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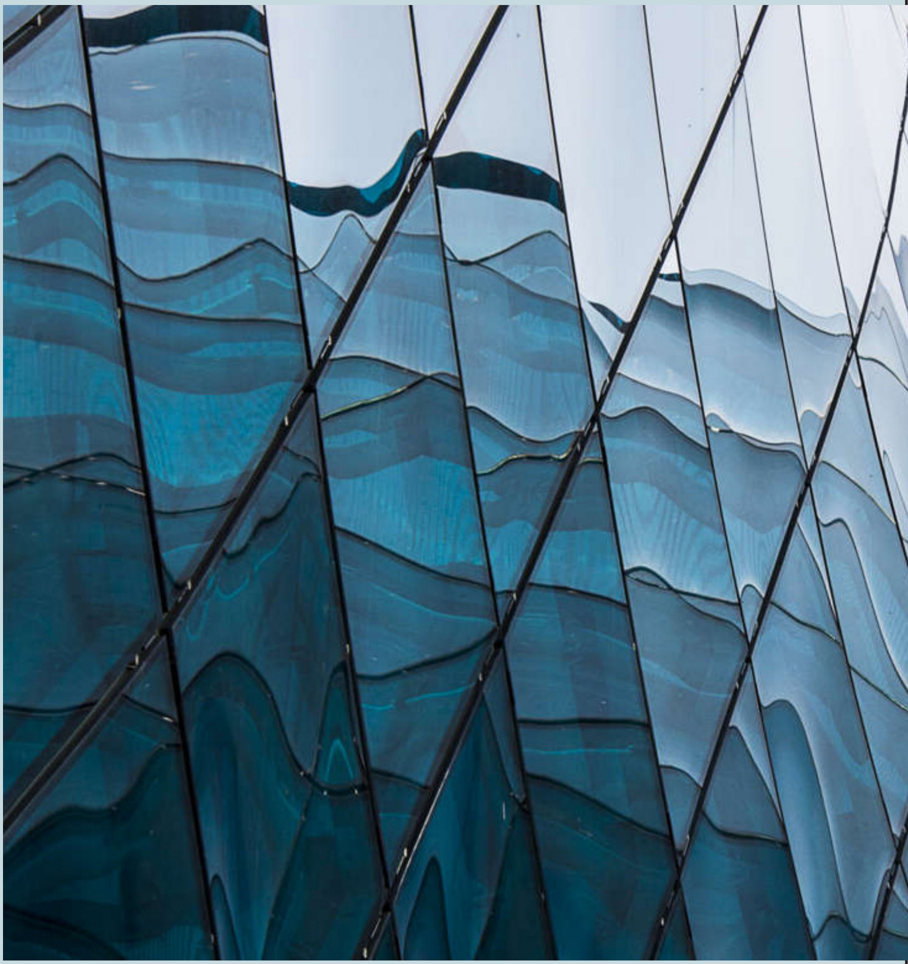
Greenhouse gas intensity of western Canadian condensate

Ishita Aggarwal, Research Analyst, Center of Emissions Excellence, Commodity Insights

Kevin Birn, Head, Center of Emissions Excellence, Commodity Insights



This report also benefited from contributions from Heather Jones of the Center of Emissions Excellence, Bill Rawlusyk of Downstream Consulting, Jordan Woloschuk of Downstream Consulting and Celina Hwang of North American Crude Oil Markets.

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Key implications

The greenhouse gas (GHG) intensity of the Canadian oil sands has been extensively modeled by S&P Global Commodity Insights. However, natural gas condensate—the diluent of choice in the oil sands—has remained a source of uncertainty. With bitumen blends accounting for over half of oil sands supply and as much as a third of a barrel of a blend being composed of condensate, understanding the GHG intensity of condensate is critical to understanding the GHG intensity of marketable heavy oil from western Canada. This report estimates the average GHG intensity of condensate used for heavy oil blending in western Canada.

- **Meeting western Canadian heavy oil diluent blending demand required over 700,000 b/d of condensate in 2021.** In 2021, total diluent demanded for blending was approximately 800,000 b/d. Condensate was the largest source of diluent, accounting for about 90% of all diluent.
- **The diversity of sources of supply and complexity of the western Canadian condensate market make it challenging to assess.** In western Canada, condensate is supplied from multiple sources that can be grouped into four main categories: domestic production, condensate imported from the United States, recycled condensate originating in western Canada, and recycled condensate originating from the US. Condensate is also produced through different processes, which adds further complexity in the supply chain.
- **The average GHG intensity of western Canadian condensate is estimated to be 35 kilograms of carbon dioxide equivalent per barrel (kgCO_2e/bbl) in 2021.** The GHG intensity of different sources of supply varies significantly, from 8 kgCO_2e/bbl to 58 kgCO_2e/bbl. The intensity is also dynamic, being sensitive to changes in sources of supply, such as share of recycling, as well as changes in upstream oil and gas operations.

Greenhouse gas intensity of western Canadian condensate

Although bitumen is the name of the crude oil extracted from oil sands operations, it is not what is marketed. There are two general categories of crude oil that are marketed from the oil sands. Synthetic crude oil (SCO) is principally the product of legacy oil sands mining operations that have integrated heavy oil processing units typically found in downstream refineries. Known as upgraders, these units convert extra-heavy crude oil or bitumen found in the oil sands into a lower-density or lighter SCO. The other major product is diluted bitumen (dilbit). Bitumen in its natural state is too dense and viscous to meet pipeline specifications. In the absence of upgrading, operations dilute bitumen with lighter hydrocarbons. The upgrading or blending of bitumen with diluents means that the volume and properties of marketed products are different than raw production.

As oil sands output grew, its demand for diluent also increased as smaller thermal operations and newer mines opted to forgo the significant capital cost of upgrading. Some heavier conventional oil production in western Canada also requires blending. In 2021, S&P Global Commodity Insights estimates western Canadian heavy oil blending requirements topped 700,000 b/d of diluent. Although there have been a variety of diluents and diluent cocktails, the use of natural gas condensate accounts for over 90% of all diluents used in western Canada. In turn, heavy oil diluent demand has resulted in a price premium for condensate in western Canada and helped stimulate unconventional drilling activity that has sought out regions in emerging unconventional fields capable of yielding a greater share of condensate.

