catalysts for Lean-burn Natural Gas Engines	Project term ends in 2025
	Waukesha/U.S. DoE	Ultra Low Methane Slip Reciprocating Engine	Project term ends in 2025
	Colorado State University & Caterpillar/U.S. DoE	Lean-burn Natural Gas Engine System to Achieve Near-zero Crankcase Methane Emissions from Existing and Future Engine Fleet	Project term ends in 2025
Methane Slip - Flaring	Cimarron Energy/U.S. DoE	Flare and Control for Ultra High Destruction and Removal Efficiency	Project term ends in 2023
	University of Minnesota/U.S. DoE	Plasma-assisted In-situ Reforming of Flare Gases to Achieve Near-Zero Methane Emissions	Project term ends in 2025
Fugitives	University of Calgary/Alberta Innovates	Scalable Mobile Methane Sensing System for Emissions Detection and Reduction	Project term ended May 2022

4.3. Production and Capital Expenditure Forecasts

In 2021, the AER forecasted oil production in the province to increase from 69.6 10^3 m^3 per day to 82.4 10^3 m^3/d (18% increase) in 2025 before declining to 76.1 10^3 m^3/d by 2031 (Alberta Energy Regulator, 2022c). Marketable natural gas production was forecasted to stay relatively flat from 2021 to 2031. These forecasts are illustrated below in Figure 14 and Figure 15.

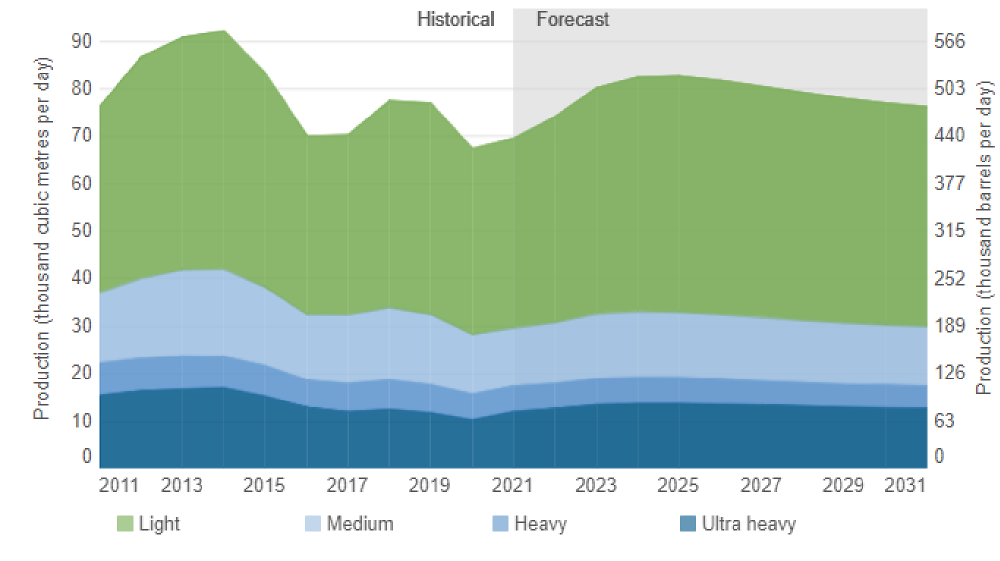

Figure 14. AER historical and forecast data for crude oil production in Alberta. Source: (Alberta Energy Regulator, 2022c).

