



## Final Report

# Potential Technologies to Capture and Utilize Associated Gas at Upstream Oil and Gas Sites in the Duvernay and Viking Petroleum Systems

Prepared for Petroleum Technology Alliance Canada

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## EXECUTIVE SUMMARY

This document is intended to provide a high-level overview of wellsite emissions from the Duvernay play in Alberta and the Viking play in Saskatchewan through an assessment of their history, current activity, operational processes, and gas production. Potential emissions mitigation technologies are presented, which may or may not be applicable in these regions. The technologies are evaluated based on criteria provided by NRCan.

An overview of the Duvernay found that most sites should be low emitting if they are connected by gathering lines to oil batteries or gas plants, as there is generally little in the way of emitting equipment on site, and what is there is newer. They are also more likely to be based on low emission technologies that are already available. The exceptions are isolated single wells, field expansion single well batteries, and wells with low pressure gas production requiring on-site processing and compression.

In the Kindersley area of Viking oil well production, the wells are not as isolated as many other scenarios. However, the older wells are largely low producers that would not presently justify the investment required to develop an extensive gathering system to add pipeline infrastructure. Around 82% of facilities in the Viking vent or flare less than 900 m<sup>3</sup> per day. Without access to gas gathering lines the associated gas is currently either vented or flared. For a gas mitigation technology to be applicable in the Viking, it must be economic at low volumes.

Technologies with the potential to reduce venting at these wells were investigated. They included:

- Compressors, including vapour recovery units (VRU), compressed natural gas (CNG) and liquefied natural gas (LNG).
- Combustion, including flares and enclosed combustors.
- Gas to Power technologies, including gen-sets, microturbines, thermo-electric generators, and organic Rankine cycle (ORC).
- Gas to Liquids technologies, including Fischer-Tropsch, and methane to chemicals such as methanol, dimethyl ether (DME), and ammonia.
- Emerging technologies, including methanotrophic biofilters, tank covers, and natural gas hydrates.

Of the technologies investigated, compression offered the greatest reduction in emissions, but relied heavily on access to infrastructure and/or transportation. Combustion was the technology that offered the best scalability for the low flowrates experienced by most wells in the study.

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## 1. INTRODUCTION

Natural Resources Canada (NRCan) is seeking a greater understanding of the Western Canadian Viking and Duvernay oil and gas plays, including its geology, production history, well numbers and configuration, associated gas emissions, current infrastructure, and potential technological options that may be employed to reduce emissions in the future. The data gathered during this study will “help guide on-going research to improve capture and utilization of greenhouse gases from upstream oil and gas sites in Canada.” The Petroleum Technology Alliance Canada (PTAC) has sub-contracted the Saskatchewan Research Council (SRC) to gather information on the Viking oil field. New Paradigm Engineering has been sub-contracted to provide similar information on the Duvernay petroleum system.

### 1.1 Objectives

The goal of this project is to provide a high-level overview of the Viking and Duvernay formations, including their production history and emissions profile, and identify and assess technologies that could be used to capture and utilize associated gas produced in the region. The work is divided into three tasks:

#### Task 1- Petroleum System Overview

To provide background of the Duvernay and Viking petroleum systems to allow a preliminary assessment of the technologies in each system. The background includes the following information:

- Brief description of the geology, oil reserves, lateral extents of the petroleum system, depth to reserves, production, porosity, permeability, average TOC, mineralogy, gas to oil ratio, etc.
- Description of the production challenges as they pertain to gas emissions.
- Data regarding typical gas emissions over time for the first 1-5 years of a well.
- Data regarding flaring/venting/fugitive emissions in each system over time.
- Emission chemistry (methane, ethane, H<sub>2</sub>S, CO<sub>2</sub> etc.).
- Number of number of wells, location of wells, and well pad details (size of leases, equipment, number of wells).
- Oil and gas infrastructure in place, typical, pipelines, gas processing facilities, storage facilities.

**Task 2 – Identify Potential Emission Mitigation Technologies**

To identify new potential technologies that may be used to capture and utilize associated gas at upstream oil and gas sites in the Duvernay and Viking, in addition to options suggested in references which include creating natural gas liquids, on-site power generation, compressed natural gas, gas capture and re-injection, and gas-to-liquids.

**Task 3 - Assessment of Available Technologies**

To provide a simple assessment of the technologies identified in Task 2 using the information gathered in Task 1.

This study will review the current status of the Duvernay and Viking plays, identify potential technologies, and carries out a preliminary assessment of the potential for these technologies to be deployed.

## 2. TASK 1- PETROLEUM SYSTEM OVERVIEW

Task 1 provides background on the Duvernay and Viking petroleum systems. Section 2.1 will discuss the Duvernay resource, and Section 2.2. will cover the Viking.

### 2.1 Description of the Duvernay Resource

Emissions from oil and gas operations can vary between operations of various types and at different stages in their development. The Duvernay play in Alberta is one of the latest unconventional oil and gas shale resources to be developed in western Canada. It is still in the early stages of development as there have been relatively few wells drilled. These have mainly been drilled to evaluate the formation productivities to allow producers to high grade their lease holdings, as well as to meet the requirements for lease retention. This play is the deepest organic shale formation in the Western Canada Sedimentary Basin (WCSB), and there are still significant conventional resources and shallower shale formations which can be accessed and produced at a lower cost than the Duvernay. The main “commercial” Duvernay development, at the current time, appears to be focused on oil production in the Red Deer region. Drilling for natural gas and natural gas liquids appears to have declined in importance, after an initial flurry of resource assessments in the liquids-rich Fox Creek area of the Duvernay over the last decade.

#### 2.1.2 Physical Description of the Duvernay Resource

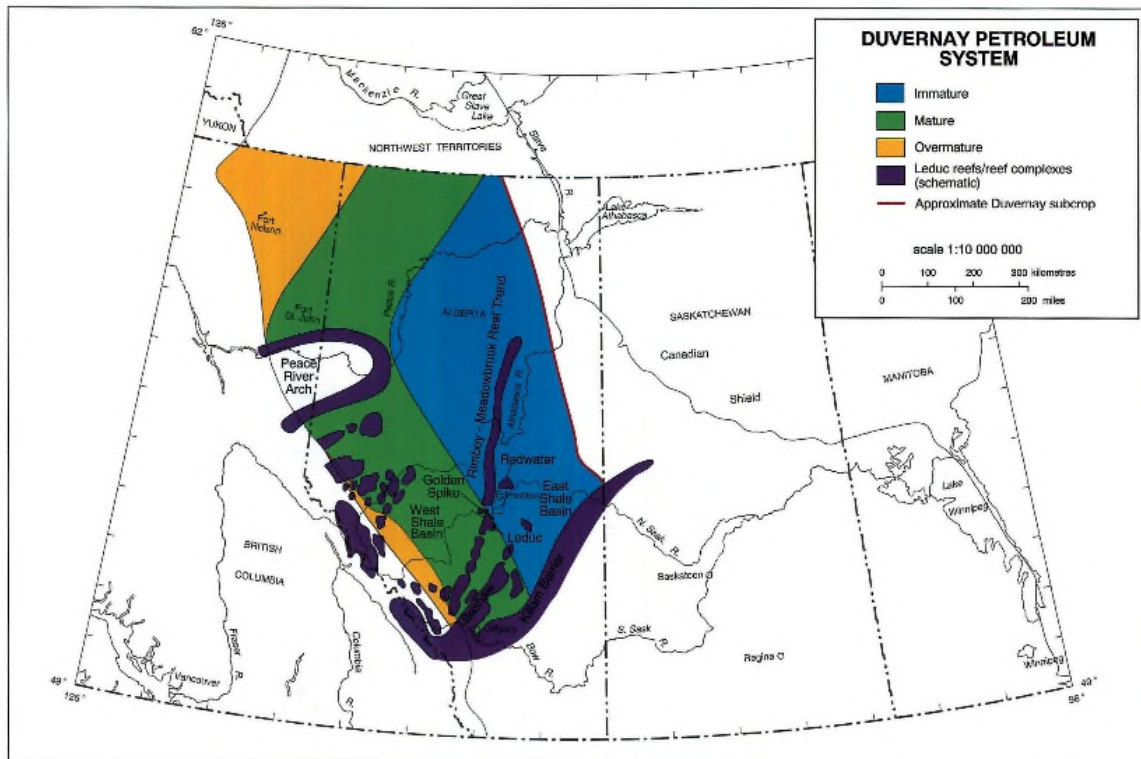
##### *Duvernay Petroleum System*

**Figure 1** shows a diagram of the Duvernay Petroleum System as described by the Alberta Geologic Survey (AGS, 2012), based on data from wells drilled in the province that were deep enough to penetrate this formation. The formation covers most of Alberta north of Calgary and the types of hydrocarbons found in the Duvernay changes with depth. Only the portion of the Duvernay south of the “Peace River Arch” area is designated as the Duvernay play in Alberta, while a similar formation north of the arch is called the Muskwa play. The Muskwa is comparable to the Duvernay in the size, composition and resources contained within it. The map shows four separate areas of the system:

- **Immature** – The blue area (eastern portion) is where the Duvernay/Muskwa is relatively shallow, and has not been heated. Therefore, very little, if any, of the organic material has been thermally converted to oil or gas. However, some may have been biologically converted to natural gas by microbes (biogenic gas), which can survive at shallower depths at temperatures below about 80°C.



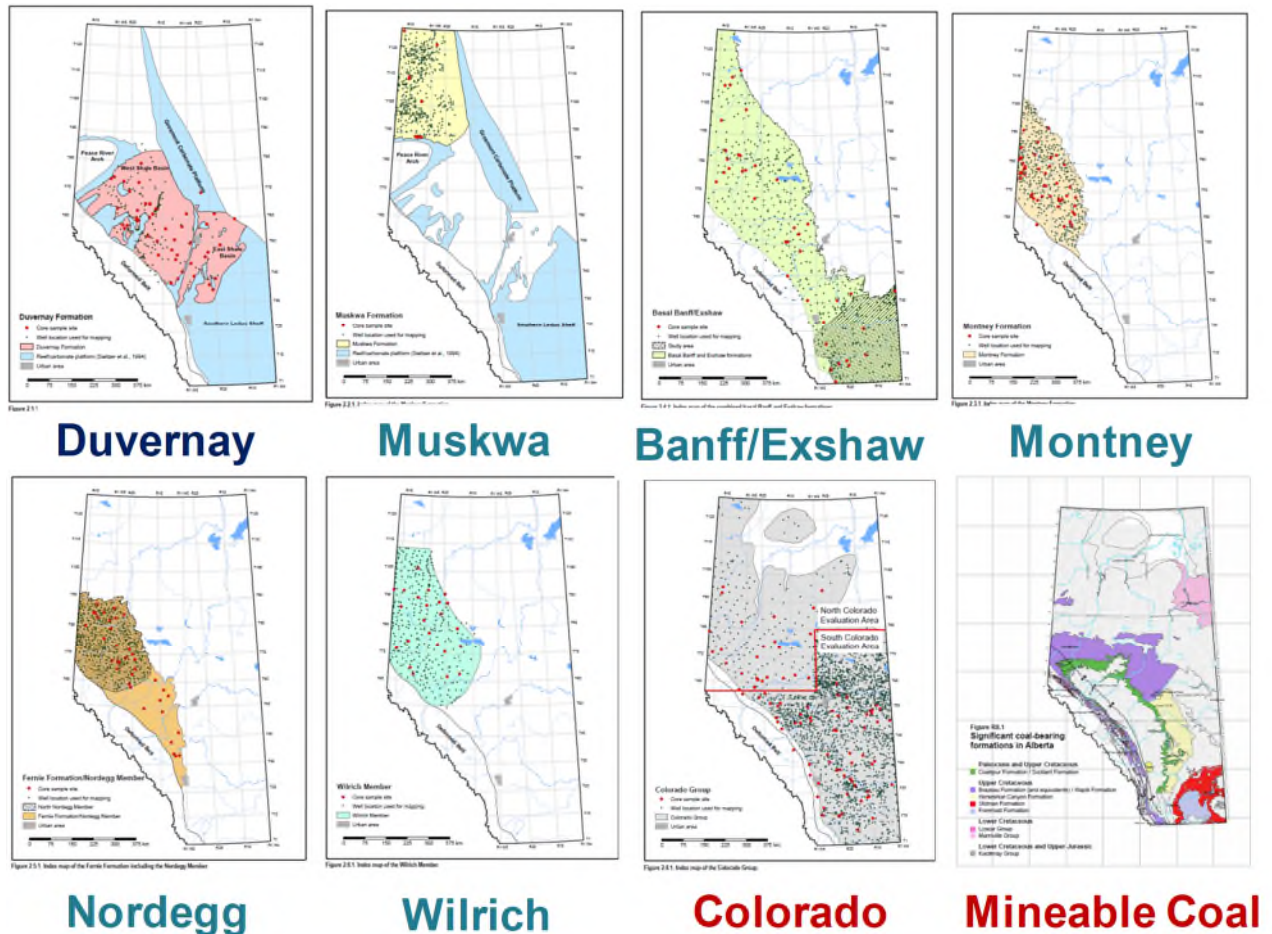
- **Mature** – The green (central) area is the “oil window” where the organic material has been heated enough to be turned into oil or Natural Gas Liquids (NGLs), which will also contain some volumes of methane or other gases like ethane, propane and butane in solution.
- **Over mature** – In the gold (northwestern and southwestern) areas the hydrocarbons have been heated to the point where most of the hydrocarbon material formed has continued to be heated and converted to natural gas.
- **Leduc Reefs/Reef Complexes** – The less continuous purple areas are major areas where coral reefs grew at the same time as the Duvernay was forming. They are not part of the Duvernay but are generally connected (or were at one time) to the Duvernay, so some of the oil and gas produced in the Duvernay migrated into these formations, which became large conventional oil and gas reservoirs.



**Fig. 1: The Occurrence and Maturity of the Duvernay Source Facies in the Western Canadian Sedimentary Basin**

## Geology

A number of stacked oil, gas, and even coal formations are found in Duvernay area of the Western Canada Sedimentary Basin. Most have seen some production in the past, while others are just recently attracting attention for potential development with horizontal multi-stage fracturing techniques.



**Fig. 2 – Duvernay Distribution in Relation to Other Shale Oil and Gas Formations in West Central Alberta**

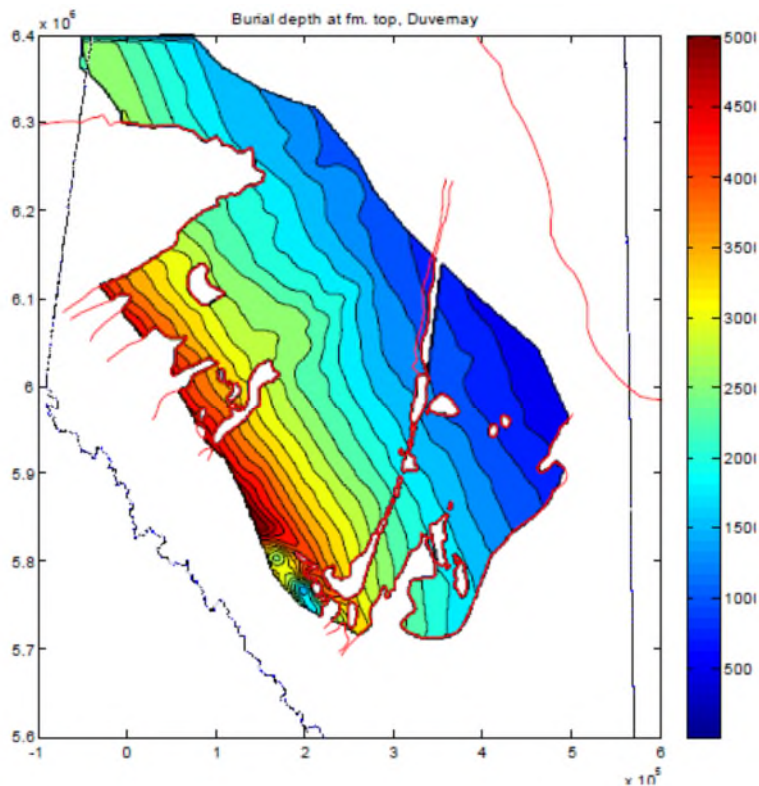
(excludes many layers of conventional oil and gas formations which are also found in this area)

The Duvernay Shale is a formation of organic rich sedimentary rock in the WCSB. The Duvernay was formed in the Upper Devonian Period (360-380 million years ago), when much of Alberta was covered by a warm, tropical shallow sea supporting the growth of large carbonate platforms and coral reefs, with the Duvernay forming through the deposition of organic rich muds. These Duvernay deposits cover most of the province, except for the northeast corner and the disturbed

zone of the Rocky Mountains. Over geologic time (~100 million years ago) these muds became buried and heated, which converted the organic matter into oil and gas. Some of these mobile hydrocarbons, were able to migrate from the Duvernay “source rocks” into shallower reef formations like the Leduc reef trend, medium depth sandstone formations like the Viking, and even into shallow sand and carbonate formations near the surface where the oil was biodegraded into bitumen in the oil sands. While the Duvernay and Muskwa Shales are similar and both contain oil and gas resources, the term “Duvernay” is generally applied to the formation in central Alberta.

### **Mineralogy**

The Duvernay is classed as “bituminous shale” and contains a high percentage of “organic rich, lime mudstone (limestone)” (AGS, 2017). The western portions of the Duvernay are thicker but contain more mineral shale. As the formation rises going east it becomes thinner but has a higher limestone content. Permeability and porosity can vary widely across the formation; however, they are all generally low porosity (0.001 to >0.120%) and permeable shales, which require hydraulic multistage fracturing to be productive. Total Organic Carbon (TOC) ranges from 0 to 6 weight percent. Gas to Liquids (GLRs), or Gas to Oil Ratios (GORs), range from <300 m<sup>3</sup> gas/m<sup>3</sup> oil in oil prone wells to >30,000 m<sup>3</sup> gas/m<sup>3</sup> liquids in dry gas wells. Wells with intermediate GLRs could contain oil or a range of other hydrocarbon liquids (state at formation temperature and pressure conditions), which can range from propane and butane to light oil. The GLRs indicate the maturity of the formation with the deep, low GLR portions of the formations containing less liquid and are therefore less desirable for production. Figure 3 indicates the depth of burial of the Duvernay formation. Deeper regions will be hotter and more of the total hydrocarbon will have been turned into natural gas.



**Fig. 3 - Diagram of the Duvernay Hydrocarbon System and Burial Depth to the Top of the Duvernay Formation from Near Surface in the NE to 5000m in the SW (AGS, 2017)**

Table 1 shows the overall range of Duvernay properties from the latest AER report, and is applicable to the two regions of the Duvernay which are the most likely to be developed for NGLs. The values come from analysis of wells drilling in these areas. The key properties are:

- Porosity – Is the volume percentage of the shale that can contain hydrocarbon fluids or gases, which when combined with an area and thickness, indicates the volume of the resources which might be found in the rock matrix;
- Porosity-thickness – Is the thickness of the shale that is porous enough to contain oil and gas. AER plots resources per section ( $\text{mi}^2$ ) so Porosity times Porosity-thickness times the area will give the volume of shale that can contain hydrocarbons which may be produced.
- Total Organic Carbon – Is the mass percentage of the shale that is organic material. This is important as not all of the organic material in the shales has been turned into liquid or gaseous hydrocarbons. The solid organic carbon is contained in kerogen a waxy mixture of hydrocarbon compounds. Kerogen is insoluble in water and immobile, but could, in future, be converted to hydrocarbon liquids or gases through in-situ heating. So is a potential, although currently uneconomic resource.

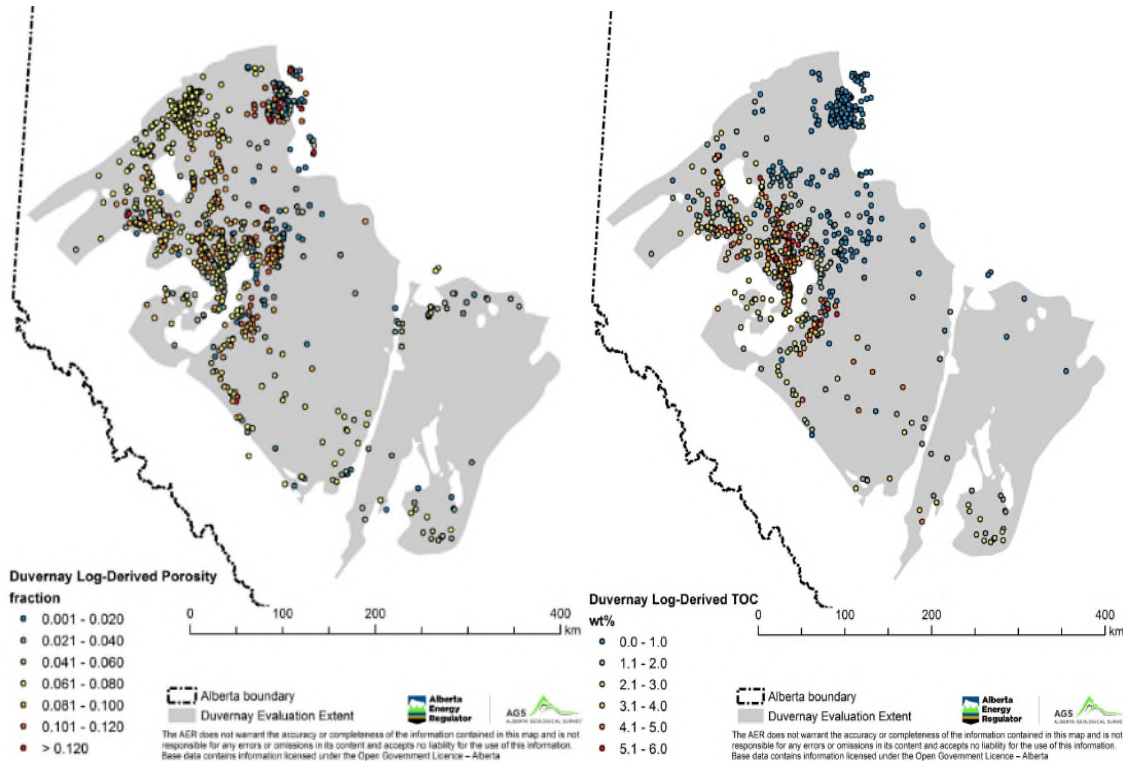
- Brittleness Index – Is an indication of a shales tendency to fracture and is defined in various ways but is generally the ratio of the compressive strength vs. tensile strength of the rock, which indicates how susceptible the are to being fractured, which is necessary to release the hydrocarbons contained in the shales.

**Table 1: Table of Geology Parameters (AER, 2018)**

Table 1. Duvernay geological parameters

Parameter	Units	Kaybob			Edson-Willesden Green		
		P90	P50	P10	P90	P50	P10
Porosity	%	7.0	8.5	9.5	7.0	8.0	10.0
Porosity-thickness	m	1.5	3.0	4.0	1.0	1.5	2.0
Total Organic Carbon	Weight %	3.0	4.0	5.0	3.5	4.5	5.5
Brittleness Index	%	43	49	54	45	47	50

The maps in Fig 4 show the distribution of wells providing samples included in the AER analysis above and shows the ranges of values obtained from each area for porosity and TOC. As can be seen from the plots there are still large areas of the Duvernay where there is very little geologic data available so are still relatively undefined, which leads to considerable uncertainty in resource assessments.



**Fig. 4 – Variation in Duvernay Porosity and Total Organic Carbon (TOC) <sup>1</sup>**

## 2.1.2 Oil Production

### Hydrocarbon Resources in Place

As the Duvernay is among the deepest producing formations in the basin, the number of historic wells penetrating to this depth is still relatively limited, so estimates of resources contained in the formation were highly speculative. The AGS developed an assessment of resources in each of the main shale plays, which was published in 2012. In a recent 2017 update, specifically for the Duvernay, estimates of the resource in place have more than doubled as more data has been obtained from newly drilled wells. Table 2 provides a comparison of the resources in place estimates produced by the 2012 and 2017 assessments, that shows the significant change in estimates due to an increase in the amount of data available as new wells are drilled. These types of assessments, based on relatively little data over a large area, tend to be conservative, so the ultimate resource in place may still change as more well data and geologic information becomes available.

**Table 2 – Comparison of Duvernay Resources in Place by AGS for 2012 and 2017**

Hydrocarbon Type	AGS 2012 Estimate of Resources P50 (P90-P10)	AGS 2017 Estimate of Resources P50 (P90-P10)
Natural Gas ( $10^9$ m <sup>3</sup> )	12,479 (9,934-15,219)	23,000 (22,100-24,100)
Natural Gas Liquids ( $10^6$ m <sup>3</sup> )	1,798 (1,190-2,589)	15,200 (14,600-18,800)
Crude Oil ( $10^6$ m <sup>3</sup> )	9,803 (7,009-13,172)	33,100 (31,500-34,900)

Note that resource determinations are probability estimates. The P10, P50 and P90 values assessed as:

- P10 = 10% probability that the resource volume is larger than this value.
- P50 = 50% probability that the actual value has an equal chance of being higher or lower.
- P90 = 90% probability that the resource volumes will be found to be contained in the formations.

