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Oil Sands Industry Energy Requirements and Greenhouse Gas (GHG) Emissions Outlook (2015-2050)

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OIL SANDS INDUSTRY ENERGY REQUIREMENTS AND GREENHOUSE GAS (GHG) EMISSIONS OUTLOOK (2015-2050)

Oil Sands Industry Energy Requirements and Greenhouse Gas (GHG) Emissions Outlook (2015-2050)

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Table of Contents

List of Figures

List of Tables

Executive Summary

This study highlights the contribution of the oil sands industry to the Canadian economy, energy use, and the environment.

In 2014, Alberta's economy was estimated to be $305.5 billion, the third largest in Canada after Quebec and Ontario. Within Alberta, the mining, quarrying, and oil and gas sector (including the oil sands) was $83.8 billion or 27.4 percent of the provincial economy and 5.2 percent of the Canadian economy. In 2013, capital investment from the oil sands was $30.8 billion,[1] 27.7 percent of Alberta's total, and 7.7 percent of Canada's total capital investments.

Alberta's crude bitumen reserves are some of the world's largest deposits of crude oil behind those of Saudi Arabia and Venezuela (BP, 2015). From the onset of development in the late 1960s, advances in extraction methods have unlocked vast amounts of oil sands resources. Production of oil sands crude has increased rapidly, reaching over 2.3 million barrels per day (MMb/d)[2] by the end of 2014. This accounted for 74.9 percent of Alberta's crude oil production, 59.2 percent of total crude oil production across Canada, 12.3 percent of North America's crude oil production, and 2.6 percent of the world's total crude oil production. This places Canada fourth behind the United States, Russia and Saudi Arabia, among the largest crude oil producers in the world.[3]

The oil sands industry is one of the largest producers of primary energy both in Alberta and in Canada. The industry is also one of the largest end-users of energy including the use of natural gas for thermal energy and hydrogen production, the use of electricity, and diesel fuel use. From an environmental perspective, continued growth in production from the oil sands, coupled with increasing energy use, have resulted in an increase in greenhouse gas (GHG) emissions from fuel combustion and fugitive sources.

Oil sands crude extraction accounted for 46.7 percent of Alberta's primary energy production in 2014, and 33.6 percent of end-use energy demand.[4] In 2014, the oil sands industry accounted for 20.8 percent of the province's total electricity demand, 29.5 percent of natural gas use in the province (excluding gas used for power generation),[5] and 19.5 percent of total diesel fuel demand.

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[1] Based on estimates from (ARC Financial Corp., 2015) and (Canadian Association of Petroleum Producers (CAPP), 2015)

[2] Refers to bitumen extraction as opposed to net oil sands supply

[3] Based on data from (BP, 2015) and (Canadian Association of Petroleum Producers (CAPP), 2015)

[4] Based on data from (Alberta Electric System Operator (AESO), 2014), (Alberta Energy Regulator (AER), 2014), (National Energy Board (NEB), 2015), (Statistics Canada, 2015), and CERI estimates

[5] The percentage share increases to 40.7% when including natural gas purchases for power generation for oil sands projects, which in turn accounted for 63.9% of the total natural gas used for power generation in 2014, according to data from (Alberta Energy Regulator (AER), 2014)

Increased economic activity in the province over the last decade, led by strong and growing oil sands production, coupled with a growing share of energy use by the oil sands industry, have in turn resulted in growing GHG emissions from the industry.

The oil sands sector GHG emissions of 62 million tonnes of carbon dioxide equivalent (MMt CO_2 eq.) was 23 percent of total provincial emissions of 267 and 8.5 percent of the total national emissions of 726 MMt CO_2 eq. in 2013.[6] This is a 94 percent increase from 2005 GHG emissions of 32 MMt CO_2 eq.

The federal government has recently announced its intentions to reduce national GHG emissions to 30 percent below 2005 GHG emissions (of 749 MMt CO_2 eq./year) by 2030. In Alberta, the 2008 climate change action strategy called for a province-wide GHG emissions target of 236.0 MMt CO2 eq./year by 2020, and 176.0 MMt CO2 eq./year by 2050, with an emphasis on the energy efficiency improvements, decarbonizing energy production, and deployment of carbon capture and storage (CCS) technologies.[7] More recently, the provincial government has indicated its ambition to review and change the climate change strategy.[8]

The focus of this report is on quantifying GHG emissions associated with energy use from the oil sands industry, including fuel used to generate electricity to meet the requirements of the industry. Energy intensity factors were assessed for different types of energy and different types of projects across the oil sands industry. Intensities per unit of output (crude bitumen or synthetic crude oil) are estimated to range from as low as 0.14 gigajoules per barrel (GJ/bbl) to as high as 4.07 GJ/bbl.

Estimates for cumulative (2015-2050) production volumes, energy used, and GHG emissions were developed. However, given the temporal extent of the period considered for this analysis and various assumptions, which exists in developing such estimates,[9] a scenario approach was used to understand the ramifications of changes to the different variables. The business as usual (BAU) scenario represents conditions that are most likely to unfold based on historic trends. Constrained growth (CG) assumes that global economic and crude oil market demand are not conducive to new investments and only existing and under construction oil sands projects operate in the period 2015-2050. The increased energy efficiency (IEE) scenario assumes that technology learning and innovation lead to increased energy efficiency in the oil sands sector. Conversely, the decreasing reservoir quality (DRQ) scenario assumes that over time the reservoir quality deteriorates, increasing energy intensity of bitumen extraction. The electric heating technology adaptation (EHTA) scenarios assume that a large portion of in situ projects adopt electrical extraction methods as opposed to steam based thermal recovery. Two EHTA scenarios

[6] Based on Environment Canada's National Greenhouse Gas Inventory (Environment Canada, 2015)
[7] GHG emissions reductions via CCS in the 2008 provincial climate change strategy are estimates to account for 139 MMt CO_2 eq. in reductions by 2050, or 69.5% of the total anticipated GHG emissions reduction (of 200 MMt CO_2 eq.)
[8] Alberta Environment Climate Change Strategy, http://esrd.alberta.ca/focus/alberta-and-climate-change/climate-change-strategy/default.aspx. Accessed in August 2015.
[9] See Figure 47 on Chapter 1 for more on these

(low adaptation and high adaptation) represent a situation where electricity based recovery techniques may potentially be attractive under a stringent carbon policy. Table E.1 presents the results for the aforementioned six different scenarios.

Table E.1: Cumulative (2015-2050) Oil Sands Production Volumes, Energy Used, GHG Emissions, and Intensity Factors Under Different Scenarios

Scenario	Production		Energy Used			GHG Emissions		
	Production (billion bbl)	Difference from BAU (%)	Energy used (billion GJ)	Difference from BAU (%)	% chg. Energy/% chg. Prod.	Emissions (billion tCO2 eq.)	Difference from BAU (%)	% chg. Emissions/% chg. Energy
BAU	52.4	0%	66	0%	n/a	4.2	0%	n/a
CG	35.2	-33%	45	-32%	1	2.9	-32%	1.0
IEE	52.4	0%	47	-30%	n/a	3.0	-29%	1.0
DRQ	52.4	0%	97	46%	n/a	6.1	44%	1.0
EHTA-Low	52.4	0%	63	-6%	n/a	4.4	4%	0.6
EHTA-High	52.4	0%	59	-11%	n/a	4.6	8%	0.7

Source: CERI

Energy and emissions outlook under the BAU scenario shows that energy intensity and emissions intensity marginally decreases over the outlook period. Nonetheless, the total emissions continue to grow due to growing production levels.

Under the CG scenario, cumulative production volumes for oil sands from 2015 to 2050 are 32.8 percent lower compared to the BAU scenario, cumulative energy use decreases by 32.0 percent, and cumulative GHG emissions decrease by 31.7 percent. Those reductions are due to lower production, negating any economic benefits that are plausible under the BAU production level. Energy intensity and fuel mix are assumed the same as in the BAU case.

In the remaining four scenarios, the production volumes are the same as in the BAU case. IEE and DRQ are opposite scenarios in the spectrum of advances in technology and process optimization versus ageing reservoirs and deteriorating reservoir quality.

In the IEE scenario, increasing energy efficiency results in a 29.5 percent decrease in cumulative energy used compared to the BAU scenario, and subsequently, a 28.7 percent decrease in cumulative GHG emissions.

In the DRQ scenario, decreasing reservoir quality results in an increase of 46.0 percent in cumulative energy use, and subsequently, a 44.2 percent increase in cumulative GHG emissions compared to the BAU case.

In the *low* adoption rate case (EHTA-Low), overall energy use decreases by 5.8 percent compared to the BAU scenario. However, cumulative GHG emissions actually increase by 3.6 percent. In the *high* adoption case (EHTA-High), a similar trend is observed, with cumulative energy use decreasing by 11.0 percent and cumulative GHG emissions increasing by 8.1 percent. In the EHTA scenarios, thermal energy is replaced for electricity in a large cross-section of in situ projects. That leads to lower energy intensity, but the emissions increase under the electricity generation mix assumed in this analysis.

These scenarios are useful in understanding the effects on energy use and GHG emissions from the oil sands industry due to changes in production volumes, intensity factors, and adoption of new technologies.

A key finding is that thermal energy and electricity combined generally account for between 80 percent and 90 percent of both energy use and GHG emissions across the scenarios. The majority of the emissions will continue to be generated from the production of thermal energy.

Chapter 1: Introduction

In 2014, Alberta's economy was estimated to be $305.5 billion, the third largest in Canada after Quebec at $311.8 billion and Ontario at $600.6 billion. Within Alberta, the mining, quarrying, and oil and gas sector (including the oil sands) was $83.8 billion or 27.4 percent of the provincial economy and 5.2 percent of the Canadian economy. In 2013, total capital investment in Canada was $398.8 billion, with capital investment in Alberta leading the way at $111.2 billion. Capital investment from the oil sands was $30.8 billion,[1] 27.7 percent of Alberta's total, and 7.7 percent of Canada's total. The oil sands sector is also an important contributor to exports, employment, and government revenues[2] provincially and nationally. Investment in this sector has helped Alberta's economy out-perform most provincial economies over the last decade. Investment and economic activity in the oil sands industry drives activity and growth in other sectors of the economy such as manufacturing, transportation, professional services, and finance, among many others, within the province and across Canada.

Alberta's crude bitumen reserves are some of the world's largest deposits of crude oil behind those of Saudi Arabia and Venezuela (BP, 2015). From the onset of development in the late 1960s, advances in extraction methods have unlocked vast amounts of oil sands resources. Production of oil sands crude has increased rapidly, reaching a level of 2.3 million barrels per day (MMb/d)[3] by the end of 2014. This level of production accounted for 74.9 percent of Alberta's crude oil production and 59.2 percent of Canada's total, 12.3 percent in North America and 2.6 percent globally. This places Canada fourth behind the United States, Russia and Saudi Arabia, among the largest crude oil producers in the world.[4]

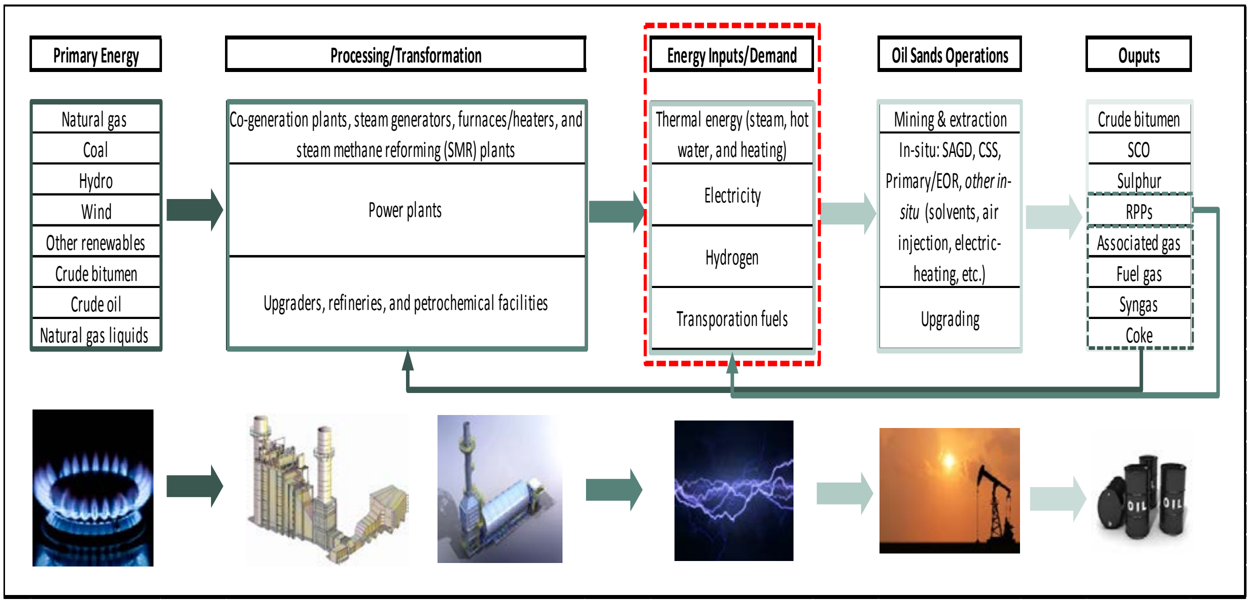
Oil sands crude extraction accounted for 46.7 percent of Alberta's primary energy production in 2014 (Alberta Energy Regualtor (AER), 2014). Also in 2014, the oil sands industry accounted for 33.6 percent of end-use energy demand in the province,[5] 20.8 percent of electricity demand, 29.5 percent of natural gas use (excluding gas used for power generation),[6] and 19.5 percent of diesel fuel demand.

[1] Based on estimates from (ARC Financial Corp., 2015) and (Canadian Association of Petroleum Producers (CAPP), 2015)
[2] In the form of land bonuses, various forms of taxes, and resource extraction royalties
[3] Refers to bitumen extraction as opposed to net oil sands supply
[4] Based on data from (BP, 2015) and (Canadian Association of Petroleum Producers (CAPP), 2015)
[5] Based on data from (Alberta Electric System Operator (AESO), 2014), (Alberta Energy Regulator (AER), 2014), (National Energy Board (NEB), 2015), (Statistics Canada, 2015), and CERI estimates
[6] The percentage share increases to 40.7% when including natural gas purchases for power generation for oil sands projects, which in turn accounts for 63.9% of the total natural gas used for power generation in 2014 (Alberta Energy Regulator (AER), 2014)

Oil sands projects are energy-intensive operations. In general, end-use energy demand for oil sands projects can be divided into four categories: thermal energy demand; electricity demand; hydrogen (H_2) demand for upgrading;[7] and demand for transportation fuels (such as diesel fuel).

Figure 1.1 displays a flow chart with pathways from energy inputs to product outputs for the oil sands industry. The portion of Figure 1.1 highlighted in the red-dashed box (energy inputs/demand), also known as secondary, final, or end-use energy demand,[8] is the focus of discussion.

Figure 1.1: Oil Sands Energy Requirements, Sources and Outputs



Source: Images from various data sources; Figure by CERI

Increased economic activity in the province over the last decade, led by strong and growing oil sands production coupled with a growing share of the province's and Canada's energy use by the oil sands industry, has resulted in growing greenhouse gas (GHG) emissions from the industry.

In 2013, GHG emissions from the oil sands industry[9] accounted for 22.6 percent of total Alberta GHG emissions or 267.1 million tonnes of carbon dioxide equivalent (MMt CO_2 eq.) and 8.3 percent of the national total of 726.0 MMt CO_2 eq. Oil sands GHG emissions are estimated to

[7] While hydrogen (H_2) is not used for its energy content in the upgrading process per se, natural gas is the main feedstock for H_2 production, and natural gas' (alternative) main uses are for fuel (power generation) and thermal energy (heat) purposes

[8] Refers to useful energy such as electricity and thermal energy that has been transformed from primary or raw energy sources

[9] Estimated at 60.3 million tonnes of carbon dioxide equivalent (MMt CO_2 eq.) by CERI and 61. 4 MMt CO_2 eq. by (Environment Canada, 2015) for 2013

have increased by 77.4 percent by 2013 compared to 2005 levels of 34.0 MMt CO_2 eq. corresponding to a compound annual growth rate (CAGR) of 7.4 percent.[10]

The federal government has recently announced its intentions to reduce national GHG emissions to 30 percent below 2005 GHG emissions of 737.0 MMt CO_2 eq. by 2030, or 515.9 MMt CO_2 eq. In Alberta, the 2008 climate change action strategy called for a province-wide target of 236.0 MMt CO2 eq. by 2020 and 176.0 MMt CO2 eq. by 2050. This strategy relies on the commercial development and deployment of carbon capture and storage (CCS) technologies (Alberta Environment, 2008).[11] More recently, the provincial government has appointed an expert panel to review its existing climate action strategy.

The overall objectives of this report are:

- To provide an overview of the oil sands sector in the context of the economy, energy use, and environmental impacts in Alberta and Canada.
- To provide a detailed overview of the different energy requirements and sources of energy used by oil sands projects.
- To quantify the industry's energy requirements and the associated GHG emissions under different assumptions by using scenarios.

Chapter 2 discusses the different energy requirements for different types of oil sands projects and quantifies energy demand for the industry and GHG emissions under the assumption of a business as usual (BAU) scenario (to 2050). This analysis is presented in a structured manner and considers the forecast for oil sands production, quantifies the associated energy requirements and estimates GHG emissions. In addition, the assessment highlights the assumptions and variables that can affect the results.

Chapter 3 discusses the scenario methodology and results of five alternative scenarios which affect the level of energy required by the industry and GHG emissions.

Chapter 4 summarizes the results of the analysis.

[10] Based on data from (Envrionment Canada, 2014) and (Environment Canada, 2015)

[11] GHG emissions reductions via CCS in the 2008 provincial climate change strategy are estimates to account for 139 MMt CO_2 eq. in reductions by 2050, or 69.5% of the total anticipated GHG emissions reduction (of 200 MMt CO_2 eq.)

Chapter 2: Oil Sands Industry Energy Requirements and GHG Emissions

Types of Energy Required

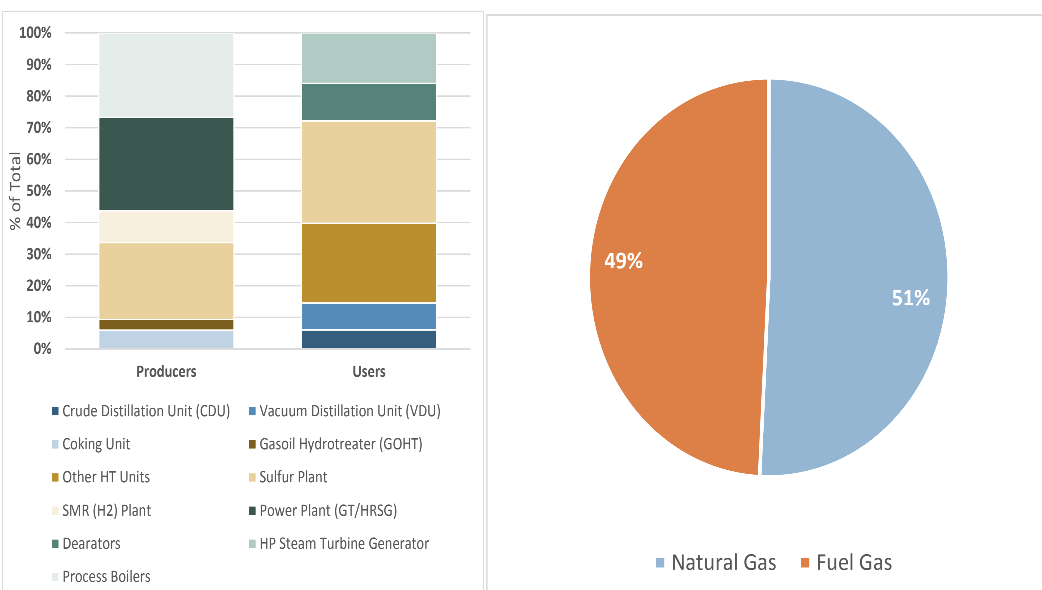
Thermal Energy

Thermal energy for oil sands operations is primarily used in the form of steam, hot process water (HPW) and heating fuel requirements for different processes and facilities. Natural gas is the main fuel used for this purpose. Upgraders' fuel gas and synthetic gas, as well as in situ associated gas (and even in some instances, solid petroleum coke) are also used as fuels for thermal energy production.

Steam is used at in situ *thermal* operations[1] in order to mobilize the bitumen from the reservoir to the wellhead. Steam is also used in the separation process at mining and extraction operations. At upgrading projects, steam is used (and generated) across various process units as seen on Figure 2.1.

Hot process water is used in mining and extraction projects at the different extraction and separation stages and it accounts for the majority of the thermal energy used in mining and extraction projects (Figure 2.1).

Figure 2.1: Steam Generation and Consumption at a Typical Coking Upgrading Facility, by Process Unit (left) and Steam Generation Fuel Sources' Estimated Breakdown (right)



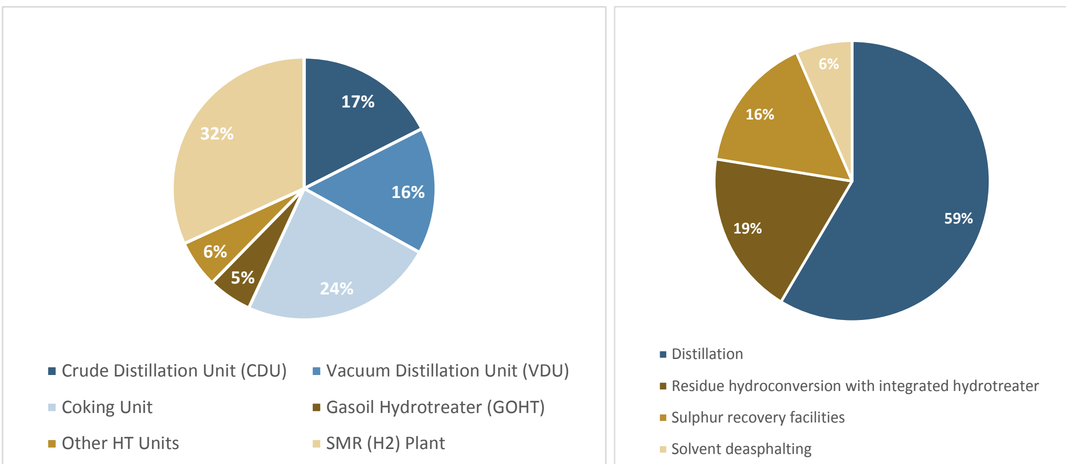
Source: AERI, CERI

[1] Including steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) projects

The largest producers of steam in a typical coking upgrading complex include heat-recovery steam generators (HRSGs) and process boilers such as once-through steam generators (OTSGs), as well as the sulfur and steam methane reforming (SMR)/H_2 plants. The largest steam users in the upgrading complex include the sulfur plant, various hydro-treating (HT) units, and a small auxiliary HP steam turbine generator.

Heating fuel is used in various primary upgrading units (via furnaces) in order to drive the fractionation, distillation, and cracking processes. It is also used to provide heat for the hydrogen production plant (SMR) and the various hydro-treating (HT) units in the secondary upgrading process. The breakdown of heating fuel requirements for primary versus secondary upgrading units will vary depending on the upgrading process, but generally, it is evenly distributed between the two upgrading stages, as seen on Figure 2.2.

Figure 2.2: Thermal Energy Use Breakdown for a Typical Oil Sands Coking[2] (left) and Hydro-cracking[3] (right) Upgrading Project



Source: AERI, CERI

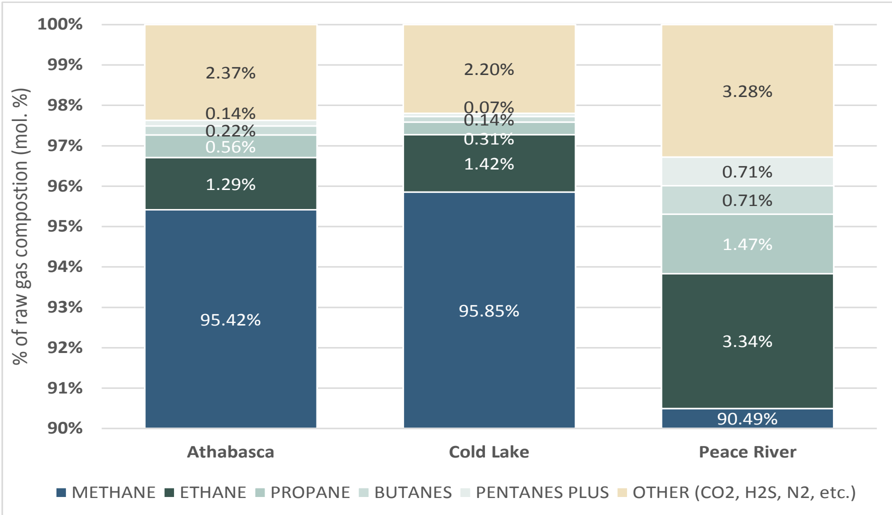
In situ projects normally produce associated gas in conjunction with the extracted crude bitumen. The amount, composition, and heating value of the produced associated gas varies by deposit (Figure 2.3), and thus, by extraction method. This associated gas is normally used within the operation's limits (after being treated and processed) in order to provide a portion of the gas requirements for steam or power generation, and potentially for natural gas powered pumps (in gas lift) and compressors. In general, produced associated gas supplies need to be supplemented

[2] *Coking* refers to the primary upgrading *thermal cracking* process, which takes place at high temperatures, in the absence of catalysts, to upgrade heavy residues, or crude bottoms such as vacuum residue, to lighter fractions. The process normally results in the production of solid petroleum coke

[3] The terms *hydro-cracking* and *hydro-conversion* are used interchangeably within the context of this report. These terms refer to the primary upgrading *catalytic cracking* process, which consist of adding hydrogen, under pressure, in the presence of catalysts, to upgrade heavy residues (which generally originate from the vacuum distillation units) to lighter hydrocarbon fractions.

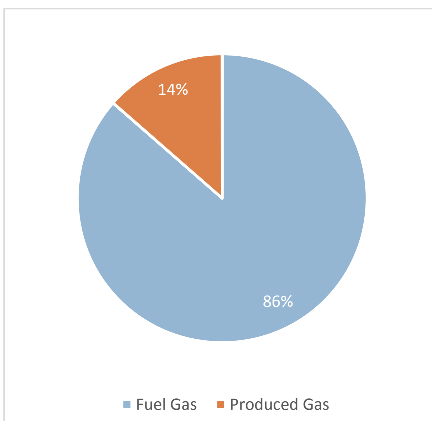
with external gas purchases (Figure 2.4) in order to satisfy in situ projects' thermal energy requirements.

Figure 2.3: Average In Situ Associated Gas Composition by Oil Sands Area (mol. %)



Source: CERI

Figure 2.4: Thermal Energy Fuel Breakdown for a Typical In Situ Cyclic Steam Stimulation (CSS) Oil Sands Project[4]



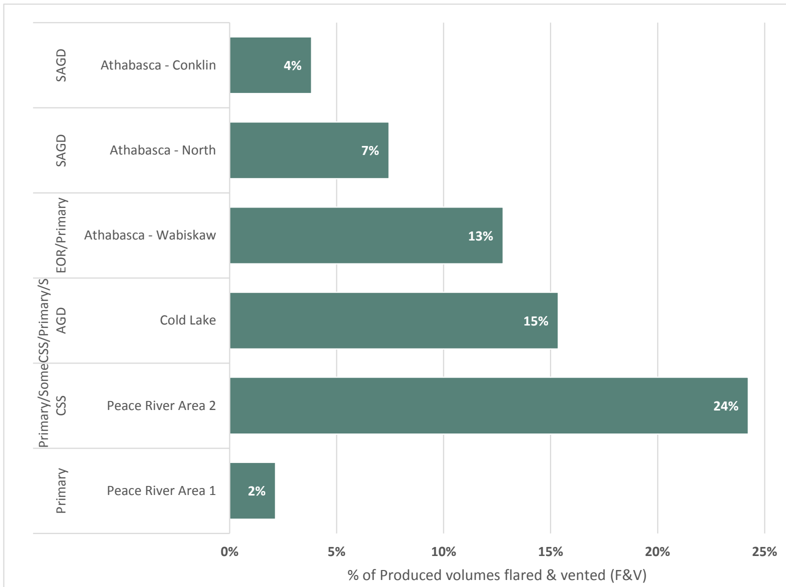
Source: Alberta Environment, CERI

Depending on the project's gas demand levels and other factors such as proximity and access to processing and marketing infrastructure as well as economic viability, a portion of the in situ

[4] The percentage of co-produced and used gas as a percentage of total thermal energy/gas requirements varies significantly by area and by in situ extraction method. CERI estimates this portion to be <10% of the total for SAGD projects, 10% - 30% for CSS projects, and 60% - 70% of the total for Primary/EOR projects. This also helps explain different F&V levels in different OSAs.

associated gas production may be flared or vented.[5] This indicates that different oil sands in situ producing areas exhibit different levels of flaring and venting (Figure 2.5).

Figure 2.5: Associated Gas Flaring and Venting by In Situ Oil Sands Area, Percentage of Associated Gas Production, 2014



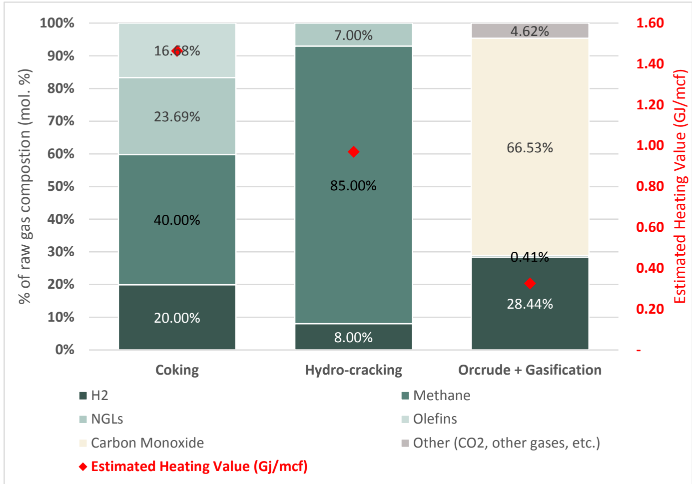
Source: AER, CERI

Upgrading processes produce fuel gas and syngas,[6] the composition and heating value of which depends on the upgrading process used (Figure 2.6). This gas is produced mainly at primary upgrading units (via distillation, thermal cracking and gasification processes). Fuel gas and syngas are internally used for meeting thermal energy needs, some level of direct hydrogen use (if gas is H_2-rich) and as a hydrogen feedstock. In some instances, it is used for power generation.

[5] For more information on issues regarding associated and solution gas in Alberta see (Canadian Energy Research Institute (CERI), 2015)

[6] Upgrader *fuel gas* is generally produced from the primary upgrading processes such as distillation and cracking, while upgrader *syngas* is produced from the gasification of petroleum residue (such as coke or ashphaltenes). *Fuel gas* is generally a mix of hydrogen and light paraffinic (and sometimes olefinic (in coking upgraders only)) hydrocarbons, while *syngas* is primarily composed of hydrogen (H_2) and carbon monoxide (CO). Fuel gas and syngas will generally contain sulfur (S) in the form of hydrogen sulfide (H_2S), which is removed as elemental sulfur at gas treating and sulfur removal facilities

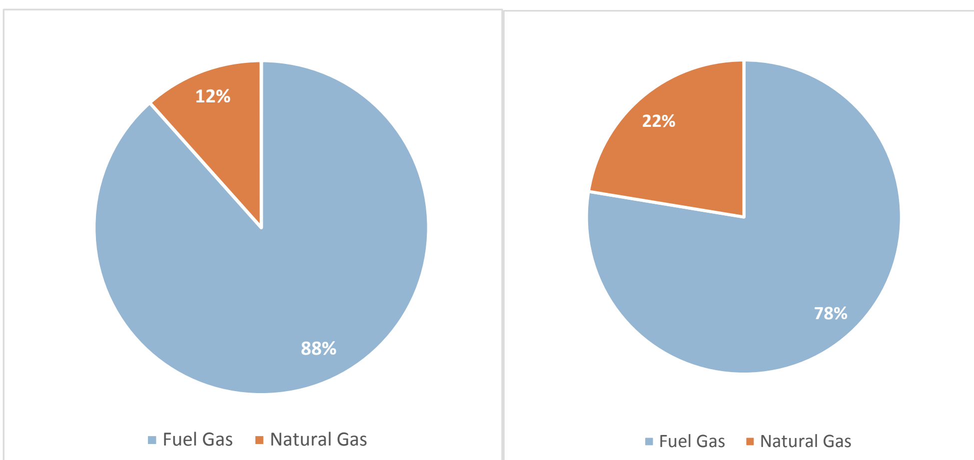
Figure 2.6: Estimated Upgrading Fuel Gas and Syngas Composition and Heating Value, by Process



Source: Alberta Environment, CERI

Figure 2.7 shows that upgrader fuel gas is generally used to meet the majority of heating fuel energy requirements for upgraders.[7] It can also be observed that coking upgraders are generally more self-sufficient compared to hydro-cracking (HC) upgraders. The heating value of coking fuel gas tends to be higher than that of hydro-cracking fuel gas, explaining the need for supplemental fuel in the form of natural gas purchases for hydro-cracking upgraders.

Figure 2.7: Heating Fuel Sources' Breakdown for a Typical Oil Sands Coking (left) and Hydro-cracking (right) Upgrading Project



Source: Alberta Environment, CERI

[7] The estimated thermal energy breakdown between steam and heating requirements in a coking upgrading process is approximately 25%/75%, respectively, according to data from (Suncor Energy and Jacobs Consultancy for CCEMC, 2012)

Mining projects generally meet their thermal energy needs through heat integration with nearby upgrading or cogeneration operations, but can alternatively purchase natural gas from the local distribution system.

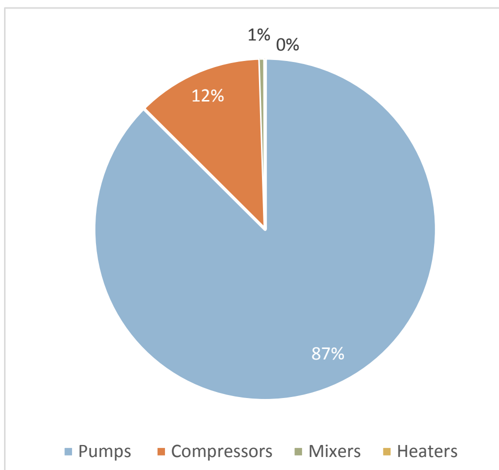
Electricity

Electricity is used at in situ operations primarily for powering pumps, compressors, mixers, heaters, and injectors both at the well pads and at central processing facilities (CPFs) (Figure 2.8).

Some in situ projects use natural gas instead of electricity at the reservoir level, depending on the artificial lift method being employed (i.e., natural gas in gas lift, versus electricity in down-hole electric submersible pumps (ESPs) for mechanical lift).

The amount of electricity used by in situ operations may also vary depending on the type of water treatment used at the CPF for the production and treatment of boiler feed water (BFW) (i.e., lime softening and ion exchange, versus evaporators).

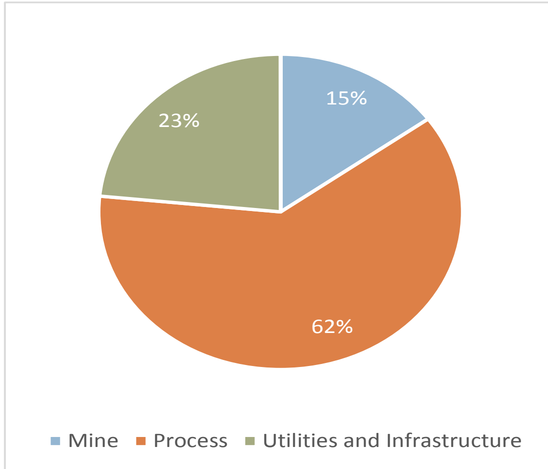
Figure 2.8: Electricity Requirements' Breakdown for a Typical In Situ Steam Assisted Gravity Drainage Oil Sands Project



Source: Alberta Environment, CERI

In mining operations (see Figure 2.9), electricity can be used to power electric shovels. It is also used to power feeders and crushers at the mine site, as well as conveyor belts, pumps, valves, compressors, and other equipment.

Figure 2.9: Electricity Requirements' Breakdown for a Typical Mining and Extraction Oil Sands Project[8]



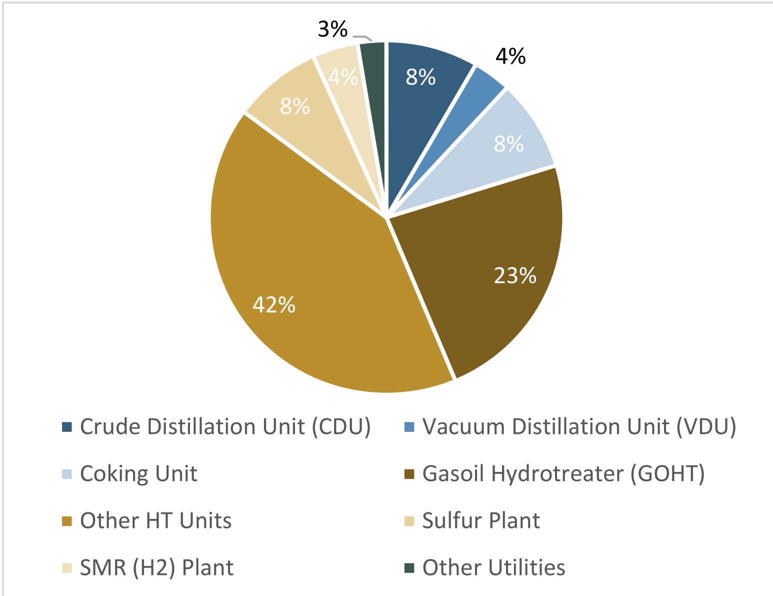
Source: Alberta Environment, CERI

In upgrading operations, electricity is used to power pumps and valves that move the bitumen and its fractions through the different process units as well as to power the different process units. The amount of electricity used in upgrading operations will largely depend on the upgrader's configuration (such as coking versus hydro-conversion) and complexity (or level of hydro-treating[9]) (Figure 2.10).

[8] *Mine* facilities includes truck and shovels used in the mining operations. *Process* facilities include the ore preparation plant (OPP), bitumen extraction facilities, froth treatment facilities, and tailings management facilities. *Utilities and infrastructure* include power and steam generation, water treatment facilities, linear infrastructure (such as roads, power lines, and pipelines), tankage, chemical storage, water storage, and disposal facilities

[9] i.e., primary versus secondary upgrading

Figure 2.10: Electricity Requirements' Breakdown for a Typical Oil Sands Coking Upgrading Project



Source: AER, CERI

Electricity for oil sands operations can be produced at on-site cogenerations facilities which produce both electricity and thermal energy, or can be purchased directly from the provincial grid. CERI estimates that there are a total of 15 cogeneration plants serving oil sands projects with a capacity of 2,440 megawatts (MW), or about 16.3 percent of total current generation capacity in the province (of about 15,000 MW[10]).