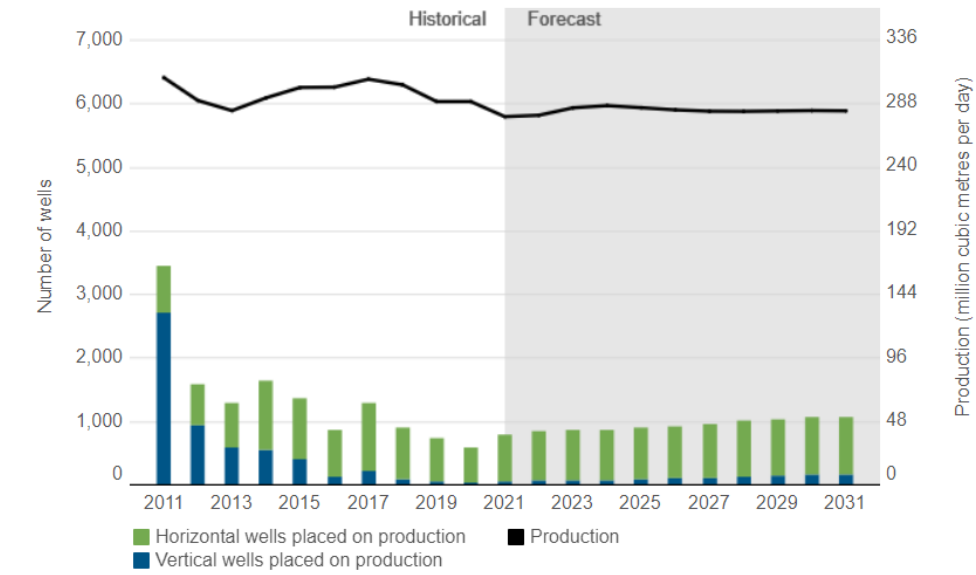

Figure 15. AER historical and forecast data for marketable natural gas production in Alberta. Source: (Alberta Energy Regulator, 2022c).

The above production forecasts were made in 2021, before geopolitical conflicts in Europe destabilized world energy markets and caused an increase in commodity prices. The AER forecasted 2023 upstream oil and gas capital expenditures to be $30.6B CAD (Alberta Energy Regulator, 2022c). However, the Canadian Association of Petroleum Producers (CAPP) recently updated their own 2023 CAPEX forecast to $40.0B, the third straight year of growth in upstream investment since 2020 (CAPP, 2023). This recent infusion of capital means that the AER's production forecasts may have also be underestimated, at least in the short to medium term:

- Actual 2022 crude oil production was 28.5 10^6 m^3, 12% higher than forecasted (Alberta Energy Regulator, 2023c).
- Actual 2022 marketable natural gas production was 110.9 10^9 m^3, 9% higher than forecasted (Alberta Energy Regulator, 2023c).

It is not our intention to assess the likelihood or risks of any price or production forecasts. In fact, if Alberta's methane emission reduction framework is operating as intended, we should see a 'decoupling' between oil and gas production and methane emissions. We cannot assume however, that any emissions reductions trend observed between 2014 to 2021 is guaranteed to continue in that direction through 2025 and 2030. Instead, Alberta should continue to pursue technology development and early action incentive programs to ensure the sector meets or exceeds the 75% target.

MODERN WEST ADVISORY

5. Recommendations and Next Steps

The following section provides some initial recommendations for new programming and considerations for additional research. This list is understandably not comprehensive, as the stakeholder workshop is expected to bring forward additional ideas. The main elements we considered in our recommendations are targeted at improving data/inventories and deploying technologies towards hard to abate emissions sources. Alberta has been blessed with a very comprehensive system of program funding up and down the technology development and deployment chain, and this approach has been helpful for the sector to achieve methane emissions reductions.

Given this experience and given the ambition of the new Federal target (time and volume), we believe there is opportunity to design and deliver effective programs and research initiatives in short order. New programs to be designed and implemented for the 2023 to 2030 timeframe should leverage the expertise of current program administrators, accounting systems, resource configurations, and data platforms but re-design the programs to target data collection and technology deployment for emissions sources at the most vulnerable facilities.

Some of these recommendations attempt to address "hard to abate" sources. These sources are either currently unregulated and therefore unreported (engine slip) or have extreme temporal variability (tank vents, SCVF, non-routine venting). Therefore, these programs may also have added benefit of helping to reconcile the discrepancy between estimated and observed emissions highlighted in Section 4 of this report.

5.1. Program Recommendations

BROA[21] for Uncontrolled Venting: Tanks, Methane Slip from Engines, Surface Casing Vent Flow, Non-routine Venting

a. **WHY:** The processes and data management system for this program have already been built; vendors and industry are aware of the program and comfortable with its data requirements. The new program could be deployed quickly. The initial BROA program was fully subscribed and was influential in improving data quality and accelerating technology deployment as a result of improved baseline data.

b. **BENEFIT:** Baseline data in these three categories is sparse, but they are largely agreed upon to be the key sources of methane by 2030 (estimated to be in the range of 60%-70% of the inventory by 2025, under the current regulatory landscape).

c. **BENEFIT:** This program will collect critical data that could be used by the AER to design future regulations and will help the sector and province meet Federal targets.

