A Greenhouse Gas Reduction Roadmap for Oil Sands

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A Greenhouse Gas Reduction Roadmap for Oil Sands

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Table of Contents

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Executive Summary

SUNCOR ENERGY JACOBS Consultancy

Executive Summary

Suncor Energy Services Inc. (Suncor), with funding from the Climate Change Emissions Management Corporation (CCEMC) and support from Alberta Innovates - Energy and Environment Solutions, teamed with Jacobs Consultancy Canada Inc. (Jacobs Consultancy) to complete an Oil Sands Energy Efficiency and Greenhouse Gas (GHG) Emissions Roadmap Study.

The primary objective of the Study was to identify, assess, and quantify energy efficiency and GHG reduction opportunities for commercial oil sands operations and determine their potential impact on the GHG intensity of fuels refined from oil sands derived bitumen. The facilities evaluated in this Study include In Situ bitumen production, mining and extraction, and upgrading. Energy efficiency and GHG reduction opportunities included operational improvements, capital investment projects, and technology advancement opportunities. The improvement opportunities were identified based on detailed review of each processing step by Suncor technical specialists and key operations staff together with industry specialists from Jacobs Consultancy.

Improvement ideas were screened and top ideas were evaluated using a combination of plant operating data and simulation models. To determine the impact of improvement projects on total GHG emissions, a life cycle analysis (LCA) was conducted to demonstrate how the identified energy improvements affect the GHG emissions on a well-to-wheels basis for fuels derived from oil sands-based crude oils.

This Study provides a high-level evaluation of GHG reduction opportunities for crude oil production from oil sands, including a preliminary evaluation of the economics and a qualitative assessment of the risks of their implementation. While some of the opportunities evaluated had sufficient detail to advance them toward implementation, most of the opportunities identified in this Study will require more detailed techno-economic evaluation before implementation. Therefore, while efforts were made to quantify benefits, the information in this report provides a foundation and direction for future work to improve the energy efficiency of oil sands operations and reduce their GHG emissions.

In this Study, Suncor and Jacobs Consultancy (the Study Team) used the Suncor Firebag production site to represent a typical in situ facility. The Suncor Millennium mine and base plant extraction facility represented typical mining and extraction facilities. Suncor’s Upgrader No. 2 represented typical upgrading facilities.

The intended audience for this Study is key stakeholders, policymakers, regulators, and industry peers. The major findings of the Study are as follows:

Energy Efficiency Potential for Oil Sands Operations

Implementation of economically viable operational and capital projects can improve the energy efficiency of and reduce the GHG emissions from existing oil sands operations. In addition, potential technology developments for improving energy efficiency over a timeframe greater than 10 years offer significant opportunity to close the GHG intensity gap between crude oils derived from bitumen and heavy crude oils produced outside of Alberta.

Improvement ideas evaluated in the Study were categorized as follows:

1. **Operational Improvements—**Opportunities mostly based on procedural modifications that do not require significant capital to implement.
2. **Project Improvements—**Opportunities that require capital and have to go through a corporate capital projects stage-gate opportunity evaluation, development, and execution process.
3. **Technology Improvements—**Opportunities that relate to the selection of the major technology used for each step of the bitumen production process. Some of the ideas may be known technologies that would be good to consider when building a new plant, or they may be ideas of new technologies that have been developed but have not yet been fully commercialized. Finally, technology ideas could be solutions developed to fill gaps that exist with the known technologies.

Estimated energy efficiency improvement and GHG intensity reduction for crude oil production from oil sands projects and technologies are summarized in Table ES-1.

Table ES-1.
Impact of Projects and Technology on Reducing GHG Emissions from Crude Oil Production from Oil Sands

	Percent GHG Reduction			GHG Reduction per 100 KBbl of Bitumen			Timing - Uncertainty
	In Situ	Mining and Extraction	Upgrading	In Situ	Mining and Extraction	Upgrading	
				MT CO_2/ 100k bbl bit	MT CO_2/ 100k bbl bit	MT CO_2/ 100k bbl bit	
Operational Improvements	3%	2%	2%	310	70	80	-Near term (1-3 years) -low risk
Project Improvements	9%	5%	6%	900	170	220	-Mid term (3-5 years) -moderate risk
Technology Improvements	20%	30%	10%	1820	980	350	-Long term (10+ years) -higher risk

Note: The improvements are relative to a baseline GHG intensity of each area.

Technology developments for improving energy efficiency offer the most significant potential to close the GHG intensity gap between crude oils derived from bitumen and heavy crude oils produced outside of Alberta.

Carbon capture and storage (CCS) offers additional significant GHG reduction potential. However, due to the high capital and operating cost of CCS it is not expected to be economic in the near to midterm.

Development of Energy Metrics for Benchmarking

A preliminary set of energy consumption metrics was developed to show the relative energy consumed in each processing step. These values were created to develop more detailed energy monitoring metrics for bitumen production facilities. Two levels of metrics were created:

- Primary metrics provide a basis to compare energy consumed in each facility as a function of bitumen produced.

- Secondary metrics use the individual utilities for each facility to better identify where opportunities for improvement exist.

The metrics were applied to one year of operating data for the typical facilities used in the Study. Table ES-2 is a summary of the values for the primary metrics. Values for the secondary metrics are presented in the report.

Table ES-2.
Summary of Potential Primary Metrics

	In Situ	Mining and Extraction	Upgrading*
Primary Metric, GJ energy / m^3 bitumen	8.6	1.7	2.7

*The metric for upgrading is highly dependent on the amount of product hydrotreated; development of a general metric for upgrading must account for extent of hydrotreating.

These metrics could potentially be used to benchmark the energy efficiency of other oil sands producers and establish a foundation for energy efficiency evaluation for oil sands production facilities. However, further validation is needed from a broader section of the industry before these metrics can be used to establish energy efficiency benchmarks for the industry.

Energy Efficiency Potential from Integrated Facilities

Another way to reduce the GHG intensity of crude oil production from oil sands is to integrate production facilities with co-generation and/or use low-grade waste heat from upgrading for extraction of mined bitumen. Integration with other facilities and use of low-level waste heat can reduce energy consumption and GHG emissions. Currently most existing facilities have some level of integration that reduces GHG emissions and improves energy efficiency; thus, maximizing these opportunities is a key component in an efficiently designed facility.

Technology Roadmaps

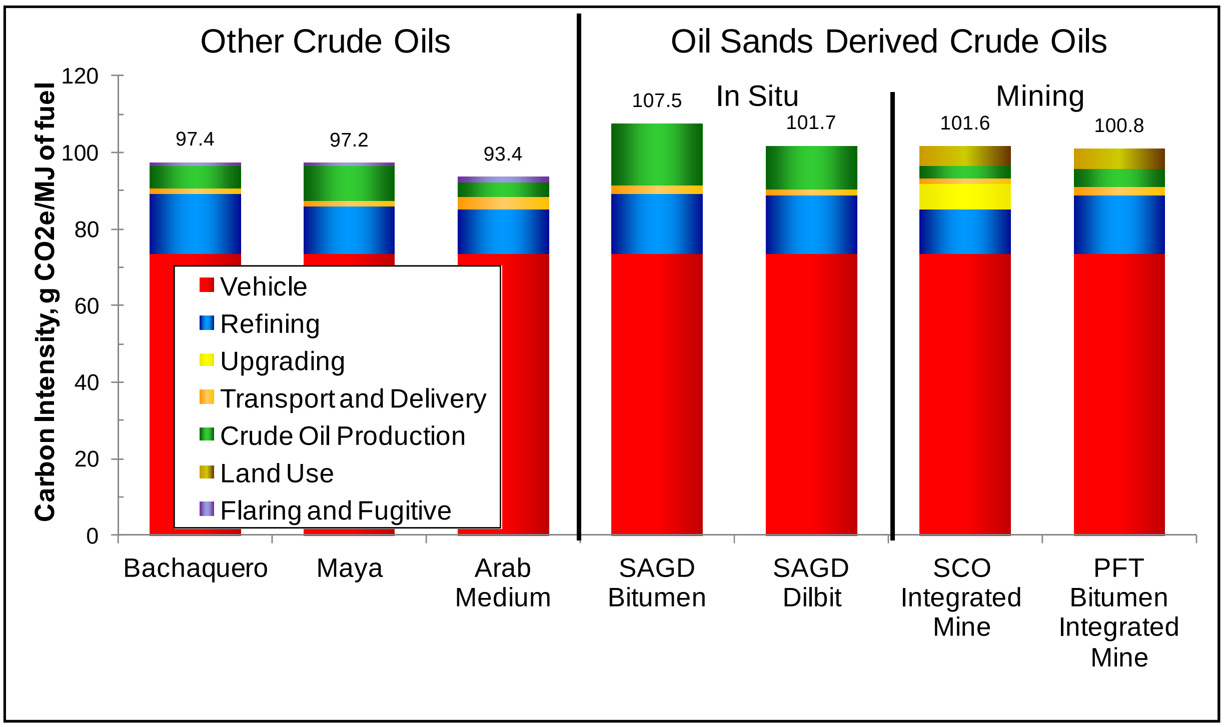
Individual Energy Efficiency GHG Reduction Roadmaps were developed for In Situ Production, Mining and Extraction, and Upgrading which show the amount of CO_2 reduction per cubic metre of bitumen produced vs. CO_2 pricing through operational, project and technology improvements. The timing and risks of potential reductions are summarized in Section 9 of this report. The roadmaps show the high impact of technology improvements and the need to continue investing in the development and deployment of new technologies, particularly for In Situ production, which will become the major source of future bitumen production.

Updated Well-to-Wheel Life Cycle GHG Assessment

Results from this Study were used to update the well-to-wheels (WTW) carbon intensities (CI) of gasoline and diesel from oil sands-derived crude oils reported in the AERI Study published in 2009.

Figure ES-1 compares the WTW carbon intensity of gasoline from bitumen-derived crude oils with several of the crude oils from the AERI Study (i.e., Bachaquero from Venezuela, Maya from Mexico, and Arab Medium from Saudi Arabia).

Figure ES-1.
LCA Baseline Summary—Gasoline



Notes for Figure ES-1:

- The AERI Study results used here reflect the methodology from the recent study by Jacobs Consultancy for the Alberta Petroleum Marketing Commission titled *EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context* published in 2012.
- The AERI Study and the EU Pathway Study results are based on somewhat different energy and GHG emissions for producing bitumen and SCO than shown here, which are from the typical production facilities used in the Study.
- The refinery location for the AERI Study and for this Study is PADD II. It is PADD III for the EU Pathway Study.

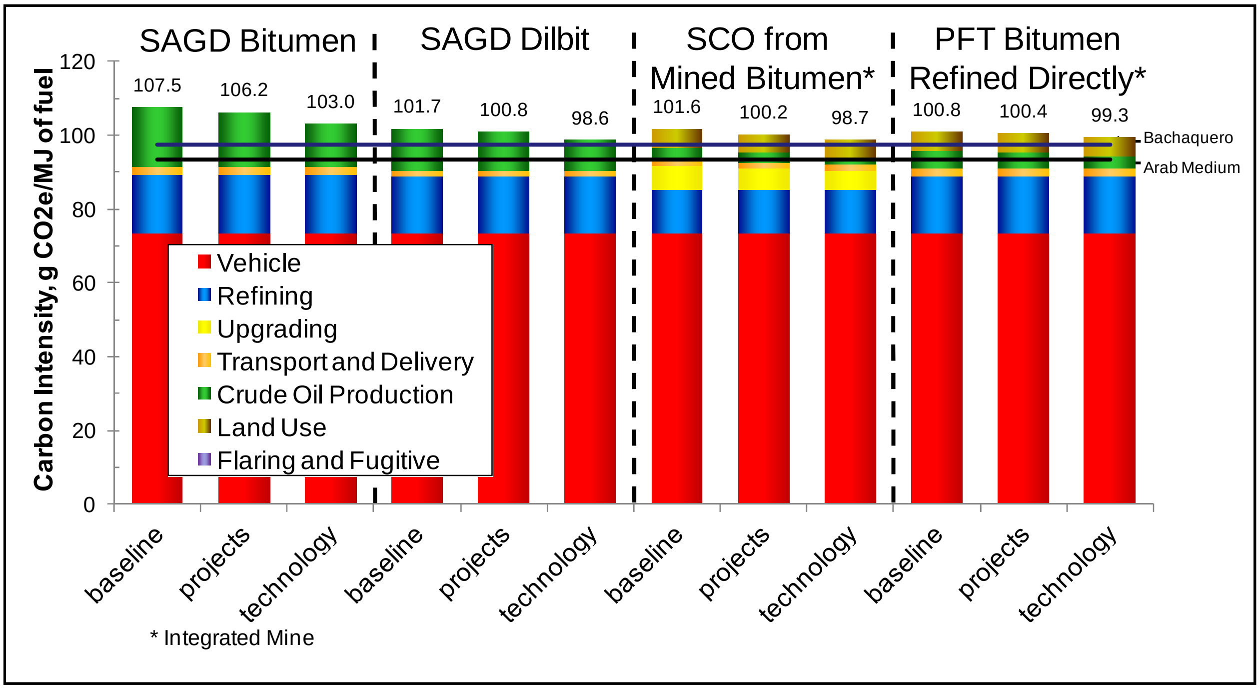
- The vehicle emissions for the AERI Study and for this Study are based on US type of vehicles. In the EU Pathway Study, the vehicle emissions are based on EU type of vehicles.
- Other changes to the results shown here and those in the AERI Study since its 2009 publication include updating emission factors and energy consumption.
- Thus the results for the AERI Study reported here will be somewhat different than those reported in the 2009 report. Also, because the pathways are different, the results shown here will be somewhat different than the EU Pathway Study published in 2012.
- Labels
  - Bachaquero, Maya, and Arab Medium crude oils are representative of non-Alberta crude oils used in the AERI Study
  - SAGD Bitumen—Bitumen produced by the typical In Situ SAGD facility in this Study, transported to a US PADD II refinery with diluent return to Alberta
  - SAGD Dilbit—Bitumen from the typical SAGD facility of the Study refined with diluent in a PADD II refinery
  - SCO-Integrated Mine—Refining of SCO produced from a coking-based Upgrader processing bitumen from a mining operation that uses hot water generated from low-level waste heat from either the Upgrader or from on-site power generation
  - PFT-Bitumen Integrated Mine—Direct refining of bitumen produced in an integrated mine that uses paraffin froth treatment; hot water is generated using low-level waste heat from on-site power generation or another source

In Figure ES-1, the differences in gasoline carbon intensity (CI) from oil sands-derived crude oils in this Study and gasoline from Bachaquero and Arab Medium crude oils are as follows:

- Gasoline from SAGD bitumen has a CI 10% higher than gasoline from Bachaquero and 15% higher than gasoline from Arab Medium
- Gasoline from SAGD Dilbit has a CI 4% higher than gasoline from Bachaquero and 9% higher than gasoline from Arab Medium
- Gasoline from SCO from mined bitumen has a CI 4% higher than gasoline from Bachaquero and 9% higher than gasoline from Arab Medium
- Gasoline from PFT bitumen refined directly has a CI 4% higher than gasoline from Bachaquero and 8% higher than gasoline from Arab Medium

Implementation of energy efficiency projects and new technologies to reduce energy consumption and GHG emissions can close the CI gap to Bachaquero and Arab Medium crude oils. Figure ES-2 shows the impact of projects and technology options on reducing the WTW CI of gasoline produced from oil sands crude oils. The upper line in the horizontal band in Figure ES-2 shows the CI for gasoline from Bachaquero. The lower line in this band is the CI for gasoline from Arab Medium.

Figure ES-2.
Impact of Energy Efficiency Improvement on WTW CI of Gasoline



Notes for Figure ES-2:

- Baseline—Base case operation of In Situ SAGD, Mining and Extraction, and Upgrading
- Projects—Implementation of projects to reduce energy and GHG emissions from bitumen production
- Technology—Implementation of technology to reduce energy and GHG emissions from bitumen production

The impact of projects and technology on reducing the CI of gasoline from oil sands-derived crude oils from Figure ES-2 is summarized in Table ES-3. For example, implementation of energy efficiency projects can reduce the CI for gasoline from bitumen produced from SAGD by 1.2 percent from the baseline. Implementation of new technologies can reduce this gap from the baseline by 4.2 percent.

Table ES-3.
Impact of Projects and Technology on Reducing Baseline Gasoline WTW CI

Crude Oil for Producing Gasoline	WTW CI Reduction from Baseline	
	Projects	Technology
SAGD Bitumen	-1.2%	-4.2%
SAGD Dilbit	-0.9%	-8.3%
SCO from Integrated Mining & Extraction	-1.4%	-8.2%
PFT Bitumen Refined Directly	-0.5%	-7.6%

Conclusions and Recommendations

- Energy efficiency improvements offer the potential for a significant reduction in GHG emissions from producing bitumen-derived fuels. Additionally, while it is believed that investment returns for some energy efficiency projects can be challenging, particularly given current historical low natural gas prices, they will likely exceed returns on CCS at current prices for avoided CO_2.
- Integrating co-generation plants with new bitumen production facilities can reduce energy use and GHG emissions and has the potential to reduce well-to-tank (WTT) GHG intensity of producing gasoline and diesel by up to 5% versus a separate Natural Gas Combined Cycle (NGCC) and a separate natural gas boiler.
- Integrating low-level waste heat sources from Upgraders or on-site power generation with Mining and Extraction can reduce the GHG intensity of bitumen extraction by 30-50% over stand-alone Mining and Extraction that uses natural gas to generate hot water for extraction. It is important to note that most existing Mining and Extraction facilities already have a high degree of integration to use low level waste heat.
- Technology developments for improving energy efficiency offer significant potential to close the GHG intensity gap between crude oils derived from bitumen and heavy crude oils produced outside of Alberta.
- Upgrading and then refining bitumen to finished products versus processing the bitumen directly in a refinery to finished products increases the GHG intensity 8-10% on a well-to-tank basis.
- A well-to-wheels (WTW) life cycle assessment of energy inputs to producing finished products and GHG emissions from producing these products is needed to evaluate and compare pathways for producing crude oils from oil sands.

Acknowledgements

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Section 1.

Introduction

Introduction

Crude oil is produced from the oil sands region of Alberta either by in situ methods or by mining and extraction of bitumen from oil sands ore. Crude oil produced by in situ methods is generally diluted with lower gravity material such as naphtha and sent to crude oil refineries to be refined into gasoline, diesel, and other products. Crude oil from mining is generally first upgraded into synthetic crude oil (SCO) before it is refined into gasoline, diesel, and other products. Relative to other methods of producing crude oil, the energy intensity and the GHG emission intensity of producing crude oil from oil sands in Alberta tends to be somewhat higher than the energy intensity to produce most other crude oils.[1,2,3,4] An objective by both the government of Alberta and the oil producers in Alberta is to reduce the energy and GHG intensity of crude oil produced from oil sands.

With funding from the Climate Change Emissions Management Corporation (CCEMC) and support from Alberta Innovates - Energy and Environment Solutions, Suncor Energy Services Inc. (Suncor) engaged Jacobs Consultancy Canada Inc. (Jacobs Consultancy) to identify, assess, quantify, and report on the range of GHG reduction opportunities for oil sands operations resulting from energy efficiency improvements and technologies (the Study). The Study objectives were as follows:

- Develop a set of metrics for measuring efficiency improvement that can be used to evaluate energy consumption and GHG emissions for crude oil production from other oil sands production facilities.
- Evaluate the energy consumption and greenhouse gas emissions for crude oil production from typical in situ, mining and extraction, and upgrading facilities.
- Determine the impact of energy efficiency improvements and new technologies on reducing the GHG emissions from typical bitumen production facilities.

In this Study, Suncor and Jacobs Consultancy (the Study Team) used the Suncor Firebag production site to represent a typical in situ facility. The Suncor Millennium mine and base plant extraction facility represented typical mining and extraction facilities. Suncor's Upgrader No. 2 represented typical upgrading facilities.

This Study provides a high-level evaluation of energy and GHG emission reduction options for crude oil production from oil sands and a preliminary evaluation of their economics, a qualitative assessment of their risk, and a timeline for their implementation. The audience for this Study is key stakeholders, policymakers, regulators, and industry peers.

Study Approach

The Study identified, assessed, and quantified energy and GHG reduction opportunities from the following two pathways for producing bitumen from oil sands:

- Pathway 1: Mining and Extraction to produce bitumen that is routed to an Upgrader that produces SCO, which is then sent to a refinery.
- Pathway 2: In Situ production of bitumen that is diluted with naphtha and sent to a refinery.

We conducted detailed reviews on the following oil sands production facilities:

- In Situ bitumen production using steam assisted gravity drainage (SAGD)
- Mining and Extraction of bitumen from oil sands ore
- Upgrading of bitumen

Study Scope

Energy consumption in the Study includes all direct and indirect energy requirements for producing crude oil from oil sands. Direct energy is consumed directly within the production facilities—for example, natural gas or associated gas used to generate steam on site or diesel fuel used on site to mine bitumen ore. Indirect energy is consumed by facilities that supply utilities to the site—for example, imported power, imported hot process water, or imported steam.

GHG emissions in the Study are based on energy consumed in producing crude oil from oil sands. The impact of GHG emissions from changes in land use, from tailing ponds, and from the mine face will be used in the Life Cycle Analysis but are not further evaluated in this Study.

Technology opportunities for energy efficiency improvement and GHG reduction, including CO_2 capture and storage (CCS), were identified, assessed, and quantified as part of the Study

Deliverables

The deliverables of this Study include:

- Analysis and modeling of the energy consumption and greenhouse gas emissions for bitumen production from oil sands facilities (supported with Suncor operating data).
- Opportunity analysis and results, including:
    - Energy savings potential,
    - GHG emission reduction potential,
    - Capital costs (+100% / -50%), and
    - Identification of potential risks.
- Detailed roadmap for staged GHG emission reduction.
- Methodology and metrics to assess and develop GHG improvement plans for similar oil sands facilities (validated with Suncor operating data).
- An update to the AERI Study well-to-wheels LCA of GHG emissions from the production of gasoline and diesel from crude oils to incorporate identified mitigation opportunities.[1]
- Recommendations for new technology development needs.

Report Organization

Our report is divided into the following sections:

- Section 1 is the Introduction to the Report
- Section 2 provides an overview of bitumen production
- Section 3 describes the methodology and basis used in the Study
- Section 4 covers the energy assessment and efficiency improvement for a typical In Situ bitumen production facility
- Section 5 covers the energy assessment and efficiency improvement opportunities for a typical bitumen Mining and Extraction facility
- Section 6 covers the energy assessment and efficiency improvement for a typical bitumen upgrading facility
- Section 7 evaluates the impact of energy integration between processing facilities

- Section 8 compares the life cycle well-to-wheels assessment of greenhouse gas emission intensity of gasoline and diesel produced from crude oils derived from oil sands with gasoline and diesel derived from other heavy crude oils
- Section 9 presents our Conclusions and Recommendations

References

1. *Life Cycle Assessment Comparison of North American and Imported Crudes,* Jacobs Consultancy for AERI, 2009
2. *EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context,* Jacobs Consultancy for the Alberta Petroleum Marketing Commission, March 2012
3. *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Righ*t, IHS CERA Inc., 2010
4. du Plessis, D. (AIEES), Buchanan, I. (Jacobs Consultancy), *CO_2 Mitigation through Energy Efficiency Improvements*, July 2010

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Section 2.

Bitumen Production

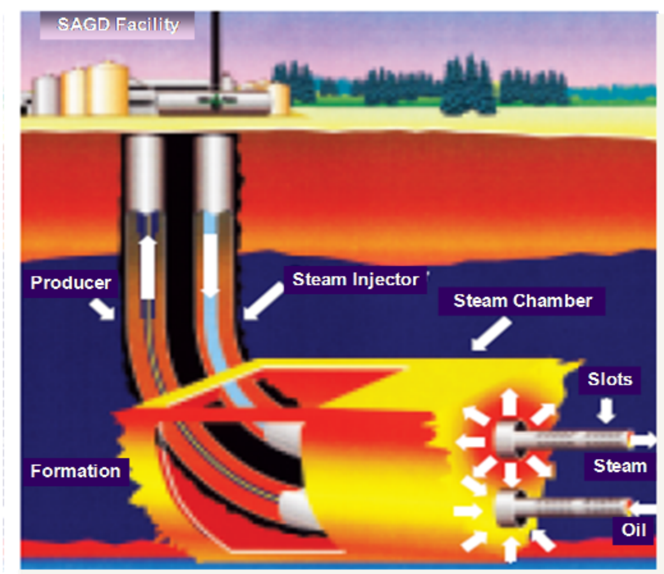
Bitumen crude oil is produced in the Alberta oil sands region using a variety of methods. The processes we examined in the Study include mining and in situ production. Some bitumen crude oil from oil sands is upgraded to synthetic crude oil (SCO) in Alberta before it is refined to gasoline, diesel, and other products in a crude oil refinery.

In Situ Production

In situ processes include thermal and non-thermal production methods. Thermal production in Alberta is by means of either cyclic steam stimulation (CSS) or steam assisted gravity drainage (SAGD). Other methods used for in situ bitumen production are Cold Heavy Oil Production with Steam (CHOPS), Polymer Flood, and Solvent Injection (which may be utilized alone or in conjunction with steam injection).

The focus of In Situ bitumen production in this Study is on SAGD because it is the most common technology in use by industry.[1] A schematic of the SAGD process is shown in Figure 2-1.

Figure 2-1.
SAGD Schematic



Bitumen production by SAGD uses steam to thermally heat the bitumen in the reservoir to reduce its viscosity and allow it to be pressurized or pumped to the surface. Bitumen together with condensed water and associated gas is sent to the surface facility, where the bitumen is separated from the water and gas. The produced water is treated and the majority is returned to the boiler to generate steam. Associated gas is treated and used with natural gas as fuel. The key parameter in determining the energy intensity of SAGD is the steam-to-oil ratio (SOR), defined as barrels of cold water used for steam production per barrel of oil produced.

Figures 2-2 and 2-3 are block flow diagrams for SAGD with and without on-site electricity generation. Cogeneration, also known as Combined Heat and Power generation, uses natural gas to produce electricity and steam. When there is no cogeneration of electricity, stand-alone boilers [usually once-through steam generators (OTSGs) or drum boilers] supply all of the steam. When there is cogeneration, some of the steam is provided using the energy contained in the power generator turbine exhaust.

Figure 2-2.
SAGD Schematic with Imported Electricity

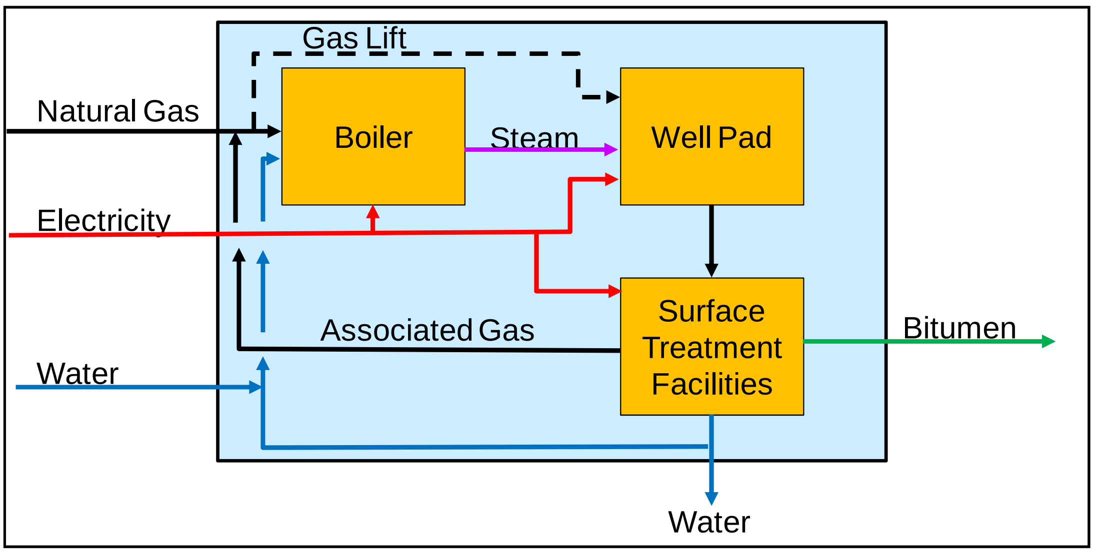
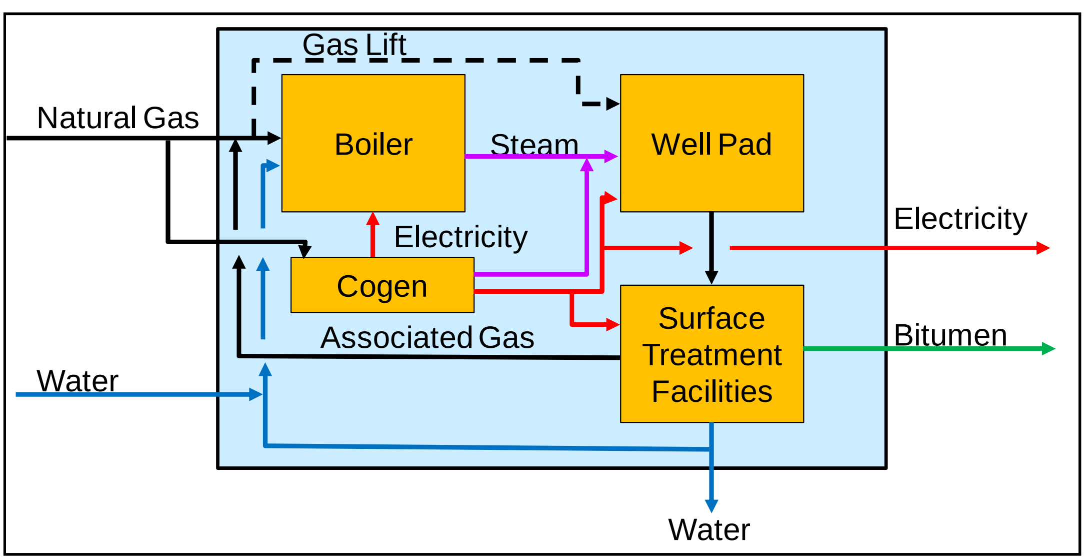


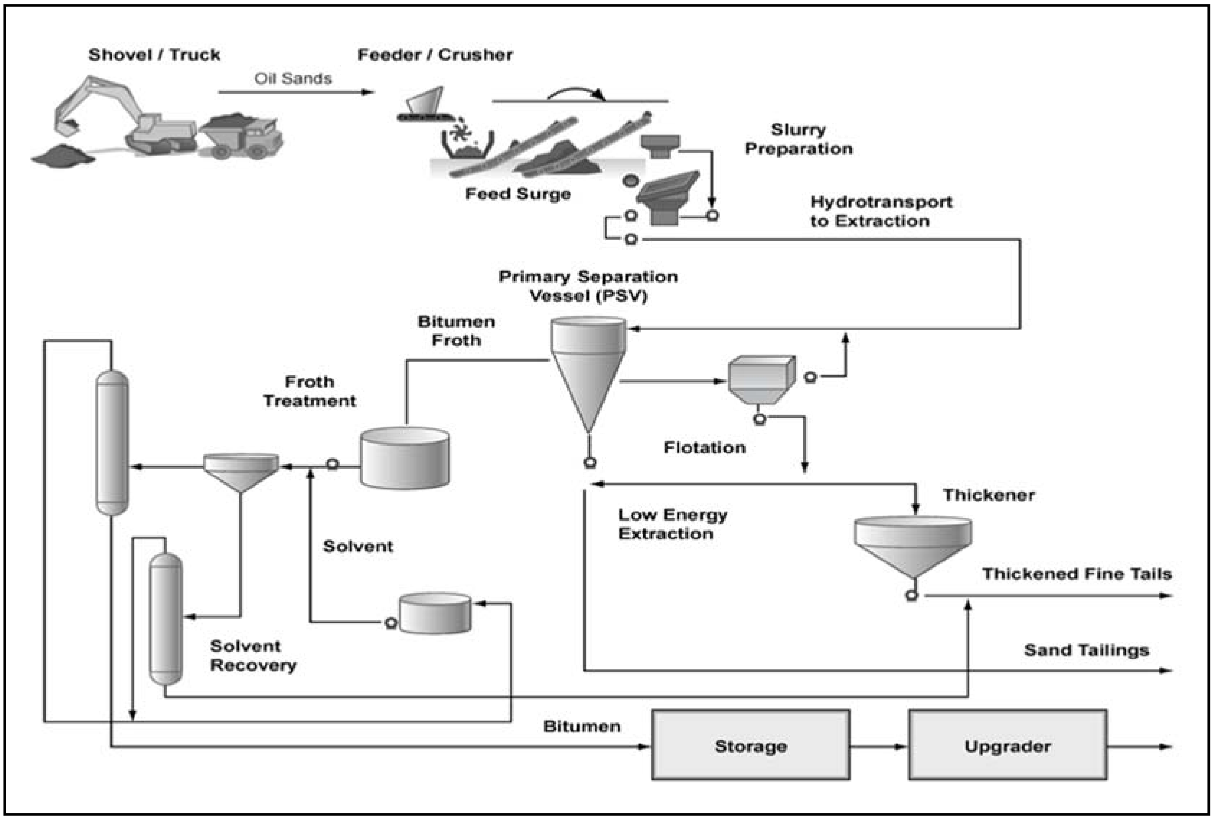
Figure 2-3.
SAGD Schematic with Cogeneration



Mining and Extraction

Oil sand surface mining is by truck and shovel. The bitumen is separated from the oil sands ore by flotation in the extraction plant and is then sent to an upgrader or refinery for further processing. Figure 2-4 depicts the flow scheme for bitumen from mining and extraction.