Table 2.1: Oil Sands Cogeneration Facilities

Plant	Owner	Operator	Oil Sands Project	Area	Type	Capacity (MW)
Suncor Base Mine Legacy Turbines	Suncor Energy	Suncor Energy	Suncor - Base Mine	Athabasca - Mining	Mining & Upgrading	40
Mildred Lake Cogeneration Plant	Syncrude Canada Ltd.	Syncrude Canada Ltd.	Syncrude - Mildred Lake Mine (Base Mine)	Athabasca - Mining	Mining & Upgrading	97
Primrose Cogeneration Plant	ATCO Power (50%), Canadian Natural Resources Ltd. (CNRL) (50%)	Canadian Natural Resources Ltd.	CNRL - Primrose/Wolflake	Cold Lake	In Situ - CSS	85
Muskeg River Cogeneration Plant	ATCO Power (70%), SaskPower (30%)	ATCO Power	Shell Canada - Muskeg River/Albian Sands	Athabasca - Mining	Mining	170
Scotford Cogeneration Plant	ATCO Power	ATCO Power	Shell Canada - Scotford Upgrader	Industrial Heartland	Upgrading	175
Mahkeses Cogeneration Plant	Imperial Oil Ltd.	Imperial Oil Ltd.	Imperial Oil - Cold Lake	Cold Lake	In Situ - CSS	220
Aurora Generation Station	Syncrude Canada Ltd.	Syncrude Canada Ltd.	Syncrude - Aurora Mine (Satellite Mine)	Athabasca - Mining	Mining	170
Foster Creek Cogeneration Gas Power Plant	Cenovus (50%), Conoco Phillips Canada Resources Corp. (50%)	Cenovus	Cenovus - Foster Creek	Athabasca - Conklin	In Situ - SAGD	80
OPTI/Nexen Long Lake Cogeneration Plant	Nexen Inc.	Nexen Inc.	Nexen - Long Lake	Athabasca - Conklin	In Situ - SAGD	170
Firebag Stage 4	Suncor Energy	Suncor Energy	Suncor - Firebag	Athabasca - North	In Situ - SAGD	415
Christina Lake Project (Phase 2)	MEG Energy	MEG Energy	MEG Energy - Christina Lake	Athabasca - Conklin	In Situ - SAGD	170
Algar Operations	Connacher Oil and Gas Limited	Connacher Oil and Gas Limited	Connacher - Algar	Athabasca - Conklin	In Situ - SAGD	13
Horizon Oil Sands Project	Canadian Natural Resources Ltd. (CNRL)	Canadian Natural Resources Ltd. (CNRL)	CNRL - Horizon	Athabasca - Mining	Mining & Upgrading	100
Poplar Creek Power Station	TransAlta Energy Corp.	TransAlta Energy Corp.	Suncor - Base Mine Operations + SAGD	Athabasca - Mining	Mining & Upgrading	370
MacKay River Power Plant	TransCanada Pipelines Ltd.	TransCanada Energy Ltd.	Suncor - Mackay River	Athabasca - North	In Situ - SAGD	165

Source: Canadian Industrial Energy End-use Data and Analysis Centre, Desiderata Energy Consulting, CERI

[10] Based on data from (Alberta Energy, 2015) with the addition of the recently commissioned Shepard Energy Centre (400 MW)

Cogeneration facilities at in situ and mining operations generally rely on market purchased natural gas to meet their fuel requirements. Cogeneration facilities at integrated extraction and upgrading projects will use internally produced fuels such as associated gas from the reservoir, fuel gas and syngas from the upgrading process, and in some instances petroleum coke, to supplement natural gas purchases.

Generally, cogeneration facilities produce a surplus of electricity which is sold to the provincial market, providing an additional revenue stream for oil sands project operators.

Hydrogen

Hydrogen is used in the primary upgrading stage at hydro-cracking upgraders and in all upgrading projects with secondary upgrading processes for the purpose of hydro-treating. This allows for the production of clean sweet SCO[11] (or fractions thereof such as naphtha and diesel fuel).

Hydrogen is mainly produced at upgrading operations from natural gas purchases via steam methane reforming (SMR). Some upgraders will use internally produced fuel gas to produce hydrogen. In some areas where industrial integration exists, upgrading operations have the option of purchasing pure hydrogen streams from nearby industrial facilities.[12] Steam methane reforming (SMR) is a two-step process that produces hydrogen (H_2) from methane (CH_4).

Diesel

Diesel fuel is mainly used to power trucks and shovels at the mine sites in mining and extraction operations. Some integrated mining and upgrading operations produce diesel on-site at their upgraders in order to meet their project's needs. Diesel fuel may also be used at non-thermal in situ operations[13] for powering pumps and compressors.[14]

Methodology and Business as Usual Scenario

Under the business as usual (BAU) scenario, the unconstrained production forecast is adjusted by applying probability factors that serve to curtail a projects' originally stated production capacity, and by applying delays (expressed in number of years into the future) to the originally stated project commissioning or start dates. This is a way of adding risk to the unconstrained (or risk-free) scenario. These probability and delay factors have guided the production forecast such that announced projects have been taken out of the forecast, as these are seen as speculative.

[11] Free or with minimum levels of sulfur, nitrogen (N_2), and heavy metals

[12] As an example, upgrading projects can purchase hydrogen streams from nearby refineries and petrochemical facilities

[13] Bitumen production methods via primary production and enhanced oil recovery (EOR) are also known as "cold" bitumen production methods. The term cold heavy oil production with sand (CHOPS) is also used to refer to these types of projects.

[14] Energy demand for CHOPS operations is for the purposes of water re-injection, gas treatment, crude lifting, water treatment, and gas re-injection (Jacobs Consultancy/Life Cycle Associates prepared for Alberta Energy Research Institute (AERI), 2009). CHOPS operations are similar to conventional crude oil operations in terms of their surface configuration and footprint

After these adjustments, a total of 188 oil sands project phases are included in the BAU scenario: 21 mining project phases at 6 mining projects/complexes; 147 thermal in situ project phases at 53 steam assisted gravity drainage (SAGD) projects and 10 CSS projects; and 20 upgrading project phases at 9 upgrading complexes.

The main BAU energy demand elements of oil sands projects discussed in this section include electricity (together with its fuel requirements and sources),[15] gas[16] (for thermal energy and hydrogen production requirements) and diesel fuel. Demand for energy in the oil sands industry will be a function of oil sands production volumes and energy intensity factors.

Intensity factors for energy use at oil sands projects will vary depending on reservoir characteristics and conditions (or reservoir quality), production processes and technology choice.

Energy intensity factors, the type of energy required, and the fuel mix sourced to satisfy the oil sands industry's energy needs, will in turn determine GHG emissions intensity per unit of output.

GHG emissions from the industry will then be a function of the availability of different energy sources, technologies used to meet the industry's energy needs, evolving energy intensity factors, and production volumes.

Intensity factors are derived as implied estimates by dividing the energy demand of a given type of project by its output. However, the data necessary for such calculations is not always readily available on an individual project, project type, or geographical area basis.

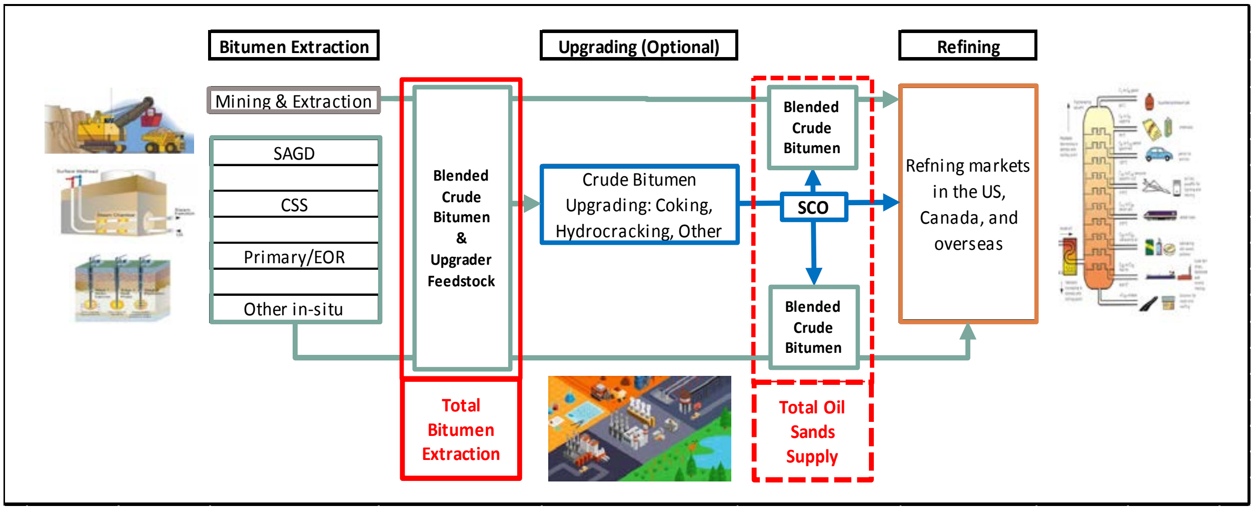
If oil sands production estimates are similar across different forecasts and the overall energy demand estimates are comparable as well, this then indicates that the energy intensity factors are generally in line across the different forecasts in question.

It is important to clarify the different measures of output for oil sands production. Figure 2.11 shows that the main two categories of oil sands production quantified in this analysis are bitumen extraction (solid red-highlighted box) and oil sands supply (dashed-red highlighted box).

[15] Indirect primary energy demand

[16] Unless otherwise specified, in the context of this section "gas" refers to total gas use including natural gas, fuel gas, syngas, and associated gas. The term "natural gas" is used in the context of this section to refer to *marketable natural gas* as purchased from the local distribution system.

Figure 2.11: Bitumen Extraction and Oil Sands Supply Flowchart



Source: Images from various data sources; Figure by CERI

Bitumen extraction includes total production of crude bitumen from mining and extraction, as well as production from the different in situ methods (including SAGD, CSS, CHOPS, and others[17]). The *oil sands supply* estimate, on the other hand, accounts for the fact that a portion of crude bitumen extracted is upgraded to SCO before being shipped to refinery markets. A growing portion of crude bitumen is blended (or diluted[18]) and shipped to refinery markets without being upgraded.[19]

This distinction is important in the context of energy demand for the industry. Energy demand requirements are quantified for the extraction (mining and in situ) and upgrading processes, and therefore any energy or emissions intensity factors estimates for the "*oil sands industry*" should be quantified on an oil sands supply basis (a combination of bitumen and SCO) rather than bitumen extraction.

Figure 2.12 displays the historical bitumen extraction and oil sands crude supply volumes for the period 2007 to 2014, and CERI's outlook estimates for the period between 2015 and 2050.[20]

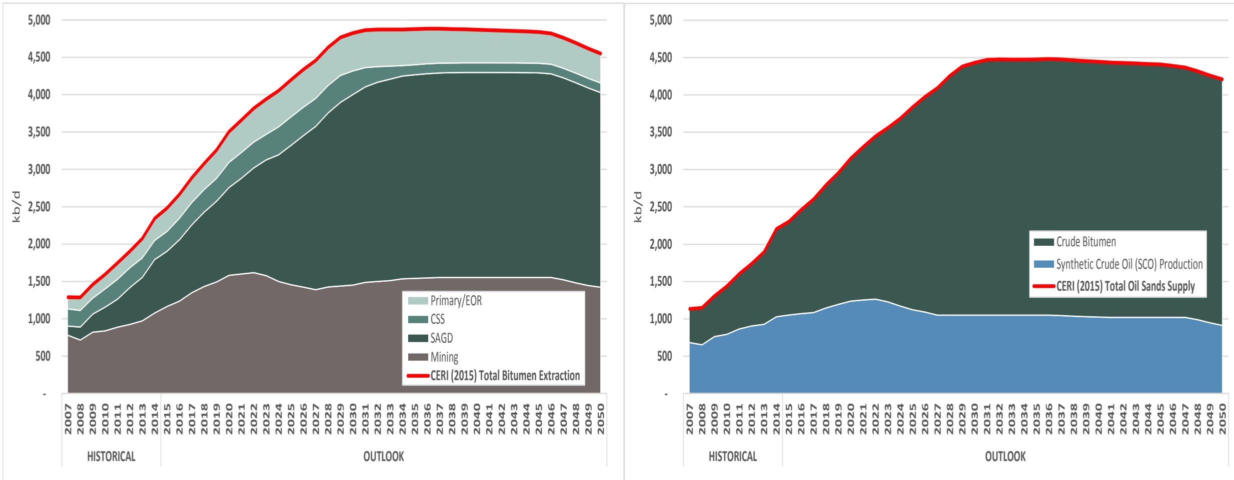
[17] Other in situ production methods may include solvent based methods, air injection combustion methods, and electric-heating technologies, amongst others. As of the time of writing most of these production methods are at the pilot or test stage

[18] Diluent choices include butanes, pentanes plus, condensate, light crude oil, and SCO. The choice of diluent used depends on a combination of price, availability, and technical considerations

[19] Diluent demand for bitumen blending is not included in this analysis or the totals presented

[20] Unless otherwise specified, within the context of this section, historical numbers are generally presented for the period from 2007 to 2014, while forecast or outlook estimates are for the period from 2015 to 2050

Figure 2.12: Bitumen Extraction (left) and Oil Sands Supply (right) Volumes
Thousands of barrels per day (kb/d), 2007-2050



Source: CERI

As can be observed, total bitumen extraction volumes are expected to continue an upward trajectory and peak by 2037 at 4.9 MMb/d, more than double 2014 levels of 2.3 MMb/d, and slightly decline to 4.6 MMb/d by 2050. This implies a net increase of 2.2 MMb/d between 2015 and 2050 or a 94.3 percent increase, at a compound annual growth rate (CAGR) of 1.9 percent.

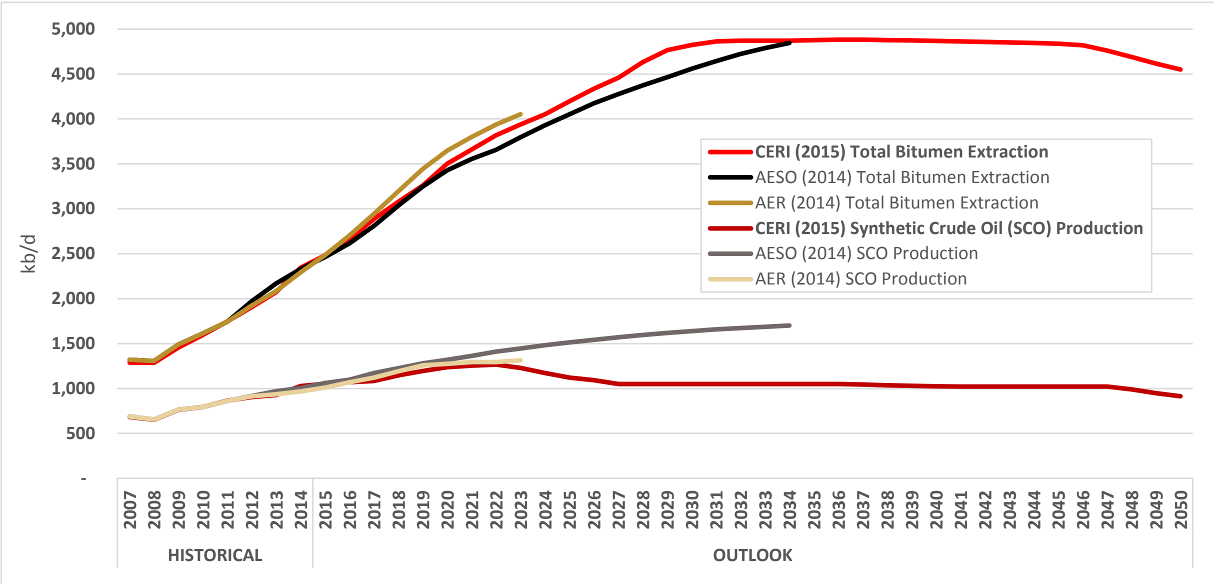
The majority of this increase in bitumen extraction is driven by increased production of bitumen from in situ projects, particularly SAGD projects, thus resulting in an increased share of crude bitumen going to market in raw form rather than an upgraded form (such as SCO). This is the case as, historically, the majority of the upgrader's bitumen feedstock has been sourced from mining and extraction projects.

With this brief overview of CERI's outlook estimates for output from the oil sands industry, we can then compare CERI's results with other recently completed and publicly available relevant estimates.

Figure 2.13 displays total bitumen extraction (mining + in situ projects) and SCO production volume estimates, as well as data from equivalent forecasts sourced from the latest available versions of the Alberta Electric System Operator's (AESO) long-term outlook (LTO)[21] (2014) and the Alberta Energy Regulator's (AER) ST-98 report (2014).[22] However, these forecasts have not taken into account more recent crude oil market conditions.

[21] See: (Alberta Electric System Operator (AESO), 2014). Note that oil sands production numbers in the AESO's LTO are sourced from The Conference Board of Canada's (CBoC) long-term provincial economic forecast. See: (The Conference Board of Canada, 2015)
[22] See: (Alberta Energy Regulator (AER), 2014)

Figure 2.13: Bitumen Extraction and Synthetic Crude Oil Production Forecasts, 2007-2050 (kb/d)



Source: AESO, AER, CERI

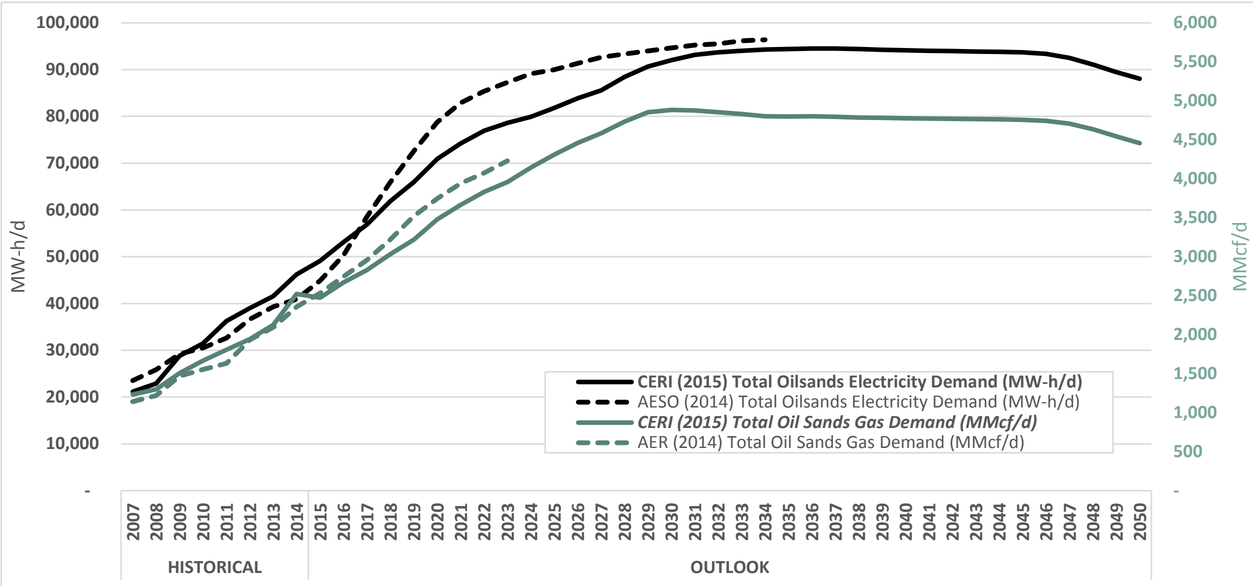
The three forecasts are similar for bitumen and SCO. The exception is the SCO production forecast presented by the AESO which exhibits a continued upwards trajectory past the early 2020s, compared to the trends observed in CERI's and the AER's projections of peaking (AER's) and declining (CERI's) past that point.

Given that production, volumes are comparable across the different forecasts (CERI, AESO, and AER); if electricity and natural gas demand estimates are also similar, then it must be true that energy intensity factors are within comparable ranges.

This is an important consideration given that oil sands energy intensity factors generally exhibit a large degree of variability across individual projects. This makes it challenging to estimate future energy needs for the oil sands.

AESO's 2014 LTO provides estimates for future electricity demand to 2034 for the oil sands industry, while the AER's 2014 ST-98 provides gas demand estimates to 2023. These estimates are compared with CERI's own in Figure 2.14.

Figure 2.14: Oil Sands Industry Electricity (MWh/d) and Gas Demand (MMcf/d) Forecasts 2007-2050



Source: AESO, AER, CERI

CERI's estimate for oil sands electricity demand is 94.3 gigawatt hours per day (GWh/d) for 2034, compared to the AESO's estimate of 96.3 GWh/d for the same year. CERI's estimate for gas demand for the oil sands industry is 4.0 billion cubic feet per day (bcf/d) by 2023, compared to the AER's estimate of 4.2 bcf/d for the same year.

Gas Demand Outlook

Three oil sands industry related energy use datasets were created by extracting detailed information from:

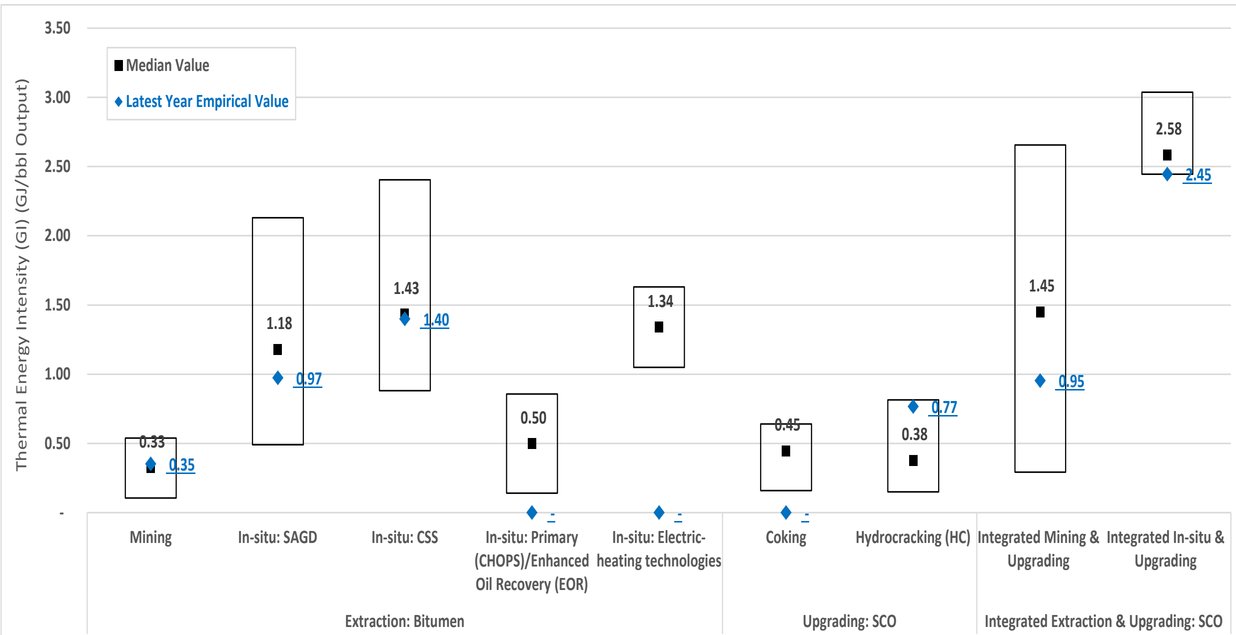
1) a large empirical/historical project-by-project dataset built using various statistical forms and documents sourced from the AER, together with a supporting dataset published as part of a scientific journal article (Jacob G Englader, 2013).
2) a comprehensive literature review of 23 publicly available government and consultant reports and models, as well as published academic journal articles on oil sands energy use and emissions issues (such as life-cycle assessment (LCA) literature).
3) Information provided in energy balances for recently completed or recently approved oil sands projects (submitted through the environmental impact assessment (EIA) process in *Volume I* under the projects' descriptions).

These datasets were then used to develop a comprehensive statistical set of data ranges for energy intensity factors across different types of oil sands projects.

These ranges are meant to capture the large degree of variability and uncertainty across several estimates developed for oil sands energy use metrics. Meanwhile, these intensity factor ranges are used to generate scenarios for energy demand.

Figure 2.15 displays the range for gas intensity (GI)[23] factors for the different project types including extraction processes such as mining, in situ (SAGD, CSS, primary/EOR, and electric-heating technologies), upgrading projects such as coking and hydrocracking, as well as integrated extraction (mining/SAGD) and upgrading projects. These intensity figures have been derived using historical consumptions reported by project operators and published primarily by the Alberta Energy Regulator.

Figure 2.15: Oil Sands Industry Thermal Energy Intensity Factors by Project Type (GJ/bbl of output)



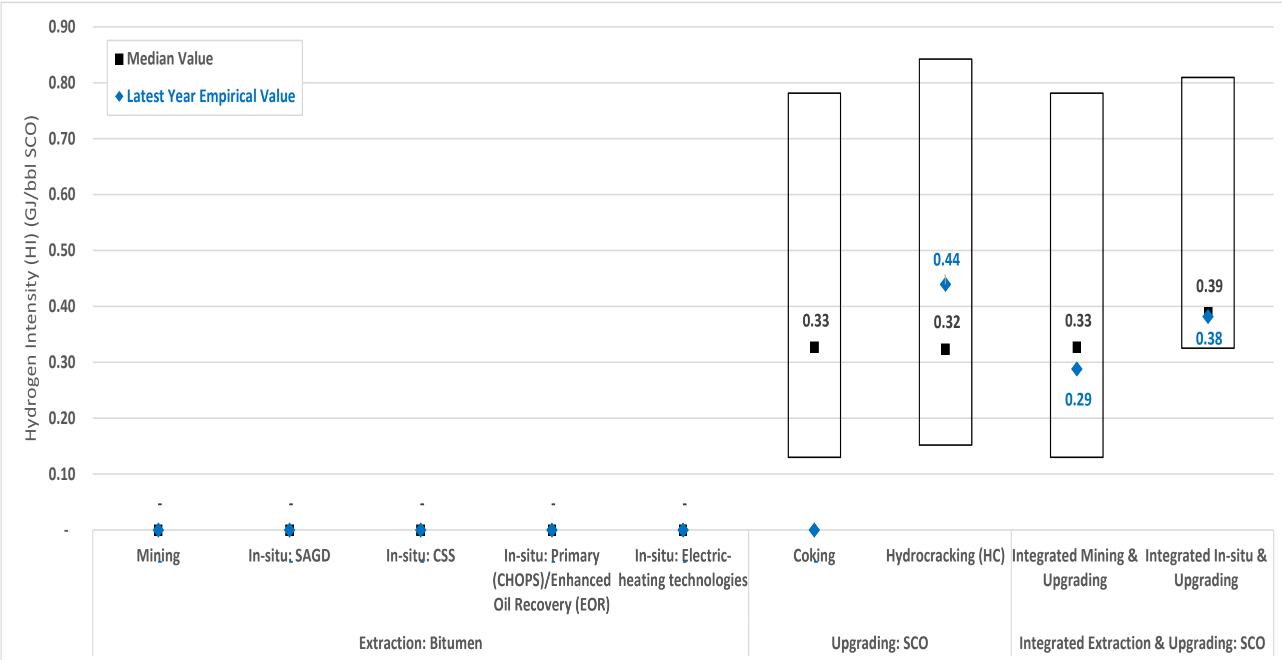
Source: CERI

Figure 2.16 displays (natural gas equivalent) hydrogen intensity (HI) factors for upgrading projects.

The ranges were calculated based on statistical methods to capture the majority of the collected data values from the three datasets. A median value is illustrated by the black square-shaped marker, while the blue diamond-shaped marker displays the latest empirical value collected for a given project type (where applicable), which is generally an average for 2014 (or 2013, depending on data availability).

[23] Includes purchased natural gas and internally produced and associated gas.

Figure 2.16: Oil Sands Industry Hydrogen Energy Intensity Factors by Project Type (GJ/bbl of SCO)



Source: CERI

Thermal energy and hydrogen intensity factors are converted to a volumetric basis (using the fuels' energy density) in order to generate an estimate for gas demand from the oil sands industry by project type, which is comparable to other forecasts (such as the AER's).

Figure 2.17 illustrates the total oil sands demand for gas (including natural gas, fuel gas, syngas, and associated gas) for meeting thermal energy requirements as well as a feedstock for hydrogen production. These estimates *do not* include gas requirements for power generation from oil sands cogeneration plants, nor for overall power generation in the province.

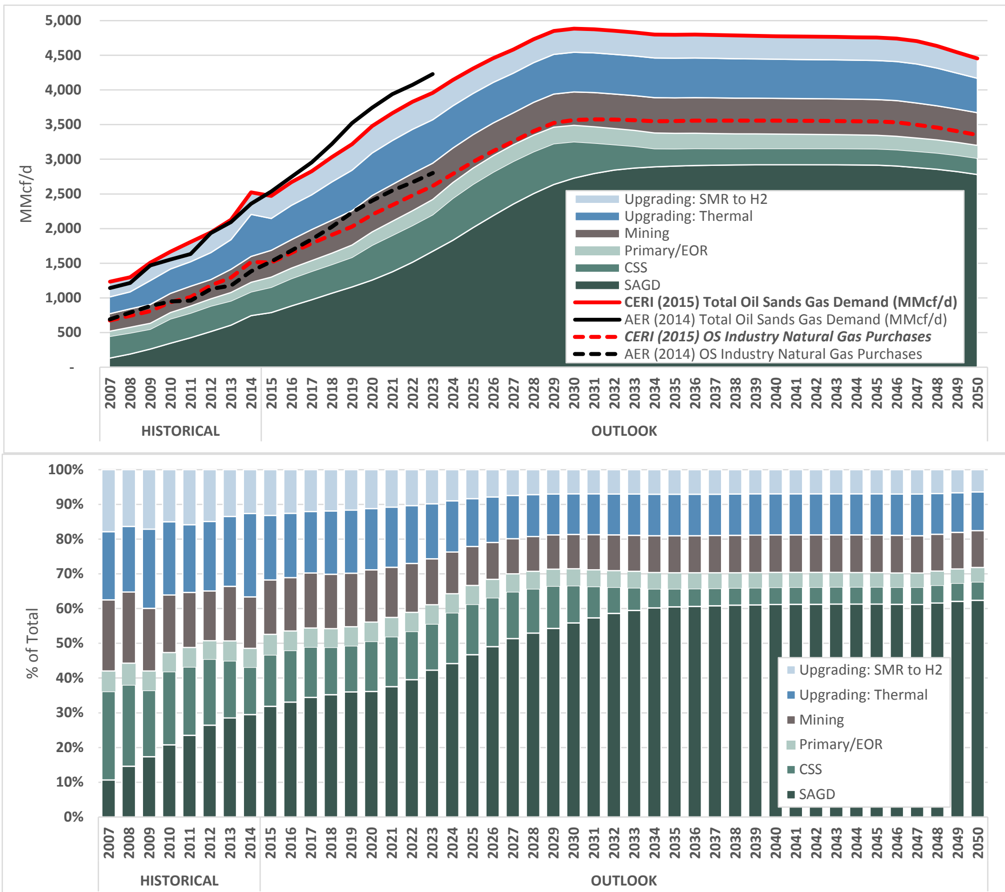
Oil sands industry *natural gas purchases* in Figure 2.17 refers to marketable natural gas purchased from the market, for meeting thermal energy and hydrogen requirements, after accounting for internally produced and utilized gas sources. In 2014, these purchases were estimated to account for 58.8 percent of total gas demand.

As can be observed in Figure 2.17, CERI's estimates for *total gas demand* for the oil sands industry as well as estimates for required marketable *natural gas purchases* are consistent with those from the AER.

Figure 2.17 also indicates that total estimated gas demand for the oil sands industry is expected to increase from about 2.5 bcf/d in 2014 to a peak of 4.9 bcf/d by 2030, and slowly decline to 4.5 bcf/d by 2050. This leads to a net increase of 1.9 bcf/d (or 76.6 percent) between 2015 and 2050, at a CAGR of 1.6 percent.

The majority of the net growth in gas demand from the oil sands industry is expected to come in the form of thermal energy demand requirements for SAGD projects, followed by mining projects, and primary/EOR projects. Meanwhile, demand for gas for upgrading projects (thermal and hydrogen), is expected to decrease slightly between 2015 and 2050.

Figure 2.17: Oil Sands Industry Gas Demand for Thermal Energy and Hydrogen Production by Project Type (MMcf/d), 2007-2050



Source: AER, CERI

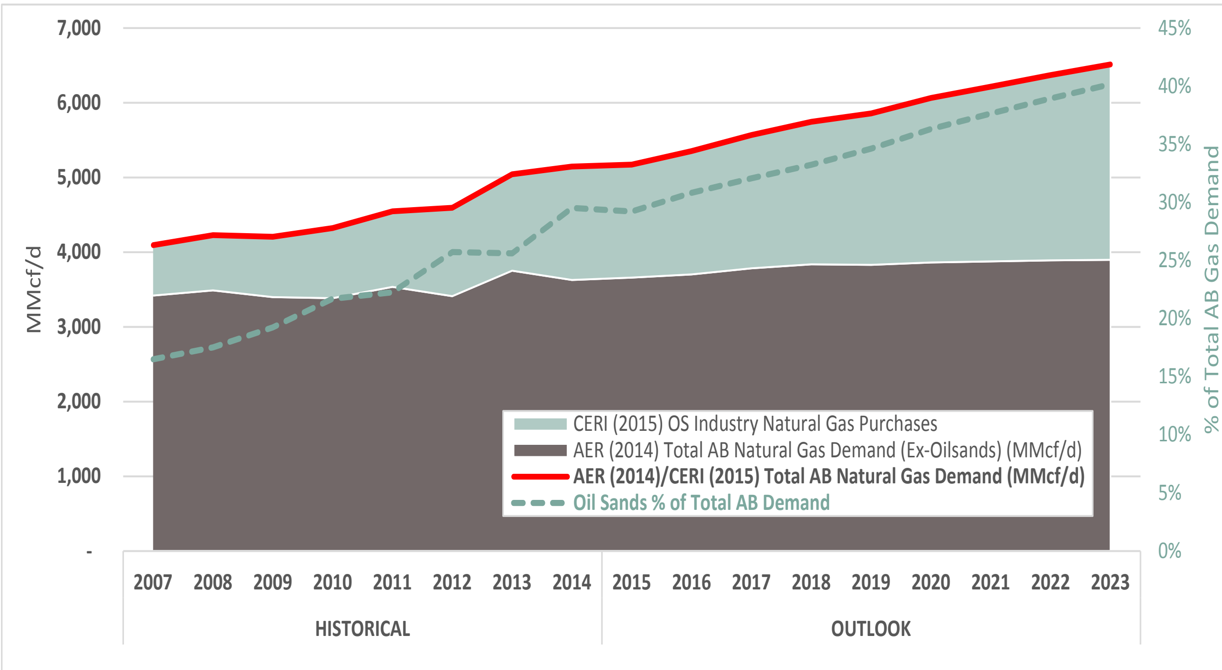
Under the assumption of *constant energy intensity factors*, this trend is primarily the result of an evolving production mix on a project basis rather than technological changes.

It is also important to place into context the level of natural gas demand from the oil sands industry compared to other demand sources in Alberta. As a large user of various energy sources within the province, the oil sands industry's demand levels will increasingly have an effect on local energy markets, regional energy systems and infrastructure, and other end-users in the province.

Figure 2.18 displays the AER's demand forecast for natural gas in Alberta to 2023 along with the breakdown between oil sands and all other sectors. CERI's estimates for oil sands natural gas purchases rely on those from the AER.[24] Natural gas demand growth in the province over the coming decade is expected to come primarily from the oil sands sector.

While the combined AER/CERI estimates indicate that total gas demand in the province is estimated to increase to 6.6 bcf/d by 2023 from 5.1 bcf/d in 2014, an estimated 80 percent of that net increase corresponds to increased demand from the oil sands (for thermal energy and hydrogen production).

Figure 2.18: Oil Sands Industry Natural Gas Purchases and Total Alberta Natural Gas Demand (MMcf/d), 2007-2023[25]



Source: AER, CERI

This then leads the oil sands industry to account for a larger portion of the provincial gas market in Alberta. The *other* or *total demand excluding oil sands* category remains relatively flat over the forecast period. This will also have implications across total energy use in the province, and subsequently, GHG emission levels.

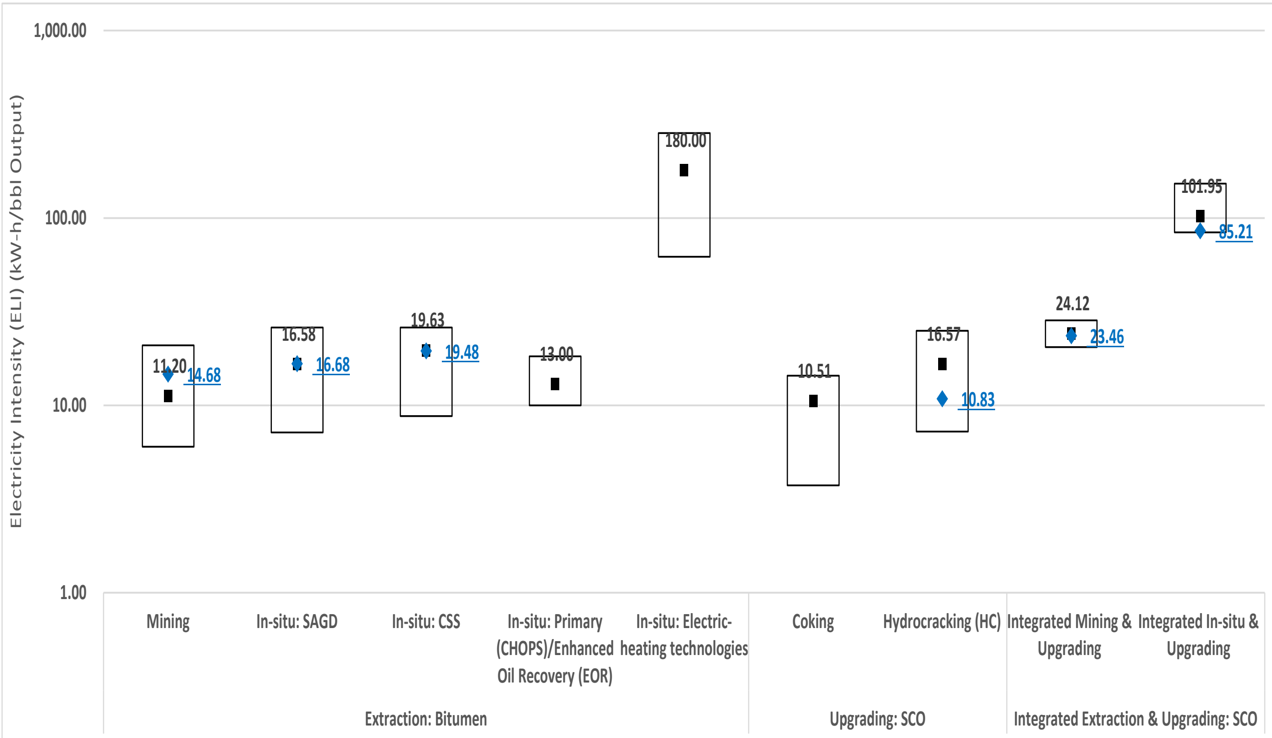
Electricity Demand Outlook

Figure 2.19 displays the electricity intensity (ELI) factor ranges for different types of oil sands projects.