### Hydrocarbon Reserves

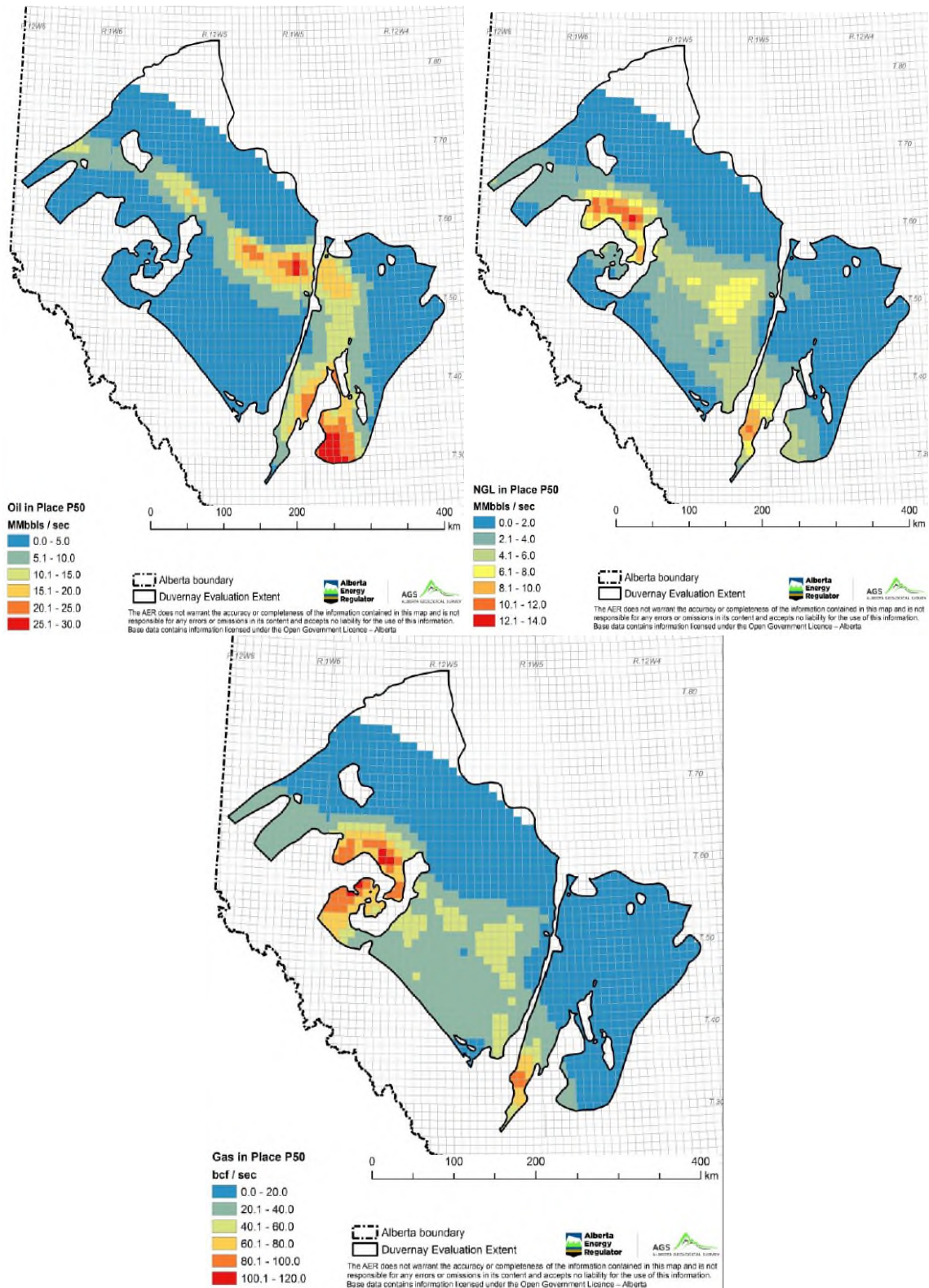
Estimates of recoverable reserves, which is the portion of the resource that is technically and economically recoverable, is even less certain for the Duvernay as few wells have reached the end of their productive lives. Current proven and probable reserve estimates by the AER as of December 2018, are only based on the portions of the resource where wells have been drilled and only indicate recoveries of 0.08% of oil resources in place and 0.4% of natural gas and natural gas liquids

resources in place. The NEB, in their 2017 Briefing Note, indicate “marketable reserves” of technically recoverable oil might be 9.5% for gas, 6.6% for NGLs and 1.6% for oil from the AGS estimated in place resources. These are certain to increase over time as the play is further developed, as has been the case in most new shale developments as operators gain experience in the formation, and production limits become better understood. Few producers are intentionally drilling for dry gas resources in the Duvernay as these are deeper and more expensive to access than remaining reserves in shallower gas bearing formations. Therefore, current natural gas and NGL reserves are linked, as producers develop the condensate and oil rich portions of the formation first. Currently, most reserve additions are being seen in the oil prone portions of the play which are more economic to develop than gas plays as they are shallower, and the product has a higher economic value.

Current estimated of Duvernay reserves of oil, condensate and gas are shown in Table 3, however, these represent only a small fraction of the ultimate potential. The maps in Figure 5 show the relative distribution of the potential oil, NGL and gas resources based on the latest 2018 AER report. This shows the impact of formation maturity on distribution for the P50 case, where there is a 50% probability of the actual values being higher or lower than the values indicated.

**Table 3 – Duvernay Formation Reserve Estimates as of the End of 2018 (AER, 2019)**

		Initial			Remaining		
		Oil (10 <sup>6</sup> m <sup>3</sup> )	Condensate (10 <sup>6</sup> m <sup>3</sup> )	Gas (10 <sup>9</sup> m <sup>3</sup> )	Oil (10 <sup>6</sup> m <sup>3</sup> )	Condensate (10 <sup>6</sup> m <sup>3</sup> )	Gas (10 <sup>9</sup> m <sup>3</sup> )
Proved	Developed	5.1	16.5	23.8	3.7	7.2	11.5
	Undeveloped	16.4	35.4	53.4	16.4	35.4	53.4
	Total	21.5	52.0	77.1	20.0	42.6	64.9
Proved + Probable	Developed	6.2	18.6	27.8	4.8	9.2	15.6
	Undeveloped	20.5	40.2	63.4	20.5	40.2	63.4
	Total	26.7	58.8	91.3	25.3	49.4	79.0



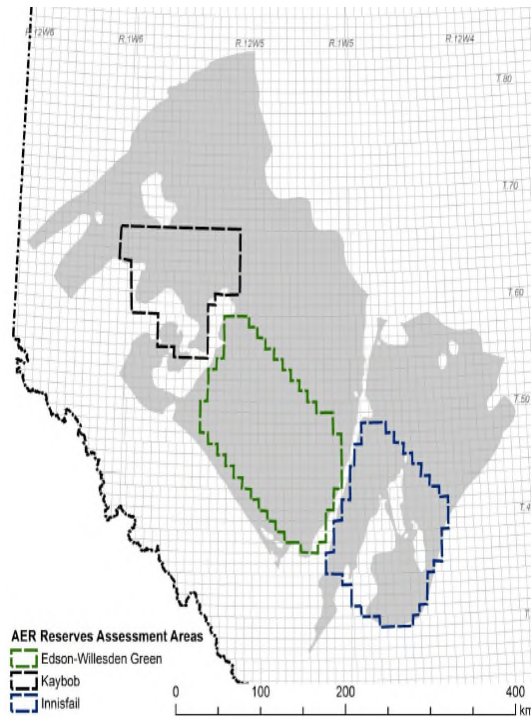
**Fig. 5 - Maps of Estimates of Duvernay P50 In Place Oil, NGL and Gas Resources by Section (AGS, 2017)**



### **Production Areas**

As of January 2020, the Duvernay had <400 wells producing from three different areas which were assessed by the AGS in their 2017 update for the Duvernay. This contained most of the producing wells, which have distinct differences in the resources, reserves and production of hydrocarbons. The three areas are:

- **Kaybob (210 wells)** - Located in the northwest portion of the play, which was mainly being assessed for NGLs, but is not as economic to produce as the larger, more prolific and shallower Montney Formation. Therefore, it has seen a drop in drilling and production activity. (Liquids/Gas in place ratio  $\sim 1.18 \text{ m}^3 \text{ liquid/e}^3\text{m}^3 \text{ gas}$ ). Main drillers active in the play since January 2015 have mainly drilled gas wells, with drilling lead by Murphy Oil ( $\sim 36$  wells), XTO Energy Canada (an ExxonMobil/Imperial affiliate with  $\sim 24$  wells) and seven wells by others.
- **Innisfail (135 wells)** – Located in the southeast portion of the play, developers are mainly targeting light oil production from a shallower portion of the play. This production is economic as light oil, i.e. is not discounted like heavy oil, and there are fewer restrictions on transportation of light oils (Liquids/Gas in place ratio  $\sim 6.4 \text{ m}^3 \text{ liquid/e}^3\text{m}^3 \text{ gas}$ ). Main drillers since January 2015 were Vesta Energy ( $\sim 87$  oil wells mainly in Lacombe and Red Deer Counties), Artis Exploration ( $\sim 35$  oil wells mainly in Kneehill County) and nine oil wells by others.
- **Edson-Willesden Green (33 wells)** – Located between the other two areas, this region has shown less consistency in hydrocarbon distribution (Liquids/Gas in place ratio  $\sim 1.0 \text{ m}^3 \text{ liquid/e}^3\text{m}^3 \text{ gas}$ ). Only 10 oil wells were drilled after 2015 – these were by Baytex (4), Teine (3), Repsol (2) and one each by Crescent Point and Paramount.



Alberta boundary  
 Duvernay Evaluation Extent  
 Alberta Energy Regulator  
 AGS  
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Area	Gas ( $10^{12}$ m <sup>3</sup> )			NGLs ( $10^9$ m <sup>3</sup> )			Oil ( $10^9$ m <sup>3</sup> )		
	P90	P50	P10	P90	P50	P10	P90	P50	P10
Kaybob AA	4.6	4.9	5.1	2.9	3.1	3.3	2.4	2.7	2.9
Edson-Willesden Green AA	7.2	7.7	8.2	4.5	4.8	5.2	2.4	2.6	3.0
West Shale Basin AA Total	12.0	12.6	13.3	7.5	7.9	8.4	4.9	5.3	5.7
West Shale Basin Total	18.7	19.8	20.8	11.2	11.7	12.3	15.2	16.3	17.7
Innisfail AA	1.8	2.0	2.1	2.0	2.2	2.4	9.4	10.5	11.4
East Shale Basin Total	3.1	3.3	3.6	3.2	3.4	3.7	15.6	16.9	18.0
All Assessment Areas Total	13.9	14.6	15.2	9.6	10.2	10.6	14.7	15.7	16.9
<b>DUVERNAY TOTAL</b>	<b>22.1</b>	<b>23.1</b>	<b>24.2</b>	<b>14.6</b>	<b>15.2</b>	<b>15.8</b>	<b>31.5</b>	<b>33.1</b>	<b>34.9</b>

Fig. 6 - Reserves/Resources for Three Main Development Areas Assessed (AGS, 2017)

### Hydrocarbon Production

Production data since 2015 shows the recent production trends for oil and natural gas and NGLs by AGS assessment area, and indicates the current development priorities of the active drillers of wells over the last five years.

- **Oil production** is mainly from the Innisfail area northeast of Red Deer, Alberta. Oil GORs tend to be low so there is little gas being produced from this area. Oil production has been growing rapidly.

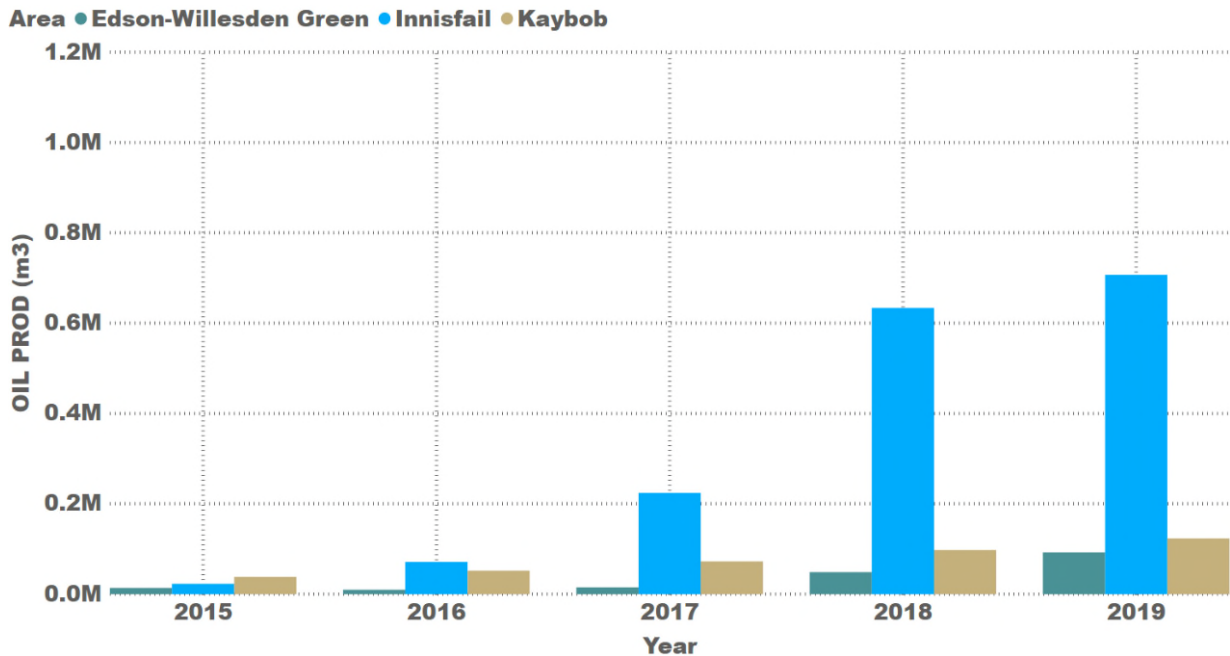


Figure 7 – Annual Duvernay Oil Production by Assessment Area from 2015 to 2019

- **Natural Gas and NGLs** - Most of the gas and condensate production is in the Kaybob area where the active producers are likely targeting natural gas and diluent needed for their oil sands operations. Most of the focus on new drilling seems to be focused on natural gas from areas with lower condensate content, compared to what was developed earlier by Encana and Shell. The two most active producers (Murphy and XTO) generally have leases outside of the region which has the highest condensate production. Gas in the Innisfail region will mainly be solution gas produced with light oil, and should grow in volume with the oil production, as all the wells in that area are crude oil wells and GORs for oil wells appear to be consistently low.

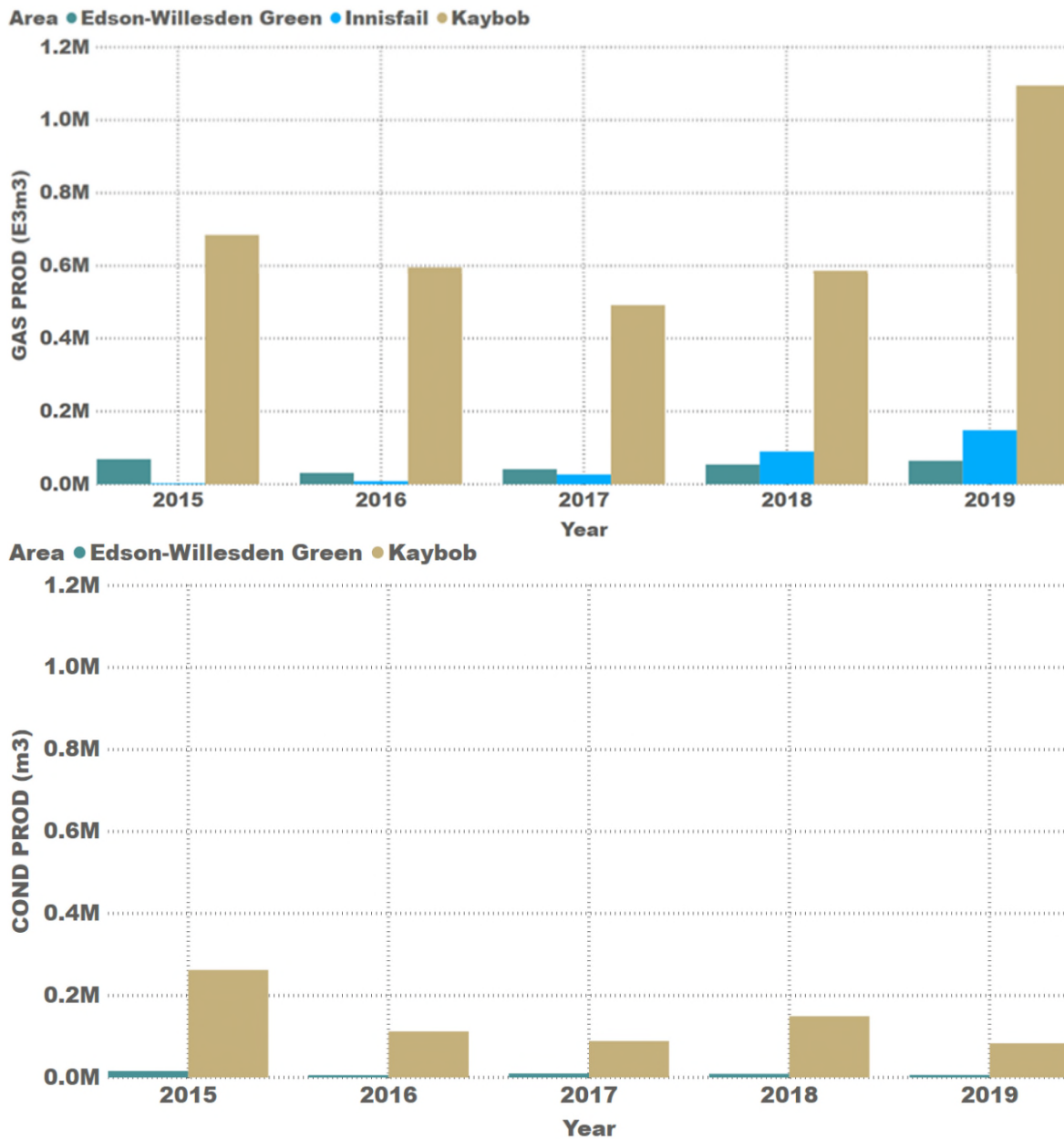


Fig. 8 – Annual Duvernay Natural Gas and Natural Gas Liquids Production by Assessment Area from 2015 to 2019

### Hydraulic Fracturing in the Duvernay

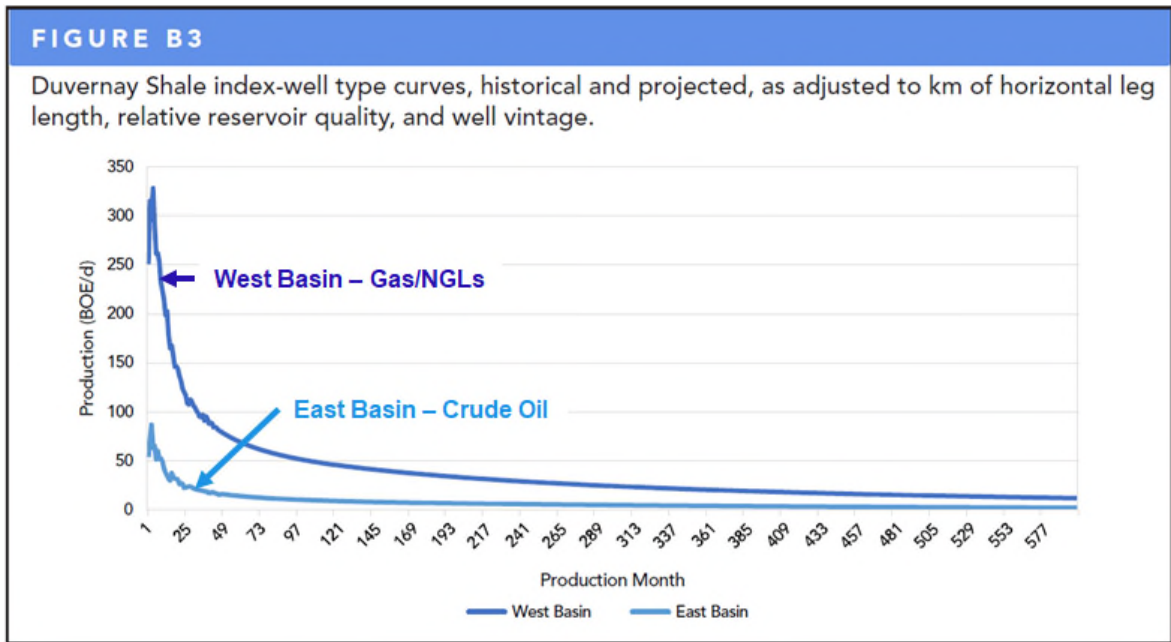
Hydraulic fracturing of horizontal wells has been utilized to open many different types of formations in North America, and other parts of the world. These formations range from the relatively thin and shallow Viking formation found in east central Alberta, to deep and thick shale formations like the Duvernay. While the basic technology is the same, how it is applied and the resources required for each formation can be quite different, even if the same number of wells are drilled from a pad. For the Duvernay formation, producers have consistently chosen hydraulic

“slick water” fracturing with large volumes of water. Since January 2013, data on well completion methods, carrier fluids, and chemicals used by producers, has been required to be reported to the Alberta Energy Regulator, under Directive 059 “*Well Drilling and Completions Data Filing Requirements*”, with much of the basic information provided for public access through the website [www.fracfocus.ca](http://www.fracfocus.ca). A previous assessment of Duvernay fracturing practices in 2015 (PTAC), provided a summary of fracturing practices for the Duvernay. A sampling of more recent wells confirms that the basic “slick water” fracturing methods used in 2015 are still in use today. The main components used in the Duvernay are:

- **Carrier Fluid** – In all completions, water is used as the main fracturing fluid and makes up between 85-95% of the injected material, but almost 50% of the wells showed that the carrier fluid also included hydrochloric acid (15% HCl solution <0.5% of total frac water volume) which is often pumped during fracture stimulations in limestone or carbonate formations to help break down the rock. The volume of water used varies with the number of fracture stages, the length of the well and the amount of other components (mainly sand) used in the completion. Water use per well averages about 28,000 m<sup>3</sup>/well, and ranges from about 7,000-85,000 m<sup>3</sup>/well, or about 1,600 m<sup>3</sup>/fracture stage with the average number of fracture stages per well of ~17.
- **Proppant** – Is needed to hold open the small fractures formed in the rock and in the Duvernay is usually quartz sand, but producers in deeper formations sometimes use ceramic proppant, metal oxide particles or resin coated proppants. Proppant averages about 5-10% of the mass of the fracture treatment, but the range is from 2-15%. On a mass basis, the average amount of proppant used is about ~1,500 tonnes/well.
- **Other Chemicals** – Generally <0.1% of the remaining fracture treatment mass is composed of a range of widely available chemicals, which are used to control bacteria, or change the viscosity of the carrier fluid to reduce pressure drop through the wellbore.

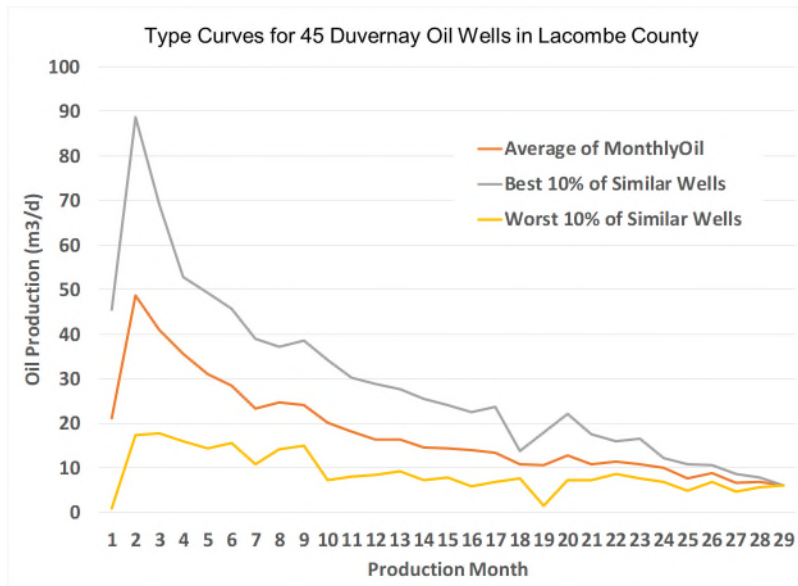
### **Well Production**

Well production characteristics can often be indicated by a “Type Curve” which is a normalized performance curve for a specific well type in a given area. Type curves for shale formations, such as the Duvernay are characterized by high initial production rates followed by a rapid decline, and then a long period of steady production at a lower rate. Unlike conventional wells, water influx is not usually an issue for shale wells so production could last decades.



**Fig. 9 – Normalized Duvernay Type Curves for East and West Basins on a BOE/d Basis**  
(NEB, 2017)

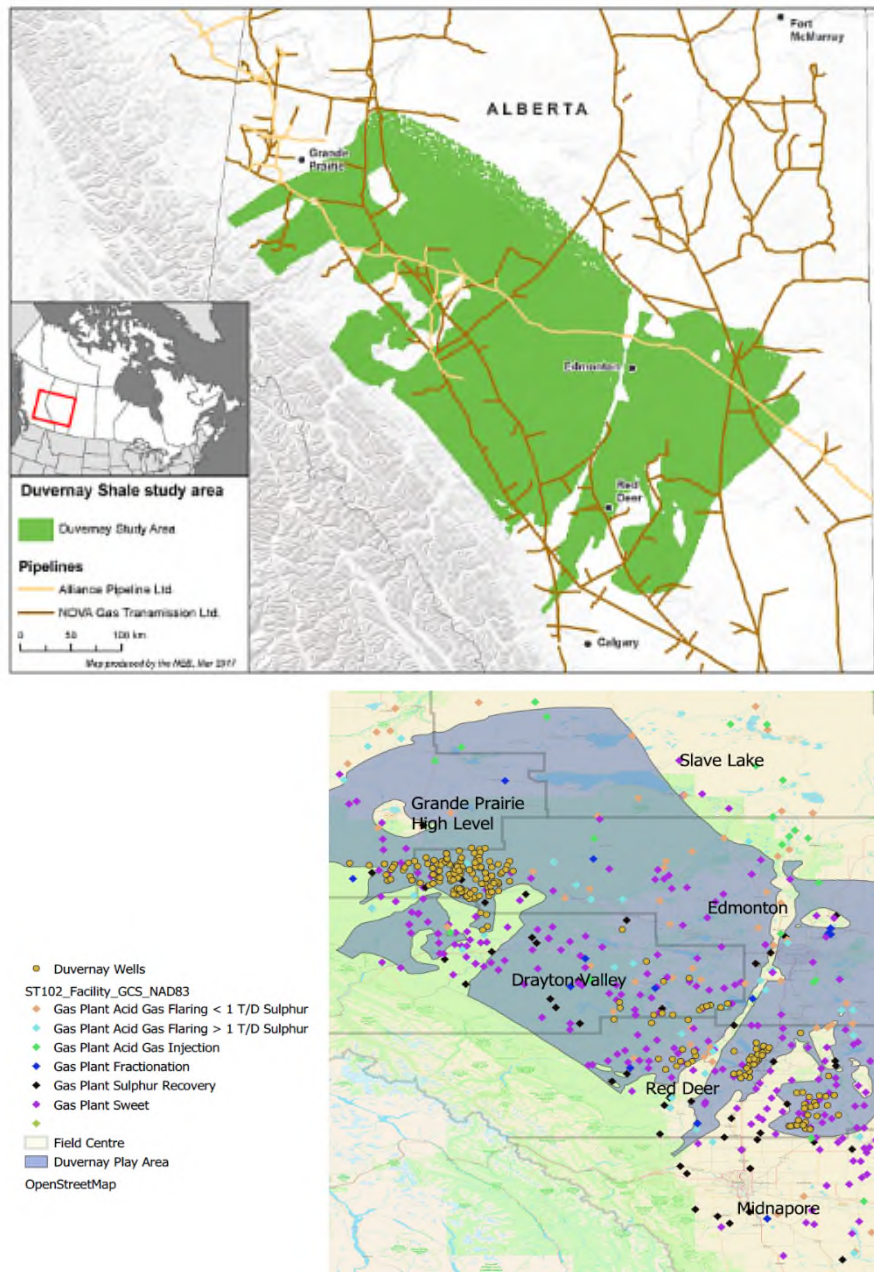
Care must be taken in using type curves, as normalizing on factors such as horizontal length, BOE equivalents, etc. do not represent the average wells in each population. Also, the number of wells used in the type curve must be enough to provide statistical validity and represent the current completion methods being used after some period of “learning”. BOEs also ignore the relative value of NGLs, Oil and Gas and the relative drilling and economic costs. The curve in **Fig. 9** for the East Basin is normalized to 1 km horizontal length on a BOE basis, yet most of the recent wells in the Duvernay are longer so produce more per well. **Fig. 10** shows a set of type curves for Duvernay oil wells in Lacombe County, all drilled and operated by the same company between 2016 and 2018. The average well here is between 2-3 km in length and shows the spread in performance between the best wells and the worst wells in the group.



