Trottier Energy Futures Project

Greenhouse Gas Emissions from the Canadian Oil and Gas Sector

R.L. Evans & T. Bryant

PROJET TROTTIER POUR L'AVENIR ÉNERGÉTIQUE

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By R.L. Evans and Tyler Bryant

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Introduction and background

In developing low carbon scenarios for Canada, it is important to understand the role of the oil and gas sector as a major contributor to greenhouse gas (GHG) emissions. As outlined in the first Trottier Energy Futures Project report on Low Carbon Scenarios, Canada is the only country of the eight reviewed that is a net fossil fuel producer.[1] The CanESS (Canadian Energy Systems Simulator) model has been chosen by the Trottier Energy Futures Project (TEFP) to provide estimates of current and future energy use and GHG emissions. The authors of this report have been asked by the TEFP Management Board to review the way the CanESS model deals with emissions from the Canadian oil and gas production sectors to ensure that model predictions are consistent with actual production data. In order to do so this report compares results from the model predictions with emissions data reported by Statistics Canada and other government agencies where such data is available. Particular care has been taken to examine the emissions from the production of synthetic crude oil and diluted bitumen ("dilbit") from the Alberta oil sands. This report is divided into two main sections examining GHG emissions from oil and gas production in Canada. The first section describes historical levels of GHG emissions from oil and gas production which have been used to "calibrate" the CanESS model. The second section discusses emission levels projected by the CanESS model to mid-century using production levels assumed in the TEFP "reference scenario". Unless otherwise stated, all data used in this report has been obtained from the CanESS model which uses input data from Environment Canada, Statistics Canada, the National Energy Board, and the Alberta Energy Resources Conservation Board, as well as input from the GREET and GHG Genius models used to track GHG emissions. In addition, some data from an extensive study of emissions from oil sands production prepared for the government of Alberta has been used as a check on the CanESS model assumptions.

[1] Ralph D Torrie et al., *Low-Carbon Energy Futures : A Review of National Scenarios* (Vancouver: Trottier Energy Futures Project, 2013).

Historical emissions from oil and gas production in Canada

The distribution of GHG emissions in Canada by sector are shown in Figure 1 for the year 2006. Emissions from oil and gas production, including extraction, mining, pipelining, and refining were 163 Mt in 2006, and represented 28% of all GHG emissions. This large share of total Canadian GHG emissions attributed to oil and gas production illustrates the difficulty of reducing overall emissions by 80% if the industry were to proceed on a "business as usual" (BAU) scenario.

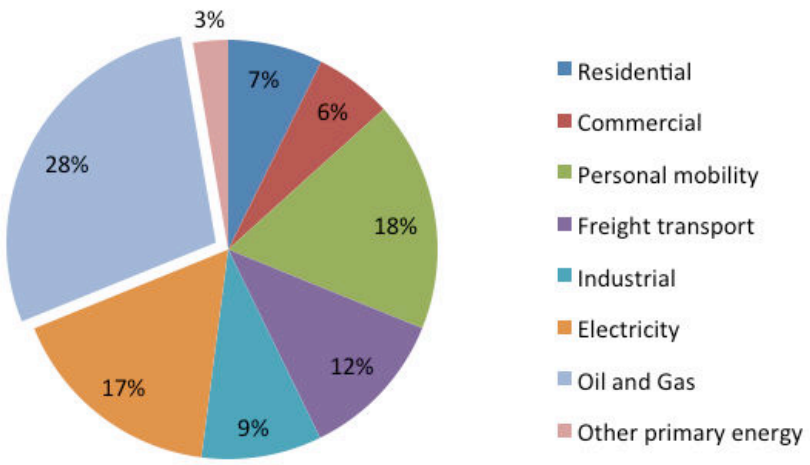

Figure 1: Share of GHG Emissions by sector in Canada (2006)

The authoritative source of GHG emissions in Canada is the "National Inventory Report for GHG emissions" published by Environment Canada [1]. Canada submits an Inventory Report every year as part of their obligation to the UN Framework Convention on Climate Change (UNFCC). The inventory Reports for all countries follow a template for submission based on a specific categorization of emissions. Items in the Inventory Report specific to oil and gas emissions in Canada are:

- Fossil Fuel Production and Refining:
  - Petroleum Refining: "Emissions from the combustion of fossil fuels during the production of refined petroleum products
  - Fossil Fuel Production: "Fuel combustion emissions associated with the upstream oil and gas industry."
  - Mining and Oil and Gas Extraction: "Emissions associated with oil (particularly crude bitumen from the oil sands), gas and coal extraction, as well as emissions associated with non-energy mining such as metals and aggregates."

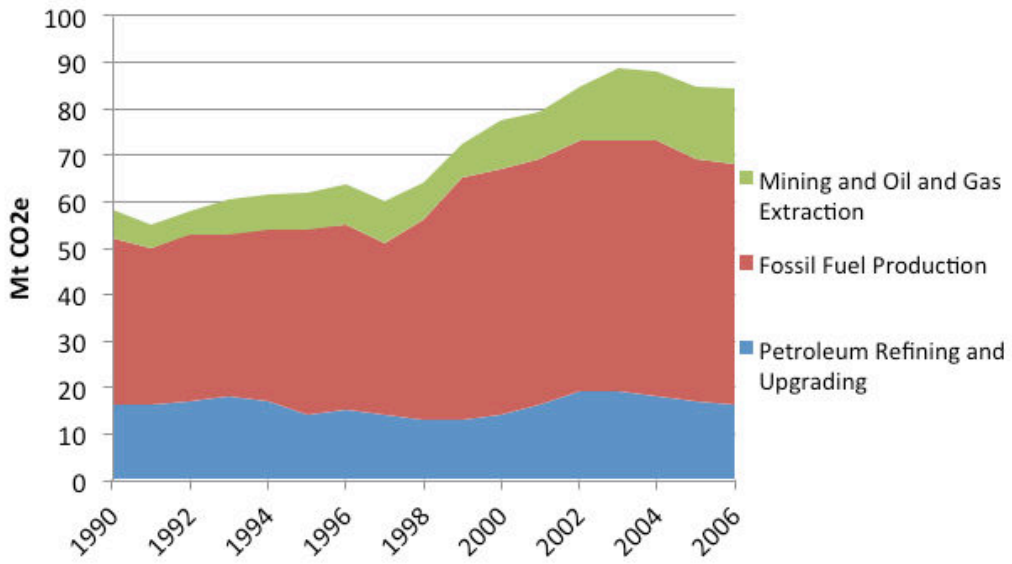

Figure 2: GHG Emissions from Oil and Gas Production

Figure 2 shows the GHG emissions for the Canadian oil and gas production and mining sectors in the format required by the UNFCC. However, this categorization is not adequate to form a detailed understanding of emissions-related activities in the oil and gas sector in Canada. Lumping bitumen mining with coal, gas and metals extraction does not provide the specificity required to track emissions from oil and gas production which have significantly different energy and emissions profiles than mining. Also, a single category for emissions from fossil fuel production, as required by the UNFCC, does not provide sufficient detail on the breakdown of GHG emissions from the production of natural gas, and both conventional and unconventional crude oil production which is of interest in to the Canadian context. Finally, this representation does not completely describe oil and gas sector emissions since fugitive emissions and emissions from oil and gas transmission are left out. Environment Canada publishes oil and gas sector emissions with more detail, including fugitive emissions and those resulting from transmission by pipeline, as shown in Figure 3. Total oil and gas sector emissions are currently approximately 160 Mt, including fugitive emissions and those from transmission. Using Environment Canada's emissions breakdown, downstream oil and gas includes all petroleum refining and natural gas distribution through low pressure pipelines to commercial, residential and industrial users. Oil and gas transmission is the use of pipelines for transporting bulk quantities to oil and gas to retailers, refineries and distributors.

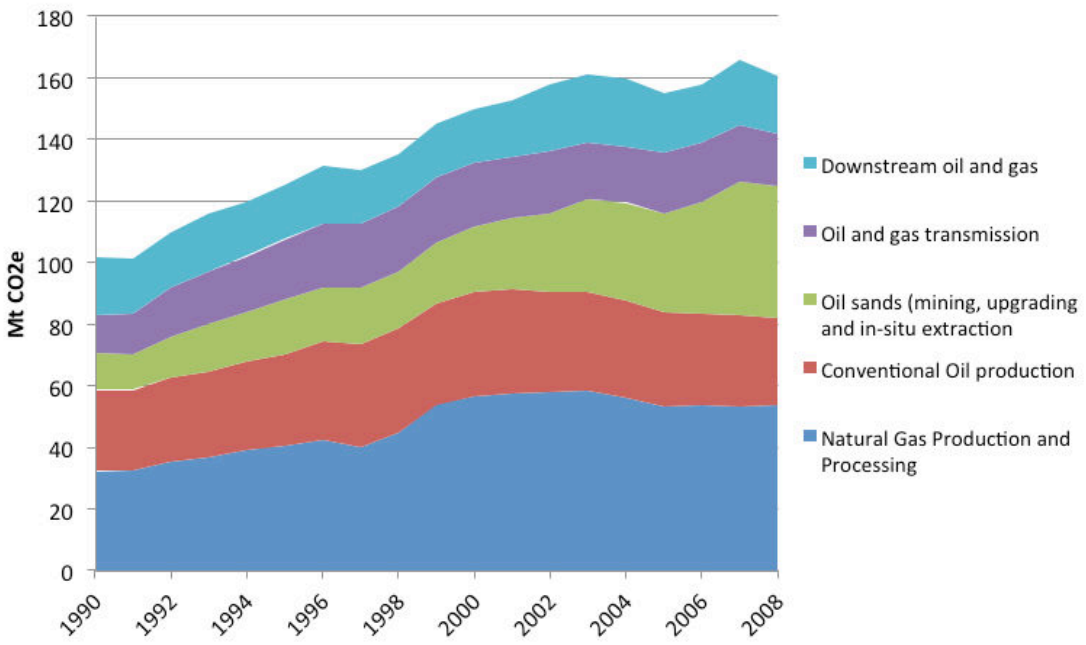

Figure 3: Oil and Gas Emissions (Environment Canada)

The CanESS model used by the Trottier Energy Futures project is historically calibrated to the Report on Energy Supply and Demand (RESD) which is the official source of energy consumption and production produced by Statistics Canada. It then uses the National Inventory Report of GHG emissions provided by Environment Canada to determine emission intensities for the various fuel sources by matching oil and gas energy consumption and production activities with their respective GHG outputs in the inventory report. The data used for these calculations are not as detailed as the confidential data available to Environment Canada used to build their emission inventory. As a result, projections of GHG emissions by the CanESS model until about the year 2000 show significant differences from the more detailed data in the Environment Canada reports, as can be seen in Figure 4. After 2000, however, more detailed reporting in the RESD data has enabled the CanESS projections to closely match the data reported directly to Environment Canada. As can be seen in Figure 5 this resulted in a much more accurate representation of total GHG emissions by the CanESS model, especially after about 2006.

