Alberta Energy Regulator

Upstream Petroleum Industry Emissions Report

Industry Performance for Year Ending December 31, 2021

April 2023

Alberta Energy Regulator

ST60B-2022: Upstream Petroleum Industry Emissions Report

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Executive Summary

The Alberta Energy Regulator (AER) has published this report annually since 2001. It provides stakeholders with fuel, flare, vent, and fugitive emissions information reported to the AER.

As a result of the more extensive emission reporting introduced in 2018 by *Directive 060*, this report now includes source specific information and fugitive emissions information. It also includes production and fuel gas volumes. The report does not include emission volumes from processing plants approved under section 11 of the *Oil Sands Conservation Act*, oil sands mining schemes, or pipelines that are not regulated by the AER. The primary data used to compile the report is obtained from Canada's Petroleum Information Network (Petrinex) and the AER's OneStop reporting tool.

Key statistics from 2021:

Production (from ST98: Alberta Energy Outlook)

- Crude bitumen production increased by 9.3 per cent to 188.9 10^6 m^3.
- Crude oil production increased by 3.3 per cent to 25.4 10^6 m^3.
- Gas production decreased by 3.9 per cent to 101.0 10^9 m^3.
- Solution gas production from crude oil and bitumen batteries increased by 6.2 per cent to 24.1 10^9 m^3.

Fuel Use

- Total reported Petrinex fuel use increased by 6.5 per cent to 28.25 10^9 m^3.

Flaring

- Total reported Petrinex flaring increased by 17.3 per cent to 1168.33 10^6 m^3.
- Solution gas flaring increased by 23.9 per cent to 589.45 10^6 m^3.

Venting

- Total reported Petrinex venting increased by 2.8 per cent to 362.73 10^6 m^3.
- Solution gas venting decreased by 10.5 per cent to 133.47 10^6 m^3.

Fugitive Emissions

- Total equipment-based fugitive emissions decreased 20.8 per cent to 47.2 10^6 m^3.

Surface Casing Vent Flow (SCVF) and Gas Migration (GM)

- There were 706 surface casing vent flow (SCVF) and gas migration (GM) events recorded in 2021, averaging a vent rate of 76.6 m^3/d over the year. As of 2021, Alberta has 10 636 unresolved events emitting 62 10^6 m^3/year.

Methane Reduction

- Results from 2021 indicate Alberta is on track to achieve its 45 percent reduction target in 2025. Using both reported and estimated emissions, Alberta is currently sitting at 44 percent reduction from 2014 levels.

1 Introduction

The mandate of the Alberta Energy Regulator (AER) is to ensure the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. Under this mandate, the AER is responsible for disseminating energy-related information, including emissions information.

Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting sets out requirements for flaring, incinerating, and venting for all upstream petroleum industry wells and facilities in Alberta. These requirements also apply to pipeline installations that convey gas (e.g., compressor stations, line heaters) licensed by the AER in accordance with the *Pipeline Act* and all schemes and operations approved under section 10 of the *Oil Sands Conservation Act*, except for oil sands mining schemes and operations approved under section 10 of the *Oil Sands Conservation Act*.

Directive 060 includes flaring and venting recommendations from the multistakeholder Flaring and Venting Project Team of the Clean Air Strategic Alliance (CASA) as well as methane emission reduction requirements that were designed to support the Government of Alberta's methane emission reduction targets. *Directive 060* requirements ensure that public safety concerns and environmental impacts are addressed before and during flaring, incinerating, or venting events. Requirements in this directive are aligned to ensure compliance with *Alberta Ambient Air Quality Objectives and Guidelines* (*AAAQOG*).

ST60B: Upstream Petroleum Industry Emissions Report, published annually, fulfils the AER's commitment to report flaring and venting volumes as set out in *Directive 060*.

The data used to compile the report is primarily from Canada's Petroleum Information Network (Petrinex) and OneStop. Petrinex data is reported to the AER monthly, while OneStop data for the previous calendar year is received annually on June 1. OneStop data presented in this report represents data that was submitted on or before August 4, 2022.

For information on flaring, incinerating, and venting requirements, see *Directive 060*.

1.1 Important Notes for this Year's Publication

Changes to the fuel, flare, and vent definitions resulted in significant differences in reported volumes from 2019 to 2020. These changes are explained throughout the report. It is important to understand that these year over year differences are not reflective of emission increases and should be a better reflection of what is being emitted to atmosphere than what was reported using previous definitions. To avoid confusion, the data from the two different time periods are graphed separately.

Differences in Petrinex and OneStop total vent volumes. In the 2021 data, we once again observed differences in the total vent volumes reported to Petrinex and the defined vent gas (DVG) volumes reported to OneStop. While we do not expect these volumes to be the same (Petrinex includes nonroutine venting), we would expect Petrinex total vent volumes to be *greater* than OneStop DVG volumes, and that was not always the case. The reasons for these differences may include a lack of operator equipment inventories, the combination of monthly reporting (Petrinex) and annual reporting (OneStop), Petrinex reliance on metering difference, and OneStop reliance on emission estimation.

2020 OneStop Amendments/Late Submissions. This year's publication includes the OneStop data for both 2021 and 2020, but because it was extracted in August 2022, the 2020 data will include amendments and late submissions, resulting in slightly different values compared to last year's report.

Well testing information used to be gathered manually by reaching out to companies. Starting this year, we now use flaring, venting, and incineration data already reported to the AER annually, which allows for better year-over-year comparisons. Also, horizontal wells drilled are now separated into gas, crude oil, and crude bitumen.

Flaring Volumes, current and historical, now include acid gas.

Intensity Calculations are now differentiated between oil-sands and non-oil-sands assets. This was done to provide better clarity of emissions at various facility types. The oil sands category comprises in situ oil sands facilities and sulphur at oil sands facilities; mining and tailings are excluded.

1.2 Facility Information

For this report, facility subtypes are consistently used to report emissions (see *Manual 015*, table 4). This categorization is relevant to both Petrinex and OneStop, as reporting is required by Facility ID, which includes a facility subtype identifier. To provide more context for the emission data presented in this report, it may be helpful to understand how many active facilities there were. Table 1 shows the number of facilities in each subtype (for active reporting facilities) in 2019, 2020, and 2021. The per cent change column compares 2020 to 2021.

Table 1. Number of facilities that must report methane emissions by subtype, 2019–2021 ("% change" column compares 2020 to 2021)

Facility subtype	2019	2020	2021	% change
Crude bitumen batteries	4 157	3 542	3 228	−8.87%
Crude oil batteries	8 699	8 521	8 447	−0.87%
Gas batteries	9 585	9 509	8 957	−5.81%
Gas plants	527	531	511	−3.77%
Gas gathering / compressor stations	6 633	6 899	5 855	−15.13%
Other	1 935	1 935	1 900	−1.81%
Total	**31 536**	**30 937**	**28 898**	

The crude bitumen battery facility subtype category includes batteries producing thermal and nonthermal bitumen, such as crude bitumen multiwell proration batteries and in situ oil sands batteries (as described in AER's Manual 11: *How to Submit Volumetric Data*).

Facility subtypes within the “other” category include meter stations, disposal facilities, pipelines, and tank farms, etc. Emissions and production data from facilities associated with bitumen mining are not included in the data for this report.

Table 2. Mapping of ST60B category to facility subtype codes (*Manual 015*, table 4)

ST60B category	Facility subtypes
Crude bitumen batteries	331, 341–345, 501, 506, 508
Crude oil batteries	311, 321, 322, 611, 612
Gas batteries	351, 361–367, 371
Gas plants	401–407
Gas gathering / compressor stations	206, 601, 621, 622, 631
Other	204, 207–209, 381, 502–505, 507, 509, 632–634, 637, 640, 651, 671–673, 675, 801, 902, 903

2 Fuel Use

The upstream oil and gas industry uses natural gas to fuel equipment when producing, gathering, and processing natural gas, oil, and bitumen. Fuel use volumes are provided in this report to complement the flaring and venting volumes reported to Petrinex. Fuel use volumes are also important to include when reviewing the impacts of the change in fuel, flare, and vent definitions.

Figure 1 and figure 2 show fuel volume use since 2010 as reported to Petrinex. These volumes represent the yearly total of monthly reported fuel volume by facility subtype. In 2021, fuel gas use was 28.25 10^9 m^3.

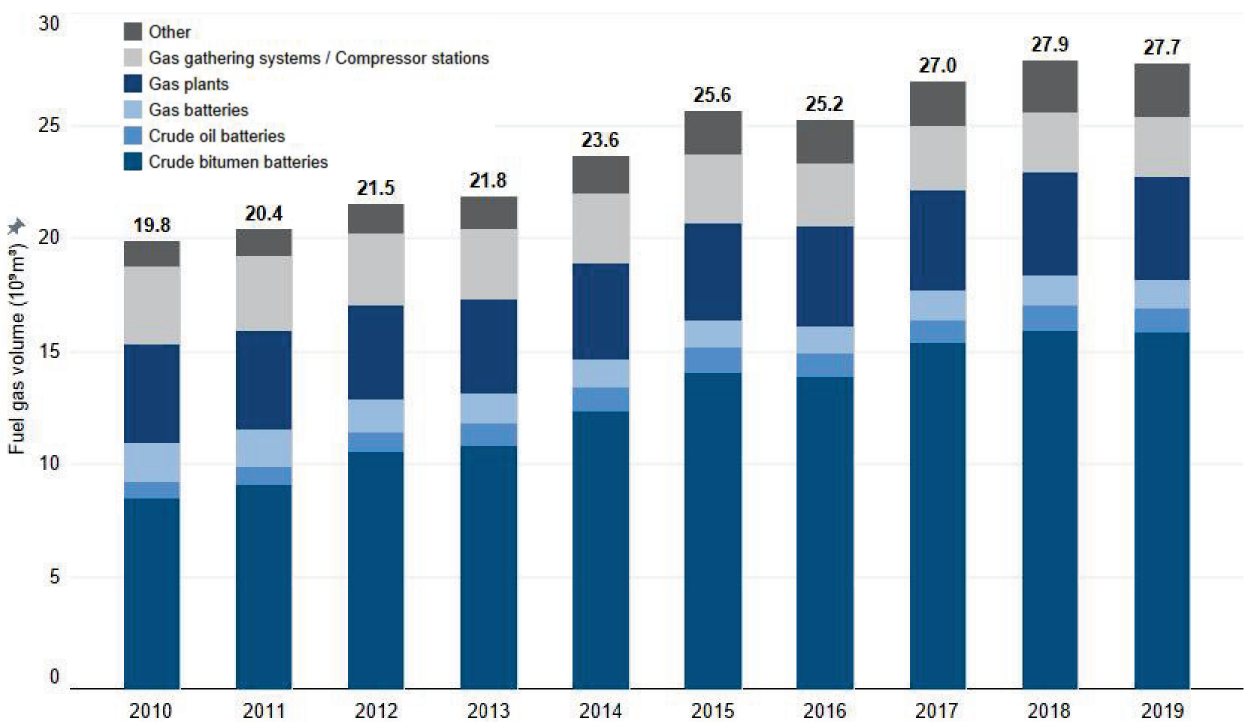


Figure 1. Fuel gas usage, 2010–2019 (Source: Petrinex)

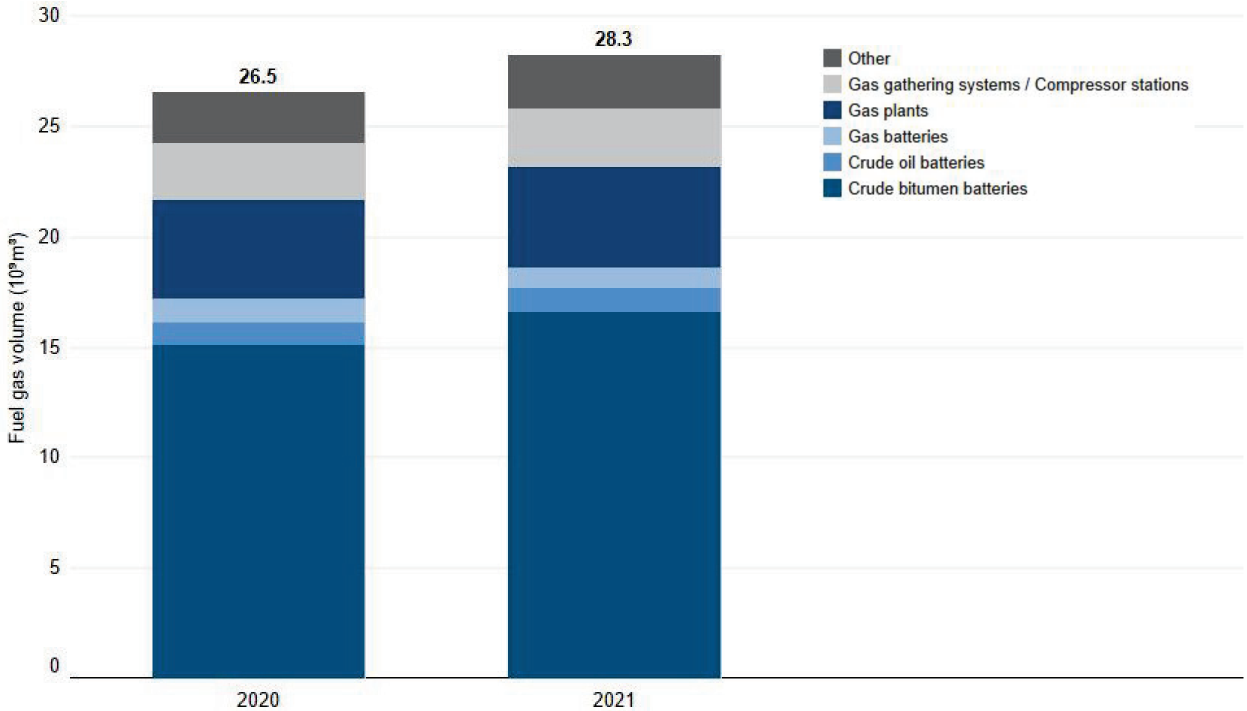


Figure 2. Fuel gas usage, 2020–2021 (Source: Petrinex)

Fuel gas use has primarily been increasing each year from about 19.85 10^9 m^3 in 2010 to over 27.00 10^9 m^3 in 3 of the last 4 years. In 2020, fuel gas use decreased to 26.52 10^9 m^3 because of a change in the fuel gas definition within both *Directive 060* and *Directive 017*. Volumes that would have previously been reported as fuel gas are now being reported as vent gas. For example, the previous definition of fuel gas would have included gas used to drive a pneumatic device. However, since this gas is vented to the atmosphere, we changed the definitions to now consider this as vent gas and require it to be reported as such in Petrinex.