Figure 2-4.
Oil Sand Mining and Extraction



Surface mining of oil sand ore is applicable for reservoirs where the depth of the oil is less than 100 m below the surface. Mining begins with removal of the overburden, which consists of 1 to 3 metres of soil on top of a layer of clay and barren sand. The underlying oil sands are in a band that is typically 40 to 60 metres thick, on top of a layer of limestone rock. The oil-containing layer is removed using surface mining methods. The oil and clay particles then are sent to the extraction plant where hot water at 50-80˚C is added to the ore; the formed slurry is pumped through a hydro-transport line to a primary separation vessel where oil is recovered by flotation as bitumen froth.

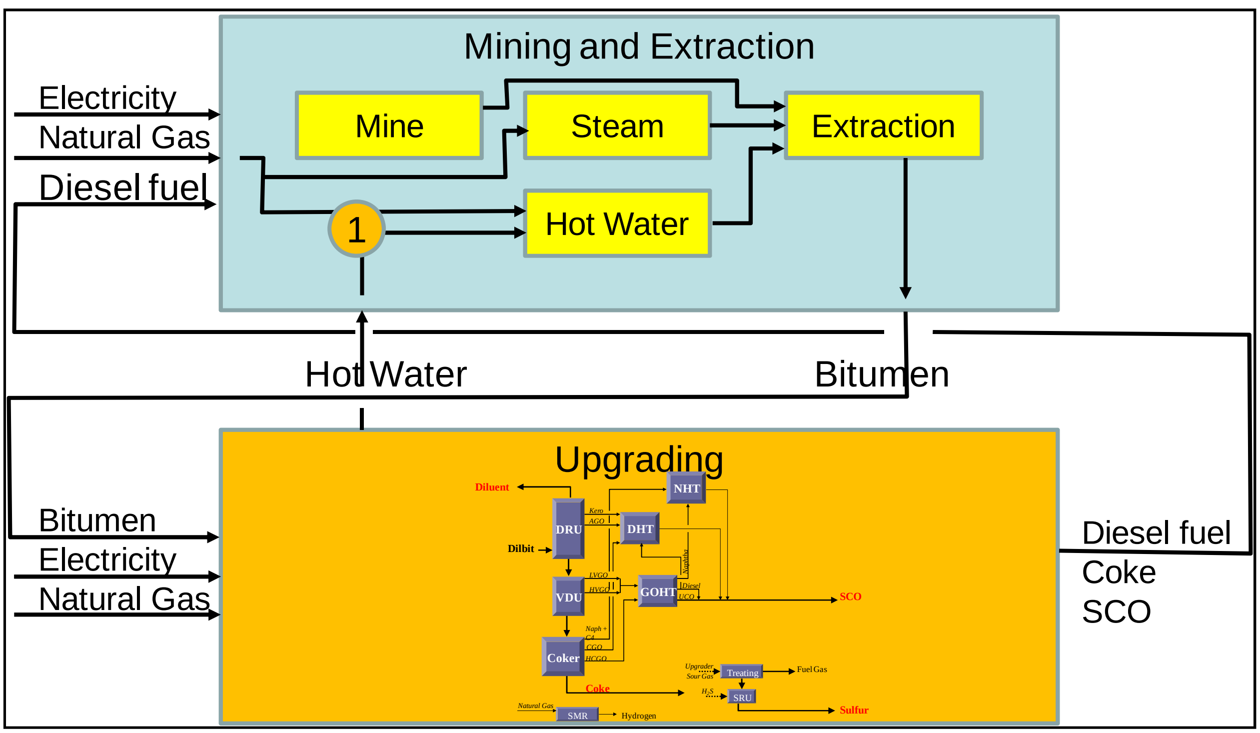
The recovered bitumen froth consists of roughly 60% bitumen, 30% water, and 10% solids by weight, and must be cleaned to reject the contained solids and water to meet the requirement of downstream upgrading processes. Depending on the oil content in the ore, between 90 and

100% of the oil can be recovered using modern hot water extraction techniques. After oil extraction, the spent sand and other materials are returned to the mine; the land eventually is reclaimed.

Energy for bitumen production by mining includes the diesel fuel for the trucks and diesel fuel or electricity to power the shovels used in mining. Electricity is used for the mechanical equipment used to move the ore and spent clay and to run the separators. Energy is also needed to generate the hot water used in bitumen separation from the ore and for recovery of solvent used in bitumen separation from the ore.

Bitumen produced by mining is generally processed in an Upgrader, which may be on-site and integrated with the mining process or a separate facility. Hot water for bitumen extraction from the ore can be produced from low-level waste heat from the Upgrader, from low-level waste heat from on-site electricity generation, or from a natural gas-fired hot water heater. Figure 2-5 shows a schematic for a mine integrated with an Upgrader.

Figure 2-5.
Integrated Mining and Upgrading Schematic



[1] Hot water produced from Upgrader waste heat, from waste heat from on-site electricity generation, or from natural gas heater.

Our evaluation of the carbon intensity of mining and upgrading is based on commercial mining and upgrading data. We analyzed two cases: the first assumes that waste heat from the Upgrader or from on-site power generation is used to produce hot water for bitumen extraction from the ore, and the second assumes that natural gas is used to generate hot water for bitumen extraction. We labeled these cases as follows:

- Integrated Mining and Extraction—Hot water from waste heat, either from the Upgrader or from on-site electricity generation. This is the predominant method of producing bitumen via mining in Alberta.
- Non-Integrated Mining and Extraction—Hot water for extraction from natural gas heater. This example is included to show how much higher energy consumption and GHG emissions are when extraction does not use low-level waste heat for process water heating. This is not a significant method of bitumen production from oil sands.

Upgrading

The processing steps in bitumen upgrading are designed to convert bitumen to SCO that will be processed in a refinery to produce transportation fuels and other products. A number of bitumen upgrading configurations are being practiced by the industry. Some reject refractory carbon, as in delayed coking or solvent deasphalting. Some add hydrogen to the bitumen in upgrading, thereby reducing the amount of refractory material produced. Other upgrading schemes use some of the refractory carbon as an energy source in processing. The following technologies are commonly used to upgrade heavy crude oils including bitumen:

- Coking (delayed coking and flexi-coking)
- Ebullated bed hydrocracking
- Deasphalting and thermal cracking

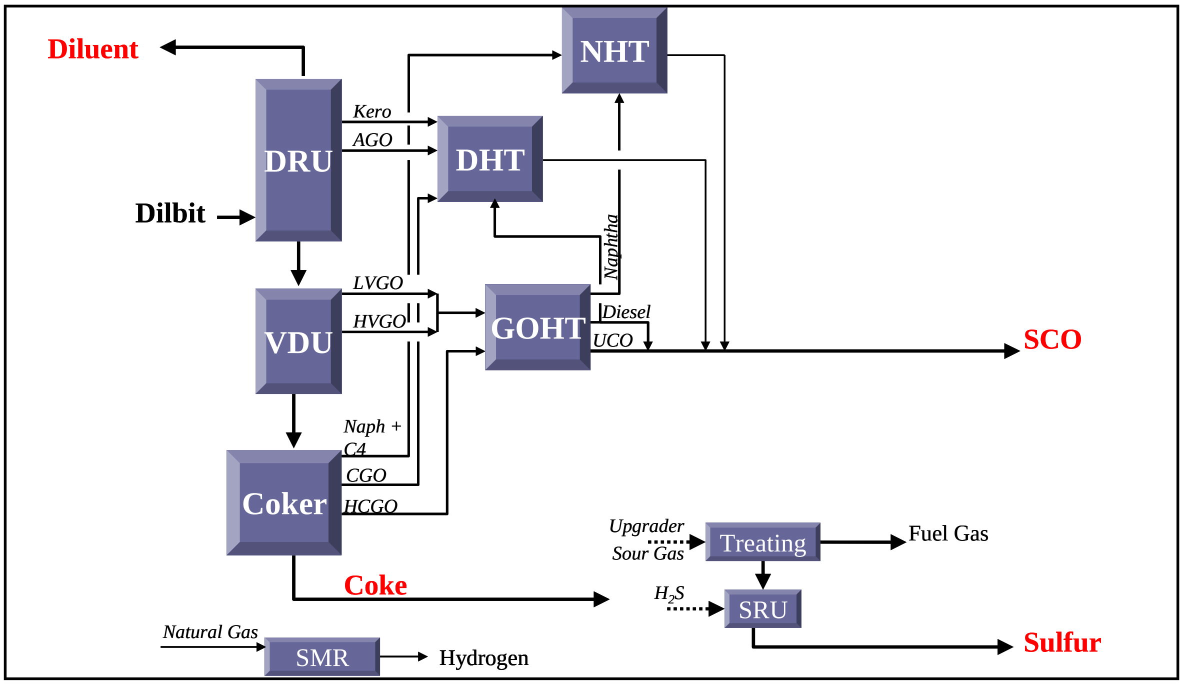
Our focus in this Study is on delayed coking, which is one of the predominant upgrading technologies practiced by the oil sands industry.

In delayed coking, the coker separates refractory low-hydrogen-content coke from lighter materials that, together with other streams, can be converted further to SCO in the other processing units of the Upgrader. The coke that is produced is stored and not subject to further conversion. SCO from a coking-based Upgrader is virtually bottomless.

Coking-based upgrading includes a gas oil hydrotreating unit (GOHT), a distillate hydrotreating unit (DHT) and a naphtha hydrotreating unit (NHT). In addition, the Upgrader requires a sulphur plant that converts H_2S to elemental sulphur; a gas plant to separate C_4- components into fuel gas and C_4s (C_3s are used in fuel gas); and a hydrogen plant that converts natural gas to hydrogen via steam methane reforming. In this analysis, coke from the coking-based Upgrader is stored and not used as fuel.

The overall flow scheme for the coking-based upgrading configuration is shown in Figure 2-6. A brief description of the process units follows.

Figure 2-6.
Coking-Based Upgrader



Process Units in Coking Based Upgrading Configuration

- **DRU**—The distillate recovery unit (DRU) separates the naphtha diluent from the bitumen and fractionates the bitumen into distillate and heavy atmospheric resid. The resid is fractionated in the vacuum distillation unit (VDU). The DRU is a single column with a one- or two-stage preflash. Atmospheric gas oil (AGO) goes to the DHT (distillate hydrotreating unit). The DRU atmospheric residue bottoms (AR) is sent to the VDU for further gas oil recovery. The AGO cut point is typically set to generate a distillate stream that will produce a 650˚F (343˚C) end point in the diesel hydrotreater product stream.
- **VDU**—The vacuum distillation unit (VDU) produces vacuum resid, which is sent to a coking unit, and light and heavy vacuum gas oils, which are sent to the gas oil hydrotreating unit (GOHT). Light vacuum gas oil (LVGO) and heavy vacuum gas oil (HVGO) streams are drawn above the flash zone. HVGO reflux is used as a final wash to remove entrained metals and asphaltenes from the slop wax zone vapours. The

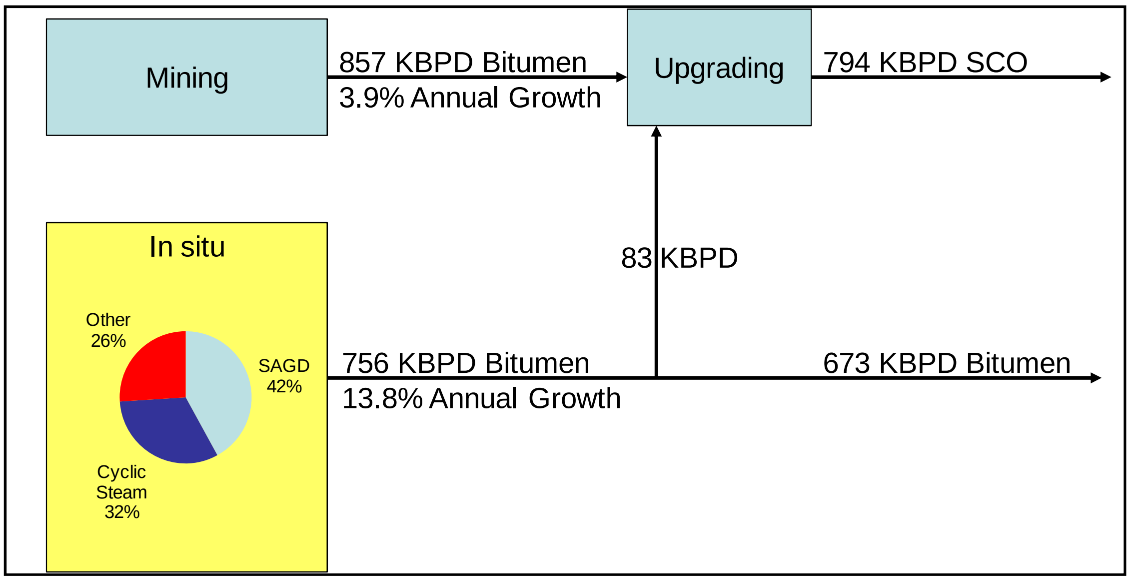
overhead vacuum is drawn by the steam jet ejector system. The DRU and VDU are typically heat integrated.

- **Delayed Coking Unit**—The coking unit converts vacuum resid from the VDU into lighter components, fuel gas, C_3 and C_4 olefins, naphtha, distillate, and gas oils. The delayed coker consists of several coke drums that feed a common fractionator. Fuel gas and C_3s go to the gas plant. Naphtha and C_4s from the coker are routed to the NHT where any olefins are saturated to ensure stability of the SCO. The light coker gas oil (LCGO) from the coker is low in cetane number and high in sulphur, and requires processing in the distillate hydrotreater. The heavy coker gas oil (HCGO) is processed further in the GOHT to achieve the sulphur target. Coke from the delayed coker is stored in a landfill.
- **GOHT**—The gas oil hydrotreating unit (GOHT) desulphurizes heavy gas oil from the DRU, VDU, and coking units. The GOHT is a desulphurization unit similar to the NHT and DHT but desulphurizes the gas oil streams from the VDU and Coker units in the presence of hydrogen and catalyst. Pressures greater than 120 $bar_{(g)}$ are typically required to remove the sulphur and nitrogen compounds from the gas oil streams. The GOHT is a significant user of hydrogen.
- **NHT**—The naphtha hydrotreating unit is designed to process C_4s together with naphtha from the coking unit, as well as naphtha from the DHT and GOHT as needed to meet SCO specifications. Naphtha and C_4s from the NHT are blended to SCO. The NHT is a low to moderate user of hydrogen.
- **DHT—**The distillate hydrotreating unit (DHT) processes distillate from the DRU, coker, and GOHT units. A DHT is very similar to a NHT. It is designed to remove sulphur from diesel in the presence of hydrogen and catalyst. The main difference is that diesel hydrotreating typically uses more catalyst, higher pressure, and higher hydrogen recycle gas rates to achieve desulphurization. An amine absorber is also used to eliminate H_2S from the recycle hydrogen. Depending on the severity of diesel hydrotreating, a finished product of ultra-low-sulphur diesel (ULSD) may be exported from the Upgrader. The DHT unit is a significant user of hydrogen.
- **Hydrogen**—Hydrogen is produced from natural gas via steam methane reforming. Process heat to the hydrogen plant is supplied by fuel gas which is supplemented by natural gas as needed. The hydrogen plant includes a pressure swing adsorption unit (PSA) to achieve 99%+ purity hydrogen.
- **Sulphur Plant**—Sulphur is recovered in the sulphur plant from H_2S that is produced during the upgrading steps. The sulphur plant consists of a Claus unit, tailgas treating plant, amine regeneration, and sour water stripper.
- **Gas Plants**—The gas plant is designed to remove 90% of the C_4s from the fuel gas, which consists of C_1s, C_2s, and C_3s, as well as any unrecovered C_4s. Process units in the gas plant include a primary absorber, stripper, debutanizer, and amine treating.

Bitumen Disposition

Another key piece of information to understanding bitumen production in Alberta is the disposition of the oil produced from bitumen in Alberta. Data reported by the industry to the Energy Resource Conversation Board (ERCB) in Alberta for 2010 are shown in Figure 2-7.[1] Currently, all mined bitumen in Alberta is upgraded to SCO, whereas most in situ production is sent directly to downstream heavy crude refineries. In 2010, 42% of in situ production was from SAGD, 32% from CSS, and 26% from other in situ methods.

Figure 2-7.
2010 Production and Disposition of Alberta Crude



Source: *ST98-2011, Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011-2020*, Energy Resource Conservation Board (ERCB), 2011

In Section 3 we discuss the methodology and basis used in evaluating energy consumption and efficiency improvement from typical bitumen production sites. Then we discuss energy consumption and efficiency improvement from a typical SAGD In Situ bitumen production facility in Section 4, from a typical mining and extraction facility in Section 5, and from a typical Upgrading facility in Section 6.

References

1. *ST98-2011, Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011-2020***,** Energy Resource Conservation Board (ERCB), 2011

Section 3.

Methodology and Basis

Establishing a consistent methodology and basis for energy estimation from each type of bitumen production facility were key steps in meeting the objectives of this Study. We used a systems-based approach that considers all aspects of the production chain in the evaluation. This approach is significantly different than an energy management audit and improvement process that is typically commissioned for individual facilities.

For each production facility we completed the following tasks:

- Determined total energy consumption and GHG emissions. This information was used to develop a set of metrics for measuring the relative energy efficiency of oil sands facilities that can be used to develop benchmarks to evaluate energy consumption and GHG emissions for crude oil production from other oil sands production facilities.
- Conducted facility-level energy efficiency assessments for in situ, mining and extraction, and upgrading by compiling energy consumption data from each area and conducting energy performance audits on each facility.
- Determined the impact of energy efficiency improvement on reducing the GHG emissions from typical bitumen production facilities.
- Identified and developed energy efficiency-based GHG abatement options for each type of bitumen production facility (mining, extraction, SAGD, and upgrading), including both operational and capital opportunities.
    - Quantified the GHG emission reduction potential from the top ranked improvement ideas.
    - Developed the preliminary capital and operating costs (+100/- 50%) to implement energy efficiency improvement and GHG reduction options.
    - Identified preliminary economic benefits and other impacts of energy reduction and GHG emission reduction.
    - Discussed in a qualitative manner the potential risks of energy reduction and GHG emission reduction opportunities that were identified.
    - Developed energy efficiency roadmaps that identified significant potential for reduction in the GHG emissions from oil sands production.
- Reviewed potential technology opportunities for each area with subject matter experts.
- Identified and evaluated next generation technology options for energy and GHG emission reduction and their impact on the design of future oil sands production facilities. These options include CCS.
- Assessed the impact of integration between operating areas on energy efficiency

- Evaluated the impact of energy and GHG emission reduction options on the Life Cycle well-to-wheels GHG emission intensity of gasoline and diesel from crude oil produced from oil sands. LCA methodology used in this Study is similar to what was used in the AERI Study.[1]

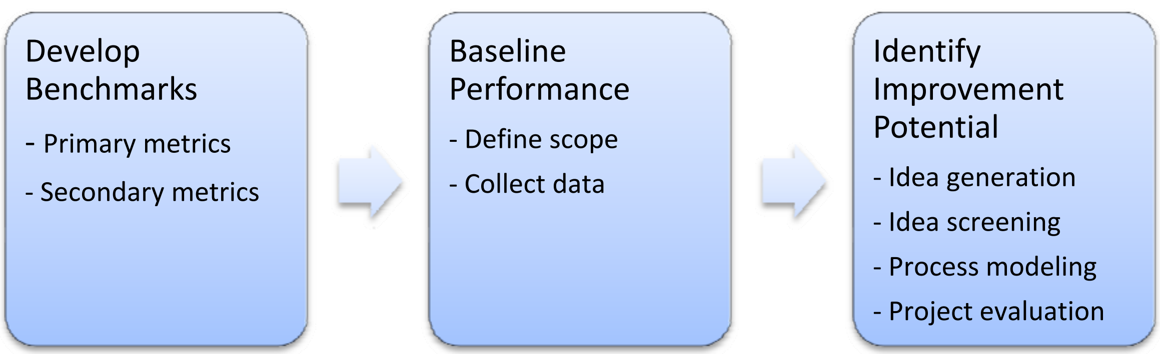
Some of the opportunities identified and evaluated in this Study had sufficient detail to advance them toward implementation. However, most of the opportunities require more detailed techno-economic evaluation before implementation. Therefore, the quantification of benefits in this Study is intended to provide a foundation and direction for future work to improve the energy efficiency of oil sands operations.

The results of the Study were also used to update the LCA model that Jacobs Consultancy developed for the AERI Study.[1]

Facility-Level Assessments

The following diagram (Figure 3-1) provides a brief overview of the work process for the individual Study areas:

Figure 3-1.
Work Process for Facility Level Energy and GHG Assessment



These study areas are further explained next.

Develop Metrics for Benchmarking

To better understand the energy efficiency of each facility, a set of metrics was developed to estimate primary and secondary energy consumption per barrel of bitumen produced. Primary metrics provide a basis to compare energy consumed in each facility as a function of bitumen produced. Secondary metrics use the individual utilities for each facility to better identify where opportunities for improvement exist.

Baseline Performance

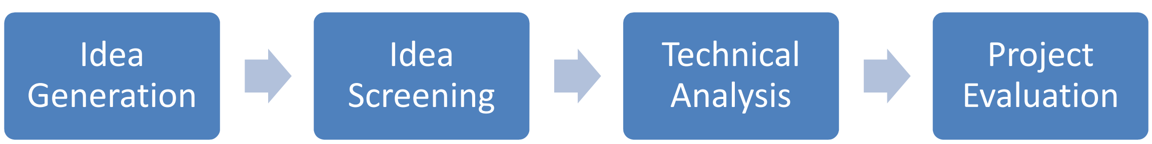
The Study Team evaluated the baseline, or as-is performance, of each facility. Included in this analysis was a determination of study boundaries, as well as a review of operating data for each facility from 2010. This information was used to determine the existing configuration and energy usage for each type of facility.

Identify Improvement Potential

Identifying energy improvement potential required reviewing the basic mechanical design of each unit and applying the benchmarks developed as part of this Study to identify potential energy gaps. We used a team-based approach to engage a wide range of experts from Suncor and Jacobs Consultancy to identify opportunities for energy reduction.

Figure 3-2 depicts the Study Team's approach to identify improvement potential.

Figure 3-2.
Improvement Potential Work Process



Idea Generation

The Study Team set up a series of idea generation sessions with energy and process experts from Suncor and Jacobs Consultancy who helped identify where technologies and operational and capital improvements could be applied to improve energy efficiency of both the existing plants and/or new plant designs. Workshops were also conducted with operating staff to identify specific plant improvements using current technology that would result in improved energy efficiency of the existing Suncor facilities. These improvements included both operational improvements and capital project ideas.

Idea Screening

All the ideas were screened for applicability in each operating area and placed into one of four categories, as follows:

1. **Operational Improvement ideas—**These are opportunities that are mostly based on procedural modifications and do not require significant capital to implement. Although several of these ideas were identified, their overall impact on the energy efficiency of the plant was low. Therefore no further discussion is included here.
2. **Project ideas—**These are opportunities that require capital and have to go through a corporate capital projects stage-gate opportunity evaluation, development, and execution process. The bulk of the ideas considered for implementation were in this category.
3. **Technology ideas—**This is a broad category of opportunities that relate to the selection of the major technology used for each step of the bitumen production process. Some of the ideas may be known technologies that would be good to consider when building a new plant, or they may be ideas of new technologies that have been developed but have not yet been fully commercialized. Finally, technology ideas could be solutions developed to fill gaps that exist with the known technologies.
4. **Non-energy ideas—**These are ideas that increase the capacity of the plant but may not necessarily lower the energy intensity to process bitumen. Although these are viable solutions to plant capacity issues, they were not included in this Study, which evaluated energy efficiency ideas per cubic metre of bitumen produced. Also included in this category are reliability projects which would improve the overall energy efficiency of the plant but are not strictly energy projects.

All of the project ideas were put into a matrix and ranked using a selection of weighted criteria. The weighted criteria included:

- GHG emissions reduction potential
- Capital and operating costs to implement (+100% / -50%)
- Potential energy savings and other benefits
- Qualitative discussion of potential risks—including safety, reliability, and operability
- Qualitative discussion of technology risks

Based on a statistical break in the ranking of the ideas, the top 20 to 30 project ideas for each bitumen processing facility were further evaluated to provide preliminary estimates of capital costs, GHG impact and potential payback, and for the identification of potential risks.

Technical Analysis

A model of each typical existing bitumen production facility was developed to provide a baseline operation that would represent current operation. The model was based on an integrated view of how processes and technologies can impact each other and the overall efficiency of a facility. The model was used to evaluate the potential improvement ideas identified in the brainstorming sessions. Each model was developed by and is proprietary to Jacobs Consultancy.

To baseline the performance of the typical bitumen production facilities used in the Study, the Study Team reviewed Process Flow Diagrams and their associated heat and material balance data. The results of the review were compiled into process criteria that provided input to the models.

Project Evaluation

Using the technical analysis tools, the top project ideas from the idea screening were evaluated to determine their potential impact. The following information was developed as part of the evaluation:

- Level of energy savings potential
- GHG emissions reduction potential
- Capital and operating costs to implement (+100% / -50%)
- Benefits and other impacts
- Qualitative discussion of potential risks

The projects that were developed fell into one or more improvement categories.

Improvement Categories

After the evaluations were completed, the projects were grouped into the following categories:

- **Flaring and Hydrocarbon Losses—**Includes any hydrocarbon that is disposed of through venting, combusting in a flare, etc. For the purposes of this Study, flaring occurs at In Situ and Upgrading facilities but not at Mining and Extraction.
- **Heat Losses to Earth and Water—**Heat losses to earth and water are typically associated with in situ bitumen production and are specifically related to geophysical features of the well and how the well is developed. Heat lost to water that is sent to the tailings ponds in the Extraction process could be another source of low-level heat.

However, the temperature of the water is usually too low for heat recovery and this heat may be required to aid in the operation of newer tailings technologies.

- **Fuel Type and Use—**Captures the reduction in GHG emissions associated with switching from a more carbon intensive fuel to a less carbon intensive fuel.
- **Energy Monitoring and Management—**Identifies opportunities related to day-to-day stewardship of the energy being used in the plant.
- **Utilization Efficiency—**The first step in improving the energy efficiency of an operating plant is to keep the plant operating reliably and to reduce the number of unplanned outages. By doing this, the extra energy required during start-ups and shutdowns is avoided.
- **Heat Exchange / Integration and Fired Heater Efficiency—**Most of the operating plants have some level of heat integration and waste heat recovery, but there are still opportunities to improve the heat exchanger networks in these facilities. Additionally, opportunities to improve the operation of fired heaters and boilers either through burner design, air preheat, or stack temperature reduction were included in this category.
- **Utilities—**Reduction in utility consumption is a key component of improving energy efficiency. This category focused on the ability to produce the required utilities more efficiently. Typical examples include improving boiler efficiencies and using power recovery turbines.
- **Process / Technology Changes—**Although evaluation of technology is a separate part of this Study, there are still opportunities to optimize existing bitumen processes that were included in this category. An example of potential process / technology changes is the impact from operating pressure changes in some of the units in the Upgrader.
- **Control Systems—**Once a facility is operating reliably and has been optimized, control systems can be used to help maintain the optimal operation of the facility. These opportunities typically include advanced process control and on-line analyzers.