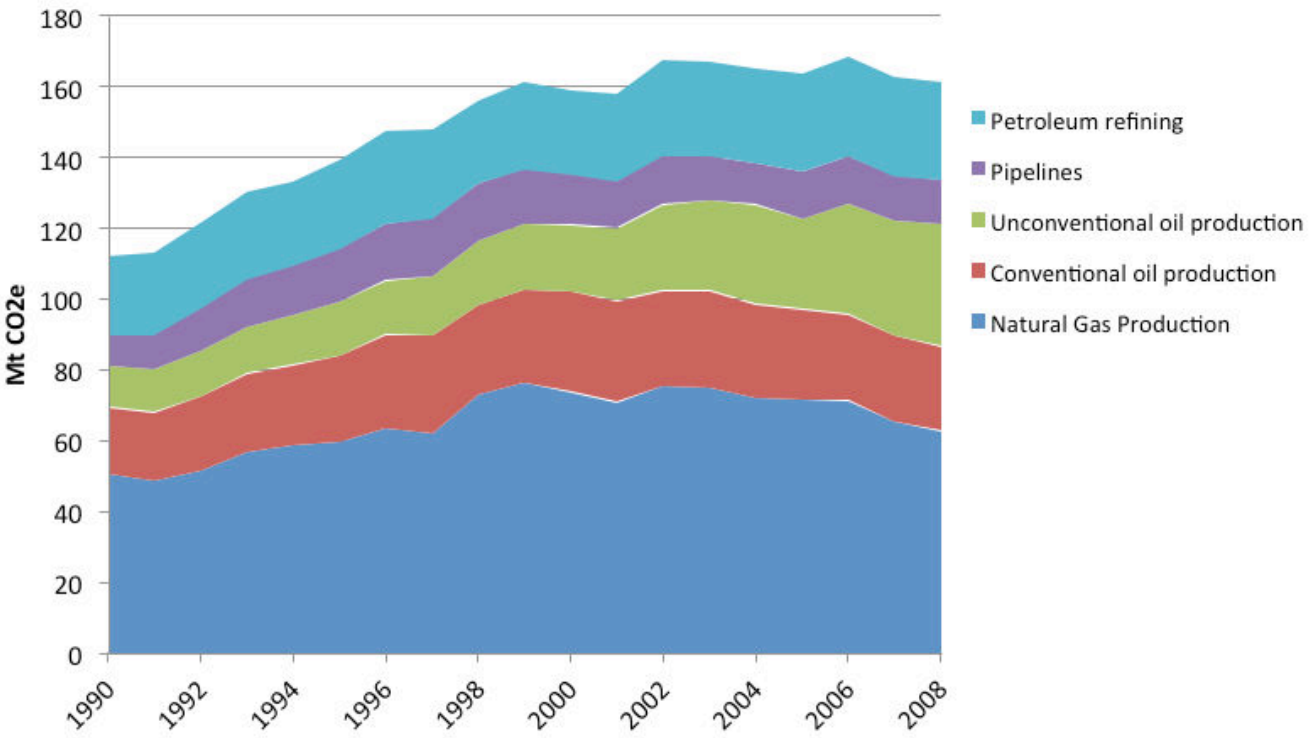

Figure 4: CanESS Oil and Gas Emissions

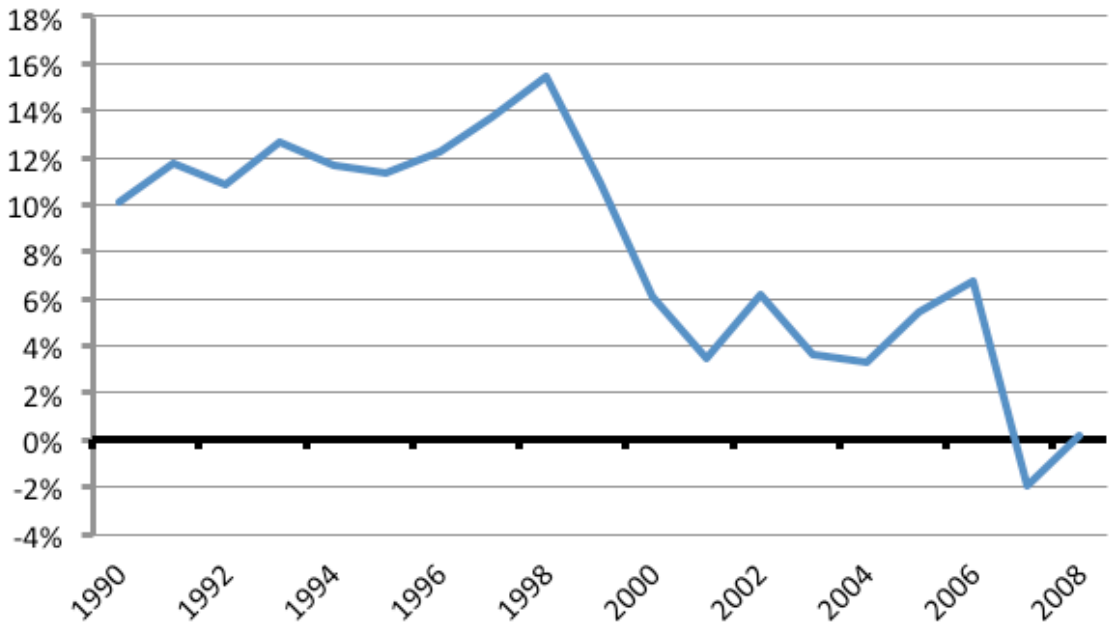

Figure 5: Differences in Oil and Gas GHG Emissions provided by the CanESS model compared to Environment Canada data

The CanESS model has a detailed representation of the energy use and GHG emissions related to fossil fuel extraction. The model separately calculates emissions from natural gas, conventional oil and oil sands production. The total volumes of future production are set exogenously by modellers using a scenario analysis. Each fuel type has a detailed process representation from extraction though to processing into a marketable commodity. Total production of each fuel is then divided into domestic and export shares based on either the historical relationships between exports and domestic consumption, or on specific scenario assumptions for future production. The following sections describe the basic logic that is used in CanESS to calculate emissions from the production of natural gas, conventional oil and oil sands products.

Natural Gas Production

The CanESS model being used by the TEFP determines natural gas emissions based on intensity factors of production. This is done by using ratios of emissions per unit of production by gas type and extraction or production process. Determining the total production levels for natural gas is therefore an important first step in modelling gas emissions. The natural gas sector is first separated into conventional and unconventional gas production. Conventional gas production is set by the provinces and is constrained by an assessed value of the total provincial conventional gas reserves, as reported by the National Energy Board. When natural gas is produced the remaining reserves are adjusted based on the amount of production and then carried through to the next year of the scenario meaning that production cannot exceed the size of the reserve. The reserve size can also be updated exogenously by the modeller to represent changing recovery technologies and economics.

Estimating unconventional production is more complex. CanESS provides for five different unconventional gas types among 46 different basins. Production of unconventional gas is constrained by the size of the estimated reserves. The National Energy Board and others have done assessments for specific regions but the variance in the basin characteristics has led to an incomplete picture of the size of the reserves in place currently. Unconventional gas production in CanESS is therefore set by modellers using the "well rate plan." Modellers estimate the number of new wells built by basin per year in a particular scenario and the model then calculates production based on the number of wells. Basin-specific well decline rates are also input by the modeller based on reported data. This representation allows the model to develop a representation of the decline of unconventional well production and the required new well development to make up for this decline specific to each basin. As widely reported, the move to shale gas development has shown that production declines are an important issue to be considered. The CanESS model can also include gas produced from oil sands, biomass, or coal to gas processes. While not a significant source of natural gas at present, the model is set up to account for the different emission factors and energy requirements of these processes, enabling modellers to provide complete coverage of gas disposition in Canada.

Canadian exports of natural gas to the U.S. have traditionally been at a similar level to that of Canadian consumption as seen in Figure 6. Looking ahead, however, this production split may well change significantly. American gas production has experienced significant increases in recent years due to the shale gas boom which may limit American demand for imported gas. Conversely, opportunities for liquefied natural gas exports from BC may diversify Canadian export opportunities and offset lost exports to the U.S. or increase the total volume of exports. The role of imports has been increasing in recent years with gas imports from American shale production in the north-east moving to Eastern Canada. These will impact the balance of trade, the price of gas and the production of gas into the future.

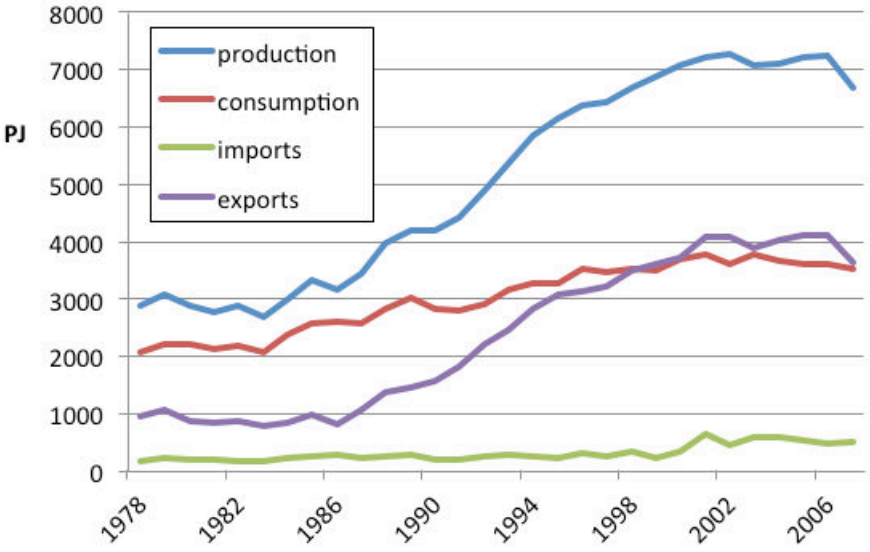

Figure 6: Historical Natural Gas Production, Domestic Consumption, Imports and Exports

Natural gas emissions comprise two important sources, those from the combustion of fossil fuels for energy to extract, process, and pipeline the gas and those from the fugitive releases of methane and CO2 in the extraction, venting and flaring of gas during processing. Fuel use for natural gas production comes from the Report and Energy Supply and Disposition (RESD) is reported by province of origin. Fuel use in the natural gas production sector is represented in the 'Mining' category of the RESD which includes metal, coal, and oil sands mining. In order to separate natural gas fuel use in the natural gas sector, CanESS uses data on energy use in the metal mining sector from NRCan's Mining Census and natural gas use in the oil sands sector from the Energy Resources Conservation Board and subtracts that from the Mining sector total in the RESD. The fuel use for natural gas production is then calculated as a ratio of energy inputs for extraction and processing to total energy output of the marketable gas. These production intensity ratios are developed specifically for each province for both conventional and unconventional gas production. Increases in the energy intensity of gas production over time reflect a declining quality of the conventional resource, as can be seen in Figure 7. The Canadian Energy Research Institute and the University of Calgary have shown that the energy content of per cubic meter of raw gas produced dropped 25% between 2002 and 2006 [2].

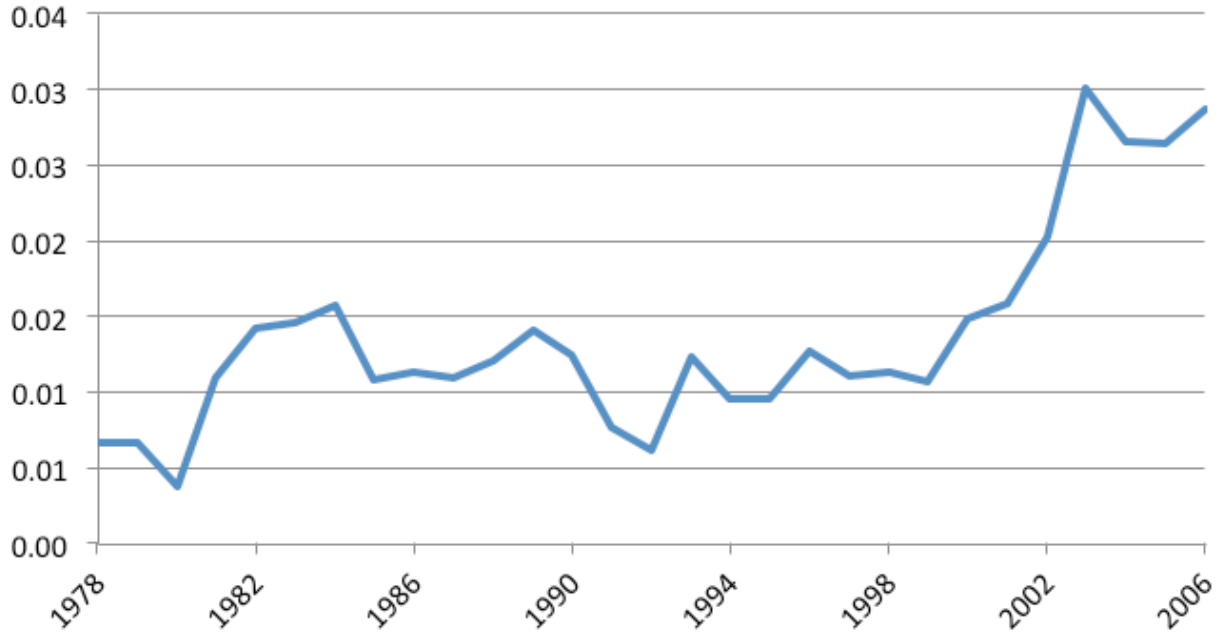

Figure 7: Ratio of energy inputs to energy output for Alberta natural gas

The second component of natural gas emissions are fugitive releases. Fugitive emissions are the emissions that occur at the well head from leakage and at the natural gas processing facility which strips the raw gas of CO2 and some methane to be vented or flared. Fugitive emissions are again calibrated using Environment Canada's National Inventory Report for Greenhouse Gas Emissions as the primary data source. Fugitives are calculated as a fraction of total natural gas production. The fugitive intensity of natural gas production is then multiplied by total production to provide an estimate of total natural gas fugitive emissions. Fugitive emissions, reported as Mt of CO2e are shown in Figure 8 for the period from 1978 to 2006.