Table 3 shows the change in fuel gas use by facility subtype from the previous year. Crude bitumen batteries increased in fuel gas use. This can be attributed to the increased price of oil and enhanced production across the province. Fuel gas use by facilities associated with gas batteries decreased the most.

Table 3. Change in fuel gas use volumes, 2020–2021 (Source: Petrinex)

Facility subtype	2020 (10^9 m^3)	2021 (10^9 m^3)	% change
Crude bitumen battery	15.11	16.62	9.97%
Crude oil battery	1.00	1.05	5.09%
Gas battery	1.07	0.95	−11.11%
Gas gathering / compressor station	2.58	2.60	0.65%
Gas Plant	4.46	4.56	2.06%
Other	2.28	2.47	8.04%

3 Flaring

Flaring is the controlled burning of gas that takes place during production and processing and includes flaring, incineration, and enclosed combustion. Flaring is managed by *Directive 060*, which sets limits on the routine and nonroutine flaring allowed to occur at a given site. Flare volumes are reported to the AER through Petrinex monthly.

3.1 Reported Flare Data

Figure 3 and figure 4 show reported flare volumes since 2010, as reported to Petrinex, broken down by facility subtype. Well testing is not included here and is presented in a subsequent section.

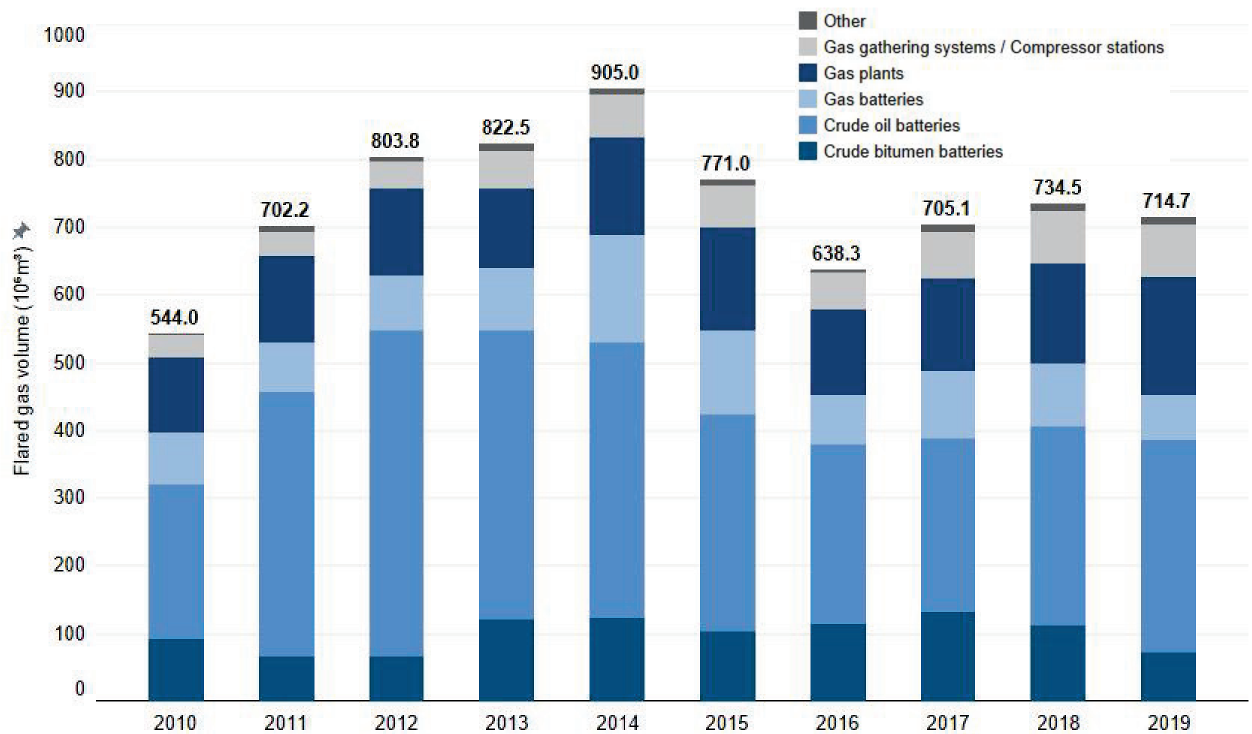


Figure 3. Flare volumes, 2010–2019 (Source: Petrinex)

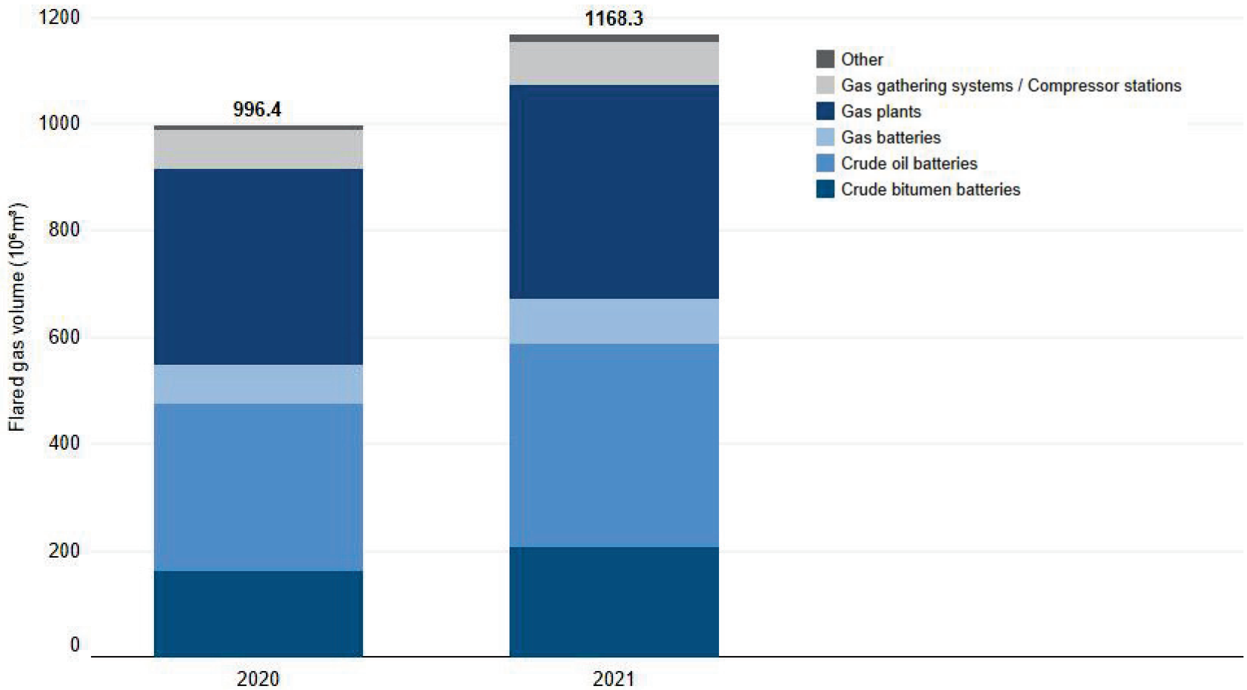


Figure 4. Flare volumes, 2020–2021 (Source: Petrinex)

3.1.1 Flaring Trends

In 2021, flaring volumes increased to 1168.33 10^6 m^3. This is likely the result of both the definition change and the introduction of new methane requirements in 2020 that emphasize methane (vent gas) reductions. Vent gas can be reduced through either conservation or combustion. As operators choose to minimize venting through combustion, reported flare volumes may increase, as was observed in 2021.

Table 4 shows the change in reported flaring by facility subtype. Flaring has increased in all facility types.

Table 4. Change in flared volume, 2020–2021 (Source: Petrinex)

Facility subtype	2021 (10^6 m^3)	2020 (10^6 m^3)	% change
Crude bitumen battery	206.02	162.51	26.78%
Crude oil battery	383.43	313.17	22.43%
Gas battery	83.13	72.43	14.76%
Gas gathering / compressor station	81.21	73.34	10.73%
Gas plant	400.30	367.85	8.82%
Other	14.25	7.11	100.46%

In addition to the total amount of flare volume increasing in 2021, the flaring intensity also increased (see table 5).

Table 5. Flaring intensity, 2020–2021 (Source: Petrinex)

Year	Province-wide BOE	Flare volume (m^3)	Intensity (m^3/boe)
2020	1 517 292 988	996 400 000	0.6567
2021	1 612 021 357	1 168 330 000	0.7248

3.1.2 Flare Volumes at Gas Plants

Table 6 shows the top 30 gas plants that flared in 2021 by volume and the percentage of the total gas received at each plant that is flared. The total amount of flaring from these gas plants (278.24 10^6 m^3) makes up approximately 68 per cent of total flaring at gas plants.

Table 6. Top 30 flaring gas plants, 2021 (Source: Petrinex)

Gas plant	Operator	Land location	2021 flare (10^6 m^3)	Gas flared as a percentage of gas receipts (%)
ABGP0001147	Veresen Midstream General Partner Inc.	11-18-074-12W6	59.91	1.52
ABGP0001004	Keyera Energy Ltd.	02-05-044-01W5	43.45	2.03
ABGP0149088	Baytex Energy Ltd.	03-18-084-17W5	23.23	20.18
ABGP0001892	Ovintiv Canada ULC	04-08-075-07W6	12.18	0.62
ABGP0118855	Pembina Gas Services Ltd.	08-13-063-05W6	10.34	0.87
ABGP0001855	Tidewater Midstream and Infrastructure Ltd.	09-15-084-14W5	10.02	14.73
ABGP0150386	Keyera Energy Ltd.	04-07-073-08W6	9.35	0.53
ABGP0001901	Plains Midstream Canada ULC	10-11-020-01W4	8.10	0.07
ABGP0001350	Cenovus Energy Inc.	01-08-070-11W6	7.21	0.53
ABGP0001037	Pieridae Alberta Production Ltd.	13-13-025-05W5	7.09	0.95
ABGP0001084	Repsol Oil & Gas Canada Inc.	04-11-053-18W5	6.97	0.68
ABGP0001623	Strathcona Resources Ltd.	06-08-062-03W6	5.84	0.66
ABGP0153429	Pembina Gas Services Ltd.	14-28-062-20W5	5.63	0.35
ABGP0152315	Tidewater Midstream and Infrastructure Ltd.	12-35-070-09W6	5.55	0.57
ABGP0001060	AltaGas Ltd.	09-27-031-04W5	5.02	0.14
ABGP0001107	Energy Transfer Canada ULC	01-12-062-20W5	4.96	0.33
ABGP0001108	Keyera Energy Ltd.	06-12-046-14W5	4.71	0.30
ABGP0001113	Keyera Energy Ltd.	09-06-063-25W5	4.28	0.22
ABGP0001134	Caledonian Midstream Corporation	02-04-021-04W5	4.09	3.16
ABGP0145129	Pembina Gas Services Ltd.	14-28-062-20W5	4.05	0.17
ABGP0001144	Energy Transfer Canada ULC	03-15-059-18W5	4.01	0.29
ABGP0001133	Keyera Energy Ltd.	11-35-037-09W5	3.92	0.28
ABGP0001506	Canadian Natural Resources Limited	01-01-078-10W6	3.90	0.32
ABGP0094954	Pembina Gas Services Ltd.	08-11-060-03W6	3.73	0.15
ABGP0001351	Canadian Natural Resources Limited	04-08-069-08W6	3.72	0.15
ABGP0001129	Canadian Natural Resources Limited	13-26-067-05W6	3.59	0.43
ABGP0001056	Pieridae Alberta Production Ltd.	02-20-004-30W4	3.50	0.29
ABGP0001520	NuVista Energy Ltd.	06-19-073-08W6	3.32	0.38
ABGP0001381	New Star Energy Ltd.	10-04-051-04W5	3.30	5.79
ABGP0001130	Canlin Resources Partnership	02-27-040-03W5	3.25	3.86
Total			**278.24**	

3.2 Well Testing

Directive 060 requires that operators seek alternatives to well test flaring. Operators are required to test in line when it is both economically viable and safe to do so. Testing in line can mean either connecting to an existing gas gathering system directly or laying a temporary surface pipeline to connect a well to a remote gas gathering system. By either method, the gas from the well test is conserved.

If in line testing is not possible, licensees must design completions and well testing programs to minimize emissions while ensuring technically sound well completion and acquisition of sufficient reservoir and productivity information for future development decisions

Well testing data is required to be reported to the AER through *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*. This data was retrieved, as reported, through the AER's compliance and operations management (COM) system. Given they are a unique subset of flaring, they are presented separately here.

In 2021, 747 well tests were completed, up from 500 tests being reported in 2020 (table 7). On average, flaring volumes per test decreased and vent volumes per test increased.

Table 7. Well drilling and testing data, 2019–2021 (Source: COM, ST59)

Year	Total wells drilled	Number of well tests	Total flare volume during well tests (10^3 m^3)	Average flare per test (10^3 m^3)	Total vent volume during well tests (10^3 m^3)	Average vent per test (10^3 m^3)
2019	3 850	706	44 273.78	62.71	1 070.67	1.52
2020	2 338	500	41 359.63	82.72	277.95	0.56
2021	5 486	747	48 975.09	65.56	875.17	1.17

4 Venting

Vent gas is uncombusted gas that is released to the atmosphere at upstream oil and gas operations. The AER manages vented emissions from upstream oil and gas facilities through *Directive 060*, which includes both site-specific and equipment-specific limits. Improving venting performance is important to the AER for both the protection of the environment and for meeting provincial emission reduction goals.

The AER collects venting data through Petrinex (monthly) and OneStop (annually). Petrinex vent gas volumes include both routine (including venting from pneumatic devices, compressor seals, dehydrators, tanks, etc.) and nonroutine vent gas, while OneStop only includes routine vent gas. However, OneStop provides greater emission breakdowns by source type, as discussed and shown below.

In the 2021 data, the AER observed differences in the total vent volumes reported to Petrinex and the defined vent gas (DVG) volumes reported to OneStop. While these volumes are not expected to be the same (Petrinex includes nonroutine venting), we would expect Petrinex total vent volumes to be *greater* than OneStop DVG volumes, and that was not always the case. The reasons for these differences may include the combination of monthly reporting (Petrinex) and annual reporting (OneStop), Petrinex reliance on metering difference, and OneStop reliance on emission estimation. While data inconsistencies are to be expected as operators adjust to new requirements, we are working towards better understanding these differences.