Understanding diluent and condensate is not only important for understanding the western Canadian oil market, unconventional activity, and oil sands economics (because diluents represent a significant cost) but also the GHG intensity of oil sands and heavy conventional crude oil marketed products.[1]

Consistent with life-cycle methodology, and as documented in *The Right Measure*, upstream GHG intensity of fuels used in oil and gas production should be considered.[2] In the oil sands, this includes upstream natural gas production, production of the diesel used by the mobile mine fleet, and diluents used in blending. There are several internal and external studies that have estimated the greenhouse gas (GHG) intensity of western Canadian natural gas.[3] Diesel fuel is produced locally from integrated oil sands mines and is captured in our estimates of oil sands emissions. Condensate, however, remains a source of uncertainty and to date has been included in our prior analysis using a constant factor.[4]

Condensate is particularly challenging because the western Canadian condensate supply chain is complex and not well understood. Most condensate is sourced domestically in western Canada, but US imports are also required to meet regional demand. There is also evidence that some condensate is recycled—separated by the refineries and a few other facilities for economic reasons. These intricacies matter and make determining the GHG intensity of condensate challenging and very complex.

This report explores the challenges and complexity of estimating the various sources of condensate supply and the implications for the average GHG intensity of condensate used for heavy oil blending in western Canada.

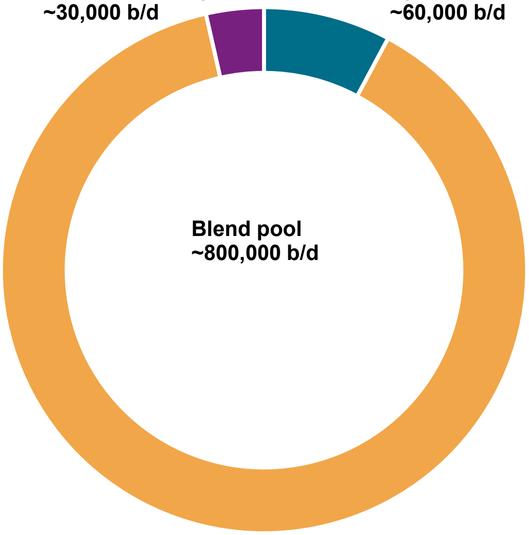
Understanding western Canadian diluent demand

In 2021 , two-fifths of oil sands bitumen production was upgraded leaving the rest—the majority—to be diluted. Although there are various diluents used in the oil sands, natural gas condensates are preferred because of their lower density. The lower the density of the diluent, the less of it is required per barrel of bitumen to meet pipeline specifications. In 2021, nearly 90% of all diluents used in the oil sands were condensate (see Figure 1). The remaining diluents—conventional light oil and SCO—make up a relatively small share, with SCO in particular being extensively modeled and published on by Commodity Insights.

The typical oil sands dilbit is, on average, a ratio of 28% condensate to 72% bitumen. However, the ratio of condensate to bitumen is not constant across oil sands operations or throughout the year. The quality

Figure 1

Oil sands blend pool (2021)



Data compiled Jan. 12, 2023.
Source: S&P Global Commodity Insights.

1. In addition to oil sands, some heavy conventional crude in western Canada also requires diluent blending to meet pipeline transportation requirements.

2. See the Commodity Insights Strategic Report *The Right Measure: A landmark study of life-cycle GHG intensity of crude oil.*

3. See *LNG Production in British Columbia: Greenhouse Gas Emissions Assessment and Benchmarking* or *Greenhouse Gas Emissions of Western Canadian Natural Gas: Proposed Emissions Tracking for Life Cycle Modeling.*

4. For more information, refer to Table B-1 in *The trajectory of oil sands GHG emissions: 2009–35: Appendix B, Detailed method*, April 2021.

of bitumen and condensate can vary, and seasonal temperatures can affect blending requirements. On an annual average basis (which includes seasonal variation), the ratio of diluent to bitumen and heavy oil on a barrel of marketed product basis (per barrel of blended marketable heavy oil) ranges from approximately 17% to over 30% in some regions.[5] Some conventional heavy oil also requires blending in western Canada, which requires lower levels of blending.

What is condensate?

Asking what condensate is may seem like a silly question, but the definition of condensate can vary as it encompasses a range of hydrocarbon molecules.

At the simplest level, condensate is a coproduct of oil and gas extraction.[6] In oil and gas extraction, an array of hydrocarbons can be recovered to the surface. This ranges from methane or natural gas on the lightest end, which is gaseous at atmospheric pressure, to heavier, more complex hydrocarbons that are liquid at atmospheric pressure and are labeled crude oil. Hydrocarbons near their boiling point at atmospheric pressure or that are gases at atmospheric pressure and liquids at higher pressure are known at natural gas liquids (NGLs). Examples include ethane, propane, butane, isobutane, and pentane and heavier. The precise definition of what is considered condensate can vary. In the western Canada, condensate is defined as pentane and heavier (pentane plus) NGLs through to ultralight crude oil with an API gravity greater than 60 degrees. This definition is broad enough that condensate can include naphtha as well as natural gasoline which is imported from the United States. Generally speaking, the lighter the condensate, the more desirable to the upstream operator because less of it is required to meet blending requirements.

Upon extraction, condensate is entrained in a spectrum of hydrocarbon molecules. Condensate must be separated from oil and gas production streams through different processes. Figure 2 provides a visual illustration of the three processes where condensate is separated from oil and gas production streams. These processes are described below.

- **Atmospheric separation.** A pressure difference can exist between an oil and gas reservoir and the surface or atmosphere. As recovered volumes are depressurized on the surface, lighter and heavier hydrocarbons will separate. Some condensates can be isolated at this stage, which is known as field or lease condensate.
  The fraction of condensate separated this way is typically quite small (e.g., approximately one-fifth of Canadian production). In more remote dispersed areas of activity (such as in the Canadian Montney) condensate separated in the field may be trucked to an NGL pipeline for transport to market. In areas of greater density of activity—like in the Permian—field/lease condensate may be able to access gathering pipelines from the wellhead.
- **Gas processing.** Not all condensate separates from atmospheric pressure changes in the field. Some condensate remains entrained in an interphasic (gas/liquid) state with other NGLs as part of the produced gas stream (also known as wet gas). This material is typically piped a short distance by gathering pipeline to a natural gas processing plant. These plants separate methane from the NGL mix. About three-fifths of Canadian-produced condensate is isolated in this process. Gas processing plants typically have access to long-distance NGL transportation pipelines that can

5. On a per barrel of bitumen and heavy oil basis, 33–42% condensate would be required per barrel of heavy oil.

6. Naphtha is similar to condensate and is a coproduct of the refining process. Some naphtha is believed to make its way into the Alberta diluent pool but in relatively limited volumes. Naphtha is also very difficult to distinguish from condensate in western Canada, as condensate can encompass an API gravity range from 54 to 83, which overlaps with naphtha.