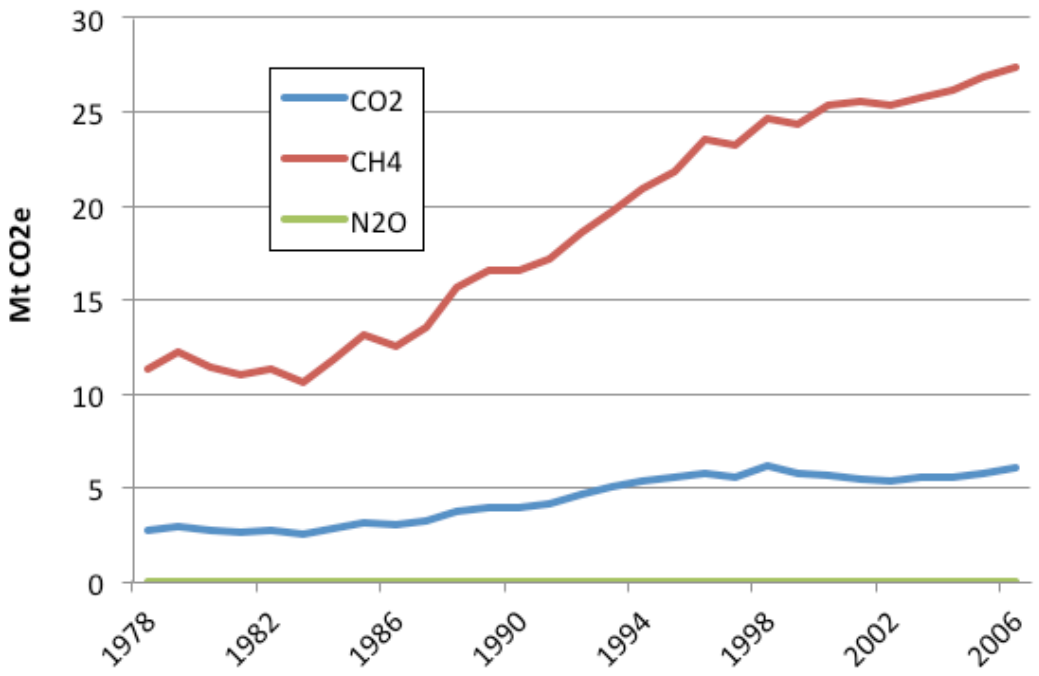

Figure 8: Fugitive emissions from natural gas production

Using the estimates of both processing fuel and fugitive emissions, the total upstream carbon intensity of natural gas production in Canada can be determined by the CanESS model. Dividing total GHG emissions from natural gas production by the amount of natural gas production gives us an estimate of 12,750 grams CO2e per MJ of natural produced in 2006. This compares to the GHGenius estimation of carbon intensity of 12,332 gCO2e/MJ in 2006. Figure 9 compares the emissions intensity of the natural gas sector as calculated by both CanESS and GHGenius. The results from both models show that the extraction and processing emissions estimated by both are very similar.

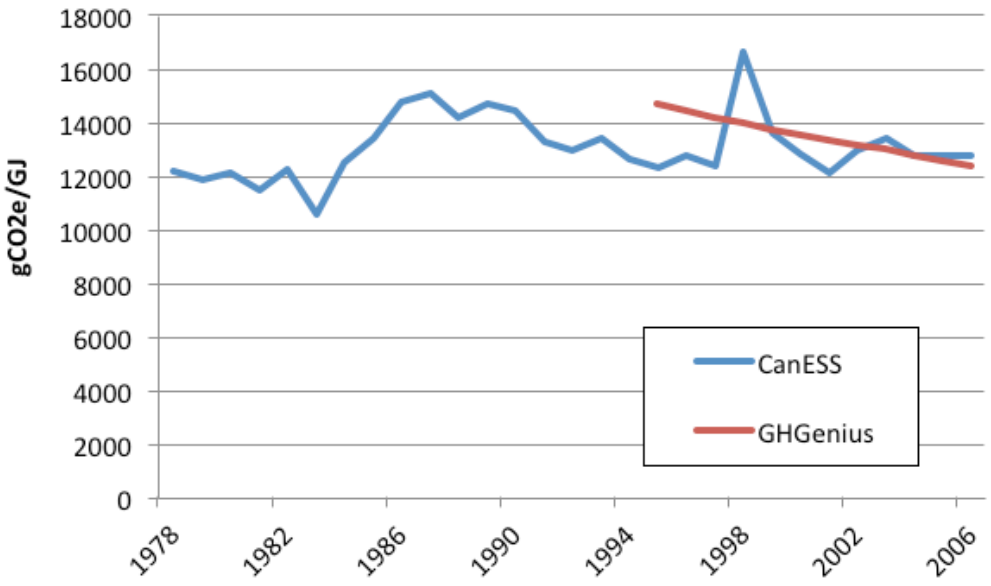

Figure 9: Carbon intensity of natural gas production in Canada

Crude Oil production

Canada's emergence as a net oil exporter has been taking place over the past 20 years. This can be seen by the disposition of crude oil shown in Figure 10 (in units of PJ, or 10^{15} Joules). Exports as a share of total production have been increasing steadily since 1990, as shown by the historical trends to 2006 in Figure 10. Since about 2006 total exports have exceeded domestic oil consumption. The other, less talked about trend in the Canadian oil market is the role of oil imports to eastern Canada. Since 1997, imports have accounted for over half of total oil consumption in Canada, although this share has levelled off over the past ten years to just over 50%. In the oil-rich west, producers are working to export their product to the United States, while in the oil poor east, provinces are importing their oil from the U.S. and overseas. The impact of this arrangement is that while Canada has seen significant increases in oil production and subsequent emissions associated with that production, it has also offset production emissions to other jurisdictions from imports. In other words, focusing on oil exports only tells part of the oil emissions story. By importing oil, Canada is outsourcing the emissions penalty from producing that oil domestically. If Canada, were to produce enough oil as it needed domestically and eliminate exports, oil sector emissions would still be very large. Current production is 6000 PJ and oil exports represent 4000 PJ while imports are current 2000 PJ. Eliminating exports and imports would drop oil sector emissions by approximately 1/3 instead of 2/3.

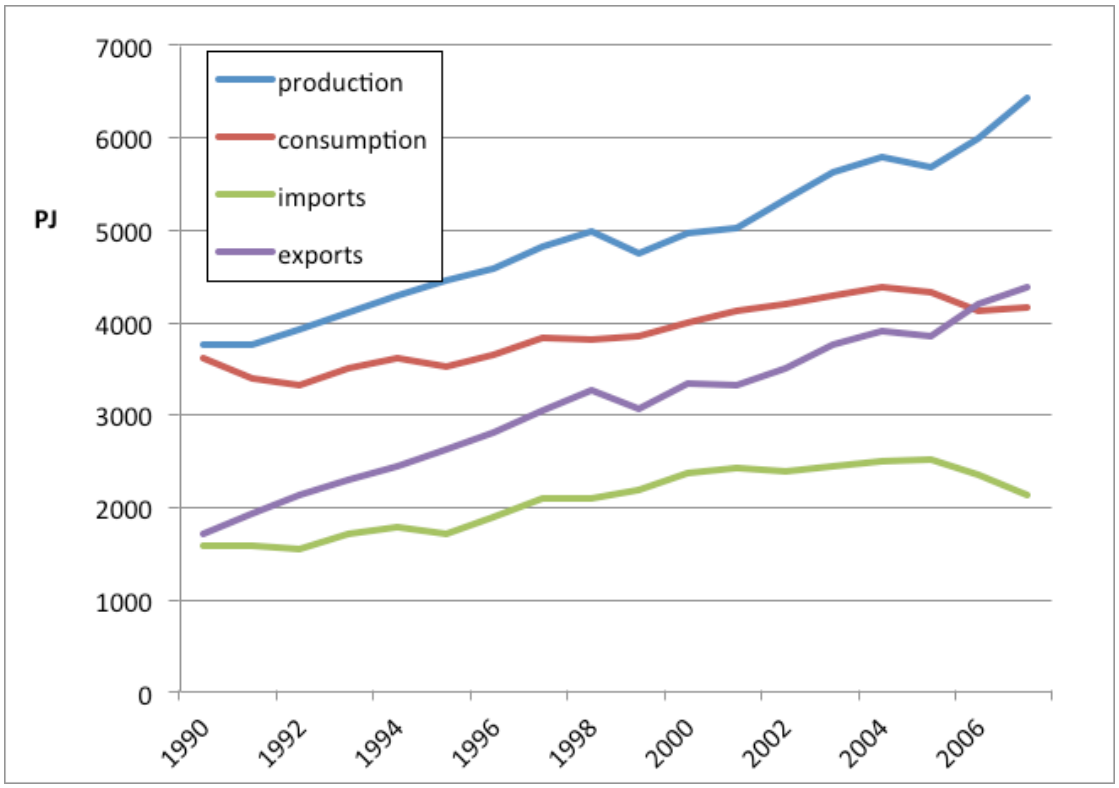

Figure 10: Canadian oil disposition

Conventional Crude Oil Production

The prediction of energy use and emissions resulting from the production of conventional crude oil is determined by applying an intensity variable for fuel use per unit of oil together with an estimate on the fugitive emissions per unit of production. Oil production levels for both conventional and unconventional crude are set exogenously by the modeller. Historical trends for the ratio of production between conventional and unconventional sources, as reported in the StatsCAN RESD reports, are used in CanESS. A further split between heavy and light conventional crude oil production is based on the historical trends, as shown in Figure 11. Total crude production is then constrained by an estimate of the conventional reserves in place first bound by an estimate of the reserves of conventional crude in place. This estimate is taken from the NEB's estimate on oil reserves in Canada [3]. Cumulative conventional crude production cannot exceed the reserves in place.

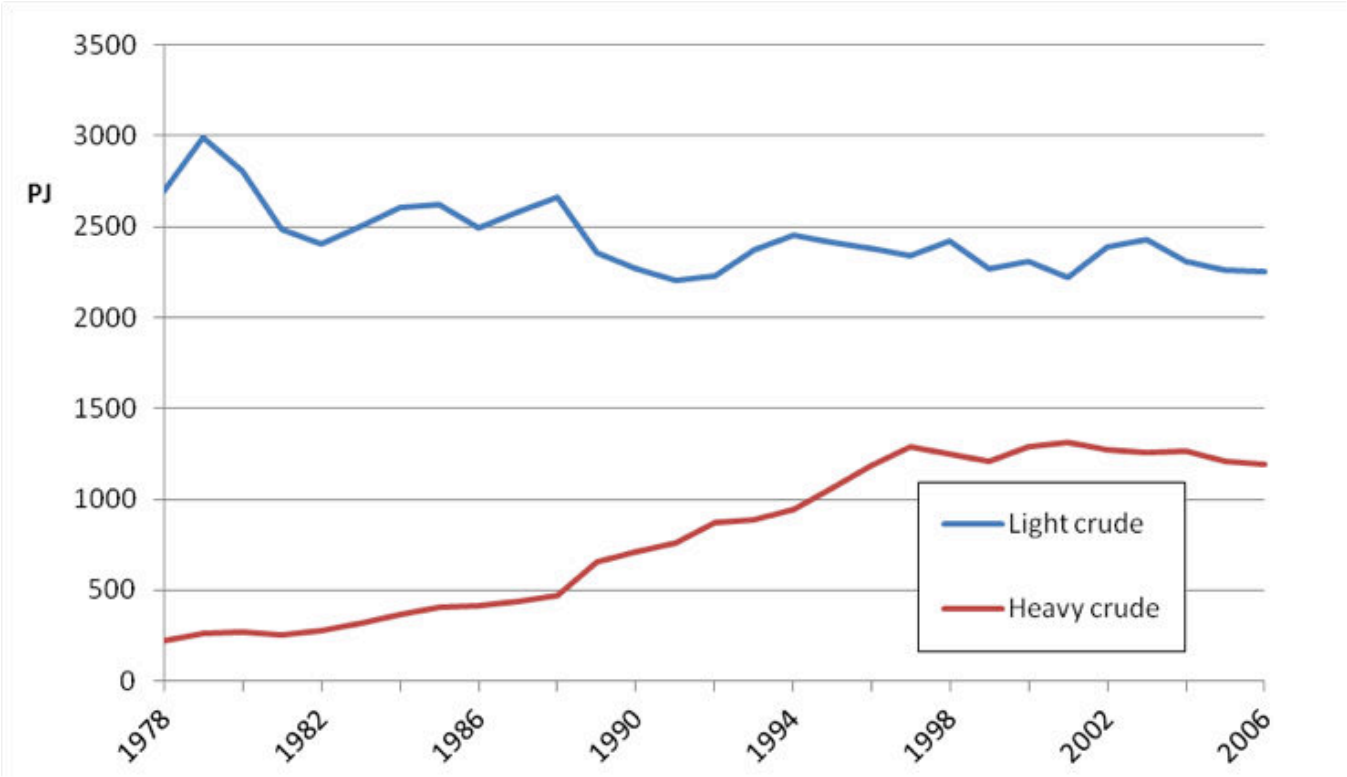

Figure 11: Conventional crude oil production

Energy use for crude oil production is represented simply in the model as an intensity of production and this is broken down by fuel type for both light and heavy crude production. The energy intensity of conventional crude oil extraction, defined as the ratio of energy used for production to crude oil energy content is shown in Figure 12. The intensity is rising, coinciding with greater production of heavy crude oil in the overall Canadian oil production mix.