Greater detail on overall methane performance can be found on our methane performance webpage.

4.1 Petrinex

Routine and nonroutine volumes are reported as a combined monthly volume to Petrinex. Figure 5 and figure 6 show annual vent gas volumes over the past 11 years by facility subtype. In 2021, reported vent gas in Petrinex was 362.73 10^6 m^3.

The vent gas volumes reported in 2021 slightly increased in relation to 2020; however, when looking at province-wide production, which increased in 2021, venting intensity decreased (see table 9).

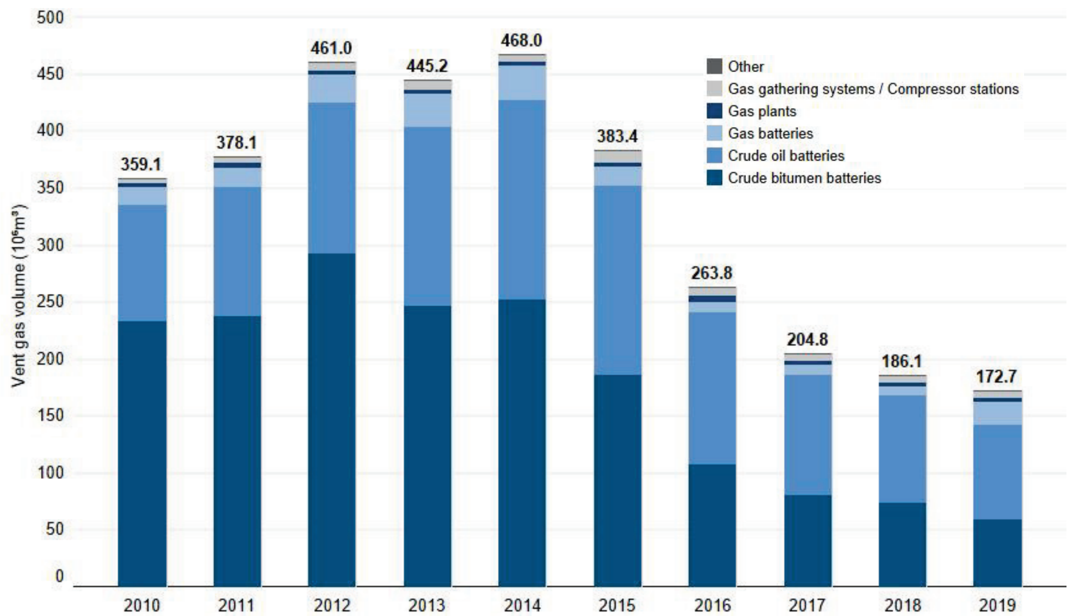


Figure 5. Vent volumes, 2010–2019 (Source: Petrinex)

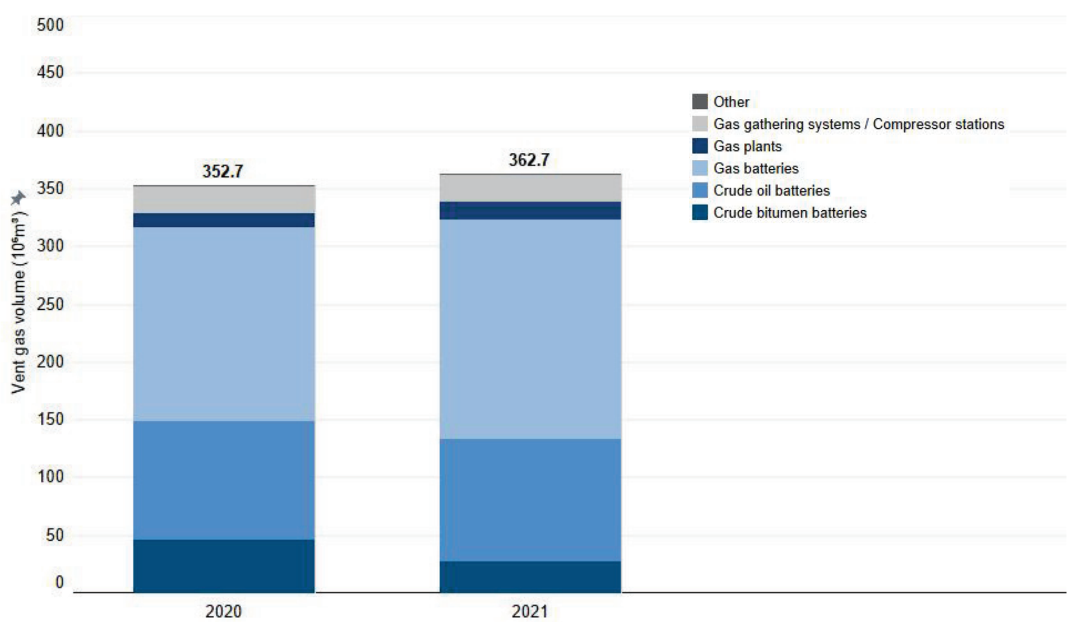


Figure 6. Vent volumes, 2020–2021 (Source: Petrinex)

Table 8 shows the change in reported vent gas by facility subtype. Venting from crude bitumen batteries significantly decreased, whereas gas plants significantly increased.

Table 8. Change in vented volumes 2020–2021 (Source: Petrinex)

Facility Subtype	2021 (10^6 m^3)	2020 (10^6 m^3)	% change
Crude Bitumen Battery	28.02	45.92	−38.98
Crude Oil Battery	105.45	103.26	2.12
Gas Battery	189.52	167.89	12.88
Gas Gathering / Compressor Station	23.56	22.42	5.09
Gas Plant	15.65	12.40	26.24
Other	0.52	0.84	−37.82

Table 9. Venting intensity, 2020–2021 (Source: Petrinex)

Year	Province-wide BOE	Vent volume (m^3)	Intensity (m^3/boe)
2020	1 517 292 988.03	352 730 000.00	0.2325
2021	1 612 021 356.57	362 730 000.00	0.2250

4.2 OneStop

Operators are expected to submit an annual methane report to OneStop on June 1st of each year. This submission is subject to the regulatory requirements contained in section 8 of *Directive 060*.

4.2.1 Summarized Emissions

Emissions data reported to the AER through OneStop provides greater detail on source-specific methane emissions. In 2021, total emissions reported to OneStop were 586.07 10^6 m^3. Figure 7 shows total source-specific emissions, and figure 8 shows these emissions broken down by source category and facility subtype. The 2020 reporting year was the first year that the AER required reporting of both vent and fugitive emissions data via OneStop. The data below represents most of the facilities that were required to report; however, there were still some data gaps at the time of publication (currently a 92 per cent submission compliance rate).

Gas batteries are the facility subtype with the greatest associated emission volumes, because of the high presence of pneumatic devices on site. We also see that DVG is the greatest contributing source for both crude oil and crude bitumen batteries, likely due to the presence of hydrocarbon storage tanks at these sites. Also, solution gas is less likely to be conserved. As the AER continues to evaluate means of improving tank emissions estimation methods, we may see fluctuations in these reported volumes in subsequent years. Please note that dehydrator emissions were excluded in this visual as they do not always report to the reporting facility identifier, meaning no facility subtype is usually available.

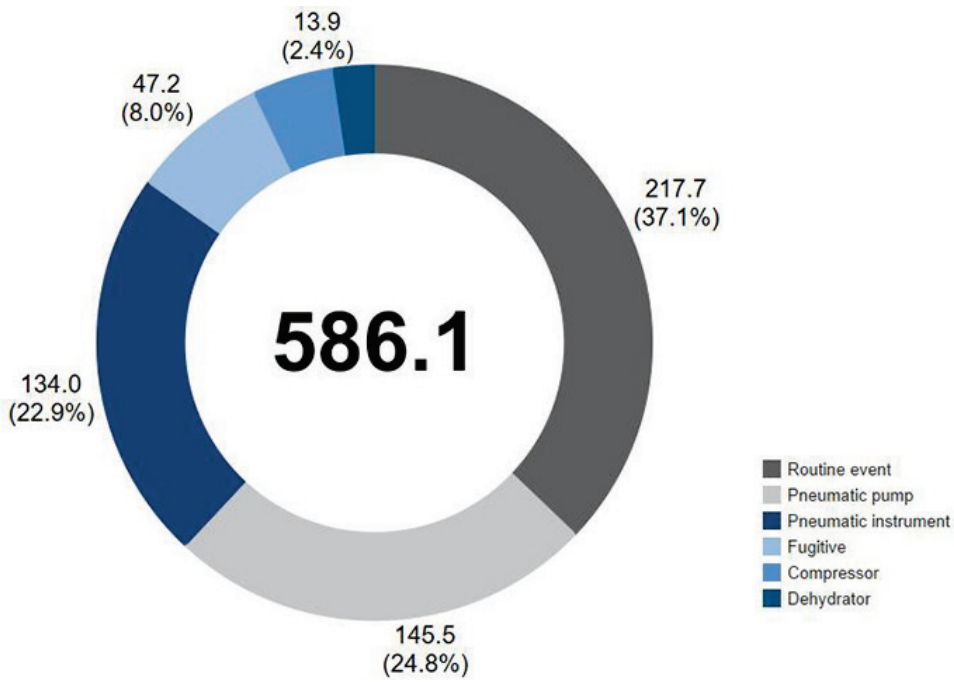


Figure 7. Breakdown of venting volumes by source, 2021 (Source: OneStop)

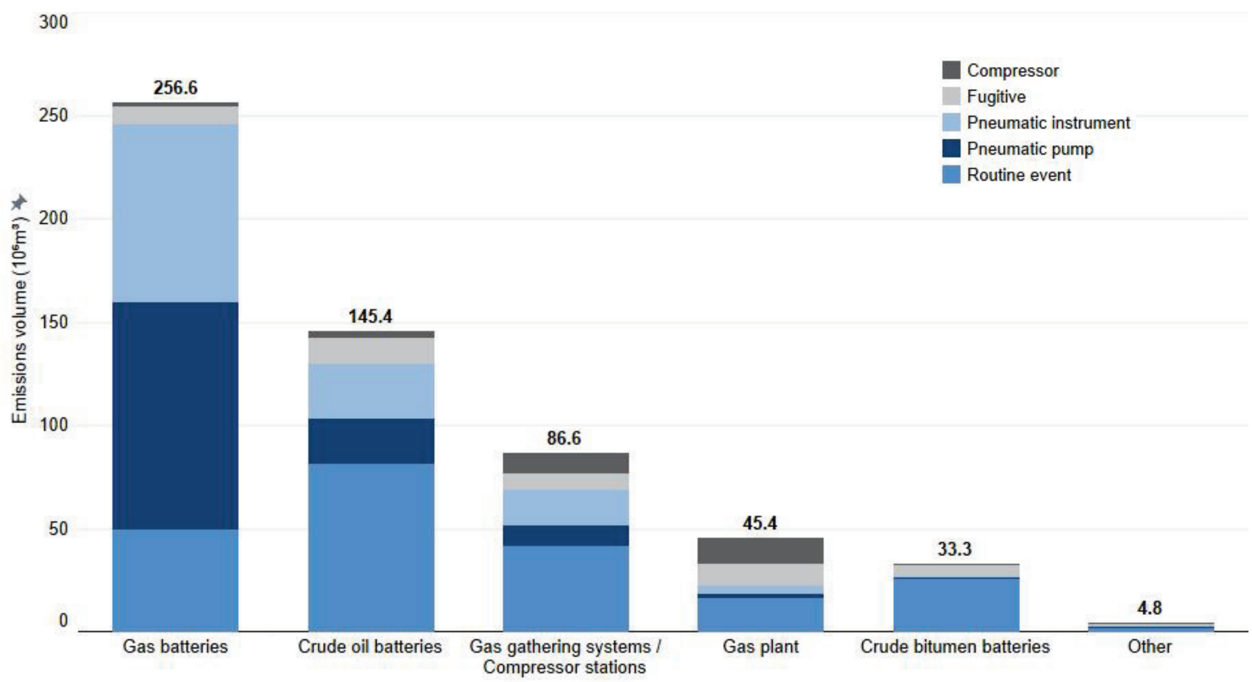


Figure 8. Breakdown of venting volumes by facility subtype, 2021 (Source: OneStop)

Figure 9 shows a side-by-side comparison of the OneStop emissions data for 2020 and 2021. Year-over-year comparisons are challenging because of potential data quality issues. The reported data is a snapshot in time and these volumes could change as companies review and update their data.

One potential contributing factor to this data quality issue is inconsistent reporting. Large increases or decreases in OneStop emissions are possible for various reasons, including acquisitions, divestitures, insolvencies, changes in operating conditions/statuses, improvements in operator equipment inventories, or changes in emission quantification methodologies. It could also indicate potential data quality issues within one or both submissions. Table 10 breaks down the top 10 companies with the largest reported emission differences in Onestop reported volumes when comparing 2020 and 2021. When warranted, the AER follows up with companies to determine if compliance action is required.