**Fig. 10– Type Curves for Duvernay Oil Wells in Lacombe County with Map Showing Relative Well Positions.**

### 2.1.3 Oil and Gas Infrastructure in Place

Most of the Duvernay play is in areas which already have considerable infrastructure for gas and oil production from other formations. As a result, producers in this area can generally find a relatively nearby oil battery or gas gathering system to tie their wells into. Some multi-well oil batteries handle production from a wide range of oil formations. In the Kaybob area, gas plants have been reactivated and new plants and pipelines have been built to handle rapidly growing Montney production in the same area, which can then also process Duvernay gas and NGLs.



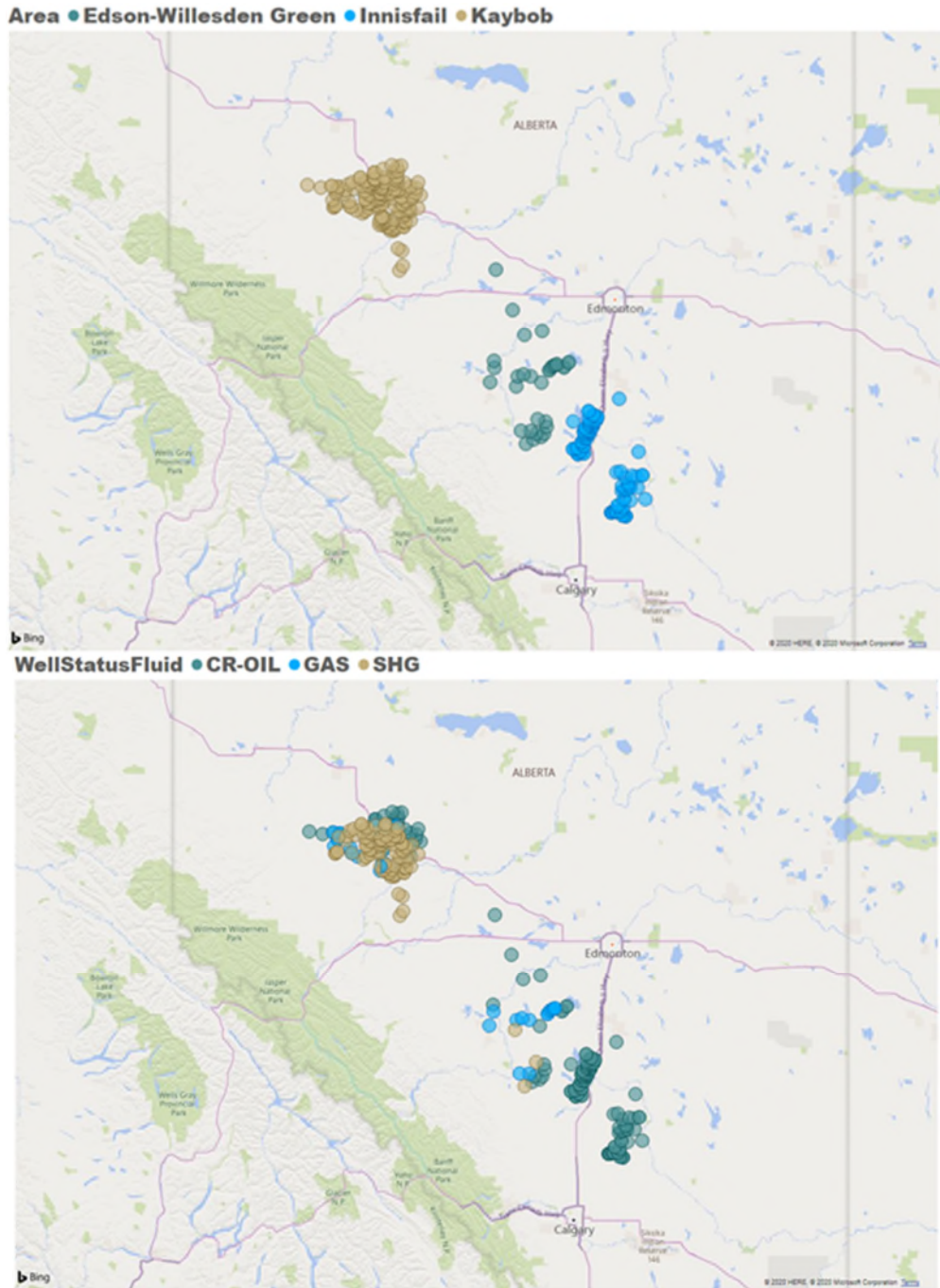
**Fig. 11 – Maps Showing Locations of Major Gas Transmission Lines (NEB, 2017) and Gas Plants (New Paradigm, 2020) in the Duvernay Play Area**

The main areas with a lack of oil infrastructure are the Kaybob area and northwestern portions of the Edson-Willesden Green area which tend to be gas prone in most formations. The Duvernay oil wells in these areas are further west than most conventional and Montney oil wells, so there is less existing infrastructure for them to tie into. Many are single well batteries with only 1-3 wells per company, relatively widely spaced and drilled before 2015, so appear to be more exploration or delineation wells which were put on production, rather than a focused development program.



**Well Drilling and Completions**

Well data obtained from Petrinex Well Infrastructure Database as of January 15, 2020, also shows the split in production types varies with the assessment areas and numbers of wells drilled or producing over time.



**Fig. 12 - Distribution of Active Duvernay Wells as of January 2020 Sorted by Assessment Area and Production Type (AGS, 2017)**

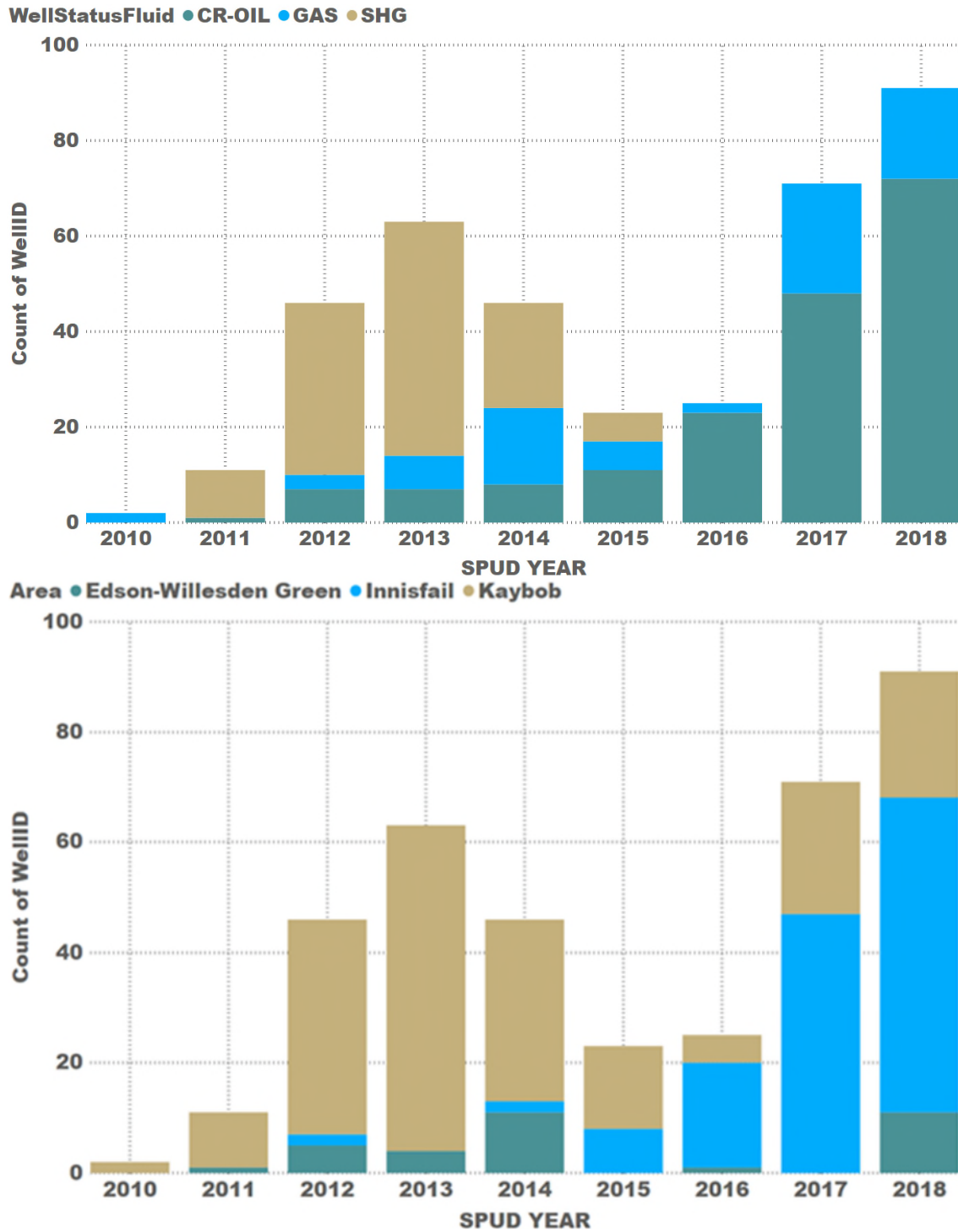
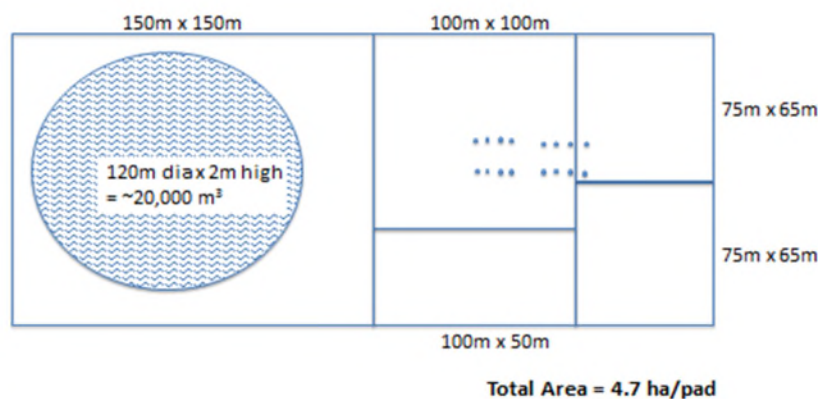
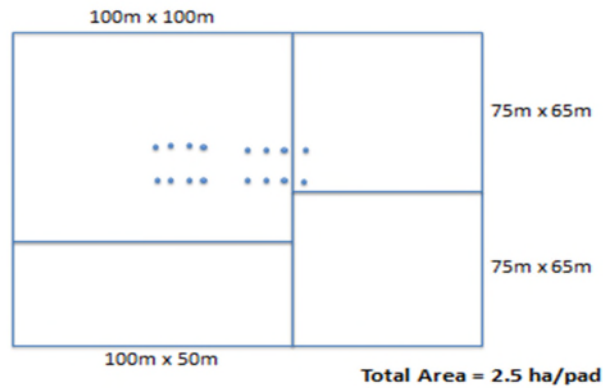


Fig. 13 - Duvernay Well Drilling Trend Over Time by Well Production Type and Assessment Area

### Lease Sizes for Duvernay Pads

The main driver for the size of Duvernay pad size is the area needed for locating the hydraulic fracturing equipment on the sites. Based on some assessments of aerial photography, the base site for four Duvernay wells on a pad during completions would be about 10,000 m<sup>2</sup> to accommodate the onsite location of hydraulic pumping equipment, frac sand storage and chemicals. Most sites drilled to date were four wells per pad, but with time they could be expected to be expanded to 16 wells per pad with about 5,000 m<sup>2</sup> of area added to allow drilling, completion and fracturing of each set of four new wells. Therefore, a fully developed pad might occupy 25,000 m<sup>2</sup> or about 2.5 ha. Normally gas well operation require only small active leases, however, with shale resources the probability is high that either additional wells will be drilled or the original wells will either be recompleted and/or refractured. For these reasons the sites are often much larger than is needed for conventional oil and gas operations, and would allow considerable room for emissions control equipment as long as it can be temporarily relocated if the space is needed for fracturing equipment. The above numbers do not include room for frac water storage which could be accommodated using large lined dugouts, above ground storage in multiple tanks or a single large storage basin. This storage is dependent on the amount of water needed for fracturing treatment. The diagram below shows that for a 20,000 m<sup>3</sup> frac treatment water storage might add another 2.2 ha to the site. This will leave space on the pad for truck access or other equipment. During normal well operations oil pads would require space for pump jacks and a test separator with room in front of the wells to allow access by a workover rig. Gas wells would normally require less equipment, such as a small building for metering equipment and maybe a dehydrator and compressor, which could potentially be moved if new wells were being drilled. Historically, a single gas or oil well site might occupy a 0.8 ha lease for drilling which would reduce over time to as little as 0.1 ha in farming areas as the drilling rig area would be reclaimed.





**Fig. 14 – Approximate Duvernay Lease Dimensions for 4 to 16 Wells on a Pad. With and Without Room for Frac Water Storage**



**Fig. 15 – Space Requirements for a Duvernay Fracturing Operation (Canyon Services)**

#### **2.1.4 Production Challenges Pertaining to Gas Emissions**

Most Duvernay sites should be low emitting if they are connected by gathering lines to oil batteries or gas plants, as there is generally little in the way of emitting equipment on site, and what is there is newer. They are also more likely to be based on low emission technologies that are already available. The exceptions are:

- **Isolated Single Well Batteries** – These wells will generally be produced into tanks, with liquid production gathered by trucks. If there is no gathering line for oil production, there is less likely to be a gathering line for the lower volumes of low value solution gas, which will be co-produced with the oil. Without a gas gathering line, the solution gas would likely be flared to avoid odours and reduce GHG emissions.
- **Field Expansion Single Well Batteries** – Due to the uncertainty of Duvernay oil well productivity, the two main oil producers in the Innisfail region may expand their operations by drilling single wells to assess the production potential. If production is good, they will likely add more wells converting the well site into a multi-well battery or satellite and connect it to an oil sales pipeline. If production is poor, they may leave it as a single well battery and tie it in separately. During the initial production test period, production may be trucked from the site which results in flaring of the solution gas. Usually, the wells would be shut-in until they are connected to a flowline to a battery, so flaring is sporadic, low in volume and not part of normal production operations as it is for isolated wells.
- **Low Pressure Gas Production Requiring On-site Processing and Compression** – As with most natural gas operations, a major emission source for natural gas is processing and compressing the produced gas. In most cases in the Canadian industry, natural gas driven turbines or engines, and natural gas fired process equipment are used for production as they are the lowest cost energy sources for these operations. In Alberta, alternate electrical power would likely be from coal fired power plants, so there would be no incentive to convert to electric drive equipment. This results in relatively large fuel use on gas production sites.
- **Emissions from Hydraulic Fracturing Operations** – The main purpose of this report is focused on long-term production systems. However, all Duvernay wells must undergo multi-stage hydraulic fracturing to be able to produce. Assessing gas emissions for these operations is much more complex than can be undertaken for the current study but has been addressed in general by other studies. Both oil and gas wells are fractured with about the same method requiring large volumes of water and sand to be trucked to the site and then pumped at high rates into the formation. This results in significant vehicle and pump engine fuel use during the operation and may result in release of some emissions during the flowback phase, which are flared and not conserved. However, these emissions are of short duration, and are not a major source over the long term.

### 2.1.5 Emissions Data

As all Duvernay wells are relatively new, most should be designed to minimize venting and other gas emissions except during fracturing operations, well testing prior to tie in, emissions from fuel

use, and flaring from isolated oil wells. For this study, data has been collected from Petrinex to assess gas emissions from flaring, venting and fuel combustion. Gas compositions are highly variable between types of wells and wells of the same type and is not readily available. However, the main production streams will tend to be rich in heavier hydrocarbons, which are very economic to capture wherever possible, and if they aren't captured would have to be flared due to odours.

### **Flaring**

As indicated flaring is the most likely process to be used for any surplus gas, which cannot be economically captured due to lack of access to gathering lines or plants, due to odours emitted with rich gas streams. Detailed data on non-continuous flaring was not reviewed due to the relatively small and variable volumes. Large volumes of flared gas, reported in 2018/2019, are from only three isolated oil wells which flared all the produced gas in those years. Two are in the Kaybob area (one well flared in both 2018/2019, while the second was only in 2019) and one in the Edson-Willesden Green area which flared both years. Most of the rest of the flared gas also came from single well oil batteries but were smaller amounts for shorter durations and were likely associated with well testing.

### **Venting**

While newer Duvernay facilities should be designed for low emission operations, there are still some vent emissions being reported mainly in the Kaybob area from a range of facility types and production types. There does not appear to be any consistent trends except that most of the venting is from single well oil and gas batteries which are less likely to be in areas where there is electrical power available for instrumentation and other devices. They would likely rely on natural gas-powered pneumatic devices. There may also be compressor seal vents which are counted in this type of emission, but which are variable over time as seals wear and are replaced. Maintenance frequency is likely to be higher and equipment is likely to be monitored more closely at multi-well batteries.

### **Fuel Use**

The final air emission source is flue gas from fuel use, which results in lower GHG emissions as it is assumed combustion in engines and burners will be efficient, resulting in mainly CO<sub>2</sub> emissions. Data is available on fuel volumes with the majority in the Kaybob area at single well batteries, where power is not as accessible.

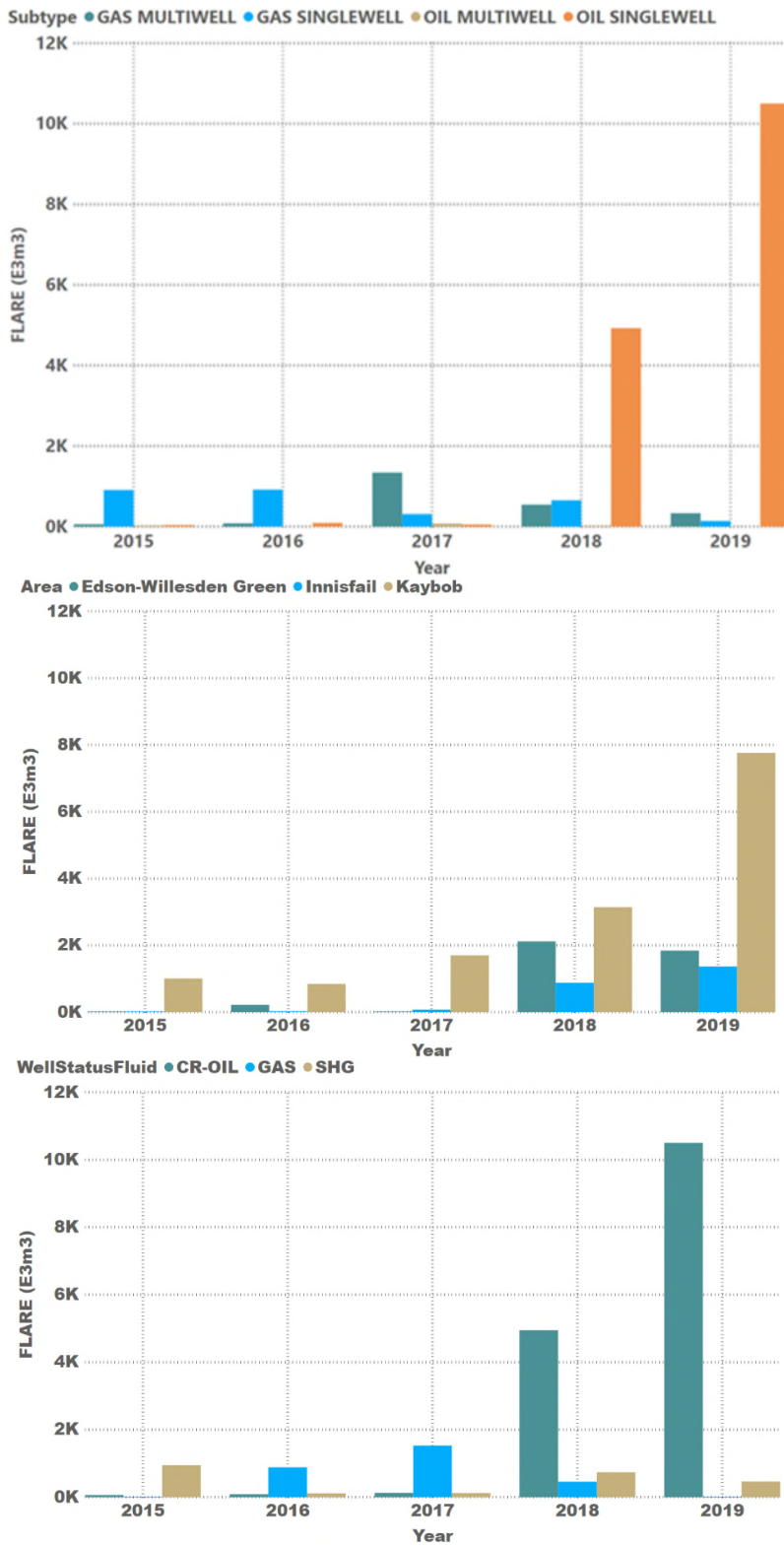


Fig. 16 - Duverney Flaring Emissions by Battery Type, Assessment Area and Production Type

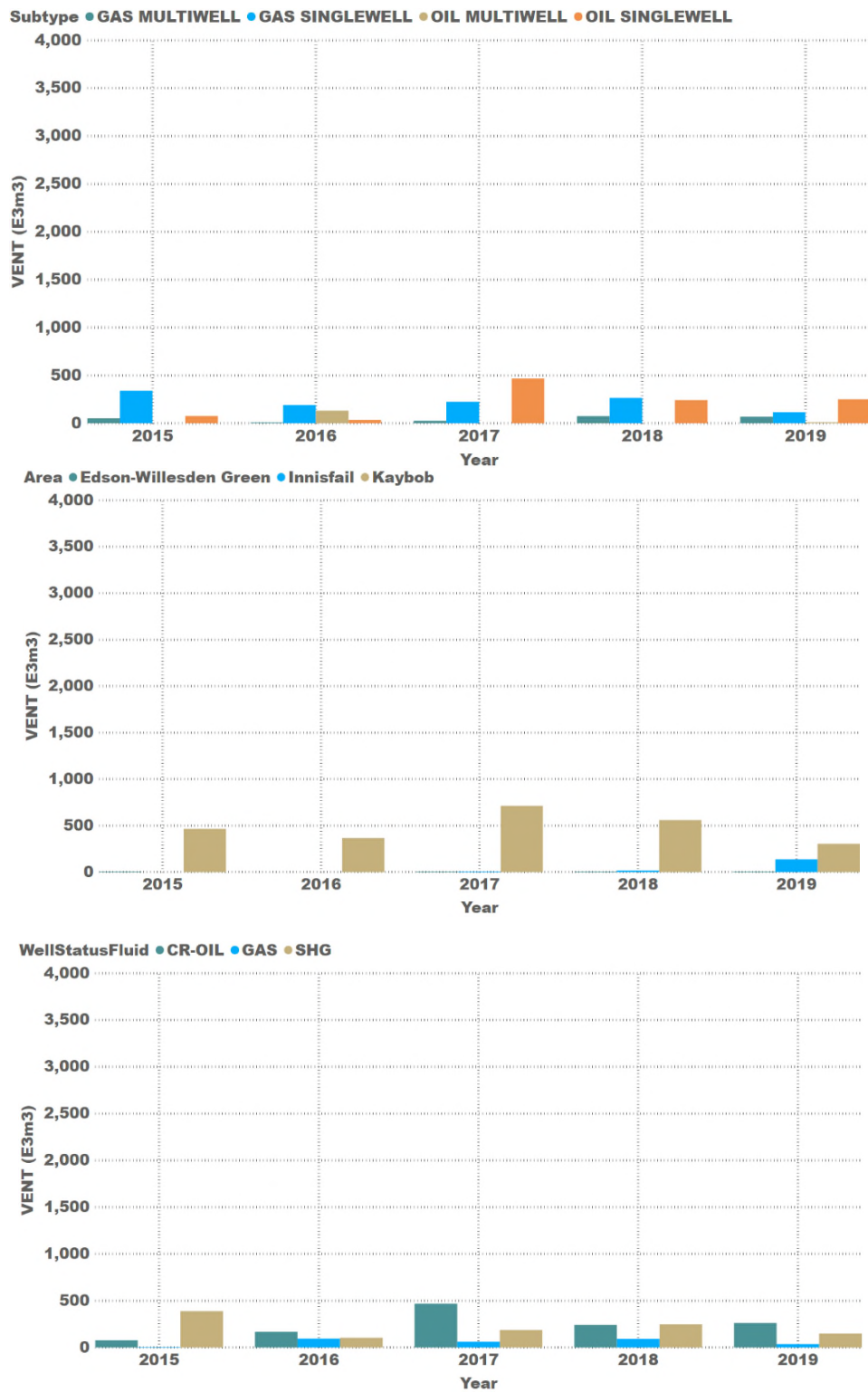


Fig. 17 – Duvernay Vent Emissions by Battery Type, Assessment Area and Production Type