[21] Alberta's Baseline Reduction Opportunity Assessment (https://www.carbonconnectinternational.com/broa)

d. **TIMELINE:** 2024-2025 (Fiscal year start and end)

e. **VALUE:** Over two fiscal years, $10M to $15M could readily be deployed given the past experience of the BROA program.

f. **CATEGORY:** Baseline Inventories

MTIP for Uncontrolled Venting: Tanks, Methane Slip from Engines, Surface Casing Vent Flow, & Other Sources

a. **WHY:** The processes and data management system for this program have already been built; vendors and industry are aware of the program, and it has proven to successfully reduce methane emissions at an efficient mitigation cost range (to both government and industry). The new program could be deployed quickly. The initial MTIP program was over-subscribed and is expected to achieve significant annual reductions with very cost-effective results.

b. **BENEFIT:** With an early enough signal to technology providers and industry that this program is coming down the pipe, mitigation solutions may emerge that otherwise would not have, as innovation in this space (for these categories) has been sparse and is difficult.

c. **BENEFIT:** Leaving this program open to other emissions source categories will ensure that deployment of mitigation solutions will continue at other venting sources.

d. **TIMELINE:** 2025-2027 (FY start and end)

e. **VALUE:** Over two fiscal years, this program could reasonably deploy $20M to $25M given the past experience of the program.

f. **CATEGORY:** Mitigation Activities

Detection & Quantification Research and Development for Uncontrolled Venting

a. **WHY:** Measurement of hard to abate emissions sources like tanks, methane slip from engines, and SCVFs is still in early stages. Some tanks programs are currently ongoing, so this can be leveraged. Further, this program could leverage emerging developments in leak detection technologies for these sources (I.e.: drones for engine methane slip have not been tested thoroughly). Quantification technologies are critical to improving the management of these emission sources.

b. **BENEFIT:** Leverage current programs evaluating detection and quantification solutions and work with academia largely focused on improving methane emissions inventories (I.e.: Carlton & StFx).

c. **BENEFIT:** May be able to expand the NGIF Emissions Testing Centre to create testing ground for these technologies and solutions.

d. **TIMELINE:** 2024-2026 (FY)

e. **CATEGORY:** Innovation Research & Development

Double Retrofit – Zero-Bleed Pneumatics

a. **WHY:** Pneumatic devices remain one of the largest source categories of emissions in the province and moving from a low-bleed requirement to a zero-bleed requirement may be a viable option for the AER to consider. However, many companies would be required to pursue a "double retrofit" for some of their pneumatics since current regulations only require conversion to low-bleed alternatives. Meaning, they already converted their high-bleed devices to low-bleed, so this new requirement would force them to retrofit these same sites before the end of the new equipment's useful life. This is particularly true at sites where electrification was not pursued or where instrument air was not pursued for cost of other considerations.
b. **BENEFIT:** Demonstrates awareness that the government is attempting to keep mitigation and compliance costs low/reasonable.
c. **BENEFIT:** Supports further reductions from one of the sectors most prominent emissions source categories.
d. **TIMELINE:** 2024-2025 (need to consider when draft regulations are completed)
e. **CATEGORY:** Mitigation Activities

5.2. Proposed Further Analysis

Facility Level Methane Modelling

a. **WHY:** The "Road to 45" and "Drive to 75" reports indicate that, historically, a certain amount of methane emissions could be linked to sector production levels. However, the phase-in of regulations and deployment of methane mitigation technologies since 2020 means that methane emissions should begin to become 'decoupled' from production. The current iteration of the MWMM aggregates Petrinex and OneStop data at the facility subtype level. the current model does not assess methane production intensities of individual facilities. With additional time and resources, a follow-up modelling analysis could be performed by drilling down to the operator and then to the facility level, creating a report that clearly identifies a facility-type level emissions profile.
b. **BENEFIT:** Determine methane emission reductions achieved by each subsector (bitumen, crude oil, natural gas).
c. **BENEFIT:** Assess the effectiveness of Alberta's methane reduction framework to 'decouple' methane emissions from oil and gas production since 2020.
d. **BENEFIT:** Breakout the MWMM "Business-as-Usual" scenario to assess methane reductions from production decline versus changes in operational efficiency and asset configuration.
e. **TIMELINE:** Fall 2023