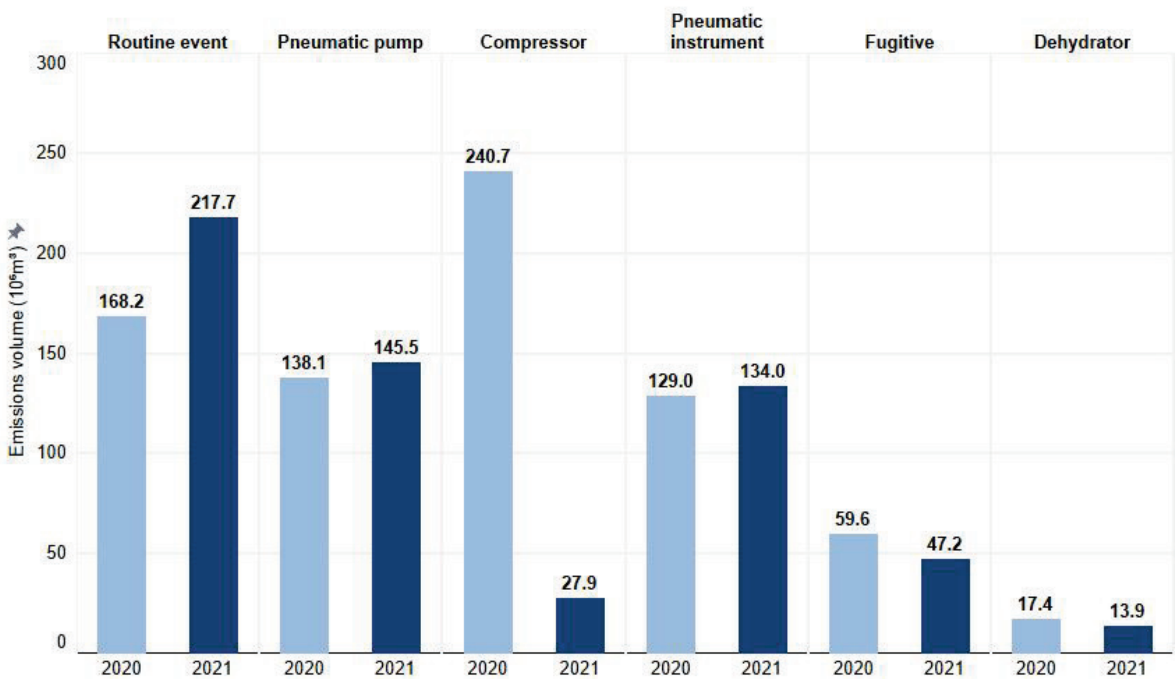


Figure 9. Comparison of venting volumes by source, 2020–2021 (Source: OneStop)

Table 10. Top ten absolute differences in reported venting volumes, 2020–2021 (Source: OneStop)

Operator	2020 (10^6 m^3)	2021 (10^6 m^3)	Absolute difference (10^6 m^3)
Canlin Resources Partnership	208.71	2.44	206.28
Long Run Exploration Ltd.	2.24	67.68	65.44
AlphaBow Energy Ltd.	0.92	27.32	26.40
Tallahassee Exploration Inc.	23.28	0.07	23.21
Cenovus Energy Inc.	53.91	75.29	21.39
Canadian Natural Resources Limited	102.99	84.58	18.41
New Star Energy Ltd.	0.12	10.61	10.49
Repsol Oil & Gas Canada Inc.	10.92	5.18	5.74
Peyto Exploration & Development Corp.	13.82	8.74	5.09
SanLing Energy Ltd.	4.75	0.00	4.75

4.2.2 Defined Vent Gas

Directive 060 includes vent limits for defined vent gas (DVG), which is reported annually to the AER through OneStop. DVG should also be captured within the vent volumes reported to Petrinex. In 2021, DVG emissions reported to OneStop were 217.72 10^6 m^3 (figure 10). This represents approximately 37 per cent of all emissions reported to OneStop. Crude oil batteries contribute the most DVG emissions by volume. Given the greater likelihood of tanks at these sites, it is reasonable that they would be the most significant contributor in this category.

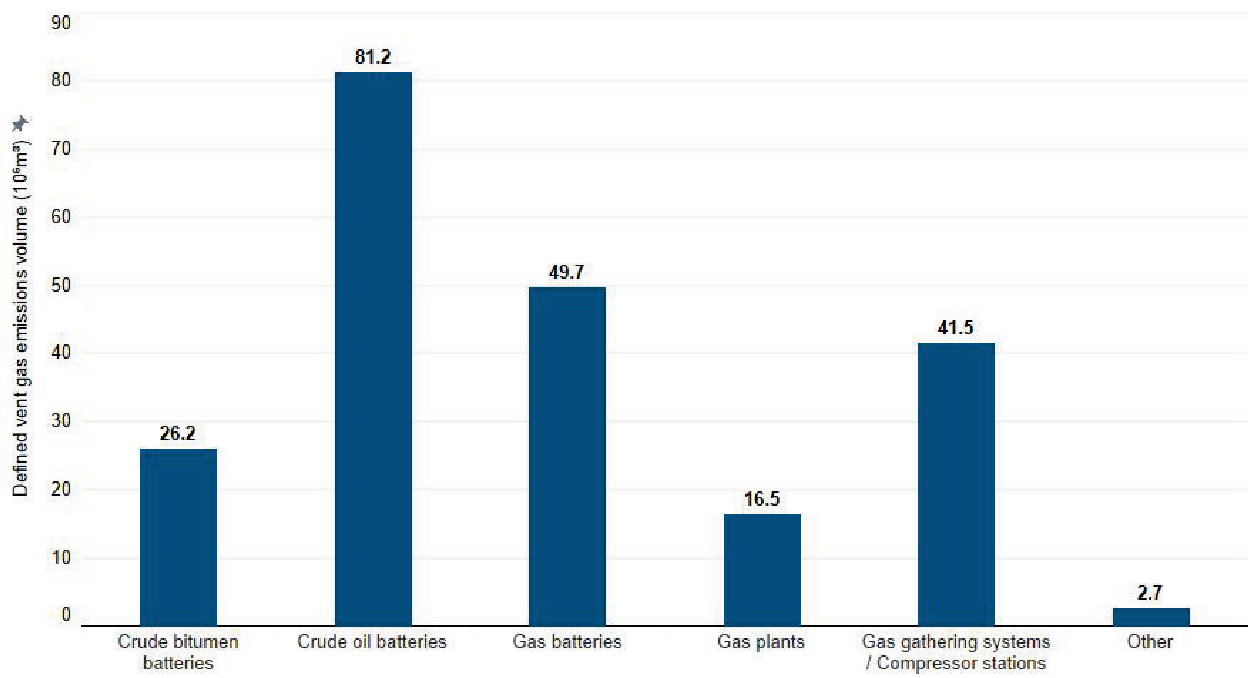


Figure 10. DVG vent volumes by facility subtype, 2021 (Source: OneStop)

4.2.3 Pneumatic Devices

Directive 060 includes vent limits for vent gas from both pneumatic instruments and pumps. Emissions from pneumatics instruments and pumps are reported annually to the AER through OneStop. These volumes should also be captured within the vent volumes reported to Petrinex. Pneumatic device inventories are not required to be reported to the AER, so comprehensive device counts are not provided here.

In 2021, emissions reported to OneStop for pneumatic devices (instruments and pumps) were 279.44 10^6 m^3. This represents approximately 48 per cent of all emissions reported to OneStop. Gas batteries were the most significant contributor, representing around 70 per cent of the total pneumatic emissions. This is a result of a large number of gas batteries and a higher likelihood for gas-driven pneumatic devices at these sites, as found in the 2018 Clearstone Engineering Report *Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas*. Figure 11 shows a breakdown of pneumatic device emissions by facility subtype.

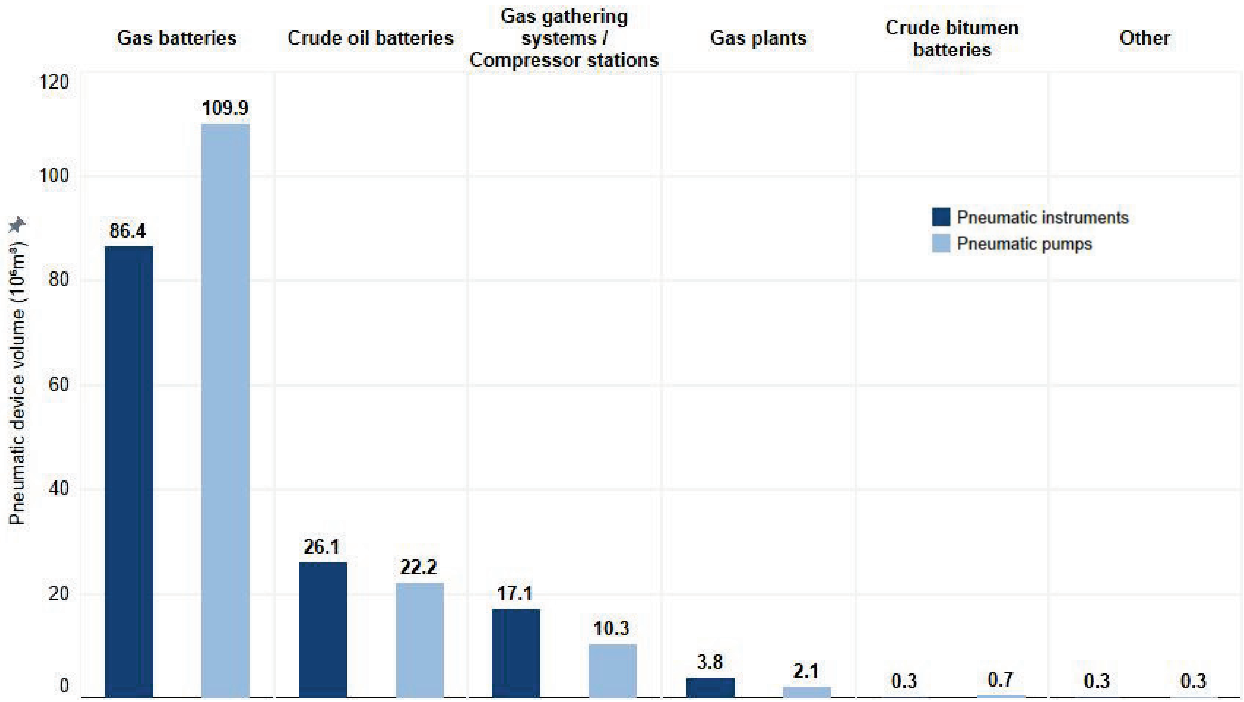


Figure 11. Pneumatic vent volumes by equipment and facility subtype, 2021 (Source: OneStop)

4.2.4 Compressor Seals

Directive 060 includes testing requirements and vent limits for both reciprocating and centrifugal compressor seals. Emission volumes for this source are both tested (measured) and estimated and are reported annually to the AER through OneStop. These volumes are captured within the vent volumes reported to Petrinex monthly.

4.2.4.1 Compressor Inventory

Directive 060 requires a comprehensive compressor inventory be reported annually to the AER through OneStop. Compressors rated 75 KW or more and pressurized for at least 450 hours per calendar year must be reported individually. In 2021, there were 3341 reciprocating compressors and 152 centrifugal compressors that reported.

4.2.4.2 Compressor Seal Emissions

In 2021, reciprocating compressor seal emissions reported to OneStop were 26.64 10^6m^3. This represents roughly 4.5 per cent of all emissions reported to OneStop. Centrifugal compressor seal emissions reported to OneStop were 0.88 10^6m^3, a small emission contributor relative to the other sources reported here, representing only 0.2 per cent of all emissions reported to OneStop. The most significant contributions came from gas gathering systems, compressor stations, and gas plants. Figure 12 shows a breakdown of compressor emissions by facility subtype.

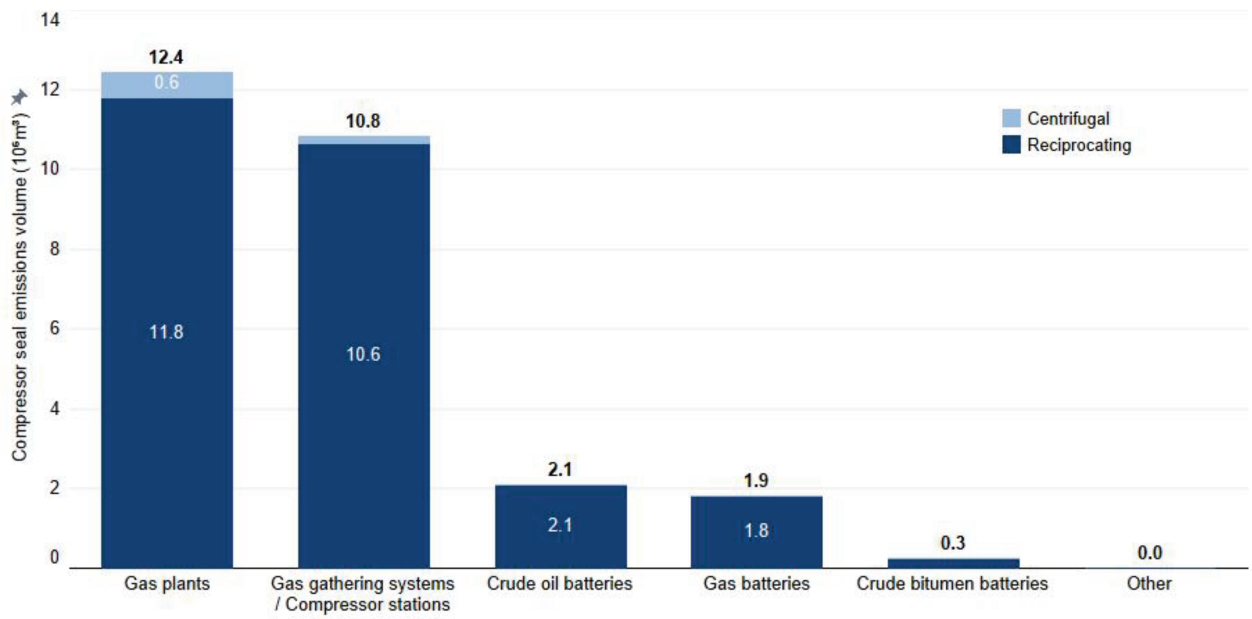


Figure 12. Compressor vent volumes by compressor type and facility subtype (Source: OneStop)

4.2.4.3 Reciprocating Compressor Seal (RCS) Fleet Average

A reciprocating compressor seal (RCS) includes the piston-rod-packing vents/drains and the distance-piece vents/drains on an individual throw. If the crankcase is uncontrolled, any emitted gas is subject to compressor limits.

The RCS fleet average can be calculated using the formula found in section 8.6.2.2 of *Directive 060*. Table 11 shows the estimated RCS fleet averages for the top 20 compressor venting operators using 2021 reported values. The requirements in section 8.6.2.2 of *Directive 060* did not come into effect until Jan 1, 2022, so the RCS fleet averages listed below are prior to the operator compliance deadline.

Table 11. Top 20 compressor venting operators with RCS fleet average, 2021 (Source: OneStop)

Operator	Vent volume (10^6 m^3)	Number of Compressors	Number of Throws	Average of vent gas from RCS fleet*
TAQA North Ltd.	3.87	156	542	0.80
Canadian Natural Resources Limited	3.47	444	1 502	0.27
Repsol Oil & Gas Canada Inc.	1.28	62	174	0.54
Tourmaline Oil Corp.	1.07	213	760	0.20
Keyera Energy Ltd.	1.02	126	404	0.28
NorthRiver Midstream Inc.	1.00	19	58	2.26
Pembina Gas Services Ltd.	0.87	91	301	0.40
Cenovus Energy Inc.	0.80	269	864	0.14
Peyto Exploration & Development Corp.	0.71	70	259	0.36
Energy Transfer Canada ULC	0.71	72	264	0.49
Baytex Energy Ltd.	0.68	24	69	1.17
Ricochet Oil Corp.	0.66	8	32	2.37
Torxen Energy Ltd.	0.60	99	325	0.24
Bonavista Energy Corporation	0.58	106	374	0.19
Lynx Energy ULC	0.53	47	181	0.34

Operator	Vent volume (10^6 m^3)	Number of Compressors	Number of Throws	Average of vent gas from RCS fleet*
Spartan Delta Corp.	0.45	52	175	0.30
Plains Midstream Canada ULC	0.42	16	6	0.28
Pine Cliff Energy Ltd.	0.40	46	170	0.27
Bonterra Energy Corp.	0.37	10	41	1.13
Rockpoint Gas Storage Canada Ltd.	0.32	22	128	2.00

* Cubic metres per throw-hour; see section 8.6.2.2 of *Directive 060* for details on how this is calculated.