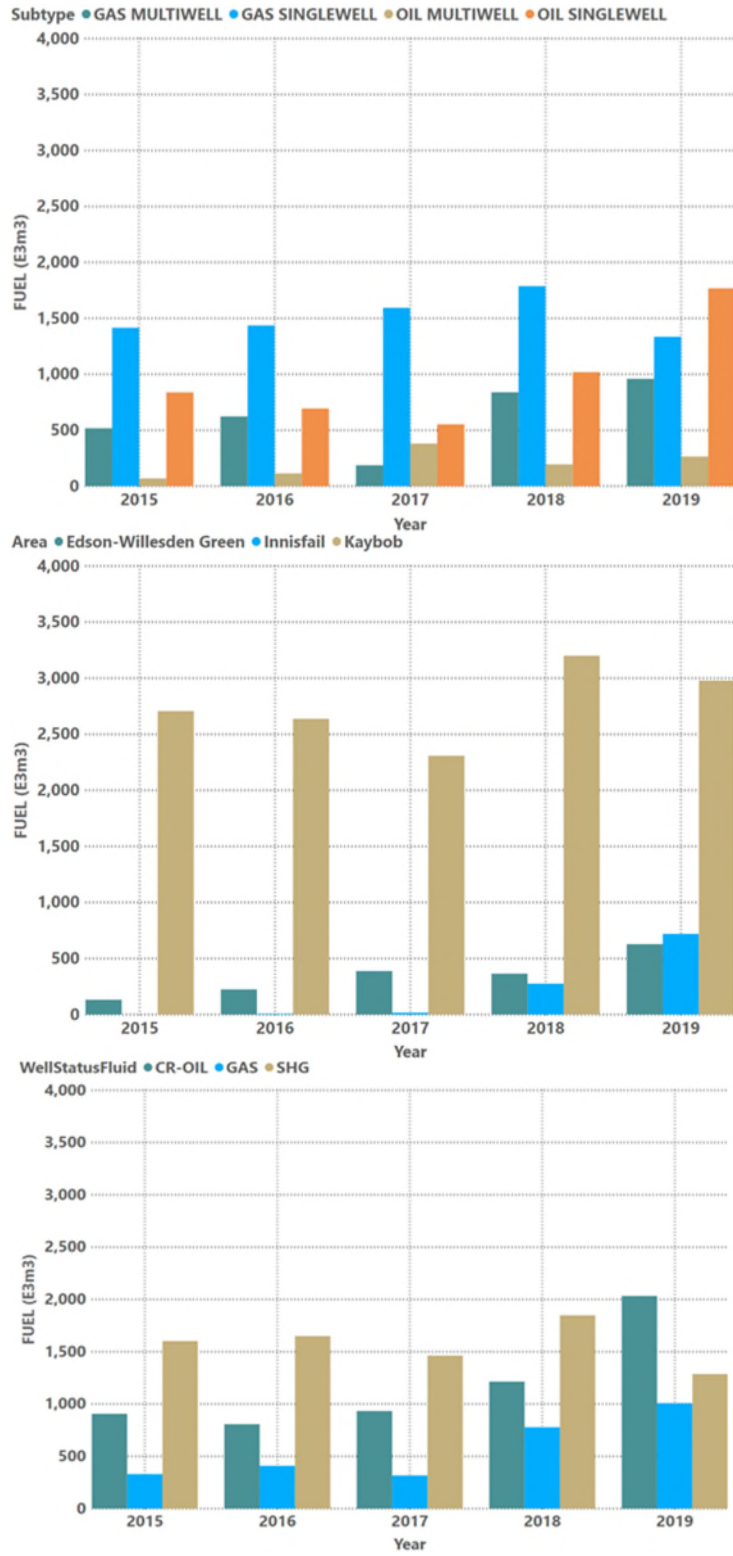


Fig.18 – Duvernay Fuel Gas Use by Battery Type, Assessment Area and Production Type

### Other Emissions

Detailed vent gas compositional data is not readily available for Duvernay resources over the entire area and can vary significantly between locations, different depths in the same location and emissions from different units on a site. Also, the data on gas composition may not reflect the composition of the gas being burned or vented, since pressure, temperature and other conditions impact the composition of the gas. For example, gas venting from a heated atmospheric storage tank will be richer in heavy components than the average gas composition for the total production stream, while gas from a compressor seal vent may be lower than the average gas composition. **Table 4** shows some estimates from various sources for rich Duvernay gas from two companies operating in different areas, a sample of sales gas composition from Duvernay oil wells near Lacombe, and an assumed composition for Duvernay gas wells based on Devonian wells in overlying conventional pools, since very few Duvernay gas wells have been drilled. The values shown may not be statistically valid as the well samples are small compared to the potential ultimate well count for this formation. It is not anticipated that the Duvernay will have significantly different emissions than other nearby formations and will have considerably lower emissions in some components such as H<sub>2</sub>S and CO<sub>2</sub>, than historic deep sour gas operations in the same area (e.g. Caroline produced conventional gas with over 45% CO<sub>2</sub> and H<sub>2</sub>S).

**Table 4 – Examples of Gas Compositions for Duvernay Production of Various Types**

Sample Gas Analyses for Duvernay Wells				
	Rich Duvernay Gas		Duvernay Oil	Duvernay Gas
	Encana 2012-2015 (~100 samples)	Shell 2012-2015 (~30 samples)	Vesta Feb 2019 (~5 wells based on sales volumes)	Based on 28 Devonian (non- Ass Pools)
CO <sub>2</sub>	0.01	0.01		
N <sub>2</sub>	0.01	0.01		0.01
C <sub>1</sub>	0.74	0.65	0.65	0.89
C <sub>2</sub>	0.14	0.16	0.05	0.04
C <sub>3</sub>	0.06	0.09	0.15	0.03
iC <sub>4</sub>	0.01	0.01		
nC <sub>4</sub>	0.02	0.03	0.10	0.01
iC <sub>5</sub>	0.01	0.01		0.01
nC <sub>5</sub>		0.01	0.05	
C <sub>6</sub>		0.01		0.01
C <sub>7+</sub>		0.01		
<b>Total</b>	1.00	1.00	1.00	1.00

- Heavier Hydrocarbon Components** – Generally the Duvernay gas, which is currently being produced, is rich in heavier hydrocarbons, which will cause odour issues if any produced gas is released. This triggers regulatory action to minimize uncombusted emissions to minimize odours. These emissions may be due to venting, inefficient combustion in flares, releases during well completions, or emissions due to fracturing

activities. Table 4 shows the Encana and Shell analysis are in the rich Duvernay area with Shell leases located east of the Encana leases in an area that has higher condensate production. Gas produced with condensate (Shell or Encana) is richer in ethane than oil solution gas (Vesta). For the assumed Duvernay gas composition the average methane concentrations were ~0.89 but the range was from 0.78 to 0.97.

- **Carbon Dioxide** – Sales gas can contain up to 2% CO<sub>2</sub> and all Duvernay sources appear to be below that threshold and generally are <1%. It is assumed that the Vesta gas may have some CO<sub>2</sub> (<1%) in the methane sales gas. The analysis used for Vesta was based on sales data (internal New Paradigm data based on production and royalty statements) rather than a direct analysis.
- **Hydrogen Sulphide** – Duvernay gas resources may, in some locations, have trace amounts of hydrogen sulphide (none reported but it could be encountered) which will be removed in sour gas plants which dominate the plants in the Kaybob Duvernay area and are also found in other assessed areas. Solution gas, in some currently undeveloped areas, may also have trace H<sub>2</sub>S levels (none reported), but may be detectable. One University of British Columbia (UBC) project was announced to map H<sub>2</sub>S levels in Montney, Duvernay and other formations in the WCSB, however, no results could be found on-line.
- **Combustion Emissions** – As indicated, drilling and completion operations depend on trucking large amounts of material and will result in emissions from diesel engines. Fuel use in compressor engines may result in NO<sub>x</sub> emissions, like other natural gas operations. Note that in a recent study New Paradigm undertook for ECCC on oil battery fuel use in the Grande Prairie region, that some shale oil batteries, reported in the Alberta Petrinex battery emissions, appeared to have shallow gas wells tied into them to provide fuel to avoid burning rich solution gas. This might also mean that some reported vent gas at similar Duvernay batteries may be gas from a different formation with a different composition.

### 2.1.6 Summary

Some main summary points to emphasize are:

- **Resource vs. Reserves** – Even though the Duvernay Formation may contain extremely large volumes of oil, NGLs and gas, there has been very little focused development until recently. Prior to 2016/17 activity was mainly focused on exploration and delineation of the resources in the formation, and very little of this resource, except some shallower oil and gas portions, may be technically and economically viable to produce in the near-term as other formations, like the Montney are lower cost, larger in size and more profitable to produce.

- **Economically Challenged** – The stand-alone economics of Duvernay production are relatively poor compared to other formations and hydrocarbon resources in the U.S. and Western Canada. Current activity levels focus on shallow light oil and are mainly driven by two small niche producers for oil, and two larger producers developing gas to fuel oil sands operations.
- **Few Motivated Developers** – The early developers in 2010/16 were mainly focused on establishing resource tenure, fulfilling contractual commitments, high grading assets or driven by integrated economics with other projects, rather than stand-alone Duvernay economics. More recent developments focus on different objectives for integrated operations looking for expanded in-house gas suppliers for oil sands and small companies specialized in aggregating small freehold leases in more developed areas.
- **High Costs and Uncertainties** – There are many uncertainties related to costs, economics, water impacts, seismic impacts and other facets of the Duvernay development, which will discourage many companies from rushing to make any additional major investments, beyond their current commitments. Therefore, the potential for rapid expansion of these operations, beyond those already underway, is small.
- **No, or Low, Proven Reserves Assigned to the Duvernay Formation** – As a result of the above issues, there are few formally recognized proven reserves assigned to this formation. “Proven” reserves assigned to the Duvernay will mainly be attributed to “production already in the tank”, or resources already drilled.
- **Emissions Related to Duvernay Production** – Few emissions are seen in this play that are not already factors in other conventional and unconventional plays, so generally there is “nothing new” in the way of emission sources with these operations. The main exception which applies to the early development phase of all resources in any new area, is associated with isolated wells and to a lesser extent production testing, which are causing flare emissions from less than 1-2% of the total sites.
- **Mitigation Technologies Needed** – To deal with remote site and test gas flaring it would be necessary to develop better, less expensive methods of providing “virtual pipelines” for low volume and low value sources of “stranded” solution gas.

## 2.2 Description of the Viking Resource

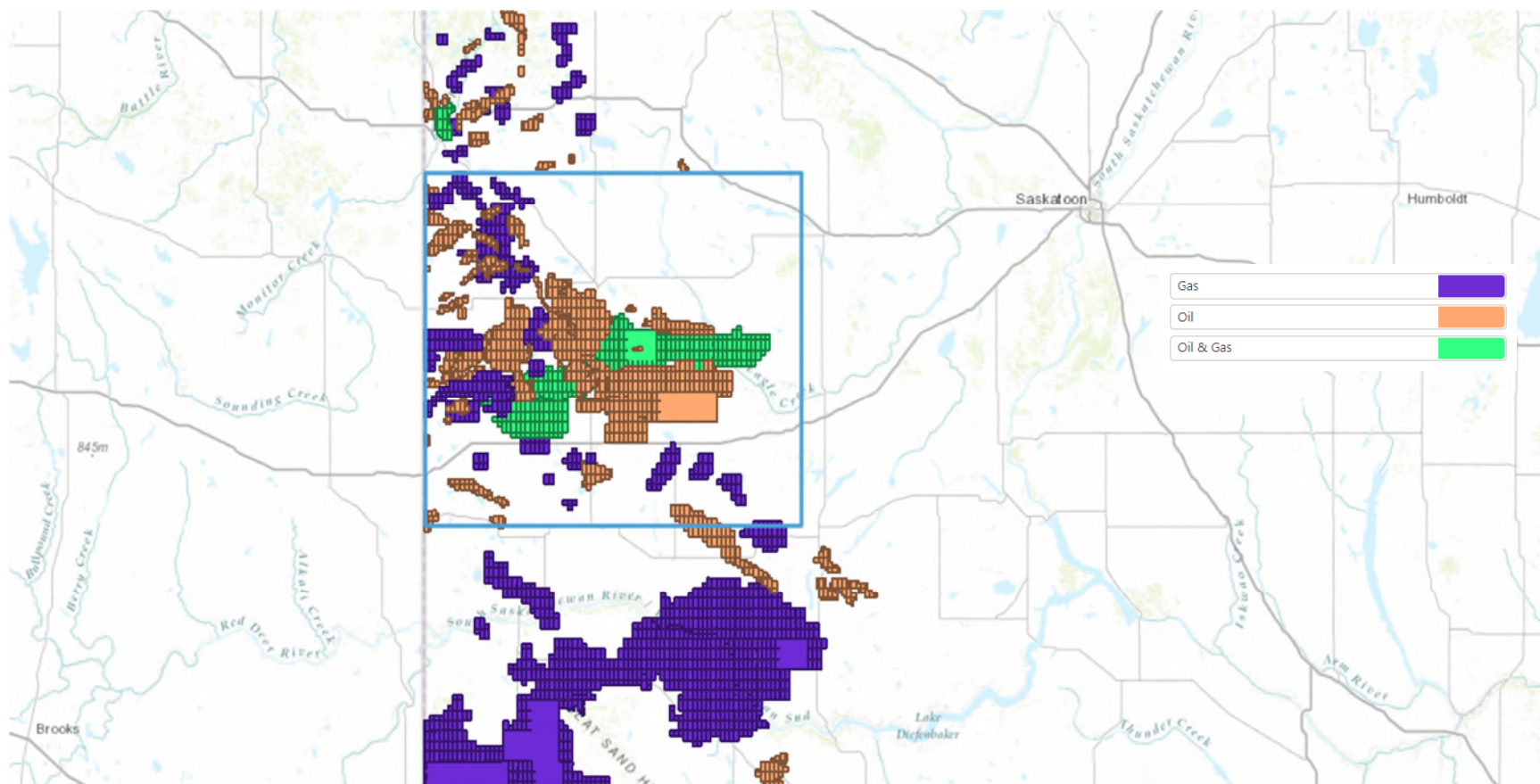
This section provides background information on the Viking petroleum play, including the following information:

- A brief description of the geology, oil reserves, lateral extents of the petroleum system, depth to reserves, production, porosity, permeability, mineralogy, gas to oil ratio, etc.
- Emission data, including the production challenges as they pertain to gas emissions, typical gas emissions over time for the first 1-5 years of a well, flaring/venting/fugitive emissions in each system over time, and emission chemistry (methane, ethane, H<sub>2</sub>S, CO<sub>2</sub> etc.).
- Number of number of wells, location of wells, and well pad details.
- Oil and gas infrastructure in place, typical, pipelines, gas processing facilities, storage facilities.

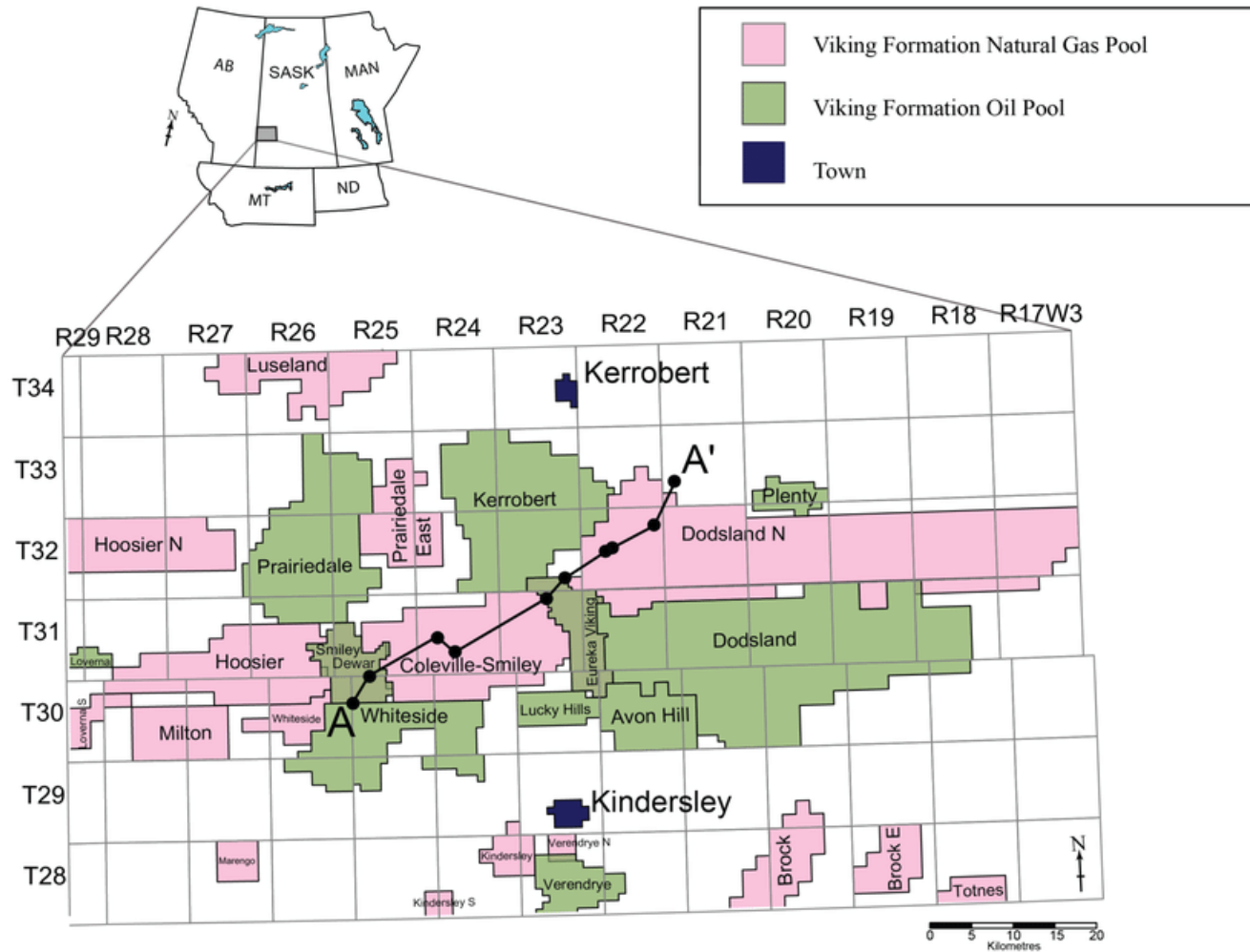
### 2.2.1 Physical Description of the Viking Resource

#### *Viking Petroleum System*

The report focuses primarily on the Saskatchewan portion of the Viking oil play, as the Saskatchewan government was a major source of information. The Viking has a mix of oil, gas and oil & gas producing regions, as seen in **Fig. 19**. Bakken pools with oil production are also present in the area.



**Fig. 19 – Location of Viking Oil Field in Saskatchewan  
(SM&P, 2020)**



**Fig. 20 – Oil and Gas Pools in the Viking Formation**

(Kohlruess, 2015)

## Geology

The late Albian Viking Formation of the Lower Colorado Group is a complex stratigraphic unit of sand bodies interbedded with marine shales in the Western Canadian Sedimentary Basin (WCSB). Regionally underlain by the marine Joli Fou Formation and unconformably overlain by marine shale of the Westgate Formation, the Viking formation is equivalent to the Bow Island Formation in southern Alberta, the Pelican Formation in north-eastern Alberta, and the silt member of Ashville Formation in Manitoba. In the United States, the Viking is correlated with the Newcastle Formation in North Dakota and the Muddy Sandstone located in Montana and Wyoming.

The Viking Formation ranges from 15 to 45 m thick over most of central Alberta, and progressively thins to the north and east and pinches out in central Saskatchewan and along the Saskatchewan-Manitoba border. Its siliciclastic sediments were sourced from the uplift of the south/southwest Cordilleran orogenic belt, when the paleo-shoreline shifted to the Western Interior Seaway within a foreland basin (MacEachern et al. 1999). Variations in lithology and mineralogy across the shoreline indicate the Viking had complex shoreface successions caused by tectonic and eustatic effects from the western interior seaway.

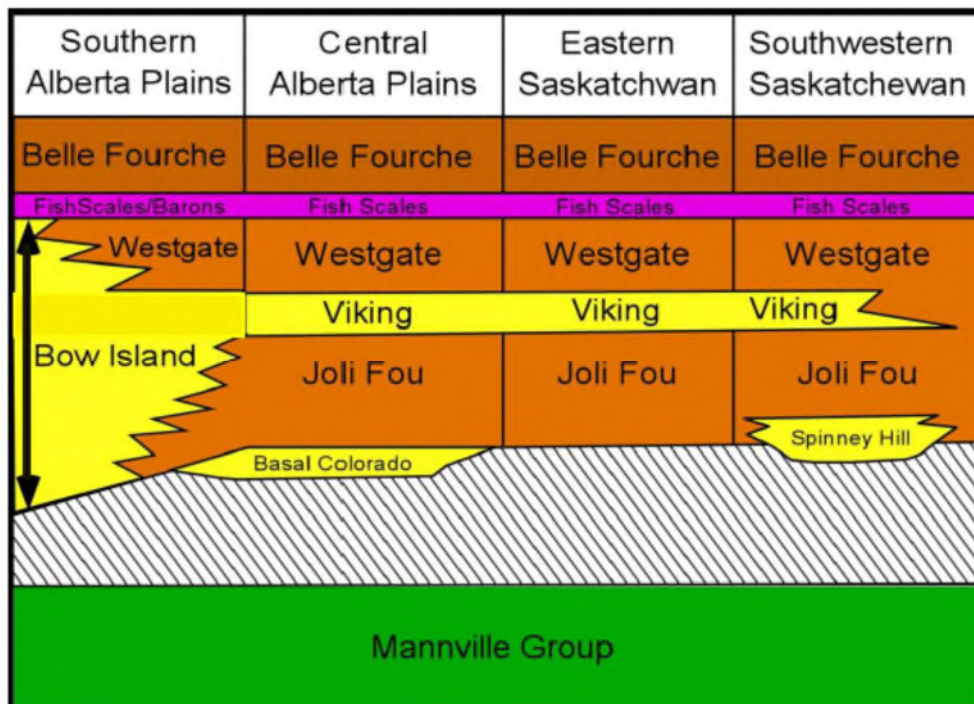


Fig. 21 – Stratigraphic correlation chart of the Viking formation and equivalent Bow Island formation in Alberta and Saskatchewan



## Mineralogy

Because of transitional to offshore depositional environment, the Viking formation is featured as thinly laminated, bioturbated, argillaceous, fine to medium-grained shaley and clean sandstone/siltstone, where 25% of the formation consists of relatively porous sandstones and conglomerates, which are considered better-quality petroleum traps. High percentages (up to 50 wt%) of clay minerals, mainly composed of smectite, interlayered smectite-illite, and kaolinite, are distributed across the Viking formation (Foscolos et al. 1982). Detailed core analysis and facies descriptions were seen in literature for a variety of oil and gas reservoirs. In general, several distinctive facies are commonly present across the Viking formation: a) bioturbated sandstones/siltstone/mudstones; b) sandstone/conglomerate containing dark chert pebbles; c) muddy siltstone/mudstone; and d) fine to medium-grained sandstones with nodular calcite, siderite, and/or pyrite concretions.

## Porosity

Average porosity in the Viking for the selected oil pools ranges from 21 to 24 per cent, as can be seen in **Table 5**.

**Table 5: Porosity of Selected Viking Pools (per cent)**

Pool	Avg Porosity (%)	Pool	Avg Porosity (%)
Lucky Hills	21.0	Plato North	23.0
Dodsland	21.7	Verendrye	23.0
Plato	22.0	Kerrobert	23.0
Dodsland	22.4	Eureka	23.0
Elrose	22.5	Avon Hill	23.0
Coleville-Smiley	22.5	Hoosier	23.0
Dodsland	22.6	Prairiedale	23.0
Plenty	23.0	Smiley-Dewar	24.0
Dodsland North	23.0	Whiteside	24.0

(GoS, 2016b)

## Permeability

The Viking is a tight oil play, with lower permeability and porosity than traditional oil reservoirs. Production can be improved by implementing hydraulic fracturing. Horizontal permeability barriers separate the reservoir into multiple flow units. Sandstone and mudstone layers have low to

moderate horizontal permeability of less than ten millidarcies, with poor vertical permeability. Shoal facies reservoir sands have relatively high horizontal permeability (tens of millidarcies to over one hundred millidarcies) and moderate vertical permeability (single millidarcies to a few tens of millidarcies) Lower shoreface transgressive sands have moderate to high horizontal permeability (tens to over one hundred millidarcies) but low vertical permeability (due to interbedding with mudstones) and low storage capacity due to their thinness. (Mathison, J. Edward, 2014) Permeability damage due to water sensitivity of the formation and organic solid precipitation due to pressure and temperature change both hinder effective oil production in Viking reservoirs. (Sayeg, 2009)

### Gas to Oil Ratios (GOR)

The median gas to oil ratios (GOR) were compared among the five selected pools. The range of GOR is considerable. Dodsland N, Prairiedale East and Whiteside W are classified as Oil & Gas Pools and therefore have a high GOR compared to the other pools. Recent redesign of waterfloods in the region has led to improvements in reducing GOR.