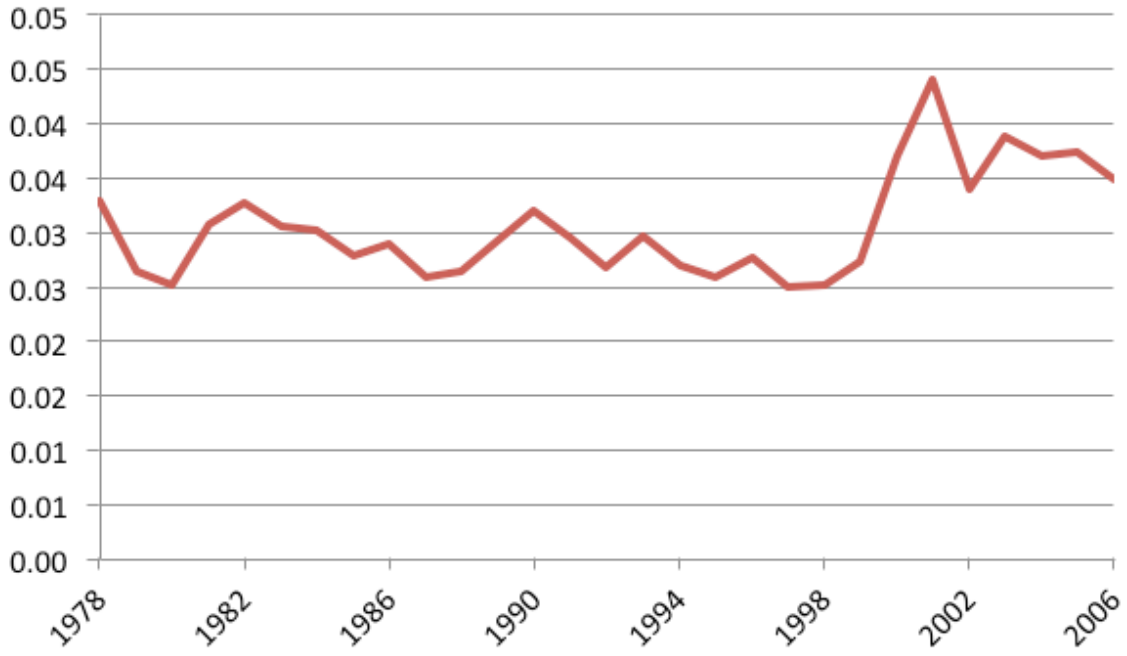

Figure 12: Conventional Crude Oil production intensity

The energy intensity of production allows CanESS to calculate GHG emissions from conventional crude oil production using emission factors for the fuels used to extract the oil. The dominant fuel is natural gas, typically a byproduct of oil extraction. Oil extraction also produces fugitive emissions such as methane leaks from the well. Fugitives are also calculated to be a function of total production, as shown by the historical data in Figure 13. Using all of this data, total historical GHG emissions from conventional crude oil production from 1978 to 2006 are shown in Figure 14. Fugitive emissions represent a much greater fraction of the total GHG emissions than do those from combustion of fuel gases used in the production process. Total GHG emissions from conventional oil production have also been rising due to increased production and the increasing level of fugitive emissions from heavy oil production.

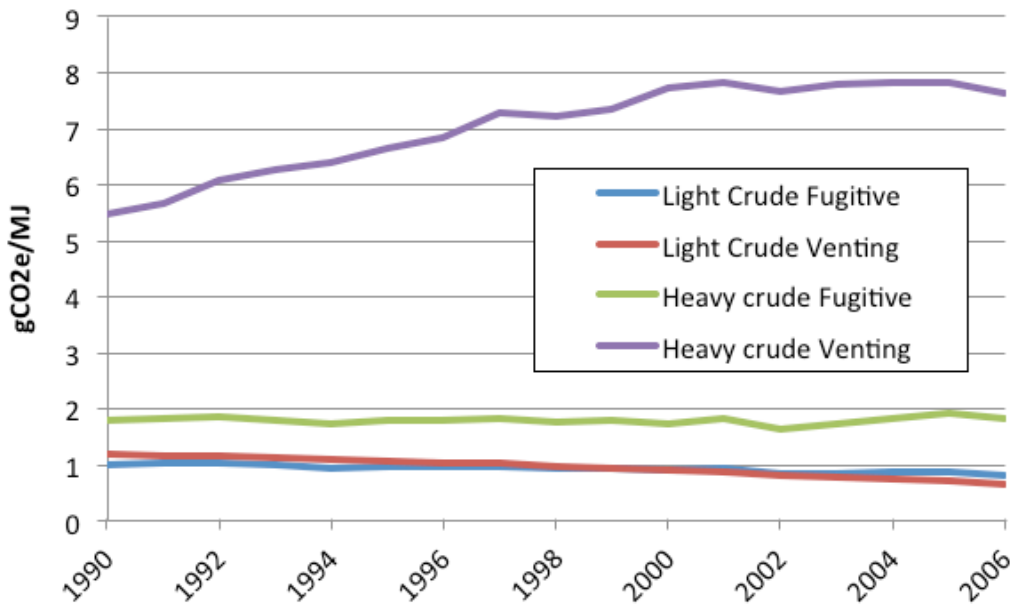

Figure 13: Fugitive emission intensity for conventional crude production

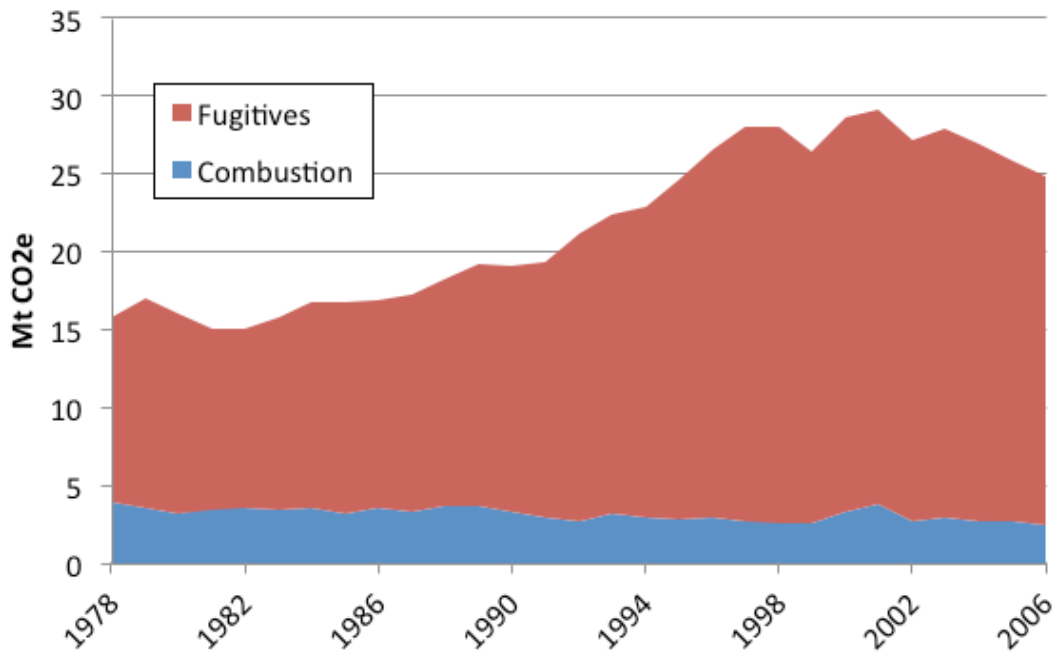

Figure 14: GHG emissions from conventional oil production

Based on these historical emission levels the CanESS model can estimate the GHG emission intensity of Canadian conventional oil extraction, as seen in Figure 15. Averaged over light and heavy production, Canadian conventional production produces which includes both production from the Western Sedimentary Basin in Alberta and Saskatchewan, as well as offshore production in Newfoundland, produces between 5 and 9g of GHG emissions per megajoule (MJ) of crude oil. This is in the same range as independent studies of lifecycle emissions from Canadian oil production. An independent study of emissions intensities for the American version of GHGenius, GREET, finds that average conventional oil extraction is 6 gCO2e/MJ [4].

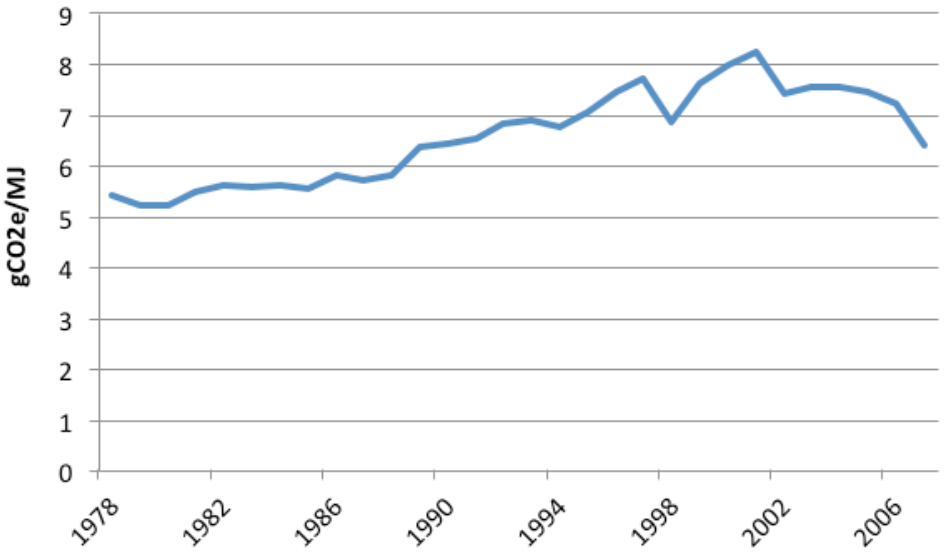

Figure 15: GHG emissions per unit production of conventional oil in Canada

Oil Sands Production

Oil sands production is classified in CanESS by the two different commodity types produced in the sector, Synthetic Crude (SCO) and Diluted Bitumen (dilbit). SCO is produced by upgrading mined bitumen to synthetic crude similar in consistency to light conventional crude oil. SCO can be used in most refineries as a substitute for crude oil. Dilbit is produced by extracting raw bitumen and then diluting it with a diluent, such as natural gas liquids, to turn it into a liquid which can then be shipped through a pipeline. Dilbit needs to be refined in refineries that are specially equipped to handle it. CanESS models the production of SCO and dilbit differently based on the process used to extract the resource. The surface mining of bitumen from open pit mines is used for SCO production, while bitumen extracted from in situ mines goes mostly to diluted bitumen production. Historically, oil sands production is calibrated to the Energy Resource Conservation Board (ERCB) data from Alberta [5]. Based on the ECRB data CanESS assumes that all surface mined bitumen is upgraded, and that 10% of bitumen production from in situ recovery is sent for upgrading. The remaining in situ production is exported. Figure 16 shows the historical production of oil sands derived products from 1978 to 2006.

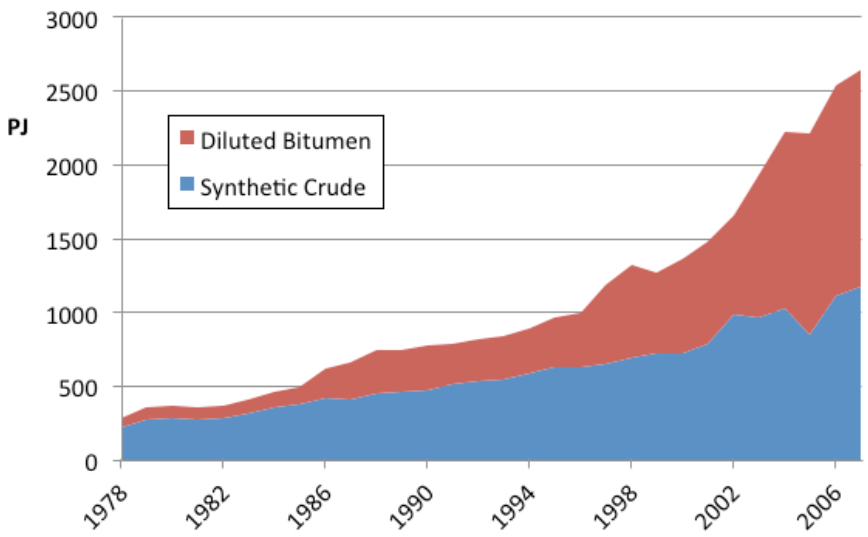

Figure 16: Historical oil sands production

CanESS calculates emissions from the oil sands operations separately for products produced by surface mining and in-situ processes. In surface mining the raw oil sand is extracted and transported to upgrading facilities. The bitumen is then separated from the sand using crushers, hot water, and steam and then upgraded to SCO by using hydrogen in the upgrader. Each process requires energy and each process has a share of fuels used to satisfy that energy requirement. Mining and crushing are electrically powered and do not have direct emissions while transport, separation and upgrading use natural gas and other fuels. Figure 17 shows the amount of energy required by process to produce a tonne of bitumen from surface mining.