4.2.5 Glycol Dehydrators

Directive 060 includes methane emission limits for glycol dehydrators. Glycol dehydrator emissions must be reported to the AER through OneStop annually. These volumes should also be captured within the vent volumes reported to Petrinex.

Companies are also required to meet the benzene emission requirements for glycol dehydrators (dehydration and refrigeration) set out in *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators*. Under *Directive 039*, licensees must complete and submit to the AER an annual dehydrator inventory list that details the emissions from all their glycol dehydrators.

4.2.5.1 Glycol Dehydrator Inventory

In 2021, there were 1237 operating glycol dehydrators in Alberta. Not all dehydrators would be active for the full year but are counted in this inventory if they were operated at all in 2021. Table 12 shows the counts of all operating glycol dehydrators per year over the past 11 years.

Table 12. Number of operating glycol dehydrators, 2010–2021 (Source: OneStop)

Year	Number of dehydrators
2010	2107
2011	2006
2012	1985
2013	1905
2014	1886
2015	1778
2016	1646
2017	1528
2018	1400
2019	1328
2020	1266
2021	1237

Note: Benzene occurs in varying concentrations in natural gas streams throughout the province, and some locations may not have any benzene. All operating dehydrators are included, regardless of the concentration of benzene in the gas stream.

4.2.5.2 Glycol Dehydrator Emissions

The reporting requirements for glycol dehydrators differs from all other source categories, in that the AER only requires the methane mass emissions to be reported. The data presented in this section reflect a conversion of the reported mass to volume using methane density and an 85 per cent methane concentration estimate. In 2021, glycol dehydrator emissions were calculated to be 13.88 10^6 m^3. This represents 2.4 per cent of all emissions reported to OneStop. More detailed visuals on glycol dehydrator emissions are not included in this report, as not all facility subtypes and reporting codes could be identified.

5 Fugitive Emissions

Fugitive emissions are unintentional releases of hydrocarbon to the atmosphere and can result from the wear or failure of equipment. *Directive 060* includes requirements for screenings and surveys to inspect for and repair fugitive emissions. These emissions are reported to the AER through OneStop annually.

2020 was the first year of implementing prescribed fugitive emission requirements under *Directive 060*, and 2021 was the first year equipment fugitive emissions were reported to the AER. 2020 was also unique because there were requirement relaxations because of the COVID-19 pandemic. In 2021, fugitive emissions were 47.2 $10^6 m^3$ (figure 13). This represents 8.1 per cent of all emissions reported to OneStop.

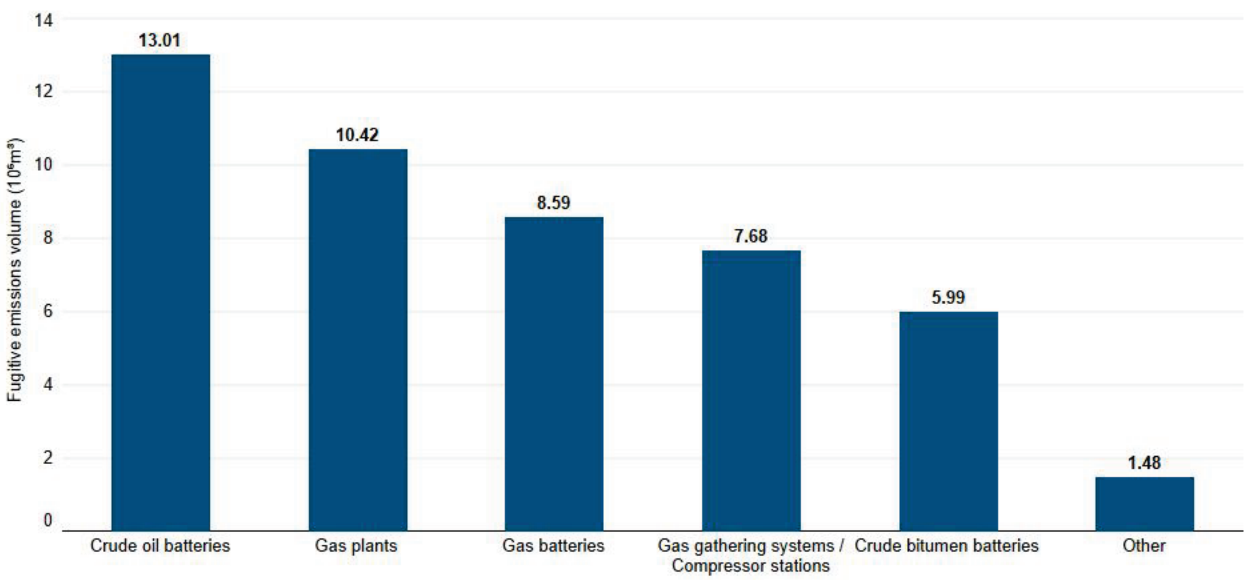


Figure 13. Fugitive emission volumes by facility subtype, 2021 (Source: OneStop)

A surface casing vent flow (SCVF) is the flow of gas, liquid, or both out of the surface casing or casing annulus of a well. Gas migration (GM) is the flow of detectable gas at the surface outside of the outermost casing string.

Section 8 of *Directive 060* now requires increased ongoing fugitive emissions surveys at active sites. This increase will result in more frequent inspections of surface casing vents, as these are identified as mandatory equipment within the scope of a fugitive emission survey.

In 2021, the AER released *Directive 087: Well Integrity Management*, which complements *Directive 060* when it comes to SCVF management. *Directive 060* contains ongoing survey requirements while *Directive 087* contains testing, reporting, and repair requirements for isolation packers, surface casing vent flows gas migration, and casing failures. *Directive 087* requires companies to report emissions from SCVFs and GM. Over the years, the AER has worked with licensees to ensure proper reporting of SCVFs and GM.

Table 13 shows the number of unresolved wells with SCVF, GM, or both in 2021, along with their respective emissions.

Table 13. Emissions from SCVFs and GM at unrepaired wells

Year	Number of wells with unresolved SCVFs, GM, or both	Annual natural gas emissions (10^6 m^3)
2010	8 926	95
2011	9 318	92
2012	9 563	88
2013	9 624	89
2014	9 982	84
2015	10 247	86
2016	9 972	81
2017	10 291	83
2018	10 128	65
2019	10 324	66
2020	10 246	65
2021	10 636	62

Notes:

For wells that have SCVF flow rates that are too small to measure and wells where a GM flow rate cannot be determined, a flow rate of 1 m^3/day was assumed.

The flow rates reported are from a single point in time and are extrapolated to determine annual emissions. Flow rates for SCVFs and GM can fluctuate significantly over a period of time.

Typically, the methane content of natural gas in SCVFs and GM is between 95 and 99 per cent.

If no emissions type (e.g. natural gas, saline water, or nonsaline water) is provided, an SCVF or GM is assumed to be natural gas and have a flow rate equal to the average of all other reported natural gas SCVFs or GM.

6 Solution Gas Performance

Solution gas is gas that is separated from condensate, oil, or bitumen production. To minimize the venting of solution gas, the AER developed requirements to guide the evaluation of alterative options, such as flaring or conserving.

The 2007 version of *Directive 060* placed significant emphasis on solution gas conservation and required that all solution gas flares or vents releasing more than 900 m^3/day be evaluated to see if gas conservation is economic and viable. When *Directive 060* was revised in 2020 to include more stringent methane reduction requirements, site vent limits were introduced that were lower than the 900 m^3/day threshold. This threshold can and is, however, still used to evaluate the economics of conservation.

Improving solution gas conservation is an important factor in the achievement of provincial emission reduction targets. Operator rankings for solution gas performance can be found in appendix 2.

6.1 Solution Gas Conservation

Gas conservation is the recovery of solution gas to use as fuel for production facilities, to sell, to inject for enhanced recovery from oil or condensate pools, or to generate power, among other uses. It is calculated as follows:

$$\text{Conservation} = \frac{[\text{Volume of gas produced} - (\text{Volume of gas flared} + \text{Volume of gas vented})]}{\text{Volume of gas produced}}$$

In 2021, 97 per cent of the solution gas produced from crude oil and crude bitumen batteries was conserved, down slightly from 97.25 per cent conservation in 2020.

Figure 14 shows total annual solution gas flared and vented volumes as well as the associated annual conservation rates. As shown in table 8, vent gas volumes from crude oil batteries increased from 2020 to 2021 because of the new definitions in *Directive 060*. This results in a minor reduction in solution gas conservation.

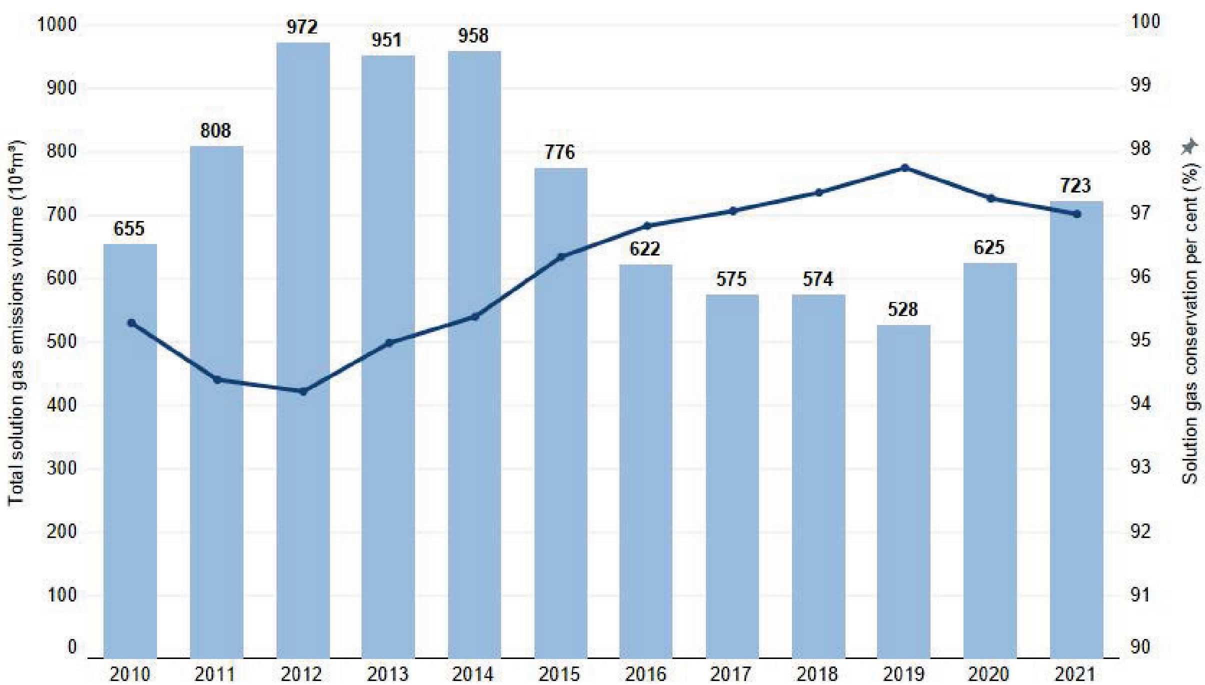


Figure 14. Solution gas conservation, 2010–2021 (Source: Petrinex)

6.2 Nonthermal and Thermal Operations

There are two types of crude bitumen operations: nonthermal operations (e.g., cold heavy oil production) and thermal operations (e.g., steam-assisted gravity drainage or cyclical steam stimulation). Thermal operations generally have less flaring and venting than nonthermal operations because the produced gas is more economical to conserve. Figure 15 shows annual solution gas conservation percentages for crude bitumen batteries broken down by nonthermal and thermal operations. Historically, there have been greater conservation rates associated with thermal operations. This remains the case for 2021, where we see that thermal operation conservation is 97.6 per cent while nonthermal operations have a conservation rate of 90.7 per cent.

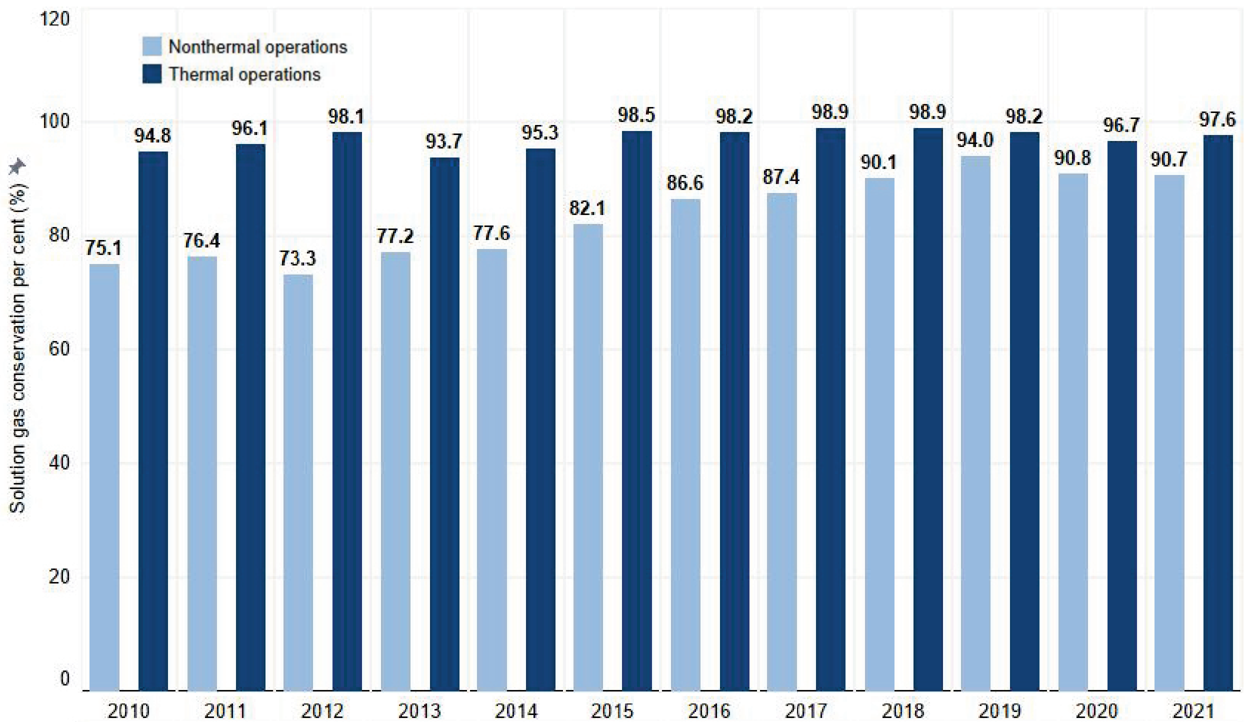


Figure 15. Solution gas conversation by operation type, 2010–2021 (Source: Petrinex)

6.3 Solution Gas Flaring

As shown in figure 16, 589.4 10^6 m^3 of solution gas was flared in 2021, which was a 53 per cent increase over 2019 and a 24 per cent increase over last year. Having 589.4 10^6 m^3 of flared solution gas is approximately 81 10^6 m^3 below the 670 10^6 m^3 solution flaring limit. As facilities continue to reduce venting, solution gas flaring is expected to continue to increase.