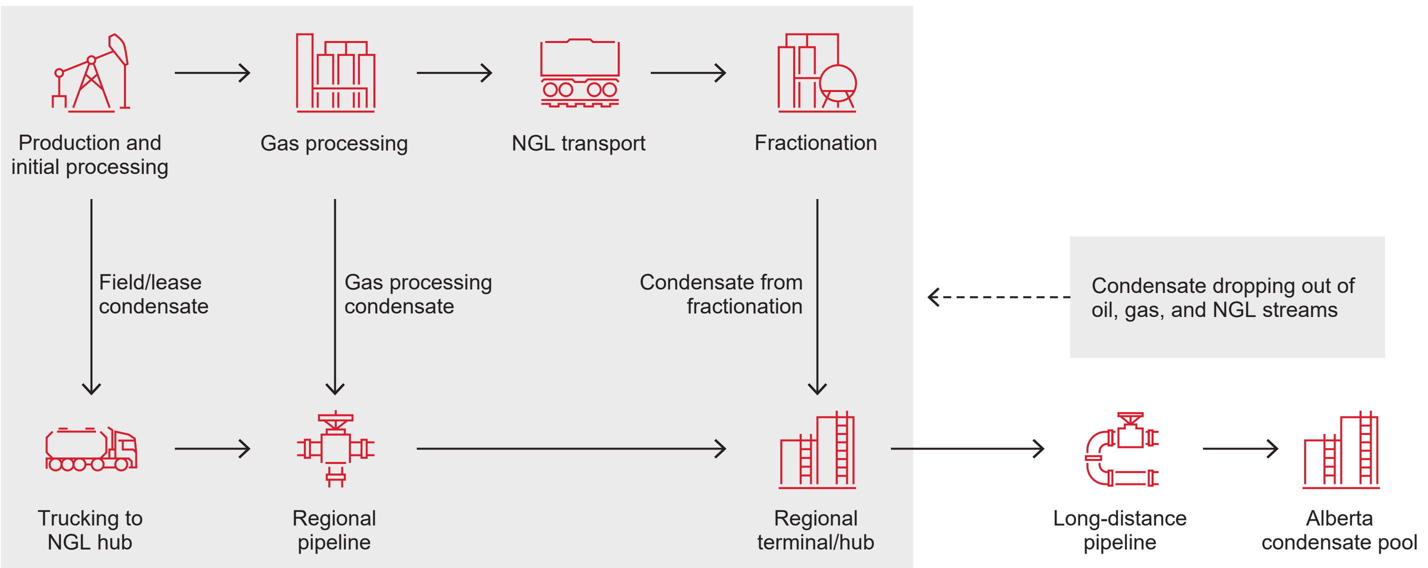
move the resulting NGL mix as well as some of the now-isolated liquid streams onto market or for further processing.

- **Fractionation.** Not all condensate falls out of the gas processing plant, and some remains entrained in the NGL stream coming out of gas processing. This material is transported from the gas processing plant to fractionation facilities. As the name suggests, fractionators are used to isolate the individual fractions within the NGL stream. Examples include propane, butane, and pentane, among others. Fractionation facilities are typically located near a market hub or major long-distance pipeline transportation systems and produce a very light, high-quality natural gasoline. Nearly one-fifth of Canadian-produced condensate is retrieved from the fractionation facilities and 100% of US-produced condensate is retrieved through this route.

Once condensate is separated and transported to a gathering area or terminal—such as a market hub—it will typically have access to further larger, and longer-distance, transportation options to take it to key demand centers.

Figure 2

Pathways for condensate C5+ production



As of March 10, 2023.
Source: S&P Global Commodity Insights.

Sourcing condensate

Meeting nearly 700,000 b/d of western Canadian heavy oil condensate blending demand—equivalent to the oil output of a country like Belgium—has resulted in a complex logistical system to supply condensate to heavy oil producers in Alberta. The aggregate condensate supply system is known colloquially as the Alberta condensate pool. Physically, the pool is a collection of terminals and storage facilities. These storage areas are spread out across Alberta, with the most significant being near Fort Saskatchewan. Other notable locations include Hardisty and Lloydminster. Together these facilities, coupled with a regional pipeline system, allow suppliers to meet producers' demand.

The pool is supplied from multiple sources each with a unique pathway and thus each potentially with a different GHG intensity. This increases the complexity of estimating the GHG intensity of condensate in western Canada.

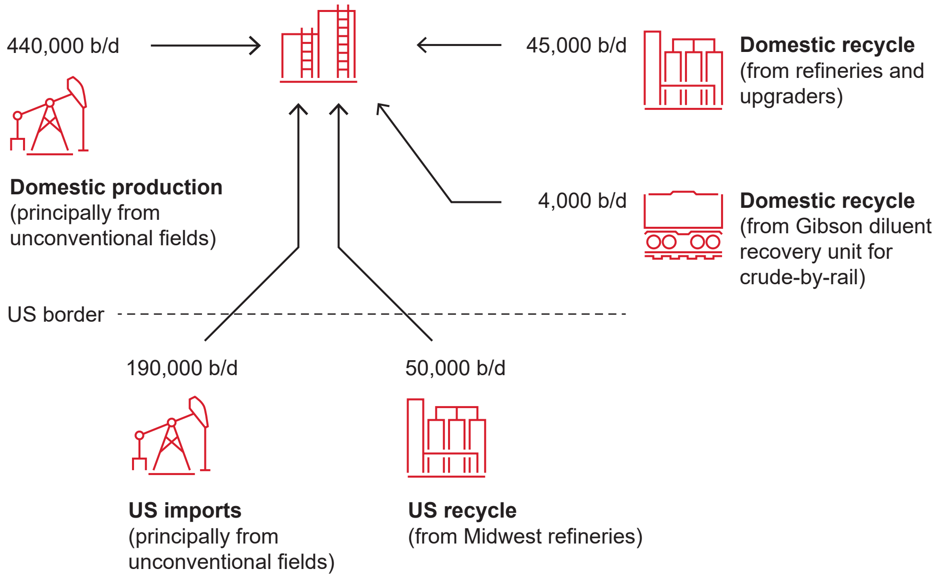
At the simplest level, there are two types of condensate supply in western Canada: produced condensate and recycled condensate. Produced condensate easily dominates the pool on a volumetric basis (see Figure 3). However, the sources of supply are more complex—there is both produced condensate and recycled condensate being sourced from both Canada and the United States. What follows is a brief description of each of these major sources of supply.

- **Produced condensate.** Produced condensate accounted for 87% of all western Canadian condensate in 2021. Western Canadian condensate demand has long outstripped regional production, resulting in imports from the United States. To incentivize the importation of US condensate, the price of condensate obtains a price premium in the Alberta market. This price premium incentivizes not only the importation of US condensate but also upstream activity in western Canada to target liquids-rich plays, which can yield a greater share of condensate.