**Table 6: Median Gas to Oil Ratio of Selected Viking Pools (m<sup>3</sup>/m<sup>3</sup>)**

Field Name	First Prod	First 3 months	First 6 months	First 9 months	First 12 months	First 18 months	First 36 months	Last 3 months	Last Prod
DODSLAND	8	27	38	42	46	51	53	63	53
DODSLAND NORTH	167	4968	8254	13944	16019	15337	24728	1111	580
ELROSE	0	0	1	2	7	16	20	139	154
KERROBERT	1	65	87	95	99	107	107	145	136
PRAIRIEDALE	74	172	218	239	258	274	307	735	750
PRAIRIEDALE EAST	426	6978	8100	9438	12299	14232	18359	657	541
WHITESIDE	22	150	215	246	270	295	301	483	482
WHITESIDE WEST	1176	2270	5094	13037	18172	14369	12126	213813	0

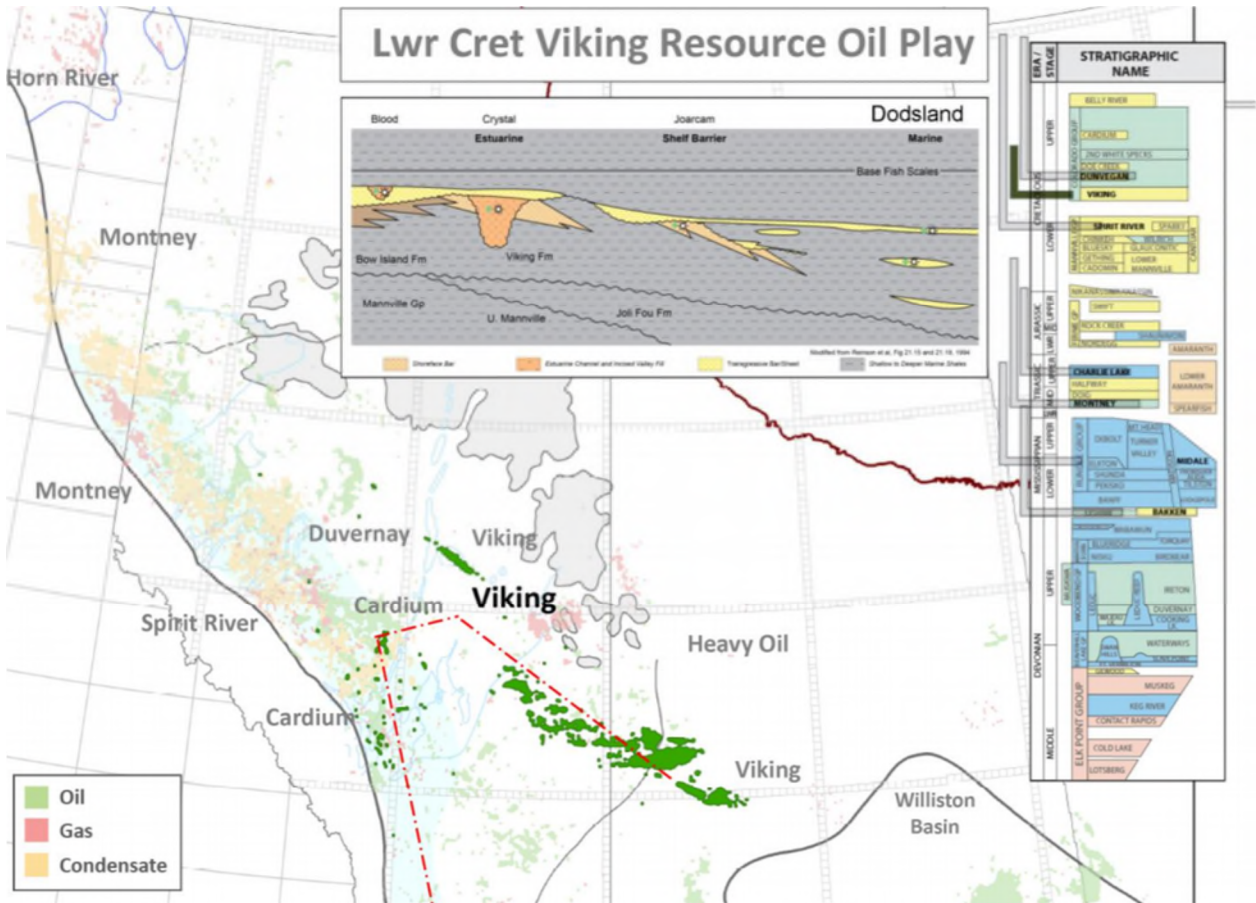
(Accumap, 2020)

## 2.2.2 Oil Production

### Historical Exploration of the Viking

The Viking Formation hosts a variety of prolific oil and gas pools in Alberta and Saskatchewan. The first Viking-Kinsella gas reservoir was discovered by Slipper in 1918. Since then, oil and gas bearing pools from the Viking and equivalent sandstones have been discovered and produced over one century. Most oil and gas production is concentrated in the northwest-southeast-trending elongated sandstone bodies of about 800 km from northeast of Edmonton, Alberta to Kindersley,

Saskatchewan (**Fig. 22**). The trending is characterized as marine sand bodies sandwiched in marine mudstones when the paleo-shoreline moved landward and seaward from sea level change (Walz et al. 2005).



**Fig. 22 – Lateral Extent of the Viking Resource Play**  
(Fockler, 2016)

Conventional oil and gas fields with higher permeability and porosity in the Alberta Viking Formation have been exploited since the early 1930s (Glaister 1959). In recent years, thanks to the horizontal well drilling and multi-stage hydraulic fracturing technologies, development has been extended to unconventional low-permeability sandstone and bioturbated sandy mudstone. Due to great complexity of geology, however, there are major challenges in how to accurately determine net pay, porosity, and initial oil saturation, which result in uncertain original oil in place estimations.

### Production Areas

Oil production volumes are divided into four producing regions in Saskatchewan. Area 2 – Kindersley includes heavy, medium and light crude production (Fig. 23, 24). The Viking makes up most of the light and medium volumes for the region.

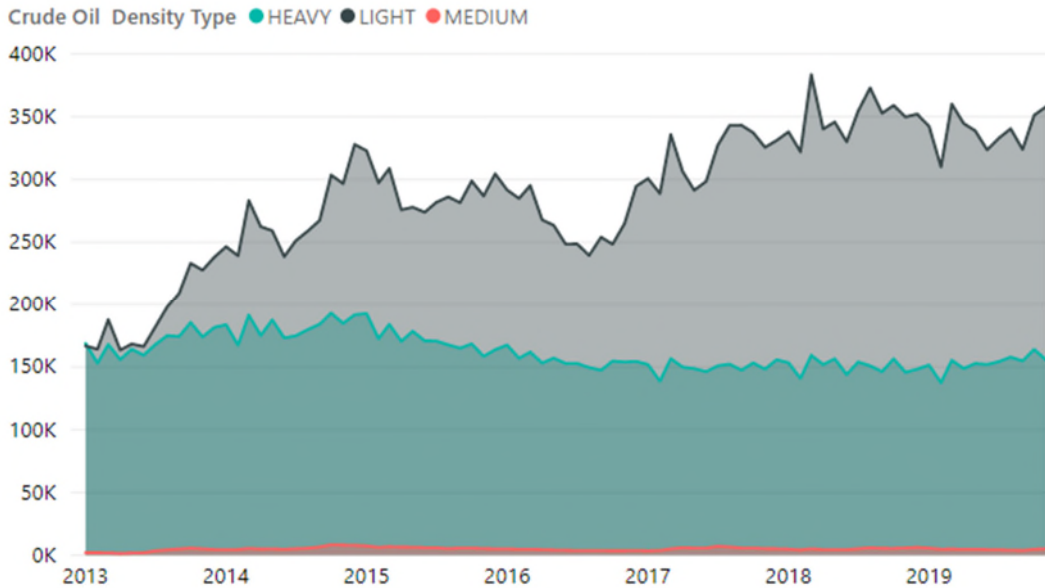


Fig. 23 – Area 2 - Kindersley Oil Production 2013-2019

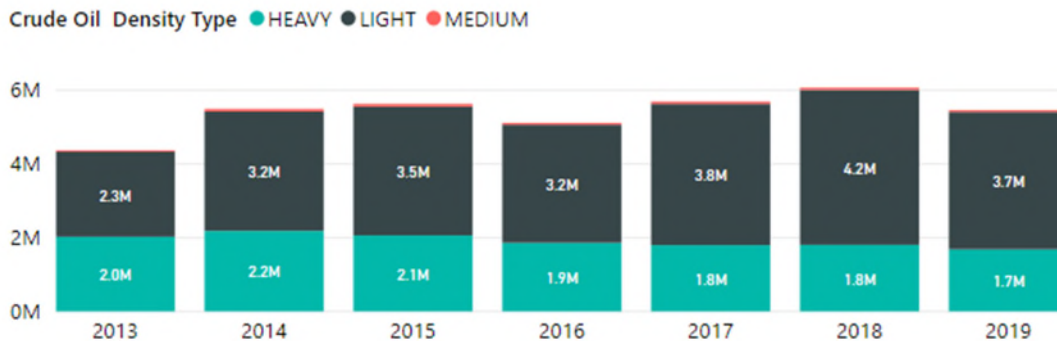


Fig. 24 – Area 2 - Kindersley Total Volumes Per Year  
(GoS, 2020)

### Viking Hydrocarbon Reserves

Reserves are provided for the pools within the Saskatchewan Viking. The largest initial total reserves are in the Dodsland and Kerrobert pools (Table 7).

**Table 7 – Viking Oil Reserves by Pool**

Pool	Initial Oil in Place (1,000,000 m3)	Initial Reserves Primary (1,000,000 m3)	Initial Reserves Enhanced (1,000,000 m3)	Initial Reserves Total (1,000,000 m3)
Doddsland	144.46	14.65	5.15	19.8
Kerrobert	63.53	3.65	2.54	6.19
Smiley-Dewar	26.24	4.11	1.4	5.5
Plato North	43.32	4.02	0	4.02
Eureka	23.71	1.77	1.83	3.61
Avon Hill	36.71	3.24	0	3.24
Whiteside	28.68	2.35	0	2.35
Prairiedale	96.92	2.08	0	2.08
Plenty	23.32	1.23	0	1.23
Verendrye	20.3	1	0	1
Plato	14.6	0.66	0.11	0.77
Coleville-Smiley	12.84	0.53	0	0.53
Elrose	12.26	0.44	0	0.44
Lucky Hills	7.36	0.44	0	0.44
Hoosier	6.94	0.22	0	0.22
Doddsland North	18.48	0.2	0	0.2
<b>Total</b>	<b>579.67</b>	<b>40.59</b>	<b>11.03</b>	<b>51.62</b>

(GoS, 2016a)

### **Hydrocarbon Production**

Oil production in the Viking has averaged around  $3.2 \times 10^6$  m<sup>3</sup>, reaching a peak of  $3.6 \times 10^6$  m<sup>3</sup> in 2017. Gas production in the region has gradually declined from  $0.9 \times 10^6$  m<sup>3</sup> to  $0.7 \times 10^6$  m<sup>3</sup> in 2018. Production data from 2015 to 2019 is provided in **Fig. 25**.



**Fig. 25 – Viking oil production volumes by year**  
(MER, 2020).

### 2019 Production – Monthly

Total Viking production for 2019 was approximately  $3 \times 10^6 \text{ m}^3$ . Monthly average production was approximately  $276,000 \text{ m}^3$ . The highest monthly oil production rate reached was in March at  $298,000 \text{ m}^3$ . Monthly production for 2019 is given in **Table 8**.

**Table 8 – Viking Monthly Production in 2019**

Month	Reported Production Volume (m <sup>3</sup> )
January	287,117
February	259,821
March	298,287
April	284,640
May	280,377
June	264,992
July	270,628
August	273,093

September	259,464
October	277,827
November	280,903
December	281,055
<b>Total</b>	<b>3,318,204</b>

### Viking Oil Production by Pool 2015-2018

Oil production volumes are broken down by pool and year in **Table 9**. Doddsland, Kerrobert and Plato North were the three largest producing pools in the Viking from 2015 to 2018.

**Table 9: Oil Production by Pool**

Pool Name	2015	2016	2017	2018
Avon Hill Viking Sand Pool	298,377	336,119	410,263	292,067
Coleville-Smiley Viking Gas Pool	69,635	30,510	20,527	13,168
Doddsland North Viking Pool	31,133	36,303	63,428	64,873
Doddsland Viking Sand Pool	960,400	893,293	860,266	836,964
Elrose South Viking Sand Pool	26,169	28,000	37,063	33,595
Elrose Viking Sand Pool	37,557	30,522	45,198	37,794
Eureka Viking Pool	24,828	21,030	38,307	40,201
Forgan Viking Sand Pool	4,941	4,786	4,265	4,976
Forgan West Viking Sand Pool	14,240	17,757	26,969	45,606
Greenan Viking Gas Pool			55	102
Hoosier North Viking Sand Gas Pool	1,481	3,077	5,334	3,183
Hoosier Viking Gas Pool	6,064	4,814	3,339	3,385
Kerrobert Viking Sand Pool	438,583	371,649	453,385	359,482
Kindersley Viking Gas Pool	5.4		10.3	5.9
Loverna South Viking Gas Pool	0.6	1.0		
Loverna Viking Pool	1,012	750	455	723
Milton Viking Sand Gas Pool	6,783	13,980	8,519	3,336
Plato North Viking Sand Pool	458,337	468,615	470,372	340,199
Plato Viking Sand Pool	10,449	34,239	95,314	80,550
Prairiedale East Viking Gas Pool	99	3,497	25,142	41,428
Prairiedale Viking Sand Pool	90,271	65,974	82,165	97,179
Smiley-Dewar Viking Pool	26,612	23,709	23,905	17,454
Totnes Viking Gas Pool	34	1.3	2.1	3,046
Verendrye Viking Sand Pool	10,360	9,131	6,734	5,190
Viking Sand (Misc Area 2)	350,767	326,561	518,699	503,956

<b>Whiteside Viking Sand Pool</b>	476617.4	353542.3	383073.9	287856.4
<b>Grand Total</b>	<b>3344755.7</b>	<b>3077861</b>	<b>3582789.4</b>	<b>3116319.5</b>

(MER, 2020)

### Estimated Recovery Percentage

The Government of Saskatchewan estimates primary and enhanced recovery for pools in the Viking, which are reproduced in **Table 10**. Primary recovery accounts for the majority of the oil recovered to 2016, the latest available data, with very little contribution from enhanced oil recovery techniques. The Smiley-Dewar Pool has the highest estimated total recovery at just over 18 per cent.

**Table 10: Estimated Crude Oil Recovery for Viking Pools (per cent)**

<b>Pool</b>	<b>Average of Estimated Recovery Primary (%)</b>	<b>Average of Estimated Recovery Enhanced (%)</b>	<b>Average of Estimated Recovery Total (%)</b>
<b>Smiley-Dewar</b>	13.45	4.75	18.2
<b>Eureka</b>	7.92	9.02	16.94
<b>Dodsland</b>	9.39	6.9	16.31
<b>Kerrobot</b>	5.75	4	9.75
<b>Avon Hill</b>	9.62	0	9.62
<b>Plato North</b>	9.28	0	9.28
<b>Whiteside</b>	8.2	0	8.2
<b>Lucky Hills</b>	6	0	6
<b>Plato</b>	4.52	0.81	5.33
<b>Plenty</b>	5.26	0	5.26
<b>Verendrye</b>	4.91	0	4.91
<b>Coleville-Smiley</b>	4.15	0	4.15
<b>Elrose</b>	3.6	0	3.6
<b>Hoosier</b>	3.17	0	3.17
<b>Prairiedale</b>	2.15	0	2.15
<b>Dodsland North</b>	1.82	0	1.825

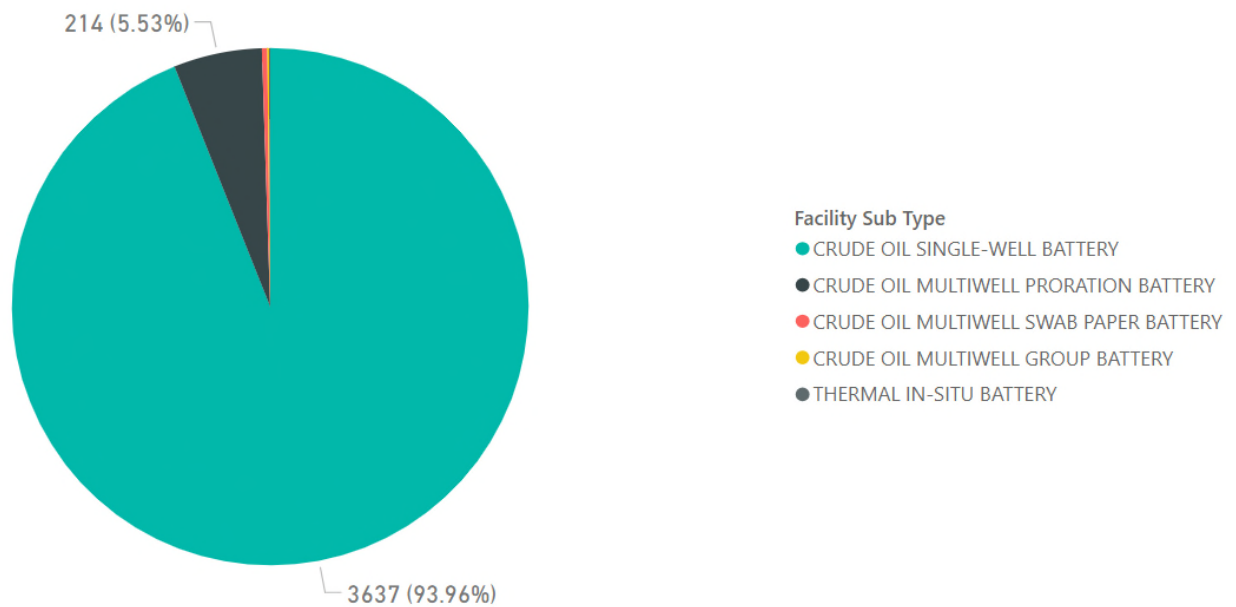
(GoS, 2016b)



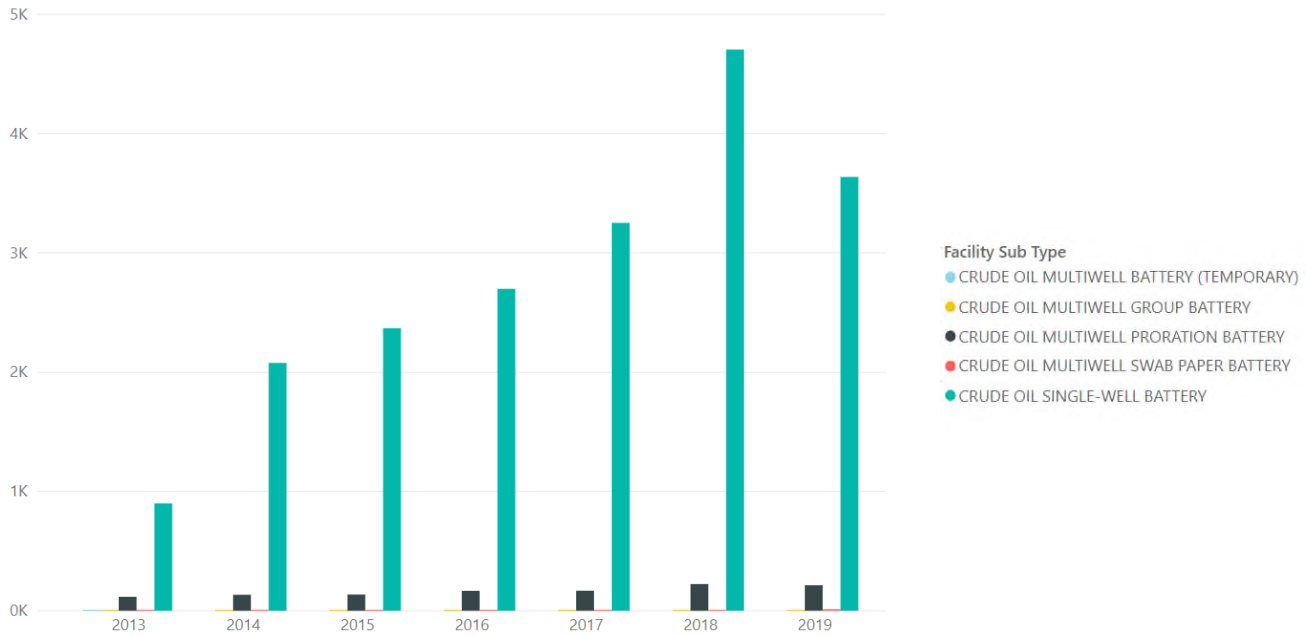
### 2.1.3 Oil and Gas Infrastructure in Place

#### Number of Wells in Viking, 2019

The number of facilities in the Viking that reported flaring, venting and fuel use in 2019 was 3,871. Nearly 94 per cent of these were crude oil single well batteries. As becomes clear from **Figs. 26 and 27**, the majority of associated gas venting in the Viking comes from single well batteries.

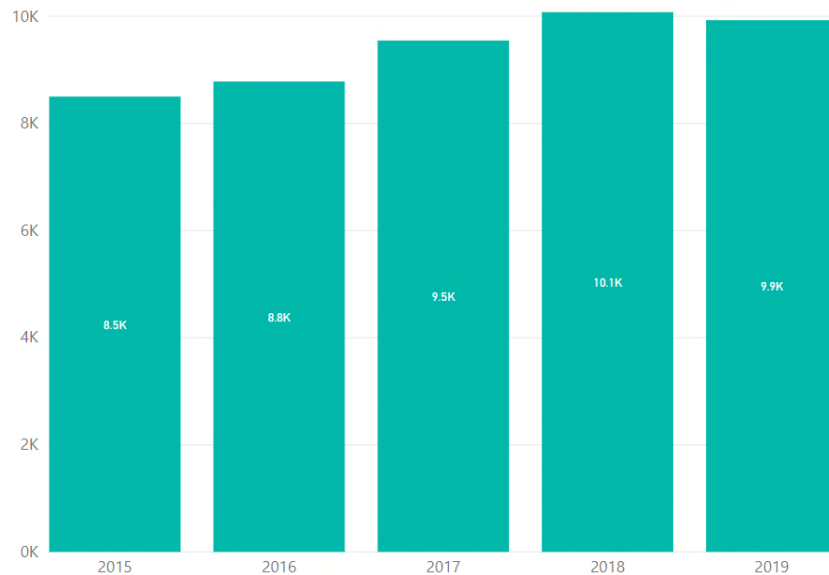


**Fig. 26: Facility Sub-types in the Viking**



**Fig. 27: Number of Facilities Reporting Associated Gas Volumes, 2013-2019 (excludes heavy oil wells and gas wells)**

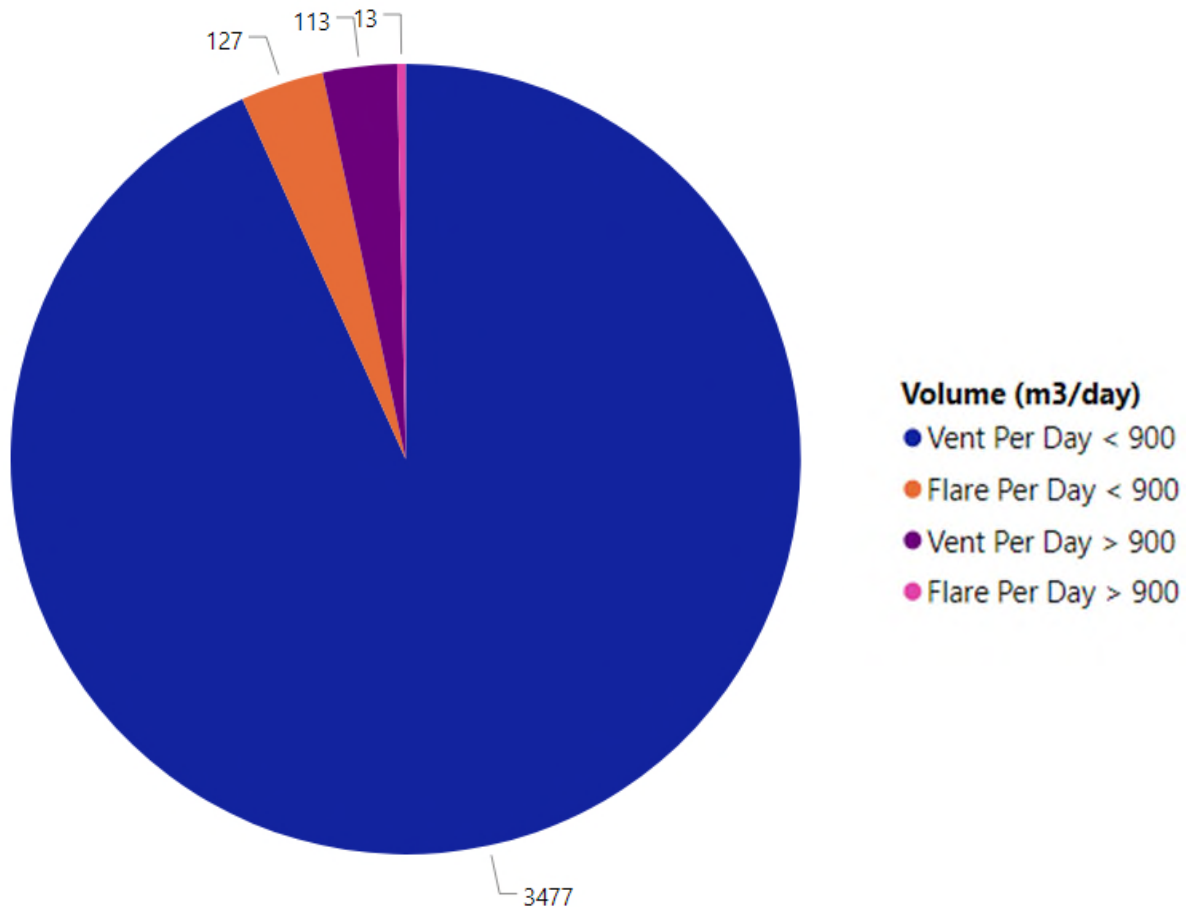
The number of active, producing oil wells increased from approximately 8,500 wells in 2015 to just over 10,000 wells in 2018 and then decreasing to just under 10,000 in 2019.



**Fig. 28: Number of Active Producing Oil Wells in the Viking (2015 to 2018) (MER, 2020)**

### Well Details

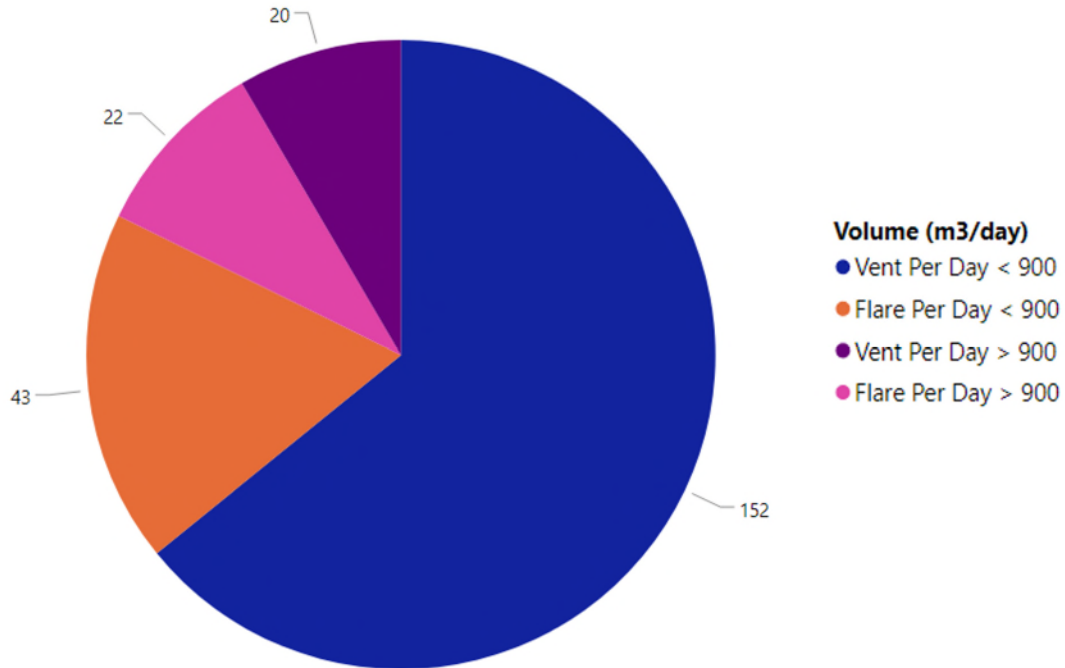
Based on the data in **Fig 29**, out of approximately 3,730 wells, only 126 wells report flare or vent volumes over 900m<sup>3</sup> per day. Approximately 3500 wells, or 96 per cent, flare or vent less than 900m<sup>3</sup> per day. As such, very few sites would be required to capture emissions under the current regulations.