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Appendix A

MWMM Methodology

The Modern West Methane Model (MWMM) follows a similar bottom-up methodology and data sources reported in the Government of Alberta's annual methane equivalency report. It is comprised of eight emission source categories. Total yearly MWMM emissions were near the GoA values (±5%) and were scaled to match the GoA reported methane values for each year between 2014 and 2021. Note that the objective of this modeling endeavor was to acquire an approximation of the breakdown of the GoA's emissions, rather than to formulate a new estimate. The assumptions and limitations of MWA's modeling is described below.

<u>Inputs for all emissions categories</u>

- Methane density = 0.6785 kg/m^3 (AER Manual 015)
- Methane GWP = 25 (IPCC AR4)

<u>General Model limitations</u>

- Due to a lack of publicly available data the model does not include emissions from some non-routine sources including well testing, liquids unloading, engine/turbine start-ups, and compressor blowdowns.
- The model only attempts to estimate methane emissions from 2014 to 2021. No attempts are made to forecast emissions past this date.
- The model relies on operator reported data for the following emission sources: Routine Vent, Compressor Seals, and Glycol Dehydrators. Full reporting compliance across the sector is assumed by the model.

<u>Calculation assumptions and limitations – Vent from pneumatic devices</u>

- Estimation of vent from pneumatic devices was based on average number of devices for each facility type, average vent rate for pneumatic devices, and assumes 8,760 hours of operation in a year, which is consistent with the NIR and GoA methodologies.
- Average number of devices for each facility type was obtained from Tyner & Johnson, 2020 (for additional details refer to Table S5 in Tyner & Johnson, 2020), and, assumed to provide a reasonable representation of vent rates from these devices for years 2014 through 2022.
- Number of facilities of each type was obtained form the public Petrinex data for Alberta. MWA had access to Petrinex data going back to 2015. Therefore, number of facilities in 2014 was extrapolated based on the number of facilities from actual Petrinex data for 2014 to 2017 assuming a consistent trend in changes in facilities between 2014 and 2017.

Calculation assumptions and limitations – Vent from compressors

- Estimation of vent from compressors was based on the number of compressors at gas facilities in 2020 and 2021 and an average annual compressor vent for centrifugal and reciprocating compressors.
- Public OneStop data includes the number of compressors of each type (centrifugal and reciprocating) as well as the reported vent volumes for each type of compressor. OneStop data for years prior to 2020 is not available. Therefore, the 2020 and 2021 OneStop data were used to estimate the number of compressors for years 2014 through 2019. This process involved calculating a weighted average of the number of compressors for the years 2020 and 2021, with the weights determined based on the number of active facilities in these years. This weighted average was assumed to be representative of the number of compressors per active facility during 2014 through 2022. The number of compressors in 2014-2019, and 2022 was finally estimated by multiplying the number of active facilities reported for each year by the number of compressors (weighted average) in 2020 and 2021. This method assumes a stable relationship between the number of active facilities and the number of compressors over these years and uses this relationship to make an informed estimation for 2014-2019, and 2022.

Calculation assumptions and limitations – Vent from glycol dehydrators

- Estimation of vent from glycol dehydrators was completed in a similar manner to vent from compressors. However, the number of compressors and their emissions was estimated for the years after 2021, as this data was available through the reports submitted to the government under the Directive 039 requirements for the years prior to 2021. Note methane was not required to be reported under Directive 039 prior to 2020. Therefore, an uncontrolled dehydrator emission factor (Clearstone 2018) was used to estimate the volume of methane releases based on the volume of processed gas which was available from Directive 039 reported data.

Calculation assumptions and limitations – Surface Venting Case Flow (SCVF)

- SCVF is reported by facilities to the Government of Alberta. These volumes are used directly in MWA's modeling and converted to a mass of methane.
- Although SCVF volumes are reported publicly, this category is still scaled in the manner as the other categories, to maintain consistency.