- **Canadian-produced condensate.** About 60% of condensate used in western Canada is sourced from western Canadian unconventional activity, the most significant being the Montney. Condensate from the Cardium, Spirit River, and Duvernay formations is also included in our analysis. Over the past decade, domestic condensate supply from unconventional production grew over 200%, from about 140,000 b/d in 2012 to over 440,000 b/d in 2021.

Figure 3

Estimated sources of western Canadian condensate pool (2021)



As of March 10, 2023.
Source: S&P Global Commodity Insights.

- **US-produced (and imported) condensate.** Commodity Insights estimates that approximately 240,000 b/d of condensate imports were required to meet demand in 2021. These imports come from the United States. Of this, about 190,000 b/d were estimated to be produced condensate. US imports are delivered from the US Midwest via two dedicated condensate import pipelines—Cochin and Southern Lights. It is difficult to pinpoint the precise area where US condensate imports originate. Certainly, condensate production occurs in numerous US regions, with some of the most notable being the Permian in West Texas, the Bakken in North Dakota, and the Marcellus in Pennsylvania. However, given the scale and dominance, as well as pipeline connectivity to western Canada, the Permian Basin (inclusive of the Eagle Ford play) was assumed to be the most likely source. From a routing and GHG intensity perspective the Permian is also the farthest from Canada, which also makes it a conservative choice.

Recycled condensate. Diluent represents a cost for western Canadian heavy oil producers—the cost to acquire it and then the cost to ship it entrained as dilbit in a pipeline. For each barrel of bitumen, approximately 40% more diluent must be shipped along with it. The regional price premium for diluent adds further incentive to develop alternative export strategies that require less diluent or to find processes that can recycle diluent. Some facilities, such as refineries, have the ability to separate the diluent from the dilbit and market it back to the Alberta pool. Information on what precisely is making its way from regional refineries into the condensate pool is not always clear—for example, refineries can produce naphtha with similar properties to condensate that could also be marketed into the pool. We estimate 13% of total condensate demand was met by recycled condensate in 2021—up from 10% in 2019. Although the volume remains relatively small, it has been increasing. Information on recycling is quite limited and is a source of uncertainty in our analysis.

- **US recycled condensate.** There is evidence that a refinery or refineries in the US Midwest have been separating condensate from Canadian heavy oil exports and marketing it back to western Canada via pipeline since 2017. In 2021, we estimate about 50,000 b/d was recycled from the US Midwest.
- **Canadian recycled condensate.** We estimate that in 2021 about 46,000 b/d was being recycled though processes in western Canada. This was composed of recycle from regional refineries that we could substantiate to some degree as well as recycle from a crude-by-rail terminal with a diluent recovery terminal. These are discussed separately.
  - Various investor relations reports as well as some of our own market intelligence indicate that some western Canadian refineries are separating the ultralight ends from Canadian heavy oil blends and recycling it back into the market. In 2021, we estimated domestic refinery recycle was about 42,000 b/d. It is also possible that at times some domestic refineries may also be marketing naphtha into the Alberta pool that we were not able to account for due to insufficient information. Naphtha is an ultralight crude oil with properties similar to condensate.[7] This is a source of uncertainty in our estimate of the Alberta pool; however, the volume is likely limited, reducing the potential error.
  - In 2021, a purpose-built diluent recovery unit (DRU) commenced operations at the Gibson crude-by-rail terminal near Hardisty, Alberta. As the name suggests, a DRU is designed to remove diluent from dilbit to enable the export of bitumen by railcar with little to no condensate. The specifications of crude oil properties required for crude by rail are different than for pipelines, where the crude is required to flow under specific temperatures and pressure. The DRU commenced operations in mid-2021 and on an annual average basis recycled about 4,000 b/d. Capacity is much greater and has since increased to 11,000 b/d in 2022.

7. In some instances, it was not entirely clear whether reported volumes were condensate or if naphtha was being produced and marketed as condensate. Naphtha is an ultralight crude oil with properties similar to condensate. However, our estimate of the volume of refinery condensate being recycled was consistent with the estimated volume of condensate that could be separated from the volume of dilbit being processed.

Estimating the greenhouse gas intensity of the western Canadian condensate pool

Life-cycle analysis requires estimating emissions associated with each stage of life of a product from origination to end use or destination. The greenhouse gases estimated include carbon dioxide (CO_2) along with any methane (CH_4) and nitrous oxide (N_2O) emissions converted to CO_2 equivalents. Our approach was consistent with the detailed methodology published in *The Right Measure*.[8] The box "Quantifying life-cycle stages: Methodology used by Commodity Insights" provides background on the method used in this analysis, with further detail included in the Appendix.

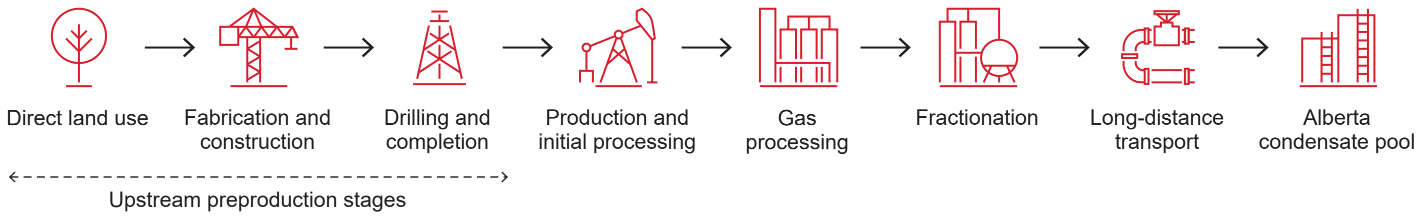
The results of this analysis are intended to improve the estimate of the GHG intensity of all marketable heavy, sour crude oil blends in western Canada. To obtain estimates of blended marketable heavy oil, additional transport from the pool to the field would need to be considered.

There are numerous pathways different sources of supply could take to meet condensate demand in western Canada. Simplifications were made to limit the total number of pathways modeled. In total, 19 distinct pathways were included (see Table A-6 in the Appendix). The 19 pathways can be generalized into four categories: Canadian production, US production, Canadian recycle, and US recycle.

Figure 4 provides a general view of the life-cycle stages included in this analysis. The figure most closely matches the pathway of produced condensate. The source/point of origination includes any activities undertaken to create the product, the transport to any regional market hub, the various stages of separation, and finally long-distance transport to the Western Canadian condensate pool. What follows are additional details on the two produced streams of condensate (from the United States and Canada) and the two recycled streams of condensate (from the United States and Canada).

Figure 4

Life-cycle stages for western Canadian condensate



As of Mar. 10, 2023.
Source: S&P Global Commodity Insights.

