CANADA'S NATURAL GAS AND OIL EMISSIONS:

Ongoing Reductions, Demonstrable Improvement

CAPP CANADA'S OIL & NATURAL GAS PRODUCERS

GREENHOUSE GAS EMISSIONS AND CANADA'S NATURAL GAS AND OIL INDUSTRY

Canada's Natural Gas and Oil Emissions: Ongoing Reductions, Demonstrable Improvement

Contents

Emissions: Ongoing Reductions, Demonstrable Improvement

Oil and natural gas will continue to be an important part of the world's energy mix for the foreseeable future. Supplying affordable, reliable and cleaner energy to a growing global population will continue to be the goal of Canada's upstream energy industry.

Climate change is a global challenge that requires global perspectives and solutions. Advancing greenhouse gas (GHG) emissions reduction is critical to realizing the vision for Canada to be a global natural gas and oil supplier of choice.

Emissions reduction performance, including emission intensity, is increasingly the basis for policies such as low-carbon fuel regulations, carbon pricing, specific reduction targets and emission caps. It's used to inform funding decisions by governments, funding agencies and investors.

Supplying affordable, reliable and cleaner energy to a growing global population will continue to be the goal of Canada's upstream energy industry.

INDUSTRY OVERVIEW

Canada has the world's third-largest oil reserves. Of the 168 billion barrels of Canadian oil that can be recovered economically with today's technology, 162.5 billion barrels are in the oil sands. In 2020, Canada's oil production averaged 4 million barrels per day (b/d), of which 94% came from producing areas in Western Canada. Currently 99% of Canada's oil exports go to the U.S. but with improved market access and infrastructure Canada can increase global market share.

2020 OIL PRODUCTION:

4

MILLION B/D

2020 NATURAL GAS PRODUCTION:

16

BILLION CF/D

Canada has vast reserves of natural gas, particularly in B.C. and Alberta. In 2020, natural gas production averaged 16 billion cubic feet per day (Bcf/d). Canada has enough natural gas to meet domestic needs for 300 years, with enough remaining for export. The export of natural gas as liquefied natural gas (LNG) will enable Canada to access markets in Asia.

The natural gas and oil industry is active across the country, either through exploration, development and production or through its multi-billion dollar supply chain.

In 2019, exported oil, natural gas and petroleum products earned $112.6 billion, Canada's top export by value.

More information on Canada's upstream petroleum industry is available at **www.capp.ca**

CANADA'S TOP EXPORT

19%

OF EXPORTS ARE CRUDE OIL, NATURAL GAS AND OTHER PETROLEUM PRODUCTS.

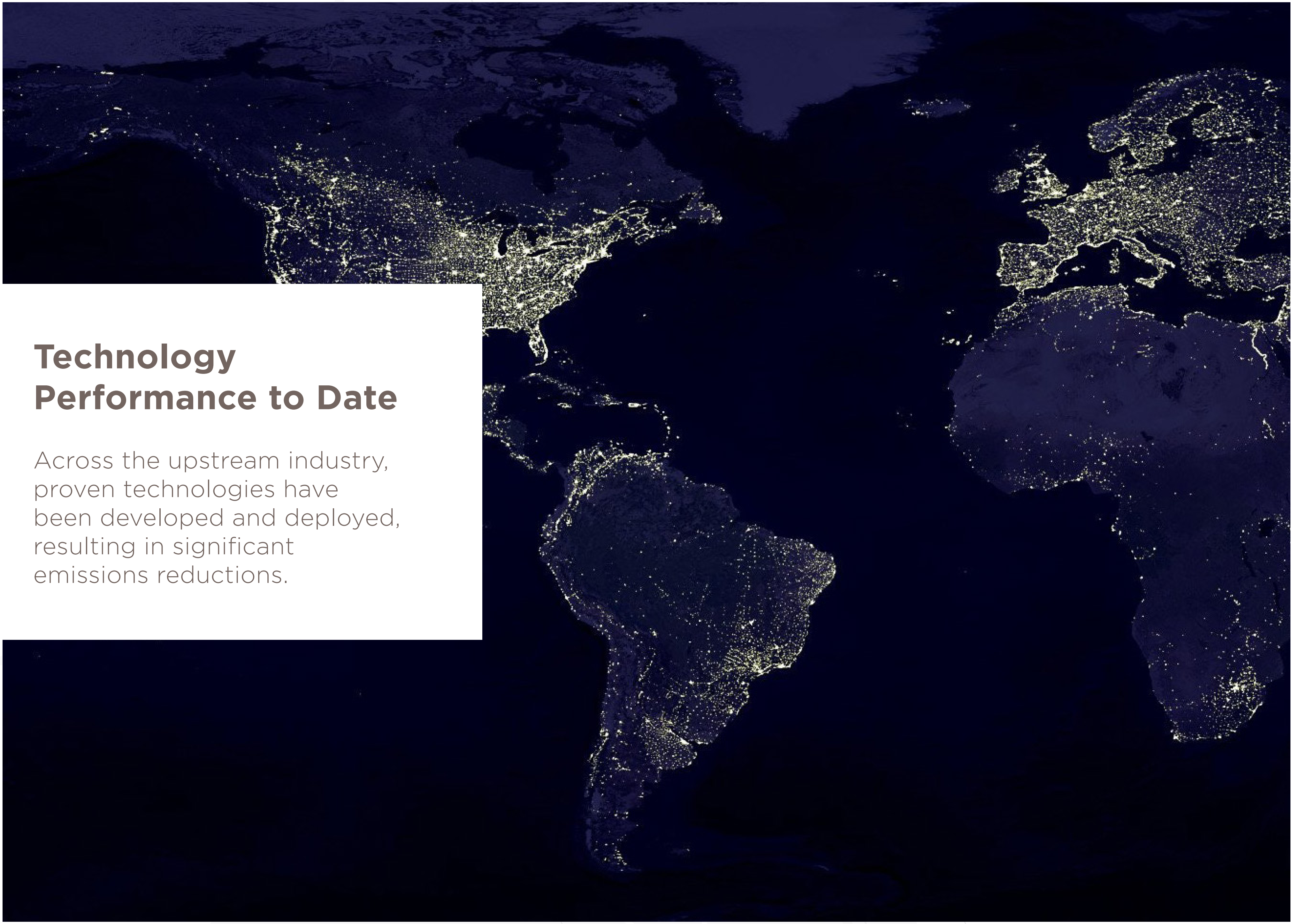
VALUE = $112.6 BILLION

Technology Overview: The Path to Emissions Reduction

Innovative technologies and process efficiency improvements are the main keys to reducing emissions across Canada's natural gas and oil industry. Many producing companies are researching, developing and deploying technologies, and the industry also has a significant commitment to collaboration and knowledge sharing, aimed at improving performance across the sector and contributing to Canada's international climate change commitments. Also, many technologies developed in the industry are transferable to other industries and to other producing jurisdictions internationally.

The industry has a broad portfolio of innovative solutions to deliver emissions reductions. Technological advances are not aspirational, they are actual: the industry is taking serious, substantial steps to reducing emissions intensity. The natural gas and oil industry accounts for 37% of environmental protection spending by industry, according to data from Statistics Canada.

Technological advances are not aspirational, they are actual: the industry is taking serious, substantial steps to reducing emissions intensity.



Technology Performance to Date

Across the upstream industry, proven technologies have been developed and deployed, resulting in significant emissions reductions.

METHANE REDUCTION

In the oil and natural gas industry, methane is released when natural gas is flared or vented. Methane is also released in small leaks, called fugitive emissions, from valves and other equipment used in drilling and production. Canada has mandated a reduction in methane emissions of 45% below 2012 levels by 2025. Among the world's top 10 petroleum exporters, currently Canada alone has a methane reduction target.