In-situ recovery currently uses hot water and steam to liquefy the bitumen underground for recovery. As a result steam and hot water generation is the main energy consuming process used. Since 2004 some in-situ bitumen has been upgraded into SCO meaning that hydrogen production and upgrading are a newer source of in- situ emissions. Figure 18 compares the energy required to extract a tonne of bitumen by the in-situ extraction process using estimates from the CanESS model and data from the Alberta Energy Resources Conservation Board (ERCB). [2] Cyclic steam stimulation (CSS) and steam assisted gravity drainage (SAGD) currently account for all in-situ production. In addition to extraction energy, in situ mines require mechanical energy to run the equipment and to pump bitumen. The N-Solv process uses solvents to improve the viscosity of bitumen before it is extracted and can thus significantly reduce the energy requirements of conventional extraction. However, N-Solv and other novel extraction methods are currently in development or limited experimental use only. In CanESS the energy intensity of the processes used to produce dilbit and SCO along with the share of fuels used are taken from the GREET lifecycle emission model.

[2] Estimates were made by John Nenniger of N-Solv Corporation using a weighted average emission intensity per production well using ST-53 at the ERCB and facility level GHG emissions from Environment Canada. GHG emissions per facility were divided by production per facility in the ST-53, arriving to GHG emissions per tonne of bitumen. Using a standard GHG emission factor energy requirements per tonne of bitumen were calculated. N-Solv energy use could not be obtained from ERCB because there are no production level wells. This was an estimate.

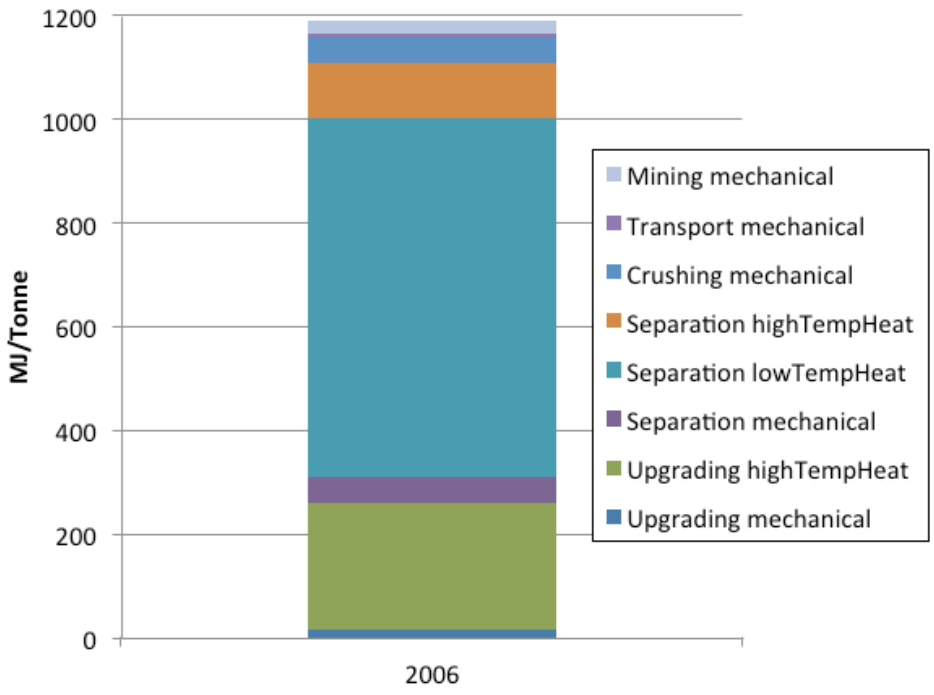

Figure 17: Surface mining energy use per tonne of bitumen

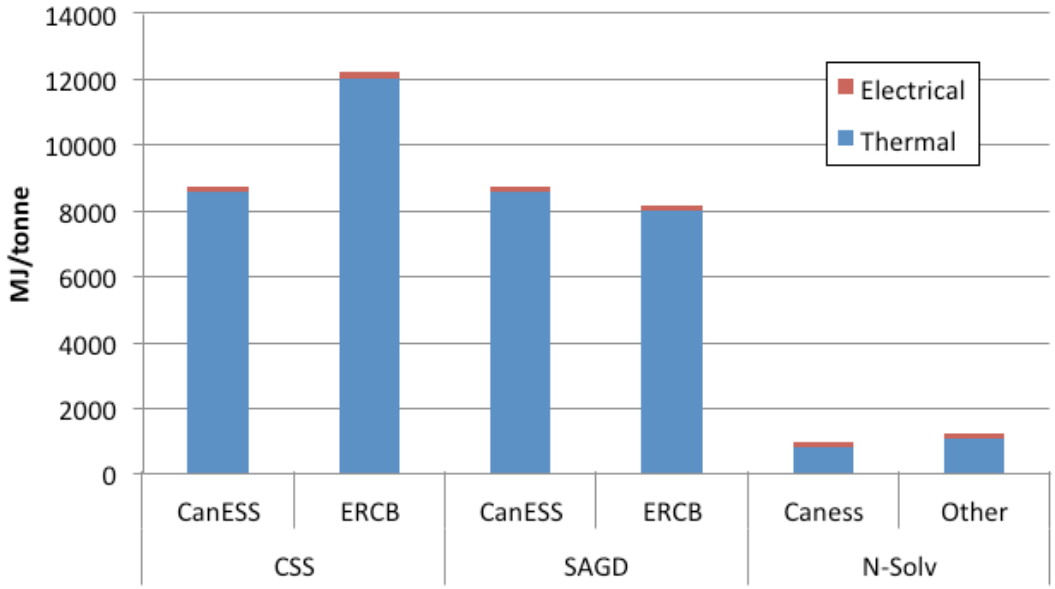

Figure 18: In-situ energy use per tonne of bitumen

The CanESS model tracks the total energy used to extract and process the raw bitumen by summing all of the fuels used in each process. The fuels used directly include diesel fuel, natural gas and electricity. CanESS also tracks the use of hot water and steam as 'fuels', and then accounts for the natural gas used to produce them. CanESS assumes that 20% of the hot water and steam required in surface mining and 33% of the hot water and steam required in-situ recovery is produced using cogeneration. The historical total energy consumption for the production of oil–sands derived products is shown in Figure 19 for the period from 1978 to 2006.

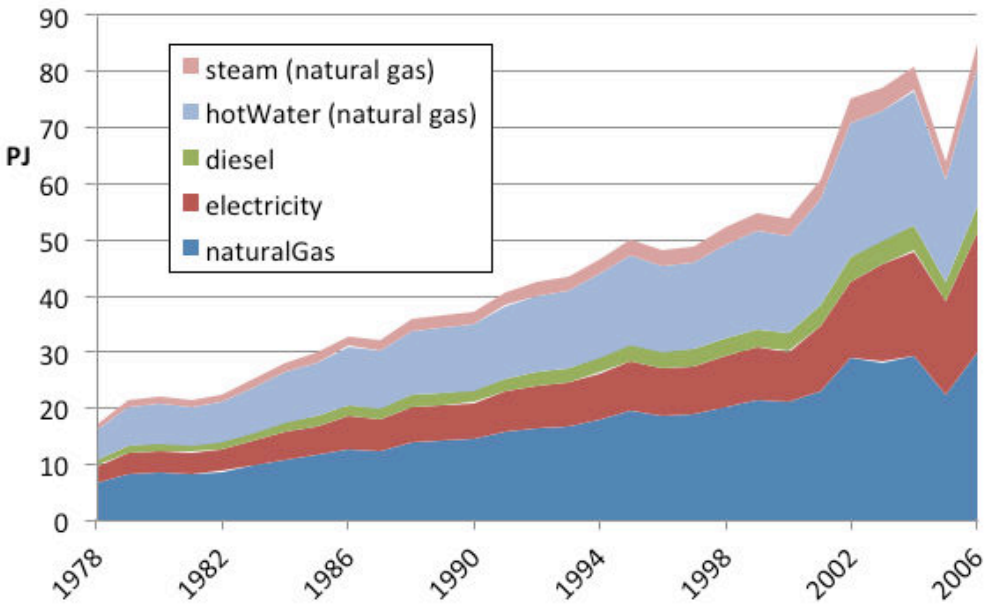

Figure 19: Surface mining energy required for Oil sands production

Emissions arising from the production of oil-sands products include those from burning the various "fuels" described above plus "fugitive" emissions and emissions resulting from reforming natural gas to provide hydrogen for the upgrading process. CanESS estimates the amount of hydrogen required based on an intensity of 1018 cubic feet of hydrogen per tonne of SCO produced. The CO2 produced from hydrogen production is tracked separately and counts toward total oil sands sector emissions. Both surface mining and in-situ processes also release fugitive emissions. CanESS calculates fugitive emissions from oil sands production processes by calibrating to the National Inventory Report with input assumptions from the GREET model. The intensity of fugitive emissions is calculated as the mass of CO2 equivalent emissions per energy unit of SCO or dilbit produced, in gCO2e/MJ. The historical record of fugitive emissions for both surface mining and in-situ processes is shown in Figure 20

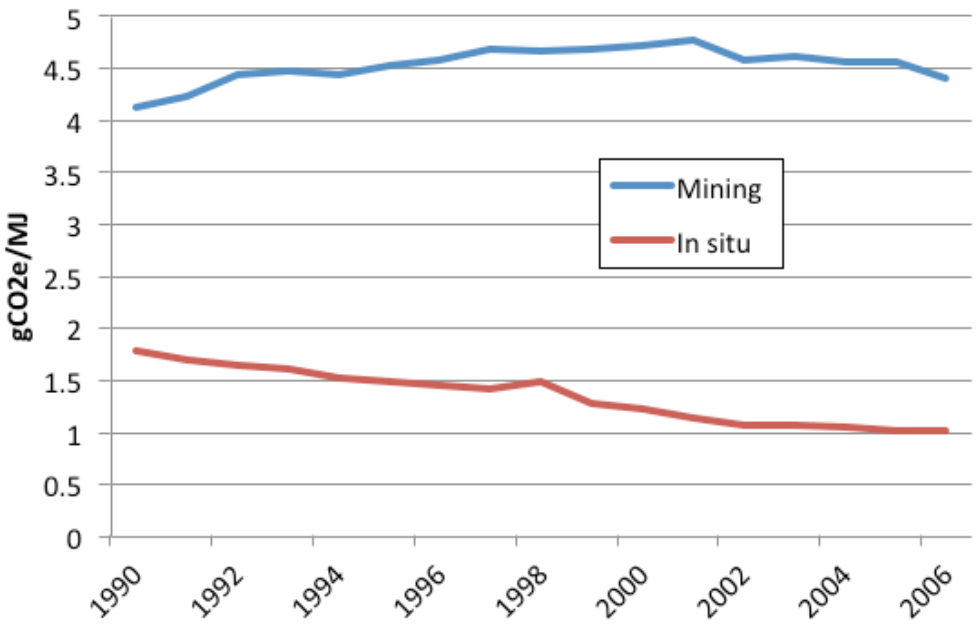

Figure 20: Fugitive emission release intensity

The overall emission intensity of oil-sands production has declined over the last 20 years as the sector has focused more on producing dilbit for export. However, the recent trend is to an increase in emission intensity as dilbit production becomes more carbon intensive from SAGD utilization. This can be seen in Figure 21, showing emission intensity, again in gCO2e/MJ, for each product as well as for total production.