Improvements were further grouped into either Project opportunities or Technology opportunities, depending on the extent of change required for implementation.

- **Project Opportunities—**Operational and capital improvements that could be applied to a typical bitumen facility to improve the energy efficiency of the facility and reduce the GHG emissions.
- **Technology Opportunities—**Technology opportunities for energy and GHG reduction identified for each area by the Study Team together with industry specialists. These opportunities varied in complexity from incremental technologies that could be used to improve existing facilities to new technologies that would change the way new bitumen

facilities are configured. For each type of bitumen facility, the following items were evaluated:

- Current technology and energy consumption
- New technology opportunities (10+ years before they could be implemented)
- Technology radar (graphical depiction of development timeline, relative risk and approximate energy efficiency improvement compared to current energy consumption)

CO_2 capture opportunities for oil sands applications were also evaluated. However, their applicability needs to be evaluated on a case-by-case basis.

Other Considerations in a Facility-Level Assessment

In addition to evaluating energy reduction opportunities for each type of bitumen production facility, the Study looked at the impact of heat integration between facilities as well as the impact of energy reduction on WTW life cycle GHG emissions from gasoline and diesel produced from oil sands derived crude oils.

Impact of Integration

Most bitumen production by mining and extraction in Alberta uses available low-level heat from upgrading or from on-site power generation to efficiently produce bitumen. In the Study, we evaluated the benefit of this integration by looking at energy consumption and GHG emissions with and without use of low-level heat. The integration discussed in this section is specific to the transfer of energy between the major processing areas with the objective of lowering the overall GHG emissions intensity of the overall facility. The potential for improvement of the heat exchange network within each specific facility (In Situ, Mining and Extraction, and Upgrading) is discussed in the sections specific to each of these areas.

Life Cycle Analysis

To understand the overall impact of the energy efficiency improvements on the production of bitumen, an LCA was completed to look at the overall GHG intensity of the finished products produced from the bitumen.

Life Cycle Analysis is a technique to assess environmental impacts associated with all stages of a product's life from cradle to grave—that is, from raw material extraction through materials processing, manufacture, distribution, use, repair and maintenance, and disposal or recycling. LCA provides a broad view of environmental issues by compiling an inventory of relevant energy and material inputs and environmental releases, evaluating the potential impacts associated with identified inputs and releases, and interpreting the results.

Conversion Factors

All of the energy consumption values in the Study were converted to a fuel equivalent basis. All combusted fuels are reported on a Lower Heating Value (LHV) basis. The conversion factors that were used are shown in Table 3-1. All values in the table are on an LHV basis.

Table 3-1.
Fuel Equivalent Conversion Factors

Utility	Fuel Equivalents
Electricity	8.54 GJ/MWhr (1)
Steam	
- 55.5 bar_g	3.17 GJ/tonne (2)
- 29.3 bar_g	3.07 GJ/tonne (2)
- 3.5 bar_g	2.73 GJ/tonne (2)
- Boiler feed water	0.517 GJ/tonne (2)
Natural Gas	0.0366 GJ/sm^3 (3)
Diesel	0.0361 GJ/L (3)

GHG emissions are calculated from energy consumption using the conversion factors shown in Table 3-2. All GHG emission factors are on an LHV basis.

Table 3-2.
GHG Emission Conversion Factors

Utility	GHG Emission Factors, gCO_2e/MJ of fuel
Electricity	244.5
Natural Gas	55.3
Natural Gas Fuel Cycle	9.0
Associated Gas	67.4
Diesel	95.0

Note that the GHG emission factors on an LHV basis are used in LCA and are from the AERI Study, updated in the EU Fuel Pathways Study.[4,5] GHG emission factors for fuels that are combusted show the CO_2 equivalents emitted on combustion. Fuel cycle refers to the GHG emissions to produce the fuel. Emission factors for electricity are for delivered grid-based electricity and include transmission losses and emissions for the fuel cycle.[1]

Type of Energy Considered

All of the direct and indirect energy requirements and CO_2 emissions were considered for this evaluation and included:

- Direct energy is utilized and CO_2 emitted within the boundaries of the typical bitumen facilities including:
  - Steam generated
  - Fuel gas fired
    - Natural gas
    - Associated gas
    - Produced gas
- Indirect energy is generated and CO_2 emitted at other facilities that supply utilities to the typical bitumen facilities.
  - Imported electricity
  - Imported steam
  - Imported hot process water
- Fugitive emissions and land use impact from bitumen production are outside the scope of the Study because they are not related to energy efficiency. However, we do include the impact of fugitive emissions and land use in reporting the WTW life cycle GHG intensity of gasoline and diesel fuel produced from bitumen.

Utility Cost Basis

The following numbers were used as a basis for utility costs and benefits:

- Natural gas - $6 / GJ (LHV)
- Electricity - $60 / MWh
- CO_2 - $15 / MT

Bitumen Production Rate Increase

Financial credit for increased bitumen production identified in the Study was not included in determining the benefits of energy efficiency and GHG emission reduction opportunities.

Capital Cost Basis

All capital cost estimates were completed based on a Fort McMurray location. The currency used was Canadian dollars. Capital cost estimates for this Study were developed based on construction costs (+100% / -50% accuracy) for first quarter of 2011 with validation from previous projects.

As detailed in the following report sections, we applied this methodology to determine the base energy consumption and GHG emissions from typical in situ, mining and extraction, and upgrading facilities. We then developed metrics for estimating energy consumption and GHG emissions.

References

1. Electricity Intensity Tables, *Canada's National Inventory Report: 1990-2008*, Environment Canada, http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=EAF0E96A-1#section10
2. Steam tables, *Steam: Its Generation and Use,* Edition 41, Babcock and Wilcox, 2005
3. *Lower and Higher Heating Values of Fuels*, US Department of Energy, http://hydrogen.pnl.gov/cocoon/morf/hydrogen/site_specific/fuel_heating_calculator
4. *Life Cycle Assessment Comparison of North American and Imported Crudes,* Jacobs Consultancy for AERI, 2009
5. *EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context,* Jacobs Consultancy for the Alberta Petroleum Marketing Commission, March 2012

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Section 4.

Bitumen Production – In Situ

Introduction

In this section of the Study we evaluate a typical operating In Situ facility to:

- Develop a set of preliminary energy efficiency metrics that can be used to assess and benchmark a facility's current performance and ongoing improvement.
- Define a baseline energy and CO_2 benchmark for a typical operating facility.
- Identify and evaluate energy efficiency improvements to determine costs/benefits and the potential magnitude of energy and CO_2 reduction opportunities.

Basis for Energy and GHG Estimation

The basis for this analysis is all direct and indirect energy requirements and CO_2 emissions from the typical In Situ bitumen production facility evaluated in this Study, which include:

- Direct energy utilized and CO_2 emitted within the boundaries of the surface facilities
- Indirect energy generated and CO_2 emitted at other facilities that supply utilities to the site (e.g., power)

The following assumptions were made:

- In situ bitumen production uses an SOR of 3.2.
- Steam generation is via OTSGs.
- Mechanical lift is used.
- Make-up water is fresh water (<4000 wt ppm dissolved solids).

Process Overview: SAGD Plant Configuration

A general overview of SAGD was given in Section 2 of this report. Additional detail is provided here to give further background for the energy and GHG reduction options considered in the Study.

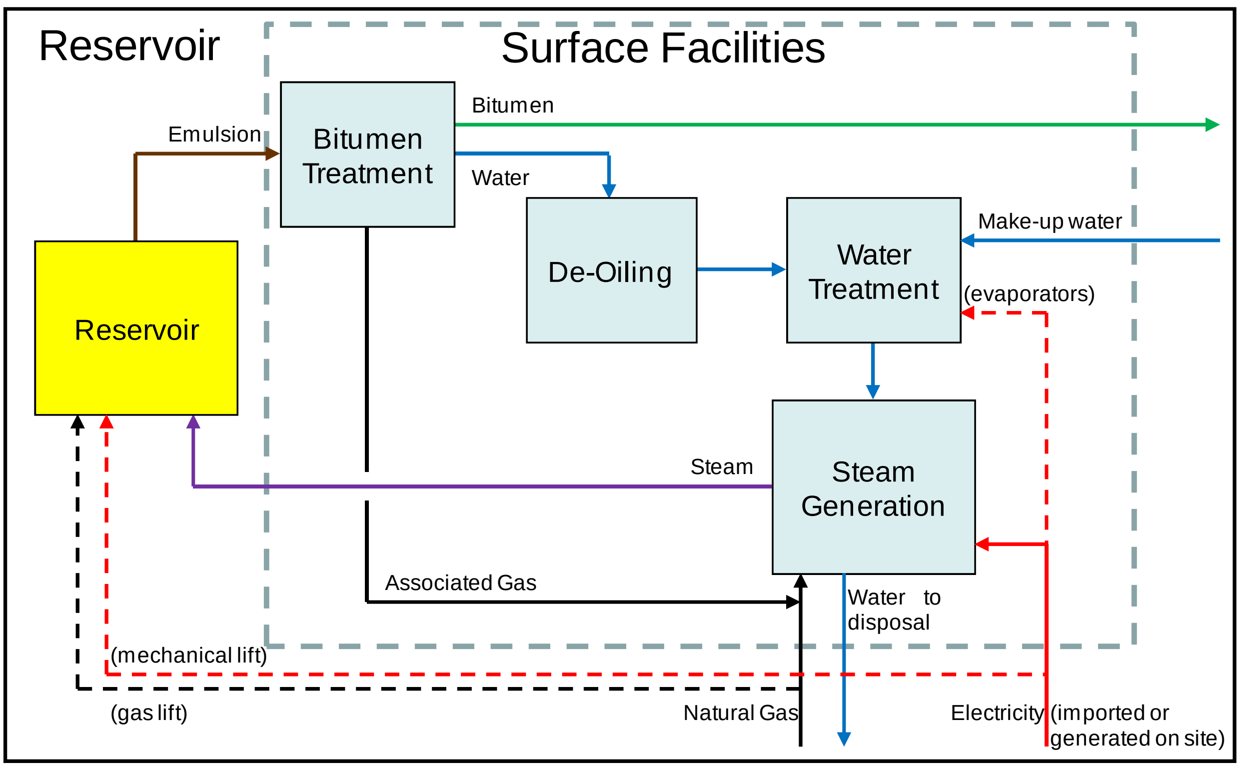
A typical SAGD operation has a centralized surface facility that treats the bitumen/water/gas mixture from multiple well pads at the reservoir. A schematic of a typical SAGD facility is shown in Figure 4-1.

Two bitumen lifting mechanisms are shown: gas lift, which injects gas into the riser to assist production; and mechanical lift, which uses a pump placed downhole to provide pressure.

Electricity can be generated on-site from natural gas or it can be imported from the grid.

Several options are shown for water treatment, which can be done either by lime softening or by evaporation. Several options are shown for steam generation, by OTSGs, heat recovery steam generators (HRSGs) in cogeneration plants, or drum boilers. Facilities are usually designed to use one or more of the options shown for water treatment (lime softening or evaporation) and one or more of the options shown for steam generation (OTSG or HRSG). Make-up water replaces water blow-down and water lost to the reservoir.

Figure 4-1.
Overview of SAGD Facility



The following discussion provides a brief description of the surface and reservoir facilities and some potential technology options that can reduce energy and GHG emissions from SAGD facilities. We will discuss first the impact of surface facilities and then the impact of the reservoir on energy consumption and GHG emissions from in situ bitumen production.

Surface Facilities

The surface facilities consist of the well pads and Central Processing Facility (CPF). Most of the processing is in the CPF where steam is produced and bitumen is separated from the water/oil emulsion. Depending on the amount of gas produced and the technology used to "lift" the oil/water emulsion to the surface, gas may be separated at the well pads and/or the CPF. The recovered water is treated for recycling to the boilers; gas is used as fuel. The CPF consists of: bitumen treatment, de-oiling, water treatment, and steam generation. The well pads consist of control facilities for steam injection, the recovery system for the produced material, gas separation (if required), and pumps to move the liquids to the CPF. The below-surface facilities consist of the well pairs, each of which consist of horizontal steam injection and horizontal recovery wells and facilities to lift the produced material to the surface. A range of technologies can be used for each of these areas, and the choices are driven by commercial and regulatory considerations. Characteristics inherent to the bitumen reservoir, availability of fresh or brackish water, waste disposal and choice of technology have significant impact on the energy use at a SAGD facility.

The CPF is the largest component of the production facility. It consumes most of the energy and generates most of the GHG emissions.

Bitumen Treatment

The bitumen treatment facility employs a free water knock-out vessel, diluent addition, and other treaters to achieve a first-order separation of the gas, water, and oil phases. The separated bitumen is diluted with a light hydrocarbon such as naphtha to aid in the separation of bitumen from water. Additional treatment to remove water and light hydrocarbons may include a flash drum and electrostatic or mechanical treaters. The final bitumen product is further diluted with naphtha to produce dilbit, which can then be stored or pipelined off site.

De-Oiling

De-oiling uses a combination of gravity and flotation processes to separate residual hydrocarbons from the water after the bitumen treatment step. This is required to maximize hydrocarbon recovery and to prevent fouling of downstream water treating processes and boilers.

Water Treatment

The produced water from bitumen production contains small amounts of free oil, suspended solids, dissolved oil, salts, and silica, which must be reduced to acceptable levels before the water can be returned to the boiler. Two commercially available water treatment options exist: lime softening and evaporation.

- **Lime softening—**Purifies water by the addition of lime to precipitate the dissolved minerals in the water. It is effective at reducing both hardness (calcium and magnesium) and silica.
- **Evaporation—**Purifies water by distillation, separating clean water as a vapor, and recovering the minerals as a concentrated brine.

Steam Generation

After treatment, the water is sent to a steam generator to produce steam for injection into the reservoir. Three primary technologies are used for steam production: once-through steam generators (OTSGs), heat recovery steam generators (HRSGs), and drum boilers.

- **Once-Through Steam Generator (OTSG)—**In OTSGs, the water moves through the steam generator in single pass horizontal water wall tubes in the radiant section of the boiler, and is then further heated in the vertical convection section of the heater. These generators generally produce steam with a maximum quality of about 80%, depending on the incoming water quality and boiler design. OTSGs typically have a thermal efficiency (enthalpy received by water / lower heating value of the fuel) of 80-85%.
- **Heat Recovery Steam Generator (HRSG)—**The HRSG is a key part of electricity generation in a combined cycle plant or cogeneration system. Cogeneration systems simultaneously produce steam in the HRSG, and electric power from a gas turbine. Electric power is used onsite for oil field operations; excess electricity is exported to the power grid. The amount of power co-produced varies by the design of the project. Some projects result in very high power production, while others mostly generate steam.

  While the steam generation efficiencies for cogeneration systems are lower than OTSGs because of electricity production, on a life cycle basis, cogeneration systems can be more efficient in delivering electricity and steam than stand-alone steam boilers and stand-alone power production facilities because cogeneration systems are able to generate steam from much of the waste heat from power production that would otherwise be rejected to the environment. We will discuss cogeneration vs. stand-alone power and steam generation in more detail in Section 7.

  The extent to which cogeneration systems are more efficient is often based on comparison to a non-optimized SAGD plant. Regardless, cogeneration often results in lower GHG emissions, since electricity from co-production receives a GHG offset credit because any net power exported to the grid offsets less efficient and more carbon intensive power produced elsewhere, thereby lowering the net GHG emissions from grid-based power. In Alberta, this credit for exported power from electricity cogeneration is currently 0.65 t CO_2/MWh. In this Study, we do not take credit for GHG offsets from power produced on-site and exported to the grid.

- **Drum Boiler—**Drum type boilers are starting to be used for in situ bitumen production from oil sands in Alberta. They offer certain advantages over OTSGs due to the reduced boiler feed water (BFW) make-up and blowdown (BD) volumes, reduced footprint, and easier assembly onsite. Furthermore, there are indirect cost savings because of reduced water treatment due to the reduced water volumes.

  Two types of drum boilers were considered in this Study: natural circulation (NC) and forced circulation (FC). In the NC boilers, the boiler water circulates due to the difference in density between cooler water in the down-comer circuits and the steam/water mixture in the riser tubes. In the FC boiler a pump ensures the flow of a steam/water mixture through the tubes. The key difference between OTSGs and drum boilers is that drum boilers have integrated water and steam separation and often operate with more steam and less water in the tubes.

Heat Exchange Network

Integral to most surface facilities is a complex heat exchange network. This network is used to reduce the amount of energy that is rejected to the environment by recovering and transferring the energy to another, lower temperature stream at the facility. A glycol loop is often used as the energy transfer medium to facilitate this heat exchange. There can be significant inefficiencies because of the complexity of the heat exchange networks. A heat exchange network can be optimized by conducting a detailed pinch analysis, which evaluates how close an integrated system is to a theoretical maximum energy transfer between the various process units.

Reservoir

The reservoir is often the most important contributor to the energy efficiency of a SAGD facility, and thus it is important to capture the effect that reservoir operation plays on the overall energy consumption. However, unlike the energy efficiency of surface facilities, the energy efficiency of the reservoir is mainly driven by the naturally occurring characteristics of the reservoir instead of by commercial, operational, or regulatory decisions.

After steam injection into the reservoir to start bitumen production, there are typically two primary modes of getting the bitumen to the surface facilities: natural lift and artificial lift. Natural lift is typically used during start-up of a new well but is not sustainable for the duration of the reservoir life. Therefore, artificial lift—either gas lift or mechanical lift—is used during normal operation.

Gas Lift

With gas lift the reservoir pressure is maintained at a high enough level to bring the bitumen-water emulsion to the surface facilities without the aid of a pump. Typically, natural gas is injected into the reservoir to assist in the lift. The decision to choose gas lift is often driven by reservoir depth, but gas lift is also perceived to be less expensive and more reliable than mechanical lift. Unfortunately, due to the higher operating pressure and temperature, more heat is lost to the earth with gas lift. At the surface, the bitumen emulsion containing the lifting gas is flashed to remove the gas, which lowers the temperature of the oil and water mixture, thereby reducing the heat available for exchange.

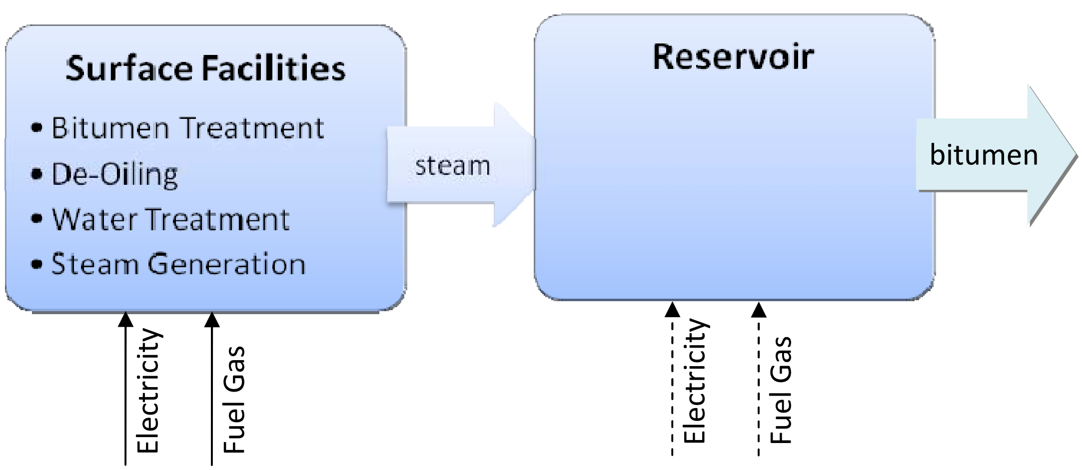
Mechanical Lift

Mechanical lift is an alternative to using gas lift to bring the bitumen-water emulsion to the surface. With mechanical lift, pumps are used downhole to lift the oil-water emulsion to the surface. This allows for a lower reservoir pressure which decreases heat loss to the Earth. In addition, the oil water emulsion arrives at the surface at a higher pressure and without any undissolved gasses. It can therefore be transferred to the CPF at a higher temperature, allowing for better heat recovery. Most SAGD facilities now being designed use mechanical lift.

Energy Overview

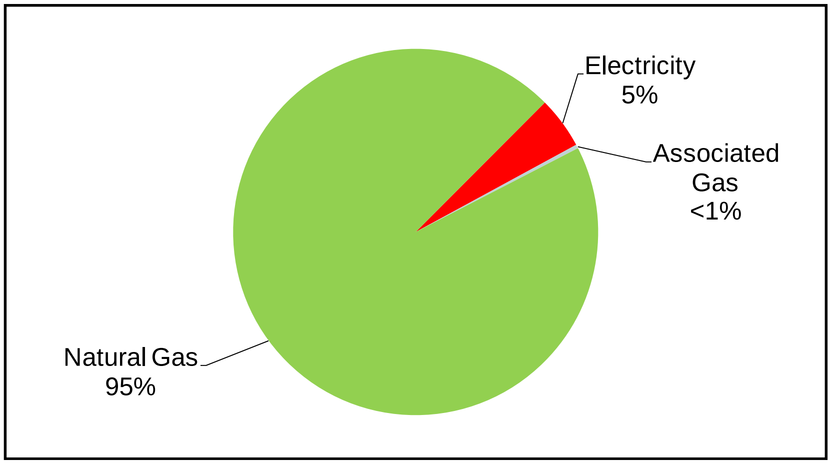
Natural gas and power are the two main energy inputs into a SAGD complex. Most of the energy is in the form of natural gas for steam production. However, electric power use is significant and is especially dependent on the type of water treatment system used. The utility sources required for each of the process areas are indicated in the following figure (Figure 4-2). Fuel gas consists of imported natural gas and associated gas produced from the reservoir. The dashed lines under *Reservoir* in the following figure indicate the two lifting mechanisms: electricity for downhole pumps used in mechanical lift and fuel gas for gas lift.

Figure 4-2.
Process and Energy Overview in SAGD



The breakdown of the energy consumption in a typical In Situ process is shown in the following figure (Figure 4-3).

Figure 4-3.
In Situ Energy Consumption



Further detail on the actual values of energy consumption in bitumen production from typical In Situ facilities is given below.

Benchmark Development

To further understand where the energy is being consumed in an In Situ facility and to assist in the development of industry benchmarks for similar facilities, we developed a set of energy efficiency metrics for In Situ bitumen production.

The metrics are based on a fuel equivalent energy per cubic metre of bitumen produced basis. For this Study, energy includes all consumed natural gas, associated gas, and imported electricity—or in the case of cogeneration, exported electricity. Cogeneration was used in this facility to generate steam and electricity. Because of the amount of steam required for bitumen production, the site exported a significant amount of electricity to the public grid. For this analysis we focused on energy and GHG associated with bitumen production and therefore subtracted the fuel for producing exported power from the total energy consumed on site to arrive at the energy used to produce bitumen.

We also developed preliminary CO_2 metrics, which are based on the energy consumption. We used the fixed conversion factors for each energy source, described in Section 3, to convert energy consumption to GHG emissions.

The In Situ metrics were developed on a per cubic metre of bitumen basis to account for the total GHG impact of bitumen production. The benchmarks were also developed on the basis of metric ton of steam to determine the efficiency of the surface facilities. The metrics are reported based on an annual average for the facility, including downtime and maintenance outages.

It is important to note that the data used here to determine the SAGD metrics are from a single year. Further work, including calculating the energy consumption and GHG emissions for a number of years as well as from other facilities operated by different companies, is needed to confirm the suitability of these metrics as industry benchmarks.

Input Variables

The following data are used to calculate the energy efficiency metrics for processing bitumen in an In Situ facility

- Reservoir
  - SOR at the well head
- Surface Facility
  - Bitumen production rate, cubic metres per year (m^3/yr)
  - Total steam generated, tonnes per year (tonne/yr)
  - Total power consumed, megawatt-hours per year (MWh/yr)
  - Total natural gas (refinery fuel gas and other fuels) consumed, gigajoules/year (GJ/yr).

For sites that export excess power to the grid, additional details of the cogeneration facilities are required, including:

- Total power generated, megawatt-hours per year (MWh/yr)
- Generated power used by the facility (or power exported), megawatt-hours per year (MWh/yr)
- Fuel burned in the Cogen turbine, gigajoules/year (GJ/yr) – on a lower heating value (LHV) basis
- Fuel burned in the heat recovery steam generator (HRSG), gigajoules/year (GJ/yr) – on a lower heating value (LHV) basis
- Total amount of steam generated, tonnes per year (tonne/yr)

All of the energy values were converted to a fuel equivalent basis and all combusted fuels are reported on an LHV basis using the conversion factors shown in Table 3-1.

Note that the conversion factor for associated gas produced in the In Situ facility will vary based on composition. For this Study, an annual average value for associated gas composition was used.

Metric Determination

Two types of metrics were generated for the In Situ facility from these input variables:

- Primary Energy Efficiency Metrics—overall site energy intensity
- Secondary Energy Efficiency Metrics—process area utility consumption

The hierarchy of metrics is shown in Figure 4-4.

Figure 4-4.
Proposed In Situ Metrics

Facility	In-Situ		
Primary Metrics	GJ energy / m^3 bitumen MT steam / m^3 bitumen GJ energy / MT steam		
Secondary Metrics	kWh / m^3 bitumen	GJ steam / m^3 bitumen	GJ fuel gas / m^3 bitumen

Primary Metrics

The primary metrics provide an overall energy intensity value for the entire In Situ bitumen production facility.

The primary In Situ metrics are:

1. *Energy Intensity of Bitumen Production:* GJ of energy / cubic metre of bitumen - GJ of fuel equivalents (steam + fuel gas + electricity) divided by the cubic metres of bitumen (100% bitumen basis) produced
2. *Energy Intensity of Steam Generation:* GJ of energy / tonne of steam - GJ of fuel equivalent (steam + fuel gas + electricity) divided by the tonnes of steam delivered to the wellpads
3. *Steam Consumption:* Tonnes of steam / cubic metre of bitumen - GJ of steam (fuel equivalent) from In Situ surface facilities divided by the cubic metres of bitumen product

Standard conditions are used for bitumen and steam in the above formulas.

For bitumen delivered at temperatures above 115°C, the steam rate will be decreased based on the correction factor. For bitumen delivered below 115°C, no correction is made as this is generally considered non-economically recoverable heat.

Table 4-1 contains the primary metrics based on 2010 values from the typical In Situ facility used in the Study. These values are reported on an LHV basis. The SOR for bitumen production was 3.2.

Table 4-1.
Primary Metric Values for Typical In Situ Bitumen Production Facility

Energy Intensity of Bitumen Production	Energy Intensity of Steam Generation	Steam Consumption (SOR)
GJ / m^3 bitumen	GJ / MT steam	MT steam / m^3 bitumen
8.6	2.7	3.2

The Energy Intensity of Bitumen Production is a site metric and is an aggregate of the primary metrics for the surface facilities and the reservoir. The site metric provides the overall energy intensity for bitumen production from the site. However, embedded in this metric is the SOR, which is a function of the geology of the reservoir and not easily amenable to change resulting from energy efficiency improvement. Different production sites have different reservoir geologies and therefore often have different SORs.

Steam Consumption is primarily a reflection of SOR, which is a function of the reservoir, and largely outside the control of the operator. Steam consumption is reported as a metric but it is not intended to drive changes in operation or improvements in energy efficiency. Energy efficiency benchmarking is only recommended for the surface facilities.

Energy Intensity of Steam Generation is a metric of the surface facilities and is a reflection of the energy intensity of the boilers, water treatment, and oil separation facilities. This is a high-level (primary) metric that is indicative of the energy efficiency of the surface facilities.

Secondary Metrics

To better understand the operation of the In Situ facility, a set of secondary energy efficiency metrics was developed. Secondary benchmarks are based on the individual utilities consumed in the In Situ facility. By evaluating the individual utilities consumed in each of the process areas, specific areas that need improvement can be more readily identified.

The secondary In Situ energy efficiency metrics are:

1. *Electricity:* kWh / cubic metre of bitumen - kWh (or GJ of fuel equivalent - LHV) divided by the total cubic metres of bitumen produced
2. *Fuel Gas and Natural Gas:* GJ of fuel gas plus associated gas / cubic metre of bitumen - GJ of fuel gas (LHV) divided by the total cubic metres of bitumen produced
3. Steam Consumption: GJ of purchased steam / cubic metre of bitumen - GJ of fuel equivalent steam divided by the total cubic metres of bitumen produced

Secondary metrics, presented in Table 4-2, are based on the 2010 operations from the typical In Situ facility used in the Study. These values are reported on an LHV basis. This facility generates all steam internally and there is no purchase of steam.

Table 4-2.
Secondary Metric Values for Typical In Situ Bitumen Production Facility

	kWh/m^3 bitumen	GJ/m^3 bitumen
Electricity	63	0.5
Fuel Gas	---	8.1
Steam Purchased	---	NA

Improvement Potential

We used the work process in Section 3 to evaluate energy and GHG reduction for In Situ bitumen production. Potential improvements were identified and put into one of two categories:

- **Project Opportunities—**operational and capital improvements that could be applied to a typical bitumen facility to improve the energy efficiency of the facility and reduce the GHG emissions.
- **Technology Opportunities—**incremental technologies that could be used to improve existing facilities and new technologies that could change the way new bitumen facilities are configured.

Potential Project Opportunities

A sample list of the operational and capital improvement ideas generated in the workshops and team meetings is shown in Table 4-3.