8. See the Commodity Insights Strategic Report *The Right Measure: A landmark study of life-cycle GHG intensity of crude oil.*

Produced condensate pathways

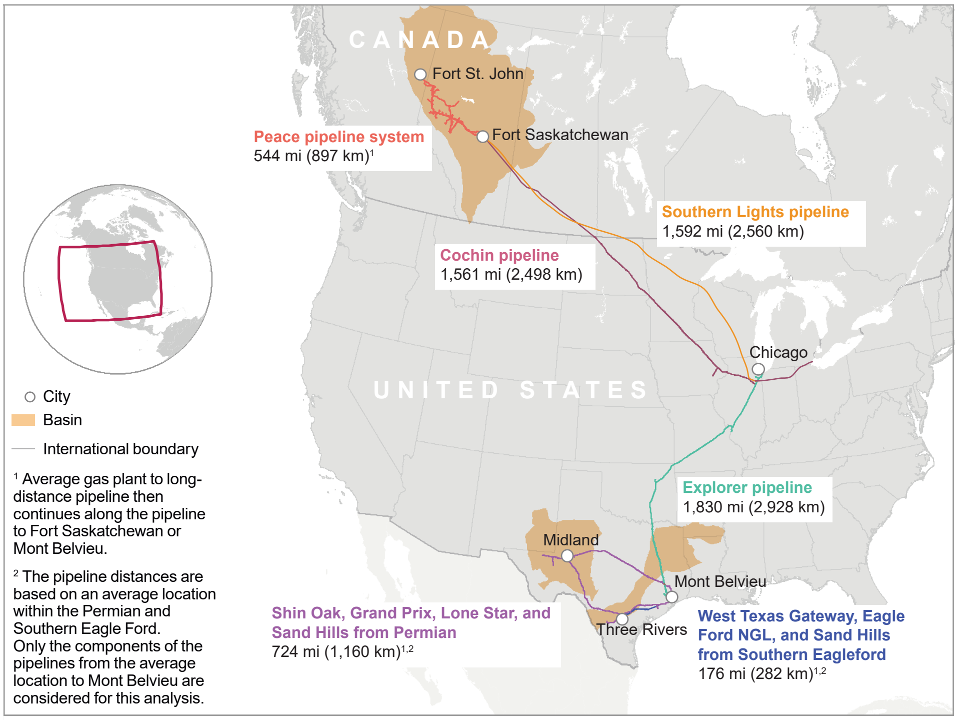
The life-cycle stages are similar for condensate produced in Canada and the United States, despite different origination and transportation distances. As previously described, condensate is separated at various processes along the natural gas value chain: atmospheric separation, gas processing, and fractionation (see Figure 2). This creates distinct pathways from the wellhead to market for each portion of the condensate fractions separated at each process. Emissions associated with each separation process and each individual pathway from separation to market hub were individually accounted for (three pathways from wellhead to market hub) with each distinct path being volume weighted into the intensity at the market hub. For Canada, this included trucking of lease condensate (the product of atmospheric separation) to larger gathering and longer-distance NGL pipelines. The remaining NGL mix is first sent to a gas processing facility where condensate is retrieved through the separation after stabilization. The leftover NGL mix is sent to a fractionation unit where the remaining condensate is fractionated out and sent to a market hub. In the United States, all the condensate and NGL mix is transported to the fractionation facilities via regional pipelines. The condensate obtained from the fractionation units is transported to the market hub in Alberta through long-distance pipelines.

Produced condensate is sourced from different geographies and results in different transportation routes. Simplifications were made to limit the number of potential routes. Figure 5 is a visual depiction of the resulting pathway modeled for Canadian and US produced condensate. The major difference between the two pathways is the transportation distance.

For US condensate, the Permian and Eagle Ford were identified as the most likely source of supply. It was assumed that condensate separated due to atmospheric changes in the field (field condensate) and gas processing was shipped with the remaining NGL mix along two potential pipeline routes to the market hub near Mont Belvieu to be fractionated. The route from the Permian consists of the Shin Oak, Grand Prix, and Sand Hills pipelines, while the route from southern Eagle Ford consists of the West Texas Gateway, Eagle Ford NGL, and Sand Hills pipelines. The distances for these pipelines are based on average location within the basins to Mont Belvieu and are not representative of actual pipeline lengths. A volumetric weighted average of the estimated flows of the two routes was used to estimate the average transportation emissions from production to the regional market hub. The resulting condensate from fractionation was assumed to be transported north from the Mont Belvieu hub via the Explorer pipeline and then onto the Cochin

Figure 5

Canadian and US produced condensate pathways



Data compiled March 23, 2023.
Source: S&P Global Commodity Insights midstream content (EDIN): 2008900.

and Southern Lights pipelines in Illinois (a volumetric weighted average between the pipelines was used to estimate the average transportation emissions for condensate delivered into Fort Saskatchewan area).

In Canada, it was assumed that field condensate and condensate separated from gas processing would be shipped with the remaining NGL mix via the Peace pipeline to Fort Saskatchewan, where the remaining NGL mix would be fractionated. The estimated transportation distance for Canadian produced NGLs/condensate from the various producing regions to the Peace pipeline was estimated using a volumetric weighted average of production from each play. A weighted-average distance from key gas processing plants in the producing region was also estimated and added to the total pipeline distance. Unlike in the United States, we assumed one-third of total lease condensate was trucked as opposed to transported via pipeline from the wellhead to the Peace pipeline. Trucking is a more GHG-intensive mode of transport than pipeline transport. Only the direct distance of the Peace pipeline was included in our estimate of the transport of NGLs/condensate from the producing region to Fort Saskatchewan. In Fort Saskatchewan, we assumed that the various sources of condensate supply are blended before being transported to the field for blending and dilution of heavier oil. In reality there may be instances where specific condensate streams could be making their way to the field isolated. This was not data we were able to attain.

Recycled condensate pathway. Recycled condensate takes a different pathway. The origination of recycled condensate was considered to be where it is separated from a heavy oil blend or dilbit at a refinery, upgrader, or DRU. Otherwise, double counting of transportation could occur. Condensate recycled from the United States was assumed to be transported from the Chicago area via the Southern Lights and Cochin pipelines. Condensate recycled in Canada, however, occurs in relative proximity to the condensate pool or heavy oil operations, and no transportation was considered.[9] For this analysis, the condensate pool refers to total amount of condensate being sourced and produced to be used for heavy oil blending in western Canada, rather than the physical location. As a result, all recycled condensate produced locally was assumed to be used remotely, whereas all delivered condensate (Canadian produced, US produced, and US recycled) was assumed to be delivered to the market hub in Fort Saskatchewan. Figure 6 provides a general illustration of the life-cycle stages for the recycled condensate.

Figure 6

Life-cycle stages for recycled condensate to western Canada

As of Mar. 10, 2023.
Source: S&P Global Commodity Insights.