[24] While two different sets of results are being used here, this should not affect the validity of the analysis, given that CERI's and the AER's oil sands production and natural gas demand estimates are very similar (as per Figures 18, 19, and 22, and the discussion above)

[25] The 2023 end year is used here instead of 2035 in order to be able to use the AER's in a relevant and consistent manner

Figure 2.19: Oil Sands Industry Electricity Intensity Factors by Project Type (kWh/bbl of output)[26]



Source: CERI

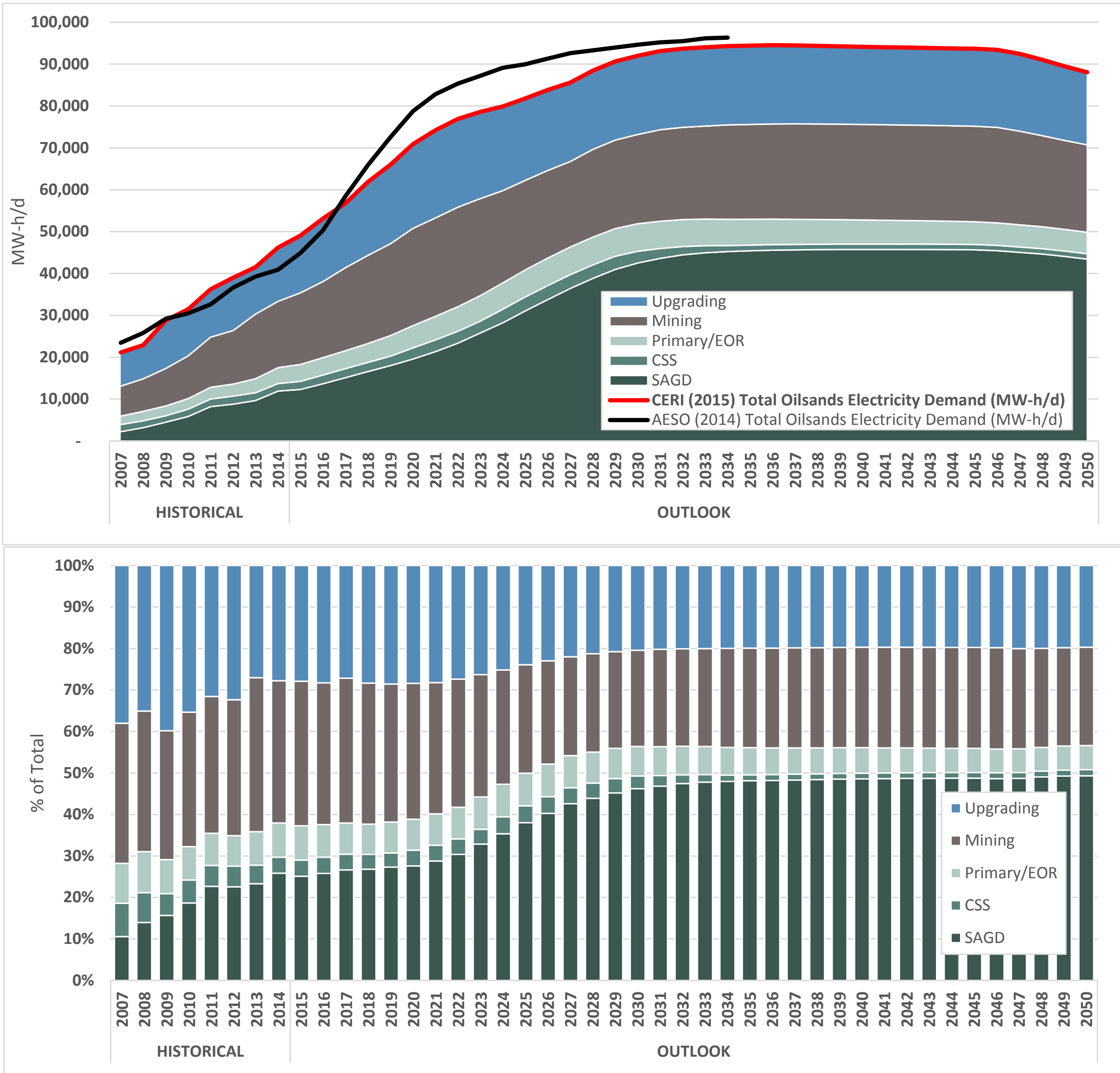
The ELI values exhibit a significant spread with values as low as 4 and 6 kilowatt hours (kWh) per barrel of output (for coking and mining projects, respectively), to as high as 300 and 150 kWh/bbl (for electric-heating technologies and integrated in situ and upgrading projects, respectively).

Historical ELI values are used to estimate historical energy demand, while the latest year's empirical data value is kept constant over the forecast period to calculate future energy requirements. If the latest empirical value is an outlier, the median value for the range or the previous year's empirical value (whichever is the most consistent with recently observed trends) is used over the forecast period in order to better represent future energy intensities for a type of project.

Figure 2.20 displays CERI's electricity demand estimates for the oil sands industry by project type, and compares the total with the AESO's most recent numbers.

[26] Note that the *y* or vertical axis in this figure is given in a logarithmic scale

Figure 2.20: Oil Sands Industry Electricity Demand by Project Type (MWh/d), 2007-2050

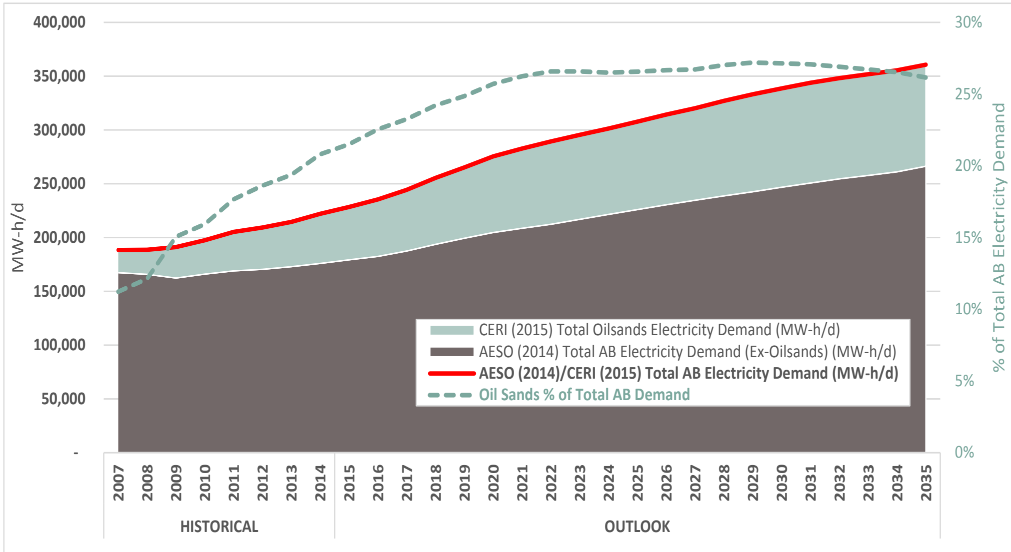


Source: AESO, CERI

Total electricity demand from the oil sands is expected to increase by 41.9 GWh/d (or by 90.6 percent) from an estimate of 46.2 GWh/d in 2014 to 88.0 GWh/d by 2050. Demand for electricity from the oil sands industry over the outlook period is expected to peak at 94.5 GWh/d by 2036.

Figure 2.21 displays the oil sands electricity demand in Alberta. As a percentage of total provincial demand, oil sands electricity demand is estimated to increase and account for 26.2 percent of total electricity demand by 2035.

Figure 2.21: Oil Sands Electricity Demand and Total Alberta Provincial Electricity Demand (MWh/d), 2007-2035



Source: AESO, CERI

Within the balance of electricity end-users in the province, AESO's numbers indicate moderate and steady demand growth across the farm, residential and commercial end-use categories. Rapid and significant growth in electricity demand is estimated by the AESO for the industrial sector (excluding oil sands projects), under the premise that electricity demand in industries that serve the oil sands (such as pipelines and manufacturing) will be driven by a strong oil sands production outlook.

Once again, this indicates that when considering the indirect or spillover effects of oil sands energy demand across other industries, the share of oil sands electricity requirements in the province can be anticipated to be greater than 26.2 percent of the total by 2035.

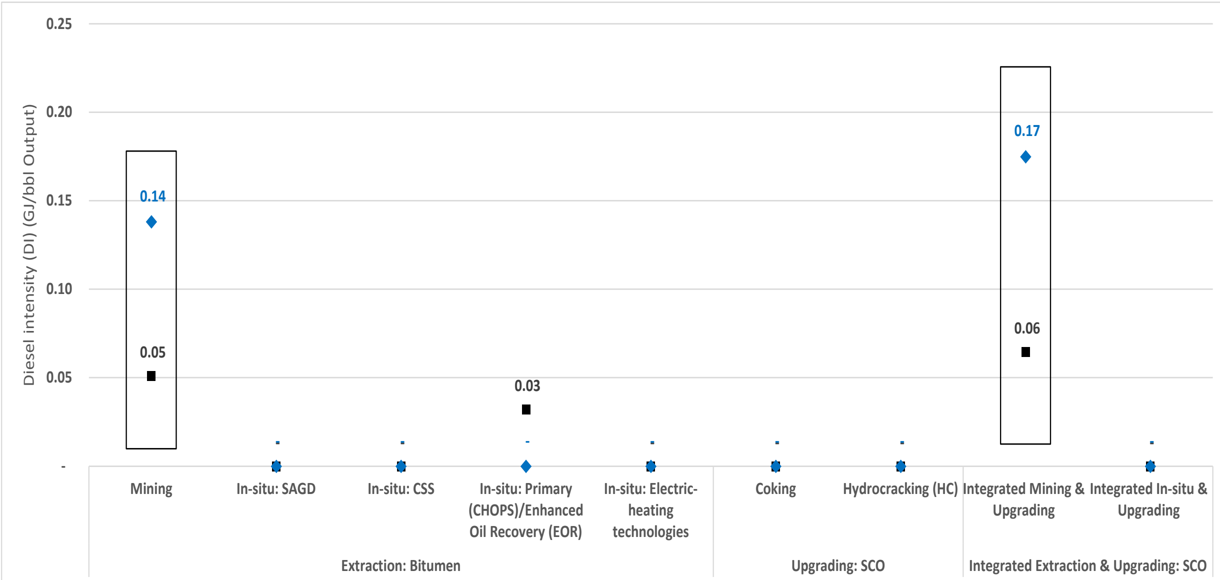
The industry's growing importance in the context of electricity demand also indicates that the fuel mix used to generate the required power for the oil sands industry will have an impact on GHG emissions from the power sector, both in the provincial and national context.

Diesel Fuel Demand Outlook

Figure 2.22 displays the diesel fuel intensity ranges for oil sands operations. Figure 2.23 displays the demand outlook on a project-by-project basis for the mining and extraction category (for mining trucks and shovels) and as a whole for the primary/EOR category for field equipment.

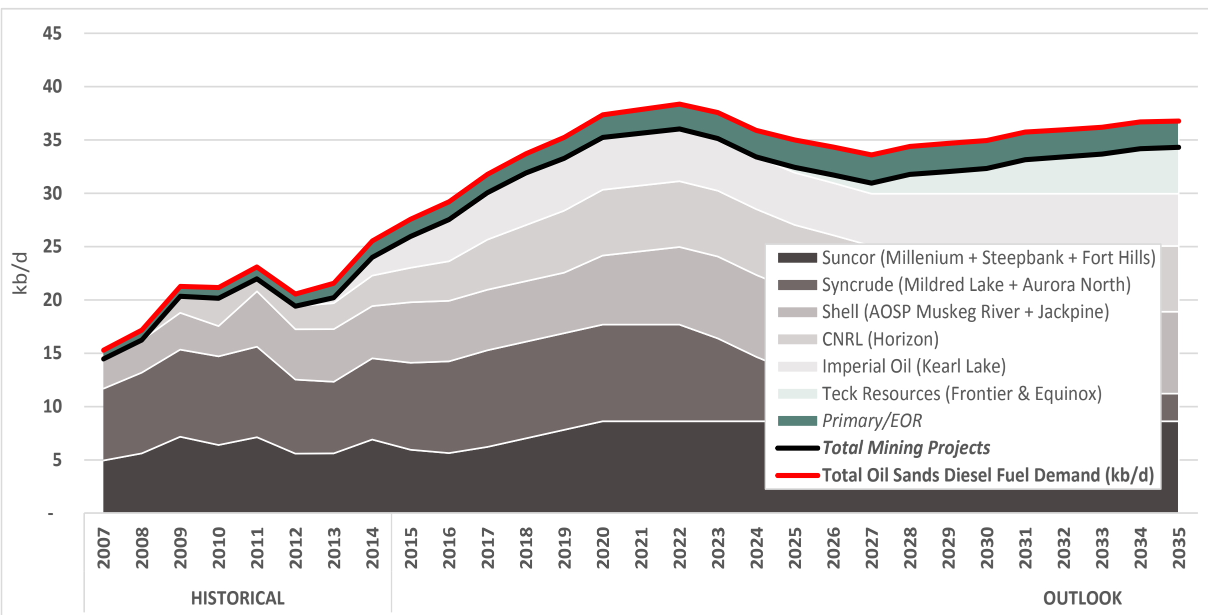
Demand for diesel fuel for oil sands operations is estimated to increase from 25.5 kb/d in 2014 to 33.7 kb/d by 2050 and peak at 38.4 kb/d by 2022.

Figure 2.22: Oil Sands Diesel Fuel Intensity Factors by Project Type (bbl of diesel/bbl of bitumen)



Source: CERI

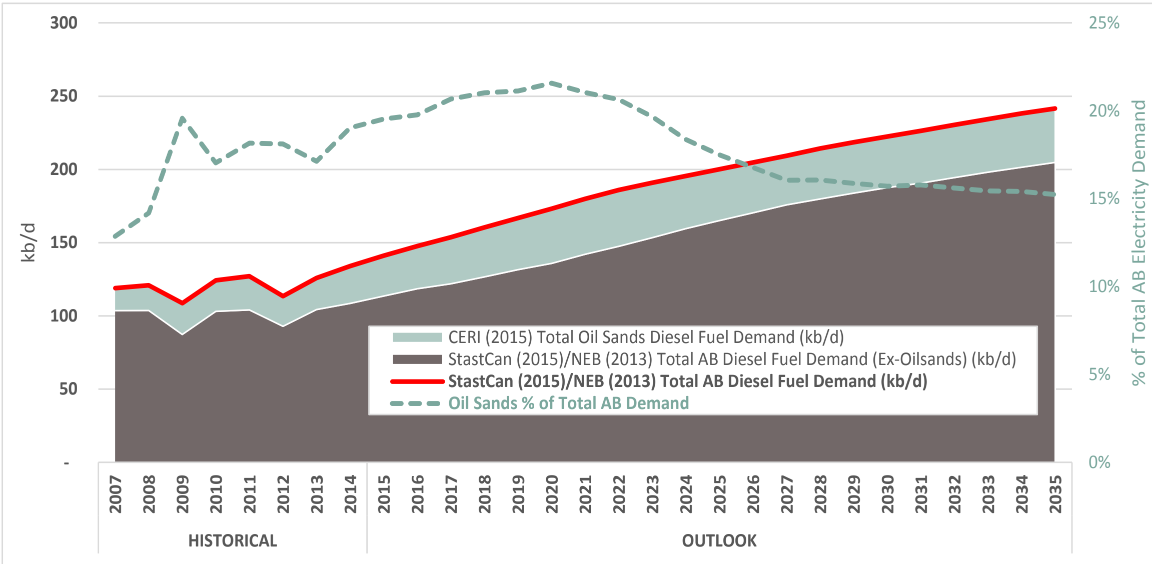
Figure 2.23: Oil Sands Diesel Fuel Demand (kb/d), 2007-2050



Source: CERI

Using data from Statistics Canada and the National Energy Board's (NEB) latest version of the Energy Future Report (2013), CERI estimates that diesel fuel demand from oil sands projects accounted for 19.0 percent of total diesel demand in Alberta in 2014, and that this percentage is expected to decrease to 15.2 percent by 2035.

Figure 2.24: Oil Sands Diesel Fuel Demand and Total Alberta Provincial Demand (kb/d) 2007-2035



Source: NEB, StatsCan, CERI

Total Oil Sands Industry Energy Demand Outlook and GHG Emissions

Power and volumetric estimates for energy demand from the oil sands industry are converted to end-use energy demand estimates on a gigajoule (GJ) per barrel of output basis.[27] This is then used to quantify total energy intensity (TEI) (by project type) and in petajoules per year for quantifying total energy demand. The estimates presented here are gross or total energy demand estimates.[28]

Figure 2.25 displays the total energy intensity (TEI) estimates by project type, and by type of energy used, on a gigajoule per barrel of output basis (BIT or SCO)[29]. These values are calculated by adding the values from the previously presented energy intensity ranges, including thermal energy intensity (GI), natural gas-equivalent hydrogen intensity (HI), electricity intensity (ELI), and diesel fuel intensity (DI).

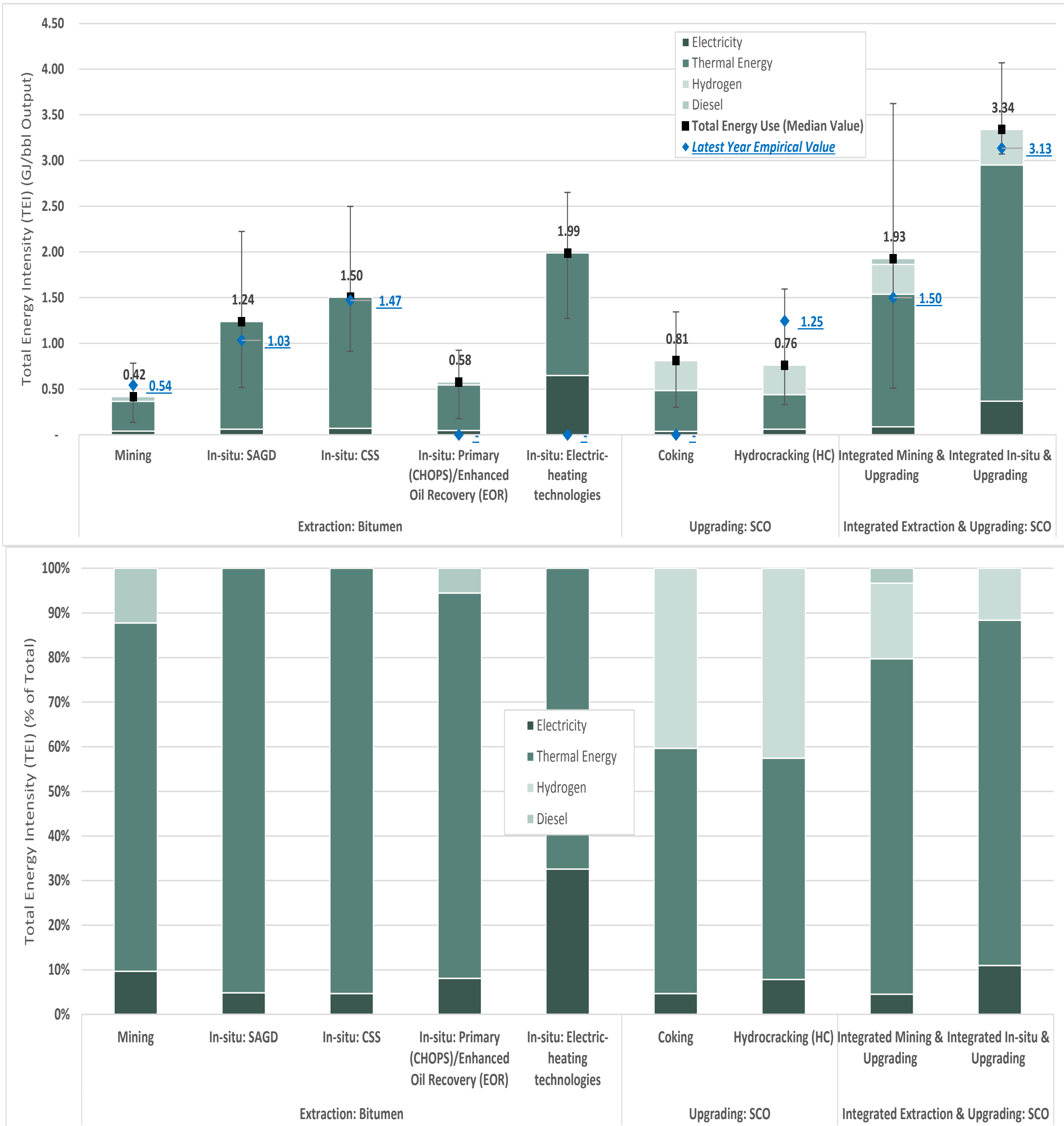
The values in the black square-shaped markers correspond to the sum of the median values across the intensity ranges, while the values in the blue diamond-shaped markers correspond to the sum of the empirical values for the latest year of data available (typically, 2014) for a given project type.

[27] Such as crude bitumen (BIT) or synthetic crude oil (SCO)

[28] That is, the internally produced and used energy in the form of associated gas for in situ projects and fuel gas for upgrading projects is *not* netted out. Gross energy demand = internally produced and used energy + required external energy

[29] In the context of this report the abbreviation BIT is used for crude bitumen, while SCO is used for synthetic crude oil production

Figure 2.25: Oil Sands Total Energy Intensity Factors by Project Type and Type of Energy Used (GJ/bbl of output)



Source: CERI

The error bars capture the lowest and highest boundaries of the intensity ranges. These are meant to describe the range of potential values for TEI and the large degree of variability within the estimates.

The lowest possible TEI is 0.14 GJ/bbl BIT (for mining projects) while the highest is 4.07 GJ/bbl of SCO (for an integrated in situ extraction and upgrading project). This large spread demonstrates the high degree of variability in energy use across different types of production technologies, as well as different levels of processing and the resulting output.

The median value across the different TEI ranges is 1.10 GJ/bbl of output, which is consistent with that for SAGD projects, while the average is 1.50 GJ/bbl of output, which is more consistent for a CSS project.

Across the empirical values, the lowest value is 0.54 GJ/bbl BIT (for mining projects), while the highest value is 3.13 GJ/bbl SCO (for an integrated in situ extraction and upgrading project).

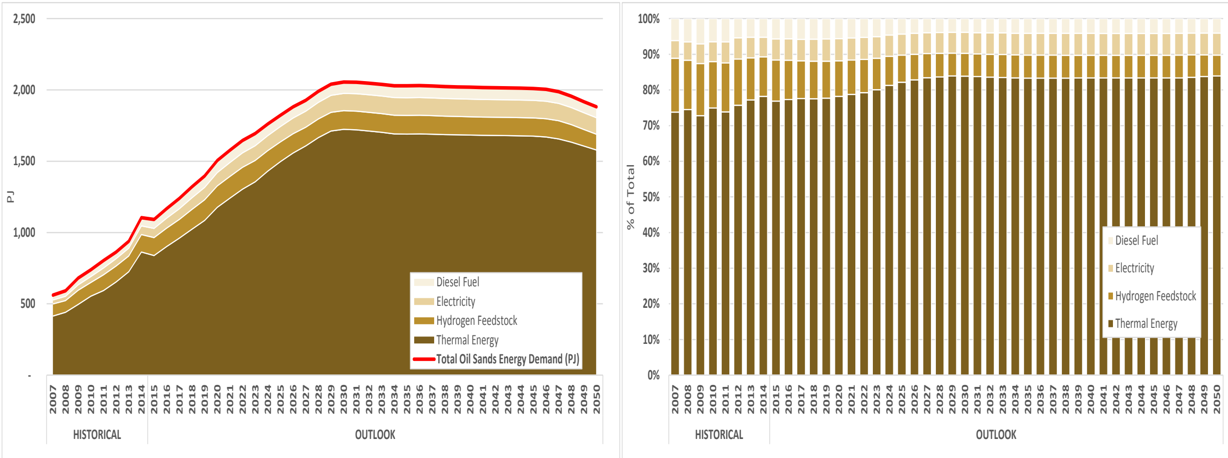
The median value across the latest year empirical values is 1.36 GJ/bbl of output (consistent with values observed for SAGD projects) while the average is 1.49 GJ/bbl of output (consistent with values for CSS projects).

This means that both the estimated TEI ranges and the median values are consistent with some of the latest observed empirical data values across the industry. It also means that the general findings hold true across both sets of estimates. Mining and extraction projects tend to have the lowest energy requirements per barrel of output (crude bitumen) while integrated extraction and upgrading projects have the highest energy requirements (per barrel of SCO). In addition, energy requirements for thermal in situ projects (such as SAGD and CSS) are a good benchmark of total energy intensity (TEI) from oil sands projects.

Across most project types, thermal energy is the single largest source of energy demand, thus having a significant impact on overall energy use in oil sands projects, and by implication, GHG emissions. The conclusion is that in order to reduce total energy demand, and consequently GHG emissions from the oil sands industry, the onus is on reducing thermal energy demand, or increasing the use of lower carbon or carbon-free fuel sources.

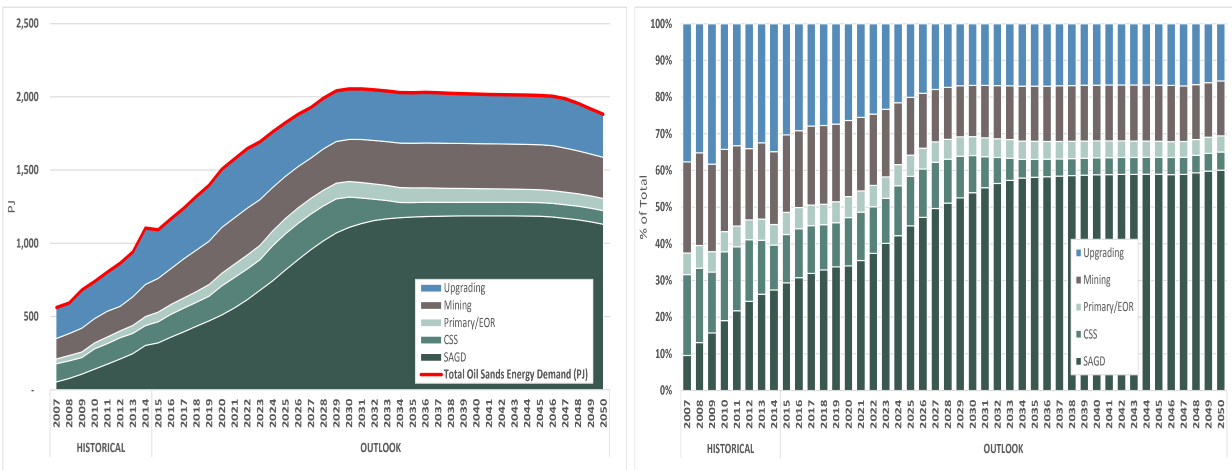
Figure 2.26 displays total end-use energy demand from the oil sands industry by type of energy, while Figure 2.27 displays total end-use energy demand from the oil sands industry by type of project.

Figure 2.26: Oil Sands Total Energy Demand by Type of Energy Used (PJ), 2007-2050



Source: CERI

Figure 2.27: Oil Sands Total Energy Demand by Project Type (PJ), 2007-2050



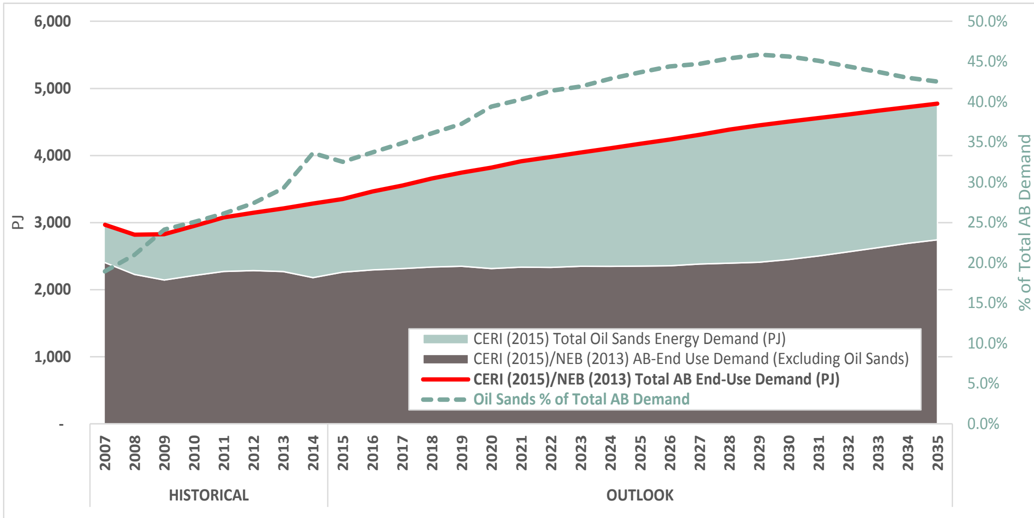
Source: CERI

Total energy demand from the oil sands industry is estimated to increase to 1,881 PJ by 2050, compared to 1,104 PJ in 2014, a 70.3 percent increase, at a CAGR of 1.5 percent. Oil sands end-use energy demand is estimated to peak at 2,055 PJ in 2031.

Thermal energy's share of total energy demand is expected to increase from 80 percent to 85 percent between 2014 and 2050. This trend is driven by the fact that thermal in situ projects are expected to account for an increasing share of bitumen extraction, coupled with the fact that thermal in situ projects are some of the most energy-intensive in terms of thermal energy use.

Figure 2.28 displays end-use energy demand for the oil sands industry in the context of total end-use energy demand in Alberta.

Figure 2.28: Oil Sands End-use Energy Demand and Total Alberta Provincial Demand (PJ) 2007-2035



Source: NEB, CERI

As can be observed, total end-use energy demand in Alberta is estimated to increase from 3,248 PJ in 2014 to 4,772 PJ by 2035, a 46.9 percent increase.

End-use demand is primarily driven by increased demand from the oil sands industry, which is estimated to account for 42.5 percent of total end-use energy demand in the province by 2035 compared to 33.6 percent in 2014, an 8.9 percent increase.

Using the oil sands production outlook together with total energy demand estimates for the industry, Figure 2.29 shows the estimated energy intensity on a barrel of output basis for the industry including:

- total energy intensity (TEI) for mining projects, expressed as gigajoules (GJ) of energy[30] per barrel of bitumen extracted (BIT);
- TEI for upgrading projects on a GJ/bbl SCO basis;
- TEI for in situ projects (including SAGD, CSS, and CHOPS)[31] on a GJ/bbl BIT basis; and
- TEI calculated for total oil sands supply[32] on a GJ/bbl of oil sands output[33] basis.

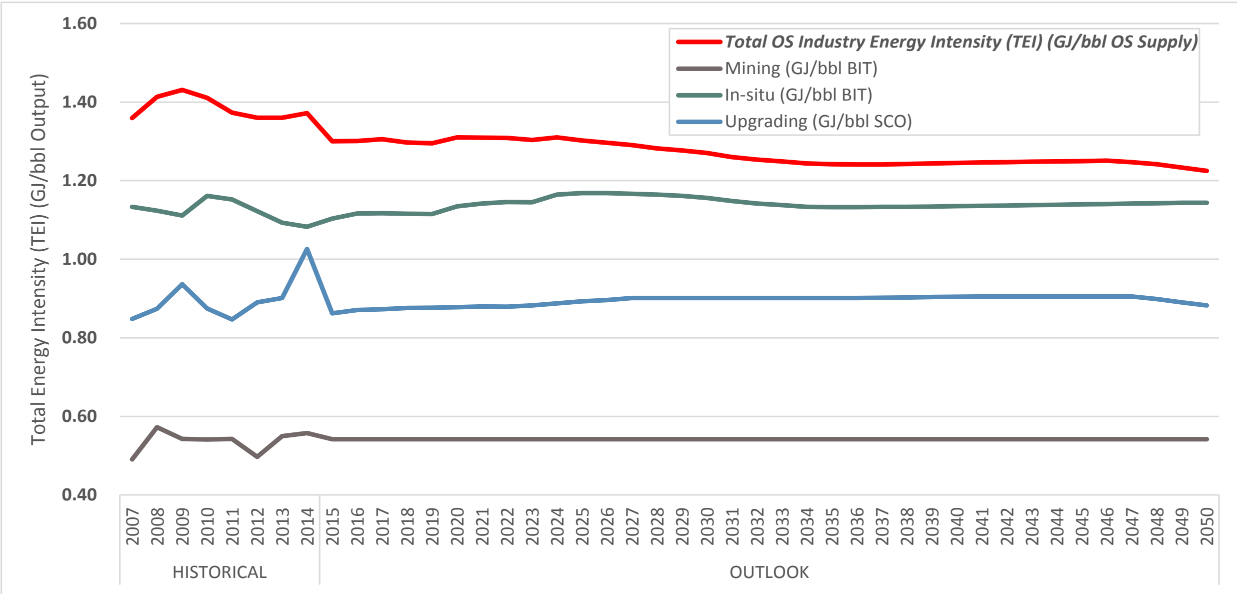
[30] Refers to all types of energy including thermal, hydrogen (where applicable), electricity, and diesel fuel (where applicable)

[31] Includes production of in situ bitumen from electric-heating technologies in the EHTA scenarios (Chapter 2)

[32] Total oil sands supply = bitumen extraction (mining & in situ) – bitumen used as upgrader feedstock + upgraded bitumen (or SCO)

[33] Sum of net crude bitumen (total crude bitumen minus bitumen used as upgrader feedstock) and SCO

Figure 2.29: Oil Sands Total Energy Intensity by Project Type and Total Oil Sands Supply (GJ/bbl of output), 2007-2035



Source: CERI

As can be observed in Figure 2.29, mining TEI estimates remain relatively constant over the outlook timeframe, while upgrading and in situ TEI estimates fluctuate between 2014 and 2050, primarily as a function of an evolving production and technology mix, within their corresponding categories.[34]

TEI for the oil sands industry as a whole or on an oil sands supply basis is estimated to decrease from 1.37 GJ/bbl of oil sands output[35] in 2014 to 1.23 GJ/bbl by 2050. This 0.15 GJ/bbl difference accounts for a 10.7 percent decrease, at a compound annual decline rate (CADR) of 0.3 percent.

While it can be observed that most TEI estimates remain relatively constant between 2014 and 2050, this trend is primarily the result of the changing mix of oil sands output over the outlook period, as a greater percentage of output from the industry is composed of crude bitumen rather than SCO. This is because a barrel of crude bitumen's demand for energy is that of the extraction process alone, while that for a barrel of SCO includes the demand for the upgrading process in addition to the energy that has already been used at the extraction stage (for that same barrel).

Specifically, a barrel that is extracted and shipped to market is much less energy-intensive than a barrel of crude bitumen which is extracted, then upgraded, and finally shipped to market.[36]

[34] As an example, the change in the production mix within in situ projects' category such as SAGD, CSS, and Primary/EOR, and; the change in the production mix for SCO based on different upgrading technologies, such as coking, hydrocracking, and other technologies

[35] Sum of net crude bitumen (total crude bitumen minus bitumen used as upgrader feedstock) and SCO

[36] Recall that this analysis does not take into account the impact of diluent requirements on energy use

These estimates are based on the assumption of increased production volumes and *constant energy intensity factors*, which are representative of the latest year of empirical data for a project type. Alternatively, median values are used from the calculated intensity ranges, whichever is most consistent with recently observed values and trends across a project type, thus assuming a "*business as usual*" (BAU) scenario. The assumptions and results for different possible scenarios are presented in the following sections of this report.

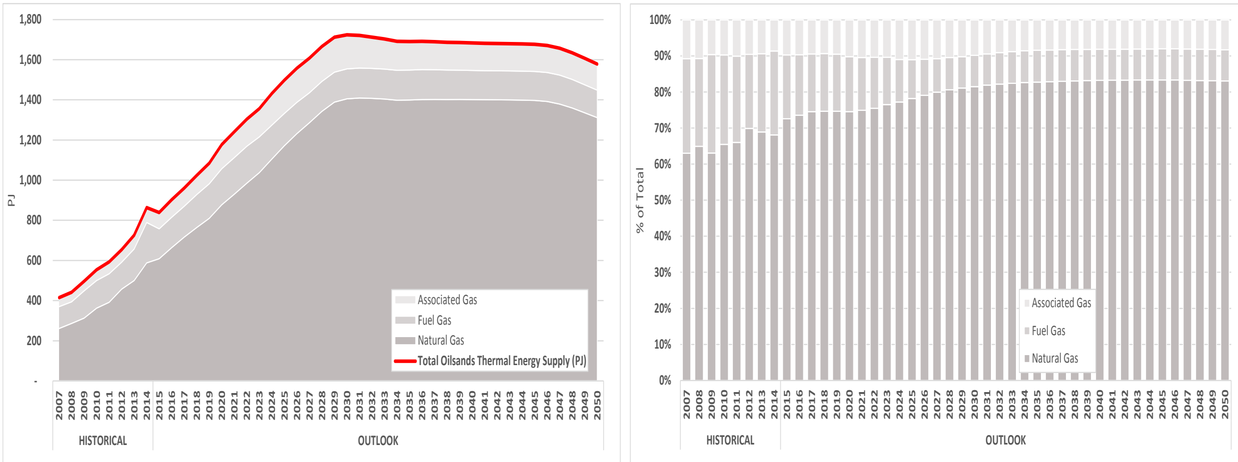
With an understanding of the different processes within oil sands operations, the types of energy used, as well as estimates of total energy demand for the oil sands industry, we can estimate greenhouse gas (GHG) emissions associated with the energy supplied to meet such energy requirements. GHG estimates presented here are for the energy required for the oil sands industry's production operations. They do not include emissions from support activities.

The primary assumption in this analysis is that the GHG emissions associated with energy demand for the oil sands industry are from the combustion of fossil fuels for generating electricity and thermal energy. Also included are process emissions for the production of hydrogen (H_2) via steam methane reforming (SMR) and combustion of transportation fuels (in the case of diesel fuel) used in the mining truck fleet and field equipment at in situ primary/EOR operations.

GHG emissions as quantified in this report do not include fugitive emissions estimates.

As can be observed in Figure 2.30, the supply mix for meeting thermal energy requirements over the outlook period is expected to be largely dominated by the use of natural gas, while the percentage of associated gas used is expected to remain relatively constant, and that of fuel gas and syngas is expected to decline.