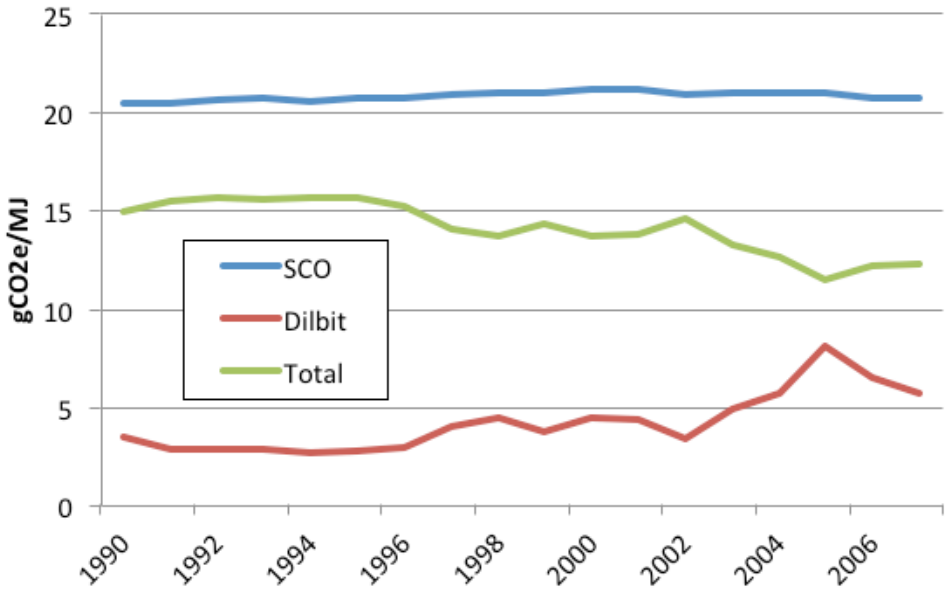

Figure 21: Oil Sands emission intensity by commodity produced

A complete breakdown of the emissions intensity by process can be seen in Figure 22 for both surface mining production of SCO and in-situ production of dilbit. It can be seen that upgrading has the greatest impact on emissions intensity of any of the individual processes used to produce oil-sands products. As a consequence it should be noted that even though in-situ processes appear to result in an emission intensity that is approximately one-half that of upgraded products, from a lifecycle emissions perspective this is only a postponement since significant additional emissions from dilbit will be emitted when it is eventually refined into petroleum products at its final destination.

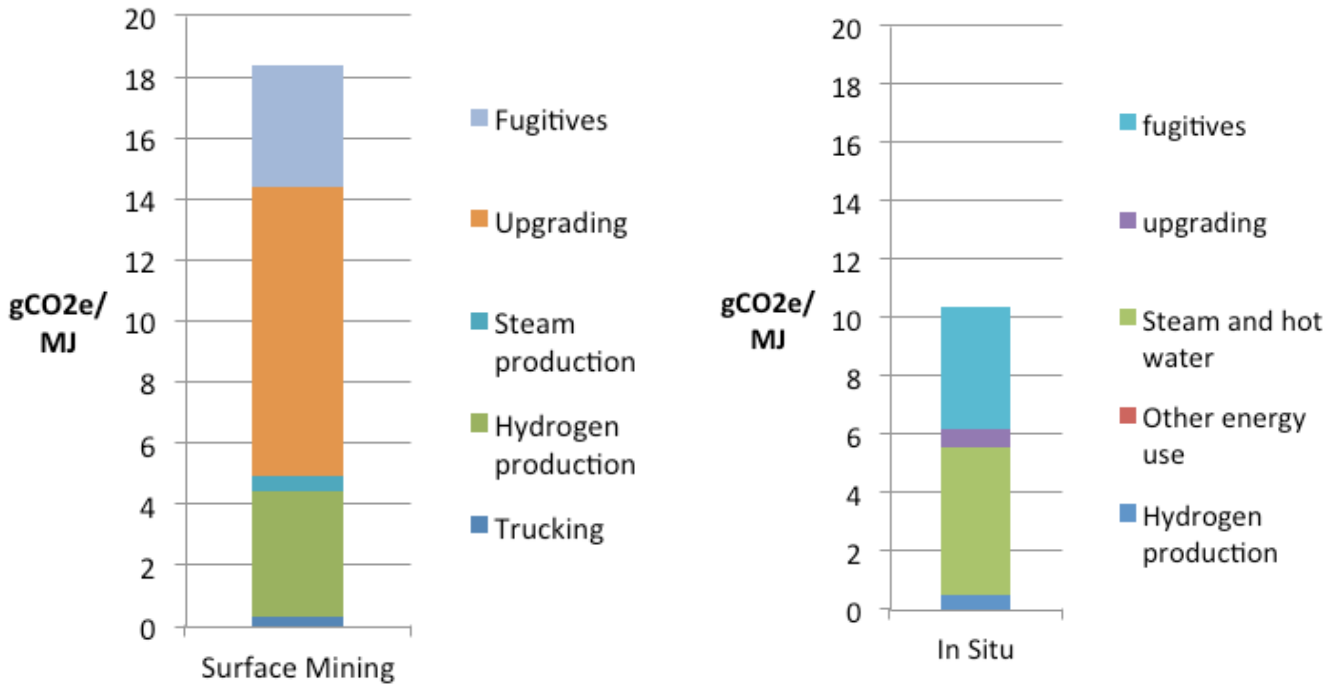

Figure 22: Emissions from production of SCO from surface mining and Dilbit from in-situ production

A breakdown by individual process of the historical production of GHG emissions from oil-sands production, in megatonnes of CO2e, is shown in Figure 23 for the reference period from 1978 to 2006. It can be seen that, in line with increased production levels, the total GHG emissions from oil-sands production have nearly tripled from 1990 to 2006.

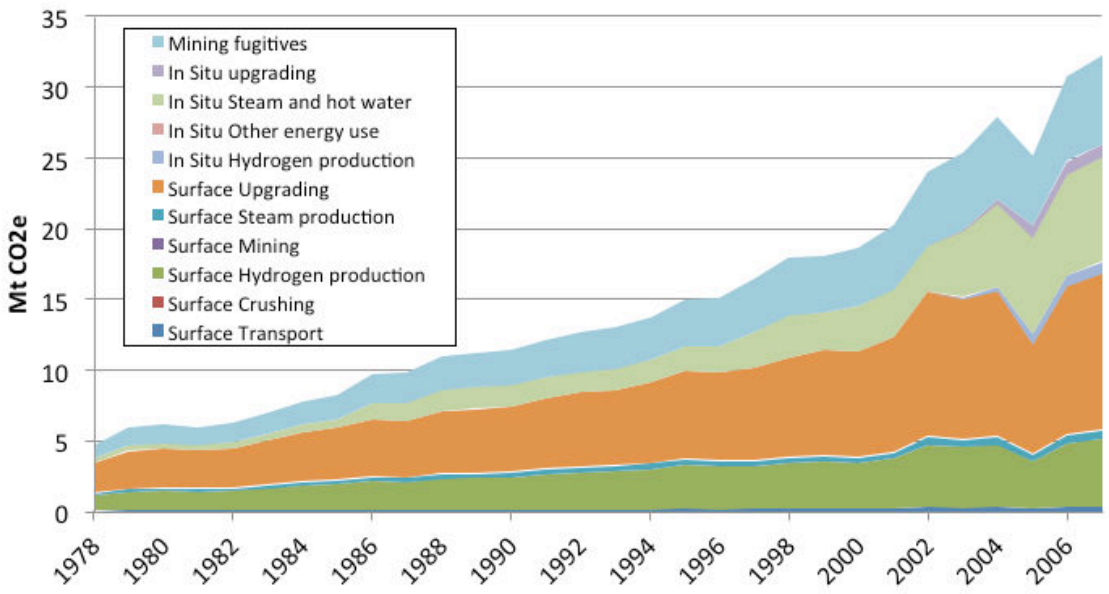

Figure 23: Oils Sands GHG emissions by process

Projection of future emissions from oil and gas production in Canada

Projecting Future Gas Emissions

Projections of GHG emissions from the oil and gas sector have been made using the CanESS model and the "reference scenario" assumptions of the TEFP project. These assumptions are consistent with a "Business as Usual" (BAU) scenario that is used by many researchers as a baseline for energy projections. Conventional gas reserves in Canada have been in decline in recent years. To compensate for this decline new production will come from untapped conventional reserves such as the Mackenzie Valley and from new unconventional reserves like shale gas in BC. The role of new reserves will have an impact on GHGs since unconventional reserves are slightly more emissions intensive. The TEFP "reference scenario" projections for gas production, shown in Figure 24, assume an increasing share of unconventional resources will provide an increase in overall natural gas supply in the future. Natural gas production levels are input into the model as an estimate. The model does not calculate absolute levels of production as a function of prices or other economic stimuli. Production levels cannot, however, be set to any amount as they are constrained by the ultimate potential of natural gas conventional reserves and unconventional reserves by gas basin as reported by provincial governments. Much of the growth in gas production is due to the anticipated development of liquefied natural gas exports from Western Canada. The Government of BC is planning that 82 million tonnes per annum of LNG will be developed by 2030 [6]. This represents at least 4000 PJ of additional natural gas production on top of growing domestic demand. The TEFP also anticipates that exports of natural gas will reach 6000 PJ by 2050, including shale gas exports on the west coast and continuing export from Alberta to the U.S.

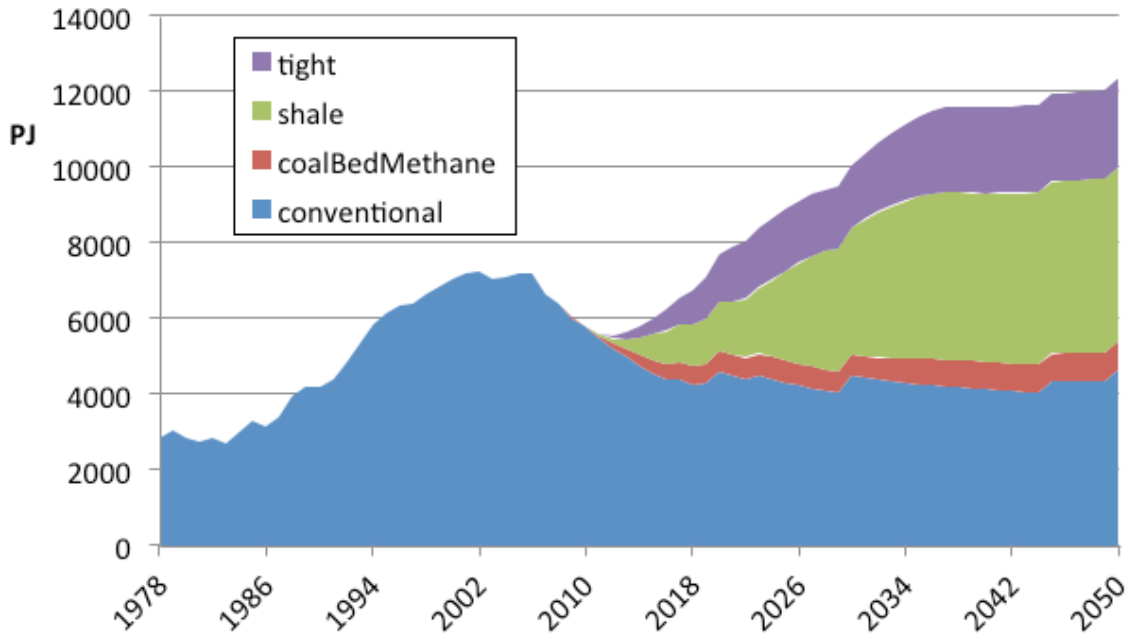

Figure 24: Natural gas production by reserve type

Much of the energy used for extraction and processing is "own use" energy, meaning that the producers divert a fraction of the gas they produce to power their operations. Supplementary energy is purchased as a fuel where economically viable based on local energy costs and market dynamics. CanESS first projects how much of natural gas energy use is considered own-use and how much is supplementary. This variable is calibrated from the RESD data on producer own use. This variable calculates what fraction of natural gas production is used in the processing of the gas. This distinction is important for accurately calculating emissions as producer own-use gas energy has a different emission factor than other fossil energy commodities used in the gas processing. CanESS then calculates how total own-use and supplemental energy for the natural gas sector based on the level of production. Total energy use is then multiplied by the corresponding emission factor depending on the fuel source. Using this information the CanESS model estimates that natural gas fuel use emissions are over 110 g of CO2 per MJ of natural gas production. This is in line with other independent estimates for natural gas production in Canada [7].

Based on the assumed level of production, and the increasing intensity of GHG emission from unconventional sources, total natural gas emissions in Canada (in Mt of CO2e) will also increase significantly in the reference period to 2050, as shown in Figure 25. Mirroring the growth in natural gas production, emissions increase by 112% between 2010 and 2050 at an average annual rate of 1.9%. This movement to more unconventional sources also served to increase the emissions intensity of natural gas production over the period. Unconventional gas production requires more input energy and depending on the basin, the concentration of CO2 in the raw natural gas can be much higher than in conventional sources. There is still considerable uncertainty on the emissions impact of shale gas production. The GHGenius model used to forecast GHG emissions estimates that shale gas production in Canada is 15% more emissions intensive on a lifecycle basis than the current average [8]. The largest growth in emissions is from fugitive emissions from unconventional gas. Most of this increase in emission intensity is due to higher levels of CO2 in the raw gas leading to more GHG intensive fugitive emissions. In the TEFP scenarios it is assumed that there is no significant difference between shale and conventional gas emission intensity but this can be updated this when better data is available. This means that for now the GHG increases result directly from production increases in the reference scenario.