9. This is a potential source of underestimation, but the alternative of transporting all the recycled condensate to Fort Saskatchewan would most likely be a source of overestimation. Moreover, in many facilities where there is evidence of recycling there are condensate use cases. For example, there is documented recycling occurring at the Lloydminster refinery and asphalt complex, which is approximate to regional heavy oil producing facilities that require diluent. Similarly, the DRU in Hardisty produces condensate that could be used within the Hardisty terminal to top up blending requirements for specific pipelines.

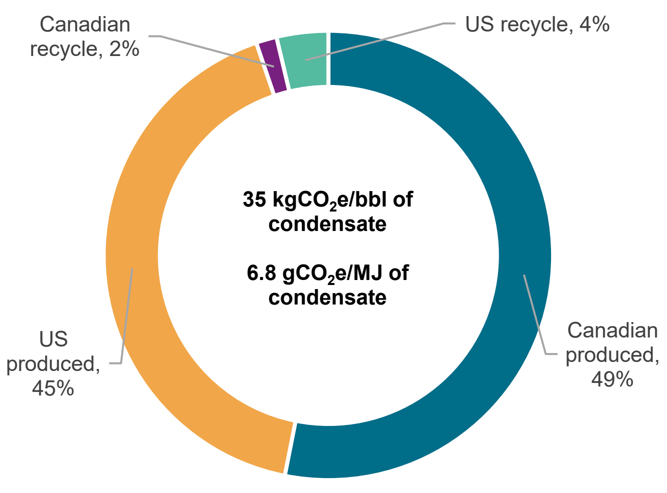
The greenhouse gas intensity of condensate in western Canada

The average GHG intensity of the western Canadian condensate pool in 2021 was found to be 35 kilograms of carbon dioxide equivalent per barrel of condensate (kgCO_2e/bbl), or 6.8 grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ). Figure 7 shows the relative contribution of different sources of supply to the condensate pool intensity. Canadian condensate, with the highest volumetric contribution, has the greatest impact on the overall weighted average. US condensate has a lower volumetric contribution, but the higher GHG intensity of the stream makes its contribution almost equivalent. Recycled condensate was the least GHG intensive but also contributed the least volume (13%), muting its impact on the overall GHG intensity of western Canadian condensate.

Figure 8 shows the relative contribution of each life-cycle stage into the overall pool average. Combustion (end-use stage), which would typically dominate a life-cycle emissions analysis, transportation was the largest source of GHG intensity of the condensate pool. This is particularly true of US-produced condensate.

Figure 7

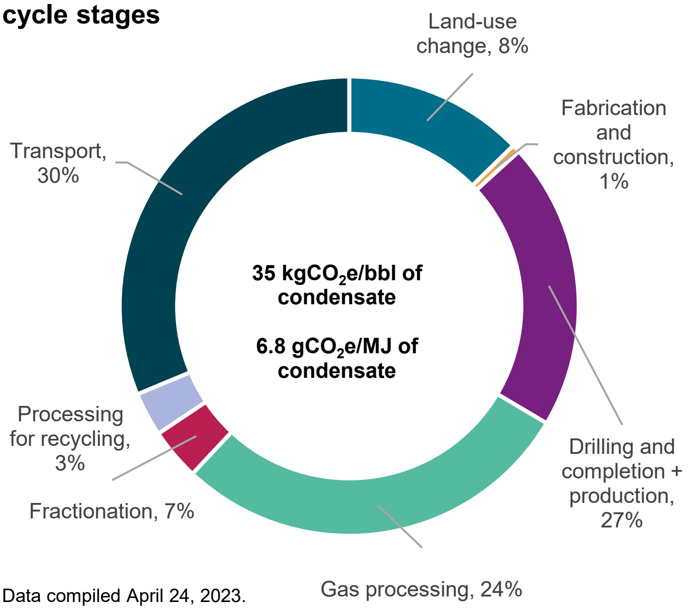
Volumetric weighted share of source toward western Canadian condensate emissions



Data compiled April 24. 2023.
Source: S&P Global Commodity Insights.

Figure 8

Western Canadian condensate GHG intensity by life-cycle stages



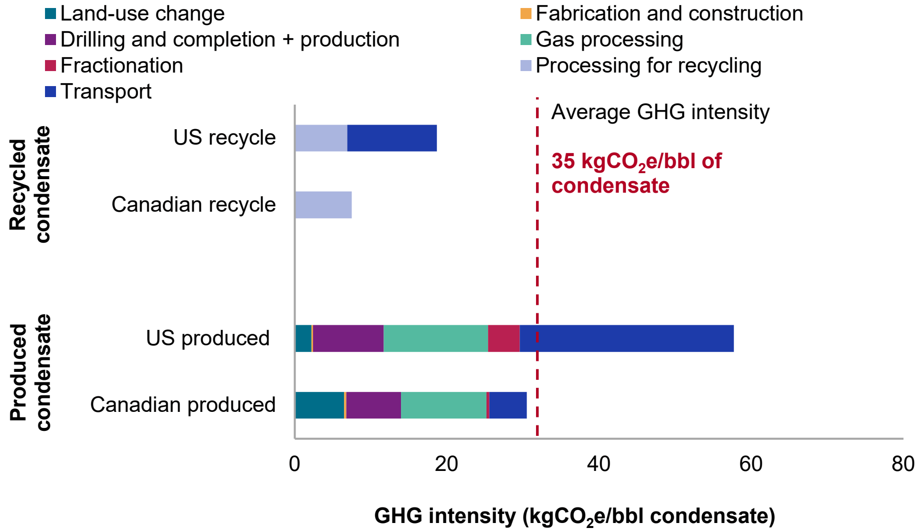
Data compiled April 24, 2023.
Source: S&P Global Commodity Insights.

The most GHG-intensive source of supply was US-produced condensate, with an estimated intensity of 58 kgCO_2/bbl of condensate (see Figure 9). Transportation distance was the largest contributor to the GHG intensity of imported US condensate emissions. The GHG intensity of Canadian-produced condensate was almost half of that of US-produced because of its relative proximity but also processing emissions. Most Canadian-produced condensate is separated from initial gas processing (inlet compression, separation, and stabilization), which is a less intensive process than condensate sourced from fractionation.

Recycled condensate was the least GHG-intensive source in the analysis owing to fewer life-cycle stages. Adding other stages (upstream production and transportation) to recycled condensate can lead to double counting of emissions; thus, only emissions associated with processing of dilbit for condensate separation and any return transportation were included (it was assumed the most likely heavy crude oil being processed for recycle was dilbit). In 2021, we estimate Canadian recycled condensate on an average had a GHG intensity of 7.5 $kgCO_2e$/bbl of condensate. US recycled condensate has an estimated GHG intensity of 20 $kgCO_2e$/bbl of condensate—again, the difference was principally related to transportation.