Figure 2.30: Oil Sands Thermal Energy Supply by Source (PJ), 2007-2050[37]



Source: CERI

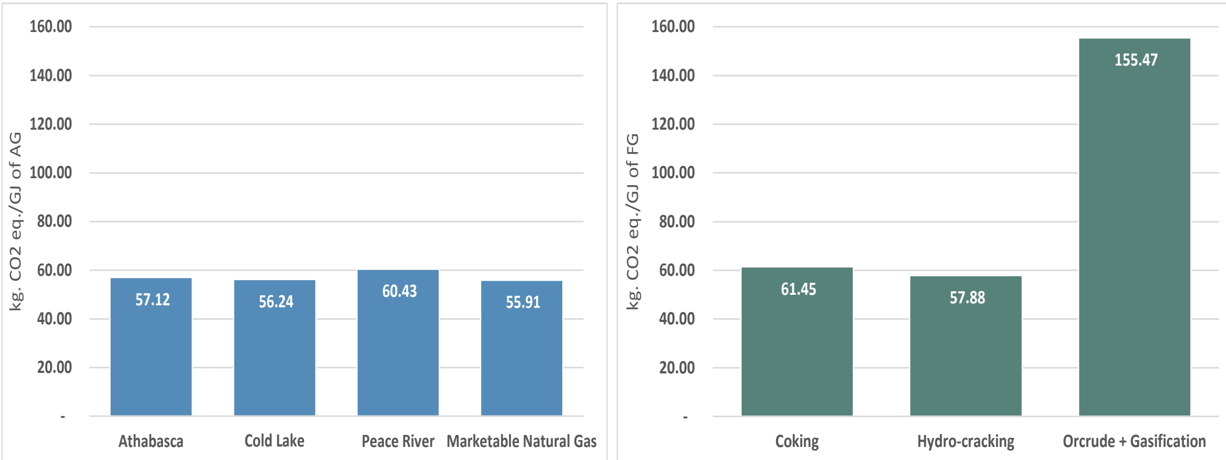
This evolving fuel source mix will in turn affect GHG emissions from thermal energy requirements for oil sands projects and the overall emissions intensity of the fuel mix. Different sources of gas such as associated gas from different formations, marketable natural gas, and different types of fuel gas and syngas from upgrading projects have different molecular compositions. As such, they have different heating values and emissions factors.

The different estimated GHG emissions factors for associated gas and natural gas, as well as those for different upgrading processes, are presented in Figure 2.31.[38]

[37] For simplification purposes, this analysis assumes that any petroleum coke used at certain oil sands projects such as Suncor and Syncrude's integrated mining and upgrading facilities is primarily used for the purpose of high-pressure steam for power generation, which is consistent with information provided in the application for Suncor's Voyageur upgrader. Furthermore, use of upgrader fuel gas and syngas is primarily assumed to be used for thermal energy purposes rather power generation or hydrogen production. Following this approach, the use of petroleum coke and its associated emissions are captured in the emissions factors and estimates for power generation, while the use of fuel gas and associated gas as fuels, and their associated emissions, are captured in the thermal energy category. "Fuel gas" in this figure refers to both upgrader fuel gas and upgrader syngas.

[38] Note that these estimates are consistent with those presented by (Environment Canada, 2015) in Part II of the National Inventory Report (NIR)

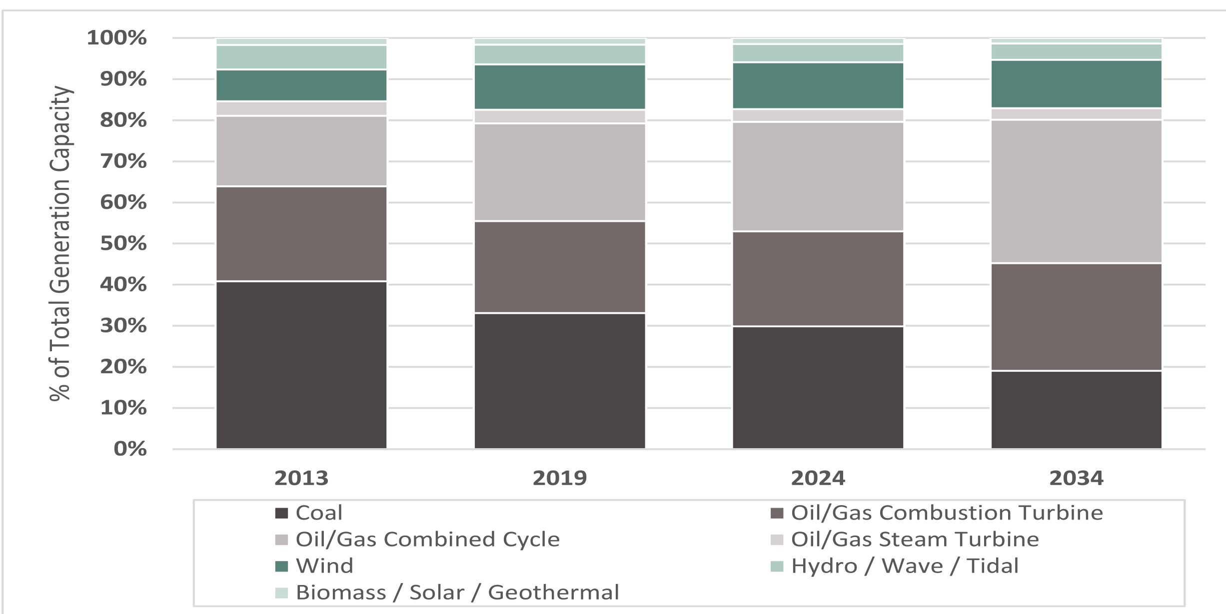
Figure 2.31: Natural Gas, Associated Gas Emission Factors (left) and Upgrader Fuel Gas/Syngas Emission Factors (right), kilograms of carbon dioxide equivalent per GJ of gas



Source: US EPA, CERI

The NEB's latest assessment of electricity markets in Alberta provides an estimate for generation capacity and the generation capacity mix (by plant type and fuel source) to 2034 and 2035. As can be observed in Figure 2.32, the generation mix transitions from one dominated by coal to being dominated by natual gas.

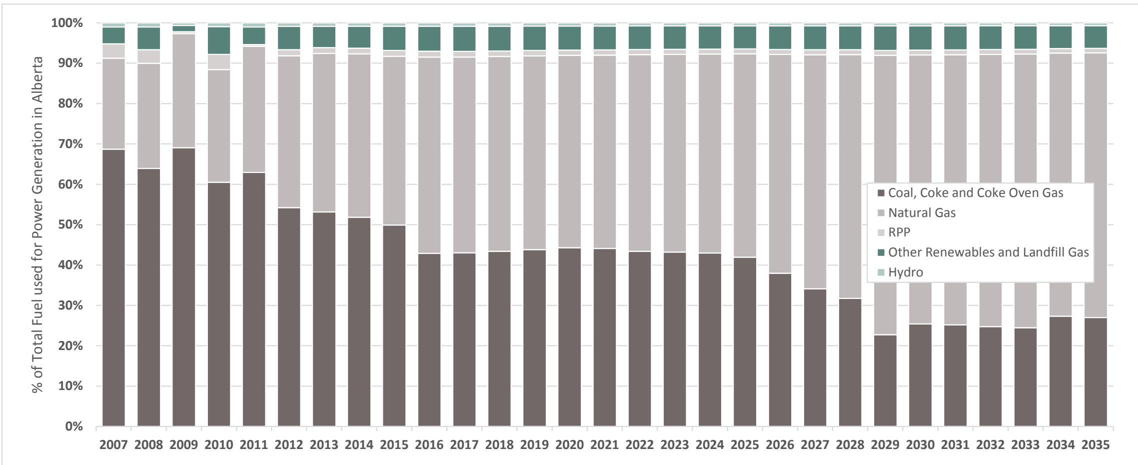
Figure 2.32: Electricity Generation Capacity by Type, 2013-2034



Source: NEB, CERI

With an understanding of the expected evolution of the electric power generation fleet and demand for power in the province,[39] an estimate for power generation by fuel source is required in order to quantify GHG emissions from electricity generation. The NEB's Energy Future project includes such estimates. Figure 2.33 displays the primary fuel mix used for the purpose of power generation in Alberta from 2007-2035.

Figure 2.33: Alberta Electric Power Generation Fuel Mix (% of total), 2007-2035



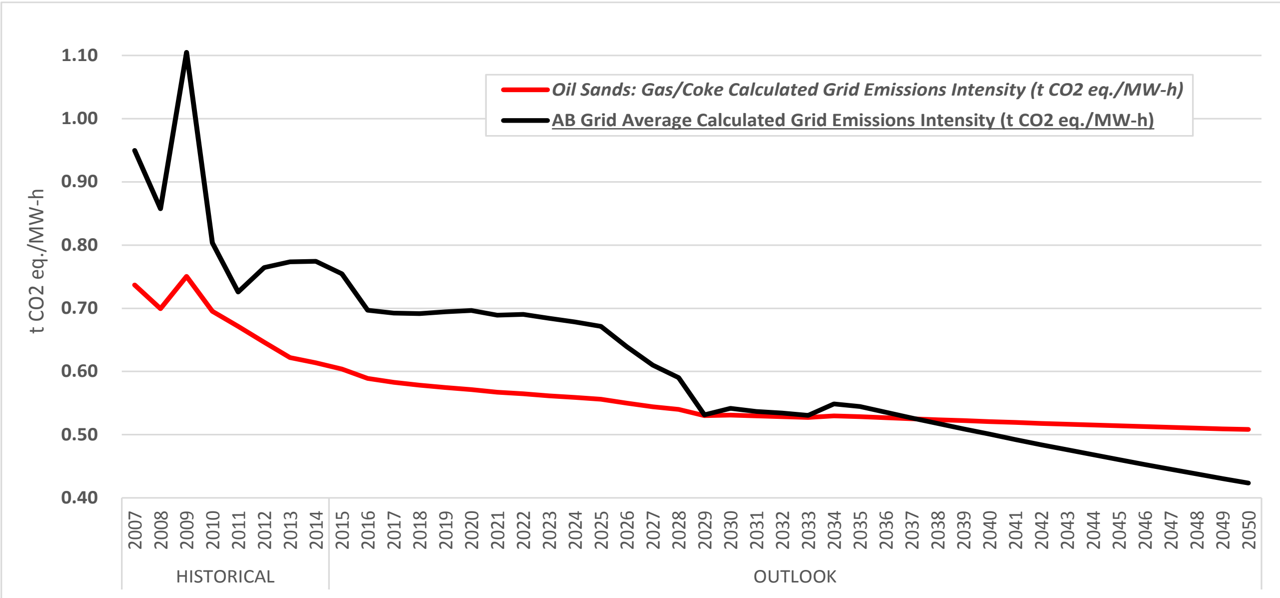
Source: NEB, CERI

Using GHG intensity factors from several sources,[40] the NEB estimates were extended to 2050. Additionally, a GHG emissions factor reflective of the fuel mix used for generating power for the oil sands industry is illustrated in Figure 2.34. This estimated oil sands electricity GHG emissions factor takes into account that some cogeneration facilities at oil sands operations use a mix of gas and petroleum coke (declining share); not all oil sands operations have cogeneration facilities and therefore purchase power from the grid (which in turn has a different GHG emissions factor).

[39] Estimates from both the AESO and the NEB indicate demand for electric power in Alberta to be about 210 GWh/d in 2014 and to reach about 330 GWh/d by 2034. Recall that CERI's and the AESO's electric demand estimates for the oil sands industry over the outlook period are very close and comparable

[40] Estimates sourced from (EDC Associates Ltd., 2013), (Environment Canada, 2015), and (United States (US) Environmental Protection Agency (EPA), 2014), (Alberta Energy Regualtor (AER), 2014) and (National Energy Board (NEB), 2015)

Figure 2.34: Alberta Electricity Generation GHG Emissions Factor (kg. CO_2eq./MWh) 2007-2050



Source: Multiple sources,[41] CERI

The two GHG emissions factors are different (Alberta grid average versus oil sands based) and both follow a different path over the outlook timeframe. However, their difference over time is only 3.6 percent (with the higher estimate being for the Alberta average).[42]

Given the evolving power generation fuel mix and an overall increasing efficiency in the power generation fleet, the estimated electric power GHG emissions intensity in Alberta is expected to decrease by 45.3 percent (or by 0.35 t CO_2eq./MWh) between 2014 (0.77 t CO_2eq./MWh) and 2050 (0.42 t CO_2eq./MWh) at a CADR of 1.7 percent.

Meanwhile, the oil sands electric power GHG emissions factor is estimated to decrease by 17.2 percent (or by 0.11 t CO_2eq./MWh) between 2014 (0.61 t CO_2eq./MWh) and 2050 (0.50 t CO_2eq./MWh) at a CADR of 0.5 percent, as the share of petroleum coke fuel use is assumed to disappear over the long-term.

These two different GHG emissions factors are provided for comparison purposes. For quantifying GHG emissions from power used by the oil sands industry, the oil sands specific electricity GHG emissions factor is used in this analysis. This GHG emissions factor takes into consideration an evolving fuel mix that is heavily weighted on the use of gas, a declining share of

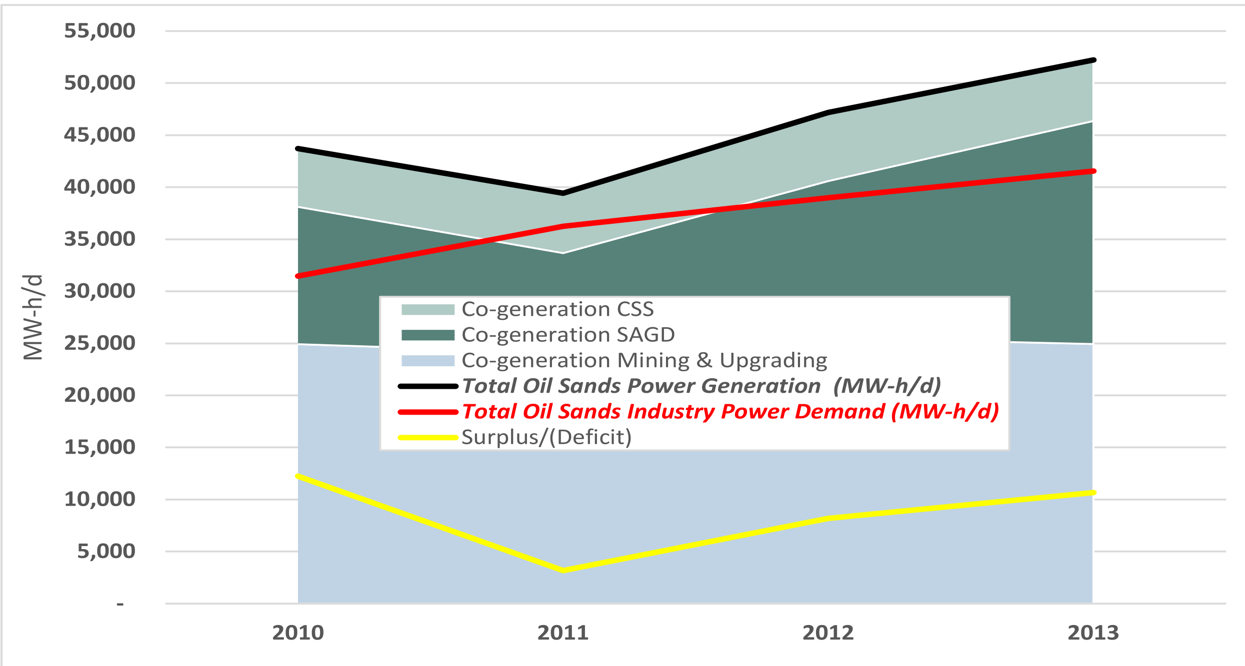
[41] Estimates sourced from (EDC Associates Ltd., 2013), (Environment Canada, 2015), and (United States (US) Environmental Protection Agency (EPA), 2014), (Alberta Energy Regualtor (AER), 2014) and (National Energy Board (NEB), 2015)

[42] 618.6 MMt CO_2 eq. vs. 596.9 MMt CO_2 eq.

petroleum coke used as a generation fuel, and oil sands operations that increasingly rely less on external power purchases from the Alberta grid.[43]

While allocating GHG emissions from electricity generation to be used by oil sands projects to the oil sands industry might be contested, the reality is that oil sands cogeneration facilities tend to produce power in excess of that required by their own operations (Figure 2.35).

Figure 2.35: Electricity Generation from Oil Sands Cogeneration Facilities and Oil Sands Electricity Demand (MWh/d), 2010-2013



Source: AER, Jacob G. Englader, CERI

In terms of feedstock for hydrogen production, CERI assumes that marketable natural gas (primarily methane (CH_4)) will be the main feedstock choice. As such, a GHG emissions factor of 47.76 kg. CO_2 eq./GJ of natural gas is used (United States (US) Environmental Protection Agency (EPA), 2008).[44]

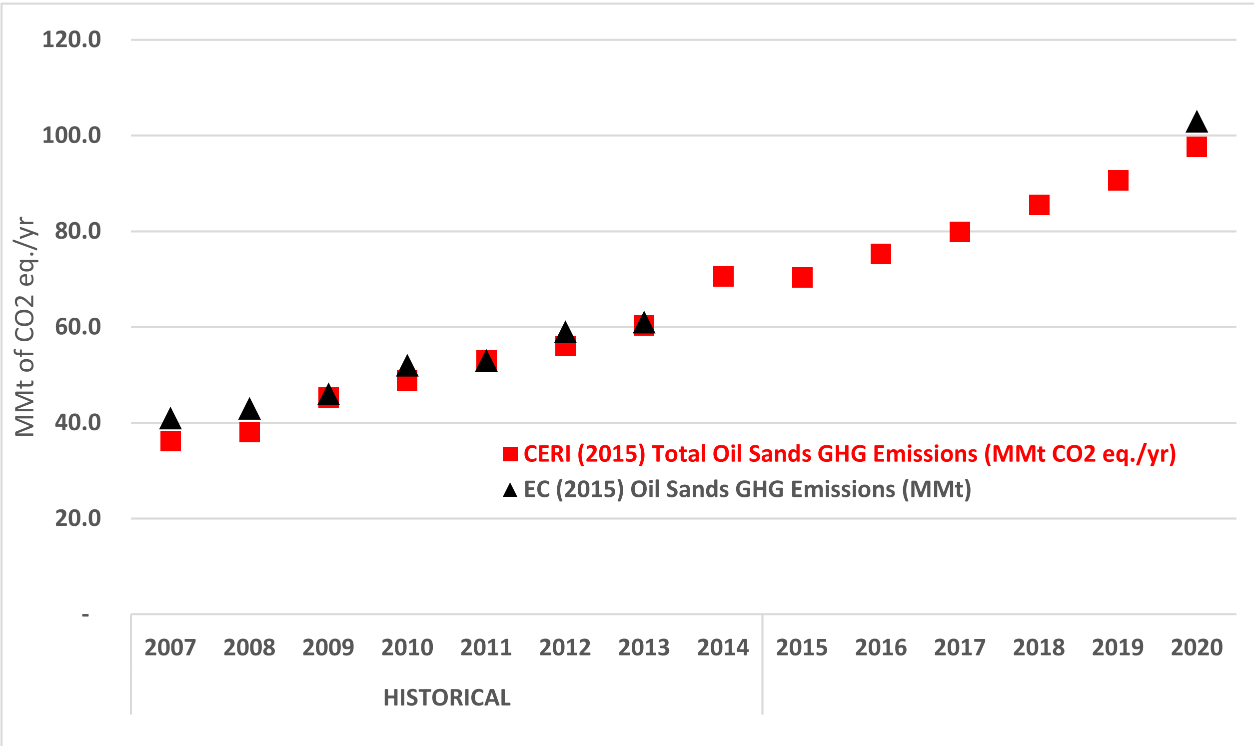
The emissions factor used for diesel fuel use is 78.24 kg. CO_2 eq./GJ of diesel fuel, based on an emission factor for off-road vehicles (Environment Canada, 2015).

Figure 2.36 displays the sum of GHG emissions from electricity generation for meeting oil sands projects' electricity loads, combustion of fossil fuels for thermal energy, use of natural gas for

[43] (Desiderata Energy Consulting Inc., 2014) indicates that over the long term, oil sand cogeneration capacity will continue to be greater on-site power demand at oil sands operations
[44] This estimate is consistent with CERI's estimate of 49.24 kg. CO_2/GJ of natural gas

hydrogen production via steam methane reforming (SMR), and combustion of diesel fuel for the mining truck fleets and field equipment at in situ projects.

Figure 2.36: GHG Emissions Estimates from Oil Sands End-use Energy Demand ($MMt\ CO_2eq./yr$), 2007-2020



Source: Environment Canada, CERI

CERI's estimates for GHG emissions from the oil sands are comparable to those developed by Environment Canada (EC). Meanwhile, both estimates suggest GHG emissions from the oil sands industry are expected to approach 100 MMt CO_2eq. by 2020.

There are differences between CERI's and EC's estimates. One difference is that Environment Canada's GHG emissions estimates include combustion of fuels and hydrogen production (consistent with CERI's approach) and fugitive GHG emissions (not quantified by CERI). Another difference is that EC's estimate does not include emissions from utility supplied electricity generation while CERI's does.

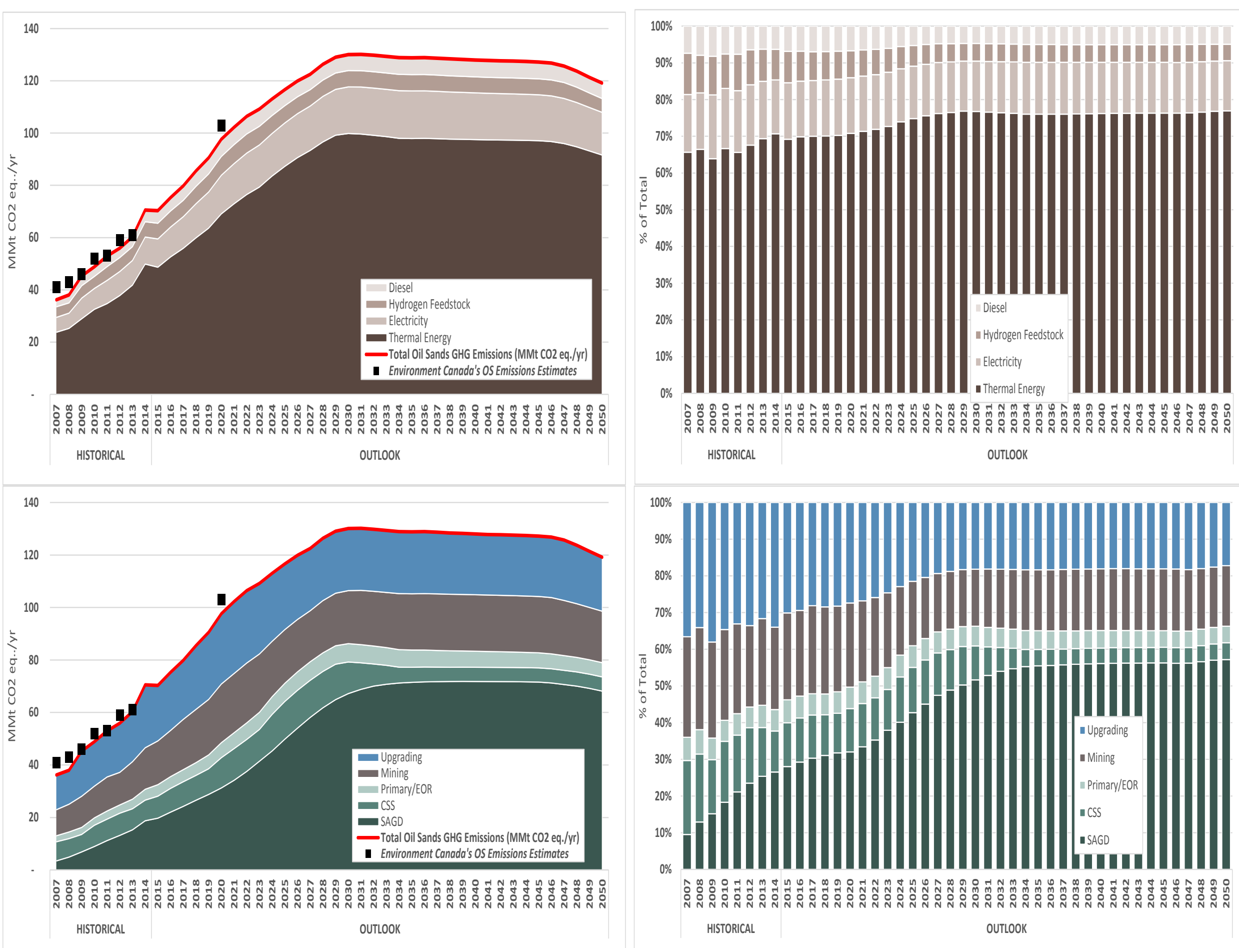
CERI estimates that approximately 39.5 percent of the cogeneration capacity at oil sands projects is currently owned by utility companies rather than oil sands operators.

If CERI's estimated GHG emissions from electricity generation for oil sands projects is multiplied by the fraction of electric power generation which reflects the ownership of cogeneration capacity by oil sands producers versus utilities, then GHG emissions from electricity used by oil sands projects can be estimated to be about 3.7 MMt CO_2eq. for 2013. This is consistent with the estimate provided by Environment Canada.

Figure 2.37 indicates that oil sands GHG emissions are estimated to increase by 48.6 MMt CO_2eq. or 68.9 percent between 2014 and 2050, at a CAGR of 1.5 percent. GHG emissions from the industry are estimated to peak at 130.2 MMt CO_2eq. by 2031.

As the top portion of Figure 2.37 indicates, the fastest growing source of GHG emissions between 2014 and 2050 will be from the use of thermal energy at 83.7 percent, while increases in GHG emissions from the use of electricity at 57.8 percent are the result of higher demand levels but a lower GHG emissions factor over the outlook timeframe. Emissions from diesel consumption are expected to increase by 32.1 percent by 2050, while emissions from hydrogen production are expected to decline by 9.8 percent as overall upgrading levels experience a net decline between 2014 and 2050.

Figure 2.37: GHG Emissions Estimates Attributable to Oil Sands End-use Energy Demand (MMt C0₂eq./yr), 2007-2050



Source: EC, CERI

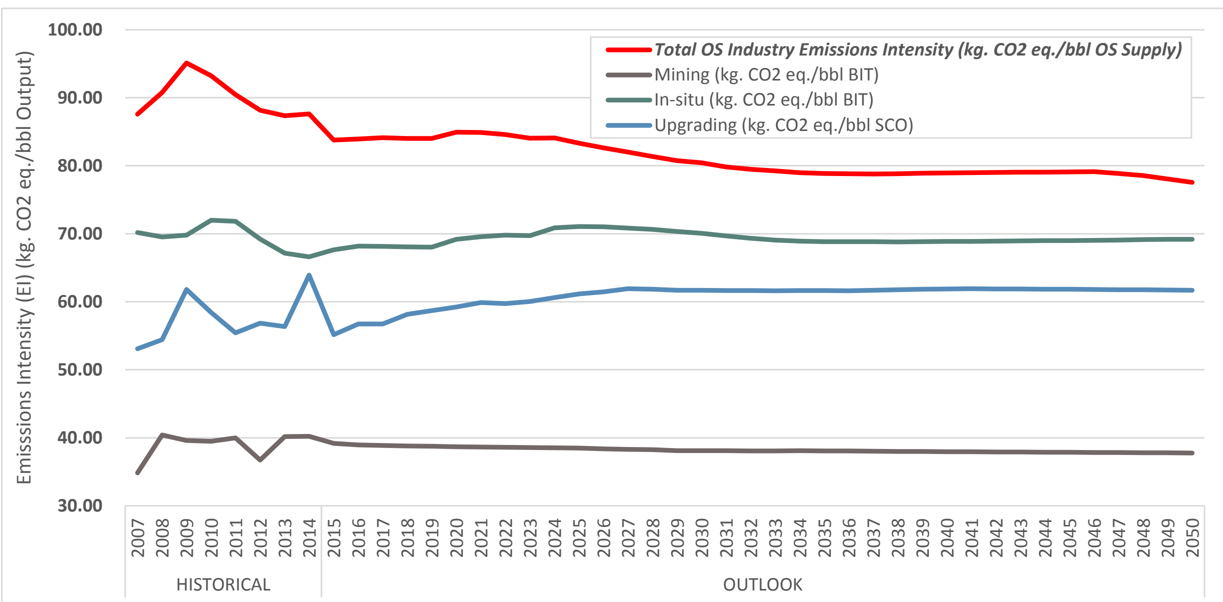
GHG emissions from thermal energy use by the oil sands industry will remain the single largest source of emissions over the outlook period, with its share of total oil sands GHG emissions increasing from just above 70 percent in 2014 to just below 80 percent by 2050.

On a project type basis, the increase in GHG emissions over the outlook timeframe will be dominated by increasing emissions from in situ projects, in particular from SAGD projects and primary/EOR projects, while emissions from CSS projects are expected to decrease slightly.

This trend is driven by the evolving production mix within the in situ category and given the fact that slightly less of the future thermal energy requirements are expected to come from associated gas. In situ projects' share of the total oil sands GHG emissions is estimated to increase from about 45 percent in 2014 to close to 60 percent by 2050.

Meanwhile, net increases in GHG emissions from mining projects are expected to moderate. GHG emissions from upgrading are estimated to decrease over the outlook period given overall SCO production declines and an increased share of natural gas used for meeting thermal energy requirements. Figure 2.38 displays the GHG emissions intensity on a kg of CO_2 equivalent per unit of output basis for the main oil sands production categories.

Figure 2.38: Oil Sands GHG Emissions Intensity by Project Type and Total Oil Sands Supply (kg. CO_2 eq./bbl of output), 2007-2035



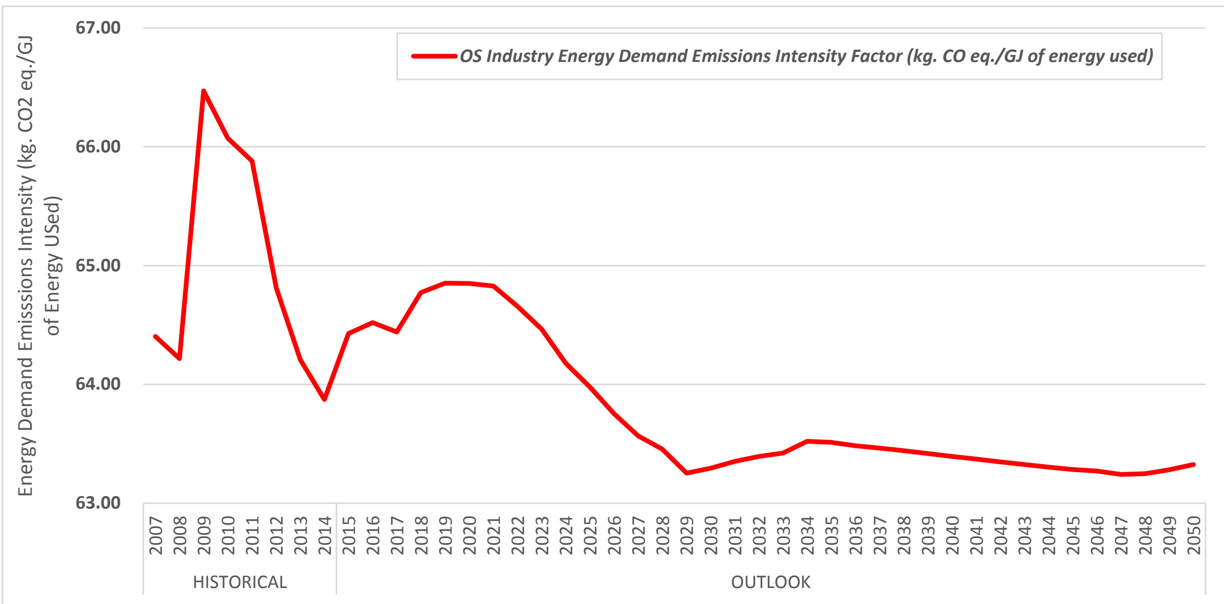
Source: CERI

GHG emissions intensity for upgrading projects fluctuate over the outlook period as more energy-intensive upgrading processes account for a larger share of total SCO production. The share of natural gas for thermal energy and power generation increases.

Estimated GHG intensity for overall oil sands output is expected to decline by 11.5 percent or 10.1 kg. CO_2eq./bbl of output between 2014 and 2050, at a CADR of 0.3 percent.

This means that the oil sands industry's energy demand GHG emissions factor (kg. CO_2eq./GJ of energy used) as displayed in Figure 2.39 approaches one that is consistent with natural gas, as it is expected to decrease by an estimated 0.6 kg. CO_2eq./GJ (or by 0.9 percent) between 2014 (63.9 kg. CO_2eq./GJ) and 2050 (63.3 kg. CO_2eq./GJ), at a CADR of 0.1 percent.

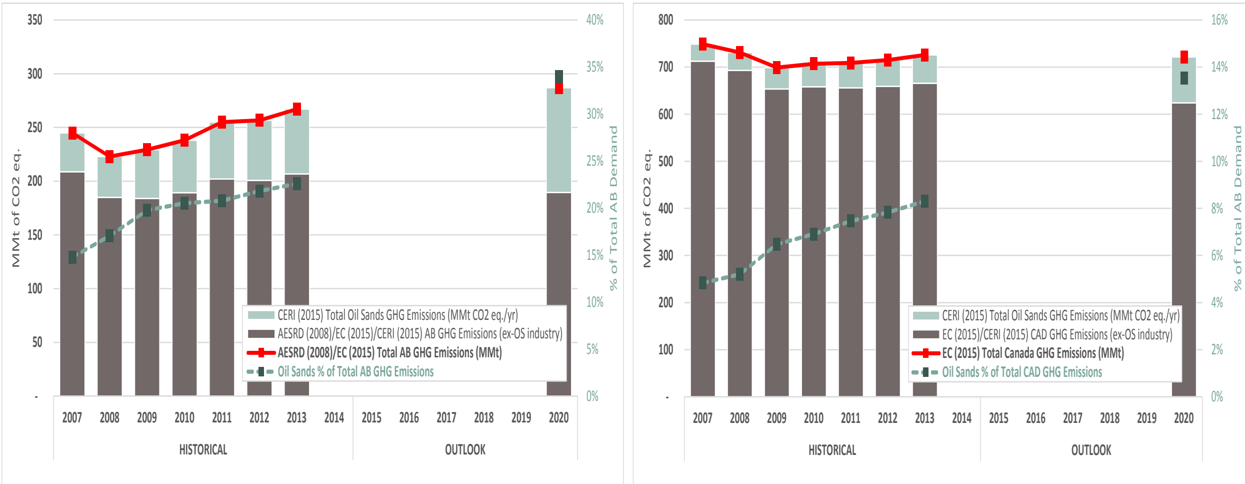
Figure 2.39: Oil Sands Energy Demand GHG Emissions Factor (kg. CO_2 eq./GJ of energy used) 2007-2050



Source: CERI

Figure 2.40 displays Environment Canada's most recent estimate for GHG emissions from the oil sands industry to 2020 for Alberta and Canada.

Figure 2.40: Oil Sands GHG Emissions for Alberta and Canada (MMt CO_2 eq. and % of total) 2007-2020



Source: EC, CERI

In Alberta, it is estimated that GHG emissions, excluding those of the oil sands sector, will decline by 17.4 MMt CO_2eq. or 8.4 percent between 2013 and 2020, at a CADR of 1.2 percent. However, growth in GHG emissions from the oil sands industry to 2020 at a CAGR of 7.1 percent will lead to an overall increase of provincial GHG emissions of 7.4 percent or 19.9 MMt CO_2eq., between 2013 and 2020, at a CAGR of 1.0 percent.

This also results in the oil sands industry's GHG emissions increasing their share of total estimated provincial GHG emissions by 11.4 percent between 2013 and 2020 to 34.0 percent.

At the national level, GHG emissions trend estimates for the period 2013 to 2020 indicate the oil sands industry almost negating any reductions in GHG emissions across other sectors, given an increase of 37.3 MMt CO_2eq. in GHG emissions from the oil sands sector, compared to a decrease of 41.7 MMt CO_2eq. across all other GHG emitters in Canada, within the same timeframe. Results of this study show that this in turn results in the oil sands industry increasing its estimated share of national GHG emissions by 5.2 percentage points between 2013 and 2020 to 13.5 percent.

Table 2.2 provides a summary of oil sands production and supply, energy use, and GHG emissions, on a BAU cumulative basis, for the period 2015 to 2050.

Table 2.2: BAU Cumulative Oil Sands Production Volumes, Energy Use, GHG Emissions, and Intensity Factors

	2015 - 2050 Cumualtive			Intensities		
	Production (Bbbl)	**Energy Used (EJ)**	**GHG Emissions (Gt CO2 eq.)**	**GJ/bbl**	**kg. CO2 eq./bbl**	**kg. CO2 eq./GJ (energy used)**
BUSINESS AS USUAL (BAU)						
Oil sands supply	**52.4**	**66.3**	**4.2**	**1.3**	**80.8**	**63.8**
Mining (BIT)	19.6	10.6	0.7	0.5	38.2	70.5
In-situ (BIT)	37.7	43.2	2.6	1.1	69.7	60.9
SAGD	*28.9*	*34.4*	*2.1*	*1.2*	*72.1*	*60.6*
CSS	*3.0*	*5.4*	*0.3*	*1.8*	*107.4*	*59.7*
Primary/EOR	*5.8*	*3.3*	*0.2*	*0.6*	*37.9*	*65.7*
Upgrading (SCO)	14.1	12.6	0.9	0.9	60.8	68.0

Source: CERI

Chapter 3: Alternative Energy Demand Scenarios

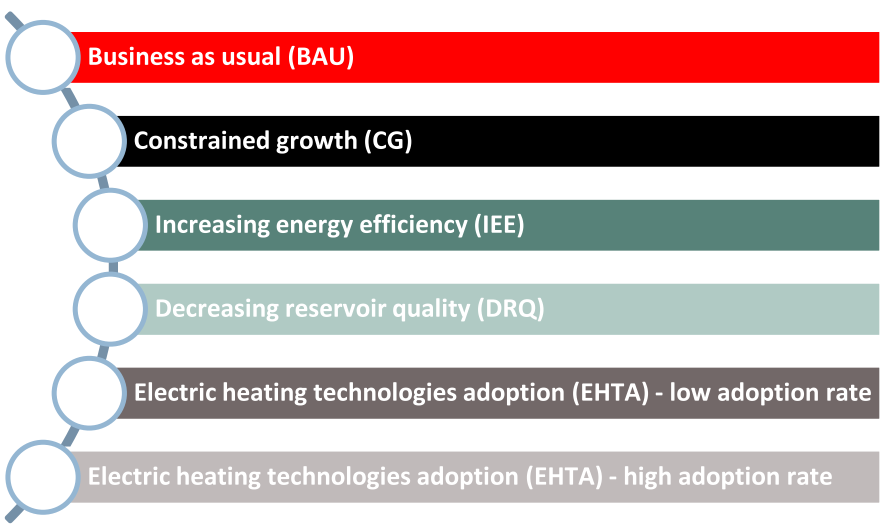
Scenario Analysis

Scenario planning is a tool commonly used in economics for understanding the potential of differing outcomes by manipulating key variables within an analytical framework. It is used to understand and quantify uncertainty associated with a model's parameters.