Table 4-3.
In Situ—Potential Improvement Ideas

Operational Improvements
• Maximize fuel gas temperature • Maximize usage of lime softening versus evaporation • Maximize steam quality to improve overall boiler efficiency. • Eliminate low-pressure steam letdown
Capital Improvements
• Add produced water/boiler feed water exchanger • Increase surface area and re-pipe emulsion and produced gas exchangers • Expand blowdown heat exchangers • Re-wheel OTSG force draft fan to improve efficiency • Add OTSG economizers and associated equipment to recover more stack heat • Add produced gas/boiler feed water exchanger • Expand emulsion/boiler feed water exchanger • Add a blowdown/boiler exchanger • Add a diluent/produced water exchanger • Add a blowdown/BFW exchanger • Lower HRSG flue gas temperature by optimizing heat exchanger configuration • Raise well pad separator pressure Recycle "clean" C & E blowdown water • Minimize flare header losses • Segregate glycol streams • Reroute initial condensed water from field gas • Find water bypass opportunities • Capture energy from high-pressure natural gas • Capture energy from high-pressure blowdown • Capture energy from high-pressure steam

The Energy Improvement Project ideas from Table 4-3 were evaluated for the typical In Situ facility used in the Study to determine their potential impact on energy consumption and GHG emission reduction. Using a model of the typical In Situ facility evaluated in this Study, the top project ideas from the idea screening were evaluated to determine their potential impact on energy and GHG emission reduction.

Results Summary for Potential Projects

The potential improvement ideas in Table 4-3 were put into the Improvement Categories described in Section 3. Each category contains multiple projects, and the results of each category are given in Table 4-4, which shows the energy and GHG reduction from the top ideas and the estimated capital costs to achieve these results.

Economically achievable energy improvements were defined as having a simple payback of five years or less. Non-economically achievable projects were defined as having greater than a five-year simple payback period. These simple payback periods are in line with typical values used for initial screening for oil sands projects. All of the potential projects represented in Table 4-5 were considered economically achievable. Energy is on a LHV basis

Table 4-4.
Summary of Energy Improvement Projects – In Situ

In Situ	Energy Reduction, GJ/m^3 bit	GHG Reduction, kg/m^3 bit	Capital Cost, $\$M/m^3$ bit
Flare & hydrocarbon losses	*	*	*
Heat losses to earth and water	0.01	0.4	0.1
Fuel type and use	*	*	*
Energy monitoring and management	*	*	*
Utilization efficiency	*	*	*
Heat exchange / integration & fired heater efficiency	0.31	16.7	1.4
Utilities	0.34	61.6	3.2
Process / technology changes	0.01	2.6	<0.1
Control systems	*	*	*
Total	**0.67**	**81.3**	**4.7**

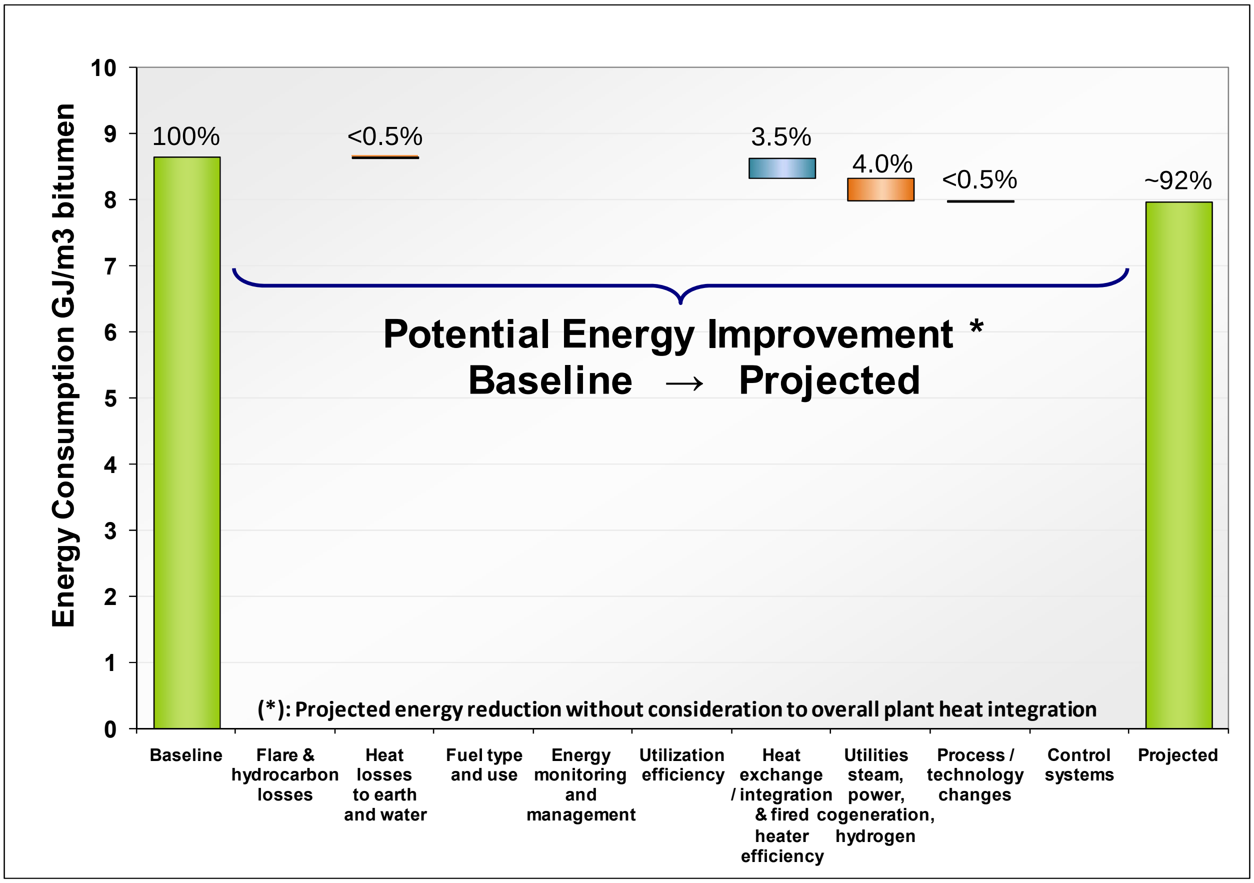
Energy Reduction Potential

All the energy improvements evaluated were compared in a waterfall chart in Figure 4-5. This figure shows the energy baseline developed from 2010 operating data for the typical In Situ bitumen production facility evaluated in this Study as the left-hand bar on Figure 4-5. The baseline energy intensity for In Situ bitumen production is 8.6 GJ/m^3 of bitumen on an LHV basis. From this baseline, the projected benefits of the energy improvements are displayed for each of the project groups shown in Table 4-4.

Implementation of the energy improvements shown will reduce total energy consumption for the typical In Situ SAGD operation in this Study by about 8%, resulting in an energy intensity of 8.0 GJ/m^3 of bitumen on an LHV basis, shown on the right-hand side of Figure 4-5.

All of these results are based on preliminary project evaluations completed for this Study. A more detailed evaluation to confirm the capital costs and benefits will need to be conducted before these projects could be implemented.

Figure 4-5.
Energy Improvements Identified for the Typical In Situ Bitumen Production Facility



GHG Emission Reduction Potential

The impact on GHG emission reduction from improving energy efficiency through the implementation of the potential projects identified in this review is approximately 12 percent. The baseline GHG emissions on the left-hand side of Figure 4-6 were reduced from 0.65 MT/m^3 of bitumen to 0.57 MT/m^3 of bitumen as a result of the energy improvements identified.

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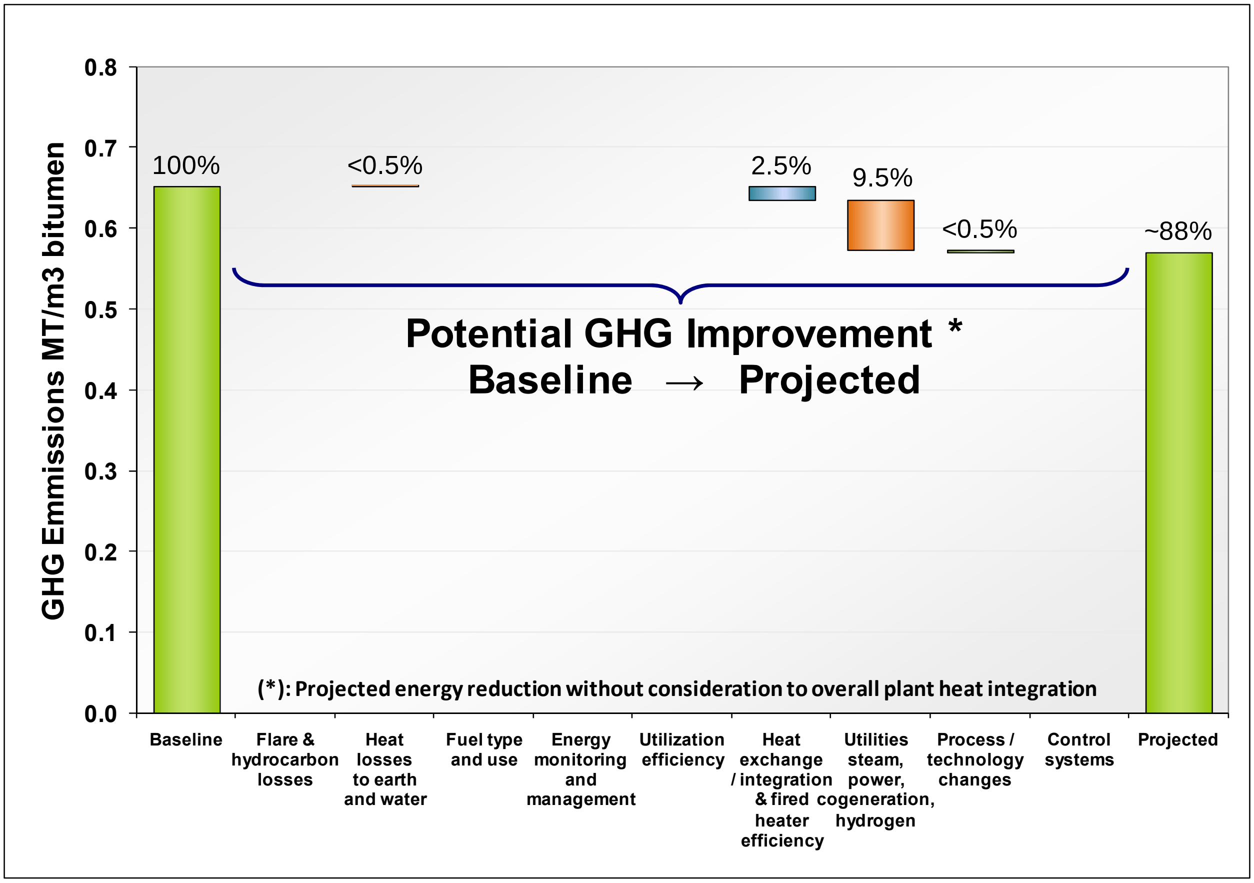
Figure 4-6.
GHG Emissions Reduction for the Typical In Situ Bitumen Production Facility



Technology Opportunities

The next step in the analysis identifies technologies that could be applied to improve energy efficiency of both the existing plants and/or new plant designs. The technologies were placed into the following categories: Steam Generation, Heat Recovery, and Alternatives to SAGD.

Areas for Improvement

Areas for improvement of In Situ production of bitumen were separated into categories:

- Steam Generation
- Heat Recovery
- Alternatives to SAGD

Steam Generation

With the current technology, steam generation represents more than 90% of the energy used in a typical in situ facility. The technologies identified to improve energy efficiency are as follows:

- Organics removal technology to reduce organics in boiler feed water
- Alternate fuels for boilers
- Microwave technology
- Nuclear technology
- Electrical induction
- Plasma generator
- Solar thermal technology
- Down-hole steam generation

Heat Recovery

There are several technology ideas to aid in the recovery of heat from the existing SAGD facilities:

- Down-hole pump technology
- Using organic Rankine cycle on boiler stacks and glycol circuits
- Ultrasonic separation
- Improved heat exchanger design to minimize fouling
- Membrane separation

Alternatives to SAGD

Although some of the technology ideas were for reducing the SOR, most of the technologies identified would move away from the current method of using steam to produce bitumen. These technologies are as follows:

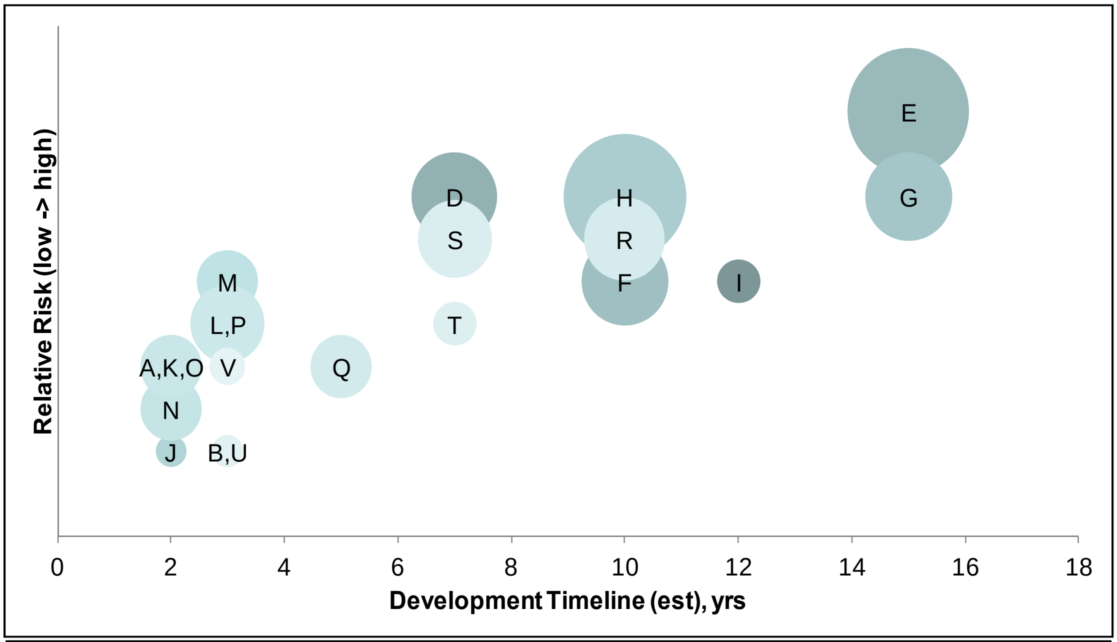
- Non-condensable gas injection
- Polymer co-injection
- Surfactant co-injection
- Hydrocarbon co-injection
- Solvent co-injection
- Water and air injection
- Warm water extraction
- Catalyst injection to reduce viscosity

Potential Benefit

Each identified technology was ranked based on potential energy benefit, relative risk, and approximate development timeline based on current status. The qualitative assessment of relative risk included both operational and commercialization risks, including impacts on technology development, safety, reliability, operability, and production.

The results of the ranking are shown in Figure 4-7. The size of the marker on the figure indicates the magnitude of the energy improvement. The horizontal axis plots estimated development time, and the vertical axis plots relative risk from low to high.

Figure 4-7.
In Situ Technology Assessment



A	Organic Rankine Cycle	N	Hydrocarbon co-injection
B	Organics removal technology	O	Solvent injection
C	Alternate fuels	P	Solvent co-injection
D	Microwave technology	Q	Water & air injection
E	Nuclear technology	R	Warm water extraction
F	Electrical induction	S	Catalyst injection to reduce viscosity
G	Plasma generator	T	Ultrasonic separation
H	Solar thermal technology	U	Improved heat exchanger design
I	Direct firing of O2, fuel & water	V	Membrane separation
J	Optimize downhole pump design		
K	Non-condensable gas injection		
L	Polymer co-injection		
M	Surfactant co-injection		

Based on the above ranking and additional input, the top ideas for improving the energy efficiency of In Situ bitumen production are as follows:

- Surfactant co-injection
- Solvent injection
- Polymer injection
- Warm water extraction
- Catalyst injection to reduce viscosity

Carbon Capture from In Situ Facilities

Carbon capture and storage (CCS) can be applied to large point sources in oil sands operations, and can contribute significant reductions in GHG emissions. The extent of CO_2 reduction from CCS is likely to be larger than what is expected to be obtainable with other technologies, although at much higher cost, and complexity. Current technologies for CCS are anticipated to cost $75-$200 per tonne of CO_2 avoided, depending on the technology employed, and the emissions stream from which CO_2 will be captured.

In addition to the cost of capture (which is currently higher than the compliance costs in any jurisdiction in the world, including Alberta), there are other barriers to implementation of CCS, which include:

- Space constraints (for retrofit facilities)
- Suitable geological sites for CO_2 storage
- Pipeline access, and costs of the pipeline to transport CO_2 to storage sites
- The significant utility needs (steam and/or electricity) for CCS that offsets much of the gain from capturing CO_2

The primary source of CO_2 emissions from an In Situ facility are the OTSG boilers and cogeneration units. Typically these sources account for 95%+ of the direct emissions from an In Situ facility.

OTSGs are generally more suited to CO_2 capture than cogeneration facilities because the CO_2 is present at higher flue gas concentrations (typically 8-10% versus 4-8% in a cogeneration facility, depending on the configuration). Also, OTSGs have lower stack gas temperatures and are simpler in design than cogeneration facilities.

Given the large size of the relatively few number of emission sources, upwards of 90% of the CO_2 emissions could be captured from In Situ facilities using existing or near commercial technologies. This would result in avoided CO_2 emissions in the range of 75%, depending on how the utilities (steam/power) were produced to run the capture facility. It is important to note, however, that under the current and anticipated economic and regulatory environment, CCS is not economically viable for in situ facilities. Also, CCS will increase the energy requirements at the facility.

Table 4-5 outlines the CO_2 capture technologies that are applicable to oil sands operations, their readiness, and expected costs.

Table 4-5.
CO_2 Capture Technologies for OTSGs and Boilers

Technology / Application	Description	Readiness	Expected cost
Post-combustion capture for heaters, boilers and co-generation	Flue gas contacted with amine (MEA)-based solvent; solvent regenerated with steam. Requires significant quantities of steam. New/novel solvents and catalysts could reduce regeneration energy requirements.	Commercially available; has not yet been applied to OTSG boilers.	\$175-\$250/t. New solvents are expected to produce modest reductions in costs.
Oxy-fuel combustion for heaters and boilers	Oxygen is separated from air in an oxygen plant, and fuel is combusted in pure oxygen in boiler, resulting in CO_2-rich flue gas stream. Requires significant quantities of electricity to run O_2 plant.	In demonstration phase; oxy-firing has been in use in industry for decades, and oxy-firing for CO_2 capture has been demonstrated on coal-fired boilers.	\$125-\$150/t. New oxygen separation technologies could significantly reduce costs.
Pre- combustion capture for heaters and boilers	H_2-fired heaters and boilers where separation of CO_2 is completed in a steam methane reformer. Technologies in development consider membranes or other technologies to reduce the cost of H_2 production.	Commercially available; has not yet been applied to OTSGs.	Expected to be in-line with oxy-fired combustion. New H_2 production technologies could significantly reduce costs.
Solid Adsorbents for heaters, boilers and co-generation	Multiple configurations; most use batch-type operation to adsorb and desorb CO_2, and re-generate the adsorbent bed with heat or pressure.	Being developed at bench scale and is ready for pilot demonstration.	Potentially offers lower capex costs.
Chemical looping combustion for boilers	Uses a metal oxide (typically NiO) as an oxidation agent for the fuel, which results in a CO_2-rich flue gas stream; metal is then oxidized in a regenerator.	Being developed at bench scale and is ready for pilot demonstration.	Potentially offers lower opex costs. Capex costs expected to be higher.
Process emissions capture from hydrogen production	High pressure and concentration separation of CO_2 from hydrogen plant process streams; CO_2 is separated as part of the hydrogen production process.	Technology is commercially ready and is in use for CO_2 separation from H_2 plants elsewhere in the world.	\$75-\$125/t, depending on the configuration of the hydrogen plant.

Conclusions—In Situ Bitumen Production

- A set of energy efficiency metrics has been proposed to help evaluate and potentially benchmark the energy efficiency of an In Situ facility. Further validation from a broader section of the industry is needed before these metrics can be used as benchmarks.
- This Study identified an energy efficiency improvement for a typical In Situ facility of approximately 8 percent.
- The incremental improvements in energy efficiency identified in this Study could result in an approximately 12% reduction in CO_2 emission intensity of crude production.
- Further improvement in energy efficiency and reduction in CO_2 emissions may be possible upon completion of site-wide utility projects.
- Based on technologies identified, the potential energy consumption for In Situ bitumen production could be reduced by approximately 20 percent.
- All improvement projects and their potential benefits identified in this Study require a more detailed evaluation before these projects can be considered for implementation.
- CCS is not economically justified at current CO_2 costs.

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Section 5.

Bitumen Production – Mining and Extraction

Introduction

In this section we evaluate a typical operating Mining and Extraction facility using the methodology outlined in Section 3. The focus of this evaluation was to:

- Define baseline energy use patterns and CO_2 intensities for a typical operating facility.
- Begin the development of energy efficiency metrics that can be used to assess and potentially benchmark a facility's current performance and improvement potential.
- Identify and evaluate energy efficiency improvements to determine costs/benefits and the potential magnitude of energy and CO_2 reductions opportunities.

Project Basis

Energy consumption from the typical Mining and Extraction facility in the Study includes energy consumed in mining and ore processing equipment, in bitumen extraction and in supporting facilities such as the utility plants, which include utility boilers. All direct and indirect energy requirements and CO_2 emissions were considered for this evaluation, which include:

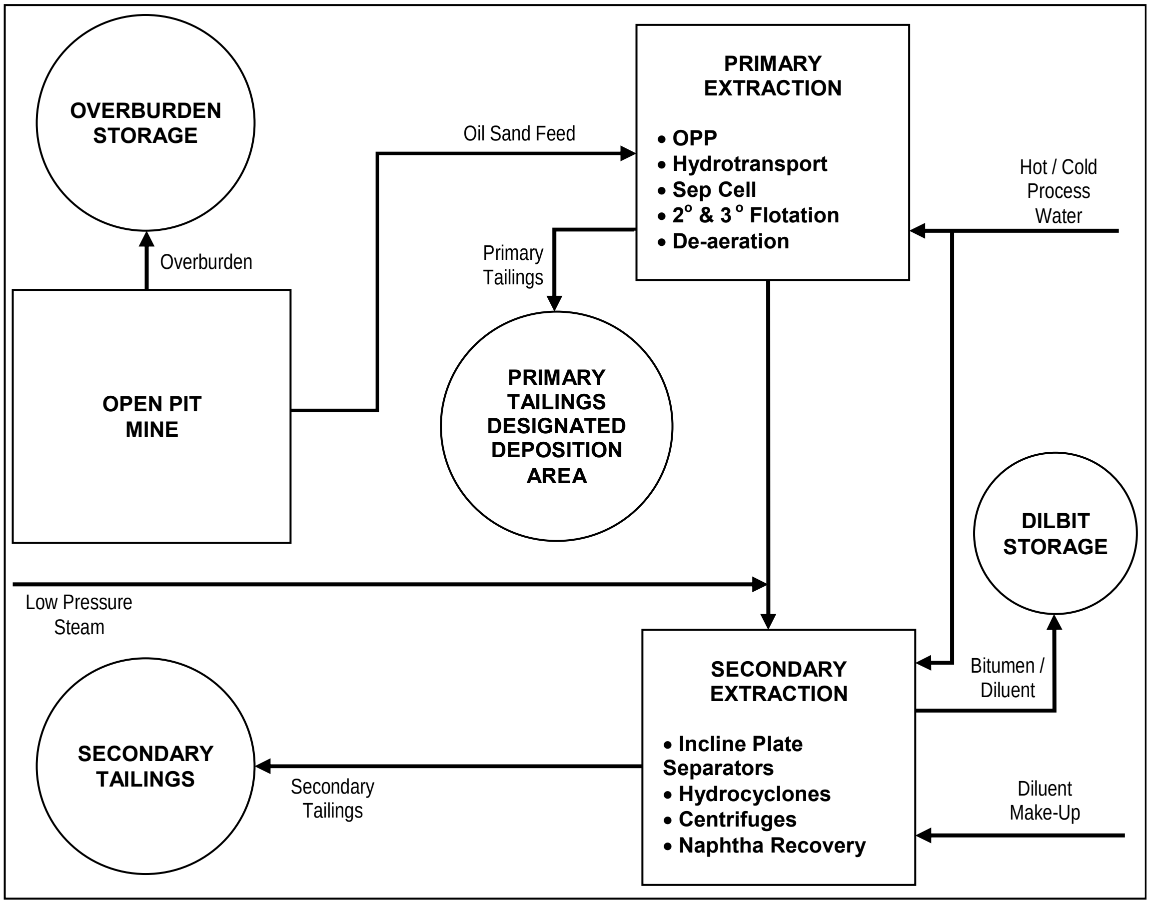
- Direct energy utilized and CO_2 emitted within the boundaries of the mine and extraction facilities; and
- Indirect energy generated and CO_2 emitted at other facilities that supply utilities to the site (e.g., power, imported hot process water, imported steam).

Reduction in GHG emissions due to land use, tailings ponds, or other fugitive emissions was outside the scope of this Study.

Process Overview: Mining / Extraction Plant Configuration

A general overview of Mining and Extraction was provided in Section 2. Additional detail is provided here to help explain some of the energy efficiency improvements and GHG reduction opportunities evaluated in the Study. A schematic of a typical Mining/Extraction Plant is shown in Figure 5-1.

Figure 5-1.
Overview of a Typical Mining and Extraction Facility



Surface mined bitumen production involves a sequence of process steps to separate and recover the bitumen from the oil sands ore.

Mine development involves site clearance and preparation (mainly overburden removal) to expose the oil sand deposit. The removed overburden is stored and ultimately used for reclamation purposes once the oil sands ore is recovered from the deposit.

Mining occurs via heavy hauler and shovel operations, with the oil sands ore being transported by a heavy hauler to an ore preparation plant (OPP). At the OPP, ore lumps are broken up in rotary breakers to which hot process water is added to form a slurry. This material is conditioned and pipelined several kilometres to a primary separation plant, which results in the liberation of a significant portion of the bitumen from the sand in the form of a bituminous froth.

Additional separation of the bitumen from the bulk of the mineral matter and water takes place in a separation vessel (Sep Cell). The mineral matter is pumped to a tertiary flotation recovery plant where additional bitumen froth is recovered and recycled back to the Sep Cell.

A middlings stream, comprised of water, bitumen droplets, and the bulk of the fine minerals, is also produced in the primary separation and is treated in a secondary flotation recovery plant for further bitumen recovery. Bitumen froth is produced in flotation cells or columns by the addition of wash water and air injection. This froth is then recycled back to the Sep Cell. Secondary flotation tailings are mixed with tertiary flotation tailings and pumped out of the Extraction plant to storage and treatment in tailings ponds facilities.

The separated bitumen is deaerated before being sent to Secondary Extraction, where its water and mineral content are reduced to low levels.

In Secondary Extraction, hot diluent (naphthenic or paraffinic naphtha) is added to deaerated froth to reduce its viscosity and specific gravity to enhance separation of the hydrocarbon and water phases. To speed up gravity separation, centrifugal force is applied by mechanical equipment. Two stages of centrifugation reduce the water and mineral content of the diluted bitumen to the low levels required for upgrading. Tailings from Secondary Extraction are pumped out of the plant to tailings treatment separately from primary tailings.

A typical surface mined bitumen production operation will have one or more open pit mine facilities attached to it, two or three OPPs, a two-train Primary Extraction Plant, and a one- or two-train Secondary Extraction Plant.

Energy Overview

The utility sources required for each of the process areas are indicated in the figure below (Figure 5-2). Energy sources are electricity, diesel fuel, steam and hot process water.

The breakdown of the energy consumption for a typical Mining and Extraction facility is shown Figure 5-3 by utility. The majority of the energy consumed in the extraction process is needed to generate hot process water. The source of the hot process water (HPW) can dramatically impact the GHG emissions of the overall Mining and Extraction facility. If the hot process water is generated from waste heat recovered in other nearby processes or facilities, such as refining or upgrading or on-site power generation, the direct GHG emissions are much lower for the Extraction facility than if steam or other high-grade heat is used to generate the hot process water.

Figure 5-2.
Process and Energy Overview for Mining and Extraction

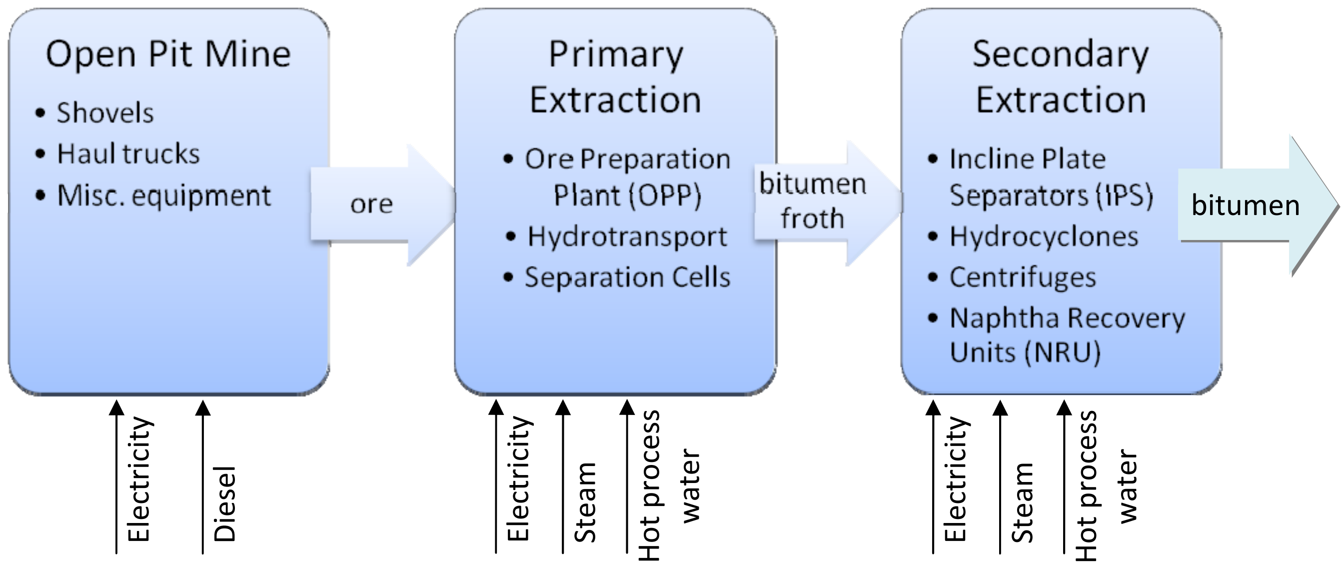
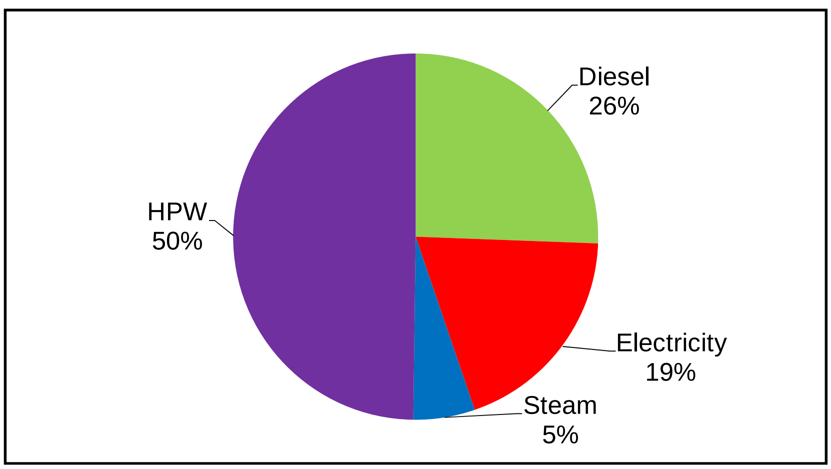


Figure 5-3.
Energy Breakdown in Mining and Extraction



Benchmark Development

To further understand where the energy is being consumed in a Mining and Extraction facility and to assist in the development of industry benchmarks for similar facilities, a set of energy efficiency metrics for surface mined bitumen production was developed as part of this Study.