Figure 9

Western Canadian condensate GHG intensity ($kgCO_2e$/bbl) by life-cycle stages



Data compiled April 24, 2023.

Source: S&P Global Commodity Insights.

Within the recycled condensate category, condensate sourced from the Hardisty DRU had the lowest relative GHG intensity because it was designed just to separate the diluent from dilbit and has less energy requirements. However, in 2021 we estimate it contributed to less than 3% of the total condensate pool, muting any impact on overall condensate intensity.

This report may be among the most comprehensive analyses to date into the composition of the western Canadian condensate pool, as well as the GHG intensity of the sources of condensate used for blending in western Canada. The pool itself is somewhat opaque, and the market composition and sources represent years of understanding by Commodity Insights. The GHG intensity of western Canadian condensate is also expected to be dynamic as both the contribution and GHG intensity of the various sources of supply change over time. For example, compared with 2019, our estimate of the GHG intensity of the western Canadian condensate in 2021 was 2% greater owing to changes in supply. Going forward, we expect the pool intensity to decline. This would occur as the volume of Canadian recycled condensate increases modestly from the ramp-up of the Hardisty DRU to full capacity and with an increase in unconventional activity in western Canada due to higher oil prices—both of which have the potential to reduce the GHG intensity of the condensate pool.

Going the last mile: A note into the GHG intensity of delivered condensate

Utilizing this more robust estimate of the GHG intensity of condensate to understand the GHG intensity of marketed Canadian heavy oil grades requires considering additional transportation from the pool terminal to regional production facilities where condensate is blended into heavy oil. The relative distance from the pool or key terminals to a particular facility can range significantly. Some operations may also be located approximate to areas of known recycling. Others are quite remote. From the most approximate to the most remote, we estimate 0–2.6 $kgCO_2e$/bbl may be added to the intensity of delivered condensate.[10]

10. Our estimate is based on the potential for some production operations to be physically close to sources of condensate supply. For example, in the Lloydminster area some heavy oil operations are quite approximate to where recycling is occurring. Conversely, other operations are far from major terminals. The upper bound of our estimate was based on delivered condensate to the Athabasca oil sands, which is over 420 km from Fort Saskatchewan.

Uncertainty in estimates

Uncertainty is inevitable in the estimation of life-cycle GHG emissions of crude oil and condensate. Key sources of uncertainty include differences in data quality, fugitive methane emissions, and gas processing emissions. Some key sources of uncertainties associated with this study are documented below:

Sources of supply: Although Commodity Insights has some of the best supply models of North American crude oil, there remains some uncertainty. For example, as stated before, some refineries may from time to time choose to market naphtha into the condensate pool. Presently there is limited ability to identify this should it occur. Supply from the United States may also be sourced from areas other than the Permian. We are unable to know how these factors may affect our analysis.

Methane emissions: Methane emissions are well-documented sources of uncertainty. This study utilizes the average flaring and venting emissions published by government/public reports such as US Energy Information Administration (EIA), Alberta Energy Regulator (AER), and BC Oil and Gas Commission reports to account for methane emissions. However, numerous studies have pointed out that methane remains a known unknown, particularly across the value chain—such as from production, transportation, and processing. Methane poses an upward risk to our estimate. More reliable methane estimates can vary the GHG intensity for different pathways as well as condensate pool. Using the methane emissions estimates based on a public source (Global Methane Tracker), the GHG intensity of the condensate pool can potentially increase by 30%. One of the potential limitations of data sources like the Global Methane Tracker is that these sources are providing country-level values, which pose significant attribution challenges for countries that market multiple streams from various extraction processes (refer to the Appendix for sensitivity analysis).[11]

Dynamism of upstream emissions: Production emissions of produced condensate used to estimate the pool average intensity are based on the production-weighted average of each source of supply (i.e., the average of all of the Permian Basin, or all of the Montney). Commodity Insights has documented on multiple occasions the considerable variation in GHG emissions intensity of oil and gas production. As a result, for any given play it is not possible to know precisely the carbon intensity of which fraction of supply from a play is flowing where. This a source of uncertainty where we do not understand yet how it may bias our analysis.

Transportation emissions: The most representative routes were selected for the modeling of transportation emissions but not necessarily the actual movements. The selection of the Permian (along with the Eagle Ford), although conservative, increases the potential of upside bias to US transportation emissions.

Processing emissions: *Alberta greenhouse gas quantification methodologies, Technology innovation and emissions reduction regulation, Version 2.2*, provides a benchmark for gas processing and fractionation modules present in the facilities around Alberta. This study was used for our estimation of processing emissions for both Canadian and US condensate.[12] Although the data is in line with data published by the US Environmental Protection Agency (EPA) for processing emissions in the Permian and Eagle Ford region, there is still uncertainty using analysis based on another region's facilities. CO_2 (used for estimating formation CO_2 emissions) and H_2S content (sulfur production) of gas produced in US basins (Eagle Ford and Permian) is

11. IEA (2023), Global Methane Tracker 2023, IEA, Paris https://www.iea.org/reports/global-methane-tracker-2023, License: CC BY 4.0.

12. *Alberta greenhouse gas quantification methodologies, Technology innovation and emissions reduction regulation, Version 2.2*, provides a benchmark for gas processing and fractionation modules present in the facilities around Alberta, *Alberta Greenhouse Gas Quantification Methodologies.*

also overestimated based on the nonhydrocarbon gases ratio to the total gas produced as published by the EPA database. This is added uncertainty but due to the low impact on the overall intensity and lack of more granular data is adopted for this study. Sulfur production for Alberta and British Columbia takes into account the total production from both provinces, which can be considered an overestimation.

Communicating confidence: The Data Quality Metric

Commodity Insights, in collaboration with the US Department of Energy National Energy Technology Laboratory, developed the Data Quality Metric (DQM). The DQM helps inform users of these data about the quality of estimates. DQM scores were produced for each pathway included in our analysis of the GHG intensity of western Canadian condensate.

DQM is measured using two major parameters: reliability and representativeness of the data. The score varies from 1 to 5, where 1 is highest score and 5 is the worst. The numerical score is further translated into the grade for ease of understanding.

Results of DQM are meant to convey confidence in emission estimates. The scores for different sources of condensate and western Canadian condensate are presented in Table 1. Our highest confidence was in Canadian-produced condensate and lowest confidence in US recycled condensate. For more on the DQM, please see *The Right Measure: A landmark study of life-cycle GHG intensity of crude oil.*[13]

Table 1

DQM for the western Canadian condensate sources

Source	GHG intensity (kgCO_2e/bbl of condensate)	GHG intensity (gCO_2e/Mj of condensate)	Data reliability	Data representativeness
Canadian condensate	30.3	5.9	C	B
US condensate	57.8	11.1	C	C
Canadian recycle	7.5	1.5	C	C
US recycle	19.8	3.6	D	B
Western Canadian condensate average	35.1	6.8	C	C

Data compiled April 24, 2023.
Source: S&P Global Commodity Insights.