Scenarios were developed in order to have a better understanding of key changes in the different components of the analysis and their potential impact on energy use and emissions. Five alternative scenarios are presented in this chapter to compare to the business as usual (BAU) scenario (see Figure 3.1).

Uncertainties are shown in Figure 3.2. In order to develop different scenarios for energy demand for the oil sands industry, the main variables to manipulate include overall industry production volumes and project-specific energy intensities. The starting point of the production forecast is CERI's Oil Sands Database (OSDB) (including 393 oil sands projects),[1] which drives an industry unconstrained forecast. This is risk adjusted for macro-economic constraints. Specifics for each scenario are listed in their appropriate sections.

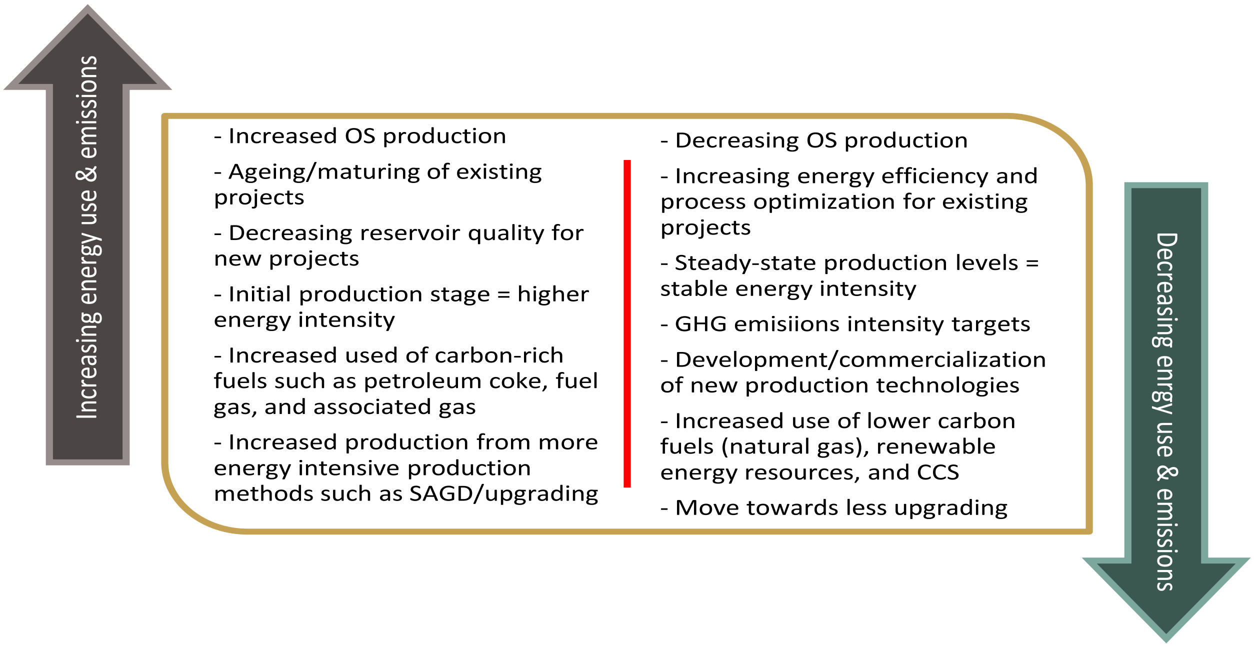
Figure 3.1: Oil Sands Energy Demand Scenarios



Source: CERI

[1] Excludes Primary/EOR projects. The production forecast for these projects is developed under CERI's conventional crude oil production forecast, the methodology for this production forecast is presented in (Canadian Energy Research Institute (CERI), 2011) and (Canadian Energy Research Institute (CERI), 2013). Based on AER data (ST-53 & ST-44), CERI estimates that at the end of 2014 there were a total of 157 primary/EOR active schemes, across the three oil sands areas (OSAs), producing an estimated 286 kb/d of crude bitumen

Figure 3.2: Factors that Affect the Oil Sands Demand for Energy, Possible Energy Supply Sources and GHG Emissions



Source: CERI

Constrained Growth (CG) Scenario

Under the constrained growth (CG) scenario, it is assumed that global economic, regulatory/policy and crude oil market conditions over the long-term are not conducive to new investments in oil sands projects. As such, only projects that are currently in operation (on-stream) and those that are currently under construction are expected to continue to operate and to be commissioned over the projection timeframe (2015-2050).

This results in the number of project phases being reduced from 188 in the BAU scenario to 92 in the CG scenario. These include 16 mining project phases at 5 mining projects/complexes; 62 thermal in situ project phases at 26 SAGD projects and 8 CSS projects; and 14 upgrading project phases at 7 upgrading complexes.

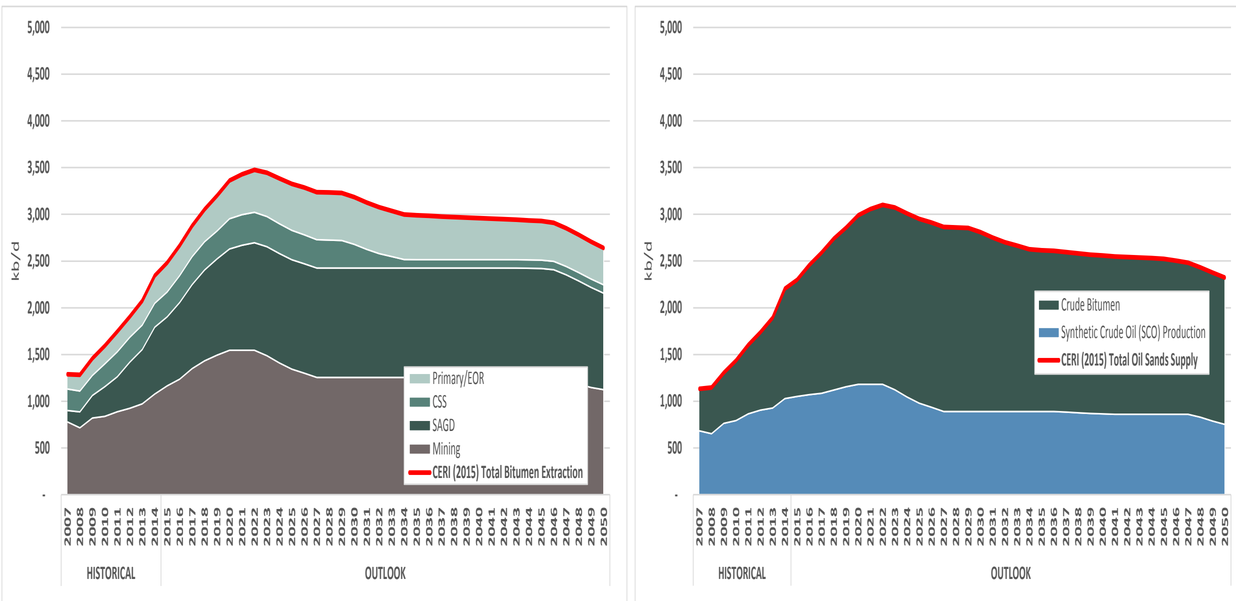
Recall that for the purposes of the macro-economic scenarios (BAU & CG), the main changes are on those assumptions that affect production levels from the industry rather than issues that affect energy intensity factors.

Therefore, for both of these scenarios, energy intensity factors are held constant over the projection timeframe, with intensity values being reflective of either median values from established ranges or the latest empirical data values, whichever is most consistent with recently observed trends across a given production type.

Oil Sands Production Outlook

Figure 3.3 displays the production outlook for the CG scenario. In this scenario, bitumen extraction peaks at 3.5 MMb/d by 2022, compared to 4.9 MMb/d by 2036 in the BAU scenario. Total production increases by 0.3 MMb/d between 2015 and 2050, or 12.7 percent, at a CAGR of 0.3 percent. In this scenario, in situ production accounts for a smaller portion of bitumen extraction, given that the majority of the growth in the BAU scenario beyond 2020 is expected to come from in situ projects and SAGD projects in particular.

Figure 3.3: Bitumen Extraction and Oil Sands Supply Volumes (kb/d), 2007-2050

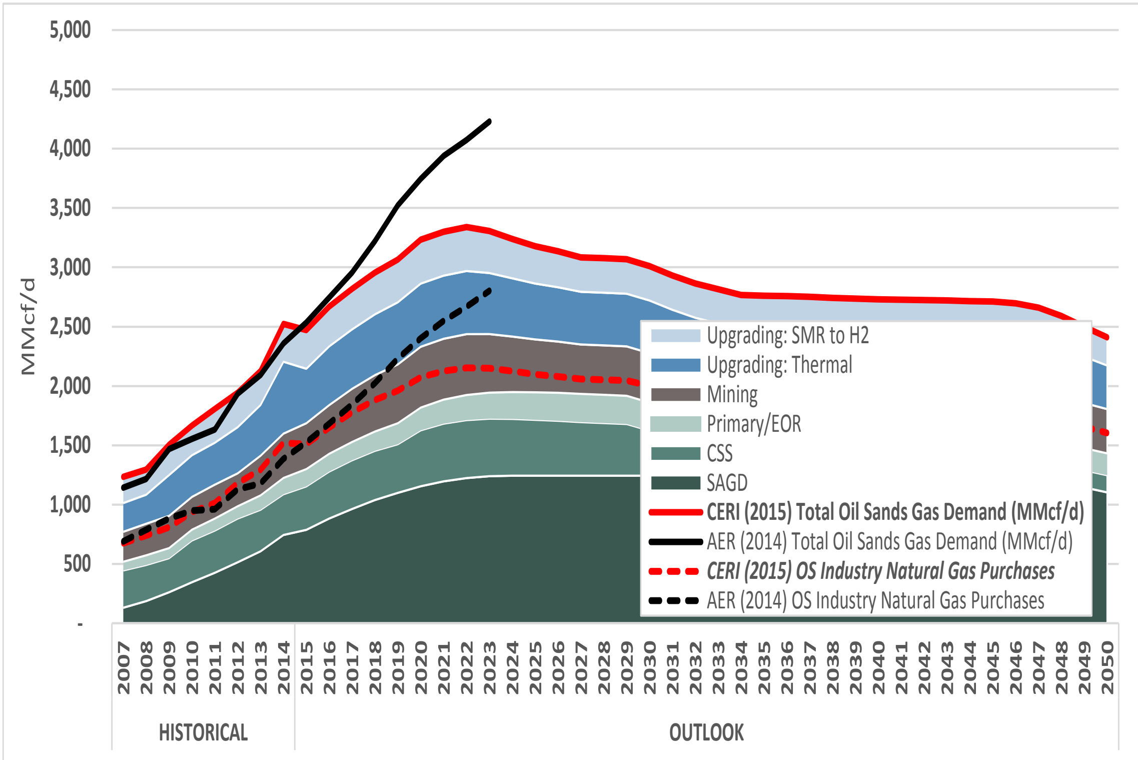


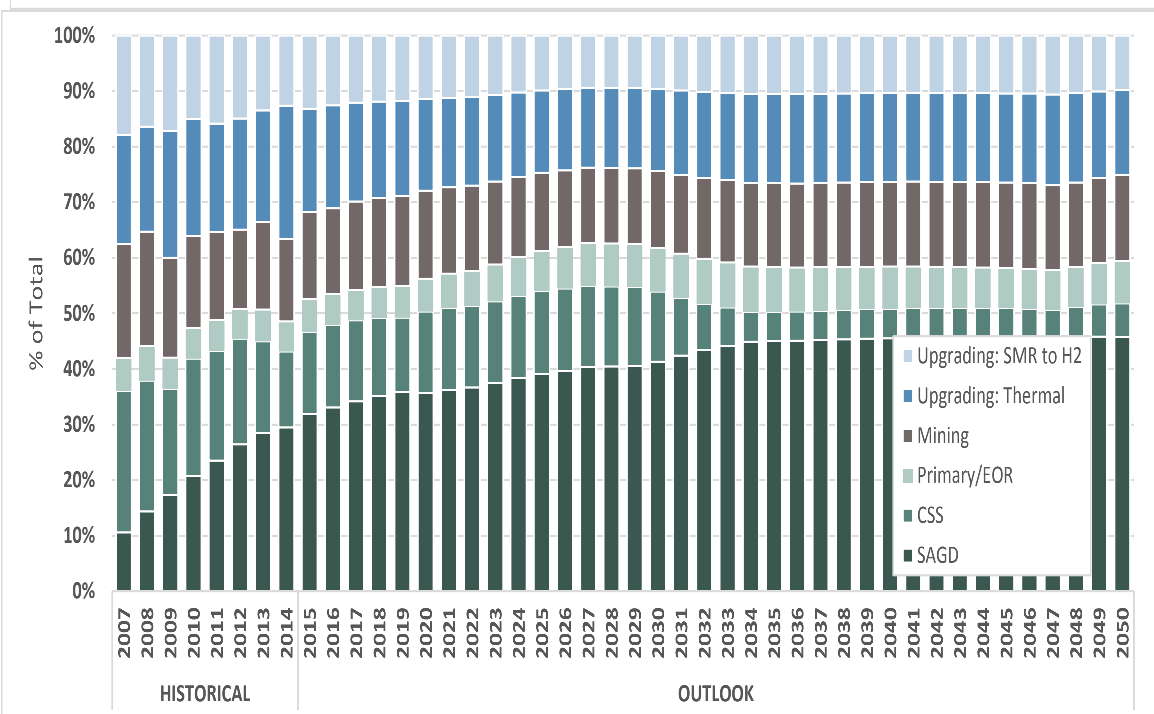
Source: CERI

Oil Sands Energy Use Outlook

The outlook for energy use in the CG scenario is shown in Figure 3.4. The pattern of demand follows that of the forecasted production, showing the strong correlation between production and gas demand resulting from a minimal amount of technology and process substitution over the period.

Figure 3.4: Oil Sands Gas Demand for Thermal Energy and Hydrogen Production by Project Type (MMcf/d), 2007-2050

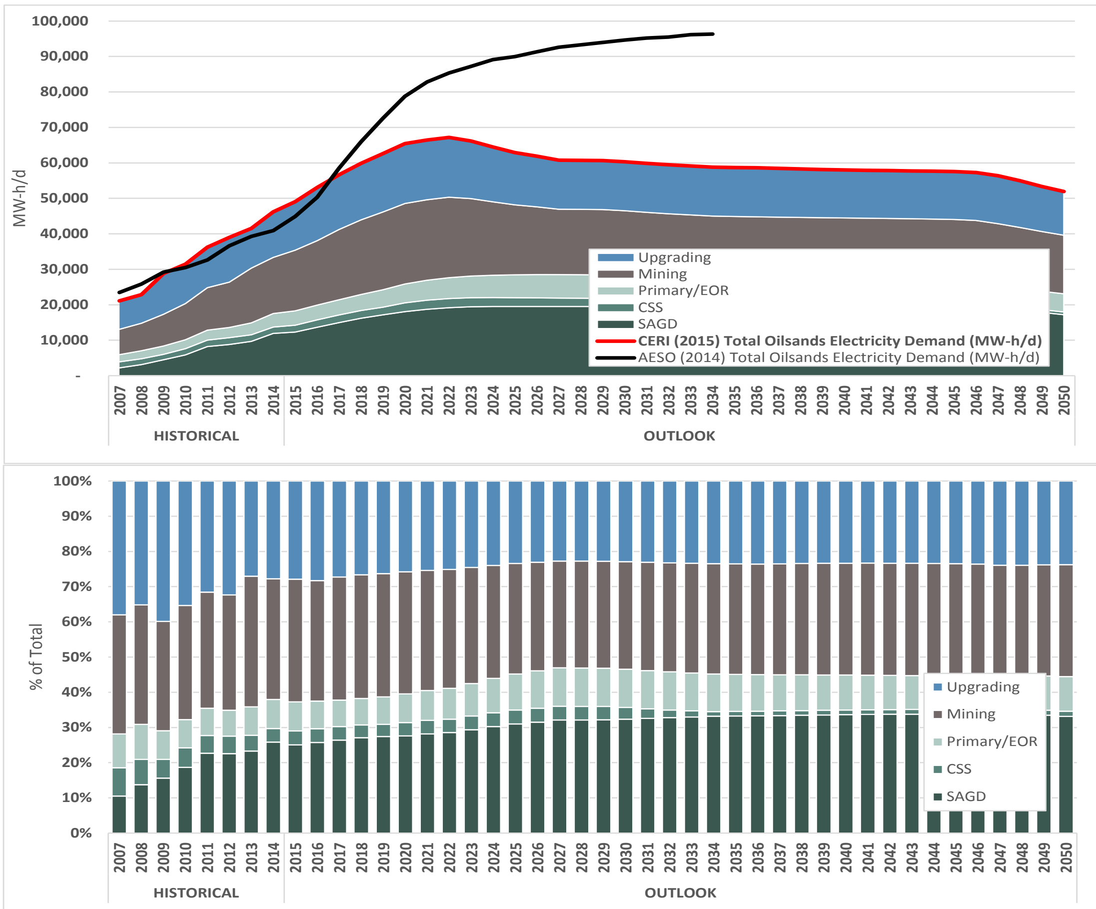




Source: AER, CERI

Figure 3.5 projects the electricity demand in the oil sands to 2050. Again, the pattern follows that of overall production.

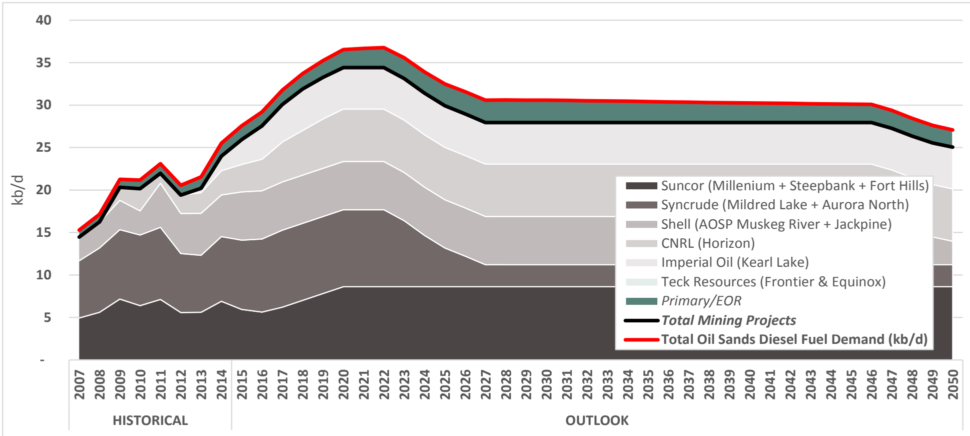
Figure 3.5: Oil Sands Electricity Demand by Project Type (MWh/d), 2007-2050



Source: AESO, CERI

Oil sands diesel demand in the CG scenario is shown in Figure 3.6. Again, there is a correlation between diesel demand and production volumes. The CG scenario is characterized by status quo processes and technologies, which means the key driver of demand is production volumes.

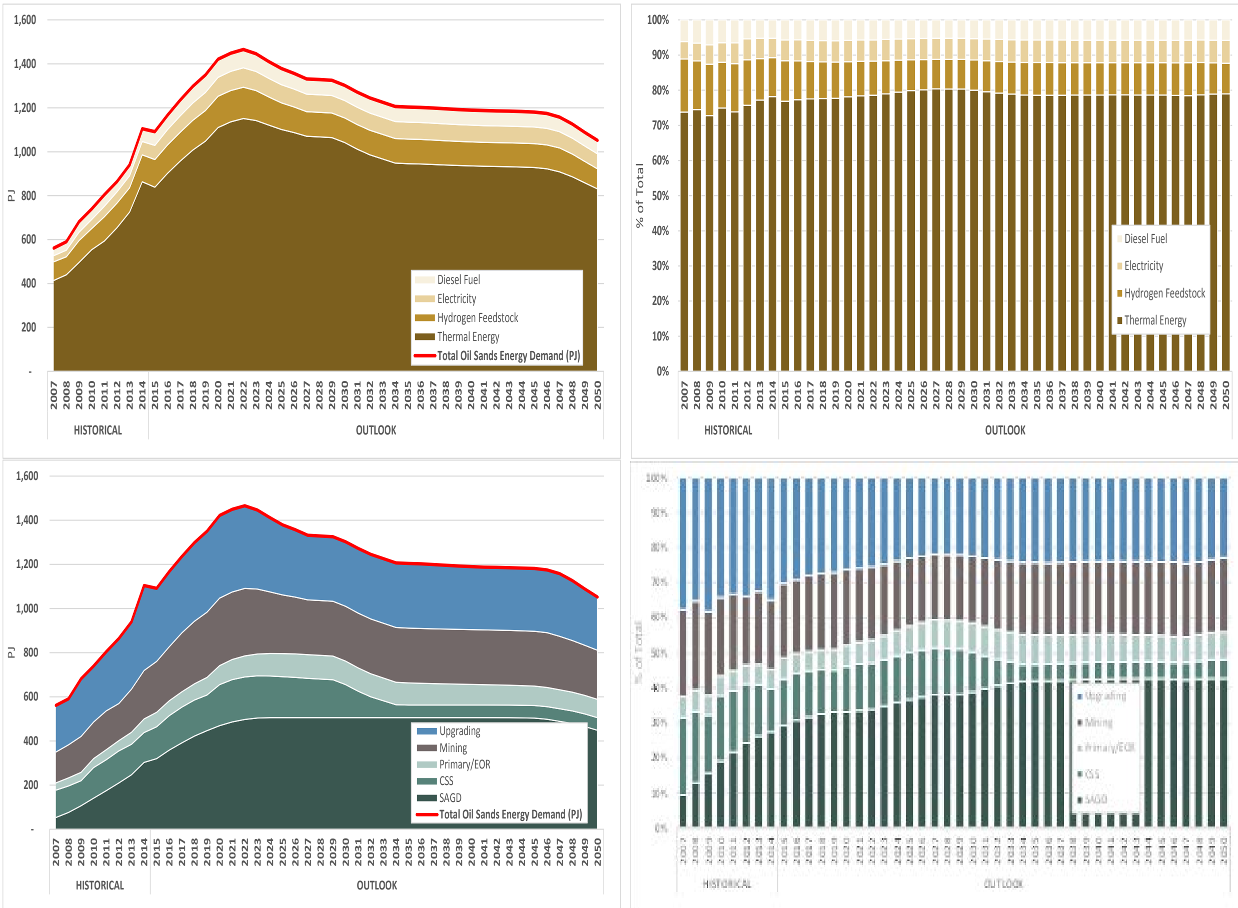
Figure 3.6: Oil Sands Diesel Fuel Demand (kb/d), 2007-2050



Source: CERI

Figure 3.7 shows the overall consumption for energy in the oil sands under the CG scenario. As expected, the combined result duplicates the pattern of energy demand peaking after 2020 while a leveling out of requirements consistent with the production forecast.

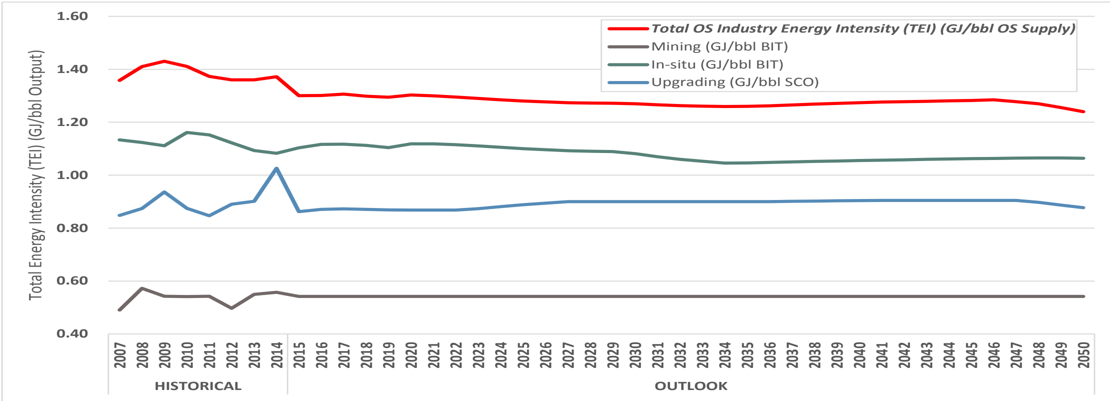
Figure 3.7: Oil Sands Total Energy Demand by Type of Energy Used (top) and by Project Type (bottom) (PJ), 2007-2050



Source: CERI

With energy use consistent with the pattern for production volumes, intensities would not change significantly over time. Figure 3.8 displays the intensities and shows little change over the forecast period.

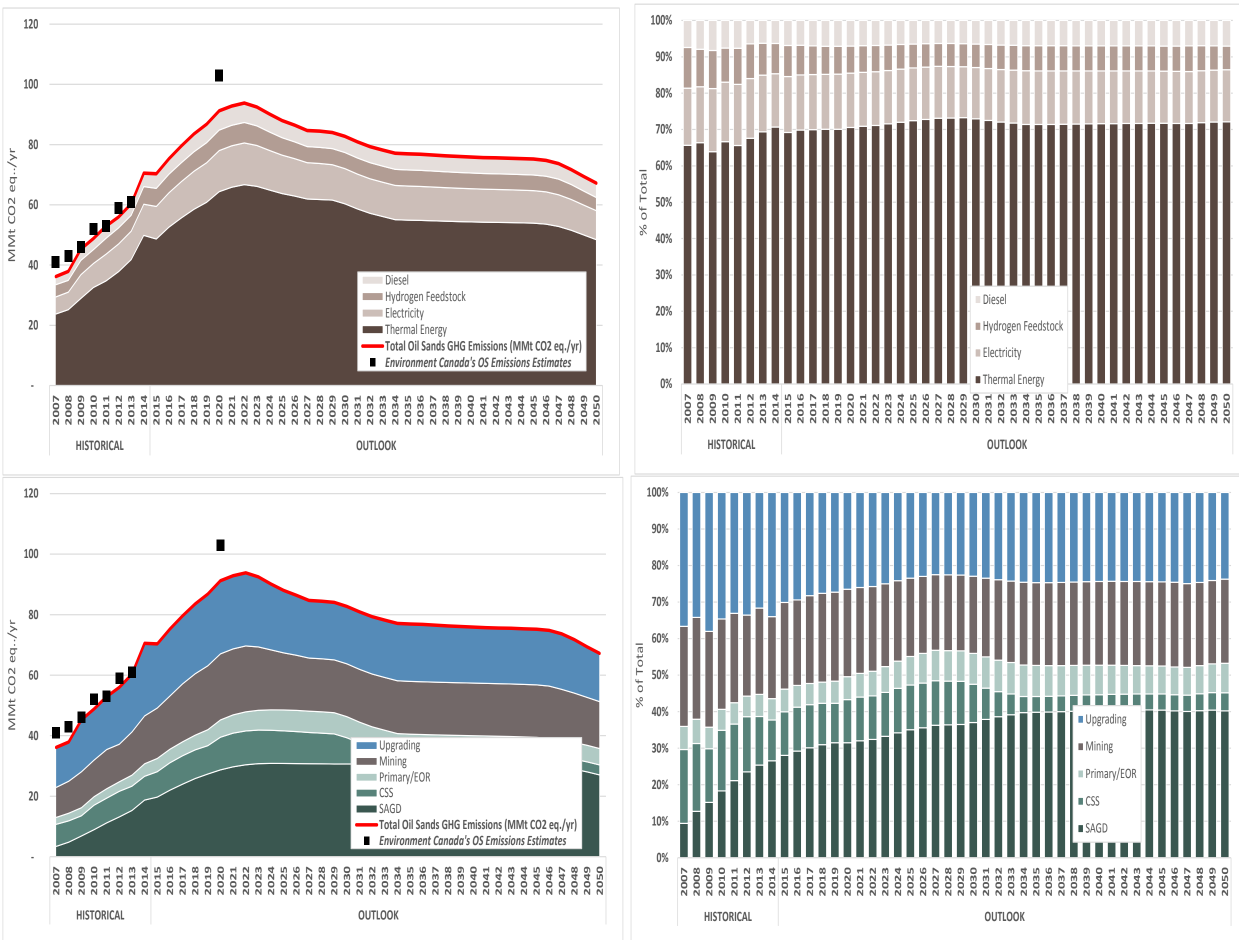
Figure 3.8: Oil Sands Total Energy Intensity by Project Type and Total Oil Sands Supply (GJ/bbl of output), 2007-2035



Source: CERI

Figure 3.9 shows the GHG emissions in the oils sands under the CG scenario to 2050. The forecast indicates that emissions will peak after 2020 at over 90 MMt CO_2eq./yr and then drop to about 70 MMt CO_2eq./yr by 2050.

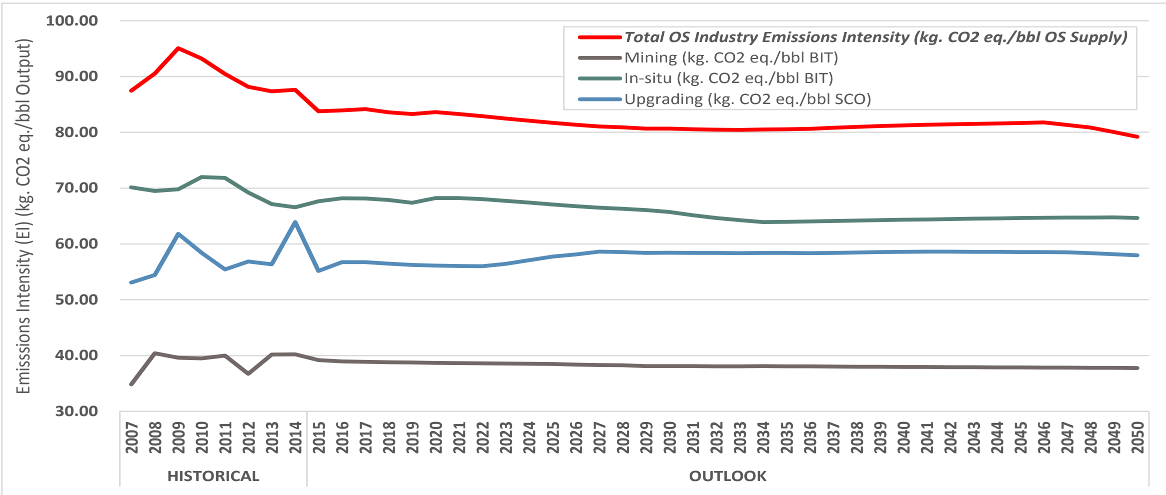
Figure 3.9: GHG Emissions Estimates of the Oil Sands by Type of Energy (top) and Project Type (bottom), (MMt CO_2eq./yr), 2007-2050



Source: Data from Environment Canada, 2015 and CERI; Figures by CERI

In Figure 3.10 emissions by project type are shown. It follows the same trend as that for energy intensity by type indicating no significant interfuel substitution over the period.

Figure 3.10: Oil Sands GHG Emissions Intensity by Project Type and Total Oil Sands Supply ($kg.\ CO_2$ eq./bbl of output), 2007-2050



Source: CERI

Increasing Energy Efficiency (IEE) Scenario

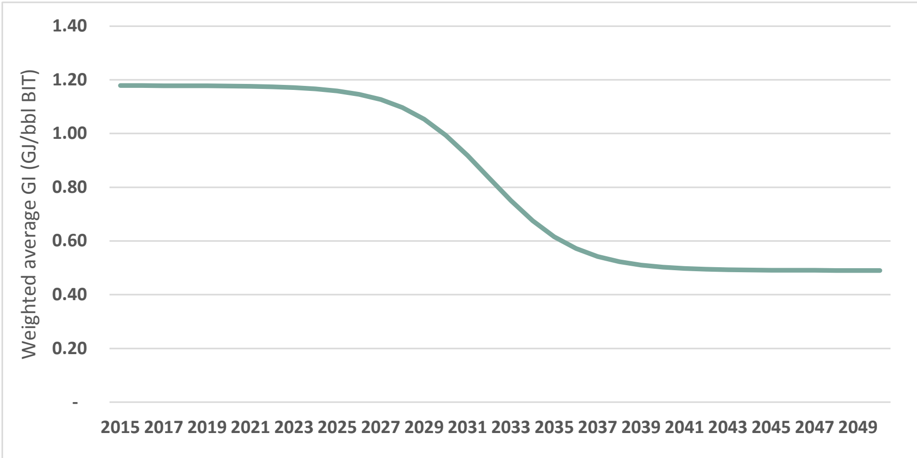
Energy intensity scenarios are based on the use of different values across the presented energy intensity ranges and how those values apply to the spectrum of projects across the industry.

In the case of the increasing energy efficiency (IEE) scenario, using lower values within the energy intensity ranges is a way of illustrating increasing energy efficiency. The opposite is applicable to the decreasing reservoir quality (DRQ) scenario, as increasing energy intensity can normally be associated with lower quality characteristics in the reservoir.

Because the values within the intensity ranges are to be assigned to all new projects within a project type category in the forecast, an S-shaped curve is used to move from the BAU value to the DRQ and IEE scenarios' boundary (or limit) values in order to smooth out the transition. Figure 3.11 illustrates how a decrease in thermal energy intensity (GI)[2] is applied to SAGD projects. In the IEE scenario as new and existing projects move from the median to the latest observed empirical value, the intensity value changes from 1.18 GJ/bbl of bitumen extracted to 0.49 GJ/bbl BIT.

[2] Note that intensity factors (and their corresponding ranges) for thermal in situ projects were also calculated on a barrel of STEAM basis. These factors are calculated using the same methodology described above.

Figure 3.11: Transition from BAU Scenario Value to the Increasing Energy Efficiency Scenario (GJ/bbl)[3]



Source: CERI

Because the stated transition in intensity factors applies to both existing and new projects, this assumes that existing projects apply process optimization and efficiency measures, while new projects start from a higher efficiency standpoint, as lessons are learned across the industry and new projects follow better designs which aim to minimize energy waste.

It is not assumed that only one factor comes into play (i.e., decreasing reservoir quality or increasing energy efficiency) but rather that at the interplay between these complex and competing factors, one trumps the other, in a given scenario.

The increasing energy efficiency (IEE) and decreasing reservoir quality (DRQ) scenarios are at opposite ends of the energy intensity spectrum, and can be best described as follows:

- IEE scenario = energy efficiency and process improvements > decreasing reservoir quality
- DRQ scenario = energy efficiency and process improvements < decreasing reservoir quality

[3] Note that while modelling the impact of potential widespread adoption of solvent/steam co-injection processes across the industry is beyond the scope of this project, the reduction in SOR, and subsequently, the reduction in gas use associated with moving from SAGD to steam/solvent co-injection is of similar magnitude to that represented in the IEE scenario. This is based on information from CERI (Canadian Energy Research Institute (CERI), 2015). In the context of this report, a reduction in the GJ for SAGD projects because of the adoption of solvent/steam co-injection would result in a significant reduction in GHG emissions intensity as the solvent in not consumed for its energy content, thus not combusted, and generates no fuel-cycle emissions. While make-up solvent needs to be accounted for given that some solvent is not recovered from the reservoir, the GHG emissions associated with the extraction of the solvent (generally a NGL such as butanes or pentanes), is beyond the scope of GHG emissions quantified in this report, but a valid concern in the context of life cycle assessment (LCA) of oil sands crudes and production technologies

In the IEE scenario, it is assumed that process optimization and implementation of best practices at existing projects lead to increasing energy efficiency. New projects implement best practices and make further advances in avoiding energy waste. Over time, the reservoir conditions are changing. In the IEE scenario, any issues related to decreasing reservoir quality are overcome by increasing energy efficiency.

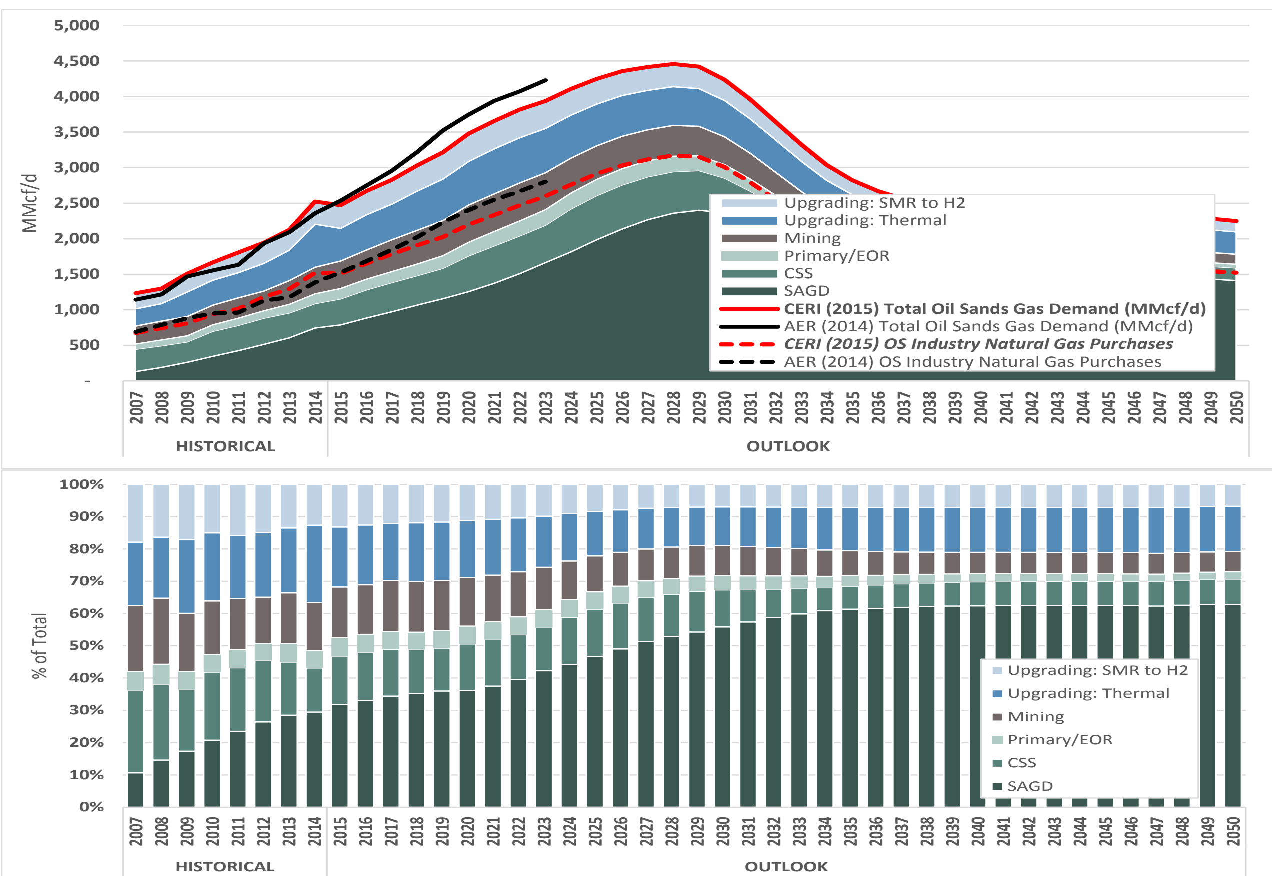
The IEE scenario assumes that existing best practices are economic for all projects, existing or new. This may not be the case in all circumstances as project economics vary. The scenario also assumes no new improvements in technology or process over the forecast period. Only those existing options that have been observed in the sector are included.