The intention of the metrics is to allow a site to easily measure and compare the energy efficiency of its mined bitumen production facility. The metrics are based on fuel equivalent energy per tonne of oil sand feed and/or per cubic metre of bitumen produced. Estimating CO_2 generation from this energy use will use fixed conversion factors for each individual energy source from Section 3. For this Study, energy includes all major direct users (purchased fuels, and self-generated fuels) and the significant indirect energy users (electricity, steam, and hot process water). Fuel used to generate electrical power exported to the grid was excluded in determining Mining and Extraction facility energy consumption.

For this determination of energy efficiency metrics, the Mining and Extraction facility was broken down into two major sections: Mining (which includes shovels, heavy haulers and miscellaneous equipment) and Extraction (which includes Ore Preparation, Primary Extraction and Secondary Extraction). This division enables a better understanding of the contributions of the mine and the extraction plant to the overall energy consumption and enables clearer understanding of the impact of efficiency improvements. The separation of the extraction facilities from the mine occurs at the point where the mining heavy haulers deliver oil sands to the ore preparation plant at the dump hopper.

Energy consumption metrics are based on data for 2010 for the typical Mining and Extraction facility used in the Study. It is important to note that this is only a single year data point. Further work, including calculating the energy consumption and GHG emissions for a number of years as well as from other facilities operated by different companies, is needed to confirm the suitability of these metrics as industry benchmarks.

The mining metrics were developed per tonne of ore delivered to extraction to account for the total GHG impact of the geophysical aspects of the mine, such as removal of overburden and variation in the mine terrain. The extraction metrics were developed on both a per tonne of ore basis and a per cubic metre of bitumen basis to account for variations in ore quality. The metrics are reported based on an annual average for the facility that includes downtime and maintenance outages.

The metrics presented in this Study are preliminary, and have not been reviewed with other producers, government, or other key stakeholders.

Input Variables

The following data are used to calculate the energy efficiency metrics for the production of bitumen from a mining and extraction facility

- Mine
    - o Total diesel fuel consumed, litres per year (L/yr)
    - o Total power consumed, megawatt-hours per year (MWh/yr)
    - o Total tonnage of oil sands mined, metric tonnes per year (t/yr)
- Extraction Facilities
    - o Total steam consumed, metric tonnes per year (t/yr)
    - o Bitumen Production Rate, cubic metres per year (m^3/yr)
    - o Total Hot Process Water (HPW) consumed, cubic metres per year (m^3/yr)
    - o Temperature difference between HPW and make-up water, degrees Celsius (^{o}C)
    - o Total oil sand feed rate, metric tonnes per year (t/yr) of ore
    - o Total power consumed, megawatt-hours per year (MWh/yr)
    - o Total natural gas (or other fuels) consumed, gigajoules/year (GJ/yr) – on a lower heating value (LHV) basis

All combusted fuels are reported on an LHV basis.

For sites that export excess power to the grid, additional details of the cogeneration facilities are required, including:

- Cogen heat rate—net (excluding supplemental fuel and steam)
- Total power generated, MW
- Generated power used by the facility (or power exported)
- Fuel burned in the Cogen turbine
- Fuel burned in the heat recovery steam generator (HRSG)
- Total amount of steam generated—MTPY

At the Mining and Extraction facility used in the Study, all power exports are considered part of the Upgrader and are therefore not included in determining the mining and extraction energy efficiency metrics.

All of the energy numbers were converted to a fuel equivalent basis using the conversion factors from Table 3-1.

Based on these variables, two types of metrics can be developed to cover the total surface mineable bitumen production site:

- Primary Energy Efficiency Metrics—overall site energy intensity
- Secondary Energy Efficiency Metrics—process area utility consumption

The hierarchy of metrics for Mining and Extraction is shown in Figure 5-4.

Figure 5-4.
Proposed Mining and Extraction Metrics

Facility	Mining		Extraction	
Primary Metrics	GJ energy / tonne ore		GJ energy / tonne ore GJ energy / m^3 bitumen	
Secondary Metrics	L diesel / tonne ore	kWh / tonne ore	kWh / tonne ore	GJ HPW / tonne ore

Primary Metrics

The primary metrics are intended to provide an overall energy intensity number for the site, covering both Mining and Extraction.

Mining—The primary mining metrics are:

1. *Mining Energy Intensity per Tonne of Ore:* GJ of energy / tonne of ore - GJ of fuel equivalents (diesel + electricity) divided by the total tonnes of ore delivered to extraction

Note: the basis for the mining energy includes overburden removal and a portion of the run-of-mine ore that are not processed through the extraction facilities.

Extraction—The primary extraction metrics are:

1. *Extraction Energy Intensity per Tonne of Ore:* GJ of energy / tonne of ore - GJ of fuel equivalents (steam + hot process water + electricity) divided by the total tonnes of ore processed by extraction
2. *Extraction Energy Intensity per Cubic Metre of Bitumen:* GJ of energy / cubic metre of bitumen - GJ of fuel equivalent (steam + hot process water + electricity) divided by the cubic metres of bitumen (100% bitumen basis) delivered as product

Table 5-1 contains the primary energy metrics from the typical Mining and Extraction facility used in the Study based on 2010 data. These values are reported on a lower heating value basis, and reflect the energy intensity of the diesel, hot process water, steam, and electric power used by the mine and extraction facilities. The metrics take into consideration all energy consumed by the mining and extraction facilities regardless of where it was generated.

Table 5-1.
Primary Metrics for Typical Mining and Extraction Production Facility

Processing Facility	Energy Intensity per Tonne of Ore	Energy Intensity per m^3 of Bitumen
	GJ/tonne ore	GJ/m^3 bitumen
Mine	0.07	0.6
Extraction	0.11	1.1
Overall	0.18	1.7

The results in Table 5-1 are based on an average bitumen content of about 10 wt%, which depends on the ore quality being mined

Secondary Metrics

To better understand the operation of the surface mining facility, a set of secondary energy efficiency metrics was developed. By evaluating the individual utilities consumed in each of the process areas, specific areas that need improvement can more readily be identified.

Mining—The proposed secondary energy efficiency metrics for mining are:

1. *Mining Diesel Consumption:* Litre of diesel / tonne of ore - Litres of diesel (or GJ of fuel equivalents - LHV) divided by the total tonnes of ore delivered to Extraction
2. *Mining Electricity Consumption:* kWh / tonne of ore - kWh (or GJ of fuel equivalent - LHV) divided by the total tonnes of ore delivered to extraction

Energy efficiency metrics presented for the Typical Mining Facility presented in Table 5-2 are based on data from 2010. Values in the table are reported on an LHV basis.

Table 5-2.
Secondary Metrics for Typical Mining Facility

Secondary Metrics	Mining Diesel Consumption	Mining Electricity Consumption	Mining Energy Intensity	
			per tonne of Ore	per m^3 of bitumen
	L/tonne ore	kWh/tonne ore	GJ/tonne ore	GJ/m^3 bitumen
Diesel	1.8	---	0.07	0.6
Electricity	---	0.66	0.006	0.05

The diesel consumption metric is related to the heavy haulers that deliver both ore and overburden. The electricity consumption metric is related to the shovels operating in the mine.

Extraction—The proposed secondary energy efficiency metrics for extraction are:

1. *Electricity:* kWh / tonne of ore - kWh (or GJ of fuel equivalent) divided by the total tonnes of ore processed by Extraction
2. *Hot Process Water:* GJ of HPW / tonne of ore - GJ of fuel equivalent HPW divided by the total tonnes of ore processed by Extraction

The values for the energy consumption metrics for the typical Extraction plant in the Study presented in Table 5-3 are based on data from 2010. These values are reported on a lower heating value basis.

Table 5-3.
Secondary Metrics for Typical Extraction Facility

Energy Consumed	Electricity Consumption	Hot Process Water Consumption	Extraction Energy Intensity
	kWh/tonne ore	GJ/tonne ore	GJ/m^3 bitumen
Hot Process Water	---	0.05	0.5
Electricity	5.4	---	0.4

Hot Process Water is responsible for 75% of the energy used in extraction and just over 50% of the energy consumed in the entire Mining and Extraction facility. Over 98% of Hot Process Water is used in the primary extraction facilities. The majority of potential energy improvement could come from reducing hot process water consumption in primary extraction.

Electricity makes up an additional 25% of the energy consumed on a fuel equivalent basis in the Extraction facility. As a result of the long distances between the extraction process units, most of the electricity is used to transfer oil sand slurry to the extraction processes and transfer tailings from the extraction processes. Therefore, there will be little opportunity to reduce electricity consumption in this area.

Improvement Potential

We used the work process in Section 3 to evaluate energy and GHG reduction for bitumen extraction from ore. Potential improvements were identified and put into one of two categories:

- **Project Opportunities—**Operational and capital improvements that could be applied to a typical bitumen facility to improve the energy efficiency of the facility and reduce the GHG emissions
- **Technology Opportunities—**Incremental technologies that could be used to improve existing facilities and new technologies that could change the way new bitumen facilities are configured. The work process used to evaluate energy and GHG reduction for upgrading bitumen was outlined in Section 3.

Potential Project Ideas

A sample list of the operational and capital improvement ideas for Mining that were generated in the workshops and team meetings is shown in Table 5-4. The sample list for Extraction is in Table 5-5.

Table 5-4.
Mining—Potential Improvement Ideas

Operational Improvements
• Reduce idling time of equipment • Measure and better manage fuel use in contractors' equipment
Capital Improvements
• Change road designs to reduce fuel usage by heavy haulers • Add electrical sub-metering to allocate and better manage mine and extraction electricity usage • Deploy newer, more-efficient mine shovels • Investigate opportunities to reduce heating, cooling and lighting energy usage at buildings • Relocate substations to reduce line losses in low voltage lines

Table 5-5.
Extraction—Potential Improvement Ideas

Operational Improvements
• Further investigate minimum hot process water temperature required for ore extraction • Establish standard operating procedures (SOP) to reduce need to operate 3 (rather than 2) hydrotransport lines • Review winter hydrotransport flushing procedure to use cold water and establish SOP for flushing with hot process water • Review SOP on inter-stage tanks to stabilize extraction operations and minimize re-heat needs • Display energy key performance indicators on operators' digital control system • Perform heat exchanger audits and establish a routine maintenance program for key heat exchangers • Perform overall site energy audit and review steam trap maintenance programs • Optimize the number of tailings lines in service • Increase seal water pressure to reduce hot process water use on the froth lines • Investigate the use of tempered water at low rates for tailings lines • Establish an SOP for flushes at the centrifuges • Establish an SOP for use of start-up water after centrifuges are on-line • Create SOP for surge pile management at the mine and extraction for more consistent operation
Capital Improvements
• Add controllers to automate line flushes • Add controllers to optimize steam use in the naphtha recovery unit • Add controllers to maintain steady flow on the tailings lines • Improve rateability of mine • Investigate alternative methodologies to prevent blockages in equipment to reduce use of hot process water • Add a properly sized automated hot process line to froth lines • Investigate opportunity to swing hot diluent and reduce or eliminate the need for steam • Add additional controls for sumps and pump boxes for the hot transfer lines to optimize cold water use • Consider adding control on the hot process water to separation cell to better balance the density and flow to the separation cells

Results Summary for Potential Projects

The Energy Improvement Project ideas from Tables 5-4 and 5-5 were evaluated for the typical Mining and Extraction facility used in the Study to determine their potential impact on energy consumption and GHG emission reduction. Using a model of a typical Extraction facility, the top project ideas from idea screening were evaluated to determine their potential impact on energy and GHG emission reduction.

The potential improvement ideas were put into the Improvement Categories described in Section 3. Each category contains multiple projects, and the results of each category are summarized in Table 5-6, which shows the energy and GHG reduction from the top ideas and the estimated capital cost to achieve these results.

Economically achievable energy improvements were defined as having a simple payback of five years or less. Non-economically achievable projects were defined as projects having a greater than five-year simple payback period. These simple payback periods are in line with typical values used for initial screening for oil sands projects. All of the potential projects represented in Table 5-6 were considered economically achievable.

Table 5-6.
Summary of Energy Improvement Projects—Extraction

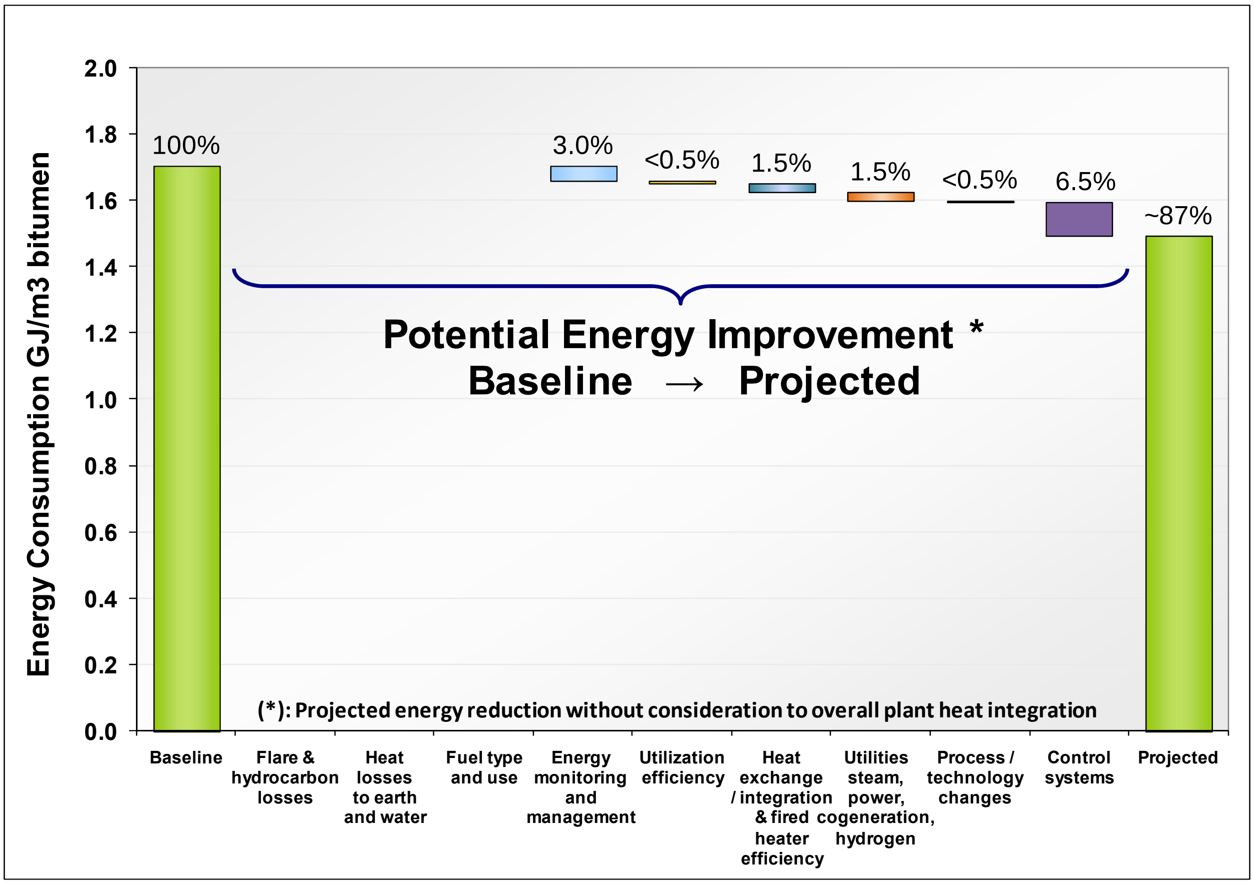
Extraction	Energy Reduction, GJ/m^3 bit	GHG Reduction, kg/m^3 bit	Capital Cost, \$M/m^3 bit
Flare & hydrocarbon losses	N/A	N/A	N/A
Heat losses to earth and water	N/A	N/A	N/A
Fuel type and use	N/A	N/A	N/A
Energy monitoring and management	0.04	3.3	<0.1
Utilization efficiency	0.01	0.7	<0.1
Heat exchange / integration & fired heater efficiency	0.03	2.0	0.2
Utilities	0.02	1.8	0.2
Process / technology changes	0.01	0.4	<0.1
Control systems	0.10	7.7	0.1
Total	**0.21**	**16.0**	**0.6**

Energy Reduction Potential

All the projected benefits from Table 5-6 for Extraction were evaluated and their impact on energy reduction compared in the waterfall chart in Figure 5-5, which provides a roadmap for efficiency improvement. This figure shows the combined impact of energy efficiency improvement on Primary and Secondary Extraction and is based on an energy baseline developed from 2010 operating data for the typical Extraction facility used in the Study.

The baseline energy intensity for the typical Extraction facility used in the Study, on the left-hand side of Figure 5-5, is 1.7 GJ/m^3 of bitumen on an LHV basis. Stepping in increments to the right-hand side of Figure 5-5, the energy consumption in Extraction could be reduced by approximately 13% to 1.5 GJ/m^3 of bitumen after implementing the potential energy improvement projects.

Figure 5-5.
Extraction - Energy Improvements Identified for the Typical Mining and Extraction Facility



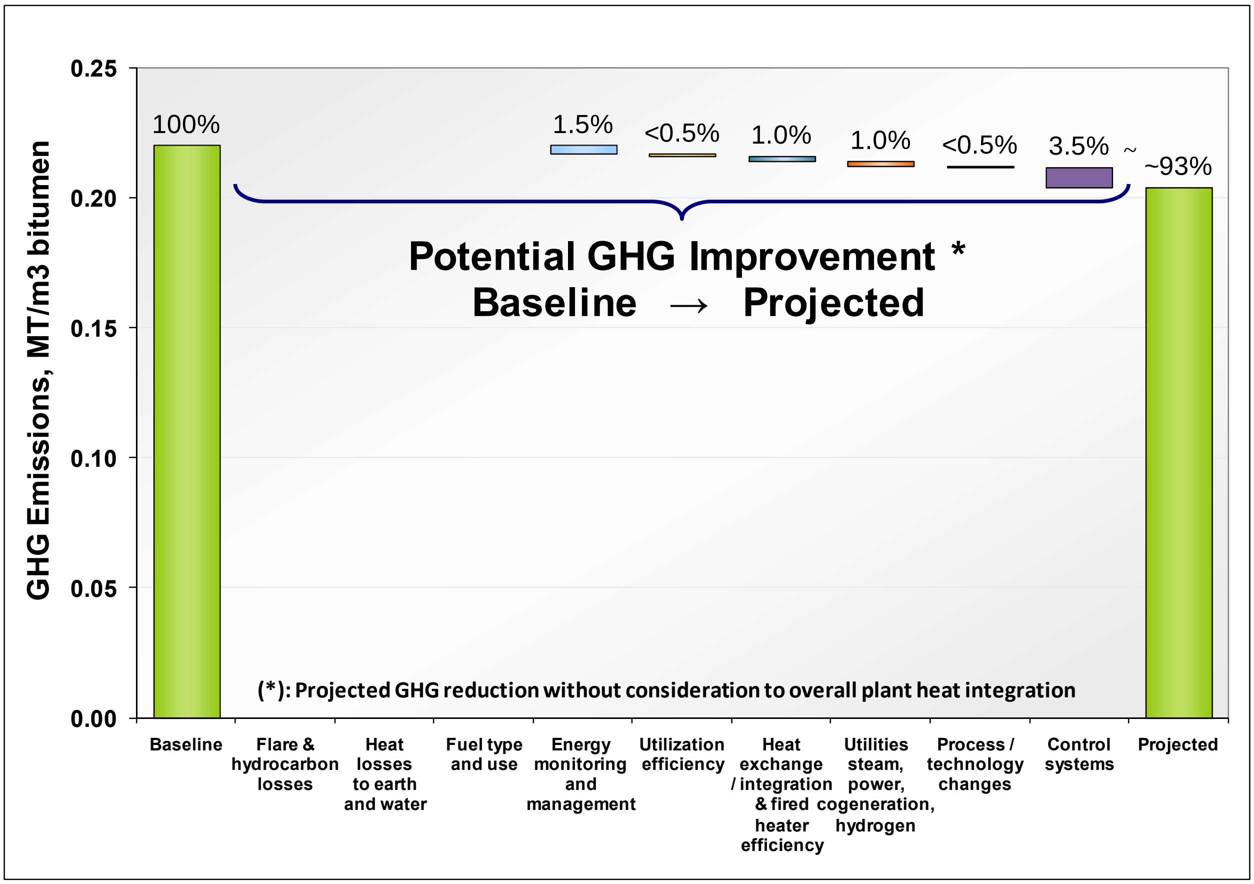
All of these results are based on preliminary project evaluations completed for this Study. A more detailed evaluation to confirm the capital costs and benefits must be conducted before these projects could be implemented.

It is also important to note that the energy savings in Extraction may not necessarily translate into reduced consumption of fuels and reduced GHG emissions—because much of the heat used in Extraction is low quality and a by-product of upgrading. The impact on emissions must be evaluated when the upgrading component is taken into account and a systems-level approach must be used to evaluate the heat integration impact of the facilities. This will be discussed further in the Section 7, the Integration section of the report.

Greenhouse Gas Emissions

The energy efficiency projects identified in this Study and discussed above could potentially reduce the GHG emissions by approximately 7%, from 0.22 MT/m^3 of bitumen to 0.20 MT/m^3 of bitumen. These results are shown in Figure 5-6.

Figure 5-6.
GHG Emissions Reduction for the Typical Mining and Extraction Facility



Two important aspects of the results shown in Figure 5-6 are worth noting. First, the baseline GHG emissions for Mining and Extraction assume that the heat used to produce hot process water for Extraction is generated from a combination of low-level heat and generated steam. This assumption overstates the baseline of GHG emissions because a great deal of the heat input in Extraction is due to indirect sources, particularly low-grade heat transfer from process cooling in upgrading. Second, the projected energy reduction in Extraction does not take into account the effect of overall plant heat integration. Consequently, efficiency improvement projects in Extraction may have a negative impact on the energy balance of the Upgrader and vice versa. These issues will be further discussed in Section 7, the Integration section of the report.

The 7% reduction in GHG emissions shown in Figure 5-8 could reduce GHG emissions from the typical Mining and Extraction facility in this Study by approximately 16 kg/m^3 of bitumen produced.

Technology Opportunities

The next step in the analysis identifies technologies that could be applied to improve energy efficiency of both the existing plants and/or new plant designs. The technologies were placed into the same categories as the current technologies: open pit mine, primary extraction, and secondary extraction.

Areas for Improvement in Mining and Extraction

The Mining and Extraction facility was separated into three sections:

- Open pit mine
- Primary Extraction
- Secondary Extraction and Tailings

Open Pit Mine

The majority of the ideas were focused on improving the efficiency of the heavy haulers or shortening haul distances. The technologies that were identified to improve energy efficiency are as follows:

- Use liquid natural gas (LNG) in heavy haulers
- Use fuel additives to improve efficiency
- Develop electrical / hybrid drive systems
- Use autonomous trucks (electric drive along main routes)
- Use coating to keep heavy haulers cleaner
- Develop clean idle systems for heavy haulers
- Use bio-fuel
- Develop mobile crusher technology
- Develop slurry-at-face technology

Primary Extraction

There are several technology ideas that can aid removing bitumen from the sand and mineral. The technologies identified are:

- Heat exchanger technology
- Use solvents to aid in bitumen separation
- Use surfactants to aid in bitumen separation
- Use other chemicals to aid in bitumen separation
- Improved ore analyzer technology
- Microwave separation technology
- Use high-specific gravity fluid for separation
- Use high shear to aid separation
- Low temperature bitumen extraction
- Low temperature deaeration

Secondary Extraction and Tailings

Very few technologies were identified that can aid in separating bitumen from water or in improving the handling of tailings. The limited number of ideas for handling tailings may be due to the fact that new technologies to reduce tailings are already being implemented. The technology ideas that were identified are:

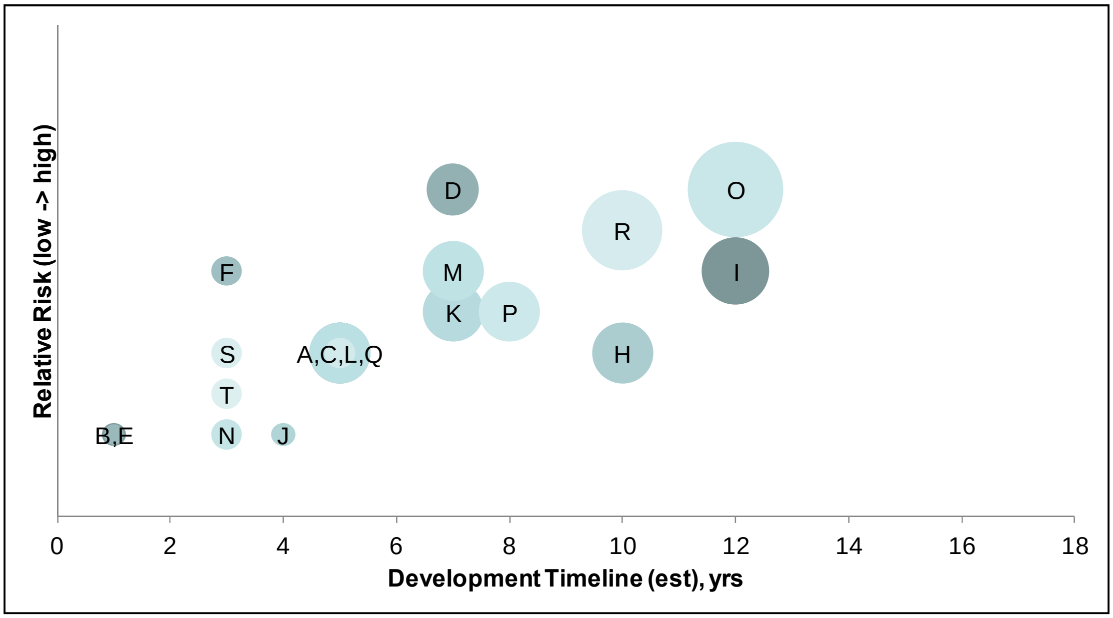
- Improved bitumen/water separation technology
- Improved water separation from tailings
- Improve thickeners to increase water recovery from middlings

All of the tailings technologies identified focus more on environmental improvements and have no direct impact on improving energy efficiency.

Potential Benefit in Mining and Extraction

Each technology that was identified was ranked based on potential energy benefit, relative risk and approximate development timeline based on current status. The qualitative assessment of relative risk included both operational and commercialization risks, including impacts on technology development, safety, reliability, operability, and production. The results of the ranking are shown in Figure 5-7. (Note: the size of the marker indicates the magnitude of the energy improvement.)

Figure 5-7.
Mining and Extraction Technology Assessment



A	LNG in heavy haulers	N	Improved ore analyzer
B	Fuel additives	O	Microwave separation
C	Electric/hybrid drive systems	P	High-specific gravity fluid
D	Autonomous trucks	Q	High shear
E	Coatings for heavy haulers	R	Low temperature extraction
F	Clean idle systems	S	Low temperature deaeration
G	Biofuel	T	Improved bitumen/water separation
H	Mobile crushers		
I	Slurry-at-face		
J	Heat exchanger technology		
K	Solvents		
L	Surfactants		
M	Other chemicals		

Based on the above ranking and additional input, the top ideas for improving the energy efficiency of Mining and Extraction bitumen production are:

- Developing hybrid/electrical drive systems for heavy haulers
- Surfactant injection in the extraction process
- Improved ore analyzers
- Improved water separation from bitumen

CO_2 Capture

The application of CCS to Mining and Extraction facilities is limited to large stationary sources. Therefore this technology cannot be applied in the mines, where the primary source of GHG emissions is the heavy haulers. In integrated extraction facilities there typically are no direct CO_2 emissions and CCS is not a technology that can be applied to reduce GHG emissions.

For stand-alone extraction facilities the main source of emissions is either boilers for steam production or co-generation facilities. As stated in Section 4 covering In Situ production of bitumen, stand-alone boilers are generally more suited to CO_2 capture than cogeneration facilities because the CO_2 is present at higher flue gas concentrations (typically 8-10% versus 4-8% in a cogeneration facility, depending on the configuration). Also, stand-alone boilers have lower stack gas temperatures, and are simpler in design than cogeneration facilities. Finally, CCS is not economically viable for Mining and Extraction facilities at current prices for CO_2, and CCS will increase the energy requirements at the facility.