The upstream oil and natural gas industry is actively working to achieve this target. Reduction efforts are focused on tank vents, pneumatics, pumps and similar fugitive emissions sources, plus further reductions in venting and flaring.

Among the world's top 10 petroleum exporters, currently Canada alone has a methane reduction target.

Examples of methane reduction activity:

- **Alberta Methane Field Challenge** is a collaborative venture between industry, the Alberta government and the Alberta Energy Regulator to field-test new methane detection technologies including hand-held and fixed sensors, plus sensors mounted on drones and trucks.
- Many operators, especially in the natural gas and conventional oil sectors, are exchanging dated equipment for newer equipment to eliminate methane leaks and small venting. For example, by the end of 2019 **Cenovus** had changed more than 1,000 high-bleed instruments and continues to advance this program.
- **NuVista Energy Ltd** has been working hard to eliminate methane emissions, including using compressed air to drive pneumatic instruments and pumps instead of pressurized natural gas, thus eliminating routine methane venting. NuVista is also incorporating compressed air pipelines (from facilities to well pads) into the ongoing build out of their new Pipestone field. New wells at the Pipestone field have no routine methane venting.

CARBON CAPTURE, UTILIZATION AND STORAGE

Carbon capture, utilization and storage (CCUS) includes several advanced technologies that capture emissions from large industrial facilities before they reach the atmosphere. Captured carbon dioxide (CO_2) can be permanently stored underground in stable geological formations, used to enhance oil production from mature reservoirs, or used to create value-added products.

Carbon capture unit at the Alberta Carbon Conversion Technology Centre.

Examples of CCUS:

- The **Quest CCS** facility captures and stores CO_2 emissions from the Shell-operated Scotford Upgrader near Fort Saskatchewan, Alberta. The CO_2 is safely captured and stored in an underground geological formation. Since it began operation in 2015, Quest has captured more than 6 million tonnes of CO_2, approximately equal to the annual emissions from 1.5 million cars.
- The **Alberta Carbon Trunk Line** (ACTL) system began operation in 2020. Operated by Wolf Midstream, the system captures CO_2 from industrial sources near Edmonton and transports it to central Alberta where it's injected into mature reservoirs for enhanced oil recovery and permanent storage by Enhance Energy. About 1.3 million tonnes of CO_2 per year is currently captured from the North West Redwater Sturgeon Refinery and 300,000 tonnes from Agrium's Redwater fertilizer plant.
- Suncor and Cenovus have acquired an equity financing agreement with Vancouver-based **Svante**, a Canadian cleantech startup, to accelerate the commercialization of Svante's CO_2 capture technology. The pilot started in 2019 at Cenovus' operations in Saskatchewan.

Carbon capture demo plant. Photo courtesy Svante.

Based on the 2021 budget, the federal government's CCUS target is to reduce emissions by at least 15 megatonnes of CO_2 annually.

In March 2021, Alberta and Ottawa jointly launched a new working group to advance CCUS technology and deployment. The group is advised by representatives from key Alberta industries including the natural gas and oil sector, and other experts. Additionally, the federal budget announced in April 2021 proposed to introduce an investment tax credit for capital invested in CCUS projects along with other financial tools, with the goal of reducing emissions by at least 15 megatonnes of CO_2 annually. This measure will come into effect in 2022.

In June 2021, oil sands operators Canadian Natural Resources Limited, Cenovus Energy, Imperial Oil Limited, MEG Energy Corp and Suncor Energy announced formation of the Oil Sands Pathways to Net Zero Initiative. The goal of this alliance is to work collectively with the federal and Alberta governments to achieve net zero emissions from oil sands operations by 2050. The pathway is anchored by a major CCUS project to enable multi-sector 'tie-in' projects for expanded emissions reductions.

FUEL GAS / ENERGY EFFICIENCY

Emissions reductions can be achieved through fuel switching (primarily from diesel to natural gas) and improved efficiency in equipment and processes at facilities of all sizes, across all upstream operations. Technologies include:

- Waste heat recovery units (WHRU) use an energy recovery heat exchanger that transfers heat from high-temperature process outputs to another part of the process, offsetting the need to burn more fuel for heat or power generation.
  - A WHRU can reduce emissions by 2,500 to 3,000 tCO_2e per well per year, or 30,000 to 78,000 tCO_2e per plant per year for a gas-processing plant capacity 90 million cubic feet per day (MMcf/d).
- Diesel displacement for drilling, well completions and natural gas processing facilities, such as using mobile natural gas power generating / energy storage units for existing electricity-powered drilling rigs.
- Offshore flare recovery systems significantly reduce flaring of natural gas. Recovered gas can be collected and used for compression, injection / re-injection and enhanced oil recovery.

Project lead Jason McGillivray helped design zero-bleed well-pad equipment at Groundbirch. Photo by Jason Dziver.

Examples of fuel gas/energy efficiency:

- **Tourmaline Oil Corp.**, Canada's largest natural gas producer, achieved an emissions intensity reduction of 46% between 2013 and 2018 and is targeting further methane and overall emissions reductions. Eliminating the use of diesel in its field operations is among the technologies employed to achieve this reduction.

- In B.C., **Shell Canada** successfully brought the first 'Generation 4' multi-well pad on stream in January 2018 at Groundbirch. This advanced well pad design utilizes zero-bleed electric valve actuators (the mechanism that opens and closes a valve) to eliminate methane emissions that typically come from natural gas-driven actuators. This new pad design reduces emissions by at least 90%, the equivalent of taking more than 40 cars off the road for every well using this technology.

- Throughout its operations, **Cenovus** is exploring advanced data analytics for continued optimization opportunities. By using data analytics and artificial intelligence to improve operational efficiency, there is a significant opportunity to potentially improve environmental performance. Cenovus is optimistic these efforts could eventually contribute to meaningful reductions in GHG emissions.

- Since 2018, **NuVista Energy Ltd** has been installing WHRUs at all major operated Montney facilities. These units recover waste heat from compressor exhaust and use it to offset fuel use in other plant processes. NuVista's 10 WHRUs now avoid approximately 15,000 tonnes of CO_2e per year.

COGENERATION

Upstream producers can use waste heat to generate electricity, thus reducing emissions by avoiding additional fuel combustion for electricity generation. The largest opportunity exists in the oil sands sector, where both mining and in situ operations use hot water or steam to extract bitumen. Heating the water requires combustion of natural gas or petroleum coke, but only a portion of the heat generated is used in extraction. Operators can capture waste heat through cogeneration to generate both heat and electricity at the same time from the same fuel source. Excess electricity not required for facility operation is sold to the Alberta power grid. Cogeneration currently supplies 34% of the province's electricity.

Cogeneration offers a significant opportunity to reduce emissions, through currently installed cogeneration and potential new installations. In 2019, Alberta's grid factor value (GHG emissions per megawatt hour of electricity produced) was 0.670 t/MWh compared to a grid factor of 0.25 to 0.30 t/MWh for cogenerated electricity. These cogeneration systems reduce GHG emissions associated with electricity production and steam generation by 30 to 40% compared to electricity purchased from the Alberta grid and stand-alone steam generation.