**Fig. 29: Number of Wells Venting or Flaring (m3/day)**  
(GoS, 2020b)

### Facilities

For facilities that report flaring and venting, 42 or approximately 18 per cent of all facilities had emissions over 900m<sup>3</sup> per day in 2019. The other 195 facilities (82 per cent) vent or flare less than 900m<sup>3</sup> per day (**Fig. 30**).



**Fig. 30: Number of Facilities Flaring and Venting (m³/day)**  
(GoS, 2020b)

The large number of wells with low volume emissions will present a challenge when implementing new gas capturing technologies in the Viking.

### Companies Operating in the Viking

Just over 20 companies make up most of the emissions for 2019. Baytex, Teine, Whitecap, Crescent Point and Novus are the largest emitters in the region.

**Table 11: Companies Operating in Viking with Associated Gas, 2019**

Facility Operator	Flare Total (103m3)	Fuel Total (103m3)	Vent Total (103m3)	Total Flared or Vented (103m3)
Baytex Energy Ltd.	15453	10903	74255	89708
Teine Energy Ltd.	10791	4368	69039	79830
Whitecap Resources Inc.	20096	4294	28990	49086
Crescent Point Resources	729	0	42179	42908
Novus Energy Inc.	5391	18087	11874	17265
NAL Resources Limited	252	9053	12102	12354
Steelhead Petroleum Ltd.	0	608	7582	7582
Vermilion Energy Inc.	34	148	7477	7511

ISH Energy Ltd.	2849	2224	2946	5796
Saturn Oil & Gas Inc.	156	5269	5454	5610
Tamarack Acquisition Corp.	11	2574	1681	1692
Turnstone Energy Inc.	0	1449	710	710
Petro One Energy Corp.	259	0	0	259
Pele Energy Inc.	0	41	258	258
Scil Resources Inc.	0	62	142	142
Leeco Resources Ltd.	0	0	96	96
Audax Investments Ltd.	0	57	54	54
Rolling Hills Energy Ltd.	0	132	40	40
Longhorn Oil & Gas Ltd.	0	1	4	4
Rocky River Petroleum Ltd.	0	66	3	3
2194942 Alberta Inc.	0	33	1	1
Smitty's Farms Ltd.	0	0	0	0
<b>Total</b>	<b>56021</b>	<b>59369</b>	<b>264887</b>	<b>320909</b>

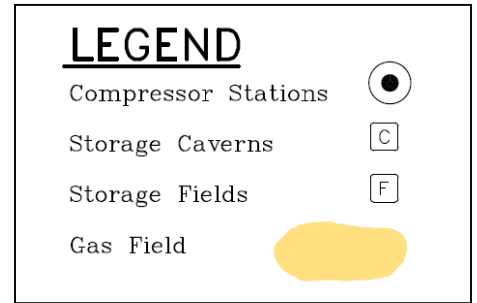
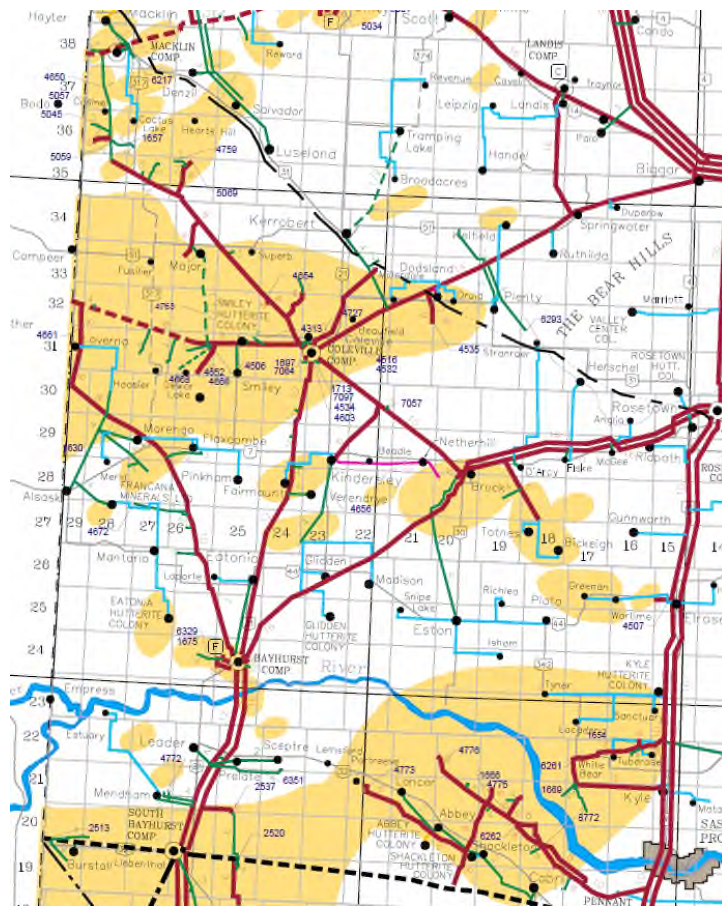
(GoS, 2020b)

### 2.2.6 Natural Gas Infrastructure – Kindersley Area

SaskEnergy, a Saskatchewan Crown Corporation, operates the natural gas pipeline system in the province through its subsidiary, TransGas Limited.

#### Transmission Lines

Throughout the province, TransGas operates over 14,000km of gathering and transmission lines. It also has underground storage fields and caverns (TransGas, 2020). The Many Islands Pipeline is the primary natural gas line that passes through the Viking and interconnects with the TransCanada Pipelines in Alberta (**Fig. 31**).

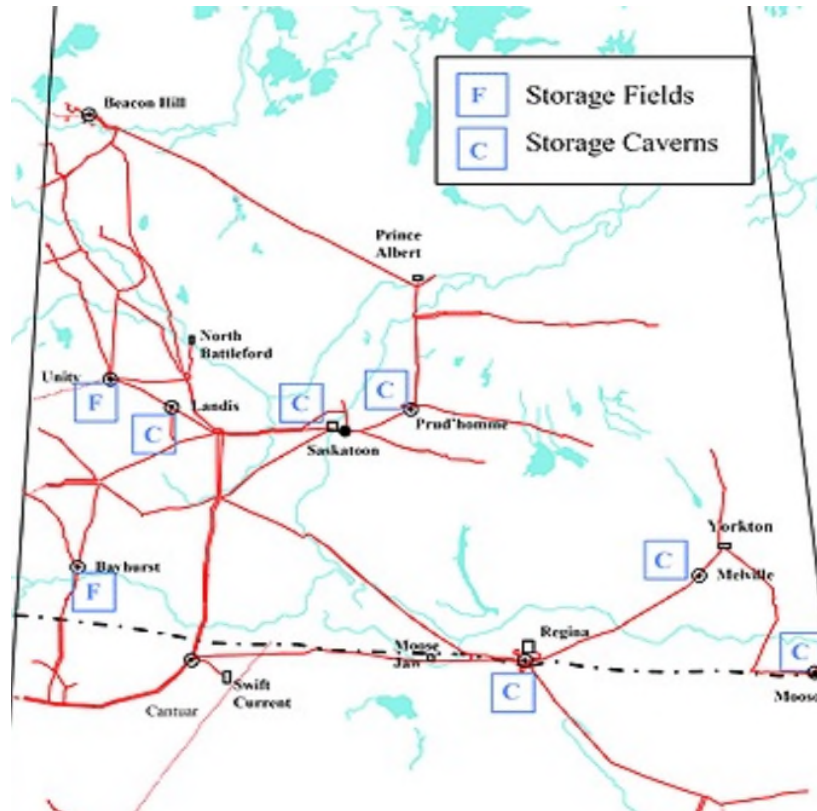


NPS 6 & Larger (Steel), TransGas Limited	
NPS 4 & Smaller (Steel), TransGas Limited	
NPS 2 & Smaller (Steel Tubing), TransGas Limited	
Many Islands Pipe Lines (Canada) Limited	
Bayhurst Gas Limited	
TransCanada Pipelines Limited	
Foothills Pipelines (Sask) Ltd.	
Apache Canada Ltd.	
Alliance Pipeline	
Polyethylene (PE), SaskEnergy Inc.	
Polyvinyl-Chloride (PVC), SaskEnergy Inc.	
NPS 12 & Smaller (Steel), SaskEnergy Inc.	

**Fig. 31: Location of Trans Gas Pipelines**  
(TransGas, 2019)

### Storage Locations

Three TransGas storage locations are in the vicinity of the Viking. To the north is the storage field at Unity and the storage cavern at Landis. The Bayhurst storage field is south of the Viking. Locations are indicated in **Fig. 32**.



**Fig. 32: Location of Storage Fields and Caverns near the Viking**  
(TransGas, 2020b)

### Gas Facilities

The Coleville processing plant is approximately 20 km northwest of Kindersley. Services include sweet gas, a lean oil plant, and a shallow cut refrigeration plant. Outputs include processed gas which enters the TransGas pipeline system and C3+ mix, which is trucked out for sale (SteelReef, 2020). TransGas sold the processing plant to Steel Reef Infrastructure Corp in 2018.

### Major Lines – Oil and Gas

Two major oil pipelines are in operation in the Viking (**Fig. 33**):

- The Enbridge pipeline, north of Kindersley, runs from Edmonton to Regina
- Plains Midstream pipeline which passes through the Viking



**Fig. 33: Location of the Pipelines near the Viking**  
(CER, 2020)

### Accessibility of Pipelines, Storage Caverns, and Facilities

With major pipelines, gas storage caverns, and a gas processing plant in the vicinity, Viking wells are not as isolated as others in Western Canada. However, low gas volumes typical of older wells are not generally not economical to transport.

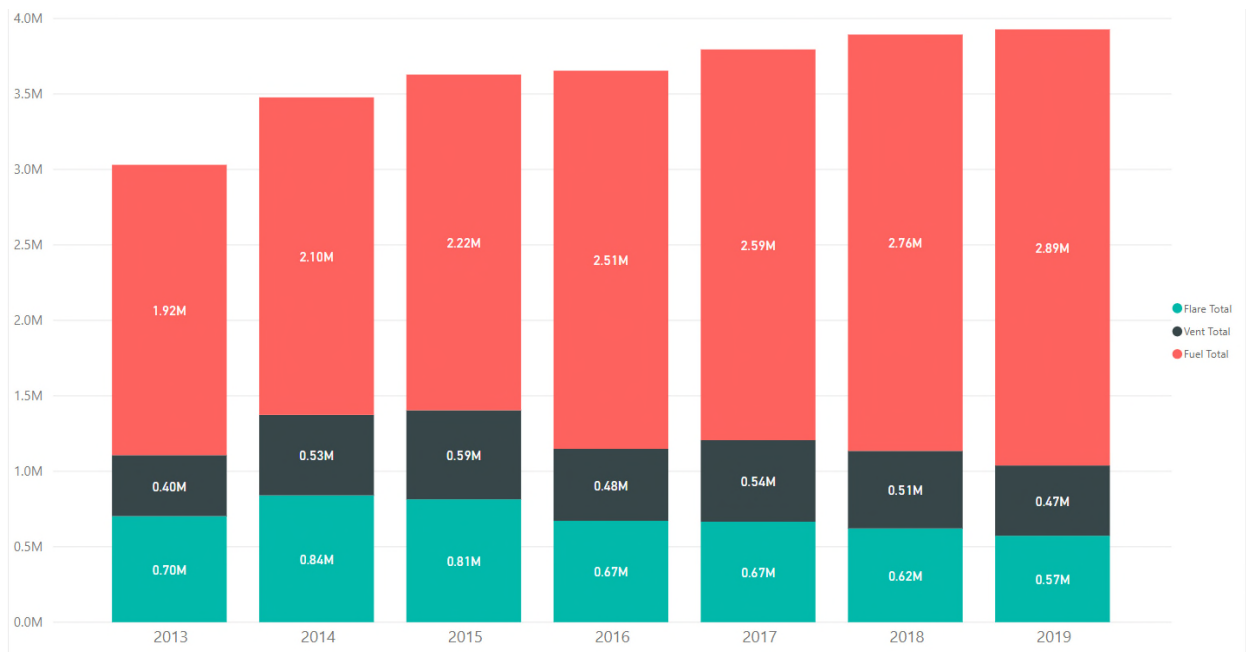


## 2.2.4 Emissions Data

### Associated Gas Production in Saskatchewan - Overview

The data for associated gas for all of Saskatchewan is provided in **Fig. 34** as a reference point when considering associated gas in the Viking. Note that all Saskatchewan data includes two categories of reporting – “facility” and “well”.

Since 2013, flaring, venting and fuel use volumes have gradually increased in Saskatchewan.



**Fig.34: Associated Gas Production in Saskatchewan (10<sup>3</sup>m<sup>3</sup>)**

**Table 12: Annual Associated Gas Production in Saskatchewan (10<sup>3</sup>m<sup>3</sup>)**

Year	Flare Total	Vent Total	Fuel Total	Total
2013	702,796	403,812	1,923,901	3,030,508
2014	840,365	533,192	2,103,753	3,477,311
2015	814,290	589,738	2,224,376	3,628,404
2016	671,672	476,993	2,505,630	3,654,295
2017	665,655	540,522	2,588,795	3,794,972
2018	621,288	513,733	2,758,682	3,893,703
2019	572,729	465,848	2,889,322	3,927,899

(GoS, 2020b)

### Flaring and Venting in Saskatchewan

Looking specifically at the flaring and venting totals in the province, volumes peaked in 2015 at 1,404,028  $10^3\text{m}^3$ . In 2019, volumes reached a historical low (since recording began in 2013) at 1,038,577  $10^3\text{m}^3$ .



Fig. 35: Total Flaring and Venting Volumes in Saskatchewan

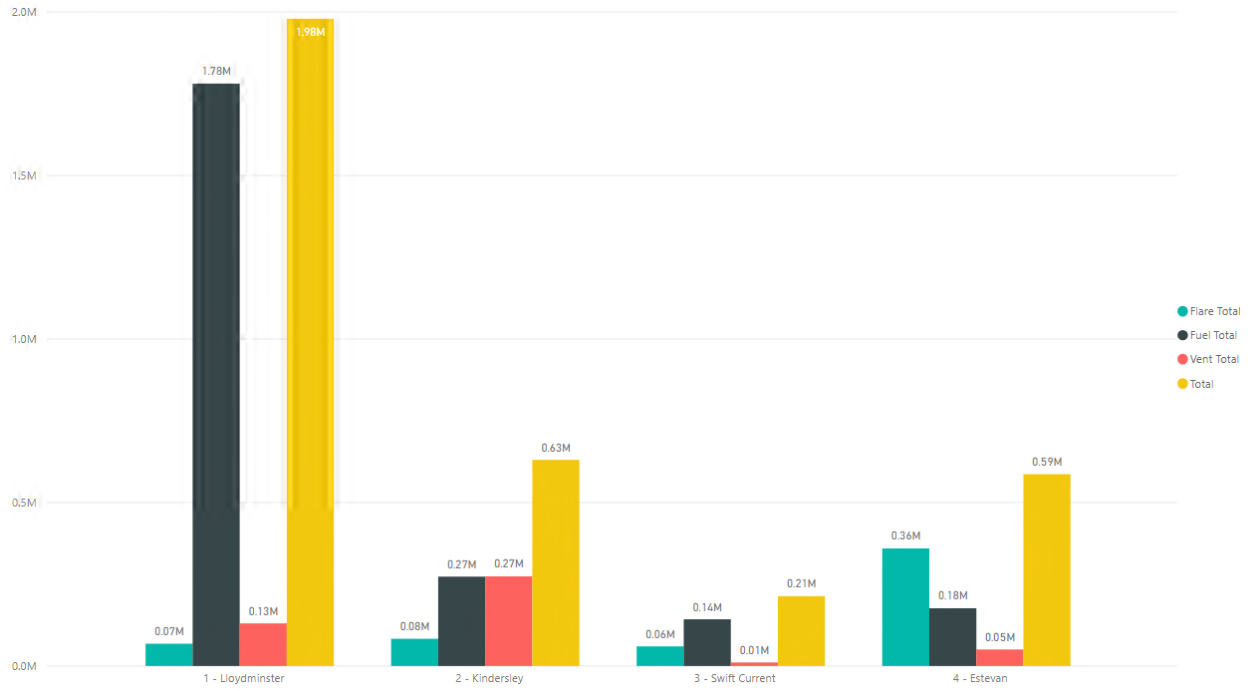
Table 13: Total Flaring and Venting Volumes in Saskatchewan

Year	Flare Total	Vent Total	Total Flared or Vented
2013	702,796	403,812	1,106,607
2014	840,365	533,192	1,373,557
2015	814,290	589,738	1,404,028
2016	671,672	476,993	1,148,665
2017	665,655	540,522	1,206,177
2018	621,288	513,733	1,135,021
2019	572,729	465,848	1,038,577

(GoS, 2020b)

### Comparison of the Four Producing Regions of Saskatchewan (2019)

In 2019, Area 1-Lloydminster recorded the highest levels of associated gas, with most of this being used as fuel. The Kindersley Area, which includes the Viking, had the second highest volumes overall. The area also has the highest volumes of venting across the province (Fig. 36).



**Fig. 36: Flaring and Venting Volumes in Four Producing Areas of Saskatchewan (GoS, 2020b)**

### *Flaring and Venting in the Viking*

Saskatchewan flare, vent and fuel data are aggregated into four production areas, and therefore, specific measurements for each pool are unavailable. However, the data is separated by light, medium and heavy production areas. Viking volumes were estimated by using the light and medium volumes and filtering out the heavy oil data.

Since 2013, flaring and venting volumes in the Viking have seen a general trend upward reaching a peak in 2018 at just under 400,000  $10^3 \text{ m}^3$ . Venting and fuel use volumes were both approximately 275,000  $10^3 \text{ m}^3$  in 2019. Flaring volumes were lower at just over 80,000  $10^3 \text{ m}^3$ .

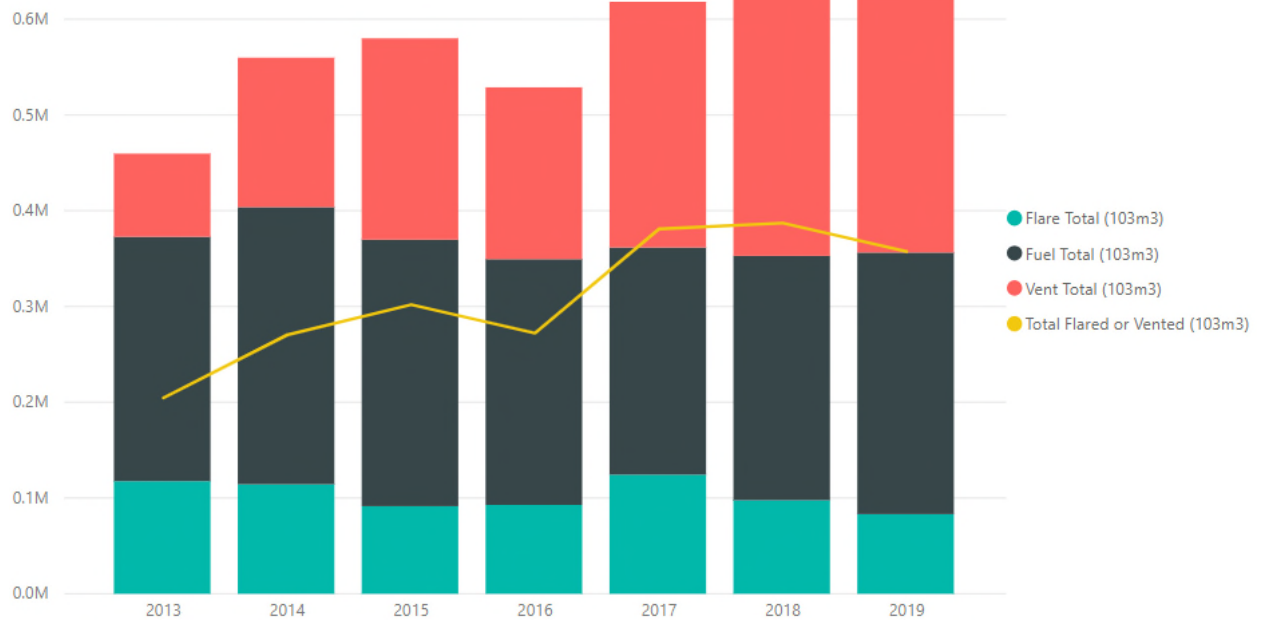


Fig. 37: Flaring and Venting Volumes in the Viking from 2013-2019 (estimate)

Table 14: Flaring and Venting Volumes in the Viking from 2013-2019 (estimate)

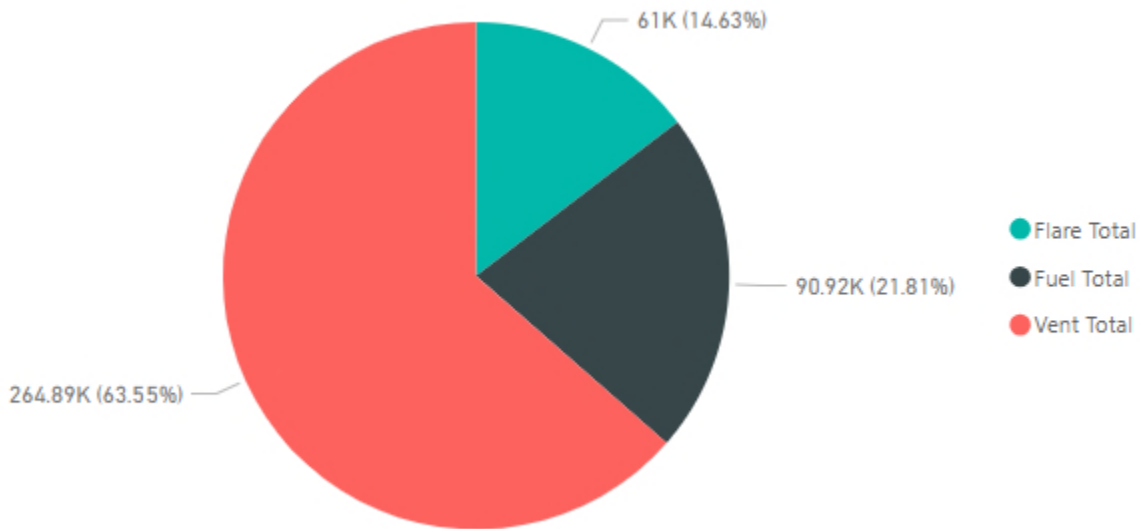
Year	Flare Total (103m3)	Fuel Total (103m3)	Vent Total (103m3)	Total Flared or Vented (103m3)
2013	117,569	255,197	86,857	204,427
2014	114,317	289,390	156,072	270,389
2015	91,477	278,260	210,256	301,733
2016	92,773	256,617	179,426	272,199
2017	124,354	237,218	256,577	380,930
2018	97,653	255,158	289,449	387,102
2019	83,135	273,195	274,106	357,241

(GoS, 2020b)

### Flaring and Venting Volumes in the Viking (estimate) in 2019

Total flared and vented in the Viking in 2019 was just over 415 10<sup>3</sup> m<sup>3</sup>. Of this:

- 265,000 10<sup>3</sup>m<sup>3</sup> (64 per cent) was vented,
- 61,000 10<sup>3</sup>m<sup>3</sup> (15 per cent) was flared, and
- 90,000 10<sup>3</sup>m<sup>3</sup> (22 per cent) was fuel use (replaces fuel gas or propane).



**Fig. 38: Distribution of Flaring, Venting and Fuel Use in the Viking (GoS, 2020b)**

### **Flaring and Venting Volumes Per Day (2019)**

Yearly totals were used to determine the number of facilities that vent or flare volumes above 900 m<sup>3</sup> per day, and therefore would require emissions reduction to be evaluated under Saskatchewan Directive S10.

**Table 15: Number of Wells and Facilities Venting >900 m<sup>3</sup>/day**

	Number of Facilities	Number of Wells
Vent Per Day < 900	152	3477
Vent Per Day > 900	20	113
Flare Per Day < 900	43	127
Flare Per Day > 900	22	13
<b>Total Number</b>	<b>237</b>	<b>3730</b>

### **Gas Emissions over Six Years**

The venting volumes of five single-well batteries were plotted over six years (from 2013 to 2019). Although Viking wells often have high initial gas volumes which drop quickly after the first two years, the figure provides a good indication of how varied volumes can be from well to well and from year to year. This will present a challenge to come up with an appropriate technology and each well may have to be dealt with on a case-by-case basis.

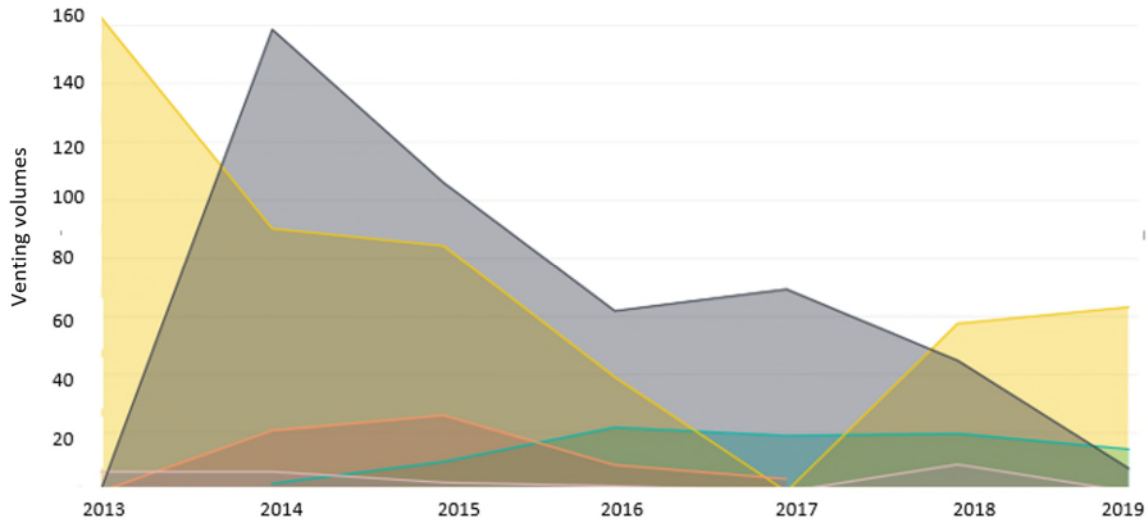


Fig. 39: Venting volumes (10<sup>3</sup>m<sup>3</sup>) of five wells from 2013 to 2019

### Gas Composition

The information in **Table 16** was used calculate an average gas composition for the Viking. The Prairiedale pool has the leanest gas with methane concentrations of about 90 percent. The richest gas is in the Elrose pool. It has the highest concentrations of nitrogen, C3 and C4. Only the Whiteside pools (Whiteside and Whiteside West) had concentrations of higher hydrocarbons (i.e. C8 and C9). Hydrogen sulphide (H<sub>2</sub>S) was not present in any of the selected pools. However, some of the Viking pools have been under waterflood for a long time. Usually even sweet oil fields that go on waterflood end up with H<sub>2</sub>S forming in the reservoir, due to the introduction of oxygen from surface during water injection, so H<sub>2</sub>S is still a possibility.