Conclusions—Mining and Extraction Bitumen Production

- A set of energy efficiency metrics has been proposed to help evaluate and benchmark the energy efficiency of a mining and extraction facility. These metrics have been tested on the typical Mining and Extraction facilities of the Study, but further validation from a broader section of the industry is needed before these metrics can be finalized for use as benchmarks.
- Even with the improvements that have already been made to optimize the energy efficiency of Mining and Extraction facilities, approximately 13% incremental improvement in energy efficiency could potentially be realized.
- These energy efficiency improvements could result in approximately 7% reduction in GHG emission intensity of crude oil production from mining bitumen. Due to the integration of the Mining and Extraction facilities in the Study, these results will be re-evaluated in the Integration section of the report to determine if these initiatives have a positive impact on reducing overall GHG emission intensity.
- Based on technologies identified, the potential for improvement in Mining and Extraction is approximately 30 percent.
- Due to heat integration of the extraction facilities with upgrading, extraction has no direct GHG emissions; mining emissions are primarily from direct combustion of diesel in the heavy haulers and indirect emissions from electricity generated to power the shovels. However, any energy saved at extraction would free up more waste heat at upgrading,

improving the economics of energy conservation initiatives, or for investment in additional energy generation technologies such as steam turbines for electricity generation. This issue is discussed further in Section 7, the Integration section of this report.

- CCS for GHG reduction is not suitable for Mining and Extraction facilities that use low level heat from upgrading or on-site power generation. Finally, CCS is not economically viable for Mining and Extraction facilities at current prices for CO_2.

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Section 6.

Bitumen Production – Upgrading

Introduction

In this section of the Study we evaluate a typical operating bitumen upgrading facility using the methodology outlined in Section 3. The focus of this evaluation was to:

- Develop a set of preliminary energy efficiency metrics that can be used to assess and benchmark the facility's current performance and ongoing improvement.
- Define a baseline energy and CO_2 benchmark for the typical operating facility.
- Identify and evaluate energy efficiency improvements to determine costs/benefits and the potential magnitude of energy and CO_2 reduction opportunities.

Basis for Energy and GHG Estimation

Energy consumption from the typical upgrading facility in the Study includes energy consumed in supporting facilities such as the hydrogen generation plant and the utility plants, which include utility boilers. All direct and indirect energy requirements and CO_2 emissions were considered for this evaluation, which include:

- Direct energy utilized and CO_2 emitted within the boundaries of the Upgrader
- Indirect energy utilized and CO_2 emitted from other facilities that supply utilities to the site (e.g., power, imported steam).

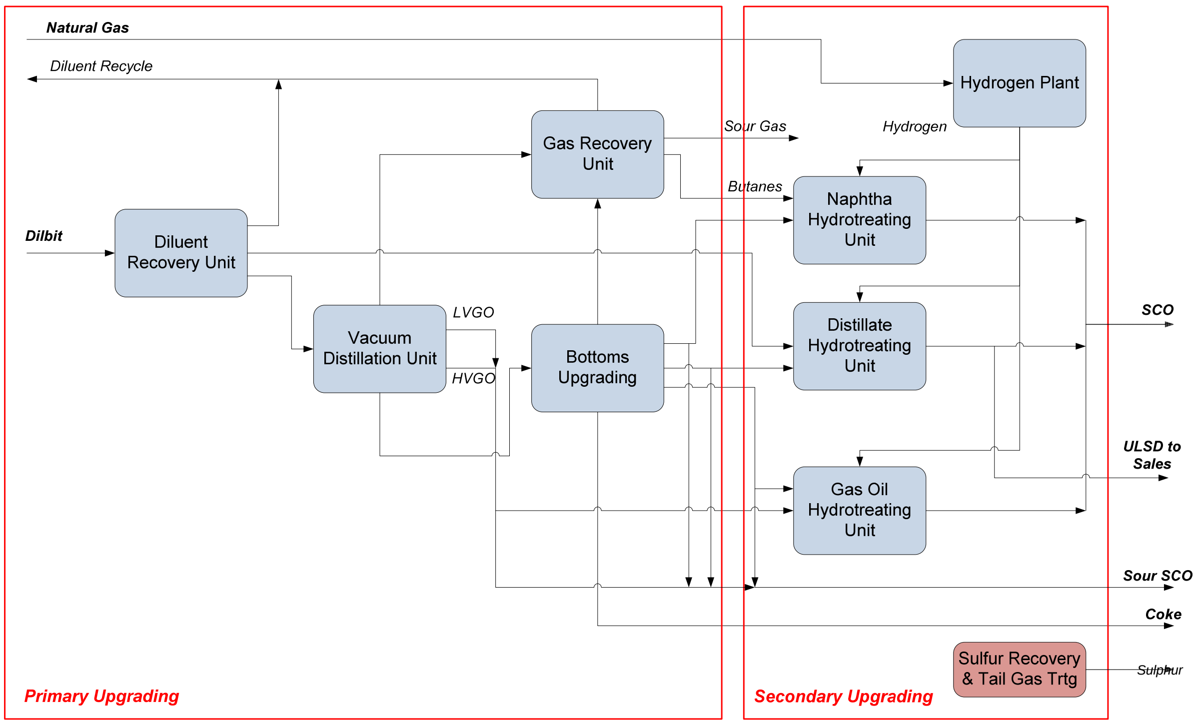
Process Overview: Upgrader Configuration

A general overview of upgrading was provided in Section 2. Additional detail is provided here to help explain some of the energy efficiency improvements and GHG reduction opportunities evaluated in the Study.

Figure 6-1 shows a schematic of an upgrading facility. We have broken upgrading down into two sections:

- Primary Upgrading—Mainly fractionation of bitumen and the products from Bottoms Upgrading. Bottoms Upgrading removes or reduces the refractory carbon in bitumen and increases the yield of lighter components.
- Secondary Upgrading—Improves the quality of products from Primary Upgrading by hydrotreating and produces SCO and other products that can be sent to market.

Figure 6-1.
Overview of Upgrading Facility



The Upgrader in this Study produces the following products for sale or disposal:

- **SCO:** Also called bottomless crude oil, which does not contain asphalt-range material). SCO is a mixture of naphtha, distillate, and gas oil. Some Upgraders produce primarily SCO and little or no other products. SCO can be sweet or sour depending on the extent of hydrotreating.
- **Diluent:** Typically a naphtha-range material that is recycled back to the Mining and Extraction facility or sold.
- **Ultra-low-sulphur diesel (ULSD):** Used in mining or sold to the market.
- **Sulphur:** All sulphur from the sulphur recovery plant is collected and exported.
- **Coke:** Residual refractory carbon product from Bottoms Upgrading; primarily stored in Alberta.

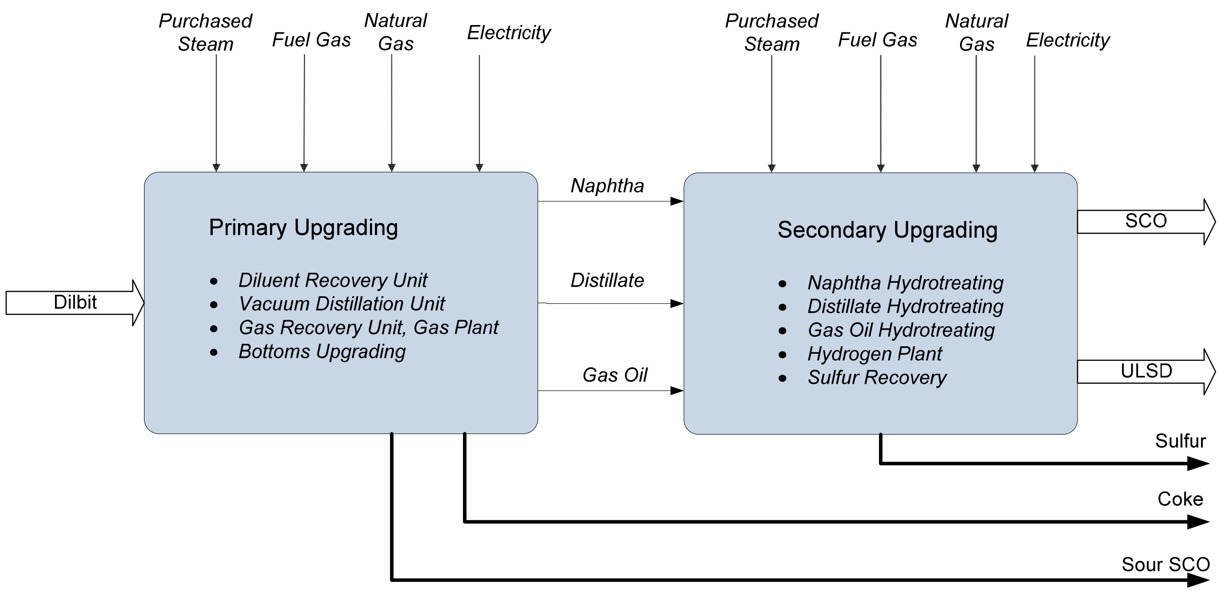
Energy Overview

The major energy inputs to the Upgrader are steam (often purchased from cogeneration facilities), natural gas, fuel gas (a gaseous mix of light hydrocarbons and hydrogen produced as a by-product of refining and upgrading processes), electricity (which may be purchased from the grid or generated on-site), and in some cases petroleum coke (produced as a by-product of delayed coking).

Based on the configuration described above, the estimated equivalent energy cost for operating an upgrading facility is approximately $4.60/bbl of bitumen processed on an annualized basis, assuming a representative energy cost of $6 per gigajoule (GJ) of energy.

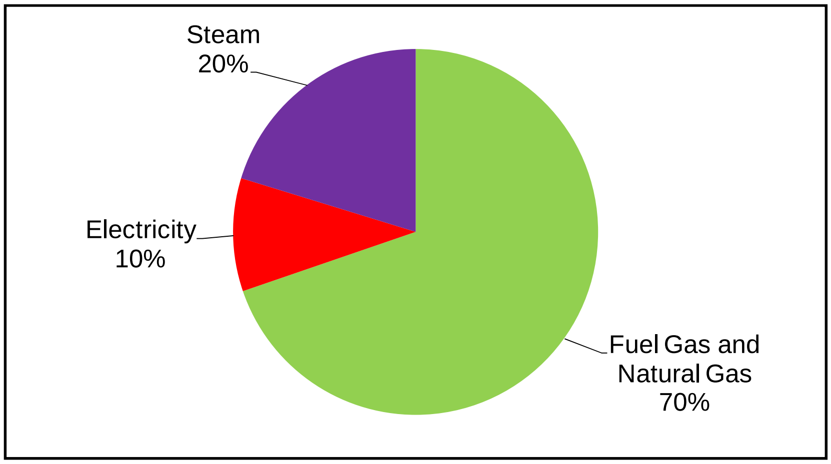
The utility sources required for each of the process areas are indicated in the figure below (Figure 6-2).

Figure 6-2.
Process and Energy Overview



The breakdown of the energy consumption for the Upgrader is shown in Figure 6-3.

Figure 6-3.
Upgrader Energy Consumption



The majority of energy used in a typical Upgrader is fuel gas produced in the Upgrader and imported natural gas. Most of the fuel gas in the Upgrader is from light gasses produced in the Upgrader. Fuel gas is used as a heat source for fractionation and in the Hydrogen Plant. Natural gas is used to make hydrogen in the Hydrogen Plant and, as needed, supplements fuel gas to provide heat for fractionation and heat for the Hydrogen Plant.

Hydrogen is added to naphtha, diesel, and gas oil in the hydrotreating units. The extent of hydrogen addition and the extent of hydrotreating in the Upgrader have a significant impact on the energy consumed by the Upgrader and can range from 2-5 GJ/m^3 of bitumen.

The other sources of energy used by the Upgrader are steam and electricity. Steam is generated from waste heat in the Upgrader and also from fuel gas. Electricity can be generated on-site from fuel gas or natural gas, or it can be imported from the grid. Most Upgraders in Alberta generate electricity on-site from fuel gas and natural gas.

Benchmark Development

To further understand where the energy is being consumed in an upgrading facility and to assist in the development of industry benchmarks for similar facilities, a set of energy efficiency metrics for bitumen upgrading was developed as part of the Study.

Although benchmarking methodologies already exist for most Upgraders, the intent of the metrics developed in this Study is to enable easy assessment and comparison of the energy efficiency of an upgrading facility. The metrics are based on fuel equivalent energy per cubic metre of bitumen processed. Estimating CO_2 generation resulting from this energy use will be based on fixed conversion factors for each individual energy source shown in Table 3-2.

In this Study, energy includes all major direct users (purchased fuels, and self-generated fuels) and the significant indirect energy users (electricity, and purchased steam). Any fuel burned to generate electrical power that is exported to the grid was excluded from the analysis of the upgrading area because the focus is on energy consumed and GHG emissions from upgrading bitumen not on electricity generation for export.

Metrics developed for the typical upgrading facility chosen for this Study are based on data from 2010. It is important to note that this is only a single year data point. Further work, including calculating the energy consumption and GHG emissions for a number of years as well as from other facilities operated by different companies, is needed to confirm the suitability of these metrics as industry benchmarks.

The metrics presented in this Study are preliminary and have not been reviewed with other producers, the government, or other key stakeholders.

The basis for the upgrading metrics is per cubic metre of bitumen processed. Because the extent of hydrotreating has a significant impact on the energy consumption of the Upgrader, the upgrading metrics were also evaluated per cubic metre of Sweet and Sour Products to capture the impact of hydrogen addition on energy efficiency. Sweet and Sour Products are defined as follows:

- Sweet Products—As used in the Study, *Sweet Products* refers to total production of hydrotreated products from the Upgrader blended into Sweet SCO or exported as finished product, including ultra-low-sulphur diesel. Sweet SCO is produced with hydrotreated gas oil, hydrotreated diesel, hydrotreated naphtha, and butane.
- Sour Products—As used in the Study, *Sour Products* refers to products from the Upgrader that are not hydrotreated, with the exception that Sour SCO may contain hydrotreated naphtha.

Metrics developed in this Study are based on an annual average for the facility, which includes downtime and maintenance outages. It is worth noting that downtime and maintenance outages will have a negative impact on the overall energy efficiency of the Upgrader even though these data are being included in the primary metrics. Reporting the extent and duration of the outage will help to quantify the results from these metrics.

Input Variables

The following data are used to calculate the energy efficiency metrics for the processing of bitumen in an upgrading facility:

- Upgrading
  - Bitumen feed rate, cubic metres per year (m^3/yr)
  - Sweet Products produced, cubic metres per year (m^3/yr)
  - Sour Products produced, cubic metres per year (m^3/yr)
  - Total steam purchased, tonnes per year (tonne/yr)
  - Pressure of steam purchased, bar gauge (bar_g)
  - Total power consumed, megawatt-hours per year (MWh/yr)
  - Total natural gas (refinery fuel gas and other fuels) consumed, gigajoules/year (GJ/yr)

For sites that export excess power to the grid, additional details of the cogeneration facilities are required, including:

- Total power generated, megawatt-hours per year (MWh/yr)
- Generated power used by the facility (or power exported), megawatt-hours per year (MWh/yr)
- Fuel burned in the Cogen turbine, gigajoules/year (GJ/yr) – on a lower heating value (LHV) basis
- Fuel burned in the heat recovery steam generator (HRSG), gigajoules/year (GJ/yr) – on a lower heating value (LHV) basis
- Total amount of steam generated, tonnes per year (tonne/yr)

All of the energy values were converted to a fuel equivalent basis, and all combusted fuels are reported on an LHV basis using the factors from Table 3-1. Energy is converted to GHG using the conversion factors in Table 3-2.

The conversion factor for fuel gas produced by the Upgrader will vary based on the gas composition and should be measured and reported by the Upgrader.

Determination of Metrics for Upgrading

Based on these variables, two types of metrics were developed for the typical upgrading facility in the Study:

- Primary Energy Efficiency Metrics—overall site energy intensity
- Secondary Energy Efficiency Metrics—process area utility consumption

The hierarchy of metrics is shown in Figure 6-4.

Figure 6-4.
Proposed Upgrading Energy Efficiency Metrics

Facility	**Upgrading**		
Primary Metrics	GJ energy / m^3 bitumen GJ energy / m^3 sweet product GJ energy / m^3 sour product		
Secondary Metrics	kWh / m^3 bitumen	GJ steam / m^3 bitumen	GJ fuel gas / m^3 bitumen

Primary Metrics

The primary metrics are intended to provide an overall energy intensity value for the site, which covers all of the upgrading facilities. The primary upgrading metrics are:

1. *Overall Bitumen Processed:* GJ of energy / cubic metre of bitumen - GJ of fuel equivalents (steam + fuel gas + electricity) divided by the cubic metres of bitumen (100% bitumen basis) received as feed
2. *Sweet Products:* GJ of energy for producing Sweet Product / cubic metre of sweet product - GJ of fuel equivalent (steam + fuel gas + electricity) from a portion of primary upgrading + all secondary upgrading divided by the cubic metres of hydrotreated product

3. *Sour Products:* GJ of energy for producing Sour Product / cubic metre of sour products - GJ of fuel equivalent (steam + fuel gas + electricity) from the other portion of primary upgrading divided by the cubic metres of un-hydrotreated product

Table 6-1 contains values for the primary metrics based on one year of data from the typical Upgrader used in the Study.

Table 6-1.
Primary Metric Values for Typical Upgrader

Bitumen Processed	Sweet Products	Sour Products
GJ/m^3 bitumen	**GJ/m^3 Sweet Products**	**GJ/m^3 Sour Products**
2.7	4.5	2.7

The above upgrading metrics reflect the energy intensity of the steam, fuel gas, and electric power used by the upgrading facilities to process bitumen and to produce products. For the typical upgrading facility shown in these metrics, it is coincidental that the Energy Intensity of Bitumen Processed and Sour Products are the same. This is not a typical result and will vary based on the ratio of sweet to sour products.

Secondary Metrics

To better understand the operation of the upgrading facility, a set of secondary energy efficiency metrics was developed. Specific areas that need improvement can be more readily identified by evaluating the individual utilities consumed in each of the process areas.

The proposed secondary upgrading energy efficiency metrics are:

1. *Electricity Consumption:* kWh / cubic metre of bitumen - kWh (or GJ of fuel equivalent - LHV) divided by the total cubic metres of bitumen delivered to the upgrader
2. *Fuel Gas Consumption:* GJ of fuel gas / cubic metre of bitumen - GJ of fuel gas (LHV) divided by the total cubic metres of bitumen delivered to the upgrader
3. *Steam Consumption*: GJ of purchased steam / cubic metre of bitumen - GJ of fuel equivalent steam divided by the total cubic metres of bitumen delivered to the Upgrader

Data from 2010 for operation of the typical Upgrader in the Study were used to calculate energy efficiency metrics, and are presented in Table 6-2. Results are reported on an LHV basis.

Table 6-2.
Secondary Metric Values for Typical Upgrader

Energy Consumed	kWh/m^3 bitumen	GJ/m^3 bitumen
Fuel Gas and Natural Gas	---	1.8
Electricity	35	0.3
Steam	---	0.6

Fuel gas including natural gas is the single largest energy source consumed in the Upgrader and constitutes approximately 70% of the energy consumed in the facility. Reducing fuel gas and natural gas consumption in upgrading is where the majority of the potential energy improvements should be focused.

Steam makes up an additional 20% of the energy consumed on a fuel equivalent basis in the upgrading facility. Optimizing the steam system in the Upgrader could reduce energy consumption and GHG emissions.

Electricity makes up the final 10% of the energy consumed in the Upgrader. Most of the electricity demands are fixed in the Upgrader, but installation of variable frequency drives in some services could reduce electricity consumption. These ideas and others for improving energy efficiency are discussed further below.

Improvement Potential

We used the work process in Section 3 to evaluate energy and GHG reduction for bitumen upgrading. Potential improvements were identified and put into one of two categories:

- **Project Opportunities—**Operational and capital improvements that could be applied to a typical bitumen upgrading facility to improve the energy efficiency of the facility and reduce the GHG emissions.
- **Technology Opportunities—**Incremental technologies that could be used to improve existing facilities and new technologies that could change the way new upgrading bitumen facilities are configured. The work process used to evaluate energy and GHG reduction for upgrading bitumen was outlined in Section 3.

Potential Project Ideas

A sample list of the operational and capital improvement ideas generated in the workshops and team meetings is shown in Table 6-3.

Table 6-3.
Upgrading — Potential Improvement Ideas

Operational Improvements
• Optimize steam balance • Optimize fuel gas management plan • Implement energy management system • Reduce blowdown from steam generators • Improve condensate recovery from diluent recovery unit • Reduce flaring by optimizing coke drum cycles • Optimize steam use in sour water strippers • Optimize compressed air system
Capital Improvements
• Implement cooling water fouling mitigation program to reduce fuel gas production • Increase furnace efficiency through maintenance improvements • Reduce steam loss through improvements in the steam trap maintenance program • Use higher-grade heat sources to produce hot process water • Eliminate hydrogen vents to flare • Reduce slops processing • Optimize energy usage by installing advanced process control on diluent recovery unit • Convert boilers to handle refinery fuel gas • Add or improve convection sections in fired heaters • Replace boilers with cogeneration plants • Install flare gas recovery system • Repair/replace economizers on heat recovery steam generators • Install let down turbine between high pressure and low pressure separator in hydrotreaters • Improve recovery of flash gas from rich amine • Reduce heat loss from hot process water lines by improving insulation • Send feed hot to hydrotreaters • Install additional power recovery turbines on steam letdowns • Recover additional steam condensate

The Energy Improvement Project ideas from Table 6-3 were evaluated to determine their potential impact on energy consumption and GHG emission reduction for the typical upgrading facility. Using a model of the typical upgrading facility, the top project ideas from the idea screening were evaluated to determine their potential impact on energy and GHG emission reduction.

Results Summary for Potential Projects

The potential improvement ideas in Table 6-3 were put into the Improvement Categories described in Section 3. Each category contains of multiple projects. The results of each category in Table 6-4 show the energy and GHG reduction from the top ideas and the estimated capital cost to achieve these results. For the typical Upgrader evaluated in this Study, the project ideas in Table 6-4 were evaluated to determine their potential impact on energy consumption and GHG emissions reduction

Economically achievable energy improvements were defined as having a simple payback of five years or less. Non-economically achievable projects were defined as projects having a greater than five-year simple payback period. These simple payback periods are in line with typical values used for initial screening for oil sands projects. All of the potential projects represented in Table 6-4 were considered economically achievable.

Table 6-4.
Summary of Energy Improvement Projects—Upgrading

Improvement Categories	Energy Reduction, GJ/m^3 bit	GHG Reduction, kg/m^3 bit	Capital Cost, \$M/m^3 bit
Flare & hydrocarbon losses	0.08	4.8	<0.1
Heat losses to earth and water	N/A	N/A	N/A
Fuel type and use	0.06	3.2	0.1
Energy monitoring and management	0.03	1.3	<0.1
Utilization efficiency	N/A	N/A	N/A
Heat exchange / integration & fired heater efficiency	0.09	5.3	1.0
Utilities – steam, power, cogeneration, hydrogen (including indirect emissions)	*	*	*
Process / technology changes	0.04	2.5	<0.1
Control systems	0.05	2.9	<0.1
Total	**0.35**	**20.0**	**1.2**

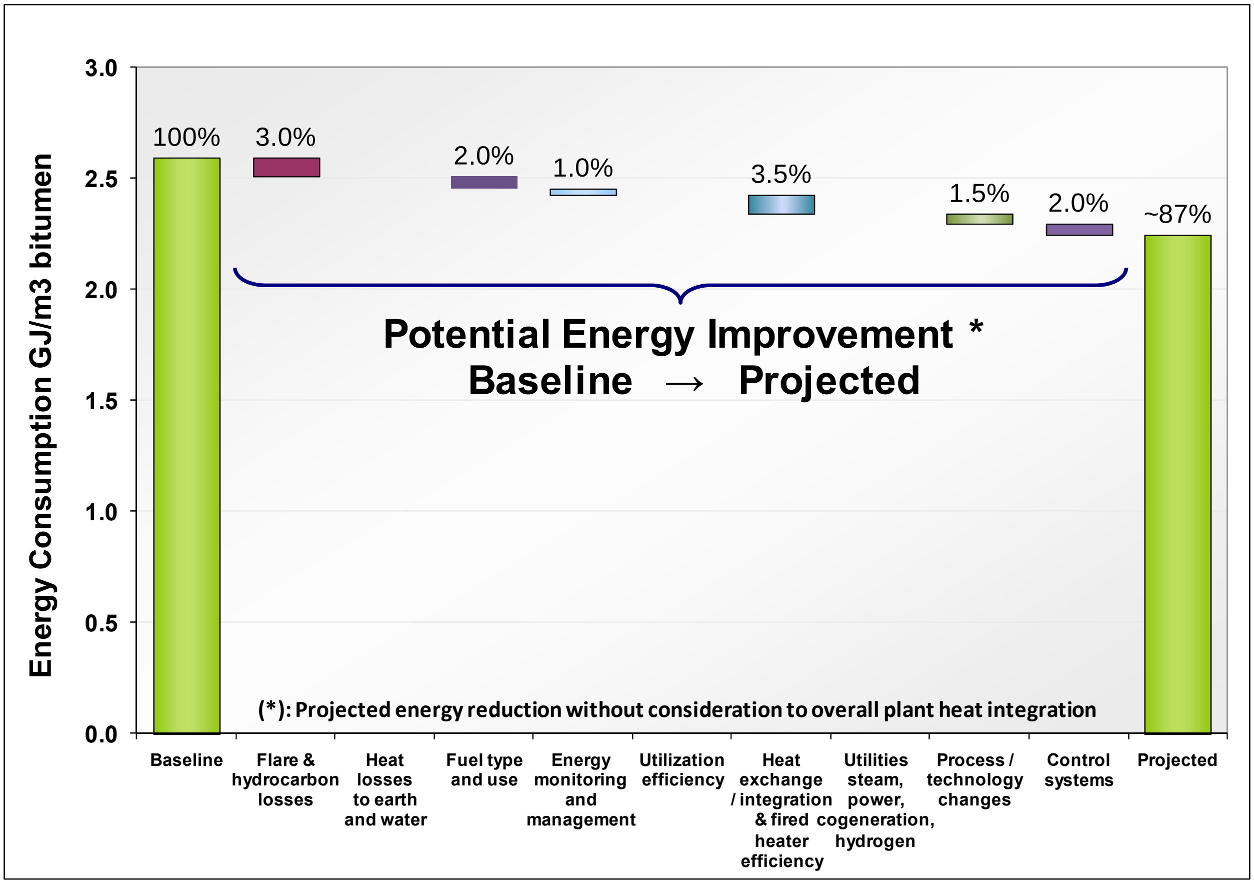
Additional projects were identified that impact the site-wide steam and power generation that are not included in the upgrading projects shown in Table 6-4. These projects resulted in an additional 0.9 GJ/m^3 bitumen energy savings and a reduction in GHG emissions of 7.7 kg/m^3, but required an additional \$0.9M/m^3 bitumen in capital for implementation.

Energy Reduction Potential

All the projected benefits from Table 6-4 were evaluated and their impact on energy reduction compared in a waterfall chart shown in Figure 6-5, which provides a roadmap for efficiency improvement.

The energy baseline, developed from 2010 operating data for the Typical Upgrader, is shown on the left-hand side of Figure 6-5. This depicts energy consumption of 2.6 GJ/m^3 of bitumen on an LHV basis. Stepping in increments to the right-hand side of Figure 6-5, the energy consumption in upgrading after implementation of potential energy improvement projects could be reduced to 2.2 GJ/m^3 of bitumen—a 13 % reduction in energy consumption in upgrading.

Figure 6-5.
Energy Improvements Identified for the Typical Upgrading Facility

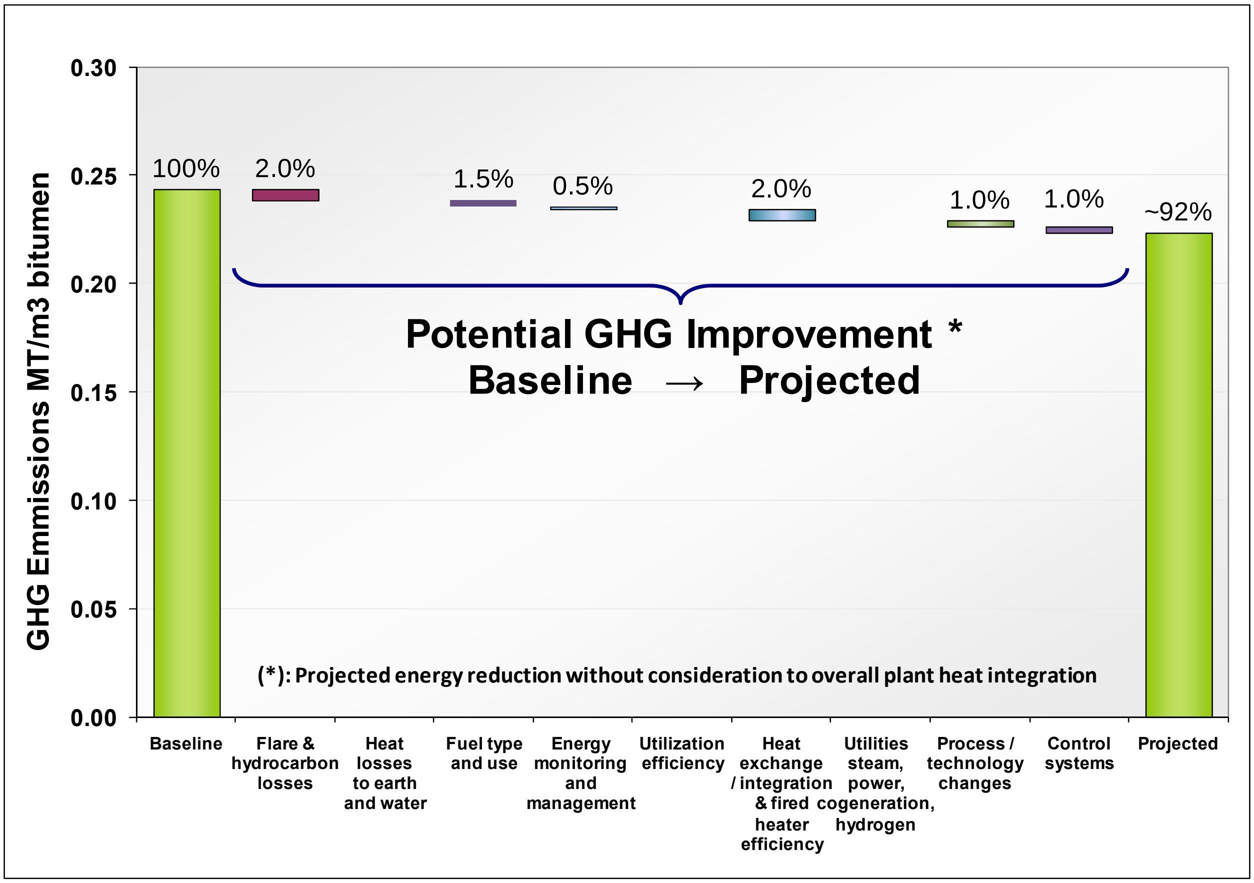


All of these results are based on preliminary project evaluations completed for this Study. A more detailed evaluation to confirm the capital costs and benefits will need to be conducted before these projects could be implemented.