Production levels are the same as the BAU scenario.

Energy Demand Outlook

In the IEE scenario, gas demand peaks in 2028-29 similar to the BAU scenario. However, peak requirements are approximately 500 MMcf/d less. In addition, by the end of the period, gas demand is more than 2,000 MMcf/d less than the BAU scenario.

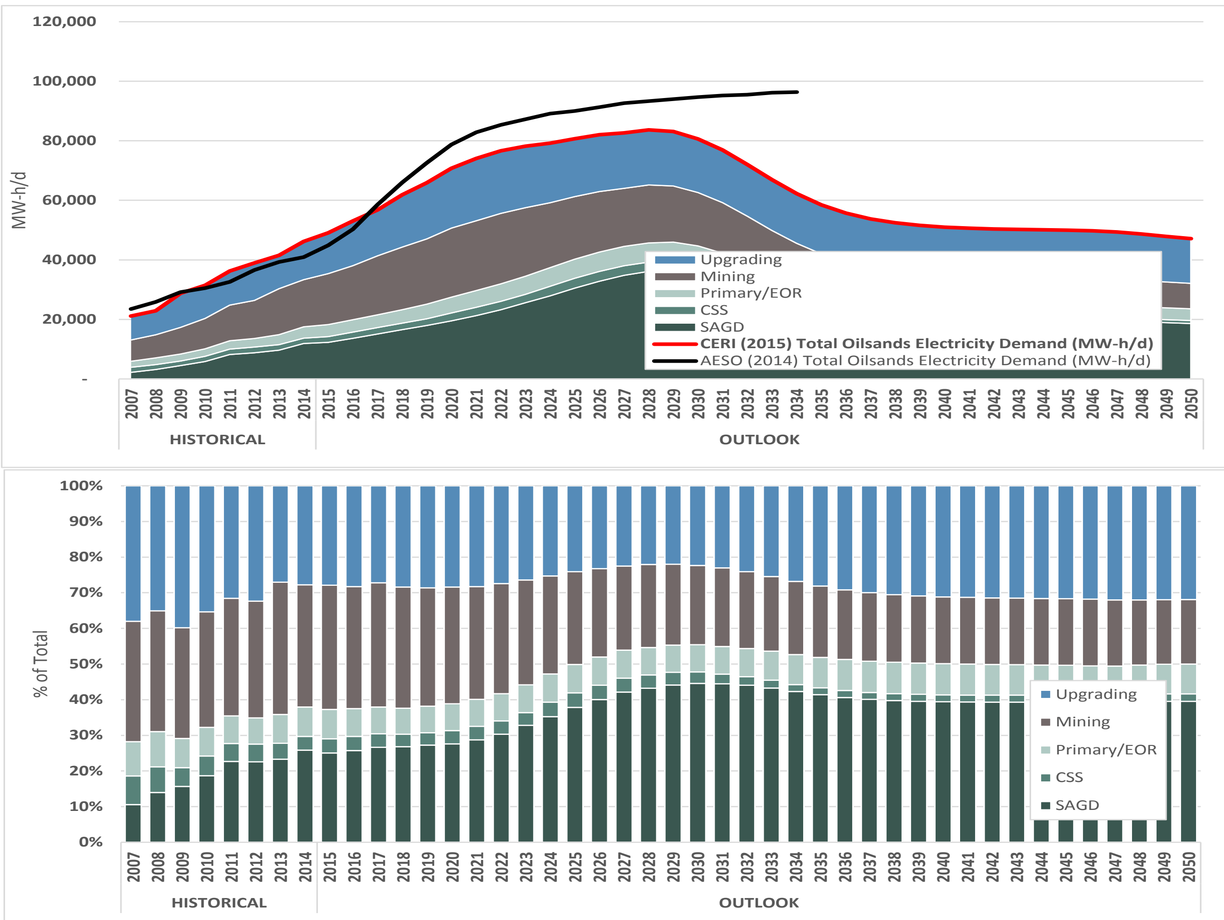
Figure 3.12: Oil Sands Gas Demand for Thermal Energy and Hydrogen Production by Project Type (MMcf/d), 2007-2050



Source: AER, CERI

Figure 3.13 shows the electricity demand to 2050. Electricity consumption peaks at the same time as the gas consumption, 2028-29 at more than 80,000 MWh/d tapering off at approximately 46,000 MWh/d. Corresponding BAU values are, for the peak, 95,000 MWh/d and by 2050 88,000 MWh/d.

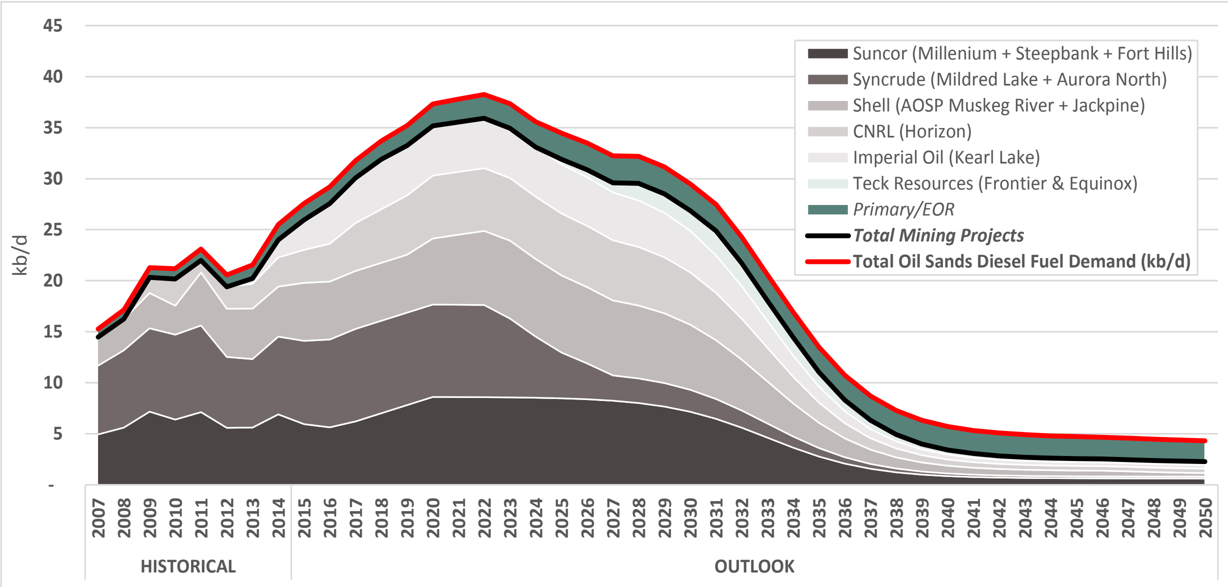
Figure 3.13: Oil Sands Electricity Demand by Project Type (MWh/d), 2007-2050



Source: AESO, CERI

Diesel fuel demand in the IEE scenario peaks around 2021 and is equivalent to the BAU peak demand. By 2050, demand has decreased to 5 kb/d compared to 37 for the BAU scenario.

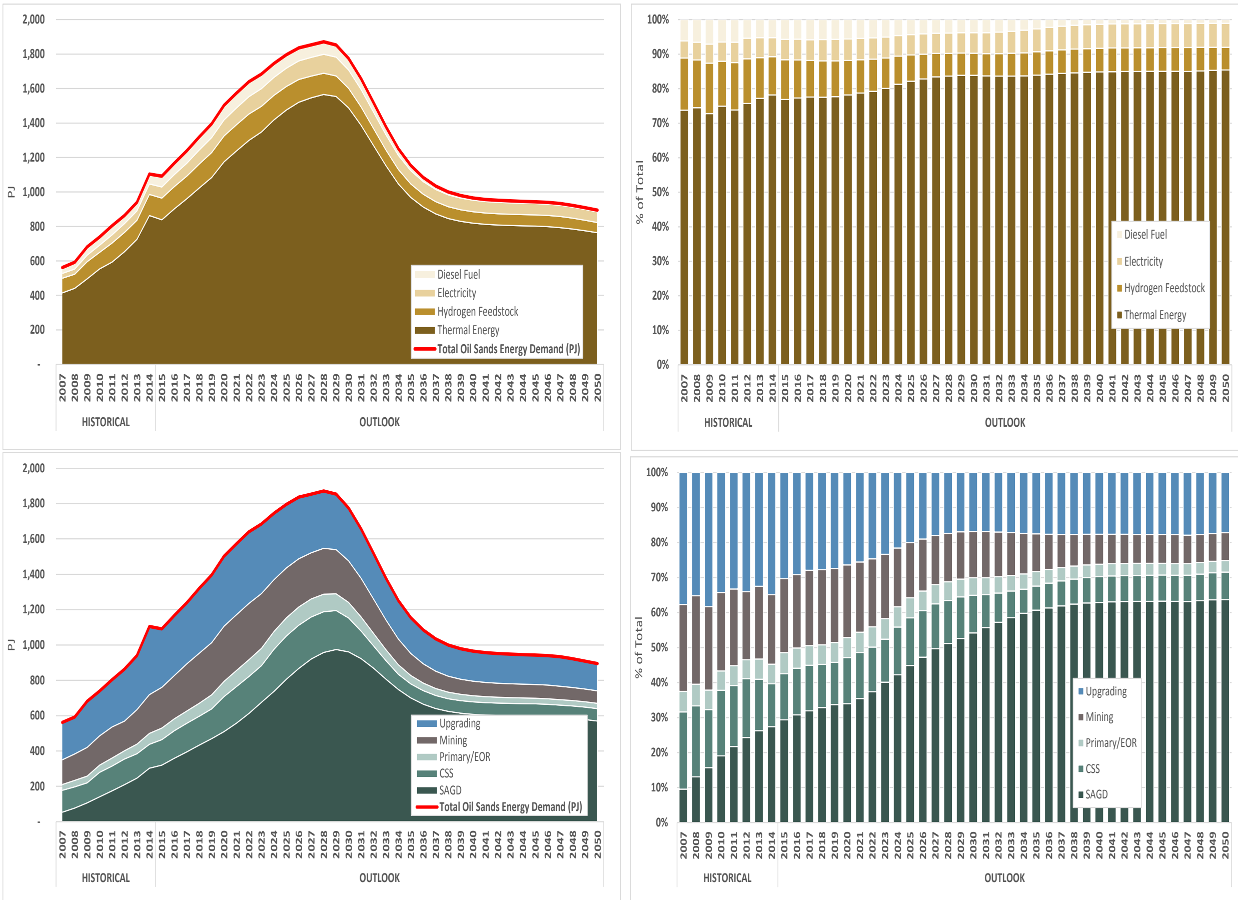
Figure 3.14: Oil Sands Diesel Fuel Demand (kb/d), 2007-2050



Source: CERI

Total energy demand is shown in Figure 3.15 for the IEE scenario. Compared to the BAU scenario, the IEE energy demand peak is approximately 300 PJ/yr lower and by 2050, the oil sands efficiency improvements result in about a 900 PJ/yr reduction in energy use.

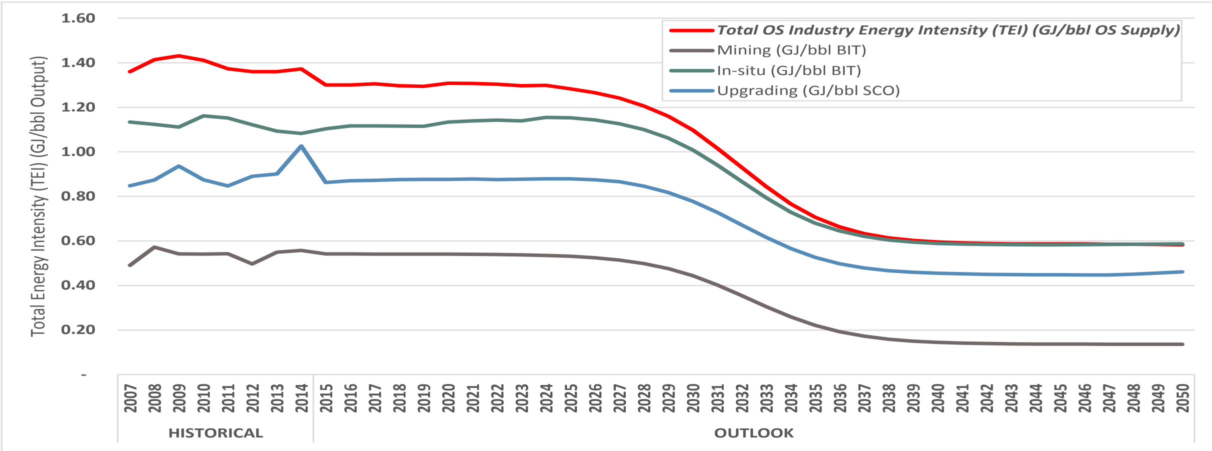
Figure 3.15: Oil Sands Total Energy Demand by Type of Energy Used (top) and by Project Type (bottom) (PJ), 2007-2050



Source: CERI

Figure 3.16 shows the trend in energy intensity over time. As efficiency options are deployed in the industry, energy consumption per barrel of output falls. For all types of projects, intensity drops by half, cutting consumption per barrel by a similar magnitude.

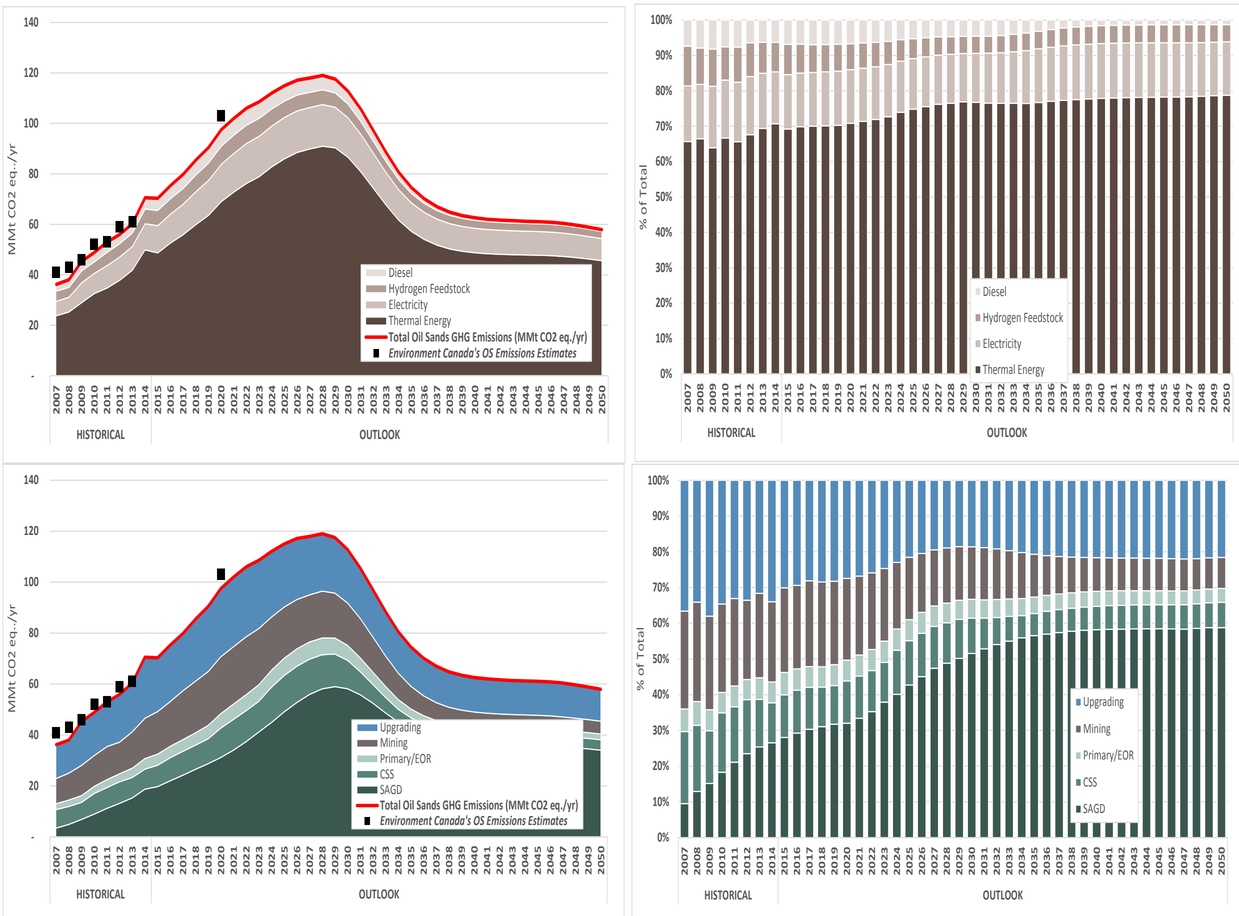
Figure 3.16: Oil Sands Total Energy Intensity by Project Type and Total Oil Sands Supply (GJ/bbl of output), 2007-2050



Source: CERI

The pattern for GHG emissions increases in the early part of the forecast period before falling by 2050. A key observation in Figure 3.17 is that energy efficiency improvements can eliminate the potential increase in emissions due to production growth.

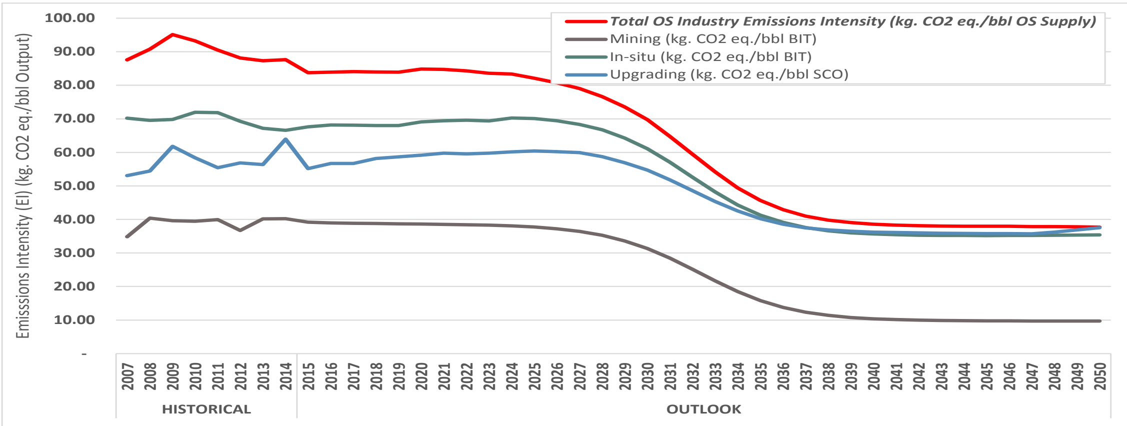
Figure 3.17: GHG Emissions Estimates Attributable to Oil Sands by Type of Energy (top) and Project Type (bottom), (MMt $C0_2$eq./yr), 2007-2050



Source: EC, CERI

GHG emissions follow the same pattern as total energy demand. There is a greater than 50% drop in annual emissions by the end of the forecast period on average for the different project types (see Figure 3.18).

Figure 3.18: GHG Emissions Intensity by Project Type and Total Oil Sands Supply (kg. CO_2 eq./bbl of output), 2007-2050



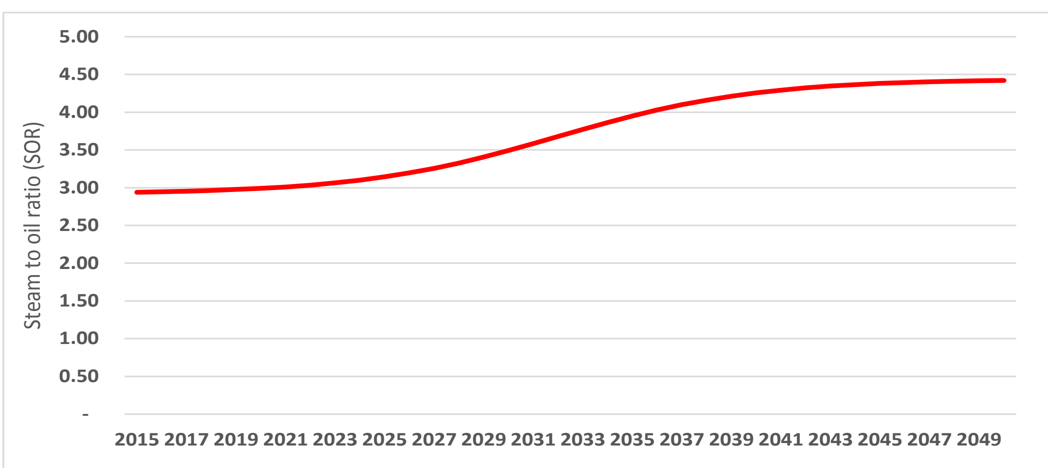
Source: CERI

Decreasing Reservoir Quality (DRQ) Scenario

In the DRQ scenario, the situation is the opposite of the increasing energy efficiency scenario. This means that any advances in extraction technologies and increasing energy efficiency are not sufficient to counter decreasing reservoir conditions and projects ageing over the long-term.

The S-shaped curve in Figure 3.19 is meant to illustrate a progressive deterioration in reservoir quality over the forecast period, rather than apply uniformly to all new production volumes at one point in time. The curve is assumed flatter here than in the increased energy efficiency scenario as it is assumed that if reservoir quality was to decrease over time, it is more likely to be a slow and gradual process (Figure 3.11).

Figure 3.19: Transition from BAU to the Decreasing Reservoir Quality Scenario: Steam to Oil Ratios for Steam Assisted Gravity Drainage Projects

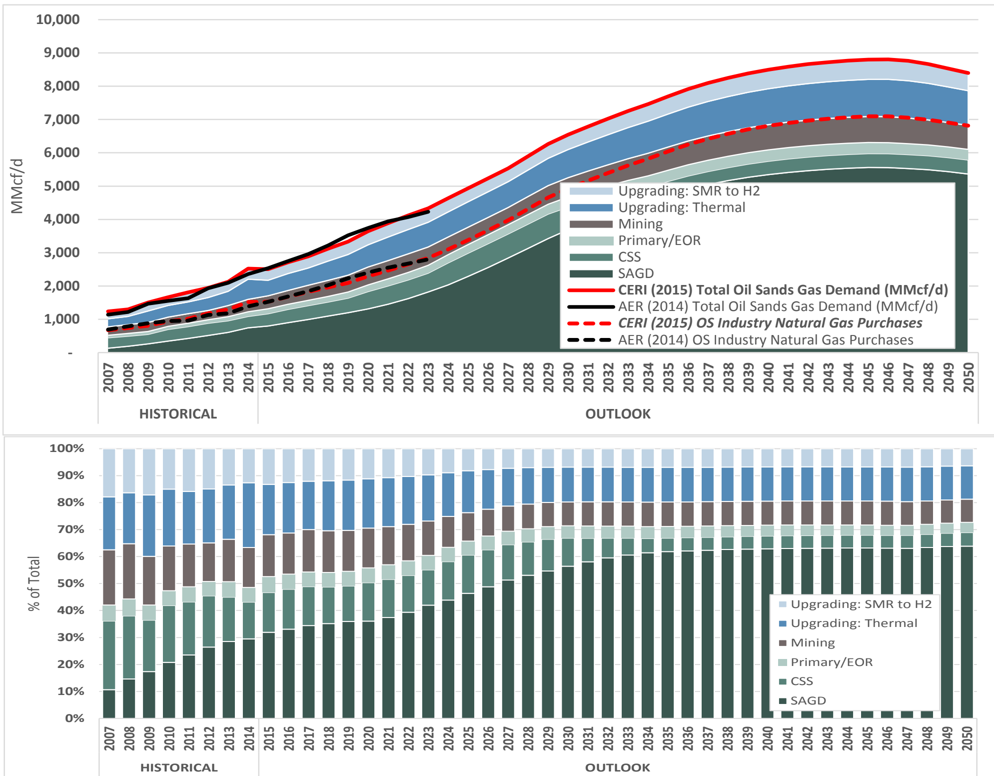


Source: CERI

Energy Demand Outlook

In the DRQ scenario, decreasing reservoir quality results in higher gas demand annually over the forecast period. Figure 3.20 shows this trend to 2050 with SAGD demand more than half the total of the oil sands.

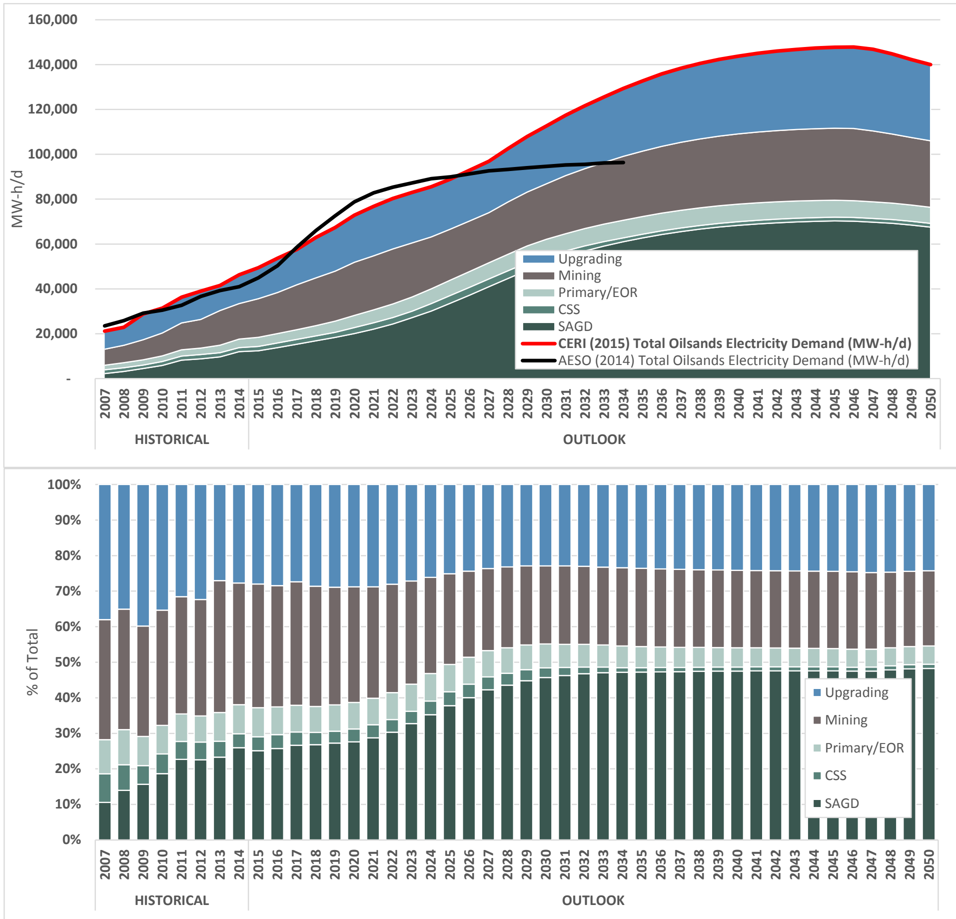
Figure 3.20: Oil Sands Gas Demand for Thermal Energy and Hydrogen Production by Project Type (MMcf/d), 2007-2050



Source: AER, CERI

Figure 3.21 shows the oil sands electricity demand to 2050. Demand continues to rise over the period peaking at approximately 150,000 MWh/day. The pattern is similar to the BAU scenario however; the DRQ scenario's peak is about 55,000 MWh/day higher.

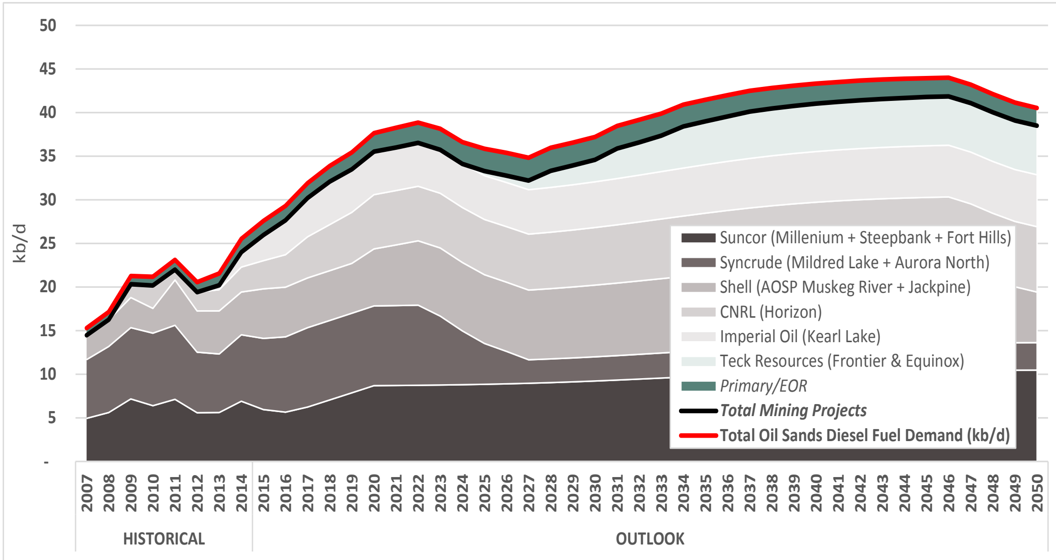
Figure 3.21: Oil Sands Electricity Demand by Project Type (MWh/d), 2007-2050



Source: AESO, CERI

Diesel demand under the DRQ scenario is shown in Figure 3.22. Consumption continues to increase over the forecast period and peaks at approximately 45 Kb/d. The peak occurs near the end of the period. In the BAU scenario, the peak is in 2022 and is about 38 Kb/d.

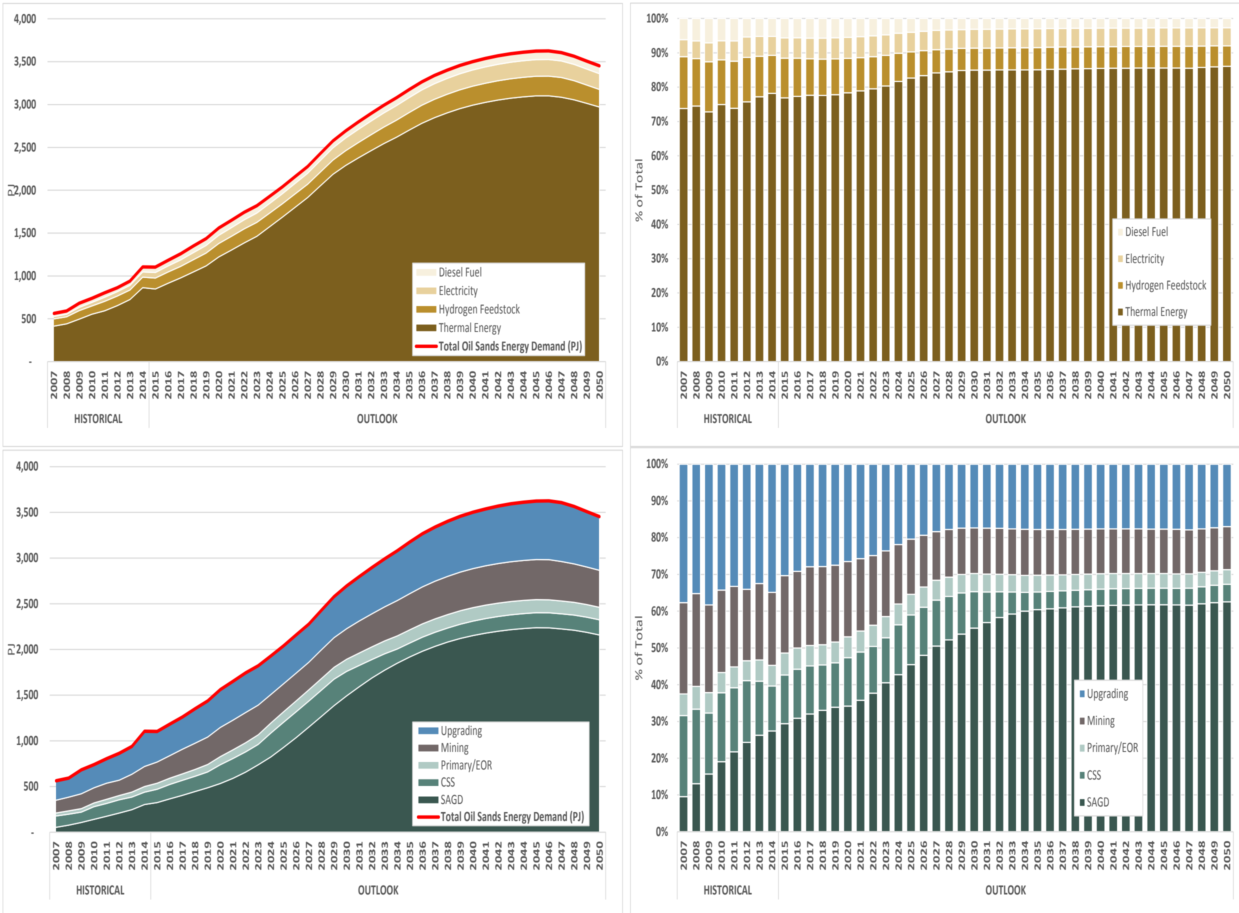
Figure 3.22: Oil Sands Diesel Fuel Demand (kb/d), 2007-2050



Source: CERI

In the DRQ scenario, total demand peaks at around 3700 PJ in 2046 significantly higher than the BAU and IEE scenarios. Figure 3.23 shows that the peak demand difference between the DRQ and IEE scenarios is approximately 1800 PJs. Nearly twice as much energy is required in the DRQ scenario comparted to the IEE scenario.

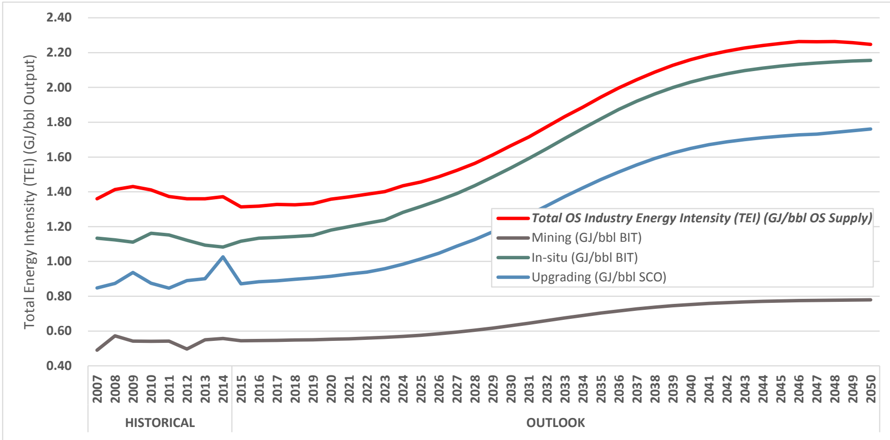
Figure 3.23: Oil Sands Total Energy Demand by Type of Energy Used (top) and by Type of Project (bottom) (PJ), 2007-2050



Source: CERI

Figure 3.24 shows the total energy intensity increasing over time. This is consistent with the total demand for energy. Energy intensity in the DRQ scenario increases more than both the BAU and IEE scenarios.

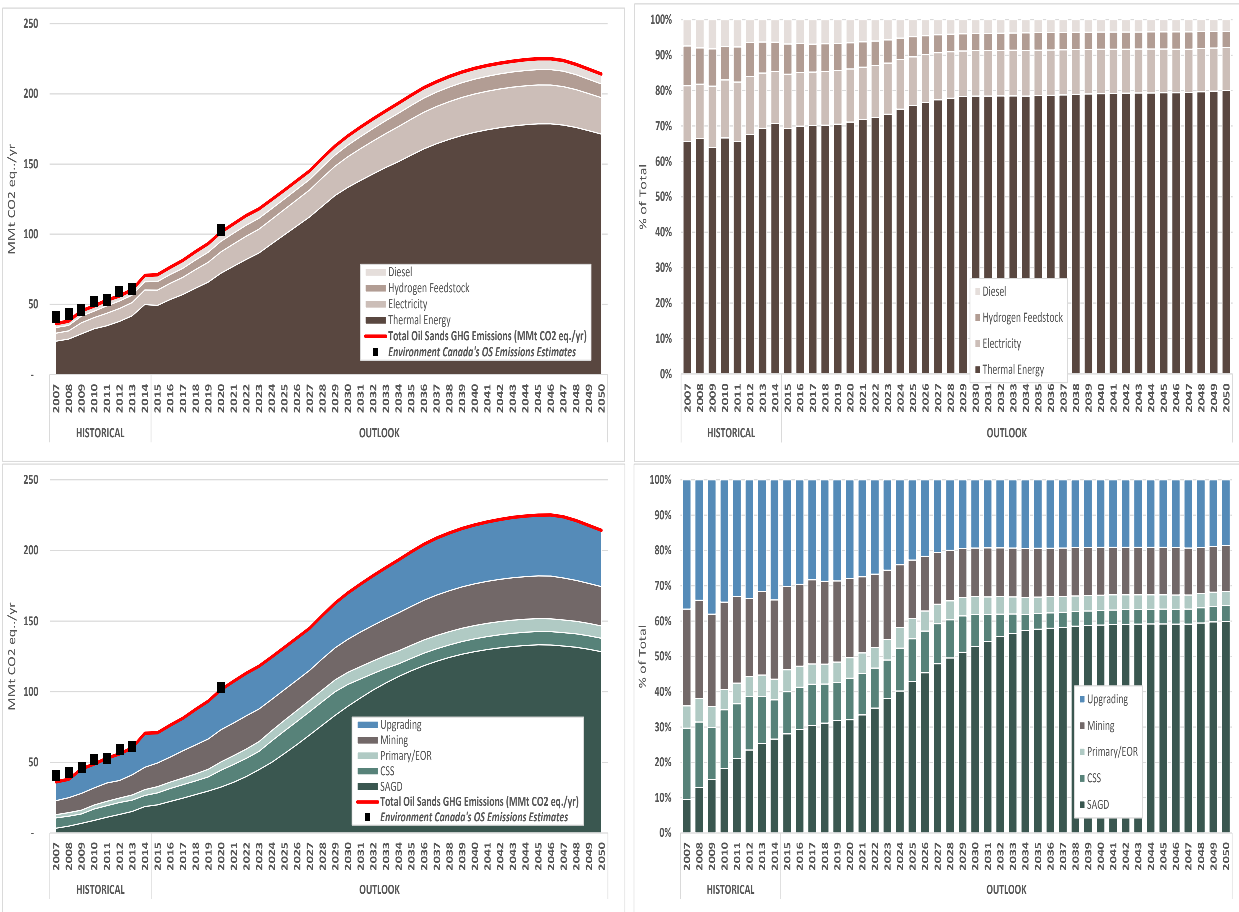
Figure 3.24: Oil Sands Total Energy Intensity by Project Type and Total Oil Sands Supply (GJ/bbl of output), 2007-2050



Source: CERI

As expected, increasing energy intensities also result in higher GHG emissions. Over the forecast period, GHG emissions increase by about 150 MMt $C0_2$eq./yr by 2050 relative to the 2014.