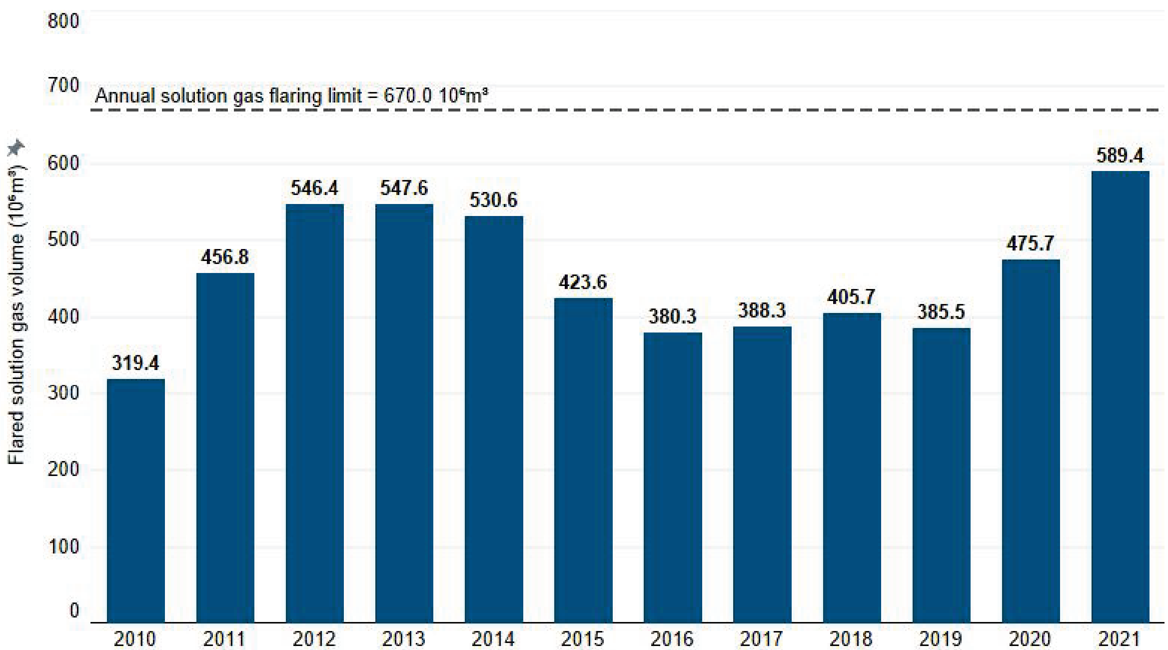


Figure 16. Solution gas flaring, 2010–2021 (Source: Petrinex)

6.4 Solution Gas Venting

In 2021, 133.47 10^6 m^3 of gas was vented from crude oil and crude bitumen batteries, which was a 10.7 per cent decrease from 2020. This is expected when looking at the continuous uptrend of solution gas flaring. The amount of solution gas vented continues to be well below the 2000 baseline of 704 10^6 m^3 (see figure 17).

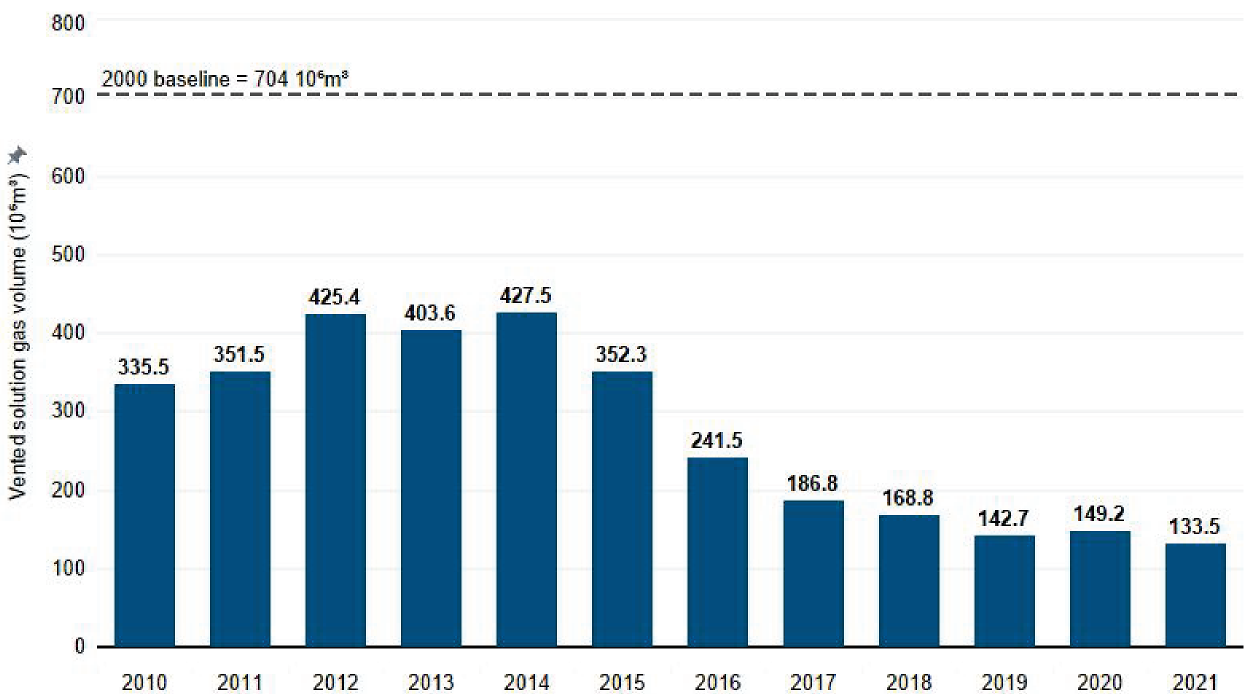


Figure 17. Solution gas venting, 2010–2021 (Source: Petrinex)

7 Methane Performance

In 2015, the Government of Alberta directed the AER to develop requirements to reduce methane emissions from upstream oil and gas operations. To accomplish this, the AER developed requirements in *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* and *Directive 017: Measurement Requirements for Oil and Gas Operations.* To learn more about these requirements and for more information on methane performance and methane compliance assurance activities, see our methane reduction page.

The emission reduction target set for Alberta by the Government of Alberta was to achieve a 45 per cent reduction in oil and gas methane emissions from a 2014 baseline by 2025. The new methane requirements have set the oil and gas industry on the path towards achieving that target. However, the emissions data that is reported above is not complete enough to be considered a comprehensive oil and gas methane emission baseline. The AER continues to supplement reported information with emission estimates to allow for an evaluation of the emission reductions achieved to date. Figure 18 shows the methane emission baseline (a combination of reported data and estimates) and the 45 per cent target. These reductions are the result of both early action through programs like offsets and the new requirements.

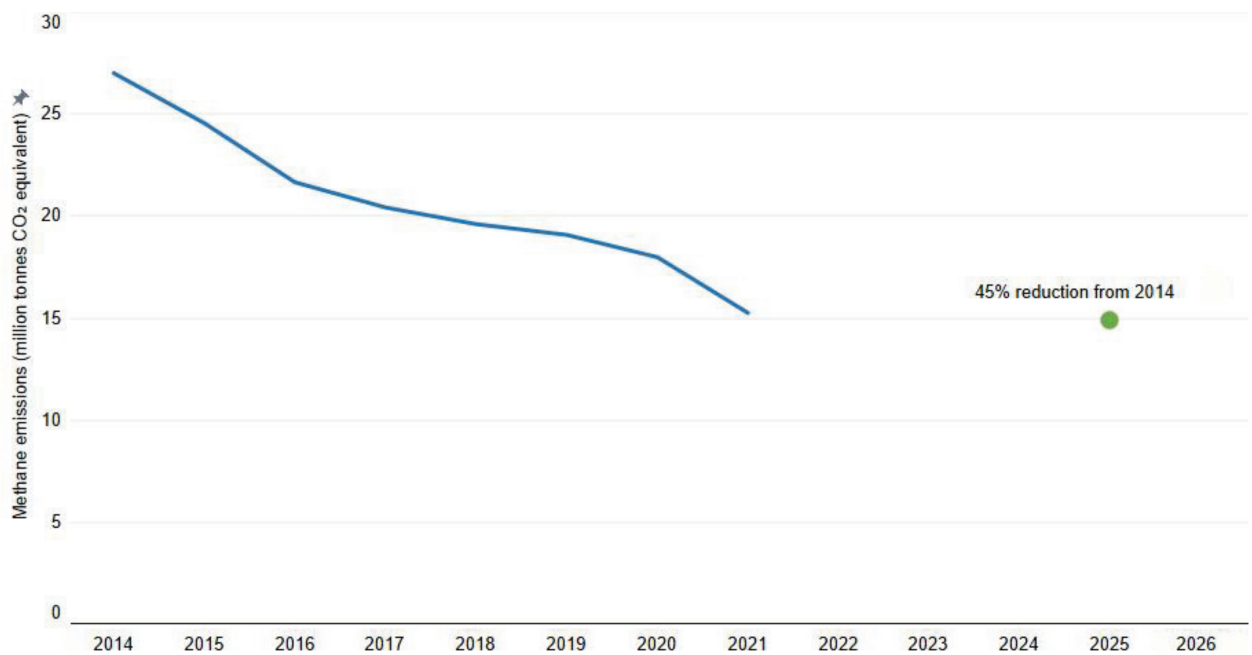
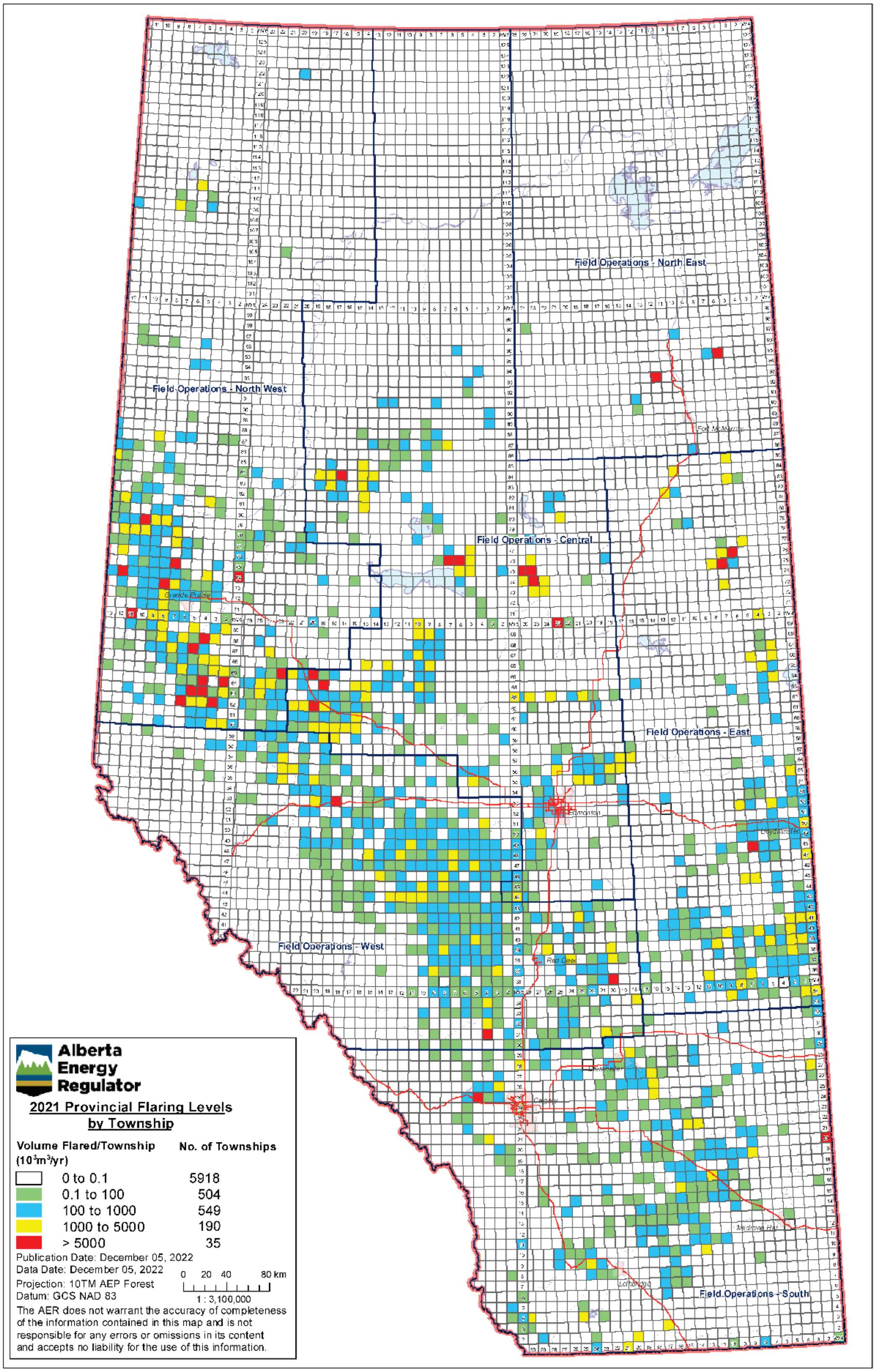


Figure 18. Methane emission reductions, 2014–2021 (reported & estimated emissions)

This graph shows that methane emission reductions from all oil and gas emissions in Alberta (including oil sands) are estimated to have been reduced by approximately 44 per cent between 2014 and 2021.