13. See the Commodity Insights Strategic Report *The Right Measure: A landmark study of life-cycle GHG intensity of crude oil.*

Quantifying life-cycle stages: Methodology used by Commodity Insights

Life-cycle GHG estimation provides a holistic approach to understanding the GHG intensity of a particular commodity. It can encompass every stage of a product's life from the origination to the destination or end use. This section documents the methods used for estimation of the GHG intensity for each stage of each segment that went into the overall estimate of the average intensity of the western Canadian condensate pool in 2021. Additional detail can be found in the Appendix.

As shown in the Figure 2 there are many stages before condensate becomes part of the condensate pool in western Canada. For this study, emissions associated with condensate production from each stage were estimated based on the energy of condensate. Lower heating value (LHV) is used to convert the measure of the energy content. Refer to the Appendix for more details about LHV of different streams considered for this analysis. The stages also depend on the source of condensate—produced or recycled. For produced condensate, the first three stages refer to the upstream pre-production, which accounts for the emissions before oil and gas extraction and production begins. These emissions are associated with land-use change, fabrication and production, and drilling and completion (D&C). Once production begins, the production stage of life begins, and condensate must be separated—either at production or through natural gas processing and further fractionation. Condensate must be transported in various forms from the wellhead through each stage and then on to the final market. For recycled condensate, there are fewer stages—condensate is separated from a heavy oil blend and then the resulting condensate transported back to the market hub. Below is a short guidance on how each stage was treated in our estimation process.

- **Land-use change:** Land-use change emissions are based on the type of the land and carbon richness of the land. According to the land type, development intensity, and carbon richness, OPGEE has been leveraged to estimate the emissions associated with the land-use change.[1]
- **Fabrication and construction:** These emissions are associated with the activities undertaken to set up an oil and gas production facility. Depending on the type of facility (unconventional, conventional, offshore, etc.) or archetype, an environmentally extended input-output (EEIO) model was used to estimate the GHG emissions associated with this stage. The EEIO model correlates between economic activities and environmental impacts.[2]
- **Drilling and completions (D&C):** Emissions associated with the purchased fuels (electricity, natural gas, or diesel) required for D&C of wells/assets are included in this stage. Fugitive emissions are also included. The Energy Studio: Impact model has been leveraged to estimate the emissions with D&C.[3]

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1. The Oil Production Greenhouse Gas Emissions Estimator (OPGEE) is an open-source, engineering-based life-cycle assessment (LCA) tool for the measurement of GHG emissions from the production, processing, and transport of crude petroleum. See *OPGEE: The Oil Production Greenhouse gas Emissions Estimator | Environmental Assessment and Optimization Group (stanford.edu).*

2. See *US Environmentally-Extended Input-Output (USEEIO) Models | US EPA.*

3. *Energy Studio: Impact* houses the Commodity Insights primary upstream GHG emissions model. The model is built on top of our extensive upstream data. These data are principally sourced from publicly available government and regulatory data. The tool currently includes over 6 million wells with over 70 distinct variables running over 250 calculations per well to derive an independent estimate of monthly emissions and emissions intensity of D&C and operational emissions by fuel and gas.

Quantifying life-cycle stages: Methodology used by Commodity Insights (continued)

- **Production emissions:** These include emissions associated with produced or purchased fuel use (electricity, natural gas, or diesel), venting, and flaring during the production of oil and gas from the wells. The Energy Studio: Impact model was sourced for production emissions because it contains estimates of production emissions of every active well in North America. This level of granularity allows us to estimate the true volumetric weighted-average intensity of a given play or region.

- **Natural gas processing and fractionation:** This includes emissions due to processing units present in the gas processing and fractionation facilities along with fugitive emissions. *Alberta greenhouse gas quantification methodologies, Technology innovation and emissions reduction regulation, Version 2.2*, providing the benchmark for natural gas and processing facilities, has been leveraged to estimate the associated emissions. The emissions from gas processing facilities include modules such as inlet compression, stabilization, amine sweetening, dehydration, sulfur plant, sales compression, formation CO_2 and any venting, flaring, and fugitives. For fractionation facilities, refrigeration and fractionation modules are considered.[1]

- **Processing for recycled condensate:** This includes emissions associated with the units required for separating diluent/condensate from heavy oil blends. It was assumed the most likely source of condensate was dilbit. The process usually requires atmospheric extraction/separation. Atmospheric separation of diluent from dilbit takes place in refineries and was modeled using PRELIM V-1.6. In addition to refinery/upgrader diluent recovery, condensate derived from a purpose-built DRU in Hardisty, Alberta, came into operation in 2021 and was included as an additional source of recycled condensate supply. The AER Statistical Report ST-39 provides data on the facility operations that include electricity consumption, process gas consumption, and natural gas consumption and is used to estimate the GHG intensity of the facility. Operational data is published by the AER on the facility operations in the ST-39 report.[2] [3]

- **Transportation:** Emissions associated with the fuel/electricity usage and fugitive release during transportation of condensate are estimated in this stage. The emissions are modeled based on the energy use for transporting the hydrocarbon through a distance based on the mode of transportation. The energy intensity factors for particular modes of transport and fuels are obtained from GREET model 2021.[4]

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1. *Alberta greenhouse gas quantification methodologies, Technology innovation and emissions reduction regulation, Version 2.2*, provides a benchmark for gas processing and fractionation modules present in the facilities around Alberta, *Alberta Greenhouse Gas Quantification Methodologies.*

2. The Petroleum Refinery Life Cycle Inventory Model (PRELIM) is a mass and energy-based process unit-level tool for the estimation of energy use and GHG emissions associated with processing a variety of crude oils within a range of configurations in a refinery. See *PRELIM | University of Calgary (ucalgary.ca)*.

3. ST-39 is a report published by AER and updated monthly. This report contains oil sands production, supplies, dispositions, and inventory of oil sands and processing products. The data are collected from monthly submissions to the AER by oil sands operators in the province of Alberta in a cumulative monthly view. See *ST39 | Alberta Energy Regulator (aer.ca).*

4. The Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model, is an open-source model used to simulate the energy use and emissions output of various vehicles and fuel combinations. See *Argonne GREET Model (anl.gov).*

CONTACTS

Americas: +1 800 597 1344
Asia Pacific: +60 4 296 1125
Europe, Middle East, Africa: +44 (0) 203 367 0681

www.spglobal.com/commodityinsights
www.spglobal.com/en/enterprise/about/contact-us.html