**Table 16: Gas Composition of Selected Pools (mole per cent)**

	Dodsland and Dodsland North	Elrose	Kerrobert	Prairiedale	Whiteside
CO <sub>2</sub>	0.01	0.01	0	0	0
N <sub>2</sub>	0.04	0.11	0.04	0.04	0.05
H <sub>2</sub> S	0	0	0	0	0
C <sub>1</sub>	0.85	0.74	0.86	0.91	0.84
C <sub>2</sub>	0.02	0.02	0.02	0.01	0.02
C <sub>3</sub>	0.03	0.07	0.04	0.01	0.02
C <sub>4</sub>	0.01	0.02	0.01	0	0

C5	0	0	0	0	0
C6	0.01	0	0	0	0
C7	0.02	0	0	0	0.01
C8	0	0	0	0	0.06
C9	0	0	0	0	0.05
C10	0	0	0	0	0

(Accumap, 2020)

### 2.2.6 Summary

As can be gathered from the information in the preceding section, there are production scenarios typical of the Viking that, though not unique, create challenges when attempting to eliminate greenhouse gas emissions. The main factors contributing to the challenge are:

**Isolated Single Well Batteries** – Single well batteries are often geographically isolated, with no nearby infrastructure or services. Without access to gas gathering lines the associated gas is currently either vented or flared. In the Kindersley area of Viking oil well production, the wells are not as isolated as many other scenarios. However, the older wells are largely low producers that would not presently justify the investment required to develop an extensive gathering system to add pipeline infrastructure.

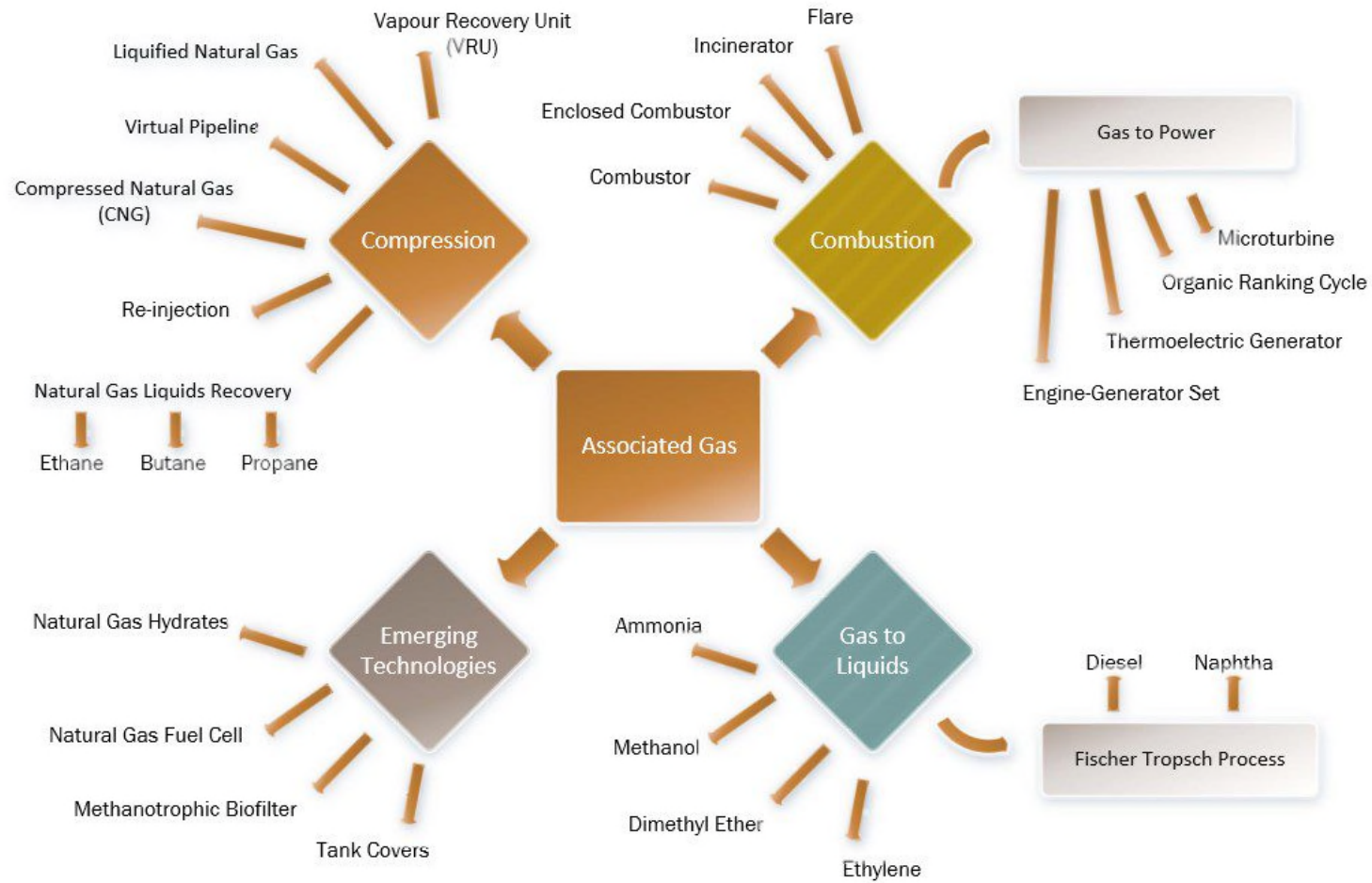
**Low and Inconsistent Gas Volumes** – Associated gas production typically declines rapidly after the first two years of a well's life, though the GOR and gas production rate vary between wells. Around 82% of facilities vent or flare less than 900m<sup>3</sup> per day. For a gas mitigation technology to be applicable in the Viking, it must be economic at low volumes.

**Low Pressure, Low Quality Gas** – Many technologies which utilize natural gas require it to be conditioned and compressed on-site. Not only are processing and compressing the produced gas emission sources in themselves, but they can also negatively affect the economics of a gas utilization technology.

### **3. TASK 2 – IDENTIFY POTENTIAL TECHNOLOGIES**

The purpose of this task is to identify technologies that can capture and/or utilize associated gas at upstream oil and gas sites in the Viking and Duvernay oil plays. Previous studies have identified potential technologies such as creating natural gas liquids, on-site power generation, compressed natural gas, gas capture and re-injection, and gas-to-liquids. There are many ways to categorize these technologies. In **Fig. 40**, SRC has provided a graphic representation of emission reduction technologies separated based on the potential end use of the associated gas. These technologies may or may not be suitable for further research and development at well sites in Canada; a brief assessment of their suitability based on the criteria provided by NRCan is performed in Task 3.





**Fig. 40: Technologies for the Utilization of Associated Gas**

### 3.1 Compression

The capture and conservation of associated gas is an obvious approach to reduce GHG emissions associated with flaring and venting. The technology to compress or liquefy natural gas is well understood. Several types of compressor are available, including flooded rotary screw, rotary sliding vane, and reciprocating piston compressors. However, a lack of accessible pipeline infrastructure can present challenges to finding a use for the gas once compressed. In the following sections compressed natural gas (CNG), liquefied natural gas (LNG), virtual pipelines, and gas re-injection for enhanced oil recovery (EOR) or cavern will be discussed.

#### **Advantages:**

- Reduced emissions
- Generation of a saleable product

#### **Challenges:**

- Lack of access to pipeline infrastructure
- No local utilities
- High NGL or incompressible content of the associated gas
- 24/7 operation at the oil well site

#### **3.1.1 Compressed Natural Gas (CNG)**

After conditioning, the compression of natural gas is reasonably straightforward. A driver, either electric motor or gas engine, runs a compressor to fill storage vessels. Natural gas can be compressed to less than one percent of its standard volume and stored at high pressure (3,000 to 3,500 PSI). In order to achieve a high-density product at ambient temperatures, high pressures are required.

Most commonly today, CNG is employed in modified engines for automobiles and trucks. The price differential between oil and natural gas has favored natural gas usage in the transportation sector. CNG has increasingly been used in virtual pipelines (see Section 3.1.3). The associated gas captured at the well site is compressed into a vessel and then transported by truck directly to end users, to a natural gas pipeline, or to a gas processing facility.

### **Advantages:**

- **Cost Savings:** CNG does not require expensive cryogenic facilities to cool the gas, as with LNG.
- **Co-production of NGLs:** CNG does not require natural gas liquids (NGL) technologies as the liquids separate out during compression (Carbon Limits, 2015). The NGL's can be sold at a profit. However, these by-products need to be stored and transported, adding to project costs.
- **Commercially Available:** The technology is commercialized: CNG is already being used in virtual and physical pipelines in the US and CNG vehicles are on the market.
- **Flexibility:** The technology is flexible in terms of end user locations and natural gas demands; CNG can be delivered almost anywhere to small or large customers.
- **Variable Flows:** The technology can handle most flowrates.

### **Challenges to CNG Use:**

- **Costs:** Transportation costs will be a major factor for these projects.
- **Equipment Weight:** Weight limitations of grid roads might be a limiting factor in terms of where the gas is delivered—some technologies have reduced CNG weights by 75 per cent, however.
- **Required Volumes:** The natural gas volumes required to make a project economic may be higher than what is available at oil batteries in the Viking and Duvernay
- **Conditioning costs:** Processing or sweetening of the gas to remove impurities and compressing the gas to the correct pressure contributes to CNG project costs.
- **Range:** The range for CNG vehicles and trucks is also limited compared to LNG (given the storage capabilities). CNG vehicles need to be refilled more often and must have high-pressure fuel tanks.

### **3.1.2 Liquefied Natural Gas (LNG)**

Liquefied natural gas is formed through the refrigeration of natural gas. Gas is pre-treated for impurities, or sweetened, and then cooled to  $-162^{\circ}\text{C}$ . The cooled liquid is stored and transported to the end customer (Baker Institute, 2010). At the end user, the cooled liquid is returned to gaseous form at a regasification facility. It can be piped or transported by truck and used by industry or for home heating.

The process of natural gas to LNG follows five steps:

1. Gas is cooled in refrigeration tanks,
2. Stored in cooled units,
3. Transported to locations (gas processing plant, community or other end customers),
4. Re-gasified on location, and
5. Connected to end user.

Like CNG, LNG is often used for transportation fleets and is emerging as a mainstream fuel option. Compared to compressed natural gas, LNG has more than double the energy density. This higher energy content makes LNG a viable option for heavy-duty trucking and shipping.

For LNG, the temperatures are very low (-162°C), but the pressure is very close to atmospheric. LNG is a liquid and is easier to handle in some respects than compressed natural gas (CNG). Storage for LNG consists of insulated, low pressure vessels. Any heat that leaks into the LNG results in some LNG being vaporized and vented. The LNG process can re-liquefy this vented gas, but during transport or use the vaporized gas must be either used or released.

#### **Advantages of LNG:**

- **Economics** – LNG could provide lower costs compared to diesel, but as stated above, LNG pre-treatment and hauling will impact costs
- **Environmental** – LNG has a lower environmental impact from emissions compared to other fossil fuels. When compared to diesel, natural gas transit buses are shown to reduce greenhouse gas emissions by as much as 37 per cent (Barclay, 2016)
- **Natural Gas Supply Stability** – Because LNG can integrate well into the natural gas system, it could be an important method for lowering natural gas imports from other regions, which may be of interest to utility companies.

#### **Challenges for LNG use:**

- **Higher CAPEX** – Capital costs for LNG projects can be high given the complex equipment that is required.
- **Required Volumes** – Mini-LNG is offered by several companies, but the scale is still such that it requires more gas than a single well battery. It presents challenges in scalability and mobility for use at the wellhead.

- **Conditioning Costs** – Additional pre-compression of NGLs is needed before liquefaction can occur.
- **Lack of Economies of Scale** – Development of a full supply chain, from sourcing LNG to the end user, is difficult to do effectively and competitively. Committed partners with capital are necessary to enter the market.

### 3.1.3 Virtual Pipelines

Virtual pipelines describe a system of delivering natural gas (LNG or CNG) using heavy-duty trucks (or in some cases, rail). Trucking allows for transporting natural gas where there is no pipeline, or in some cases, where pipeline capacity is not enough during peak loads.

The trucks load tanks at the filling station and then unload the container at the end user (community, mine site, or other commercial facility). The spent container is loaded onto the truck and returned to the filling station. The cycle is repeated, creating a stable supply of natural gas to the customer, like what a pipeline provides.

For liquid petroleum products, this is relatively simple. For natural gas, specialized processing and transport equipment are necessary. Natural gas needs to be conditioned and either compressed or liquefied prior to transport. Many natural gas virtual pipeline companies supply gas from existing infrastructure such as gas plants or high-pressure pipelines, which require no conditioning. Gas collected directly from the field requires the removal of water, carbon dioxide, hydrogen sulfide, nitrogen, natural gas liquids, etc. Gas conditioning processes would be important to any technology selection.

CNG and LNG virtual pipelines have been applied in commercial projects across North America. Currently, CNG is the more widely adopted process compared to LNG. In some cases, these systems are linked to associated gas use.

#### **Advantages:**

- **Flexibility and Scalability** – Virtual pipelines offer flexibility in terms of scalability and end-use location. The natural gas demands of the end customer will determine the size and number of trucks required for transport. With this supply volume versatility, there is less need to have sophisticated long-term demand estimates for a particular end user, community or region (as is the case in pipeline development). More demand means more trailers. Further, technological advancements are making it more economical for even end users with a smaller demand to have access to a natural gas supply. Trucking LNG or CNG

also allows almost any location with grid road access to adopt natural gas as the primary energy source.

- **Reliability** –: Virtual pipelines can also add reliability of supply, especially for commercial clients that may have interruptible contracts cut off. At peak demand times, these companies could source gas through LNG or CNG trucking companies.
- **Replacing Pipeline Development** – Developing pipelines is often not economical, especially for areas that offer challenging environments. The project may also be only short-term and not warrant pipeline construction.
- **Clean Burning Fuel** – LNG or CNG could replace fuels that typically have higher emissions, such as diesel fuels.

### Challenges:

- **Cost** – Cost appears to be the limiting factor for virtual pipelines. According to ADI Analytics, capital and operating costs can be over \$6 per mcf, not including feedstock. CAPEX has been estimated anywhere from \$50M to \$300M.
- **Distance** – Longer distances add costs to transporting of LNG and CNG. Limits for CNG are estimated to be around 200 miles.

### 3.1.4 Natural Gas Liquids (NGL)

Natural Gas Liquids (NGLs) are a byproduct of the refrigeration and distillation processing of natural gas. Gas plants and small-scale refineries extract NGL both to capture economically valuable products and to ensure the quality of natural gas to be transported by pipeline. The separation of liquids can take several different approaches, including using membranes, adsorption techniques or refrigeration. It should be noted that NGL recovery is not a complete gas utilization technology (Carbon Limits, 2015). NGL recovery is often used together with other technologies that utilize the dry gas.

NGLs are marketed separately to consumers and include ethane (C<sub>2</sub>), propane (C<sub>3</sub>), butane and iso-butane (C<sub>4</sub>), and pentanes (C<sub>5</sub>). While associated gas is often rich in NGLs, proportions vary between reservoirs. Ethane is typically the largest proportion, followed by propane and then differing proportions of C<sub>3</sub>+. Ethane is commonly used by the petrochemical industry and is one of the cheapest ways to produce ethylene (Oil and Gas Journal, 1988). Propane is often used for heating residential homes and commercial facilities, and for vehicle fuel. Butane is predominantly used in gasoline blending

A byproduct of natural gas refining is Liquefied Petroleum Gas (LPG). Typically, LPG refers to a mix of butane and propane that is compressed to a liquid. It is typically used as a fuel substitute in industrial applications or in refrigerants or aerosols (Devold, 2013). LPG is produced from associated gas during the chilling process as part of liquid separation. The primary marketing difference between LPG and NGL is that NGL are purified single products and LPG is a specific mixture of propane, butane, or a mixture of the two, which is commonly used in vehicles.

### **Advantages:**

- **Economics** – NGL recovery allows oil companies to achieve higher revenues through the sale of liquids. Separating natural gas and petrochemical liquids can provide additional value to gas otherwise flared or vented. The added value provides economic incentive to capture as much associated gas as possible and can justify the additional cost for capturing flared and vented gas.

### **Challenges**

- **Conditioning costs** – The main challenge of the technology is handling the NGLs once they have been removed. NGLs are expensive to store and transport, requiring special vessels, and need to be transported to an appropriate market. These processes will also require another technology to use the remaining dry gas, or it will need to be flared or vented. Other lower concentrations of gas, such as carbon dioxide, nitrogen, helium and hydrogen sulfide will also need to be dealt with.

#### **3.1.5 Vapour Recovery Units (VRU)**

A vapour recovery unit (VRU) captures vented gas and compresses it to be sold or used onsite. Instead of venting to atmosphere, a line connects the tank headspace to a scrubber which will condense and return any liquids to the tank. After the compressor, the dry high-pressure natural gas is directed to a sales gas pipeline, or other use. The EPA estimates between 7,000 and 9,000 VRU's are currently installed on oil tanks or tank batteries in the US (EPA 2006b).

#### **3.1.6 Reinjection for Enhanced Oil Recovery or Storage**

Miscible gas injection an enhanced oil recovery (EOR) process that has been applied to light oil reservoirs. It operates similarly to water flooding, in that both processes have the goal of a maintaining pressure after production has started to drop off. Additionally, reinjection can serve as a way to dispose of associated gas that can't be economically transported.

Lightstream Resources piloted a gas injection enhanced oil recovery (EOR) program in the Bakken Formation of southeast Saskatchewan in 2011. The Bakken Formation is another tight-oil reservoir, consisting primarily of dolomitic siltstone, with a porosity of 9% to 12% and permeability less than one mD. Gas injection rates during the pilot have been between 350 mcf/d and 1,000 mcf/d. According to Schmidt et al (2014), results to date have been encouraging. (Schmidt et al, 2014)



## 3.2 Combustion

The Intergovernmental Panel on Climate Change, in its Fourth Assessment Report, assigned methane a 100-year global warming potential (GWP) of 25 (ECC, 2020). Since methane has a much higher global warming potential than carbon dioxide (GWP = 1), combustion can be used to reduce the greenhouse gas emissions (GHG) of methane-emitting facilities by burning methane to carbon dioxide and water.

Incinerators and combustors are used in many industries to treat streams of waste gas with or without volatile organic compounds (VOCs). Both types of equipment use combustion at high temperatures to convert harmful gases such as methane, C<sub>2</sub>, C<sub>3</sub>+, impurities, or VOCs into less harmful ones, such as carbon dioxide and water vapour. It is also possible to pair combustion with a heat recovery technology, as is done by the power generation technologies discussed in Section 3.2.

### *Advantages:*

- **High Destruction Efficiency** – Most modern combustors and incinerators have a destruction efficiency of 99% or greater when operated correctly. Although regulations vary across Western Canada, the most stringent call for destruction efficiency greater than 90%.
- **Wide Range of Flowrates** – Combustors/incinerators can operate on a wide range of flowrates. They are appropriate for both casing gas (high) and tank vents (low) and can handle inlet pressures down to 0.1 psig.
- **Reduced Footprint** – Enclosed combustors mix the gas, fuel, and air in an enclosed chamber so that there is no visible flame. The Alberta Energy Regulator (AER)'s Directive 60 allows for enclosed combustors have reduced spacing requirements to wellheads and equipment compared to traditional flares (reduced to 10 m). The higher cost of an enclosed combustor can often be offset by the reduced piping and footprint allowed by this shortened distance.
- **Low Cost** – Combustors and flares are relatively low-cost and the economics to implement one can often be justified when compared to the federal backstop carbon pricing.

### *Challenges:*

- **Emissions** – Inefficient combustion results in the potential release of unburned hydrocarbons, carbon monoxide, VOCs, or particulate matter. It can be the result of

intermittent flow, poor gas quality, or operator error. Combustors/Incinerators require periodic stack testing in most jurisdictions to ensure that they are meeting destruction efficiency requirements.

- **Intermittent Flow** –Casing and tank gas flowrates can be sporadic. Although most combustors have excellent turn-down ratios, it may still be exceeded by the changes in gas flowrates over the lifetime of the installation. Incinerators or combustors may require a pressure control system before feeding into the combustion chamber.

### 3.3 Gas-to-Power

All the gas to power technologies discussed in the following section combust methane as a first step, converting it to carbon dioxide and water, and as such will have lower GHG emissions when compared to venting. Producing power can further reduce emissions if it replaces another fossil fuel used to provide power to the site. For example, an electrical grid which uses a less-efficient fuel sources such as coal will have higher emissions than power produced on site from associated gas.

#### **Advantages:**

- **Cost Savings** – One of the biggest attractors for gas-to-power use onsite is potential fuel cost reductions. Technologies that replace diesel with otherwise wasted gas onsite may be in greater demand in the present environment, as oil companies look to find efficiencies and lower costs during the slump in oil prices. The economics of gas-to-power technologies are improved if projects include NGL recovery (but note that this requires a separate technology).
- **Simplicity** – Compared to the conversion technologies described in the following sections of this report, gas-to-power systems are relatively simple to implement and operate, and do not require a large amount of additional equipment.
- **Lower CAPEX/OPEX** – Because of their simplicity, these technologies typically have lower capital and operating costs compared to more complex technologies.
- **Lower Emissions** – With many these technologies, substantial decreases in GHG and pollutants can be achieved. Reductions come from not only lowering the amount of gas being vented, but it also reflects the replacement of diesel or coal for cleaner burning natural gas in generating electricity.

### **Challenges:**

- **Low and Intermittent Flow** –Some gas-to-power technologies cannot adapt to the varying volumes that are typical of associated gas production.
- **High NGL content** – Not all technologies (e.g., generators and microturbines) are designed to handle the higher NGL content that can be found in associated gas in some regions. However, with minor modifications, most technologies should be able to use most associated gases to generate electricity.

#### **3.3.1 Power Generation via Microturbine**

A microturbine is a small-scale version of a turbine, which are in common use in the power, automotive, and aviation industries (WBD, 2018). It consists of a compressor, a mixing chamber, and an expander (DOE, 2016). Fuel is compressed and burned in a combustor; the flue gas then expands in a turbine which is connected to a generator which makes power.

Microturbines are gaining popularity in small-scale distributed power generation applications due to their compact size and low number of moving parts. Typically, they require a minimum gas pressure of 310-415 kPag (45-60 psig), and gas quality of at least 24 MJ/Nm<sup>3</sup> (650 BTU/scf).

#### **3.3.2 Power Generation via Organic Rankine Cycle (ORC)**

Organic Rankine Cycle operates similarly to the steam cycle used to generate power in a typical power plant but uses an organic liquid in place of the water/steam. The associated gas is combusted to generate heat, which vapourizes a high-pressure organic liquid. This organic vapour is then expanded to low pressure through a turbine which releases mechanical work. The turbine is connected via a shaft to a generator which produces electricity. The organic liquid is then condensed, and the loop closed (Quoilin, 2013).

One of the most promising aspects of ORC is its ability to produce power from low-grade heat. This is due to the lower boiling point of the organic liquids used as the working fluid when compared to water. ORC has been implemented at the commercial scale in the MW power range but has yet to see widespread adoption in smaller kW sizes (Tocci et al., 2017).

#### **3.3.3 Power Generation via Stirling Genset**

The term “genset” is short for engine-generator set. The generator could be a turbine, as in the microturbine case discussed in Section 2.3.4, but many commercial gensets are based on the Stirling

engine. The Stirling engine is a heat engine that operates by compressing and expanding a gaseous working fluid, typically air, hydrogen, or helium. The gas is compressed in the cold portion of the engine and expanded in the hot portion, causing a piston to shuttle back-and-forth. A linear alternator converts the mechanical motion of the piston into electrical power (Qnergy 2018).

### 3.3.4 Power Generation via Thermoelectric Generation

A thermoelectric generator (TEG), also called a Seebeck generator, is a solid device in which two semiconductors are used to convert heat flux directly into electrical energy via the thermoelectric effect. The main components of a TEG system are the gas burner, the thermoelectric module (aka thermopile) and the cooler.

Because there are no moving parts, the maintenance requirements for TEGs are very low and their reliability is high. The semiconductors used in TEG manufacturing typically contain expensive elements such as lead telluride, which can lead to higher capital costs, though recent advances in nanomaterial manufacturing have decreased these costs somewhat.

## 3.4 Gas-to-Liquids (GTL)

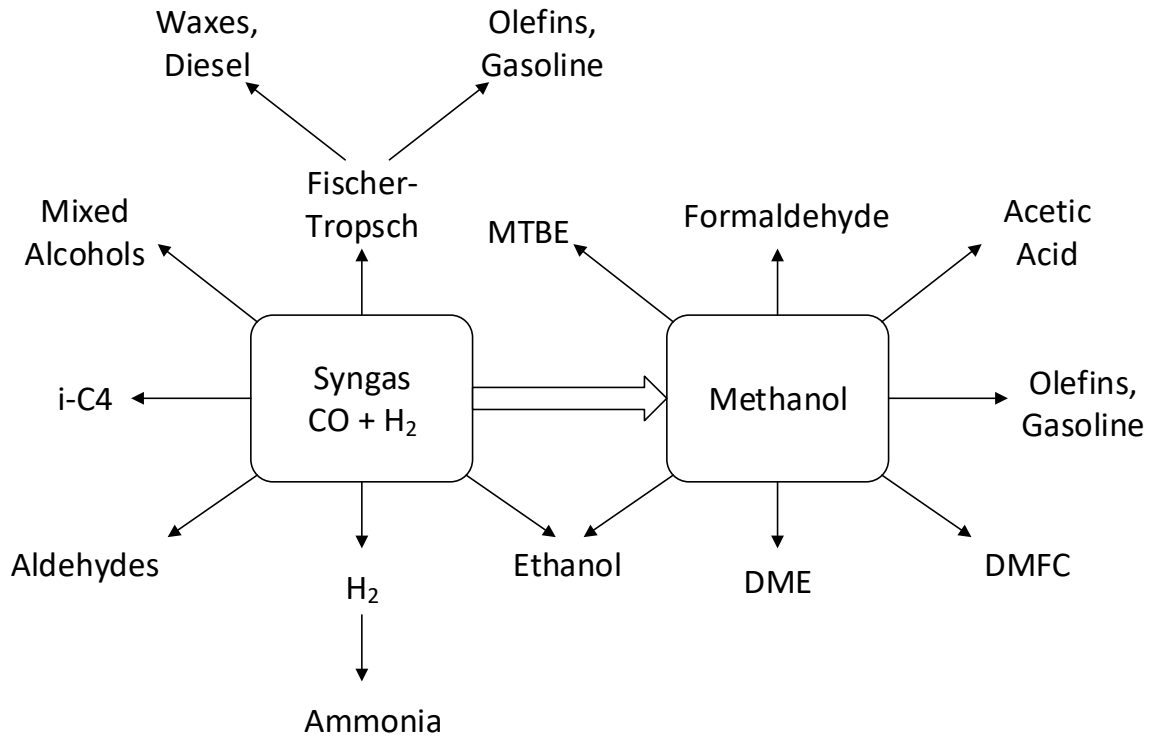
Natural gas can be burned to produce heat and power, as described earlier, but it can also serve as a feedstock for other chemical products. Gas to liquids (GTL) processes convert natural gas, methane, or other hydrocarbon gases into longer chain hydrocarbon liquids such as diesel, gasoline, or ethanol, or other specialty chemicals.