The AER will continue with compliance assurance activities and data quality assessments to shift towards using reported data when possible and minimize the reliance on estimation over time. The AER will evaluate the emission reductions annually, as part of this publication.

Appendix 1 Provincial Flaring and Venting Maps



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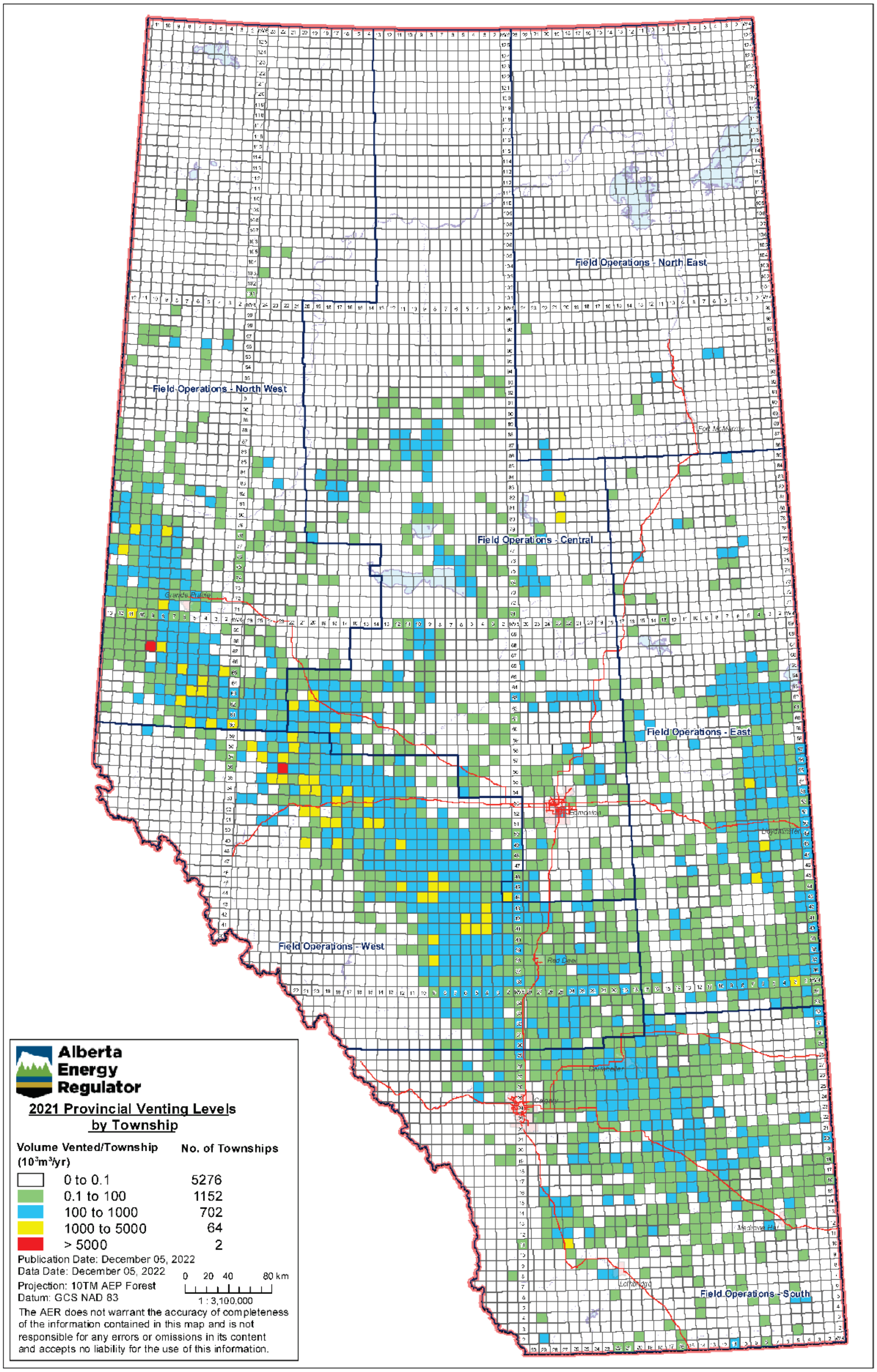

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Appendix 2 Operator Rankings

Caution is required when comparing with last year's report due to mergers, acquisitions, and divestments. This year's report provides the total volumes and differentiates the oil sands assets from the rest. Rankings are based on data as of August 5, 2022.

Venting

Oil Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Absolute change
Cenovus Energy Inc.	498 300	1	190 640 943	0.0026	0.0059	−0.0033
Suncor Energy Inc.	470 900	2	98 377 247	0.0048	0.0013	0.0035
Imperial Oil Resources Limited	391 500	3	57 110 409	0.0069	0.0043	0.0026
MEG Energy Corp.	332 600	4	38 049 410	0.0087	0.0005	0.0083
Canadian Natural Resources Limited	146 600	5	143 877 846	0.0010	0.0016	−0.0006
ConocoPhillips Canada Resources Corp.	80 200	6	58 280 271	0.0014	0.0013	0.0000
Harvest Operations Corp.	43 300	7	3 510 172	0.0123	0.0126	−0.0003
Strathcona Resources Ltd.	33 900	8	21 446 521	0.0016	0.0001	0.0015
Everest Canadian Resources Corp.	23 300	9	511 336	0.0456	0.0555	−0.0100
Athabasca Oil Corporation	18 000	10	10 881 749	0.0017	0.0019	−0.0002
PetroChina Canada Ltd.	6 000	11	4 945 068	0.0012	0.0075	−0.0063

Non-Oil-Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	67 226 000	1	89 439 579	0.75	0.85	−11.86
Cenovus Energy Inc.	32 902 500	2	50 662 170	0.65	0.64	1.31
Tourmaline Oil Corp.	26 491 600	3	94 890 662	0.28	0.25	9.90
Bonavista Energy Corporation	17 878 300	4	19 873 171	0.90	0.91	−0.67
Repsol Oil & Gas Canada Inc.	12 141 300	5	9 091 872	1.34	1.10	21.81
Peyto Exploration & Development Corp.	8 439 200	6	33 903 245	0.25	0.38	−33.93
Westbrick Energy Ltd.	7 981 300	7	13 571 296	0.59	0.55	6.93
Spartan Delta Corp.	7 724 900	8	21 230 140	0.36	0.38	−5.28
Paramount Resources Ltd.	7 574 400	9	22 052 166	0.34	0.19	85.11
Whitecap Resources Inc.	7 109 500	10	21 354 953	0.33	0.24	36.27
Torxen Energy Ltd.	7 041 700	11	22 659 711	0.31	0.28	12.77
Tamarack Valley Energy Ltd.	6 968 400	12	14 986 834	0.46	0.47	−1.99
TAQA North Ltd.	6 646 400	13	19 912 073	0.33	0.15	129.66
ARC Resources Ltd.	5 743 600	14	60 174 910	0.10	0.06	63.13
I3 Energy Canada Ltd.	4 872 800	15	4 667 281	1.04	1.12	−7.17
Obsidian Energy Ltd.	4 773 400	16	6 821 011	0.70	0.65	8.40
Ember Resources Inc.	4 294 000	17	17 101 340	0.25	0.19	34.61
Cardinal Energy Ltd.	4 188 700	18	5 364 178	0.78	0.71	10.12
Lynx Energy ULC	3 182 100	19	7 527 543	0.42	0.28	52.52
Harvest Operations Corp.	3 059 900	20	3 275 462	0.93	0.85	10.18

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Spur Petroleum Ltd.	2 888 300	21	4 440 748	0.65	1.08	−39.90
Astara Energy Corp.	2 810 600	22	1 948 674	1.44	1.20	19.96
ORLEN Upstream Canada Ltd.	2 789 200	23	4 679 131	0.60	0.41	46.50
Strathcona Resources Ltd.	2 691 400	24	10 022 422	0.27	0.26	4.24
Ovintiv Canada ULC	2 515 600	25	20 466 073	0.12	0.17	−28.56

Combined

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	67 372 600	1	233 317 424	0.29	0.33	−11.36
Cenovus Energy Inc.	33 400 800	2	241 303 112	0.14	0.15	−8.81
Tourmaline Oil Corp.	26 491 600	3	94 890 662	0.28	0.25	9.90
Bonavista Energy Corporation	17 878 300	4	19 873 171	0.90	0.91	−0.67
Repsol Oil & Gas Canada Inc.	12 141 300	5	9 091 872	1.34	1.10	21.81
Peyto Exploration & Development Corp.	8 439 200	6	33 903 245	0.25	0.38	−33.93
Westbrick Energy Ltd.	7 981 300	7	13 571 296	0.59	0.55	6.93
Spartan Delta Corp.	7 724 900	8	21 230 140	0.36	0.38	−5.28
Paramount Resources Ltd.	7 574 400	9	22 052 166	0.34	0.19	85.11
Whitecap Resources Inc.	7 109 500	10	21 354 953	0.33	0.24	36.27
Torxen Energy Ltd.	7 041 700	11	22 659 711	0.31	0.28	12.77
Tamarack Valley Energy Ltd.	6 968 400	12	18 894 758	0.37	0.39	−5.19
TAQA North Ltd.	6 646 400	13	19 912 073	0.33	0.15	129.66
ARC Resources Ltd.	5 743 600	14	60 174 910	0.10	0.06	63.13
I3 Energy Canada Ltd.	4 872 800	15	4 667 281	1.04	1.12	−7.17
Obsidian Energy Ltd.	4 773 400	16	8 619 965	0.55	0.51	9.02
Ember Resources Inc.	4 294 000	17	17 101 340	0.25	0.19	34.61
Cardinal Energy Ltd.	4 188 700	18	5 364 178	0.78	0.71	10.12
Lynx Energy ULC	3 182 100	19	7 527 543	0.42	0.28	52.52
Harvest Operations Corp.	3 103 200	20	6 785 633	0.46	0.48	−5.05
Spur Petroleum Ltd.	2 888 300	21	8 643 077	0.33	0.53	−36.98
Astara Energy Corp.	2 810 600	22	1 948 674	1.44	1.20	19.96
ORLEN Upstream Canada Ltd.	2 789 200	23	4 679 131	0.60	0.41	46.50
Strathcona Resources Ltd.	2 725 300	24	31 468 943	0.09	0.08	15.10
Ovintiv Canada ULC	2 515 600	25	20 466 073	0.12	0.17	−28.56

Flaring

Oil Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Absolute change
Suncor Energy Inc.	30 247 000	1	98 377 247	0.3075	0.0955	0.2120
Canadian Natural Resources Limited	16 686 300	2	143 877 846	0.1160	0.0921	0.0238
Cenovus Energy Inc.	11 351 100	3	190 640 943	0.0595	0.1155	−0.0560
Imperial Oil Resources Limited	4 555 400	4	57 110 409	0.0798	0.1382	−0.0585
Greenfire Resources Operating Corporation	3 910 200	5	10 487 756	0.3728	0.3315	0.0413
Strathcona Resources Ltd.	3 270 400	6	21 446 521	0.1525	0.2190	−0.0665
Connacher Oil And Gas Limited	2 746 900	7	4 907 547	0.5597	0.5219	0.0378
ConocoPhillips Canada Resources Corp.	1 581 000	8	58 280 271	0.0271	0.0553	−0.0282
Harvest Operations Corp.	1 535 900	9	3 510 172	0.4376	0.5669	−0.1294
Athabasca Oil Corporation	452 100	10	10 881 749	0.0415	0.0913	−0.0498
Everest Canadian Resources Corp.	188 000	11	511 336	0.3677	2.4887	−2.1211
PetroChina Canada Ltd.	800	12	4 945 068	0.0002	0.2087	−0.2085

Non-Oil-Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	74 557 300	1	89 439 579	0.83	0.71	18.00
ARC Resources Ltd.	55 450 700	2	60 174 910	0.92	0.73	25.57
Spur Petroleum Ltd.	45 677 100	3	4 440 748	10.29	6.73	52.94
Baytex Energy Ltd.	38 454 000	4	4 799 161	8.01	9.29	−13.78
Tamarack Valley Energy Ltd.	34 273 700	5	14 986 834	2.29	1.17	95.81
Cenovus Energy Inc.	27 560 400	6	50 662 170	0.54	0.40	35.05
Headwater Exploration Inc.	21 669 100	7	223 229	97.07	136.56	−28.92
Murphy Oil Company Ltd.	19 155 000	8	3 667 469	5.22	4.84	7.86
Spartan Delta Corp.	19 076 400	9	21 230 140	0.90	0.70	27.65
Tourmaline Oil Corp.	15 862 900	10	94 890 662	0.17	0.15	8.43
Ovintiv Canada ULC	15 739 600	11	20 466 073	0.77	1.03	−25.19
West Lake Energy Corp.	15 678 400	12	3 258 797	4.81	4.57	5.28
North 40 Resources Ltd.	15 429 600	13	1 274 999	12.10	11.14	8.64
Canamax Energy Ltd.	14 399 200	14	982 219	14.66	3.95	271.56
Pieridae Alberta Production Ltd.	13 807 700	15	5 247 292	2.63	1.97	33.65
Paramount Resources Ltd.	12 030 500	16	22 052 166	0.55	0.37	48.80
Repsol Oil & Gas Canada Inc.	11 693 700	17	9 091 872	1.29	1.11	15.40
Surge Energy Inc.	11 473 300	18	4 972 827	2.31	2.99	−22.79
Whitecap Resources Inc.	11 177 400	19	21 354 953	0.52	0.52	−0.29
Longshore Resources Ltd.	10 218 700	20	3 825 816	2.67	1.89	41.60
Hammerhead Resources Inc.	9 655 000	21	9 847 073	0.98	0.76	29.43
NuVista Energy Ltd.	9 316 500	22	14 055 000	0.66	0.71	−6.74
Rising Star Resources Ltd.	9 275 800	23	1 763 942	5.26	7.76	−32.24
Halo Exploration Ltd.	9 192 700	24	274 360	33.51	53.18	−36.99
Enhance Energy Inc.	9 067 300	25	3 095 908	2.93	25.45	−88.49