Examples of cogeneration:

- **Suncor Energy** has a cogeneration unit under construction at the company's Base Plant that will replace coke-fired generation with lower-emitting natural gas-fired generation. In addition to providing the facility with steam needed for operations and reducing direct GHG emissions, the cogeneration units will export 800 megawatts (MW) of electricity to the provincial grid, equivalent to roughly 7% of Alberta's current electricity demand. The GHG intensity of the power produced from these cogeneration units is approximately 75% lower than coal-fired power generation, reducing GHG emissions by approximately 5.1 megatonnes (MT) per year in Alberta. This is equivalent to displacing more than 1,000,000 cars from the road.

- Existing cogeneration projects in Alberta have a combined capacity of over 3,000 megawatts (MW):
  - Kearl and Cold Lake (Imperial Oil)
  - Fort Hills, Firebag, and Mackay River (Suncor)
  - Horizon, Primrose, Muskeg River, and Scotford (Canadian Natural)
  - Long Lake (CNOOC International)
  - Christina Lake and Foster Creek (Cenovus)
  - Syncrude
  - Other projects (not CAPP members) include Christina Lake (MEG), Lindbergh (Cona Resources), and Harmattan (Altagas).

Cogeneration facility at Fort Hills. Photo courtesy Suncor.

UPSTREAM ELECTRICITY - LOW OR NON-EMITTING SOURCES

Where upstream production projects are in close proximity to low-emission electricity sources such as hydro, that electricity can be used to power part or all of a facility, thus avoiding combustion of other fuels. Renewable power generation at existing facilities, especially wind or solar generation, is another option.

Using hydroelectricity to operate upstream natural gas production in northeastern B.C. offers significant opportunities to reduce overall emissions for production of liquefied natural gas (LNG).

Examples of upstream electrification:

- **ARC Resources** designed and built its Dawson Creek natural gas processing facility to produce fewer emissions. From 2010 to 2018, the plant reduced emissions by 539,743 tonnes of CO_2e using technologies including electric-driven compressors, and an instrument-air system instead of instrument-gas that eliminates the need for venting. The entire facility is linked to the B.C. hydroelectric grid. In 2018, ARC electrified its Parkland and Sunrise facilities, reducing emissions by approximately 85% or more than 100,000 tonnes of CO_2e.
- **Shell Canada** designed its B.C. Saturn natural gas processing plant to operate on hydroelectricity instead of natural gas. As a result, direct emissions from the plant are about 90% lower than if the plant operated on natural gas, representing a reduction of 150,000 tonnes of CO_2 per year.
- **LNG Canada** – with increased electrification of source natural gas production, and partial electrification of the LNG facility itself (under construction near Kitimat, B.C.), GHG emissions from LNG Canada will be lower than any facility currently operating anywhere in the world. LNG Canada estimates its facility will be 35% lower than the world's best-performing facilities and 60% lower than the global weighted average.
- Hydroelectricity powers the majority of **Ovintiv's** gas processing in the Montney area of northeastern B.C. Its Saturn, Sunrise, and Tower processing plants can avoid up to 860,000 tonnes of CO_2e emissions annually versus gas-driven facilities, comparable to the emissions from 184,000 vehicles per year. Electrification has the added benefit of reducing operational noise compared to non-electric facilities.

Imperial's Kearl oil sands mine uses paraffinic froth treatment to lower emissions. Photo courtesy Imperial.

PARAFFINIC FROTH TREATMENT TECHNOLOGY

Froth treatment uses hydrocarbon-based gravity separation to remove water and fine solids from bitumen froth produced in the oil sands mining extraction process. For more than 30 years, naphthenic froth treatment (NFT) was the only technology available to dilute bitumen froth. **Paraffinic froth treatment** (PFT) uses a much lighter diluent. As asphaltenes precipitate, water and fine solids become bound to the asphaltene, resulting in a bitumen product that meets pipeline specifications and can be sold directly to a high-conversion refinery without the need for further upgrading, thus reducing overall emissions.

PFT has been deployed at Fort Hills (Suncor), Kearl (Imperial) and Athabasca Oil Sands Project (Canadian Natural) and is likely to be deployed at all new oil sands mining operations. This is a proven technology that is substantially reducing overall emissions, allowing operators to extract carbon from produced oil and bringing full life cycle emissions in line with the average U.S. production emissions (see page 37). According to IHS Markit (2020), the ramp-up of the Fort Hills oil sands project alone accounted for nearly three-quarters of the 2017-2018 overall oil sands emissions reduction (see page 32).

Near-term / Potential Technologies

In the oil sands sector, a number of processes and technologies aimed at further reducing emissions by reducing or eliminating the need to generate steam for bitumen recovery are being tested at lab and field scales.

Foster Creek oil sands. Photo courtesy Cenovus.

SOLVENT AND SOLVENT-ASSISTED EXTRACTION PROCESSES

Increasingly, in situ oil sands projects are using solvent alone, or combinations of solvents and steam processes, to reduce the steam-to-oil ratios (SOR) and to improve bitumen recovery. In this context, 'solvents' are light hydrocarbons such as propane that are injected into the bitumen reservoir to reduce bitumen viscosity, allowing the mixture to be pumped to the surface. Solvents are recovered and re-used. The addition of solvents also has the benefit of lowering water treatment requirements, and increasing plant capacity by reducing or replacing steam generation requirements, thereby lowering overall emissions. The use of solvents reduces and may potentially eliminate the need for energy-intensive steam production for in situ extraction.

Advanced field pilots have been completed by Imperial, Cenovus and ConocoPhillips, and successfully demonstrated meaningful increases in productivity, as well as decreases in SOR and water use. Several others are in various stages of testing similar applications.

Examples:

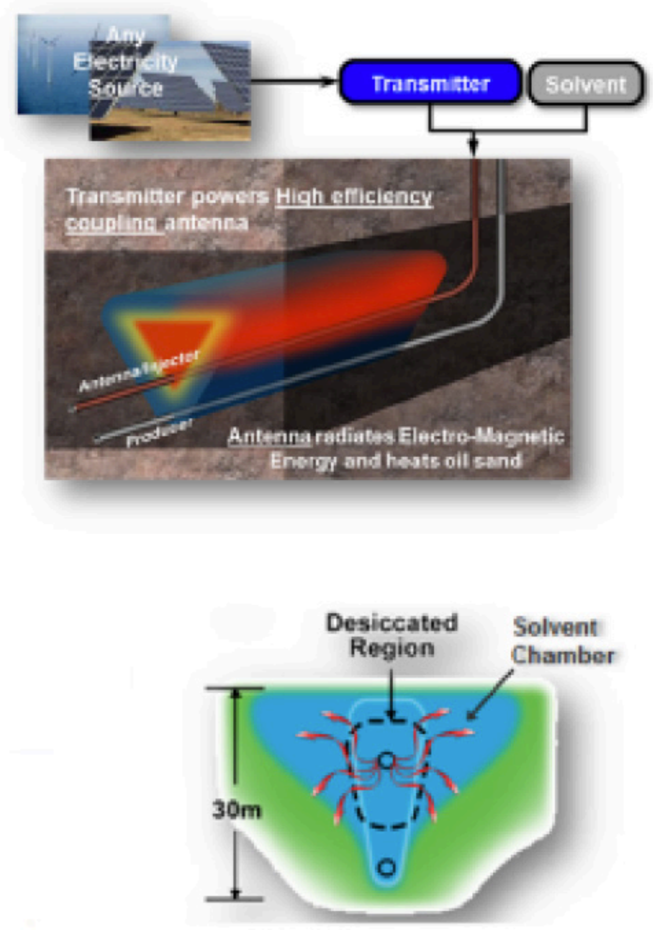
- At its Cold Lake project, **Imperial** is reducing GHG emissions intensity with its Liquid Addition to Steam for Enhancing Recovery (LASER) technology. In 2021 Imperial expanded commercial application to the Makheses field at Cold Lake.
- At its Foster Creek and Christina Lake projects, **Cenovus** is testing solvent-aided processes using a range of natural gas liquids to improve oil recovery, reduce emissions and water use, and lower operating costs. The company expects a minimum one-third emissions reduction benefit from solvent use with the potential for much greater reductions.
- **Canadian Natural** has been piloting the use of solvents at its Kirby SAGD facility, with up to 45% reduction in SOR. Based on these results, in 2021 the pilot will be expanded to the company's Primrose cyclic steam stimulation project near Cold Lake, Alberta.