Gas-to-Liquids as used in this report refers to both gas-to-liquids (GTL) and gas-to-chemicals (GTC) processes. Although the GTL/GTC process are quite diverse in terms of outputs, they generally follow three primary steps in the production process: (Salehi, 2013)

- Feedstock preparation (e.g., conversion to syngas, steam reforming, gasification)
- Fischer-Tropsch (FT) synthesis: this step converts the syngas into a range of hydrocarbons; requires the use of catalysts
- Product upgrading: Note that upgrading of GTL liquids is not always necessary; several FT technologies are at the commercial-ready stage that can produce finished products

There are several processes to convert natural gas to liquid fuels, including: ammonia production, direct methanol synthesis followed by conversion to dimethyl ether (DME), acetic acid production, formaldehyde production, and the Fischer -Tropsch process. **Fig. 41** illustrates some of the liquid

products that can be formed from these processes. Many of these processes have been demonstrated but are not yet commercially realized at this scale.



**Fig. 41: Gas to Liquids (GTL) Products**

Catalyst efficiency can have a large impact on project costs and as such, companies seek processes that either use fewer catalysts or none at all. One recent advancement in GTL is the use of microchannel technology, which can reduce the size of the plants. By dissipating the heat in the process, microchannels allow for more efficient catalysts (Jacobs, 2013). Some companies are now looking at non-Fischer-Tropsch technologies, which they claim can lower the capital costs compared to conventional GTL processes (Hamilton, 2008).

### **Advantages:**

- **Economics**– Some liquids products, such as FT-diesel, can be sold at a premium.
- **Compatible Infrastructure** – There are no switching costs for engines to use FT diesel, as is the case for LNG or CNG.
- **Diverse Markets** – For chemical production, the opportunity to sell end products into markets outside the fuel markets could be an attractive option. According to one analyst, ammonia, urea and methanol all could offer positive margins (DuBose, 2015).

### Challenges:

- **Required Volumes** – The size of GTL projects is still beyond what is suitable for associated gas use. The World Bank Group found that most of these technologies require a gas flow range of greater than 10 MMscfd (30 which is well beyond the production flow rates seen in Saskatchewan—see Section 2). Only a handful of companies can operate with flow rates less than 1 MMscfd.
- **Lack of Economies of Scale** – Mini-GTL projects are challenging because output volumes are considerably lower than the volumes produced in the larger GTL facilities; therefore, smaller projects cannot generate high revenues. Also, of note, the markets for chemicals are smaller than the fuels market, limiting sales opportunities (DuBose, 2015).
- **High Capital Costs** – GTL is capital intensive (Salehi, 2013).
- **Not Commercial** – There are still no commercial GTL projects in North America, although there are a growing number of pilot projects and testing announcements.

#### 3.4.1 Dimethyl-Ether (GTL)

Dimethyl ether (DME) is a colorless gas that liquefies at low pressure. It has the chemical formula  $\text{CH}_3\text{OCH}_3$ , and structure as shown in Fig. 42. It is currently used as a propellant, and as a propane replacement, and is being demonstrated as a diesel replacement in vehicles.

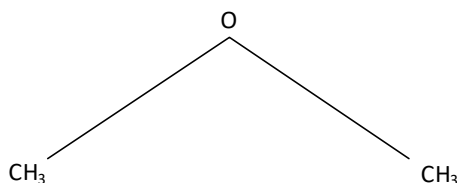
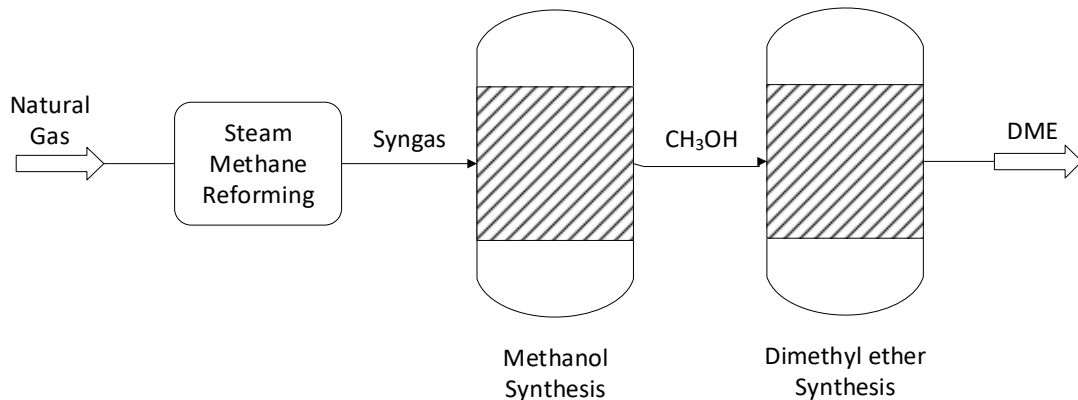


Fig. 42: Structure of Dimethyl ether

DME is approved as a renewable fuel under the U.S. Environmental Protection Agency's Renewable Fuels Standard (when produced from biogas) and has been issued specifications by ASTM International and the International Organization for Standardization (Oberon, 2019). Modifications are required to convert a diesel engine to run on DME. As a liquid fuel, it has a high cetane value of 55-60 and produces no smoke or sulfur emissions (IDA, 2019).

DME is primarily manufactured via the catalytic dehydration of methanol, though it can also be made directly from synthesis gas, or through natural gas reforming (Fig.43). Haldor-Topsoe, Lurgi,

Toyo, and others have technologies (or catalysts) to produce DME from methanol at large scale. MeOH-To-Go™ is a partnership between Haldor-Topsoe and Modular Plant Solutions. It offers a small-scale modular methanol plant that produces 215 tonne/d of methanol from 7.1 MMscf/d (200,000 m<sup>3</sup>/d) of gas (GGFR, 2018). According to the International DME Association, direct synthesis of DME is the most efficient production process (IDA, 2019).



**Fig. 43: Process Flow Diagram of Catalytic Dehydration of Methanol to Dimethyl Ether**

Rather than producing DME, other companies are using similar processes to produce methanol. The GasTechno process uses direct oxidation to convert methane to methanol, ethanol, and formaldehyde, without a catalyst. The technology has been demonstrated at 50 mscf/d (1,400 m<sup>3</sup>/d) and 300 mscf/d (8,500 m<sup>3</sup>/d). GasTechno LLC plans to have commercial offerings available in 2019 and has a pre-feasibility study available to purchase for \$50,000 (GasTechno, 2019).

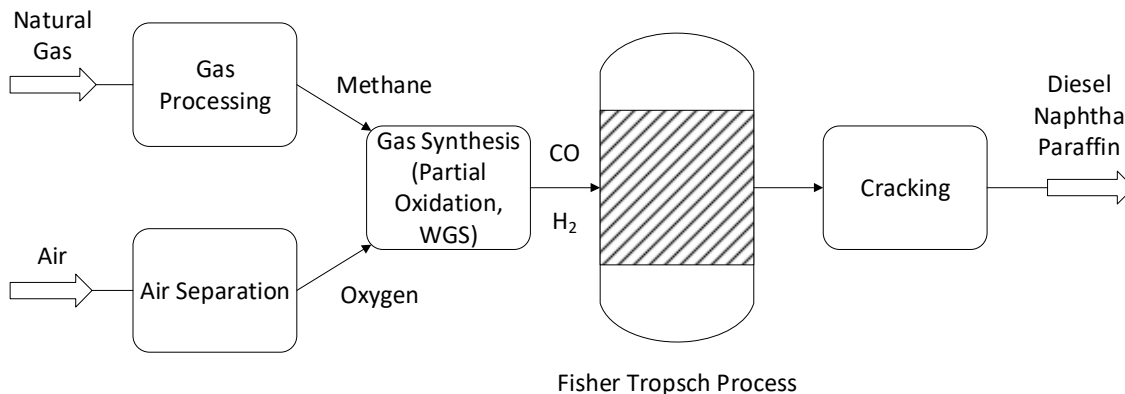
Maverick Oasis Model NG25 is a skid-mounted modular natural gas-to-methanol plant with a capacity of 8,300 gallons per day (25 tonnes/day) from 800 mscf/d (22,000 m<sup>3</sup>/d) natural gas (Maverik, 2019). Maverick has partnered with Prudhoe Bay Chemical to build a NG100 plant on the North Slope of Alaska (GGFR, 2018).

### 3.4.2 Fischer Tropsch (GTL)

The Fischer Tropsch (FT) process converts syngas into a range of higher carbon number hydrocarbon liquids. This includes lights such as naphtha, middle-distillates such as diesel, and heavier liquids and paraffins. The heavier liquids and waxes are often cracked to produce more synthetic fuel. FT-derived fuels can be blended with conventional fuels and are compatible with current infrastructure.

The FT process starts with gasification (partial oxidation) or steam reforming of methane to form syngas, a mixture of carbon monoxide and hydrogen. Next, the ratio of H<sub>2</sub>/CO is adjusted by means

of the water/gas shift reaction. The syngas is reacted over a catalyst, iron or cobalt, to produce liquid hydrocarbons and alcohols. Finally, the hydrocarbons are cracked, and the waxes removed to produce the fuel of interest. A generalized process flow diagram (PFD) is provided in **Fig. 44**.

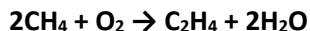


**Fig. 44: Process Flow Diagram of the Fischer Tropsch Process**

Shell, Sasol, and other companies have operated large-scale FT plants, but they are not yet commercial at smaller scale. According to a publication by the National Renewable Energy Laboratory, “economies of scale can play a large factor in lowering the product cost.” The syngas production portion of a gas-to-liquids plant accounts for more than half of the capital cost of the plant (NREL, 2003). Reactant gases entering a Fischer Tropsch reactor must be cleaned up to prevent sulfur, nitrogen, or halide impurities from poisoning the catalysts. Generally, the FT process is operated at temperatures of 200-350°C and pressures of 100-1000 kPa (1-10 atm). Conditions must be carefully balanced to maximize product yield, minimize side reactions, and maintain catalyst integrity. Selectivity of the process is approximately 40-50% gasoline and olefins, and 40-50% diesel and waxes (NREL, 2003).

### 3.4.3 Oxidative Coupling of Methane (GTL)

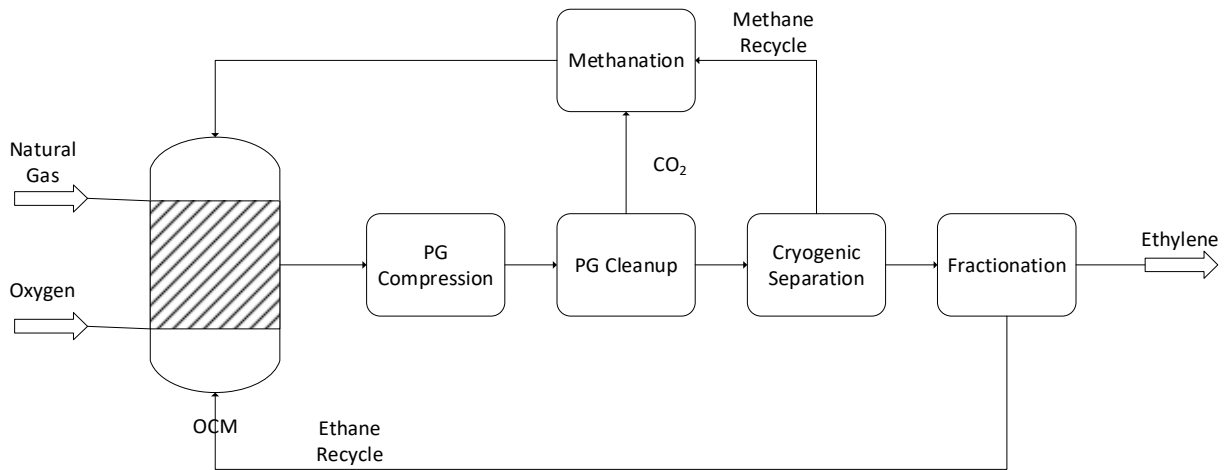
Oxidative coupling of methane (OCM) converts natural gas directly into liquid chemicals, primarily ethylene, which is considered a key building block for the global petrochemicals industry. A basic process flow diagram is provided in **Fig. 45** and the chemical reaction is written below:



While converting methane to ethylene offers potentially large economic benefits, it still faces major technical challenges and has not been widely commercialized. Siluria and Linde Engineering have jointly developed the Gemini process to directly convert natural gas into ethylene. A demonstration



plant designed to produce 1 tonne/d of ethylene has been in operation since 2014 (Siluria, 2019; Linde, 2019). They can design plants from <100,000 tonne/y to >600,000 tonne/y in size.



**Fig. 45: Process Flow Diagram for the Oxidative Coupling of Methane**

### 3.5 Emerging Technologies

There are several emerging technologies that are not yet commercial. Even though they are not ready to be deployed in the field, they may be implemented in the future. Some of these technologies fit into the categories above, while others are more difficult to classify. For the purposes of this report they are collected here.

#### 3.5.1 Methanotrophic Biofilter

Methanotrophic bacteria use methane as an energy source, converting it into CO<sub>2</sub> and more bacteria. According to research conducted at the University of Calgary (U of C), they can be used to remediate low flows of methane. The basic invention consists of a box of bacteria-laden soil buried near the gas outlet, with gas distribution piping through the bottom. Because the technology relies on bacterial activity it requires warm temperatures to operate. Hy-Bon briefly offered a tank mounted bio-filter for methane emissions reduction that operates on a similar principle. The filter is no longer advertised on their website.

Rather than a flame, it's possible to use methane consuming bacteria to convert CH<sub>4</sub> to CO<sub>2</sub> (and biomass) (Hanson and Hanson 1996). This is sometimes done in a biofilter reactor in the agricultural industry. HY-BON offers a filter that attaches to the outlet flange of a tank and can destroy 80-90% of vented VOC's (HY-BON 2016c). The University of Calgary has begun testing on a similar, but more economical version. The methanotrophic biofilter (MBF) routes the vented gas through a box of manure and soil impregnated with methanotrophic bacteria. The box can be buried underground to provide insulation in the winter months (U of C 2014).

#### 3.5.2. Natural Gas Fuel Cells

Methane can be used as a source of hydrogen in fuel cells. Each individual cell contains an anode, a cathode and an electrolyte layer. Hydrogen-rich fuel such as natural gas enters the cell and reacts electrochemically with oxygen to produce electric current, heat and water. The methane is reformed internally to produce hydrogen and carbon dioxide.

#### 3.5.3 Tank Covers

Venting can occur from storage tanks as new oil is added and the gas headspace is reduced and when liquids expand during daytime temperature changes. A CO<sub>2</sub> or gas tank blanket, or Hexa-Covers<sup>®</sup>, can provide a floating cover and reduce emissions. Hexa-Covers are plastic hexagonal tiles that float on the surface of the oil. They are relatively inexpensive and can be installed through a tank hatch. In field trials they reduced C<sub>6</sub>+ emissions by 93%. They also help insulate the tank,

reducing the amount of energy required for heating (Greatario 2016a). According to a report for PTAC by Sentio Engineering (2015), tank venting accounts for 5% of methane emissions in a typical heavy oil installation.

### **3.5.4 Gas to Solids (GTS)**

Natural gas hydrates (NGH), also called clathrates, occur when methane molecules become trapped in a lattice of crystalline water molecules. Methane gas hydrates occur naturally on the ocean floor and can often cause agglomeration and plugging in pipelines. Significant prior research has focused on how to prevent methane hydrate formation, but recently there has been an increase in research attempting to create NGH (Kanda 2006; Nakai 2012; Rehder et al. 2012).

Trapping methane in a solid form can substantially reduce the volumes and cost of transportation, as NGH occupies 1/170 of the gas volume. Due to the “self-preservation effect”, NGH are relatively stable at -20°C and atmospheric pressure despite the unfavourable thermodynamics of these conditions to hydrate formation. This effect is enhanced but not entirely caused by ice shielding and is not completely understood. NGH shipping is also predicted to be safer than LNG, as the risk of leaks or fires are reduced (Kanda 2006; Nakai 2012; Rehder et al. 2012).

#### 4. TASK 3 - ASSESSMENT OF AVAILABLE TECHNOLOGIES

NRCan has provided several criteria for each technology in order to judge their applicability to the Viking and Duvernay oil fields. These include an investigation of the following:

- The footprint required by the technology, especially as it compares to the typical lease size
- The distance from well sites to processing facilities, if applicable
- The scale of gas flowrates the technology is suitable for
- The percent efficiency expected with the technology
- The gas composition required by the technology
- The expected emissions of the gas utilization technology
- Suitability for areas with a low- or high-density of wells
- The scalability of the technology
- Whether the technology can handle highly variable volumetric flow rates
- What petroleum systems have the technologies been successfully used in?

These criteria are discussed in general for each category in the following sections, and summarized in Table 17, below.

**Table 17: Summary of Applicability of the Technology Types Investigated**

Technology Type	Foot Print	Gas Flowrate	Emissions	Gas Conditioning Required?	Scalability
Gas Compression	1-2 shipping containers (2.4 m x 6.1 m)	100-30,000 mcf/d (2,800-850,000 m <sup>3</sup> /d)	Low	Yes	Yes
Combustion	1.5-4 sq. ft	≥15 mcf/d (≥100 m <sup>3</sup> /d)	~80% reduction	No	Yes
Gas to Power	1-2 shipping containers (2.4 m x 6.1 m)	≥100 mcf/d (≥3,800 m <sup>3</sup> /d)	Same as Combustion	No	Moderate
Gas to Liquids	Large-scale chemical plant and infrastructure required	250 – >1,000 mcf/d (≥7,000 m <sup>3</sup> /d)	Unknown	Yes	No
Emerging Technologies	Variable, generally <0.55 m <sup>2</sup>	Variable	Variable	Variable	Unknown

## 4.1 Compression

Compressors are available in a variety of sizes depending on the application. Vapour recovery units use small-scale compressors to remove vapours from crude storage tanks. Larger-scale compressors are used in CNG and LNG applications; these units can range from 100 mcf/d to 30 MMcf/d. CNG and LNG benefit from economies of scale, and as such larger systems are generally more economically viable. The equipment required for micro- and mini- CNG and LNG systems is usually sized to fit in one or two shipping containers, which have average dimensions of 20 ft x 4 ft x 8 ft (6.1 m x 1.2 m x 2.4 m). Both the larger footprint and the higher gas flowrates required make this technology a poor fit for single well batteries, which make up most Viking wells. Fortunately, most Duvernay development is in areas which already have relatively easy access to gathering lines, oil batteries, gas plants and product pipelines.

Compressor technology is well-understood, and efficiencies of >80% are possible. Compressor seals are known to be a source of fugitive emissions, but recent advances in design are reducing the amount released.

Gas conditioning processes are important to all compression technologies. Most compressors are not designed to handle liquids or corrosive materials. CNG and LNG are even more sensitive to gas composition because of the specifications required for sale. Gas collected directly from the field will require the removal of water, carbon dioxide, hydrogen sulfide, nitrogen, natural gas liquids, etc. As mentioned above, compressors are available in a range of size, though turn-down is limited once built.

Distance to processing facilities is a major roadblock for CNG and LNG applications. Virtual pipelines can be implemented in cases where a sales gas pipeline is not accessible, but these are generally only economically viable over short distances. There are several LNG virtual pipeline installations in the United States, particularly in the high gas volume Bakken formation. Gas re-injection can be used as a form of enhanced oil recovery in certain reservoirs, but requires both gas conditioning and compression and laboratory experiments to determine parameters such as minimum miscibility pressure.

## 4.2 Combustion

Combustors can be sized for a variety of flowrates. In the case of very large flowrates, multiple combustors can be installed at a single site. The footprint of the combustor is dependent on the flowrate it is sized for; most are between 1.5 and 4 ft in diameter. The required footprint will scale

linearly as more combustors are installed. Most leases in the Viking and Duvernay can easily accommodate the installation of a combustor.

Combustors installed in Western Canada are required to have destruction efficiencies of >90%, and many manufacturers claim to achieve >99%. Combustors are not sensitive to gas composition, except in cases where the gas is too lean to burn without the addition of fuel gas. The associated gas produced in Viking and Duvernay fields is typically rich enough to burn without assistance, though gas composition varies from field to field, as discussed earlier. Most combustors have turn-down ratios of 5-6, making them versatile for use in fields with variable flow. However, destruction efficiency is negatively affected if the flow or pressure drop below

As discussed in Section 3.2, combustion can be used to reduce the GHG emissions of methane-emitting facilities by burning methane, with a GWP of 25, to carbon dioxide, which has a GWP of 1, and water. Distance to processing facilities is not applicable, as there is no end use for the combustion products.

Combustors are already being installed in fields across Western Canada.

### **4.3 Gas to Power**

Gas to Power technologies are applicable to a variety of flowrates, depending on the type of equipment used. Thermo-electric generators and engine-generator sets can handle flows of 100 mcf/d or less, while Organic Rankine Cycle systems require higher flows of 300-500 mcf/d or more; microturbine flow requirements are somewhere in the middle. Scalability is achieved by choosing the technology that best fits the amount of gas produced.

The required footprint varies by technology but is proportional to the flowrate requirements, with thermoelectric generators taking up only a few square feet and ORC systems requiring several shipping containers worth of equipment (combustor, heat exchangers, cooling tower, control system).

As most gas-to-power technologies start with combustion, gas composition requirements are like that for combustors. Emissions are also like those from combustion, except in cases where the power generated is used to replace power generated from other less efficient fuel sources.

These technologies work best with consistent flow, though the strictness of that requirement depends on the end use of the power. A site that is tied in to a local electrical grid has more flexibility for start-stop operation than one that provides necessary power to equipment on site.

Gen-sets are already in common use throughout the oil and gas industry, while microturbines and organic Rankine cycle units are starting to be deployed in Europe.

#### **4.4 Gas to Liquids (GTL)**

Gas-to-liquids processes, whether chemicals or fuels, require the highest flowrates of the technologies investigated in this report. They also have the highest footprint, as each requires a small-scale chemical plant, including utilities and control systems in some cases. The scale of these technologies is not suitable to single well batteries.

Emissions calculations for GTL are more involved, as a full life cycle analysis is required to account for the emissions displaced by generating the chemical or fuel from “waste” gas in place of other feedstocks. Likewise, gas composition requirements vary with the technology chosen, but conditioning is understood to be part of the plant design.

Scalability is the main drawback of these technologies. Many of them, such as Fischer-Tropsch synthesis, methanol production, and ammonia production are commercial at full scale. Mini- and micro-scale applications for use in the petroleum industry are being demonstrated in both North and South America but have not yet been commercially implemented. Distance to market for the fuel or chemical produced may prove to be a limitation as these technologies continue to be commercialized.

#### **4.5 Emerging Technologies**

The scale of the technologies in this category varies from extremely low flows in the case of the methanotrophic biofilter, to like CNG/LNG in the case of natural gas hydrates. Emissions, scalability, and footprint are all difficult to predict since these technologies haven't been fully developed. As these technologies are not yet commercial, they have not been implemented in any jurisdictions.

## 5. CONCLUSIONS

This study described the Duvernay and Viking oil plays, investigated technologies which may be used to mitigate greenhouse gas emissions at oil wells in those fields, and assessed the identified technologies based on their applicability.

Generally, the Duvernay is like most other unconventional shale resources which require hydraulic fracturing, and conventional oil and gas operations once production starts. The main difference appears to be in the widespread extent of the formation, and the fact that it is currently only seeing limited commercial development. Some commercial development appears to be underway for oil and gas, but there is now much less activity on in-situ fluid delineation exploration activities. The main emissions sources identified are primarily from gas flaring at isolated, remote single well-sites and potentially short-term emissions from well testing.

The Viking Formation hosts a variety of prolific oil and gas pools in Alberta and Saskatchewan. The number of facilities in the Saskatchewan portion of the Viking that reported flaring, venting and fuel use in 2019 was 3,871. Nearly 94 per cent of these were crude oil single well batteries, the majority of which produce less than 900 m<sup>3</sup>/d of associated gas. Single well batteries are often geographically isolated, with no nearby infrastructure or services. Without access to gas gathering lines the associated gas is currently either vented or flared.

Technologies with the potential to reduce venting at these wells were investigated. These included:

- Compressors, including vapour recovery units (VRU), compressed natural gas (CNG) and liquefied natural gas (LNG)
- Combustion, including flares and enclosed combustors
- Gas to Power technologies, including gen-sets, microturbines, thermo-electric generators, and organic Rankine cycle (ORC)
- Gas to Liquids technologies, including Fischer-Tropsch, and methane to chemicals such as methanol, dimethyl ether (DME), and ammonia
- Emerging technologies, including methanotrophic biofilters, tank covers, and natural gas hydrates

Of the technologies investigated, compression offers the greatest reduction in emissions, but relies heavily on access to infrastructure and/or transportation. Combustion was the technology that offered the best scalability for the low flowrates experienced by most wells in the Viking. Gas to Power technologies are slightly large scale than required for single well batteries but have the



potential to greatly decrease GHG emissions at sites where they are implemented. Gas to liquids technologies are continuing to be developed, such that they may eventually be economically viable at the scales required. Novel and emerging technologies may one day surpass the currently commercial offerings but are not implementable in the near term.

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