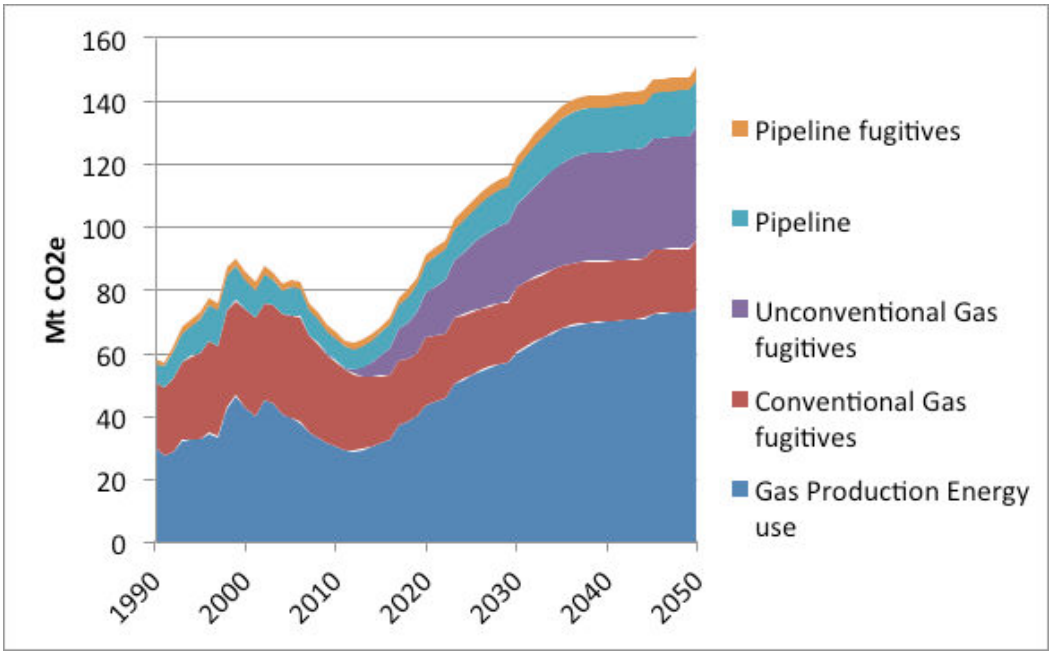

Figure 25: Natural gas production emissions by source

Projecting Conventional Oil production

The National Energy Board has projected that production of conventional crude will drop by 30% from 2010 to 2035 [9]. The projection in CanESS, developed by the Energy Futures network anticipates deeper declines in production, however. Total production used in the TEFP reference scenario declines 70% from 2010 to 2035, as shown in Figure 26. The projection of the conventional reserve size does not account for developments in the shale oil sector which has seen significant growth in the U.S. over the past 3 years. Shale oil development in Canada is not as advanced but many people in the industry believe that it could significantly expand the size of the conventional reserve. As shown in this paper conventional emission intensity is one third that of synthetic crude. If shale oil production can expand the reserve size without significantly increasing the emission intensity of production there will be important outcomes for the projection of GHG emissions in the oil sector. We have noted the importance of this emerging issue and will work to develop alternative conventional oil reserve sizes.

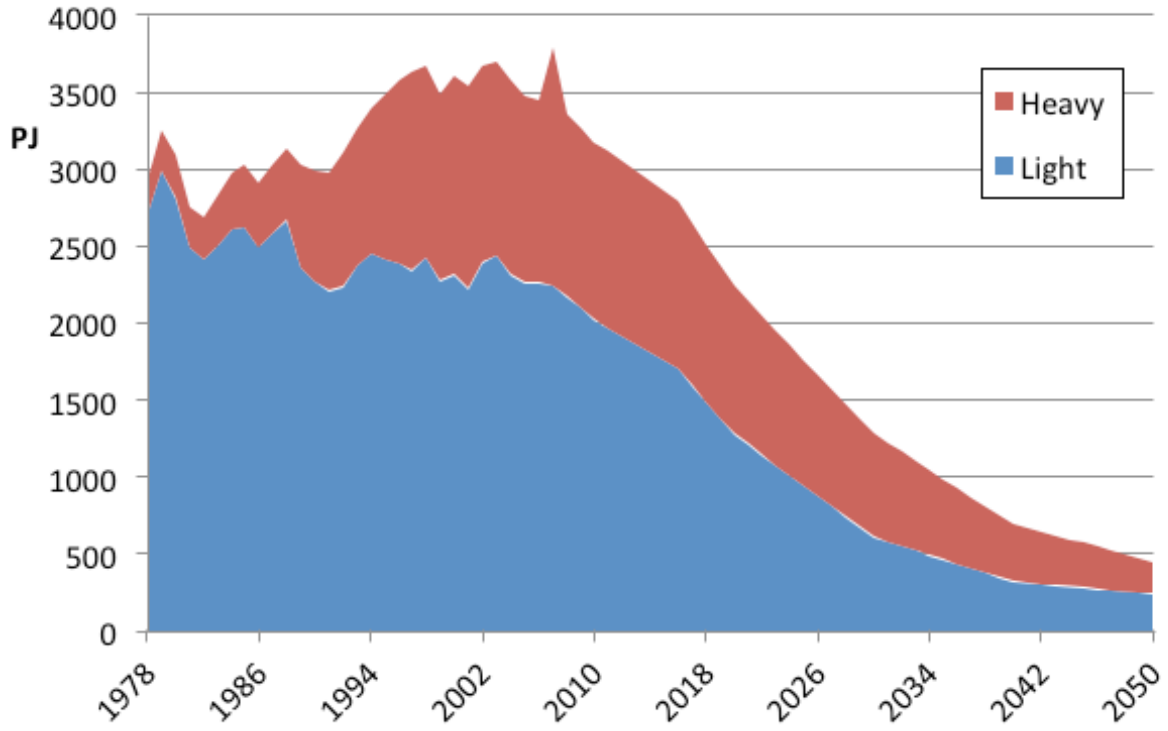

Figure 26: CanESS Projected Conventional oil production

Projecting Oil Sands Production and Emissions

Predicting growth in the oil production sector is complex and requires estimates of the future demand for oil and international oil prices, as well as estimates of the competitiveness of the oil sands sector versus competing resources. The costs of production including the broader macroeconomic context in Canada, such as the value of the Canadian dollar and the regulatory environment for the oil sands, are also important factors to be considered. In other words, projecting oil sands growth without taking an integrated economic approach only provides a general estimate. Nevertheless, for this report the following assumptions have been made:

Projected total oil production from 2010 to 2050 is shown in Figure 27. For the purposes of the TEFP reference scenario it is assumed that oil-sands production over this period will increase by 120% with total growth starting to level off by 2030. Diluted bitumen production increases 147% from 2010 to 2050 and synthetic crude by 81%. This offsets a more than 80% reduction in conventional oil production over the same period. Overall, the projected GHG emissions from oil sands production increases from 30 Mt CO2e in 2007 to nearly 80 Mt by 2050, as shown in Figure 28.

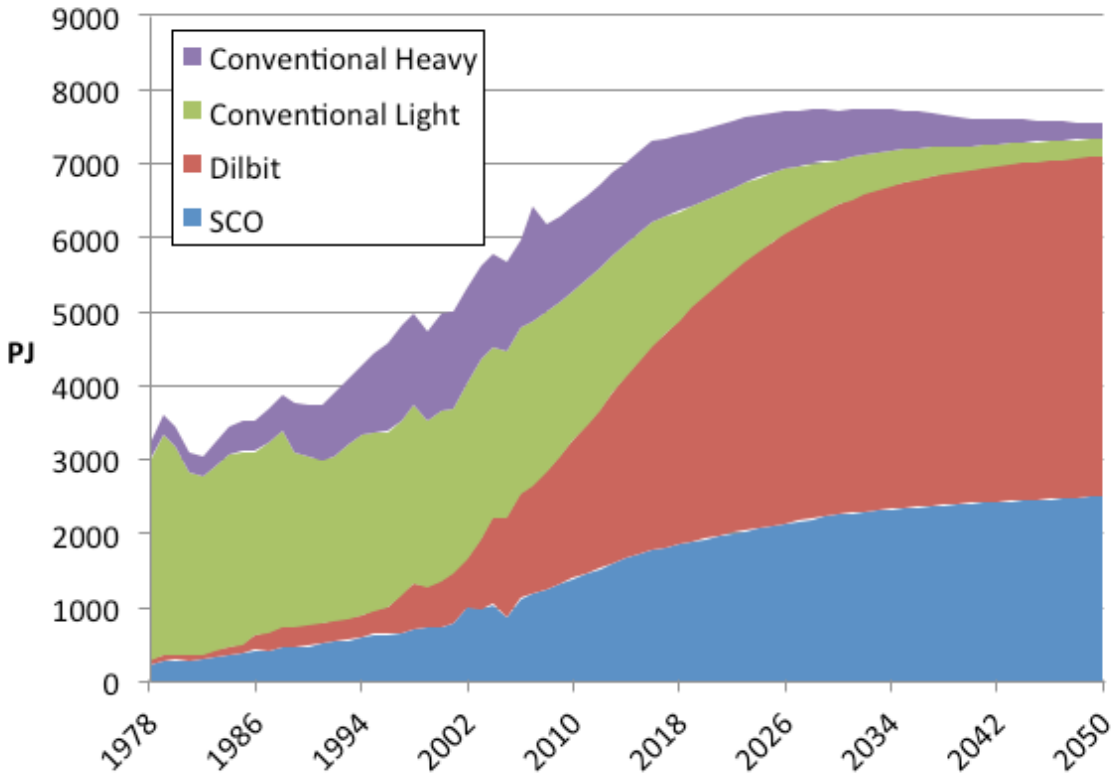

Figure 27: Projected total oil production

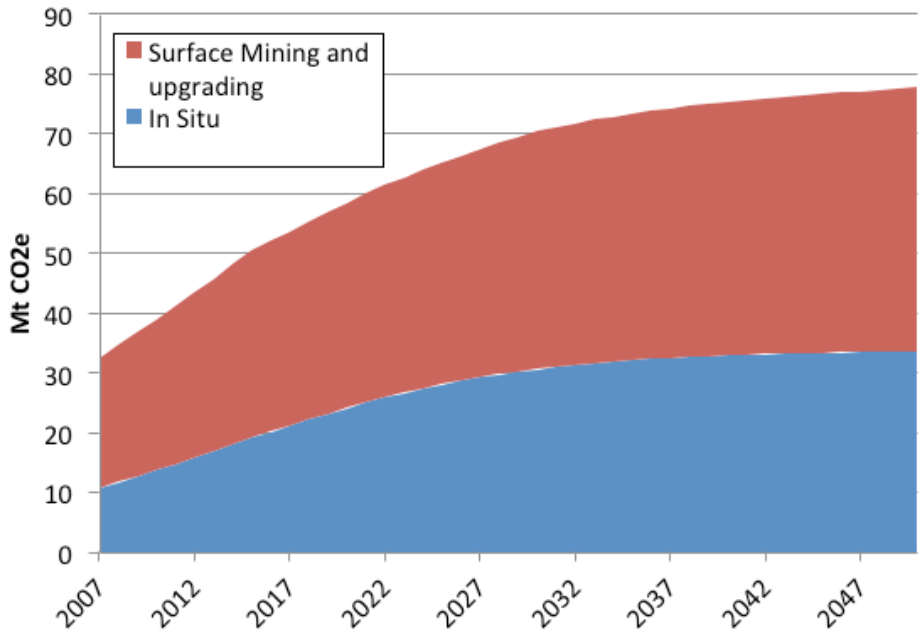

Figure 28: GHG emissions from oil sands production

Finally, taking all of the projections together, total GHG emissions from the oil and gas sector over the period to 2050 are shown in Figure 29. It can be seen that natural gas production is still the dominant factor in producing GHG emissions, while oil sands production dominates emissions from the oil sector by mid-century. Under the assumptions of the TEFP "reference scenario" total GHG emissions from the oil and gas sector increase by approximately 85% from 2010 levels by 2050.