ELECTROMAGNETIC (EM) HEATING PROCESSES

Similar in concept to a household microwave oven, EM waves from long antennae drilled into a deep oil sands deposit excite water molecules in the deposit. This generates frictional heat, which raises temperatures within the reservoir and lowers the bitumen's viscosity, allowing it to be pumped to the surface. Solvents (light hydrocarbons) are commonly injected into the reservoir to further dilute the bitumen. Solvents are recovered and re-used. The EM process eliminates the need for steam generation, thus reducing emissions that would be associated with burning natural gas to create steam.

Example:

- Together with a consortium of partners and financial support from **Alberta Innovates, Suncor Energy** is field-piloting Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH®) at its Dover oil sands development. This process uses EM heating and solvent injection to recover bitumen without the need for steam generation and injection. Pilot results are expected in 2022.



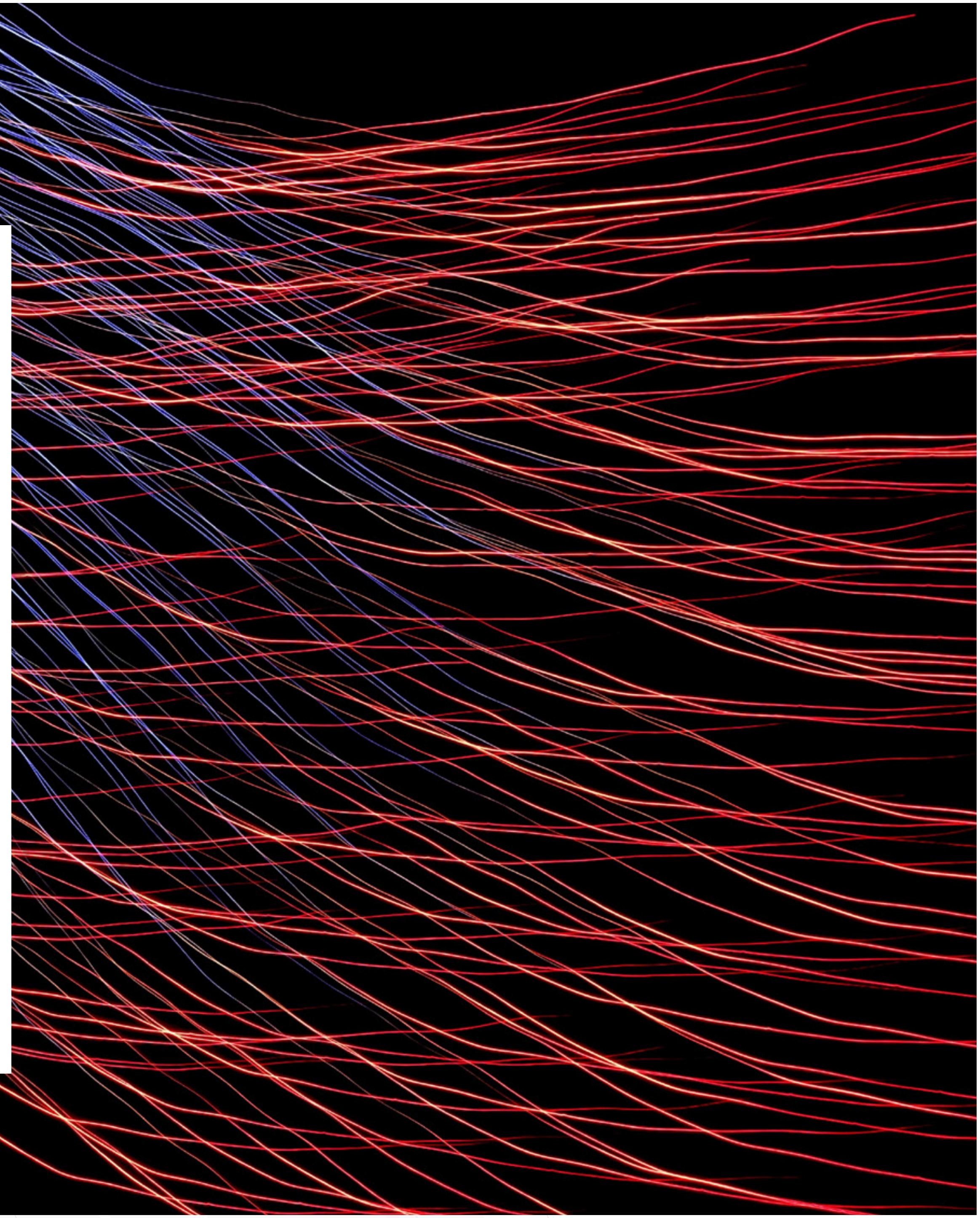
ESEIEH™ Well Layout and Process

HAUL TRUCKS AND MATERIALS HANDLING

New haul truck technology or fuel alternatives such as electric or trolley assist, and alternative modes of material transport to shorten haul distance, are being piloted at several oil sands mining sites. Timing of deployment and technology type depends on individual mines, but the potential for substantial emissions reductions appears high. Imperial, Canadian Natural and Syncrude have pilot projects underway, while Suncor has fully deployed the use of automated haul trucks at its North Steepbank and Fort Hills mines - the company continues to assess the impact on emissions reduction.

PARTIAL UPGRADING

Partial upgrading produces bitumen of pipeline quality without the need for diluent, which reduces the energy required to upgrade the bitumen and results in an estimated reduction of well-to-refinery emissions up to 12%.



Ongoing Collaboration and Research

Research and development of new technologies across the natural gas and oil industry is active and continually evolving.

Canada's upstream industry has created a unique innovation environment aimed at improving environmental performance across the industry, though collaboration-based organizations such as Canada's Oil Sands Innovation Alliance (COSIA), Petroleum Technology Alliance Canada (PTAC), Clean Resource Innovation Network (CRIN), Natural Gas Innovation Fund (NGIF), Petroleum Research Newfoundland and Labrador (PRNL), funded independent partnership organizations such as Evok Innovations, plus government-based initiatives such as Alberta Innovates and Emissions Reduction Alberta, in addition to post-secondary institutions and companies' own internal research.

DIRECT CONTACT STEAM GENERATION

The direct contact steam generation (DCSG) process involves steam generation from combustion of fuel gas with oxygen in direct contact with feed water in a high-pressure, high-temperature combustor. This creates a mixture of steam and CO_2 that replaces steam required for in situ injection, generated using conventional boiler technology. DCSG has the potential to reduce emissions because a significant portion of the CO_2 can be sequestered underground. DCSG also recycles 90% of the water used, requiring 10% of additional water that could be sourced from existing tailings ponds. Suncor and Canadian Natural are researching and testing this process.

OFFSHORE WIND-SOURCED ELECTRIFICATION

A scoping study to electrify offshore production facilities via development and installation of offshore wind farms is underway. This research includes recommendations for specific equipment and design criteria that could be implemented in different contexts including brownfield and greenfield developments.