Greenhouse Gas Emissions

The GHG emission reduction resulting from improving energy efficiency through the implementation of the potential projects identified in this review is approximately 8 percent. The baseline GHG emissions for the typical upgrading facility on the left hand side of Figure 6-6 was reduced from 0.24 MT/m^3 of bitumen to 0.22 MT/m^3 of bitumen as a result of the energy improvements identified.

Figure 6-6.
GHG Emission Reduction for the Typical Upgrading Facility



Technology Opportunities in Upgrading

The next step in the analysis identifies technologies that could be applied to improve energy efficiency of both the existing plants and/or new plant designs.

Areas for Improvement in Upgrading

The technologies were placed into the same categories as the current technologies: bitumen separation and hydrotreating.

Bitumen Separation

Most of the technologies identified were selected based on improved fractionation, which is a common focus in other hydrocarbon processing plants. The technologies identified to improve energy efficiency are as follows:

- Remove diluent loop
- Nuclear power steam generation
- Organic Rankine Cycle for low-level heat recovery
- Membrane separation
- Improve heat exchanger technology
- High-pressure fractionation
- Molecular sieve fractionation
- Cross-flow coking
- Improve tray technology specific for bitumen

Hydrotreating

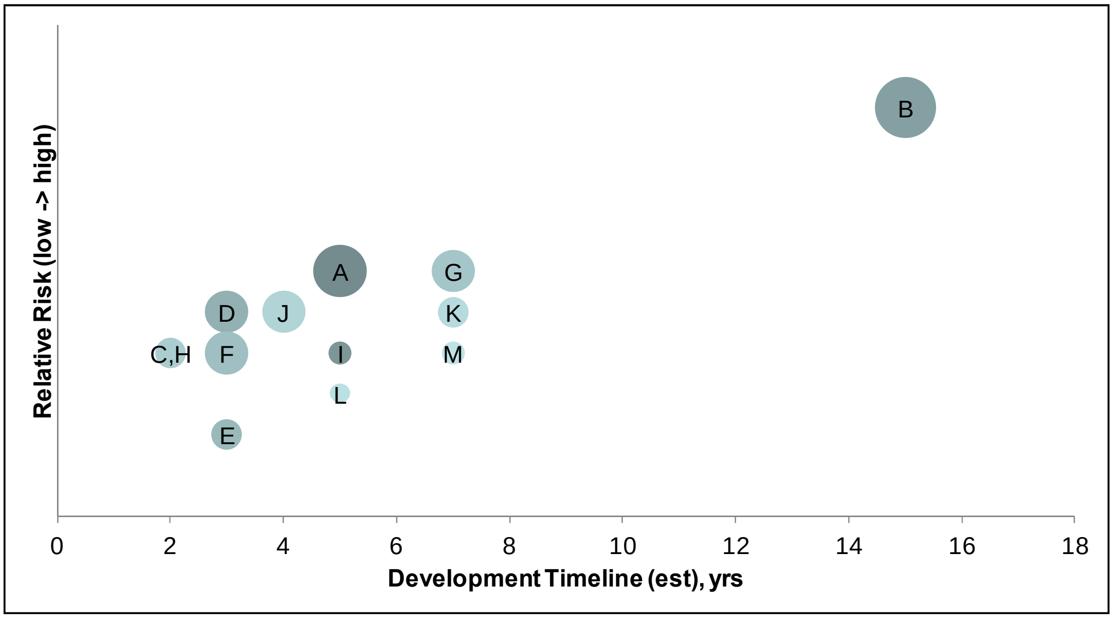
Several technology ideas can aid in removing sulphur from the bitumen while improving the overall energy efficiency of the operation. These are:

- Combined fractionation
- New technology for H_2 production
- Hydroprocessing catalyst
- Low-cost hydrogen purification technology for streams containing hydrogen

Potential Benefit

Each identified technology was ranked based on potential energy benefit, relative risk, and approximate development timeline based on current status. The qualitative assessment of relative risk included both operational and commercialization risks, which included impact on technology development, safety, reliability, operability, and production. The results of the ranking are shown in Figure 6-7. (Note: the size of the marker indicates the magnitude of the energy improvement.)

Figure 6-7.
Upgrading Technology Assessment



A	Remove diluent loop	H	Cross-flow coking
B	Nuclear power steam generation	I	Improved tray technology
C	Organic Rankine Cycle	J	Combined hydrotreating fractionation
D	Membrane separation	K	New technology for H2 production
E	Improved heat exchanger technology	L	New hydroprocessing catalyst
F	High pressure fractionation	M	Low cost H2 purification
G	Molecular sieve fractionation		

Based on the ranking in Figure 6-7 and additional input, the top ideas for improving the energy efficiency of upgrading bitumen are:

- Remove diluent loop
- Improve tray technology
- New technology for hydrogen production

CO_2 Capture from Upgrading

Upgraders are made up of numerous types of process units that each have different flue gas compositions and design considerations. Not all sources are suited for CO_2 capture. The emissions sources that are potentially suited to CO_2 capture and storage include:

- Heaters and boilers (50-60% of plant emissions)
- Hydrogen plants (30-40% of plant emissions)

Other technologies that may be on site, depending on the configuration of the Upgrader, are:

- Combustion turbines/cogeneration facilities
- Coke combustion/catalyst regeneration

One major barrier to CO_2 capture at upgrading facilities, particularly in retrofit applications, is the available space at the facility. Typically upgrading facilities are very complex and congested. Many CO_2 capture technologies require significant plot space, which may restrict installation at existing Upgraders. Because of these limitations, it is anticipated that only 30-50% of the emission sources in a typical Upgrader could feasibly be addressed with CCS, resulting in a 20-40% reduction in GHG emissions, depending on how the utilities (steam/power) are produced to run the capture facility. It is important to note, however, that under the current and anticipated economic and regulatory environment, CCS is not economically viable for bitumen upgrading facilities. Also, CCS will increase the energy requirements at the facility.

Conclusions—Bitumen Upgrading

- A set of energy efficiency metrics have been proposed to help evaluate and potentially benchmark the energy efficiency of an upgrading facility. Further validation from a broader section of the industry is needed before these metrics can be used as benchmarks.
- This study identified an energy efficiency improvement for a typical upgrading facility of approximately 13 percent.
- These incremental improvements in energy efficiency could result in an approximately 8% reduction in CO_2 emission intensity of crude production with further reduction in CO_2 emissions possible upon completion of site-wide utility projects.
- Based on technologies identified, the potential energy consumption for bitumen upgrading could be reduced by approximately 10 percent.

- All improvement projects and their potential benefits identified in this Study require a more detailed evaluation before they can be considered for implementation.
- CCS is not economically justified at current CO_2 costs.

Section 7.

Impact of Integration

Introduction

Heat integration between the various bitumen production and upgrading facilities was identified as an important component in improving energy efficiency. The potential to improve the heat exchange network within each facility (In Situ, Mining and Extraction, and Upgrading) has been evaluated in the prior sections. In this section we will address the transfer of energy between the major processing areas with the objective of lowering the GHG emissions of the overall facility.

Two specific cases of integration between the facilities examined in this Study were identified as critical to developing a high efficiency integrated facility:

1) Integration of a cogeneration plant with facilities that require both steam and power, including upgrading, In Situ bitumen production, and, to some extent, Extraction. In this Study, cogeneration is defined as a gas turbine connected to a power generator for producing electricity followed by a heat recovery steam generator (HRSG) to produce steam. In this case, steam is used directly as a heat source—for example, for In Situ production of bitumen. No steam, or minimal steam, is sent to a condensing turbine for additional power generation as is done in a Natural Gas Combined Cycle (NGCC) facility.
2) Integration of low-level heat sources in upgrading, and to some extent cogeneration facilities, with an Extraction facility to provide the low-level heat used for separation of bitumen from oils sands ore.

Maximizing these integration opportunities will result in a significant decrease in GHG emissions.

Integration of Cogeneration

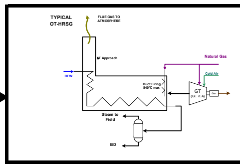
The fundamental driver for integrating a cogeneration facility with bitumen production and upgrading facilities is the inherent higher efficiencies that can be achieved when producing both steam and power simultaneously versus generating steam in a conventional boiler and importing power from an NGCC or coal-fired power plant.

The impact of cogeneration can be demonstrated by looking at the fundamental efficiencies of these two options. For this comparison it is assumed that imported power was generated in a stand-alone NGCC power plant.

Figure 7-1 shows the energy consumption to produce 333 MT/hr of steam and 82 MW of electricity from natural gas via cogeneration at the bitumen production facility with no condensing cycle (the upper figure) and from natural gas in an NGCC plant providing electricity to the grid and a stand-alone boiler at the bitumen production facility (the lower figure). In the cogeneration example, the energy input is 1372 GJ/hr. In the NGCC and stand-alone boiler example, the energy input is 1472 GJ/hr to produce the same amount of electricity and steam.

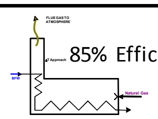
Figure 7-1.
Process and Energy Overview

Cogeneration (with no condensing cycle)



				Flow	Conversion	Energy
Nat Gas	1372 GJ/hr		Steam	333 MT/hr	2.2078 GJ/MT	736 GJ/hr
Total	1372 GJ/hr		Electricity	82 MW	3.597 GJ/MWh	295 GJ/hr
					Total	1031 GJ/hr
				Overall Efficiency	75.1% =	4540 BTU/kWh
				CO2 Emissions	1910 MT/day	(based on 0.058 MT/GJ)

Boiler + Import Power from the Grid



				Flow	Conversion	Energy
Nat Gas	866 GJ/hr	85% Efficiency	Steam	333 MT/hr	2.2078 GJ/MT	736 GJ/hr
Nat Gas	606 GJ/hr	Public Grid Assumes NGCC with 7000 BTU/kWh	Electricity	82 MW	3.597 GJ/MWh	295 GJ/hr
Total	1472 GJ/hr				Total	1031 GJ/hr
				Overall Efficiency	70.1% =	4870 BTU/kWh
				CO2 Emissions	2048 MT/day	(based on 0.058 MT/GJ)

In this example:

- The overall cogeneration efficiency is 75% (or 4540 BTU/kWhr)
- Stand-alone boiler efficiency is assumed to be 85%
- The Public Grid can supply power at a net efficiency of 7000 BTU/kWhr (~49% efficiency; roughly equivalent to an NGCC facility)

In this example, a bitumen production facility that requires both steam and electrical power will achieve a net energy efficiency improvement (and GHG reduction) of 5% on the total steam and electricity by integration with cogeneration versus importing NGCC-based power from the grid and generating steam in a boiler.

A key point is that the fundamental improvement in energy efficiency from integrating with a cogeneration facility is the improved efficiency of electricity generation. In the above examples, the advantage of natural gas-based cogeneration over NGCC is that the integrated site can use steam directly as a heat source and does not require routing this steam to a lower efficiency condensing steam turbine as is done in a typical NGCC. Note that if the comparison is made between a natural gas-based cogeneration facility and coal-fired power generation (at roughly 40% efficiency) instead of an NGCC facility, the benefits would be significantly higher. (Note that the average net efficiency of the Alberta area electrical grid is approximately 42 percent.)[1]

There are several factors that can impact a facility's ability to integrate with a cogeneration plant. One concern is balancing the ratio of steam demand to power demand at a production site with the ratio produced from a cogeneration facility. In the above examples, the maximum efficiency of cogeneration is obtained when the total steam production from cogeneration matches the steam demand of the facility integrated with it. For most bitumen production facilities, achieving high cogeneration efficiency typically results in exporting excess electrical power to the grid. Building larger cogeneration facilities with power generation beyond the site demand has the added benefit of economies of scale for the purchased equipment.

A second issue for a well-integrated cogeneration facility is the full recovery of stack heat from the cogeneration plant. Cold streams, such as low temperature boiler feedwater, can be efficiently heated by combustion flue gases in an economizer section of a cogeneration steam boiler exhaust or an economizer section of a conventional steam boiler. However, if there is insufficient demand for low-level heat—which may occur in some SAGD facilities that use down-hole pumps and return significant amounts of low-level heat to the surface facilities—there is no need for an economizer section to preheat the boiler feed water. The net result is higher flue gas temperatures and lower overall efficiencies. Unlike cogeneration plants, conventional steam boilers have the option of pre-heating combustion air to recover stack gas heat and can potentially avoid this associated energy loss. For example, the efficiency of a boiler will decline by 1.2% for a 50°C increase in flue gas temperature. Therefore, the degree of efficiency loss from the inability to recover stack heat depends on both the equipment design of the facility and the nature of the reservoir being developed.

A third issue when integrating a cogeneration facility is managing issues associated with the variability in steam demand at a site. In some cases the marginal efficiency of a boiler can be higher than the marginal efficiency of varying the supplemental firing of the cogeneration boilers. Managing the continuous supply of both steam and electricity that accounts for demand variability, equipment maintenance, and unaccounted for disruptions can have cost impacts significantly beyond the energy savings of higher efficiencies.

With consideration of these limitations, a production site with the highest degree of integration with a cogeneration facility would have the following characteristics:

- All electrical power and base load steam demand at the site would be supplied by a cogeneration facility.
- The cogeneration facility should have a high net heat rate (efficiency). This would include:
    - A modern high-efficiency gas turbine
    - Limited or no condensing cycle for power generation via a surface condenser (air or water)
    - Supplemental firing to allow minimum excess oxygen levels in the flue gas
    - Low stack temperature on the cogeneration flue gas (<220°C) representing good recovery of flue gas heat

Furthermore, the efficiency of the electricity generated in the cogeneration facility would need to be greater than that of imported power. It is understood that each integration case would need to be evaluated individually based on these factors along with the economics of capital and utility costs associated with the investment.

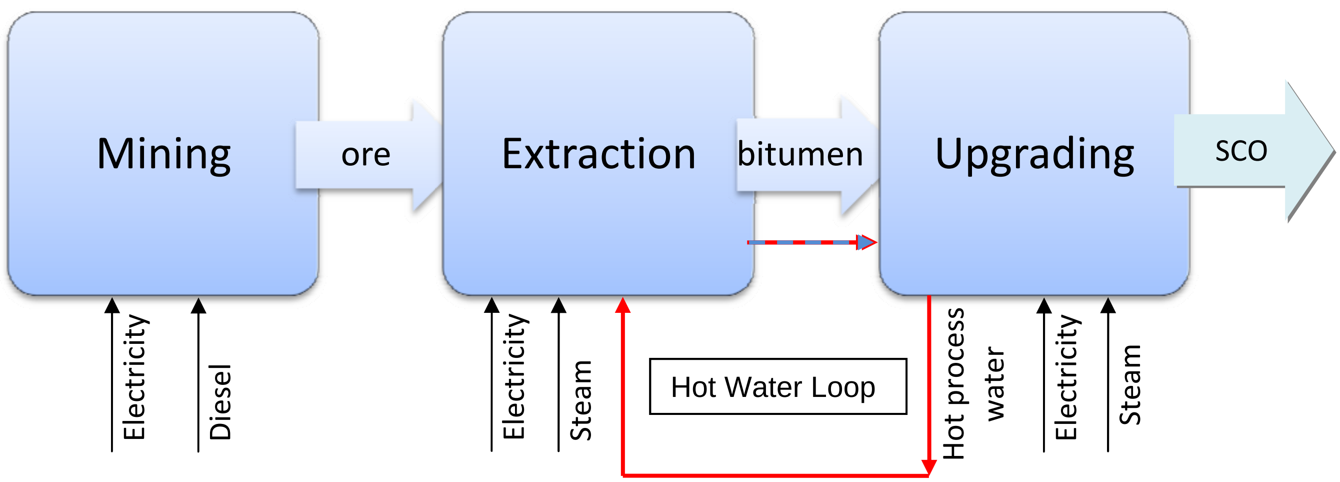
Most of the existing bitumen production facilities in Alberta, including In Situ, Mining and Extraction, and Upgrading, are currently integrated with cogeneration facilities. As a result, there is a significant amount of information available from publications from the ERCB and AI-EES that discuss the potential benefits of cogeneration.

In the utility system for a typical oil sands facility, excess steam or steam letdowns can be routed to a condensing type power generation turbine for additional electricity generation. When steam is routed to a condensing type power generation turbine, the surface condenser on the exhaust steam from the turbine can be replaced with a waste heat recovery exchanger that generates usable heat for a typical Extraction facility, thereby minimizing the efficiency loss of the condensing turbine. This optimization is discussed below.

Low-Level Heat Integration in Mining and Extraction

The mining and extraction process is unique in that the primary source of energy required for the process is the need for hot water to extract the bitumen from the oil sands ore. The hot water used in this process is typically in the range of 50-80°C. This temperature range is generally considered to be low-grade heat in most upgrading and cogeneration facilities that is uneconomic to recover. This low-grade heat would typically be sent to air coolers to dispose of the heat. However, when these facilities are linked to a Mining and Extraction process, the heat that is normally discarded to air coolers can be recovered to a hot water loop to provide heat to the Extraction process. A diagram of this type of configuration is shown in Figure 7-2.

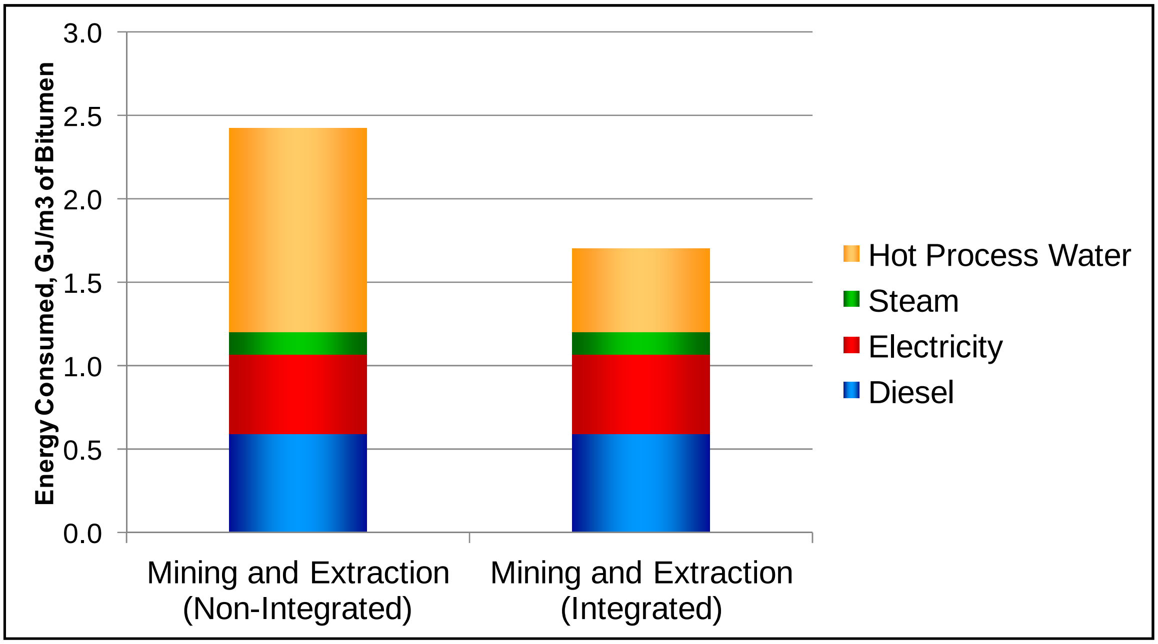
Figure 7-2.
Process and Energy Overview



In a non-integrated facility, the heat for the extraction process would likely be produced by steam from a natural gas-fired boiler.

The Extraction model based on the typical extraction facility evaluated in this Study was used to compare the energy required when hot process water is produced from low-level waste heat and from steam produced from natural gas. The difference in energy consumed per barrel of bitumen extracted is shown in Figure 7-3.

Figure 7-3.
Impact of Integration on Energy Used to Produce Bitumen from Mining and Extraction



In the above chart, the left-hand bar [Mining and Extraction (Non-Integrated)] shows the energy consumed in the Extraction process when hot water is generated by natural gas-based steam generation. The right-hand bar [Mining and Extraction (Integrated)] assumes hot water is generated from low-level waste heat either from the Upgrader or from on-site electricity generation. The major difference between these two bars can be seen in enthalpy-based energy of the Hot Process Water loop (HPW), which is reduced in the Mining and Extraction (Integrated) case by the energy recovered from waste heat sources in the integrated facilities. The amount of hot process water used is the same in both cases.

Figure 7-3 shows a reduction in energy used in HPW because of the integration. Approximately 30% of the total Extraction process energy can be reduced by integrating the hot water loop with sources of low-level waste heat, which is current practice in the industry.

Most bitumen produced by mining and extraction in Alberta uses low-level waste heat in extraction, so the right-hand bar of Figure 7-3 represents most current operations. Use of additional waste heat sources in the Upgrader could potentially reduce the energy consumed in the Extraction process to approximately 1.25 GJ/m^3 of bitumen. Several investment projects for recovering this energy were noted in the Upgrading section of this report.

Conclusions - Integration

- Integration of Cogeneration facilities primarily with In situ and upgrading facilities can improve the overall GHG and energy efficiency by roughly 5% based on the assumptions listed above. It should be noted that most In Situ bitumen production facilities in Alberta are integrated with cogeneration facilities.
- Integrating the low-level heat demand of a bitumen extraction plant with waste heat sources from, for example, an Upgrader, can result in a 30-50% reduction in energy consumed in an Extraction plant compared to a non-integrated facility. Note that most bitumen extraction facilities currently operating have some degree of heat integration with waste heat sources.
- Although there are likely applications for integrating cogeneration plants in most bitumen production facilities, potential limitations include the ability to export power, the efficient recovery of cogeneration stack heat, and the security of utility supply.

References

1. Electricity Intensity Tables, *Canada's National Inventory Report: 1990-2008*, Environment Canada, http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=EAF0E96A-1#section10

Section 8.

Impact of Energy Efficiency on Life Cycle Analysis

Introduction

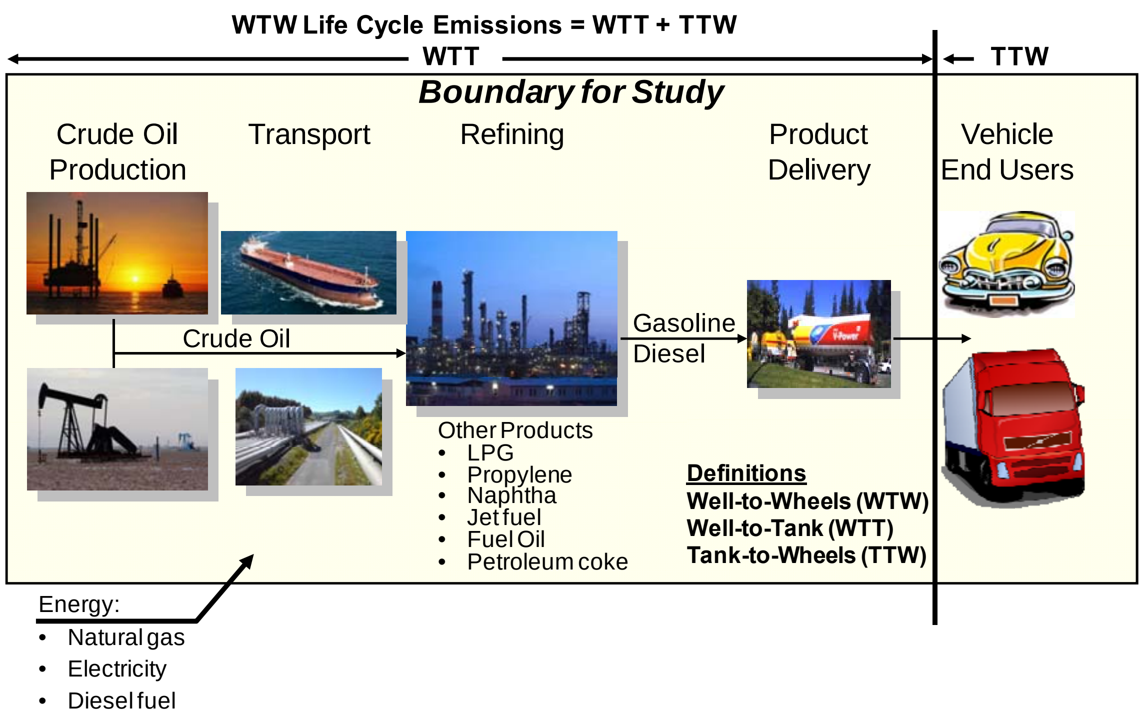
One way to understand the overall impact of energy efficiency improvements on the production of bitumen is to perform a Well-to-Wheels Life Cycle Analysis on the fuel pathway from bitumen production to consumption of gasoline and diesel in the vehicle.

What is Life Cycle Analysis?

Life Cycle Analysis (LCA) is a technique to assess environmental impacts associated with all the stages of a product's life from cradle to grave—that is, from raw material extraction through materials processing, manufacture, distribution, use, repair and maintenance, and disposal or recycling. LCA provides a broad view of environmental issues by compiling an inventory of relevant energy and material inputs and environmental releases, evaluating the potential impacts associated with identified inputs and releases, and interpreting the results.

The steps in a Well-to-Wheels (WTW) LCA of transportation fuels are shown in Figure 8-1. It begins with production of the crude oil and progresses to transport to the refinery, refining of the crude oil, delivery of refined products to the distribution point, and consumption of the fuel on board the vehicle.

Figure 8-1.
Typical WTW LCA Boundary

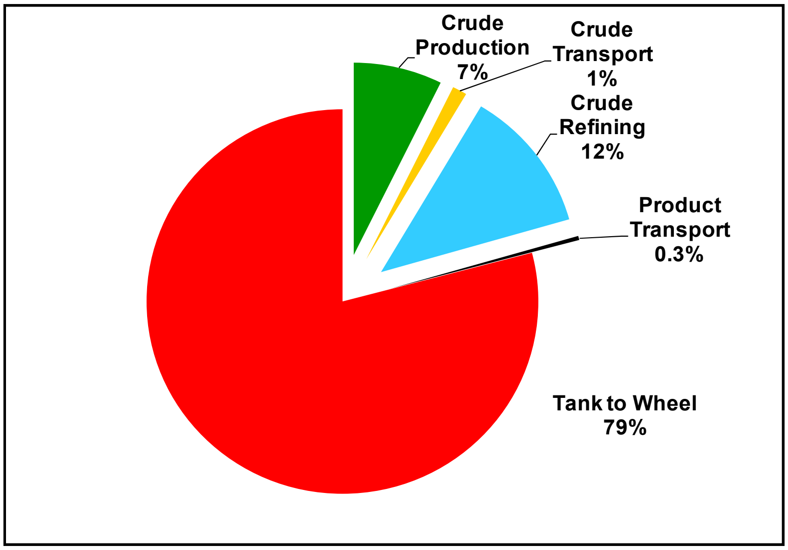


The full path from crude oil production to consumption of fuel in the vehicle is called the Well-to-Wheels pathway, which is the basis for reporting most LCA results for transportation fuels. LCA results reported without the CO_2 emitted from fuel consumption in the vehicle are referred to as Well-to-Tank (WTT) LCA results.

A key aspect of LCA is to determine the energy consumption and GHG emissions in each step. As shown in Figure 8-2, the majority of emissions associated with LCA of transportation fuels are from use in the vehicle, followed by emissions from crude oil production and refining. Transport of crude oil and delivery of products are small contributors to LCA GHG emissions.

GHG emissions of CO_2, CH_4, and N_2O are typically reported on the basis of CO_2 global warming potential (GWP) which enables the GHG emissions discussion to be simplified to a discussion of carbon intensity (CI)—that is, GWP, measured as carbon dioxide equivalents (CO_2e), per unit of fuel. In this work, the units for carbon intensity are grams of CO_2e per mega joule of transportation fuel (g CO_2e/MJ). Results in LCA are typically reported on an LHV basis.