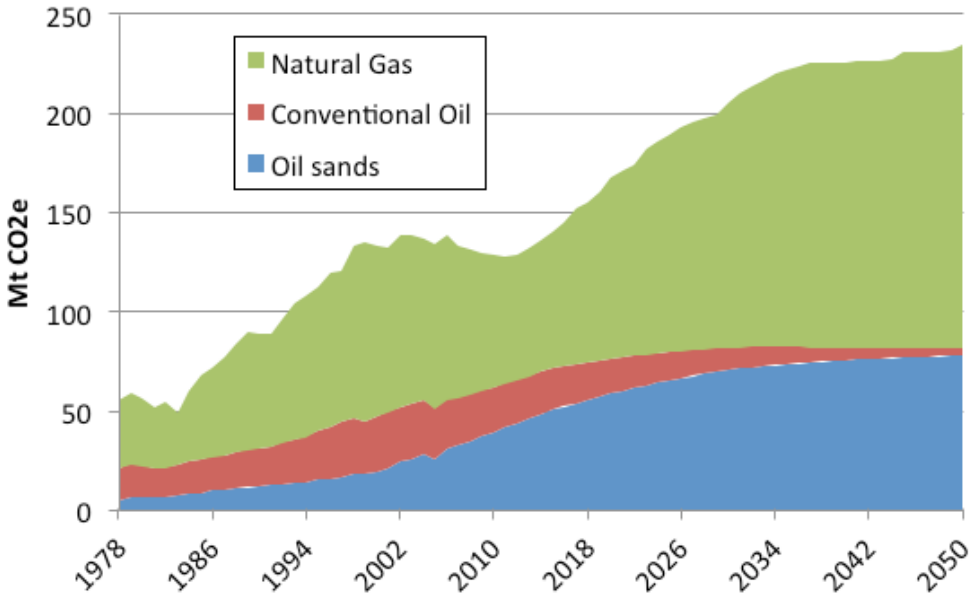

Figure 29: Total oil and gas emission projections

Comparisons with other Studies

A recent extensive study of the carbon intensity of producing Canadian crude oils has been used to check and validate the assumptions made in the CanESS model. The study, "EU Pathway Study: Lifecycle Assessment of Crude Oils in a European Context" was conducted by the Jacobs Consultancy for the Alberta Petroleum Marketing Commission and published in 2012 [10]. The 365 page report provides a detailed analysis of the carbon intensity of vehicle transportation using crude oil from a wide range of sources imported into the European Union compared to crude oils obtained from the Alberta Oil Sands. Figure 30 shows the carbon intensity, in grams of CO2 equivalent (g CO2e) per MJ of Diesel fuel for a wide array of crude oils imported into Europe. By far the largest source of GHG emissions are those related to combustion of the fuel product in vehicles, which for Diesel fuel is approximately 75g CO2e. The remaining contribution to the total carbon intensity is due to the production and processing of crude oil into the final product. This value ranges from 10g CO2e per MJ for the lightest crude oil from the North Sea to 25g CO2e for the heaviest Venezuelan crude oil. Overall, the emissions from production and processing all crude oils imported into Europe covers a range of 15g CO2e, as depicted by the purple band in Figure 30, representing some 13% of total oil emissions for the lightest crude to nearly 25% for the heaviest.

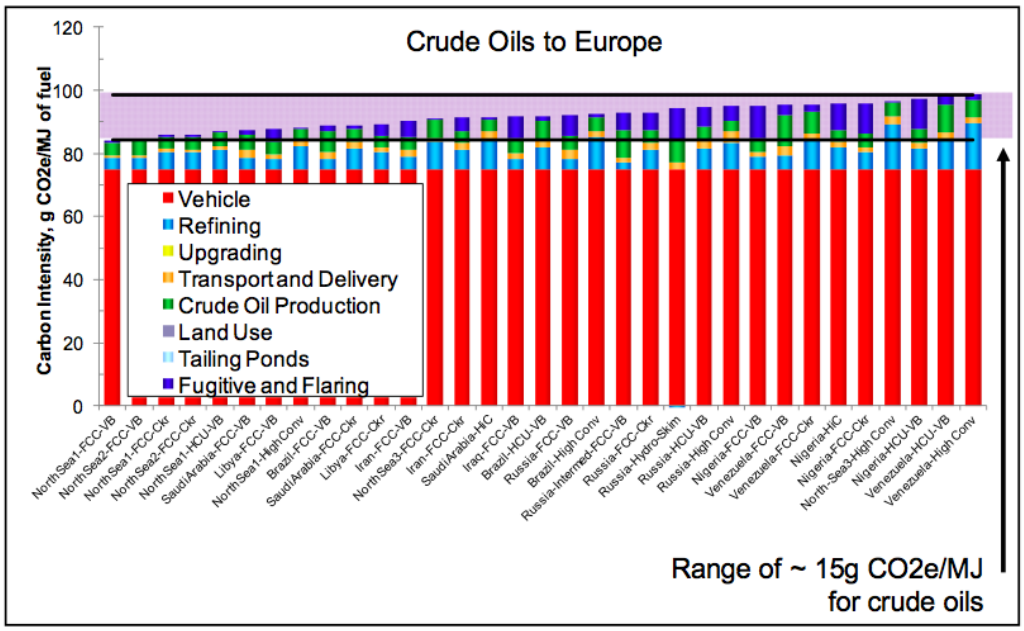

Figure 30: Carbon Intensity of producing Diesel Fuel from Crude Oils imported to Europe [10]

Comparable data for a range of Alberta synthetic crude oils produced from oil-sands is shown in Figure 31. The range of emissions from oil imported into Europe is again shown by the purple band for comparison purposes. Emission intensities for oil-sands derived crudes ranges from a low of approximately 25g CO2e for in-situ production using CHOPS (Cold Heavy Oil Production with Sand) to a high of nearly 35g CO2e for mined and upgraded oil-sands at a low-efficiency mine. These represent a range from 25% of total crude oil GHG emissions at the low end, which is comparable to the emission intensity of heavy Venezuelan crude imported into Europe to a high of approximately 32% at the high end. In other words, the carbon intensity of Diesel fuel produced from Canadian oil-sands is not significantly higher than that of Venezuelan heavy oil, at least for the most efficient processes.

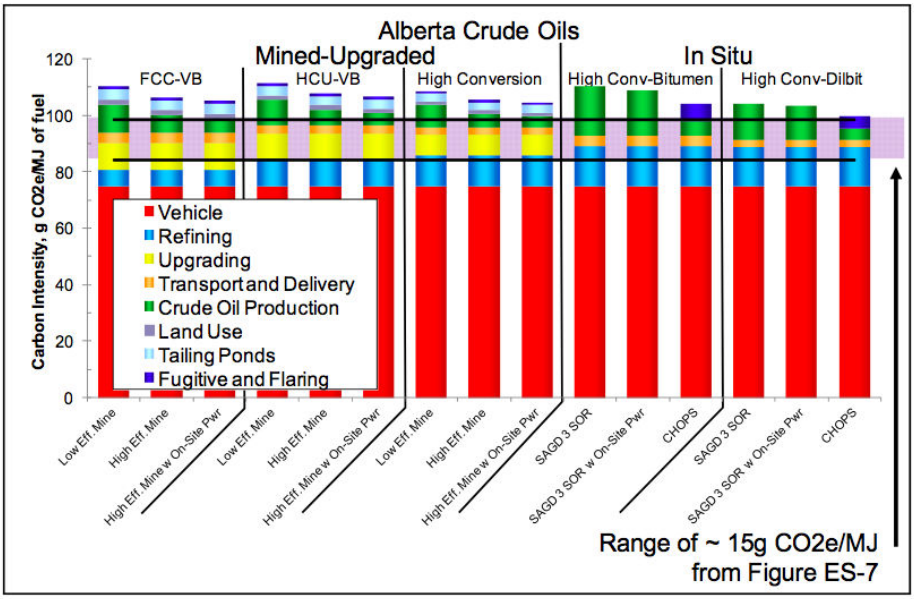

Figure 31: Carbon Intensity of producing Diesel Fuel from Oil-Sands derived Crude Oils [10]

The situation for gasoline produced from oil-sands derived crude oil is very similar to that for Diesel fuel, as shown in Figure 32. The purple band again shows the range of carbon intensities for the production of gasoline from crude oils imported into Europe, although it now covers some 18g of CO2e. The carbon intensities for gasoline derived from oil-sands processes can be seen to be slightly closer to those from imported European crude oil compared to those for Diesel fuel production. For the best case, for CHOPS production, the carbon intensity of oil-sands derived gasoline is slightly less than for the heaviest crude oil imported into Europe. For gasoline produced from a low-efficiency mining oil-sands operation the carbon intensity is some 10gCO2e higher than for the heaviest Venezuelan crude oil. However, the overall GHG emissions from production and use of this gasoline in a vehicle is only about 10% higher than from the heaviest crude currently imported into Europe. It can also be seen that the emissions intensities for producing synthetic crude oils from the oil-sands used in the CanESS model are quite comparable to those shown in the Jacobs report.

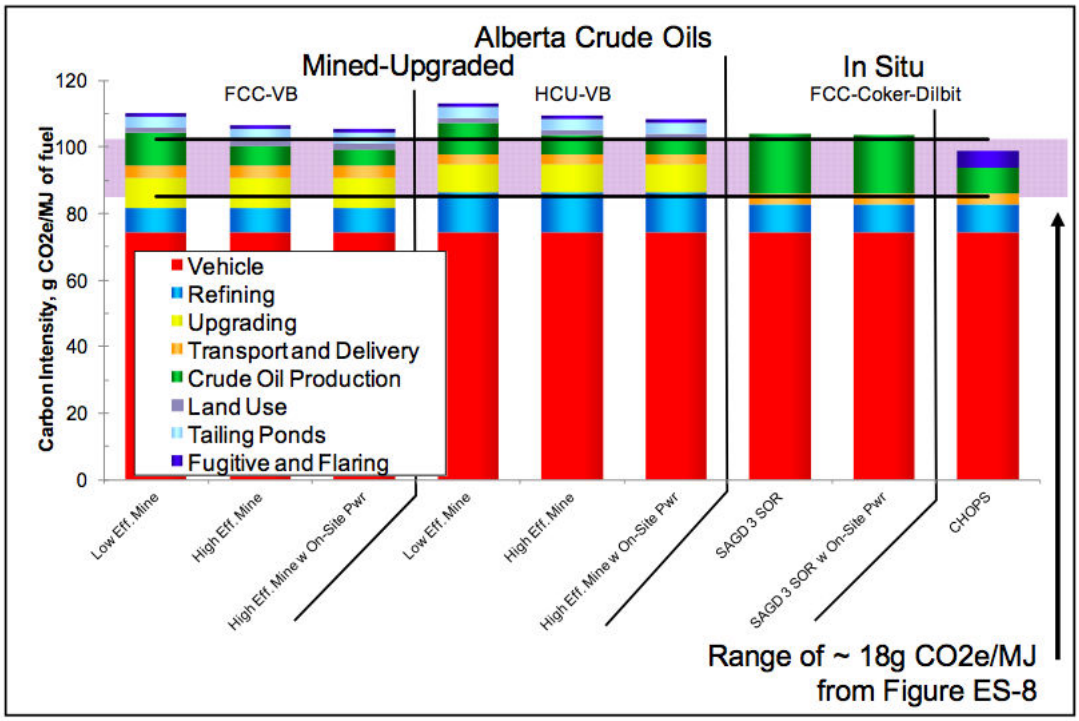

Figure 32: Carbon Intensity of producing Gasoline from Oil-Sands derived Crude Oils [10]

Summary and Conclusions

This report has provided an in-depth examination of how the CanESS model estimates GHG emissions from oil and gas production in Canada. The model uses a detailed representation of oil and gas emissions right from the original production of raw gas, conventional crude oil or oil-sands derived synthetic crude oils and dilbit to the final end-use emissions. These include the so-called "fugitive emissions" due to venting and flaring, which can be a significant fraction of overall emissions, depending on the process. Much of the data used in the model comes from the "National Inventory Report" on GHG emissions which is produced by Environment Canada each year as part of its commitment under the UN Framework Convention on Climate Change (UNFCCC). This reporting is quite detailed, and is in a similar format to the reports of all of the other nations reporting under the UNFCCC.

The emissions from oil and gas production in Canada represented about 25% of overall GHG emissions in 2010, making the industry a very important sector when examining how total emissions can be reduced. Using the assumptions of the TEFP "reference scenario" for future oil and gas projections the GHG emissions from the oil and gas sector in Canada would rise by some 85% between 2010 and 2050 to reach 230 MtCO2e by 2050. Most of this increase is due to increased production of natural gas and oil-sands products, since conventional oil production is assumed to decline to very low levels by 2050. Much of the additional oil-sands production is projected to be from in-situ production of dilbit which has an emissions intensity of approximately one-half that of upgraded synthetic crude oil. However, the reduced emissions from in-situ production are really only a postponement in lifecycle emissions since additional emissions from dilbit will occur when it is eventually upgraded to SCO at its final destination.

Overall, the GHG emissions calculated by the CanESS model for the oil and gas sector in Canada correlate quite well with data from Environment Canada and from the Jacobs report prepared for the Alberta Petroleum Marketing Commission. In some cases, however, there is a discrepancy between GHG intensities from oil sands production used by the CanESS model and actual data reported by the ERCB. For future TEFP work modellers will be able to refine the CanESS model assumptions to more accurately reflect overall emissions from the oil-sands. The authors are confident that the CanESS model can be a useful tool for tracking oil and gas production in Canada, and the related greenhouse gas emissions. Of course, like any model, it is not a predictive tool, and can only provide an estimate of future GHG emissions that depend on the input of an assumed "scenario" providing assumptions about future economic and industrial activity.

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