ELECTRIFICATION OF FPSO VESSELS

Offshore installations are not connected to existing power grids so must generate their own electricity, which is a leading source of emissions. Preliminary research of the potential for electrifying greenfield floating production, supply and offloading (FPSO) vessels using power from shore is ongoing. Preliminary results demonstrate that electrification is possible, though not economically feasible based on current offshore activity levels.

BLUE HYDROGEN

Hydrogen is an energy-dense fuel that can be used in many ways, from industrial applications to heating, producing electricity and more. When combusted, hydrogen produces no CO_2 or other GHG emissions — the only byproduct is water. 'Blue' hydrogen is derived from natural gas, with produced CO_2 captured and injected into deep rock or saline formations for permanent storage. Understanding and piloting the technology to support the commercial advancement of blue hydrogen production is ongoing. The Alberta government's **Natural Gas Vision and Strategy** includes provisions for blue hydrogen technology.

DIRECT AIR CAPTURE

Direct air capture is a technology that captures CO_2 directly from the air with an engineered, mechanical system. The CO_2 can be permanently stored in deep geological formations or used in the production of fuels, chemicals, building materials and other products.

OTHER OFFSHORE INITIATIVES

Canada's offshore industry has invested over $600 million in research and development, education and training, including research focused on generating knowledge about environmental conditions and reducing existing and potential environmental risks.

Examples:

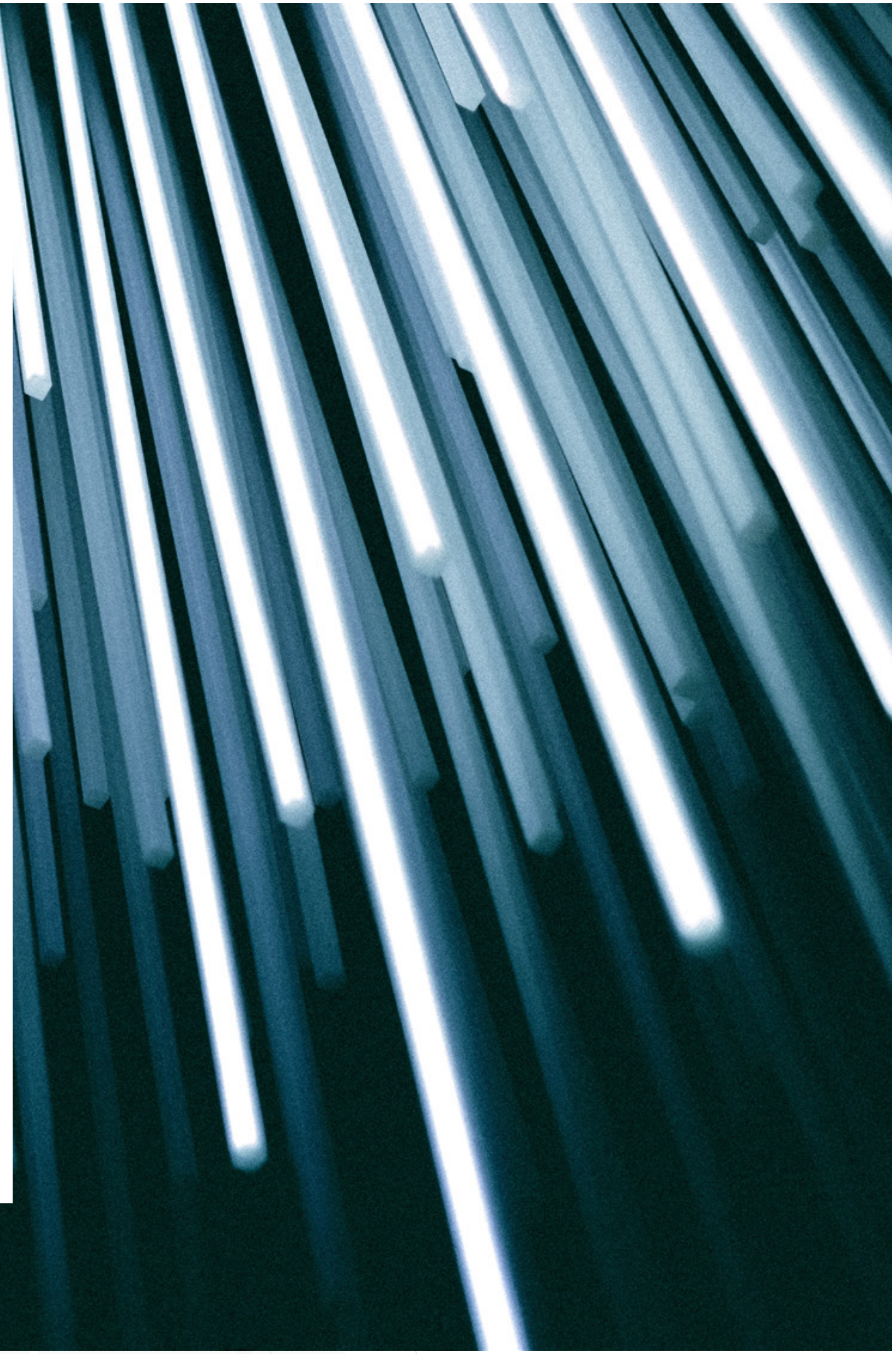
- During maintenance programs, operators look at methods to improve efficiency of operation for power generation units and other key equipment, subsequently reducing emissions.
- Supply vessels use fuel management and monitoring systems to ensure vessels are operating as efficiently as possible and continue to consider new technology as it becomes available.
- Operators are implementing fugitive emissions monitoring systems that use optical gas imaging cameras, facilitating rapid leak detection and repair.
- Work is underway internationally in the marine transportation industry to use alternative low-carbon fuels.

Emissions Intensity Performance Data

The following data demonstrates the industry's emissions intensity reduction performance to date. With ongoing development and deployment of technologies and initiatives described in Technology Overview, additional significant reductions can be expected. The industry takes a collaborative, solutions-oriented approach to achieving more reductions and the industry's climate objectives are compatible with provincial and federal objectives. The sector is committed to playing a pivotal role in helping Canada meet its stated emissions reduction goals, while maintaining a strong economic focus that includes nationwide employment, government revenue generation, and supporting quality of life with fuels and products Canadians depend on.

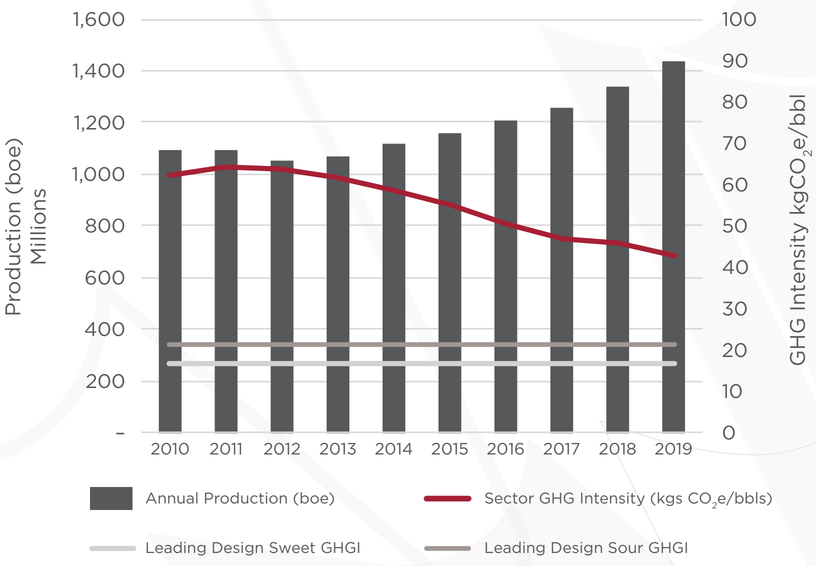
To clearly demonstrate the ongoing emission intensity reductions across the natural gas and oil industry arising from advanced technologies and process efficiencies, CAPP developed trend graphs using a bottom-up analysis for oil sands and offshore sectors that utilizes individual facilities' emissions data to create an overview of the sector's total emissions. The analysis includes both direct (Scope 1) and indirect (Scope 2) emissions. For natural gas emissions, CAPP used a top-down analysis whereby the sector is evaluated holistically. For comparison, graphs also show 'leading' performance for Canadian oil sands and natural gas production.