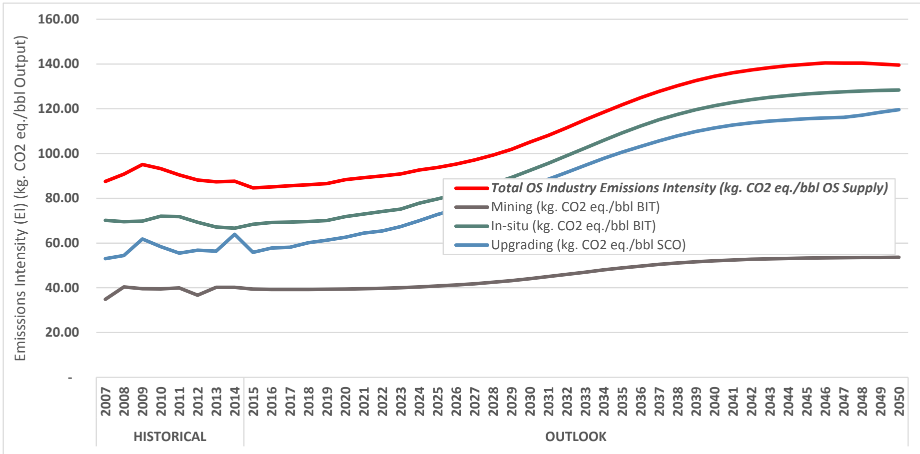
Figure 3.25: GHG Emissions of Oil Sands by Type of Energy (top) and Project Type (bottom) (MMt C0$_2$eq./yr), 2007-2050



Source: EC, CERI

Figure 3.26 shows that emissions intensity for mining activities remains relatively stable compared to other oil sands project types similar to the BAU scenario. In-situ and upgrading projects have increasing intensities over time relative to BAU.

Figure 3.26: Oil Sands GHG Emissions Intensity by Project Type and Total Oil Sands Supply (kg. CO_2 eq./bbl of output), 2007-2050



Source: CERI

Electric Heating Technologies Adoption (EHTA) Scenario

In this scenario, it is assumed that electric heating technologies (EHT) are adopted by a large cross-section of in situ projects. The main assumption is that thermal in situ projects (SAGD and CSS) which are planned to come online after 2017 make use of electrical heating technologies rather than steam for bitumen extraction.

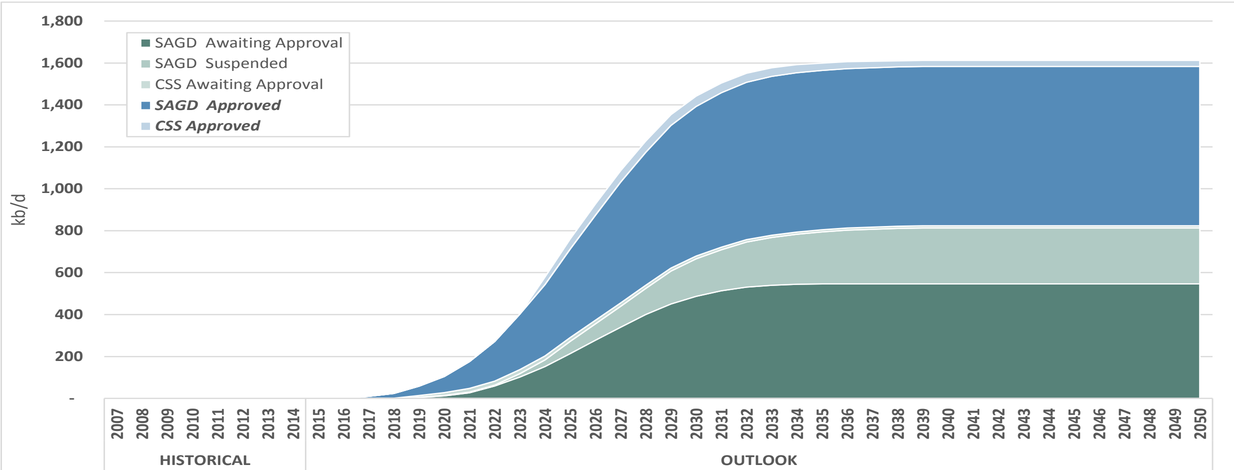
Electrical extraction methods are one set of many options that can potentially be used for bitumen extraction. In terms of carbon management of oil sands extraction, electrical extraction methods can potentially be attractive as a number of commercially ready electricity generation technologies with low or zero carbon emission exist.[4] Furthermore, the marginal cost of reducing carbon emissions in the electric power sector can be potentially lower than that of other industrial sectors. Electrical extraction methods may include electric heating, electromagnetic heating, and use of electricity for steam production. A pilot project based on electric heating for bitumen extraction is in operation in Alberta. In this analysis, the electricity demand for bitumen extraction is assumed to be 180 kWh/bbl (AESO, 2014).

It is also assumed that EHTs are adopted at two levels but only across thermal in situ projects[5] and that electrical energy replaces all thermal energy requirements for these projects (see Figure 3.27).

[4] For example, hydropower, nuclear power, carbon capture and storage, and other large scale renewable energy technologies.

[5] To date, most efforts in implementing electric-heating technologies have focused on replacing thermal energy with electrical energy at in situ operations

Figure 3.27: New Thermal In Situ Crude Bitumen Production by Project Status (kb/d), 2007-2050



Source: CERI

Under the BAU scenario, total bitumen extraction is expected to reach 4.55 MMb/d by 2050, including 2.73 MMb/d of production (or 60 percent of the total) from thermal in situ projects. Under the *low adoption level* in the EHTA scenario, about 0.8 MMb/d, the equivalent of 18 percent of total bitumen extraction volumes, are estimated to use electric-heating technologies. This compares to about 1.6 MMb/d under the *high adoption level* of the EHTA scenario, or 35 percent of the total.

The first level of adoption, a *low adoption level*, assumes that only projects that are *awaiting approval* and are *suspended* will adapt a commercially viable EHT. Projects that have been *approved* are assumed to develop their projects according to their submitted schemes rather than going back to the drawing board and starting the regulatory approval process over in order to apply a new production technology (EHT).

In the second level of adoption, a *high adoption level*, the technology is so successfully developed and implemented across the industry that *approved* projects redesign their scheme extraction plans.

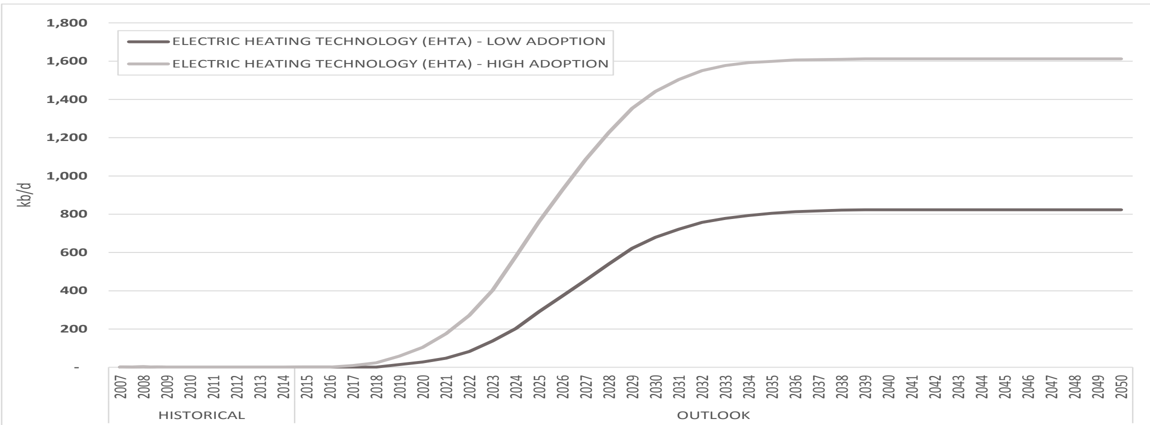
On-stream, and *under construction* projects are not included in this scenario.[6]

In the low adoption level, bitumen production reaches 824 kb/d by 2039 and plateaus thereafter. In the high adoption level, production of in situ bitumen via EHTs reaches 1,612 kb/d by 2039 and plateaus thereafter.

[6] Under the right conditions and given the proper incentives for technology, costs, or policy, operational improvements thermal in situ projects may be retrofitted to employ EHTs. However, an investigation of those conditions is beyond the scope of this analysis and as such, the analysis does not include them in the scenario.

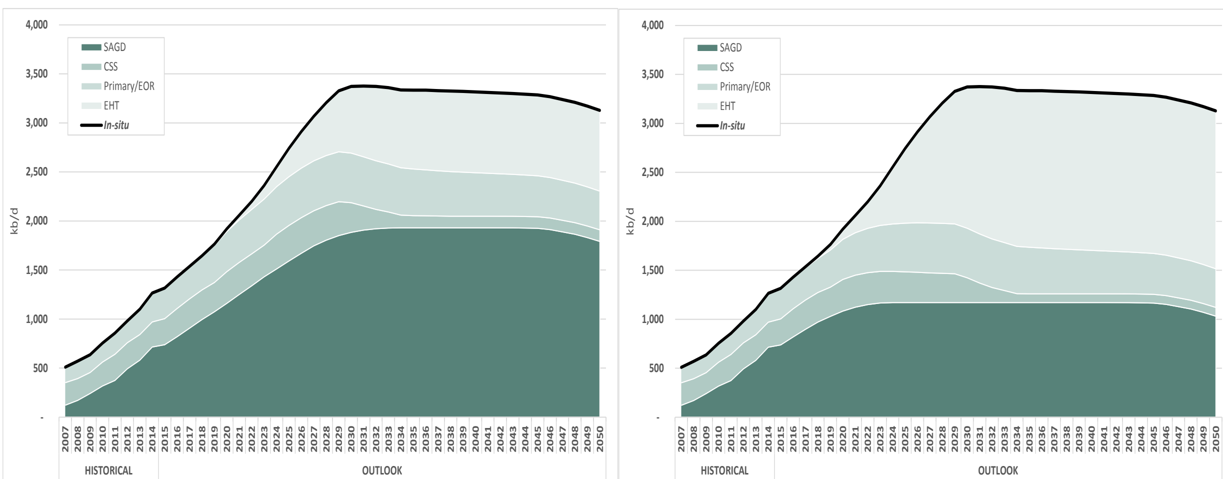
Figure 3.28 displays the production outlook for both levels in the EHTA scenario, while Figure 3.29 displays EHT production in the context of overall in situ bitumen production.

Figure 3.28: Electric Heating Technologies Bitumen Extraction Volumes (kb/d), 2007-2050



Source: CERI

Figure 3.29: In Situ Production by Type (kb/d), 2007-2050



Source: CERI

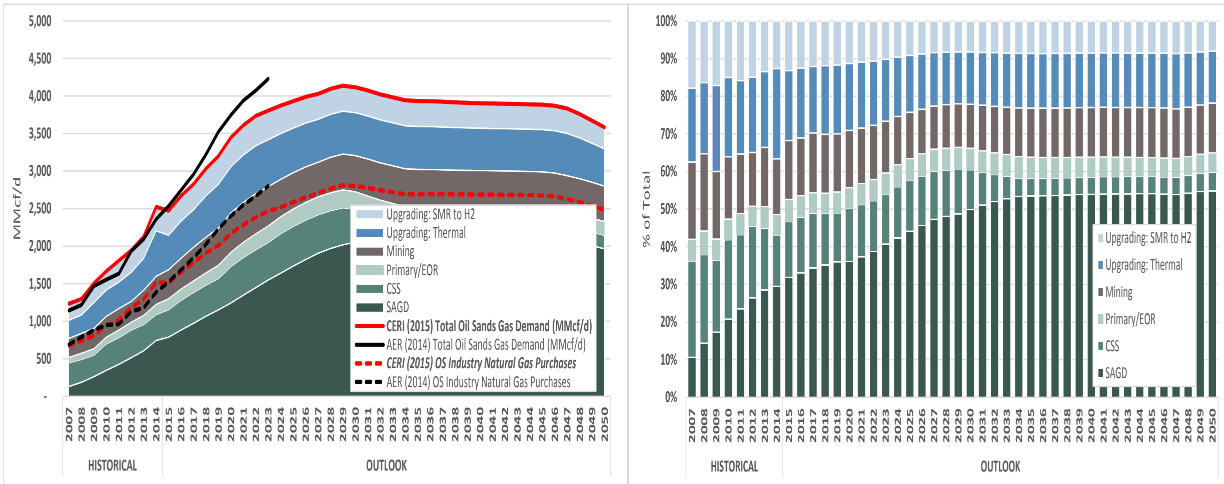
Energy Demand Outlook and Emissions

Energy demand and emissions over these two scenarios will vary over the period but not in terms of peak requirements. There difference in cumulative emissions is demonstrated in the following figures.

Low Adoption Rate

Gas demand the low adoption rate is shown in Figure 3.30. Peak demand occurs in 2028 at approximately 4,200 MMcf/d compared to 5,000 MMcf/d in the BAU scenario. This demonstrates the impact of electricity substitution on gas demand.

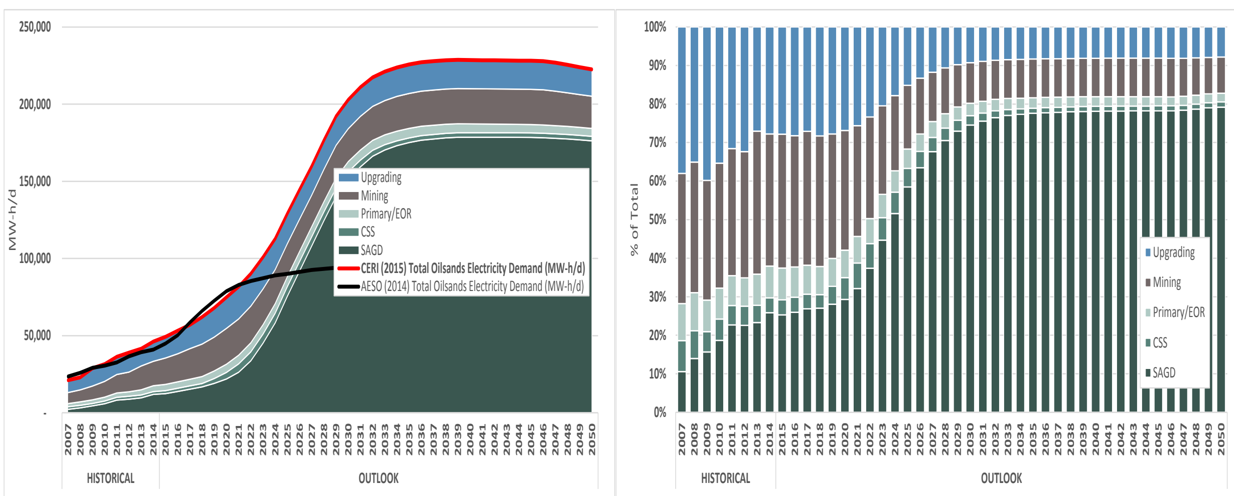
Figure 3.30: Oil Sands Gas Demand for Thermal Energy and Hydrogen Production by Project Type (MMcf/d), 2007-2050



Source: AER, CERI

Alternatively, the shift toward electricity in this scenario results in peak requirements of approximately 225,000 MWh/d compared to 95,000 MWh/d in the BAU scenario. The largest demand is for SAGD operations (see Figure 3.31).

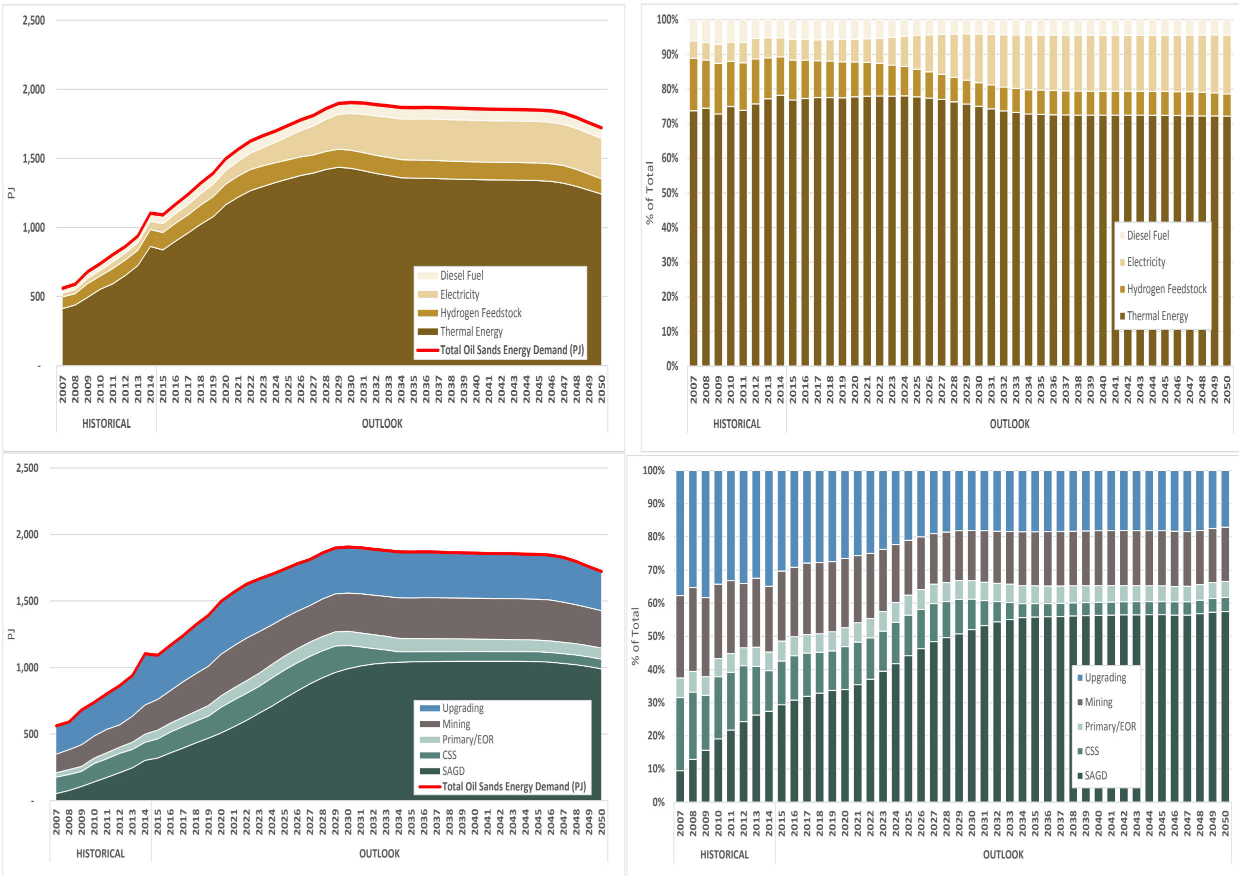
Figure 3.31: Oil Sands Electricity Demand by Project Type (MWh/d), 2007-2050



Source: AESO, CERI

Total energy demand in the EHTA low adoption scenario peaks at approximately 1900 PJ in 2028. This is about 200 PJ less than the BAU scenario, owing mainly to the generally higher efficiencies of electric technologies versus gas technologies.

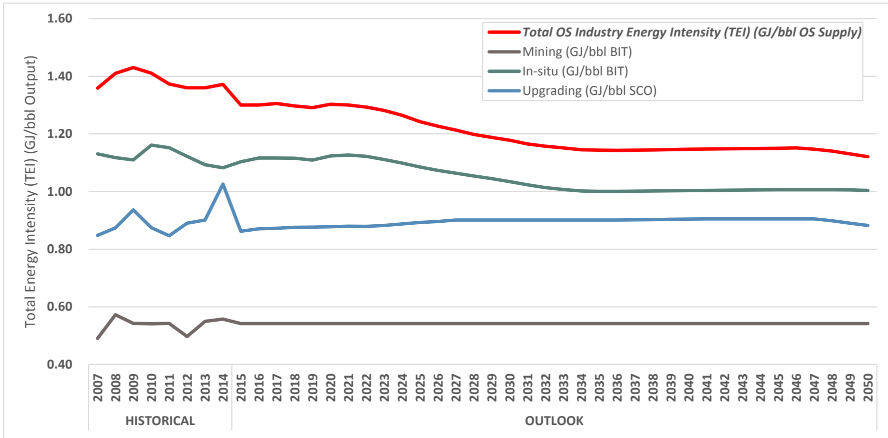
Figure 3.32: Oil Sands Total Energy Demand by Type of Energy Used (top) and by Project Type (bottom) (PJ), 2007-2050



Source: CERI

Figure 3.33 shows declining energy intensity for In-situ operations. With In-situ production being representing the majority of the output, this declining intensity affect the overall intensity for the sector.

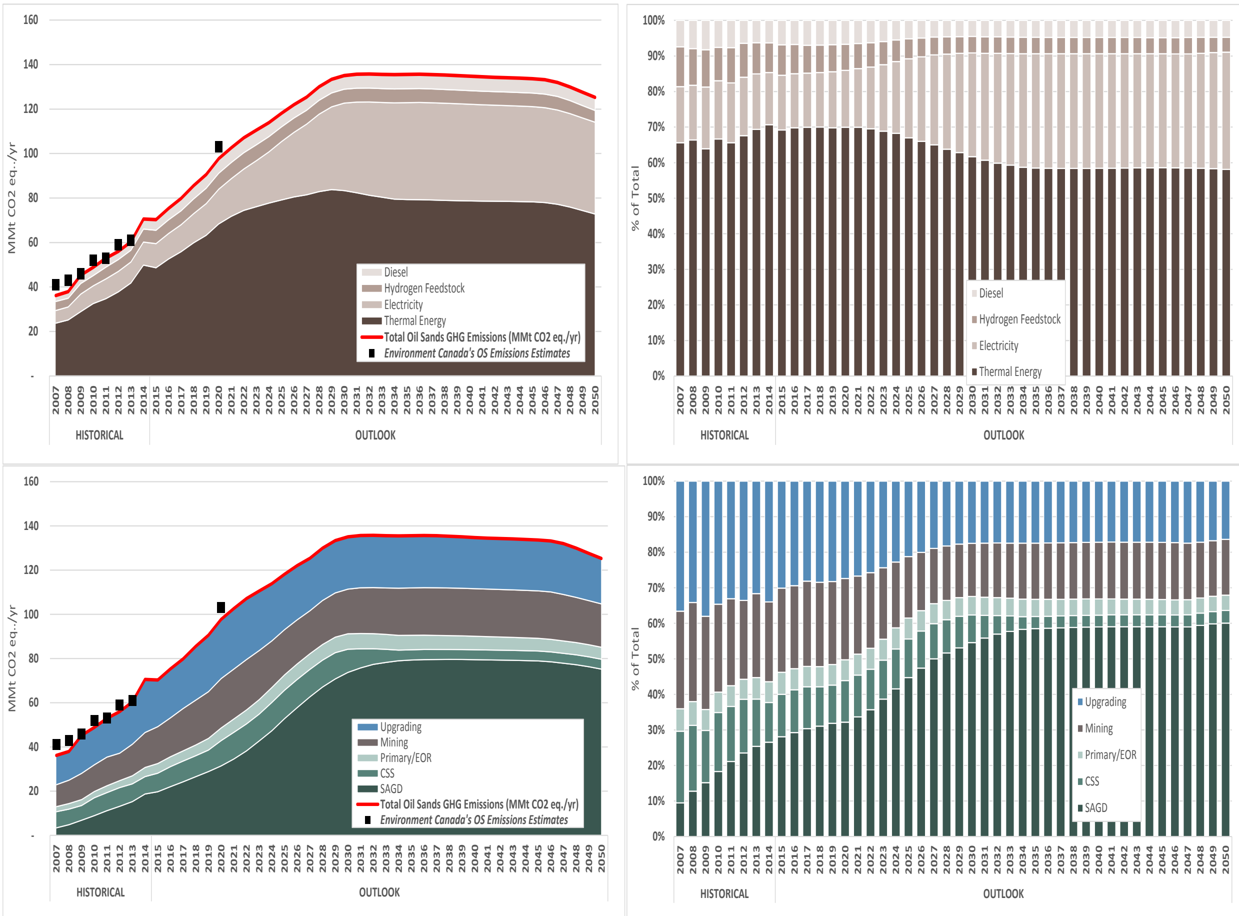
Figure 3.33: Oil Sands Total Energy Intensity by Project Type and Total Oil Sands Supply (GJ/bbl of output), 2007-2050



Source: CERI

Figure 3.34 displays the GHG results for the EHTA low adoption scenario. GHG emissions peak in 2030 at approximately 135 MMt CO_2eq./yr, similar to the BAU case.

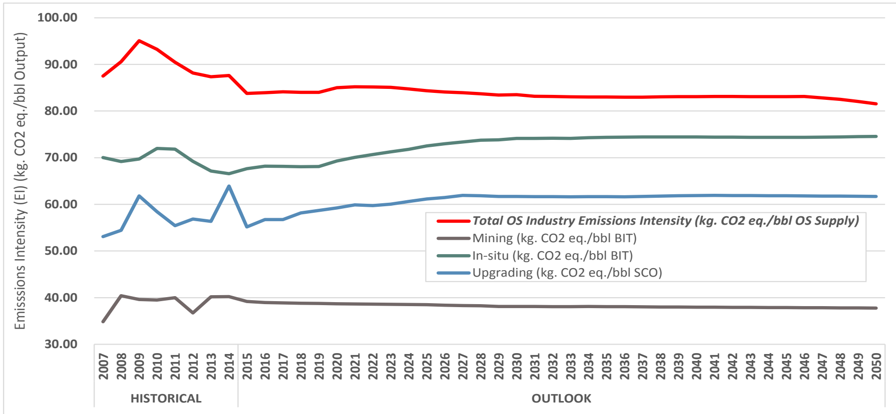
Figure 3.34: GHG Emissions Estimates for Oil Sands by Type of Energy (top) and Project Type (bottom), (MMt CO_2eq./yr), 2007-2050



Source: EC, CERI

Emissions intensity is relatively stable over the forecast period as shown in Figure 3.35. This is similar to the BAU scenario.

Figure 3.35: Oil Sands GHG Emissions Intensity by Project Type and Total Oil Sands Supply (kg. CO_2 eq./bbl of output), 2007-2050

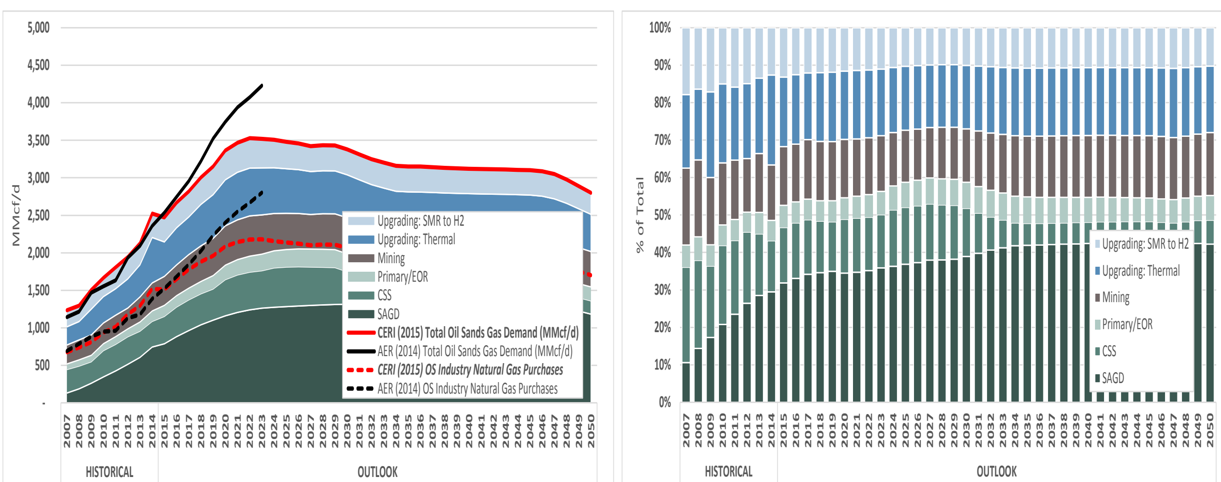


Source: CERI

High Adoption Rate

In the EHTA high adoption rate, the principle change is the rate at which electric heating technologies are installed in oil sands projects. Figure 3.36 shows that total gas demand peaks at approximately 3,500 MMcf/d in 2021, which is earlier and lower than under the low adoption rate scenario.

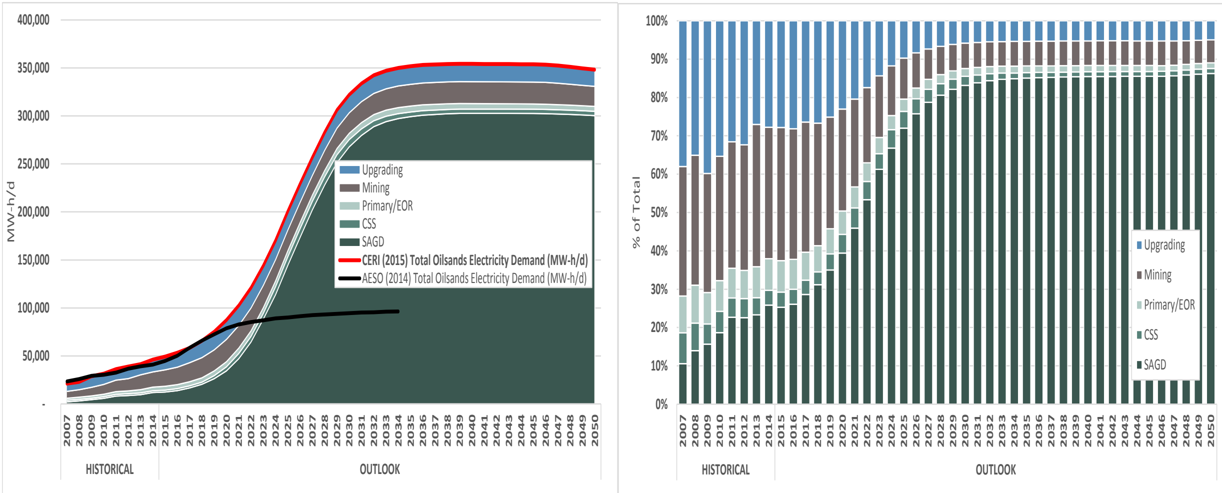
Figure 3.36: Oil Sands Gas Demand for Thermal Energy and Hydrogen Production by Project Type (MMcf/d), 2007-2050



Source: AER, CERI

As expected, Figure 3.37 shows EHTA high adoption rate electricity demand peaking higher than the low adoption scenario. In this case, the peak is approximately 355,000 MWh/d compared to about 225,000 MWh/d in the low adoption case.

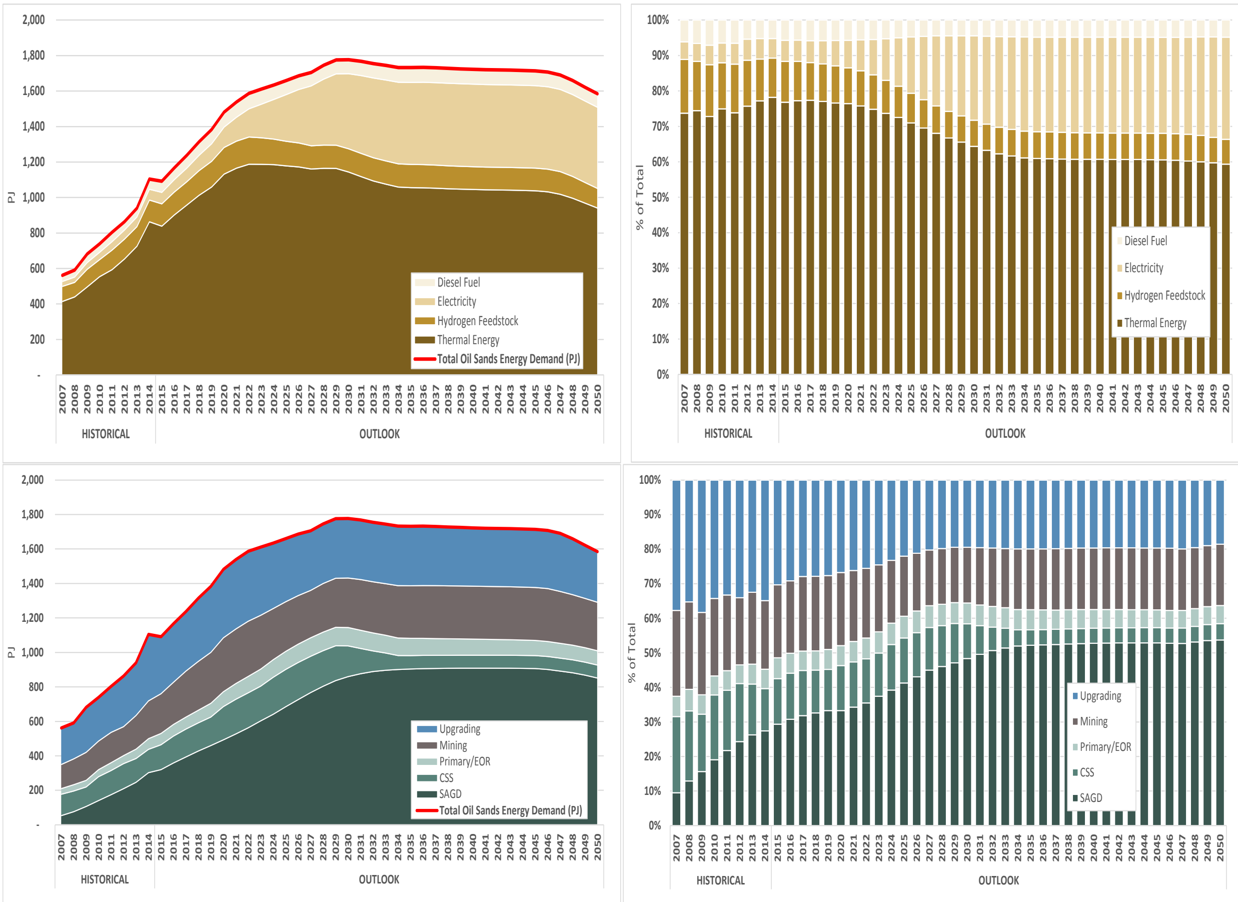
Figure 3.37: Oil Sands Electricity Demand by Project Type (MWh/d), 2007-2050



Source: AESO, CERI

Total energy use in Figure 3.38 for the EHTA high adoption case peaks at about 1800 PJ per year in 2029, approximately 100 PJ less than the low adoption rate scenario. Again, the majority of demand is due to In-situ operations.

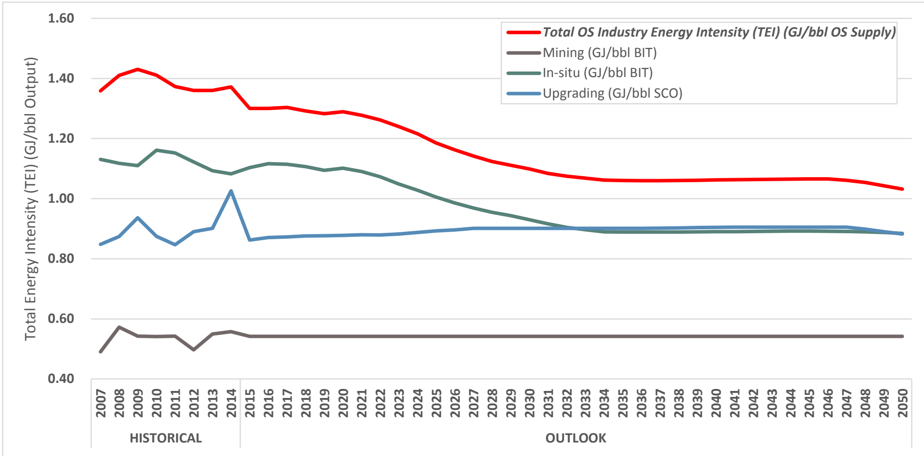
Figure 3.38: Oil Sands Total Energy Demand by Type of Energy Used (top) and by Project Type (bottom) (PJ), 2007-2050



Source: CERI

Energy intensity drops over the forecast period as shown in Figure 3.39. This is mainly due to the generally higher efficiencies of electricity consuming technologies compared to natural gas consuming technologies.

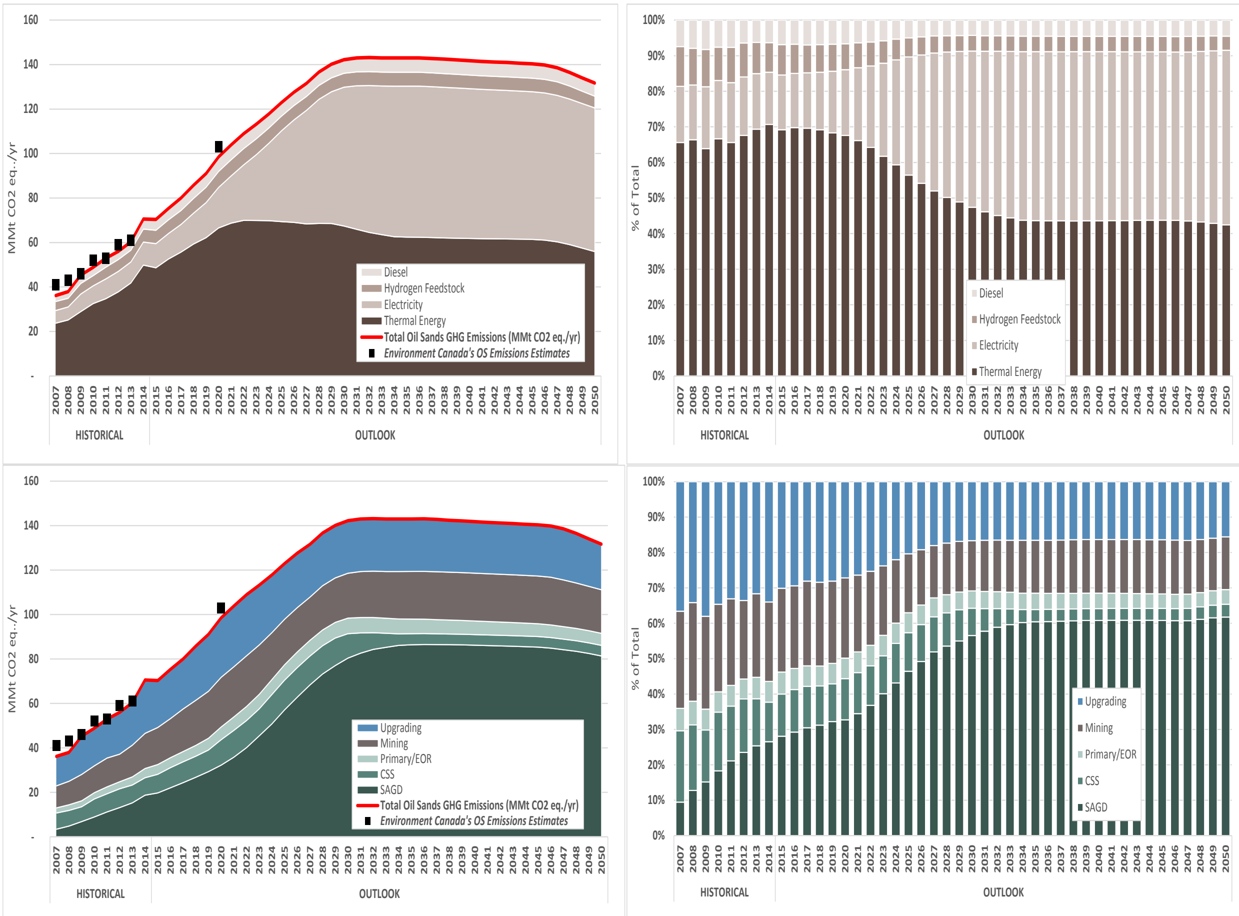
Figure 3.39: Oil Sands Total Energy Intensity by Project Type and Total Oil Sands Supply (GJ/bbl of output), 2007-2050



Source: CERI

Emissions in this scenario peak at about 142 MMt CO_2eq./yr compared to 135 MMt CO_2eq./yr for the low adoption rate scenario. The emissions in this scenario are also higher than BAU.