Combined

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	91 243 600	1	233 317 424	0.39	0.33	19.94
ARC Resources Ltd.	55 450 700	2	60 174 910	0.92	0.73	25.57
Spur Petroleum Ltd.	45 677 100	3	8 643 077	5.28	3.30	60.36
Cenovus Energy Inc.	38 911 500	4	241 303 112	0.16	0.18	−11.16
Baytex Energy Ltd.	38 454 000	5	10 131 114	3.80	4.46	−14.89
Tamarack Valley Energy Ltd.	34 273 700	6	18 894 758	1.81	0.96	89.42
Suncor Energy Inc.	30 247 000	7	98 714 324	0.31	0.34	−10.09
Headwater Exploration Inc.	21 669 100	8	2 945 598	7.36	7.75	−5.13
Murphy Oil Company Ltd.	19 155 000	9	3 667 469	5.22	4.84	7.86
Spartan Delta Corp.	19 076 400	10	21 230 140	0.90	0.70	27.65
Tourmaline Oil Corp.	15 862 900	11	94 890 662	0.17	0.15	8.43
Ovintiv Canada ULC	15 739 600	12	20 466 073	0.77	1.03	−25.19
West Lake Energy Corp.	15 678 400	13	3 355 425	4.67	4.44	5.36
North 40 Resources Ltd.	15 429 600	14	1 274 999	12.10	11.14	8.64
Canamax Energy Ltd.	14 399 200	15	982 219	14.66	3.95	271.56
Pieridae Alberta Production Ltd.	13 807 700	16	5 247 292	2.63	1.97	33.65
Paramount Resources Ltd.	12 030 500	17	22 052 166	0.55	0.37	48.80
Repsol Oil & Gas Canada Inc.	11 693 700	18	9 091 872	1.29	1.11	15.40
Surge Energy Inc.	11 473 300	19	4 972 827	2.31	2.99	−22.79
Whitecap Resources Inc.	11 177 400	20	21 354 953	0.52	0.52	−0.29
Strathcona Resources Ltd.	10 495 400	21	31 468 943	0.33	0.30	12.02
Longshore Resources Ltd.	10 218 700	22	3 825 816	2.67	1.89	41.60
Hammerhead Resources Inc.	9 655 000	23	9 847 073	0.98	0.76	29.43
NuVista Energy Ltd.	9 316 500	24	14 055 000	0.66	0.71	−6.74
Rising Star Resources Ltd.	9 275 800	25	1 763 942	5.26	7.76	−32.24

Fuel Use

Oil Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Absolute change
Cenovus Energy Inc.	3 616 570 100	1	190 640 943	18.9706	20.4645	−1.4940
Canadian Natural Resources Limited	3 433 830 700	2	143 877 846	23.8663	22.5734	1.2929
Imperial Oil Resources Limited	2 357 262 300	3	57 110 409	41.2755	41.0396	0.2359
Suncor Energy Inc.	1 869 412 100	4	98 377 247	19.0025	16.6636	2.3389
ConocoPhillips Canada Resources Corp.	1 500 275 400	5	58 280 271	25.7424	27.5530	−1.8106
Strathcona Resources Ltd.	818 659 400	6	21 446 521	38.1721	32.6469	5.5252
MEG Energy Corp.	672 538 700	7	38 049 410	17.6754	16.3762	1.2992
Athabasca Oil Corporation	356 462 000	8	10 881 749	32.7578	33.7438	−0.9861
CNOOC Petroleum North America ULC	337 923 300	9	16 623 768	20.3277	16.7366	3.5912
Greenfire Resources Operating Corporation	321 958 800	10	10 487 756	30.6985	31.3468	−0.6482
PetroChina Canada Ltd.	249 510 600	11	4 945 068	50.4565	55.7737	−5.3172
Connacher Oil And Gas Limited	193 021 200	12	4 907 547	39.3315	41.0490	−1.7175
Harvest Operations Corp.	102 519 600	13	3 510 172	29.2064	30.4297	−1.2232
Everest Canadian Resources Corp.	74 638 700	14	511 336	145.9679	535.9393	−389.9714
Ipc Canada Ltd.	8 937 700	15	459 874	19.4351	42.1536	−22.7185

Non-Oil-Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	1 462 049 400	1	89 439 579	16.35	16.89	−3.21
Tourmaline Oil Corp.	501 713 800	2	94 890 662	5.29	5.20	1.72
ARC Resources Ltd.	428 954 900	3	60 174 910	7.13	7.19	−0.83
Cenovus Energy Inc.	379 962 200	4	50 662 170	7.50	7.91	−5.15
Pieridae Alberta Production Ltd.	341 590 800	5	5 247 292	65.10	71.60	−9.08
Ember Resources Inc.	221 600 400	6	17 101 340	12.96	12.52	3.48
Peyto Exploration & Development Corp.	188 234 800	7	33 903 245	5.55	5.78	−3.95
Torxen Energy Ltd.	185 176 400	8	22 659 711	8.17	7.74	5.58
Bonavista Energy Corporation	177 824 800	9	19 873 171	8.95	9.16	−2.33
TAQA North Ltd.	149 785 500	10	19 912 073	7.52	9.11	−17.45
Baytex Energy Ltd.	148 224 700	11	4 799 161	30.89	31.45	−1.79
Repsol Oil & Gas Canada Inc.	132 963 300	12	9 091 872	14.62	13.30	10.00
Birchcliff Energy Ltd.	129 813 000	13	26 722 195	4.86	4.45	9.16
Whitecap Resources Inc.	128 932 600	14	21 354 953	6.04	5.72	5.62
Spartan Delta Corp.	115 698 300	15	21 230 140	5.45	5.27	3.36
Advantage Energy Ltd.	110 591 100	16	19 029 554	5.81	6.02	−3.51
Pine Cliff Energy Ltd.	106 516 800	17	7 003 689	15.21	14.43	5.36
Lynx Energy ULC	96 671 000	18	7 527 543	12.84	13.16	−2.44
Ipc Canada Ltd.	94 994 800	19	10 490 798	9.06	9.23	−1.90
Paramount Resources Ltd.	87 366 000	20	22 052 166	3.96	5.57	−28.89
Ovintiv Canada ULC	87 281 200	21	20 466 073	4.26	5.46	−21.86
NuVista Energy Ltd.	83 943 600	22	14 055 000	5.97	6.36	−6.12
Tamarack Valley Energy Ltd.	74 438 600	23	14 986 834	4.97	6.08	−18.32
Obsidian Energy Ltd.	71 216 500	24	6 821 011	10.44	9.22	13.19
Hammerhead Resources Inc.	68 945 300	25	9 847 073	7.00	6.06	15.62

Combined

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	4 895 880 100	1	233 317 424	20.98	20.41	2.82
Cenovus Energy Inc.	3 996 532 300	2	241 303 112	16.56	17.58	−5.79
Imperial Oil Resources Limited	2 357 262 300	3	59 816 273	39.41	39.18	0.59
Suncor Energy Inc.	1 869 412 100	4	98 714 324	18.94	19.42	−2.49
ConocoPhillips Canada Resources Corp.	1 500 275 400	5	58 741 366	25.54	27.35	−6.63
Strathcona Resources Ltd.	856 828 900	6	31 468 943	27.23	24.29	12.11
MEG Energy Corp.	672 539 000	7	41 758 534	16.11	15.56	3.48
Tourmaline Oil Corp.	501 713 800	8	94 890 662	5.29	5.20	1.72
ARC Resources Ltd.	428 954 900	9	60 174 910	7.13	7.19	−0.83
Athabasca Oil Corporation	391 724 800	10	13 185 137	29.71	29.89	−0.61
Pieridae Alberta Production Ltd.	341 590 800	11	5 247 292	65.10	71.60	−9.08
CNOOC Petroleum North America ULC	337 923 300	12	16 769 031	20.15	16.92	19.10
Greenfire Resources Operating Corporation	321 958 800	13	10 632 568	30.28	31.04	−2.46
PetroChina Canada Ltd.	249 510 600	14	8 429 900	29.60	30.09	−1.65
Ember Resources Inc.	221 600 400	15	17 101 340	12.96	12.52	3.48
Connacher Oil And Gas Limited	193 021 200	16	5 085 059	37.96	40.37	−5.98
Peyto Exploration & Development Corp.	188 234 800	17	33 903 245	5.55	5.78	−3.95
Torxen Energy Ltd.	185 176 400	18	22 659 711	8.17	7.74	5.58
Bonavista Energy Corporation	177 824 800	19	19 873 171	8.95	9.16	−2.33
TAQA North Ltd.	149 785 500	20	19 912 073	7.52	9.11	−17.45
Baytex Energy Ltd.	148 224 700	21	10 131 114	14.63	15.09	−3.06
Harvest Operations Corp.	143 447 500	22	6 785 633	21.14	19.64	7.62
Repsol Oil & Gas Canada Inc.	132 963 300	23	9 091 872	14.62	13.30	10.00
Birchcliff Energy Ltd.	129 813 000	24	26 722 195	4.86	4.45	9.16
Whitecap Resources Inc.	128 932 600	25	21 354 953	6.04	5.72	5.62

Solution Gas Conservation

The AER has ranked companies based on volumes from operated crude oil and crude bitumen batteries of (1) solution gas production, (2) vented solution gas, and (3) GHG emissions from solution gas flaring and venting.

In this section, all crude oil and crude bitumen batteries have been included except for batteries that had an experimental well reporting fluid production in a month. The information on experimental wells remains confidential. This exclusion of data from experimental wells is the reason for variances between the values in the preceding sections of this report and the values contained in the ranking tables in this section. It is possible for an operator to flare or vent a significant volume of solution gas due to the magnitude of the company's operations and still have a high percentage of gas conserved.

Greenhouse gas (GHG) emissions are expressed in tonnes of carbon dioxide equivalent (tCO_2e).[1] The GHG emission factors used to quantify emissions from flaring and venting vary depending on the type of production as set out below:[2]

- Gas production:
  - Vented gas GHG emission factor = 15.4 tCO_2e per thousand cubic metres (10^3 m^3) of gas
  - Flared gas GHG emission factor[3] = 2.7 tCO_2e per 10^3 m^3 of gas
- Crude oil:
  - Vented gas GHG emission factor = 12.5 tCO_2e per thousand cubic metres (10^3 m^3) of gas
  - Flared gas GHG emission factor = 2.9 tCO_2e per 10^3 m^3 of gas
- Crude bitumen
  - Vented gas GHG emission factor = 16.3 tCO_2e per 10^3 m^3 of gas
  - Flared gas GHG emission factor = 2.6 tCO_2e per 10^3 m^3 of gas

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[1] tCO_2e is a way of expressing the global warming potential (GWP) of a greenhouse gas relative to carbon dioxide. Since every greenhouse gas has a different capacity to absorb and trap heat in the atmosphere, carbon dioxide is used as a frame of reference for easy comparison. The GWP of other gases can be calculated and converted into the equivalent amount of carbon dioxide. For example, one tonne of methane, which is a major component in venting, has 25 times more GWP than carbon dioxide over 100 years (Government of Alberta, *Carbon Offset Emission Factors Handbook* [2015], https://open.alberta.ca/publications/2368-9528, table 1).

[2] Speciation profiles for gas, oil and bitumen production can be found within Table 2 and Table 4 in *2018 Alberta Upstream Oil & Gas Methane Emissions Inventory and Methodology* report by Clearstone Engineering Ltd., April 22, 2019, https://static.aer.ca/prd/documents/ab-uog-emissions-inventory-methodology.pdf

[3] Flaring is assumed to have a 95 per cent conversion efficiency.

Company	Volume emitted ($MtCO_2e$)	Rank	Flared (10^6 m^3)	Vented (10^6 m^3)
Canadian Natural Resources Limited	1.12	1	52.37	24.99
Deltastream Energy Corporation	0.95	2	65.26	0.54
Spur Petroleum Ltd.	0.70	3	45.68	2.53
Tamarack Valley Energy Ltd.	0.56	4	32.95	5.78
Suncor Energy Inc.	0.44	5	30.25	0.47
Cenovus Energy Inc.	0.42	6	16.98	12.04
Headwater Exploration Inc.	0.32	7	21.57	0.32
North 40 Resources Ltd.	0.25	8	15.36	1.85
West Lake Energy Corp.	0.24	9	15.57	1.42
Spartan Delta Corp.	0.22	10	14.27	1.32
Canamax Energy Ltd.	0.21	11	14.04	0.68
Murphy Oil Company Ltd.	0.19	12	13.22	0.28
Whitecap Resources Inc.	0.18	13	6.99	5.56
Surge Energy Inc.	0.18	14	10.75	1.61
Baytex Energy Ltd.	0.17	15	10.94	0.81
Longshore Resources Ltd.	0.16	16	10.04	0.99
Obsidian Energy Ltd.	0.15	17	6.57	3.79
Cardinal Energy Ltd.	0.15	18	6.39	3.95
Karve Energy Inc.	0.13	19	7.16	2.09
Halo Exploration Ltd.	0.13	20	9.19	0.02
Enhance Energy Inc.	0.13	21	9.02	0.07
Paramount Resources Ltd.	0.10	22	6.46	0.51
Crescent Point Energy Corp.	0.09	23	6.01	0.40
Tourmaline Oil Corp.	0.09	24	5.19	1.13
Ipc Canada Ltd.	0.09	25	5.28	0.91

Total Emissions

The following table ranks operators based on the total of all emissions reported to OneStop.

Company	Volume emitted ($MtCO_2e$)	Rank
Canadian Natural Resources Limited	1.22	1
Cenovus Energy Inc.	1.09	2
Long Run Exploration Ltd.	0.98	3
Tourmaline Oil Corp.	0.40	4
AlphaBow Energy Ltd.	0.39	5
TAQA North Ltd.	0.29	6
Bonavista Energy Corporation	0.19	7
New Star Energy Ltd.	0.15	8
Westbrick Energy Ltd.	0.15	9
Whitecap Resources Inc.	0.13	10
Peyto Exploration & Development Corp.	0.13	11
Paramount Resources Ltd.	0.11	12
Torxen Energy Ltd.	0.10	13
Spartan Delta Corp.	0.10	14
ARC Resources Ltd.	0.09	15
Tamarack Valley Energy Ltd.	0.09	16
Cardinal Energy Ltd.	0.08	17
Repsol Oil & Gas Canada Inc.	0.07	18
Astara Energy Corp.	0.06	19
Vermilion Energy Inc.	0.06	20
Obsidian Energy Ltd.	0.06	21
Journey Energy Inc.	0.06	22
Ridgeback Resources Inc.	0.06	23
Spur Petroleum Ltd.	0.06	24
Keyera Energy Ltd.	0.05	25