Within the oil sands sector, the biggest driver of direct emissions is natural gas combustion for steam or hot water generation, while the largest sources of indirect emissions are from diluent, land use, and imported electricity from the Alberta power grid (which currently uses mostly coal and natural gas-fired generation).



NATURAL GAS, NATURAL GAS LIQUIDS (NGLS), AND CONDENSATE

Production and Greenhouse Gas Intensity



Source: Environment and Climate Change Canada (2021 NIR Report), CER, Report Envirotech Engineering.

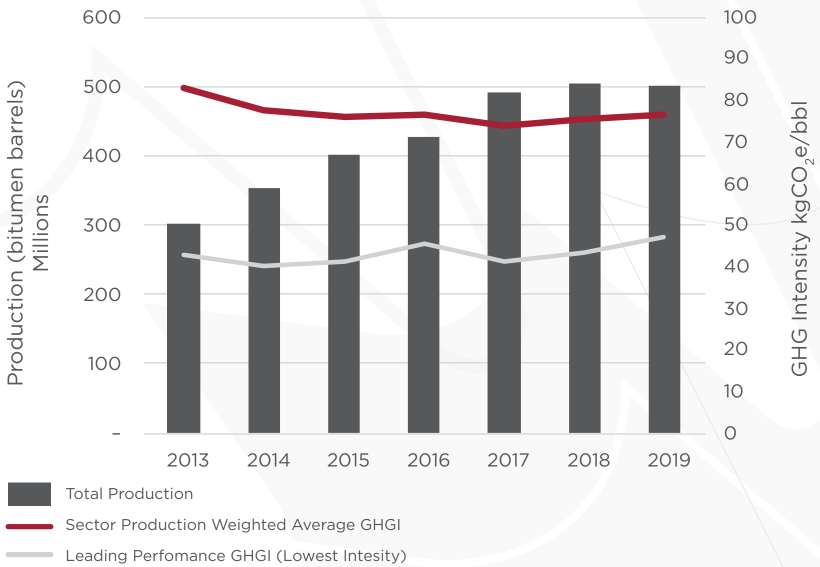
Data on this graph represents emissions intensity from natural gas extraction and processing, NGLs, and condensate production. From 2011 to 2019, emissions intensity decreased by 33% in this sector. During the same period, natural gas production in B.C. doubled and there was an increase in liquids-rich natural gas production in both B.C. and Alberta. The leading performance lines are estimated from a new design gas-driven facility for both sour and sweet gas inlets.

Another noteworthy performance indicator (not shown in the graph) is emissions intensity per kilowatt-hour (kWh) of electricity consumed for natural gas producing and processing. In Alberta, over the period 2010 to 2019, emissions per kWh declined from 1,100 grams of CO_2 equivalent (CO_2e) per kWh to 670 g CO_2e / kWh.

Improved emissions management, particularly actions aimed at achieving methane emissions reduction targets and multi-well drilling pad approaches, are key drivers in emissions intensity reduction in this sector.

OIL SANDS IN SITU

Oil Sands In Situ Production and Emissions Intensity



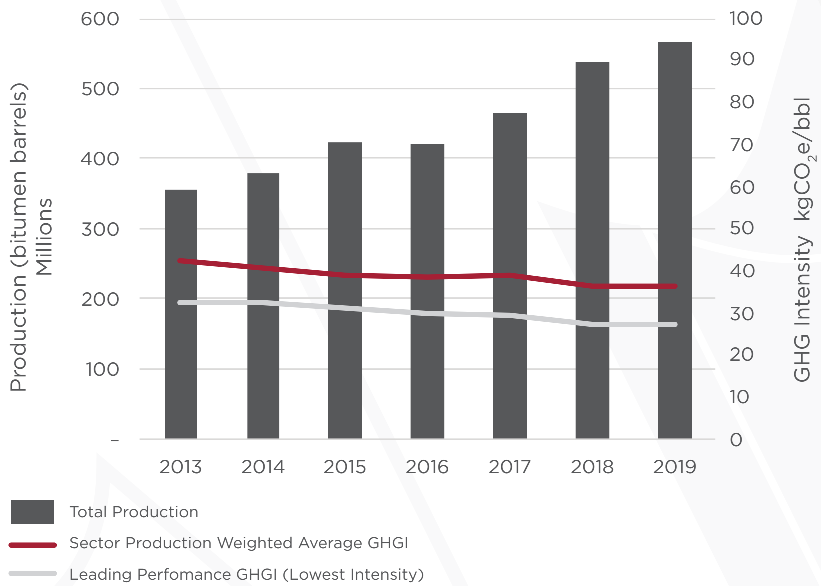
Source: Alberta Environment and Parks Alberta Oil Sands Greenhouse Gas Intensity Analysis, AER ST53, NIR 2021 Part 3. GHGI PWA = greenhouse gas intensity production weighted average.

Data on the graph includes both steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) production, Scope 1 and 2 emissions. Data indicates an emissions intensity reduction of 8% between 2013 and 2019 while production increased 66%. Production curtailment, mandated by the provincial government in response to very wide price differentials between Western Canada Select crude oil produced in Alberta and West Texas Intermediate crude, affected in situ emissions intensity in 2019. A wildfire in 2016 resulted in the temporary shutdown of many in situ oil sands projects.

The optimization of SAGD projects has substantially contributed to emission intensity reductions. The use of electric submersible pumps (ESPs) has enabled better well control and more efficient operations. Wedge or infill wells optimize production from already-heated reservoirs, capitalizing on previous combustion and steam injection, and have been widely deployed. Steam generation efficiency is also a key determinant for reducing emissions intensity for in situ projects.

OIL SANDS MINING

Oil Sands Mining Production and Emissions Intensity



Source: Alberta Environment and Parks Alberta Oil Sands Greenhouse Gas Intensity Analysis, AER ST 39. GHGI PWA = Greenhouse Gas Intensity Production Weighted Average.

For the oil sands mining sector, data indicates an emissions intensity reduction of 14% between 2013 and 2019 while production increased 59%. There was a substantial emissions intensity decrease in 2017-2018 after Suncor Energy's Fort Hills mining project started operation in 2017, as this is a PFT mine with a lower emission intensity than past projects. Wildfires in 2016 affected oil sands mining production and emissions intensity.