Calculation assumptions and limitations – Fugitives

- Fugitive emission factors by facility subtype and well type were derived from Tyner & Johnson (2020) 2017-2018 fugitive inventories. These emission factors were then applied to yearly facility and well counts pulled from the public Petrinex database for the modeled years.
- For the MMS scenario, an assumption was made for reductions achieved through LDAR surveys. Annual surveys were assumed to produce a 40% fugitive

reduction, while tri-annual surveys produced a 70% reduction[22]. Annual screenings at wells were assumed to have negligible mitigation effects.

- LDAR survey frequencies were applied to each facility subtype according to Directive 060 – Table 4.

Calculation assumptions and limitations – Spills and Ruptures

- Pipeline release incidents are reported to the AER, who publishes the data on their Pipeline Performance webpage[23].
- Reported released volumes were assigned a methane content according to the released substance (see Table 5) and the volumes were converted to Mt CO_2e.

Document Control

- The model outputs used in this report were generated using "MWA Methane Model Timeline Summary_v3.2.xlsx".

[22] https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf
[23] https://www.aer.ca/providing-information/data-and-reports/activity-and-data/field-surveillance-incident-inspection-list

Table 5. Summary of the MWMM methodology, data sources, and assumptions.

Emissions Category	Data Sources	Methane Content (% vol)	Other Assumptions
Pneumatics	• Facility and Well Counts (ICF International, 2015), (Petrinex) • Pneumatic counts ((Clearstone Engineering Ltd., 2019), (Johnson and Tyner, 2020)) • Pneumatic emission factors (Clearstone 2019, Johnson & Tyner, 2020) • Pneumatic offset data (AEOR)	• 92% (All facility types)	• Pneumatic chemical injection pumps operate 6 months per year (October – March)
Routine Vent	• 2015 - 2019 routine vent volumes (Petrinex) • 2014 routine vent volume extrapolated. • 2020 – 2021 routine vent volumes (OneStop)	• 78% (Natural Gas) • 74% (Crude Oil) • 95% (Facility subtype 331 & 342) • 97% (Facility subtype 341 & 343)	
Methane Slip – Flare	• 2015 - 2021 flare volumes (Petrinex) • 2014 flare volume extrapolated	• 78% (Natural Gas) • 74% (Crude Oil) • 95% (Facility subtype 331 & 342) • 97% (Facility subtype 341 & 343)	• 98% flare destruction efficiency • 6% unlit flares (non-gas plants) • 0% unlit flares (gas plants)
Methane Slip – Fuel Combustion	• 2015 - 2021 fuel volumes (Petrinex) • 2014 fuel volume was extrapolated. • Fuel gas heating value (Johnson & Tyner, 2020) • Fuel gas usage ratios (Johnson & Tyner, 2020) • Engine, turbine, boiler emission factors (EPA WebFIRE Database)	• 92% (All facility types)	• Assume 70:30 split between lean burn and rich burn engines, from industry conversations.

Fugitives	• Facility and well counts (Petrinex)
	• Facility and well type fugitive emission factors (Johnson & Tyner, 2020)
		• N/A[24]	• LDAR fugitive reduction factors (ICF International, 2015)[25]:
			  ○ 40% (annual)
			  ○ 70% (tri-annual)

[24] Tyner & Johnson emission factors are already in tCH_4/hour units.
[25] Annual survey factor sourced from ICF (2015). Annual well screenings were assumed to result in negligible fugitive emissions reductions.

Emissions Category	Data Sources	Methane Content (% vol)	Other Assumptions
Compressor Seals	• 2020 – 2021 compressor counts (OneStop) • 2020 – 2021 compressor vent gas volume (OneStop) • Facility counts (Petrinex)	• 92% (All)	
Glycol Dehydrators	• 2008 - 2021 dehy counts (ST60b) • 2008 – 2021 dehy processed gas volumes (ST60b) • 2020 – 2021 dehy benzene emissions (ST60b) • Uncontrolled dehy emission factor (Clearstone 2018)	• 85%	• Dehy methane emissions reductions are scaled to benzene emission reductions
SCVF/GM	• SCVF/GM annual gas emissions (GoA, 2021)	• 85%	
Spills and Ruptures	• Release volumes (AER)[26]	• 90% (marketable natural gas) • 85% (raw natural gas)	• 85 m^3/m^3 gas in solution ratio assumed for condensate and crude oil releases

[26] https://www.aer.ca/providing-information/data-and-reports/activity-and-data/field-surveillance-incident-inspection-list

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