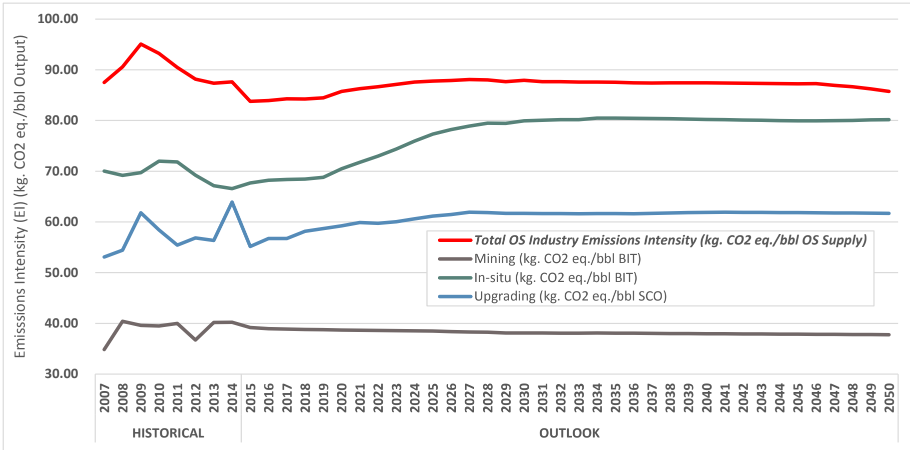
Figure 3.40: GHG Emissions Estimates Attributable to Oil Sands by Type of Energy (top) and Project Type (bottom), (MMt CO_2eq./yr), 2007-2050



Source: EC, CERI

Figure 3.41 shows a stable GHG emissions intensity to 2050 for the EHTA high adoption rate scenario. This is similar to both the low adoption rate and BAU scenarios.

Figure 3.41: Oil Sands GHG Emissions Intensity by Project Type and Total Oil Sands Supply (kg. CO_2 eq./bbl of output), 2007-2050



Source: CERI

Under the EHTA-Low scenario, overall energy use decreases by 5.8 percent compared to the BAU scenario, while cumulative GHG emissions levels actually increase in net by 3.6 percent compared to the BAU scenario. Under the EHTA-High scenario, a similar trend is observed, with cumulative energy use decreasing by 11.0 percent, but cumulative GHG emissions levels increasing by 8.1 percent compared to the BAU case.

It is important to note that the electrical energy intensity of bitumen extraction under EHTA scenarios is end-use energy and therefore a GJ of end-use electricity requires more than a GJ of fuel to be produced (the same can be said about thermal energy). In this case, the electricity intensity in the EHTA scenarios is 180 kWh/bbl of bitumen. This is equivalent to 0.65 GJ/bbl. To produce this energy at an efficiency of 57 percent using a combined-cycle gas turbine (CCGT) would require 1.14 GJ of natural gas per barrel of bitumen. This is the same amount of natural gas needed at a thermal in situ project with a steam to oil ratio of 2.78.

For electric technologies to result in a one to one replacement ratio with thermal energy, the intensity needs to be around 158.3 kWh/bbl.[7]

In this scenario, end-use electricity replacement of natural gas where the electricity itself is generated by natural gas results in higher GHG emissions. Emissions from thermal energy requirements decrease but those for the generation of electricity increase by a greater amount.

This then is reflected on the emissions estimates; while thermal energy GHG emissions decrease, the increase in GHG emissions from electricity generation are larger and thus result in an overall increase in emissions in the EHTA scenarios compared to the BAU scenario.

[7] 1 GJ of thermal energy/natural gas per barrel of bitumen is equivalent to: (1 GJ NG/bbl) x (0.57 GJ electricity/1 GJ of NG (CCGT)) x (1 MWh/3.6 GJ of electrical energy) x (1,000 kWh/1 MWh) = 158.3 kW/h/bbl

Chapter 4: Conclusion

This assessment considered the energy use and GHG emissions from the oil sands industry over the 2015-2050 period. A benchmark business as usual case was developed using a risk adjusted production forecast and trending of energy intensities. CERI`s production forecast is similar to those of the AER, NEB and about 10 percent higher than CAPP in the 2020-2030 period.

Scenarios were developed to explore the impact of different parameters. These scenarios are:

- A constrained growth forecast – this scenario has a lower production forecast than the business as usual benchmark. The forecast is a cumulative 35 billion bbls compared to 52 billion bbls in the BAU case.
- Increasing energy efficiency – this scenario contains the same production forecast but increases energy efficiency per barrel by 0.4 GJ compared to the business as usual case.
- Decreasing reservoir quality – in this scenario any efficiency improvement is overwhelmed by a deterioration in reservoir quality thus reducing the energy efficiency by 0.5 GJ per barrel compared to the BAU case. The production forecast is the same. The rate at which reservoir quality affects energy use is slower than the rate of change of energy efficiency improvements in the IEE scenario.
- Low adoption rate of electric heating technologies – with the slow adoption of electric heating technologies, this scenario results in a gradual increase in energy efficiency and a change in the energy supply mix.
- High adoption rate of electric heating technologies – with the quick adoption of electric heating technologies, this scenario results in a more pronounced increase in energy efficiency as well as a change in the energy supply mix.

Table 4.1 details the cumulative production energy use and GHG emissions for the six scenarios. It also contains energy intensities and CO_2 equivalent per barrel and per GJ.

Table 4.1: Cumulative Oil Sands Production Volumes, Energy Used, GHG Emissions, and Intensity Factors by Scenario

	2015 - 2050 Cumualtive			Intensities		
	Production (Bbbl)	Energy Used (EJ)	GHG Emissions (Gt CO2 eq.)	GJ/bbl	kg. CO2 eq./bbl	kg. CO2 eq./GJ (energy used)
BUSINESS AS USUAL (BAU)						
Oil sands supply	**52.4**	**66.3**	**4.2**	**1.3**	**80.8**	**63.8**
Mining (BIT)	19.6	10.6	0.7	0.5	38.2	70.5
In-situ (BIT)	37.7	43.2	2.6	1.1	69.7	60.9
SAGD	*28.9*	*34.4*	*2.1*	*1.2*	*72.1*	*60.6*
CSS	*3.0*	*5.4*	*0.3*	*1.8*	*107.4*	*59.7*
Primary/EOR	*5.8*	*3.3*	*0.2*	*0.6*	*37.9*	*65.7*
Upgrading (SCO)	14.1	12.6	0.9	0.9	60.8	68.0
CONSTRAINED GROWTH (CG)						
Oil sands supply	**35.2**	**45.1**	**2.9**	**1.3**	**82.0**	**64.0**
Mining (BIT)	17.0	9.2	0.7	0.5	38.2	70.6
In-situ (BIT)	23.0	24.9	1.5	1.1	66.3	61.3
SAGD	*14.7*	*17.4*	*1.1*	*1.2*	*72.0*	*60.7*
CSS	*2.5*	*4.1*	*0.2*	*1.7*	*99.3*	*60.1*
Primary/EOR	*5.8*	*3.3*	*0.2*	*0.6*	*37.9*	*65.7*
Upgrading (SCO)	12.4	11.0	0.7	0.9	57.7	64.8
INCREASING ENERGY EFFICIENCY (IEE)						
Oil sands supply	**52.4**	**46.8**	**3.0**	**0.9**	**57.6**	**64.5**
Mining (BIT)	19.6	6.5	0.5	0.3	23.7	71.2
In-situ (BIT)	37.7	30.8	1.9	0.8	49.8	60.9
SAGD	*28.9*	*23.7*	*1.4*	*0.8*	*49.5*	*60.4*
CSS	*3.0*	*4.9*	*0.3*	*1.6*	*97.7*	*59.7*
Primary/EOR	*5.8*	*2.2*	*0.2*	*0.4*	*26.6*	*68.8*
Upgrading (SCO)	14.1	9.4	0.7	0.7	48.1	71.6
DECREASING RESERVOIR QUALITY (DRQ)						
Oil sands supply	**52.4**	**96.9**	**6.1**	**1.8**	**116.5**	**63.0**
Mining (BIT)	19.6	13.1	0.9	0.7	46.6	69.8
In-situ (BIT)	37.7	65.4	3.9	1.7	104.3	60.1
SAGD	*28.9*	*53.9*	*3.2*	*1.9*	*111.6*	*59.9*
CSS	*3.0*	*7.0*	*0.4*	*2.3*	*138.2*	*59.0*
Primary/EOR	*5.8*	*4.5*	*0.3*	*0.8*	*49.9*	*64.6*
Upgrading (SCO)	14.1	18.4	1.3	1.3	89.5	68.3
ELECTRIC HEATING TECHNOLOGIES ADOPTION (EHTA) - LOW ADOPTION						
Oil sands supply	**52.4**	**62.5**	**4.4**	**1.2**	**83.7**	**70.2**
Mining (BIT)	19.6	10.6	0.7	0.5	38.2	70.5
In-situ (BIT)	37.7	39.3	2.8	1.0	73.7	70.8
SAGD	*21.9*	*26.5*	*1.6*	*1.2*	*73.4*	*60.6*
CSS	*2.9*	*4.8*	*0.3*	*1.7*	*96.9*	*58.0*
Primary/EOR	*5.8*	*3.3*	*0.2*	*0.6*	*37.9*	*65.7*
EHT	*7.2*	*4.7*	*0.7*	*0.6*	*94.3*	*145.5*
Upgrading (SCO)	14.1	12.6	0.9	0.9	60.8	68.0
ELECTRIC HEATING TECHNOLOGIES ADOPTION (EHTA) - HIGH ADOPTION						
Oil sands supply	**52.4**	**59.0**	**4.6**	**1.1**	**87.3**	**77.5**
Mining (BIT)	19.6	10.6	0.7	0.5	38.2	70.5
In-situ (BIT)	37.7	35.8	3.0	0.9	78.7	82.9
SAGD	*14.7*	*18.2*	*1.1*	*1.2*	*75.0*	*60.6*
CSS	*2.5*	*4.7*	*0.3*	*1.9*	*101.2*	*53.5*
Primary/EOR	*5.8*	*3.3*	*0.2*	*0.6*	*37.9*	*65.7*
EHT	*14.8*	*9.6*	*1.4*	*0.6*	*94.5*	*145.8*
Upgrading (SCO)	14.1	12.6	0.9	0.9	60.8	68.0

Source: CERI

Table 4.2 shows the cumulative percentage change in production, energy use and emissions by scenario compared to the BAU case.

The results indicate that under a constrained growth (CG) scenario, with cumulative oil sands production volumes 32.8 percent lower between 2015 and 2050 compared to the BAU, cumulative energy use decreases by 32.0 percent, and subsequently, a decrease of 31.7 percent in cumulative GHG emissions is observed.

Table 4.2: Cumulative (2015-2050) Oil Sands Production Volumes, Energy Used, GHG Emissions, and Intensity Factors Under Different Scenarios

Scenario	Production		Energy Used			GHG Emissions		
	Production (billion bbl)	Difference from BAU (%)	Energy used (billion GJ)	Difference from BAU (%)	% chg. Energy/% chg. Prod.	Emissions (billion tCO2 eq.)	Difference from BAU (%)	% chg. Emissions/% chg. Energy
BAU	52.4	0%	66	0%	n/a	4.2	0%	n/a
CG	35.2	-33%	45	-32%	1	2.9	-32%	1.0
IEE	52.4	0%	47	-30%	n/a	3.0	-29%	1.0
DRQ	52.4	0%	97	46%	n/a	6.1	44%	1.0
EHTA-Low	52.4	0%	63	-6%	n/a	4.4	4%	0.6
EHTA-High	52.4	0%	59	-11%	n/a	4.6	8%	0.7

Source: CERI

In the context of the different scenarios, the CG scenario illustrates that a 1.0 percent change in production levels (compared to the BAU scenario) results in a 0.98 percent change in energy use and 0.99 percent change in GHG emissions. In this scenario, the main variable that changes is the production levels. Meanwhile, the energy intensity, as well as the fuel mix, is assumed the same as in the BAU case.

In the remaining four scenarios, the production volumes are the same as in the BAU case, but different levels of energy intensity are tested (as in the IEE and DRQ scenarios) as well as the potential for adoption of new production technologies, at different levels, by the oil sands (as in the EHTA-low and EHTA-high scenarios).

In the IEE scenario, increasing energy efficiency results in a 29.5 percent decrease in cumulative energy used compared to the BAU scenario, and subsequently, a 28.7 percent decrease in cumulative GHG emissions. These results are very similar to those obtained in the CG scenario.

In the DRQ scenario, decreasing reservoir quality results in an increase of 46.0 percent in cumulative energy use, and subsequently, a 44.2 percent increase in cumulative GHG emissions compared to the BAU case.

In the EHTA-low adoption rate case, while overall energy use decreases by 5.8 percent compared to the BAU scenario, cumulative GHG emissions actually increase in net by 3.6 percent compared to the BAU scenario.

In the EHTA-high adoption case, a similar trend is observed, with cumulative energy use decreasing by 11.0 percent and cumulative GHG emissions increasing by 8.1 percent compared to the BAU case.

As can be observed in Table 4.3, the largest two components in terms of energy use are thermal energy and hydrogen feedstock, both for which natural gas is the main fuel.

However, in the EHTA cases, while thermal energy remains the largest component of energy use, hydrogen is replaced by electricity as the second largest energy component.

In these scenarios, thermal energy is replaced with electricity in a large cross-section of in situ projects, but as can be observed, given the different intensity factors and the production mix in the oil sands industry, electrical energy does not replace thermal energy on a one-to-one basis.

Table 4.3: Cumulative Energy Use and GHG Emissions by Scenario and by Type of Energy Used

	Cumulative Energy Use (EJ) (2015 -2050)					
	BAU	CG	IEE	DRQ	EHTA - LOW	EHTA - HIGH
Thermal Energy	54.6	35.5	38.5	81.5	46.3	38.4
Hydrogen Feedstock	4.8	4.2	3.6	6.7	4.8	4.8
Electricity	4.0	2.8	3.0	5.4	8.2	12.5
Diesel	2.9	2.5	1.6	3.2	2.9	2.9
Total	**66.3**	**45.0**	**46.7**	**96.8**	**62.2**	**58.6**

	Cumulative GHG Emissions (Gt CO2 eq.) (2015 -2050)					
	BAU	CG	IEE	DRQ	EHTA - LOW	EHTA - HIGH
Thermal Energy	3.2	2.1	2.3	4.7	2.7	2.3
Hydrogen Feedstock	0.2	0.2	0.2	0.3	0.2	0.2
Electricity	0.6	0.4	0.4	0.8	1.2	1.8
Diesel	0.2	0.2	0.1	0.2	0.2	0.2
Total	**4.2**	**2.9**	**3.0**	**6.1**	**4.4**	**4.6**

Source: CERI

As an example, in the EHTA-low case, thermal energy demand decreases by 8.3 exajoules (EJ) compared to the BAU case, but electrical energy use increases by 4.2 EJ, resulting in a net decrease in energy use by moving from the BAU to the EHTA-low scenario, of 4.0 EJ. The same logic can be applied to the EHTA-high scenario, which in turn results in a net decrease in energy use of 7.6 EJ.

The energy quantified here is end-use energy and therefore a GJ of electricity requires more than a GJ of fuel to be produced. The electricity intensity used in the EHTA scenarios is 180 kWh/bbl of bitumen, which in end-use energy terms is equivalent to 0.65 GJ/bbl. However, at an efficiency of 57 percent, a combined-cycle gas turbine (CCGT) would require 1.14 GJ of natural gas per barrel of bitumen, which is equivalent to the amount of gas used at a thermal in situ project with a steam to oil ratio of 2.78. CERI estimates indicate that for electric technologies to result in a one-to-one replacement ratio with thermal energy, the intensity needs to be around 158.3 kWh/bbl.[1] This indicates that an intensity factor above 158.3 kWh/bbl requires more than 1 GJ of fuel to replace a GJ of thermal energy.

A key finding is that thermal energy and electricity combined account for between 80 percent and 90 percent of energy use and GHG emissions across the different scenarios. While natural gas is expected to remain the primary fuel for meeting these energy requirements for the industry, it is important to understand and examine the potential for GHG emissions reductions from the perspective of a different fuel mix.

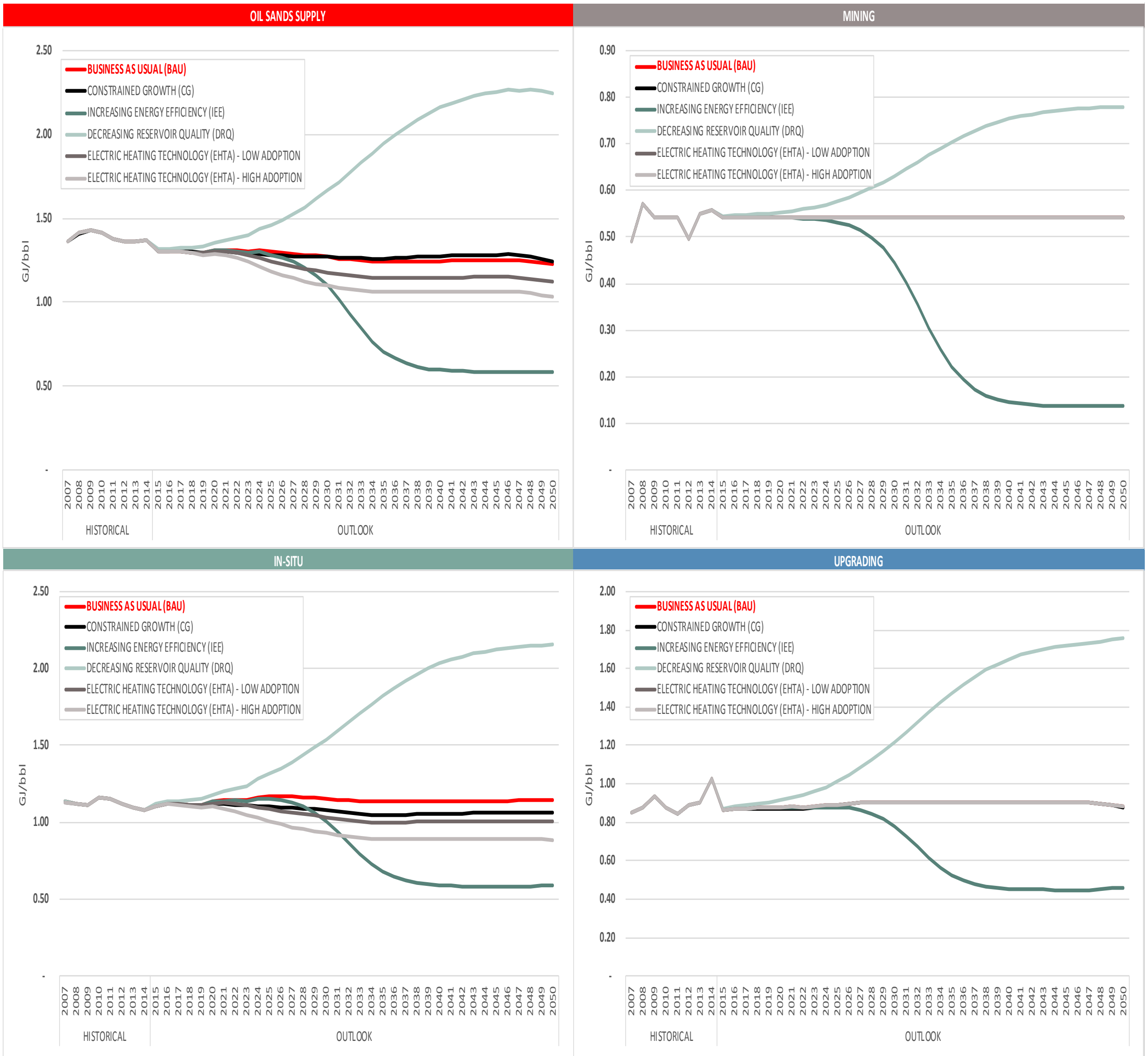
Total Energy Demand Outlook

The outlook for demand and GHG emissions changes over the 2015-2050 period. These changes are influenced by the production forecast, the change in intensity over time and the rate of adoption of electric heating technologies.

Figure 4.1 breaks down the change in energy intensities over time by production method. The pattern is similar across all production types for the same scenario. The largest changes occur in the IEE scenario where we observe the largest increase in energy efficiency; the largest decrease in net energy efficiency occurs in the DRQ scenario.

[1] 1GJ of thermal energy/natural gas per barrel of bitumen is equivalent to: (1 GJ NG/bbl) x (0.57 GJ electricity/1 GJ of NG (CCGT)) x (1 MWh/3.6 GJ of electrical energy) x (1,000 kWh/1 MWh) = 158.3 kW/h/bbl

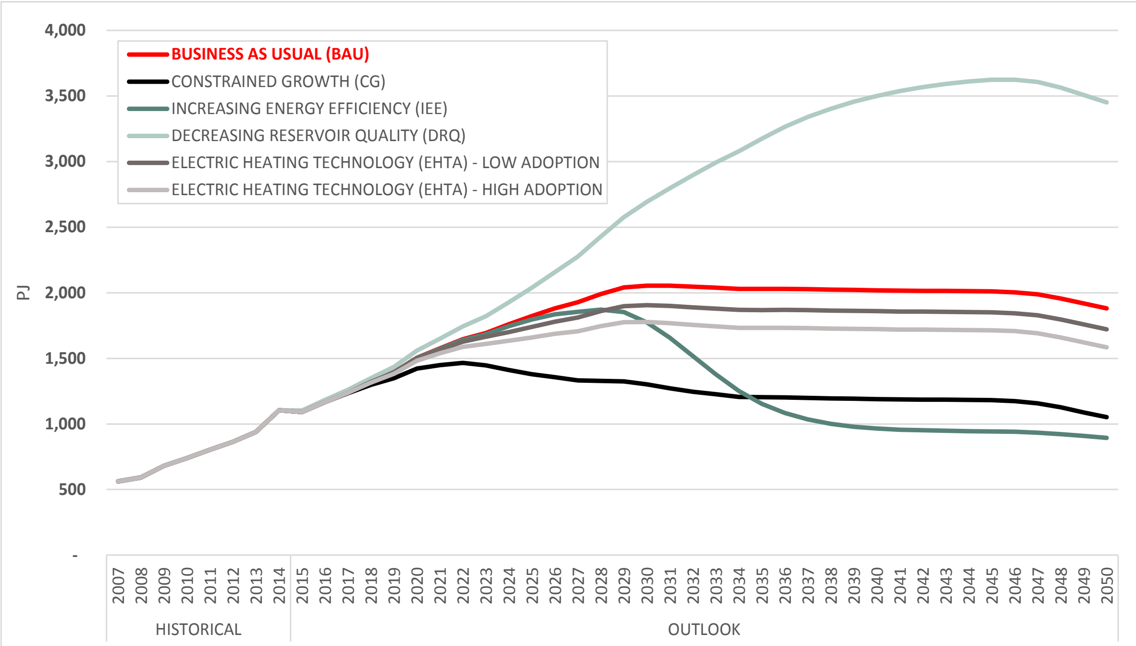
Figure 4.1: Oil Sands Total Energy Intensity by Scenario and by Production Method (GJ/bbl), 2007-2050



Source: CERI

Based on the change in intensity over time, Figure 4.2 shows the total energy demand by scenario from 2007 to 2050. By 2050, the demand for energy increases by 1,650 PJ per year for the DRQ scenario compared to BAU, the largest increase. The largest decrease is for the IEE scenario where the total demand drops by 1,000 PJ per year compared to BAU.

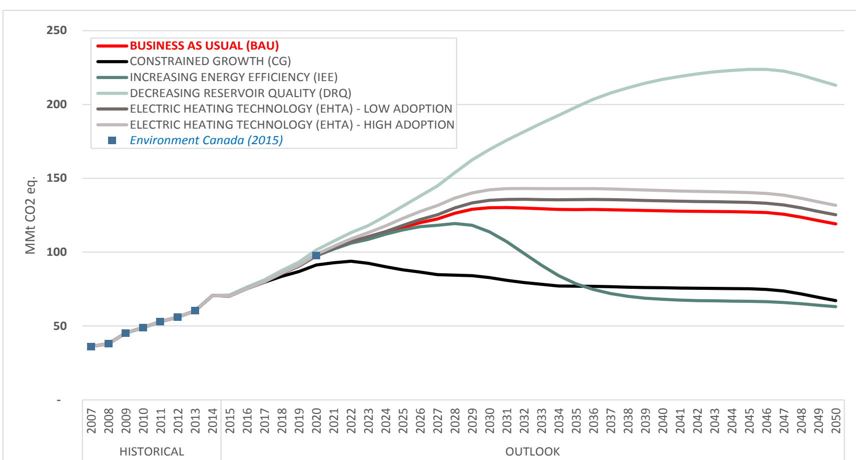
Figure 4.2: Oil Sands Total Energy Demand by Scenario (PJ), 2007-2050



Source: CERI

The change in GHG emissions is shown in Figure 4.3. This follows the same pattern as total energy demand. By 2050, GHG emissions increase by about 100 MMt CO_2 eq. per year for the DRQ scenario compared to the BAU, the largest increase. The largest decrease is for the IEE scenario where total emissions drop by 60 MMt CO_2 eq. per year compared to the BAU.

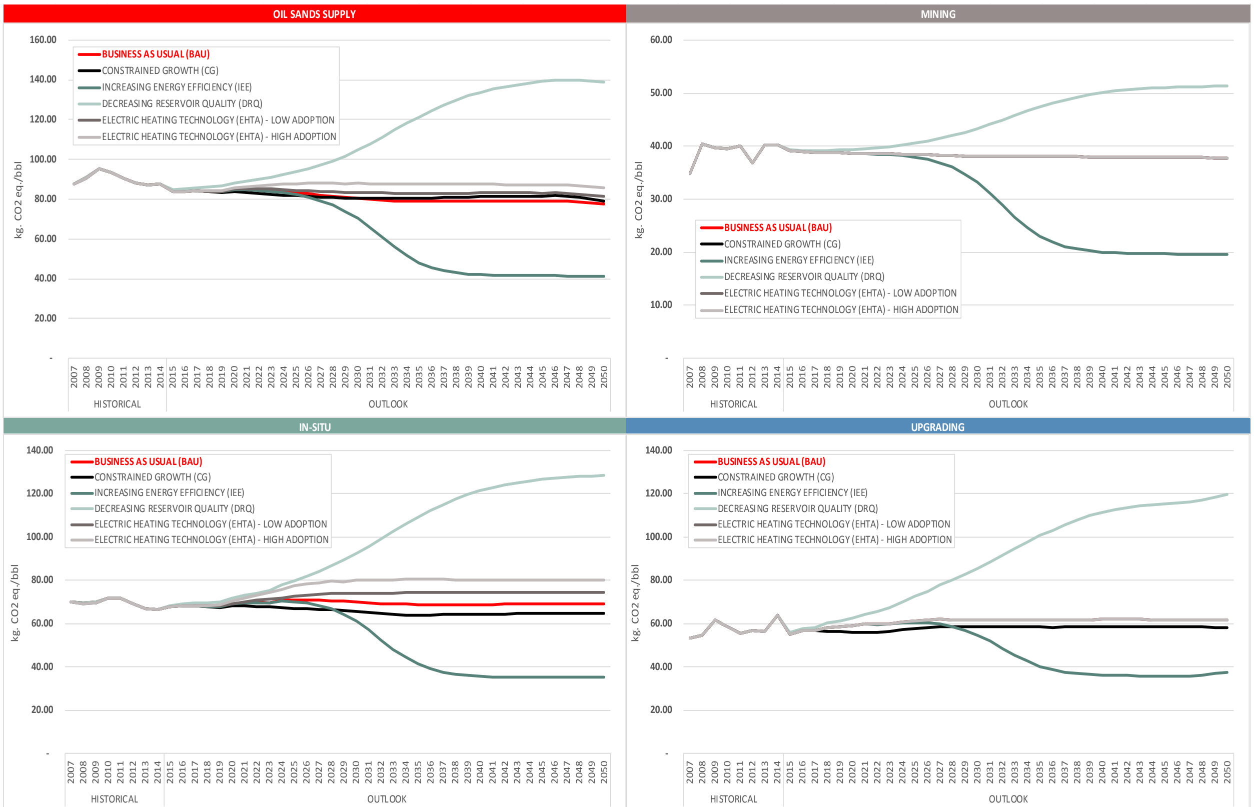
Figure 4.3: Oil Sands GHG Emissions by Scenario (MMt CO_2 eq.), 2007-2050



Source: CERI

Figure 4.4 disaggregates the GHG emissions by production method. In all cases, the DRQ scenario results in the highest emissions and the IEE scenario, the lowest emissions by 2050.

Figure 4.4: Oil Sands GHG Emissions Intensity by Scenario and by Production Method (kg. CO_2 eq./bbl), 2007-2050



Source: CERI

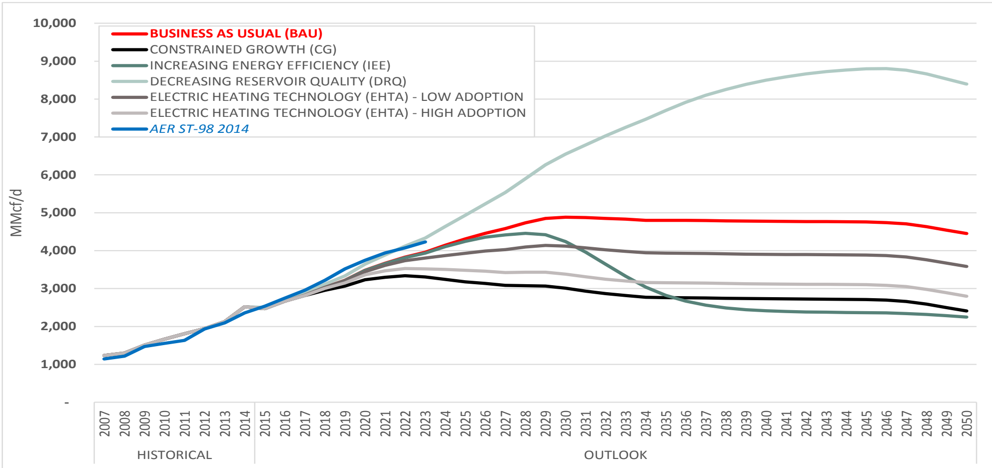
Further disaggregation of energy demand is documented below to provide a context for the total energy demand and associated GHG emissions.

Gas Demand Outlook

Figures 4.5 and 4.6 display the same pattern. The DRQ scenario shows the largest increase in gas demand and external gas purchases. This is a direct result of the increased energy use per barrel of production. By 2050, this scenario suggests the oil sands industry will require 3,900 MMcf/d of additional gas demand and 3,400 MMcf/d of additional external gas purchases respectively relative to the BAU.

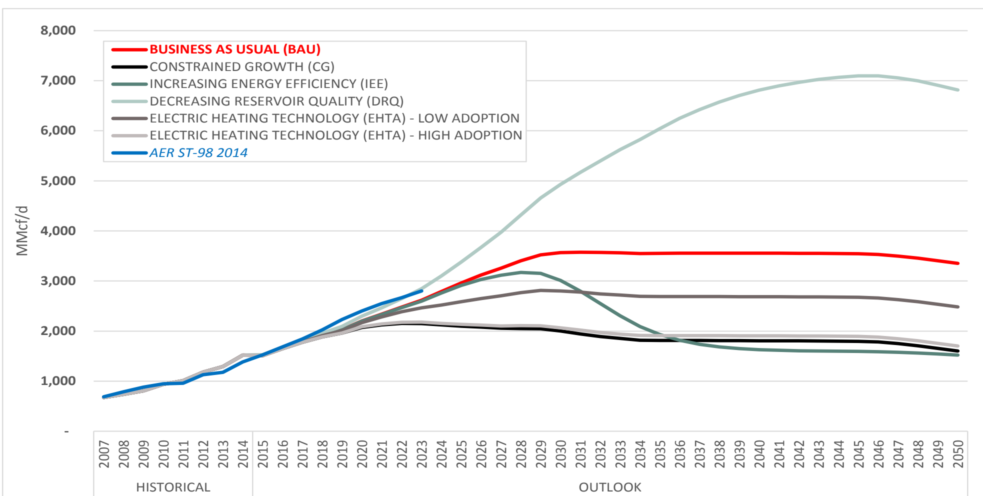
The IEE scenario shows the largest decrease in gas demand and external gas purchases. This is opposite to the DRQ scenario. In the IEE case, by 2050, the oil sands industry will require 2,200 MMcf/d less gas demand and 1,900 MMcf/d less external gas purchases respectively relative to the BAU.

Figure 4.5: Oil Sands Gas Demand by Scenario (MMcf/d), 2007-2050



Source: AER, CERI

Figure 4.6: Oil Sands Required External Natural Gas Purchases by Scenario (MMcf/d) 2007-2050



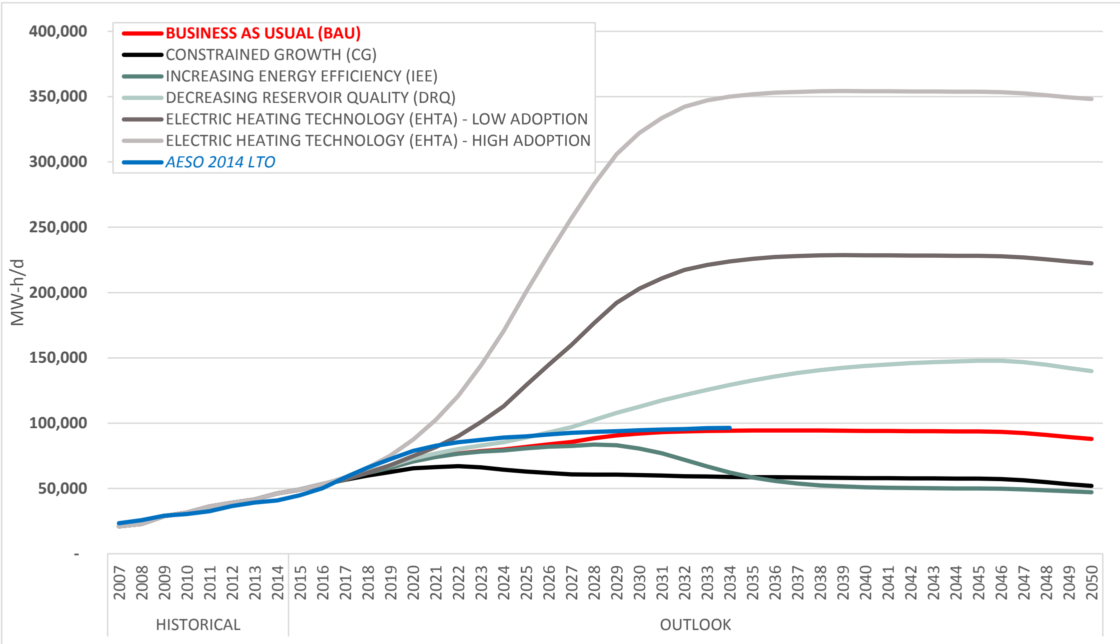
Source: AER, CERI

Electricity Demand Outlook

Figure 4.7 displays a different result for electricity use in the oil sands. The EHTA – High Adoption scenario shows the largest increase in electricity demand. This is a direct result of the increased market share of electricity technologies. By 2050, this scenario suggests the oil sands industry will require an additional 260,000 MWh per day relative to the BAU.

The IEE scenario shows the largest decrease in electricity use. By 2050, the oil sands industry demand will drop by approximately 45,000 MWh per day relative to the BAU.

Figure 4.7: Oil Sands Electricity Demand by Scenario (MWh/d), 2007-2050



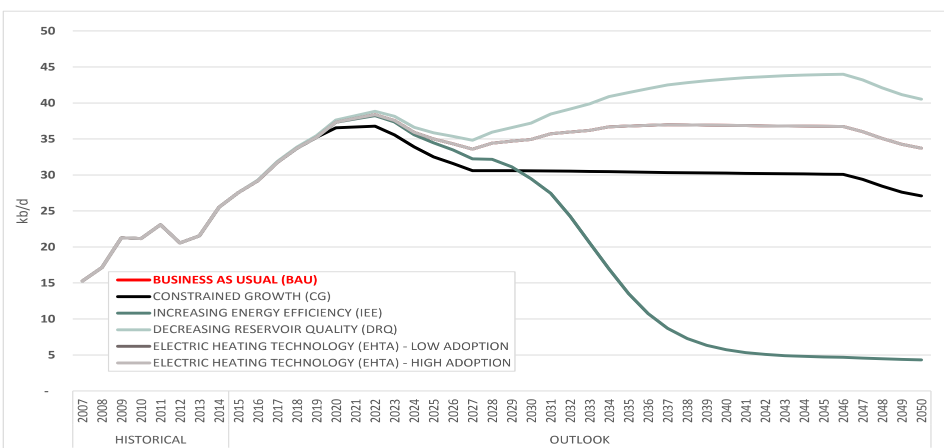
Source: AER, CERI

Diesel Fuel Demand Outlook

Figure 4.8 displays the diesel fuel demand in the oil sands. The DRQ scenario shows the largest increase in diesel fuel. By 2050, this scenario suggests the oil sands industry will require an additional 6 kb/d relative to the BAU.

The IEE scenario shows the largest decrease in electricity use. By 2050, the oil sands industry demand will drop by approximately 30 kb/d relative to the BAU.

Figure 4.8: Oil Sands Diesel Fuel Demand by Scenario (kb/d), 2007-2050



Source: AER, CERI

Future Considerations

Regardless of the choices made, there are bound to be tradeoffs between production levels (and the associated economic activity), energy use, and GHG emissions from the oil sands industry. The examination of tradeoffs must take into account the costs associated with energy options, infrastructure costs, and the cost to reduce GHG emissions.

Cost and cost effectiveness are important considerations surrounding an industry that contributes significantly to the national economy. The oil sands industry is a major energy user and as such, the management of GHG emissions has come to be a substantial environmental challenge. Understanding the production and demand of oil from the oil sands, from a technical and economic perspective, in an objective manner, is paramount, as decision makers make use of this information to address this challenge.

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