OFFSHORE

Offshore Production and Emissions Intensity

Source: Environment and Climate Change Canada, Canada-Newfoundland and Labrador Offshore Petroleum Board

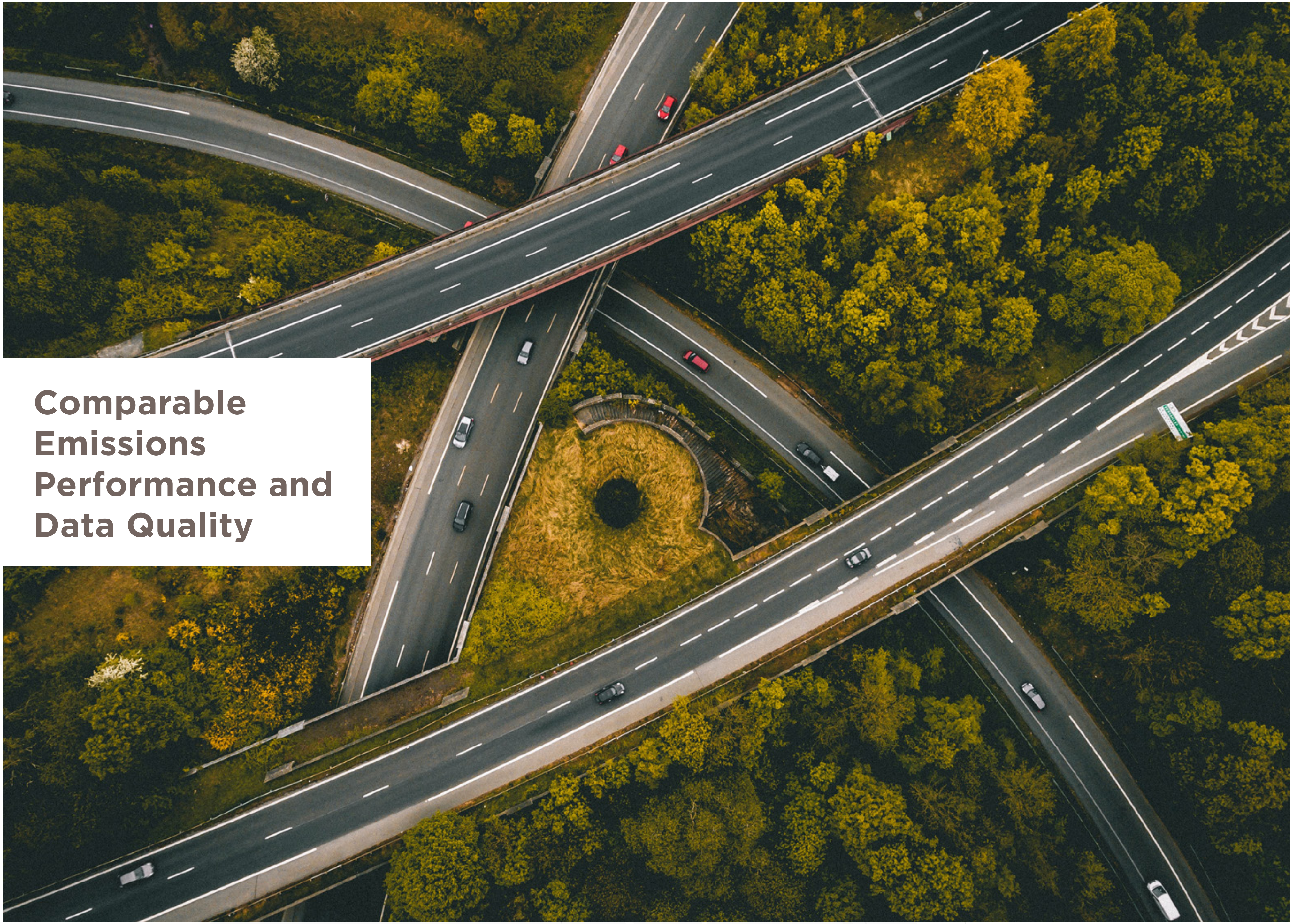
Canada's offshore industry currently consists of four major projects: Hibernia, Terra Nova, White Rose and Hebron.

Emissions related to offshore production in NL represent 14% of the province's total emissions. The most significant emissions sources in the offshore include:

- The need to generate electricity for each offshore installation, requiring natural gas combustion (no opportunity to utilize onshore electricity infrastructure).
- Flaring - offshore operators have reduced flaring significantly through the Global Gas Flaring Reduction Partnership.
- Operators are working to manage and reduce emissions through operational efficiencies and preventative maintenance, which in turn reduces energy consumption.

Overall emissions volumes from Canada's offshore operations are low. Factors affecting emissions intensity include:

- A field's age and ongoing production causes decreasing reservoir pressure, requiring additional solution gas management and higher gas injection volumes into the reservoir, which results in higher emissions intensity.
- New offshore facilities generally have higher emissions intensity for the first few years of production before achieving steady state when emissions intensity stabilizes.



Comparable Emissions Performance and Data Quality

Comparing Canada's emission intensity performance with other producing nations and regions provides context for Canada's efforts and success to date. However, due to challenges concerning data quality and availability from other producing jurisdictions, direct comparisons are problematic. Many data sets and comparison tools are based on inaccurate assumptions and incomplete data, so don't offer a robust, factual overview of emissions from other jurisdictions. For example, some data sets do not include methane emissions although methane is a much more potent greenhouse gas than CO_2.

This poses a strong risk that the investment community may make important decisions on potentially faulty data. It is vital to ensure proper comparison of data between jurisdictions to ensure an accurate picture, which in turn will help the investment community to make decisions based on the best possible data and performance. Canada is a world leader in transparent data collection, and the Canadian oil and natural gas industry has among the strongest public data in the world.

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OIL

Currently, two groups are progressing global emission comparisons that CAPP believes are robust and credible:

- **The Oil-Climate Index** (OCI) – a tool created by Carnegie-Mellon University in collaboration with Stanford University and the University of Calgary to estimate and compare total lifecycle emissions of individual crude oil types, from upstream production through midstream refining to downstream end use. Imperial, Canadian Natural and several other oil sands producers are continuing to engage with OCI authors to review and update Canadian benchmarks and explore the impacts of new technologies on Canada's production lifecycle emissions intensity. The OCI currently includes more than 75 crudes from various global sources and aggregates three emission estimation models, including the Oil Production Greenhouse Gas Emissions Estimator (OPGEE).
- **IHS The Right Measure** – a report by IHS Markit expected to be released in 2021 that will review other estimates and create a methodology to quantify and qualify emissions estimates to facilitate their interpretation and comparability. Funded in part by the Alberta government, this study seeks to develop a shared understanding of which emissions should be included in the analysis, increase the transparency around estimate quality, and create benchmarks for crude refined in the U.S.

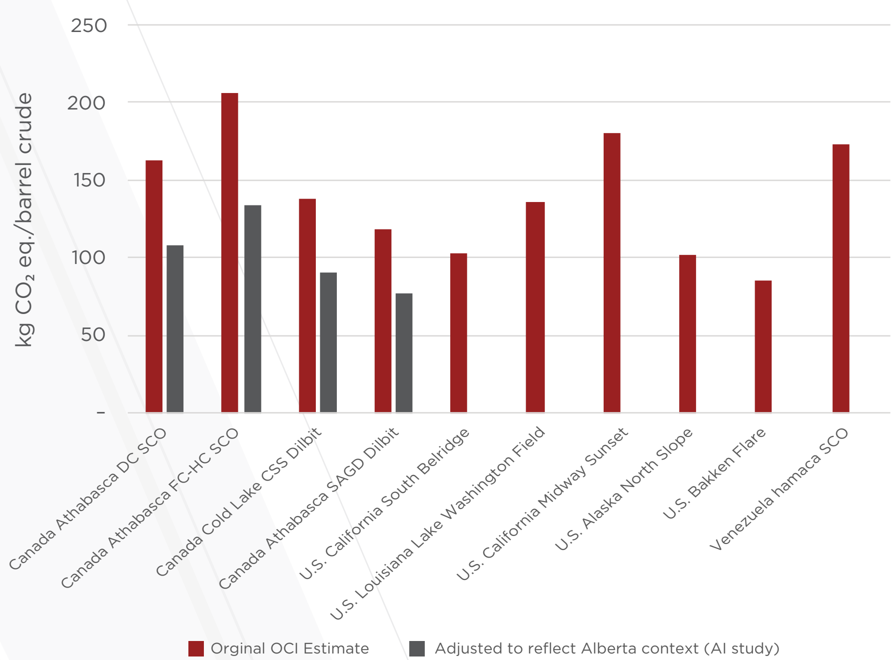
Alberta Innovates Study

A study led by Stanford University, the University of Calgary and the University of Toronto in collaboration with Alberta Innovates and published in the Journal of Cleaner Production, concluded that when Alberta-specific data is used in OPGEE, upstream GHG intensity numbers of oil sands production pathways are as much as 35% lower than previously published, making them comparable to other crudes. The study also demonstrated that current use of PFT technology is producing crude with intensities lower than the global average.

Based on the findings of the Alberta Innovates study, a re-evaluation of OCI values demonstrates a decrease in oil sands emissions intensity. Deployment of additional technologies, such as SA-SAGD (solvent-assisted SAGD, using light hydrocarbons instead of steam to recover bitumen), offers further opportunities to reduce emissions intensity even more, such that the oil sands industry could outperform comparable crudes.

SCO = synthetic crude oil
DC = delayed coker
FC+HC = fluid coker + hydroconversion system
CSS = cyclic steam stimulation
SAGD = steam-assisted gravity drainage

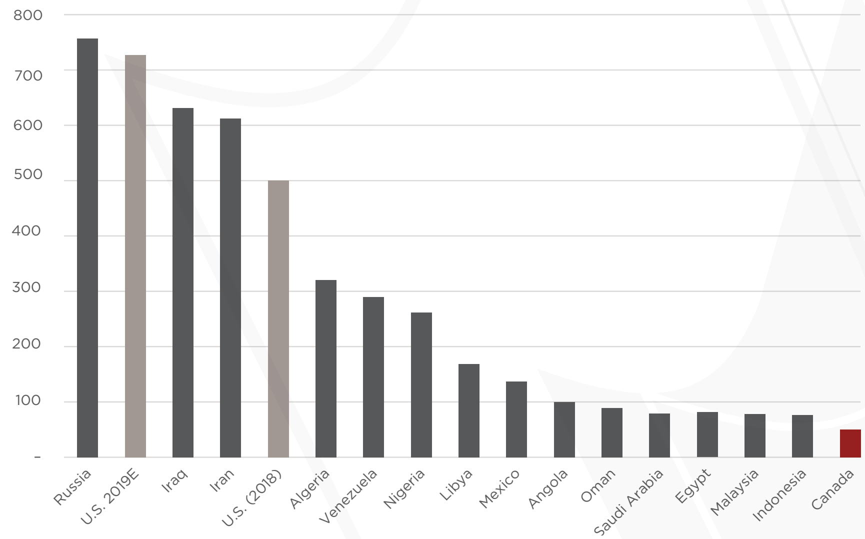
Emissions Intensity – Canada, U.S., Venezuela Crudes



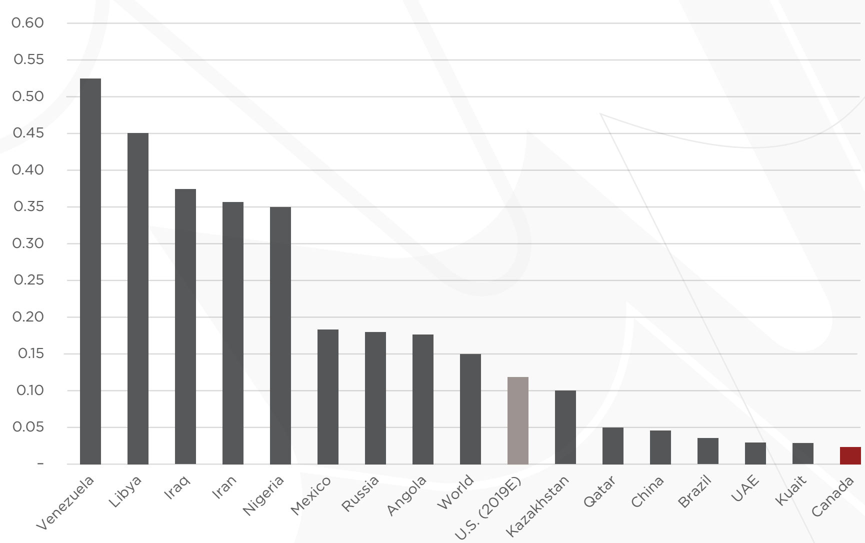
Source: Oil Climate Initiative

NATURAL GAS

Highest Natural Gas Flaring Countries vs. Canada (Bcf)



Flaring Intensity by Major Oil Producing Country (mcf/bbl)



Source: BMO Capital Markets

Analysis by BMO Capital Markets indicates that as a result of flaring practices, Canada is among the lowest-intensity natural gas producers globally. According to **research by the Canadian Energy Centre (CEC)** — which in 2020 released an analysis of flaring and emissions data from the World Bank, the U.S. Energy Information Administration and the International Energy Agency — Canada's emissions from flaring decreased by 38% while production increased by 22% between 2014 and 2018. The CEC's analysis confirmed work released in 2018 by Stanford University, which estimated that if Canada's flaring regulations were adopted by other energy-producing nations, global emissions from oil and natural gas production could be lowered by up to 23%.

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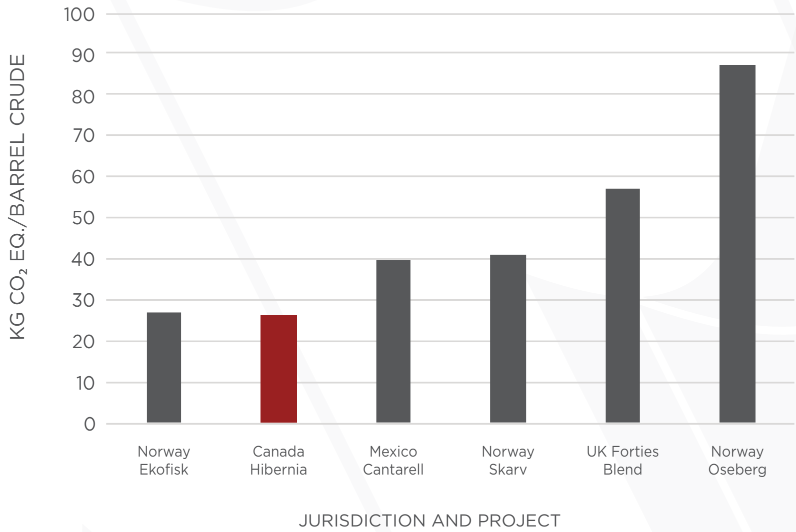
OFFSHORE

Offshore Project Upstream Emissions Intensity



Source: Oil Climate Index

This graph represents upstream data sourced from OCI for Canada's offshore, with Hibernia being the only Canadian project for which data is available to OCI. Canadian offshore (Hibernia) emissions intensity compares favourably with other offshore producers in part because the oil itself is sweeter (lower sulphur content).

Offshore oil and natural gas operators in Newfoundland and Labrador (NL) are committed to working with policy makers and other stakeholders to address climate change and are working with and supporting governments in achieving governments' net zero goals. The offshore industry is part of the solution to a lower carbon energy future and to the long-term diversification of NL's economy.

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CANADA'S OIL & NATURAL GAS PRODUCERS

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