Figure 8-2.
WTW CO_2e Emission Contribution for Producing Gasoline and Diesel Fuel

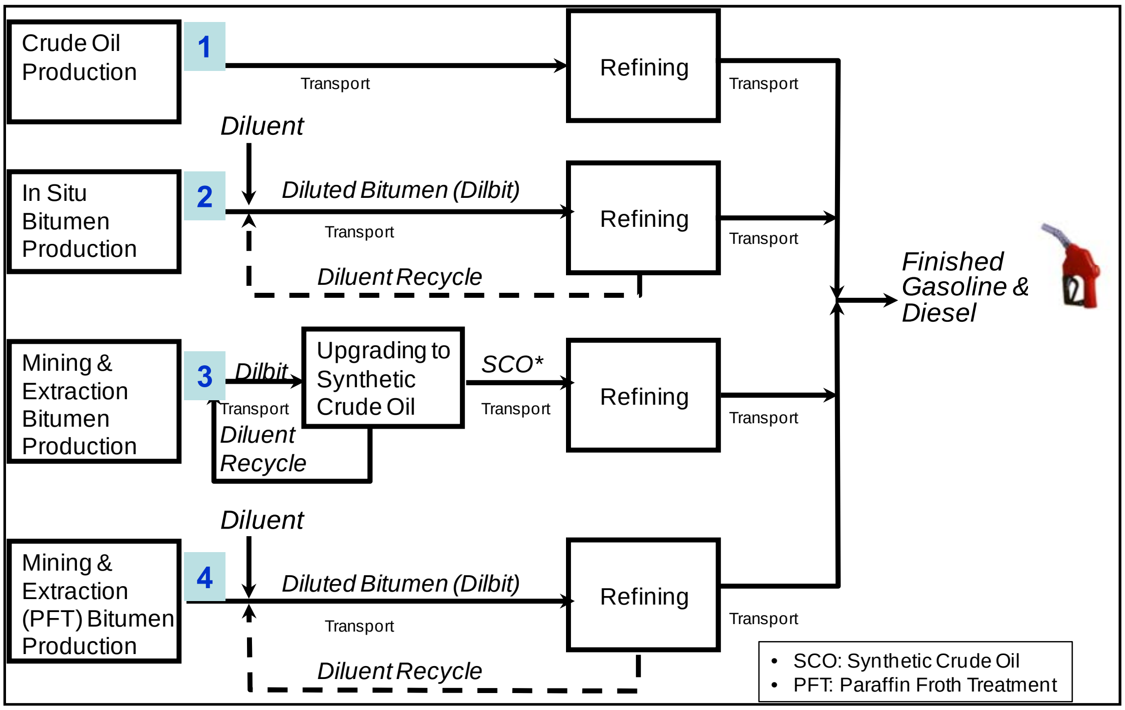


Source: California Air Resources Board, *Detailed California-Modified GREET Pathway for Ultra-Low-Sulphur Diesel (ULSD) from Average Crude Refined in California*, CARB, February 28, 2009

Fuel Pathways

The four general pathways for converting crude oil and bitumen to finished products are shown in Figure 8-3.

Figure 8-3.
Crude Oil Pathways to Finished Products



In Path 1, crude is transported from the production site to the refinery and converted to finished products. In Path 2, bitumen crude oil from in situ production is mixed with a naphtha diluent and transported directly to the refinery. Diluent is then refined to finished products or recycled back to the bitumen production site. In Path 3, bitumen from mining and extraction is mixed with a naphtha diluent and transported to an Upgrader, and the resulting synthetic crude oil (SCO) is transported to the refinery for conversion to finished products. In Path 4, mined bitumen is processed in extraction using paraffin froth treatment. The resulting bitumen crude oil is mixed with a naphtha diluent and transported directly to the refinery. The diluent can be refined to finished products with the bitumen crude oil or returned to the bitumen production site.

The pathways for the production of transportation fuels from bitumen evaluated in this Study are:

- In Situ → Refining (with diluent recycle)
- In Situ → Refining (without diluent recycle)

- Mining/Upgrading (integrated) → Refining
- Mining (PFT) → Refining (with diluent recycle)

Although other potential pathways are conceivable, these are the pathways most relevant to bitumen production. These bitumen fuel pathways were compared with fuel pathways from other crude oils produced outside of Alberta.

In Situ → Refining (with diluent recycle)

This pathway consists of producing bitumen from an In Situ facility, mixing the bitumen with diluent, and transporting this mixture to the refinery. The refinery sends the diluent back to the bitumen production site for re-use. Although this pathway is not very common for the current In Situ facilities, it must be considered because diluent must be recycled as bitumen production increases and outstrips the production of diluent.

In Situ → Refining (without diluent recycle)

This is the primary pathway for current In Situ bitumen production. This pathway consists of producing bitumen from an In Situ facility, mixing the bitumen with diluent, and transporting this mixture to the refinery. Once the dilbit reaches the refinery, the entire stream is processed into finished products. It is assumed that the diluent is from condensate produced in the province as a by-product of natural gas production.

Mining/Upgrading (integrated) → Refining

This pathway consists of producing bitumen from an open-face mine via shovel and heavy hauler trucks and using the hot water extraction process to remove the bitumen from the ore. The extracted bitumen is mixed with naphtha before being sent to the Upgrader. The Upgrader removes the naphtha and recycles it back to the extraction plant before producing a range of SCO and other products from the bitumen. This pathway represents the majority of the mines that are currently operating.

Based on input from the industry, it is understood that most of the extraction plants and upgrading plants are heavily integrated such that the majority of the heat demands in the extraction plant are provided by the Upgrader, which results in an overall reduction in GHG emissions associated with bitumen production and processing from this pathway relative to stand-alone extraction. The impact of land use from mining and extraction is currently being discussed, but at this time, representative numbers have not been put forth by the industry. Therefore, numbers that are publicly available have been used in this analysis.[1]

Mining (PFT) → Refining

Similar to the previous pathway, this pathway consists of producing bitumen from an open-face mine via shovel and heavy hauler trucks and using the hot water extraction process to remove the bitumen from the ore. The difference between this pathway and the previous one is that the extracted bitumen is mixed with paraffin as a diluent. Treatment with paraffin reduces the asphaltene content of the bitumen and the bottoms sediment and water (BS&W) content of the bitumen, which allows the resulting bitumen to be sent directly to a refinery without upgrading. Direct refining of bitumen results in an overall reduction in GHG emissions associated with bitumen production and processing relative to first upgrading before refining. This pathway represents a minority of the currently operating mines, but is being considered for some new mines being developed.

Similar to the previous pathway, the impact of land use is from public sources.[1]

Bitumen Production Energy Reduction Cases

To better understand the impact of energy efficiency on each of the bitumen production and processing steps of the LCA, four cases were developed:

- AERI—Based on 2009 AERI results,[2] updated to better reflect energy consumption and methodologies since publication of the AERI Study results in 2009.
- Baseline—The base operation of each typical bitumen production facility in the Study.
- Projects—Evaluates the impact of energy efficiency improvement projects on energy reduction in bitumen production at the different production facilities in the Study.
- Technology—Evaluates the impact of new technology on energy reduction at the different production facilities in the Study.

The 2009 AERI results have been previously published as part of the *Life Cycle Assessment Comparison of North American and Imported Crudes* study completed by Jacobs Consultancy and Life Cycle Associates.[2] GHG emissions from bitumen production via SAGD and bitumen production by mining and upgrading from the AERI Study are included for reference. The AERI Study results used here reflect the methodology from the recent study by Jacobs Consultancy for the Alberta Petroleum Marketing Commission titled *EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context*.[3] The refinery location for the AERI Study was PADD II. It was PADD III for the EU Pathway Study. The vehicle emissions for the AERI Study results used here are US vehicle-based. In the EU Pathway Study, the vehicle emissions are based on EU type of vehicles. Other changes to the results from the AERI Study since its 2009 publication include updating emission factors and energy consumption. Thus the results for the AERI Study reported here will be somewhat different than those reported in the 2009 report.

Also, because the pathways are different, the results shown here will be somewhat different than the EU Pathway Study published in 2012.

The bitumen production facility baselines developed in this Study are from commercial facilities in Alberta; three years of operating data from 2009 to 2011 were used to develop the baselines. The impact of energy efficiency improvement projects is based on efforts of this Study to identify opportunities to reduce GHG emissions by improving the energy efficiency of each of the bitumen production and processing steps.

The impact of new technology is based on a review of potential technology opportunities and their potential impact on improving energy efficiency. The numbers represented are on the low end of the potential improvement range based on the difficulties often encountered during commercialization of new technologies.

Assumptions

Information for the following items was developed as part of the previous AERI Study, and was included in the Study to complete the LCA.

- Comparison crudes (Bachaquero, Maya, Arab Medium)
- Transportation and delivery of crude oils: SAGD produced bitumen and SCO to PADD II refinery. Transportation of mined bitumen to an Upgrader in Alberta. The methodology for determining transportation GHG emissions is more fully described in the AERI Study.
- Flaring and fugitive emissions for crude oil production outside of Alberta are based on the World Bank/NOAA Study.[3] Based on industry reports to the Government of Alberta we assume no flaring for bitumen-based crude oils.[4]
- Refining GHG emissions are based on models that were developed as part of the AERI Study.

Carbon Intensity of Bitumen Production

Each bitumen processing step (i.e., In Situ, Mining and Extraction, Upgrading) was evaluated in the four cases described above: AERI, Baseline, Project, and Technology.

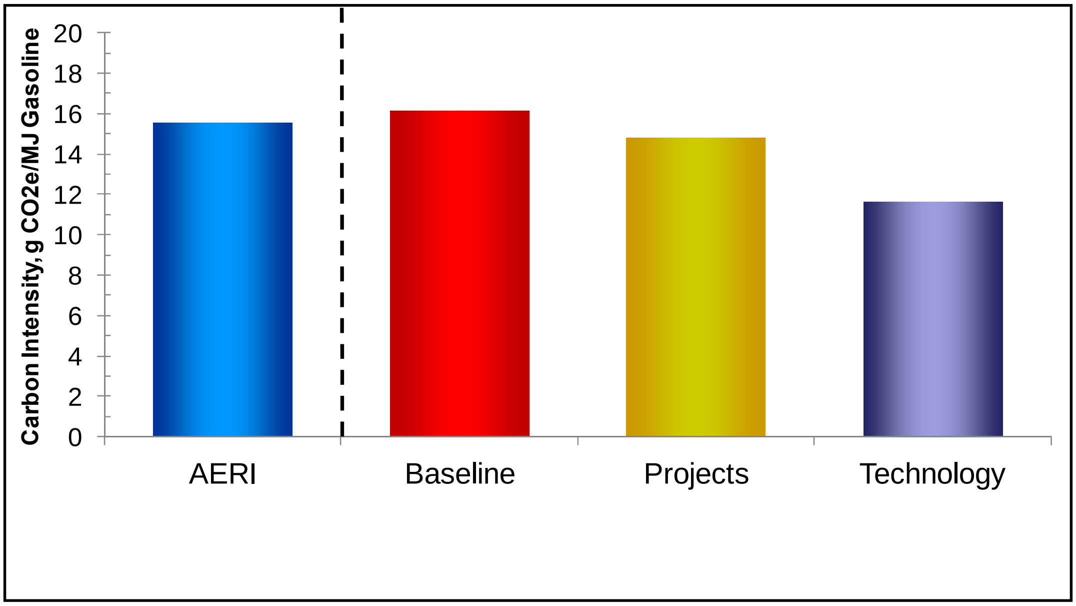
This discussion will compare the carbon intensity of crude oil production, including bitumen, dilbit, and SCO, used in the WTW LCA determination of the CI of gasoline and diesel fuel from different fuel pathways. Results in this section are reported on the basis of g CO_2e/MJ of gasoline or g CO_2e/MJ of diesel on an LHV basis. Other bases for reporting CI could have been used—for example, g CO_2e/ MJ of crude oil. The dilbit cases include the CI for producing diluent from natural gas, which was assumed to be 6.1 g CO_2e/MJ of diluent.

In Situ

This analysis uses the typical In Situ bitumen production site of the Study. Data for the baseline evaluation are based on 2009-2011 operations. The impact of energy efficiency projects, developed as part of this Study, identified a potential 12% improvement in the CI of in situ bitumen production. Similarly, the technology improvement opportunities identified approximately 20% improvement in the CI of dilbit production. Each case was evaluated using the LCA tool developed by Jacobs Consultancy.

The contribution of crude oil production to the CI of gasoline produced from bitumen for the four fuel pathways is shown in Figure 8-4. These results are on the basis of g CO_2e/MJ of gasoline.

Figure 8-4.
Crude Oil Production Impact on Gasoline Carbon Intensity from Bitumen



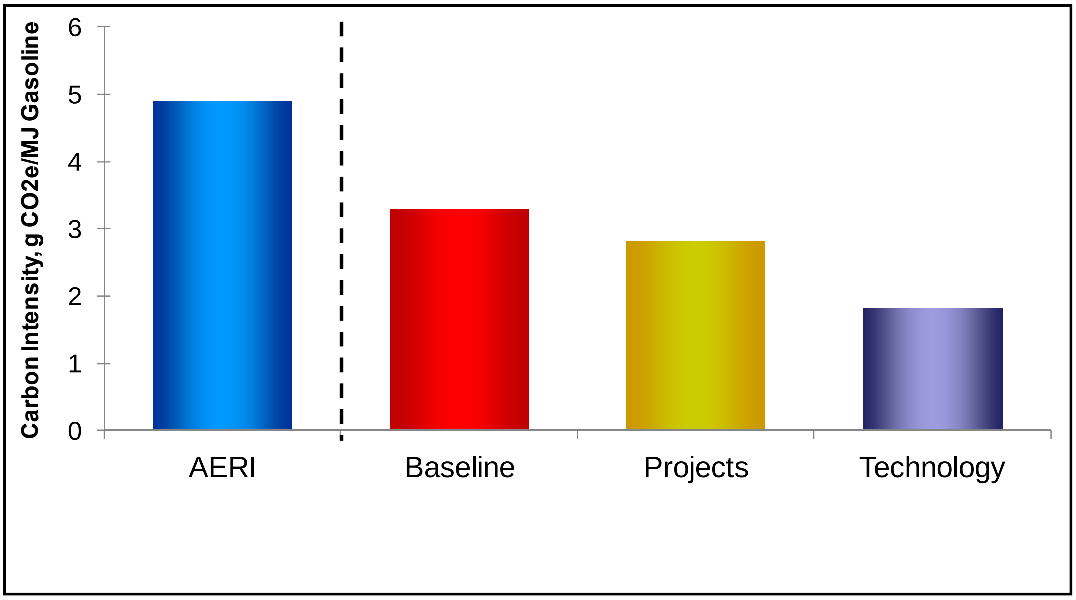
The CI results indicate that the 2009 AERI Study may have been slightly optimistic in its representation of In Situ facilities compared to actual operation. The variation between the AERI results and the Baseline are indicative of the difference between model results of a plant operating with no interruptions versus actual operations and the impact of planned and unplanned outages on the overall efficiency of that operation. Technology improvements, shown as the Technology case in Figure 8-4, have the potential to reduce the CI of bitumen production and the overall CI of gasoline by as much as 3 g CO_2e/MJ of gasoline relative to the Baseline case.

Mining and Extraction

This analysis compares the typical Mining and Extraction facility used in this Study to the stand-alone mining-extraction facility represented in the 2009 AERI LCA study. The energy efficiency projects, developed as part of this Study, identified a potential 7% improvement in the CI of bitumen production from bitumen mining and extraction. Similarly, the technology improvement opportunity identified approximately 30% improvement in CI. Each case was evaluated using the LCA tool developed by Jacobs Consultancy.

The contribution of crude oil production to the CI of gasoline produced from SCO in each of the four cases described above is shown in Figure 8-5.

Figure 8-5.
Crude Oil Production Impact on Gasoline Carbon Intensity from SCO



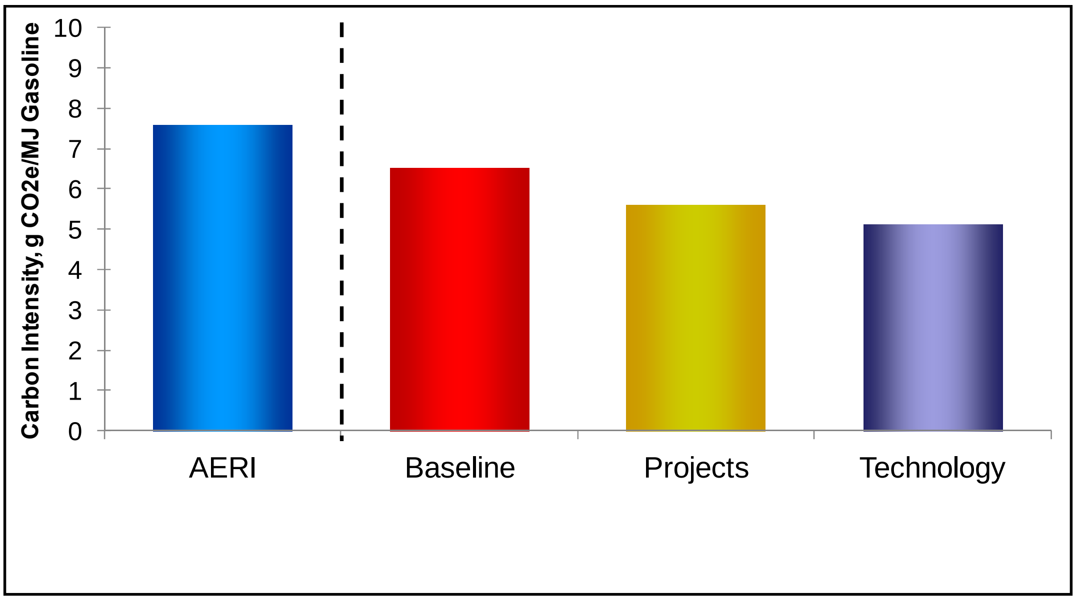
The comparison in Figure 8-5 shows that the impact of mining and extraction on gasoline CI in the AERI Study are comparable to the operation of a stand-alone Mining and Extraction facility with no integration to use low-level waste heat. However, in evaluating the Mining and Extraction facilities as part of this Study, it is now understood that most of the Mining and Extraction facilities are integrated with an Upgrader, which provides the heat needed in Extraction and reduces the CI of gasoline compared to a stand-alone Mining and Extraction facility. The Baseline results are indicative of Mining and Extraction using low-level waste heat from an Upgrader or other source. The results shown here do not include the impact of land use.

Upgrading

The typical upgrading facility in the Study was compared to the upgrading facility represented in the 2009 AERI LCA Study. The energy efficiency projects, developed as part of this Study, identified a potential 8% reduction in the CI of gasoline from SCO. Similarly, the technology improvement opportunities identified a further reduction in the CI of gasoline from SCO of approximately 10 percent.

The contribution of upgrading to the CI of gasoline produced from SCO in each of the four cases is shown in Figure 8-6.

Figure 8-6.
Upgrading Impact on Gasoline Carbon Intensity from SCO



The contribution from upgrading in the 2009 AERI Study is slightly higher than from the typical Upgrader in this Study, primarily due to differences in hydrogen consumption.

Land Use

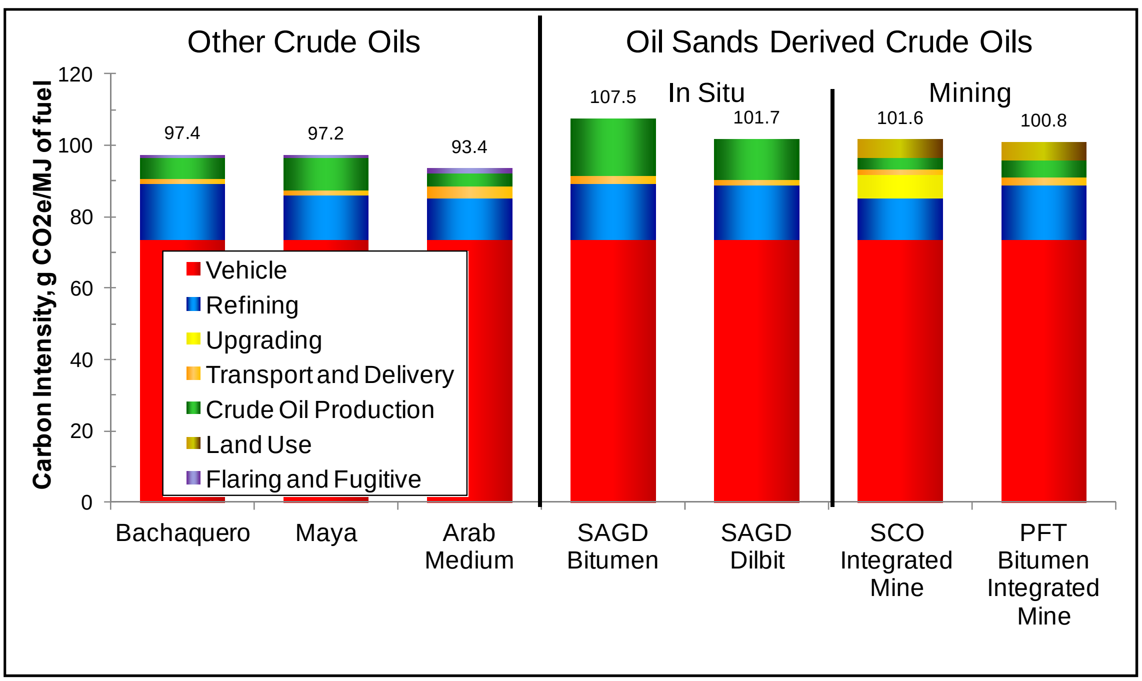
The impact of land use from bitumen production use has become an important part of the LCA of bitumen. There is a wide range in the impact of land use published by different authors. For the purpose of this Study, the land use from Yeh, et al, has been used in the LCA.[1]

LCA Results

The summary of the baseline WTW LCA results are represented on a gasoline basis in Figure 8-7 and on a diesel basis in Figure 8-8. The CIs for gasoline and diesel from the crude oils produced outside of Alberta are lower than for gasoline and diesel from bitumen, dilbit, and SCO. Gasoline and diesel from dilbit has a lower CI than gasoline from bitumen because dilbit is a blend of bitumen and diluent, which has a low CI. The differences in CI between gasoline from oil sands-derived crude oils and from Bachaquero crude oil in Figure 8-7 are as follows:

- Gasoline from SAGD bitumen has a CI 10% higher than gasoline from Bachaquero and 15% higher than gasoline from Arab Medium
- Gasoline from SAGD Dilbit has a CI 4% higher than gasoline from Bachaquero and 9% higher than gasoline from Arab Medium
- Gasoline from SCO from mined bitumen has a CI 4% higher than gasoline from Bachaquero and 9% higher than gasoline from Arab Medium
- Gasoline from PFT bitumen refined directly has a CI 4% higher than gasoline from Bachaquero and 8% higher than gasoline from Arab Medium

Figure 8-7.
LCA Baseline Summary – Gasoline



Notes for Figures 8-7 and 8-8:

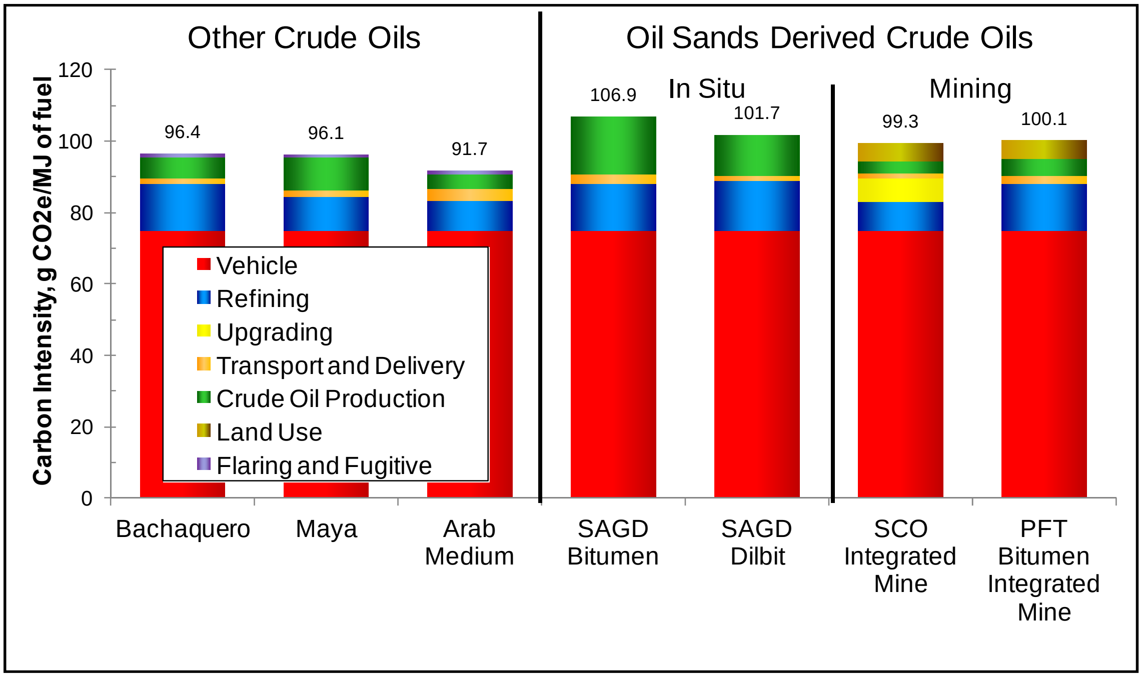
- The AERI Study results used here reflect the methodology from the recent study by Jacobs Consultancy for the Alberta Petroleum Marketing Commission titled *EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context* published in 2012
- The AERI Study and the EU Pathway Study results are based on somewhat different energy and GHG emissions for producing bitumen and SCO than shown here, which are from the typical production facilities used in the Study.
- The refinery location for the AERI Study and for this Study is PADD II. It is PADD III for the EU Pathway Study.
- The vehicle emissions for the AERI Study and for this Study are based on US type of vehicles. In the EU Pathway Study, the vehicle emissions are based on EU type of vehicles.
- Other changes to the results shown here and those in the AERI Study since its 2009 publication include updating emission factors and energy consumption.
- Thus the results for the AERI Study reported here will be somewhat different than those reported in the 2009 report. Also, because the pathways are different, the results shown here will be somewhat different than the EU Pathway Study published in 2012.
- Labels
    - Bachaquero, Maya, and Arab Medium crude oils are representative non-Alberta crude oils used in the AERI Study
    - SAGD Bitumen—Bitumen produced by the typical In Situ SAGD facility in this Study, transported to a US PADD II refinery with diluent return to Alberta
    - SAGD Dilbit —Bitumen from the typical SAGD facility of the Study refined with diluent in a PADD II refinery
    - SCO-Integrated Mine—Refining of SCO produced from a coking-based Upgrader processing bitumen from a mining operation that uses hot water generated from low-level waste heat from either the Upgrader or from on-site power generation
    - PFT-Bitumen Integrated Mine—Direct refining of bitumen produced in an integrated mine that uses paraffin froth treatment; hot water is generated using low-level waste heat from on-site power generation or another source

The differences in CI between diesel from oil sands-derived crude oils and diesel from Bachaquero crude oil in Figure 8-8 are as follows:

- Diesel from SAGD bitumen has a CI 11% higher than diesel from Bachaquero and 17% higher than diesel from Arab Medium in this Study
- Diesel from SAGD Dilbit has a CI 5% higher than diesel from Bachaquero and 11% higher than diesel from Arab Medium
- Diesel from SCO from mined bitumen has a CI 3% higher than diesel from Bachaquero and 8% higher than diesel from Arab Medium

- Diesel from PFT bitumen refined directly has a CI 4% higher than diesel from Bachaquero and 9% higher than diesel from Arab Medium

Figure 8-8.
LCA Baseline Summary—Diesel

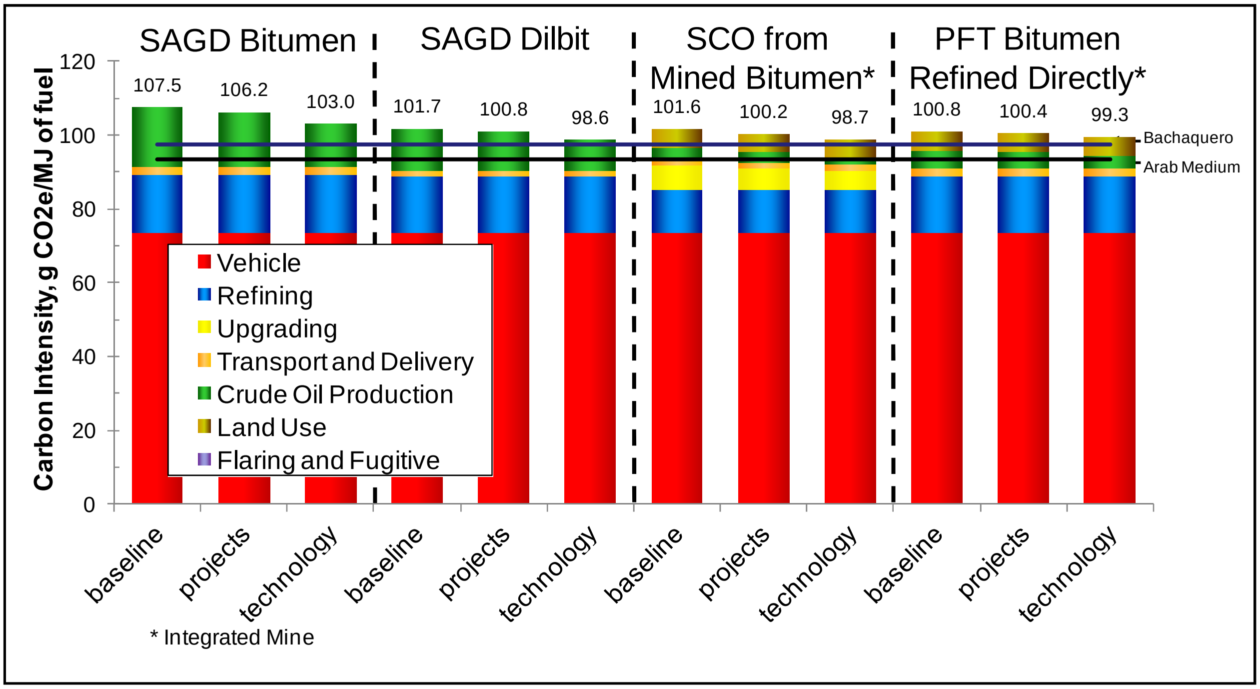


Impact of Energy Improvement in Bitumen Production on the CI of Gasoline and Diesel

The potential impact of the identified energy efficiency projects and technology opportunities on the LCA CI of gasoline from bitumen produced by the four pathways are shown in Figure 8-9. Although there is a wide range of potential GHG reduction associated with technology, the LCA results shown here are a conservative representation of the potential impact of technology.

The upper horizontal line shown in Figure 8-9 is the CI for producing gasoline from Bachaquero. The lower horizontal line is the CI for producing gasoline from Arab Medium.

Figure 8-9.
Impact of Energy Efficiency Improvement on WTW CI of Gasoline



Notes for Figures 8-9 and 8-10:

- Baseline—Base case operation of In Situ SAGD, Mining and Extraction and Upgrading
- Projects—Implementation of projects to reduce energy and GHG emissions from bitumen production
- Technology—Implementation of technology to reduce energy and GHG emissions from bitumen production

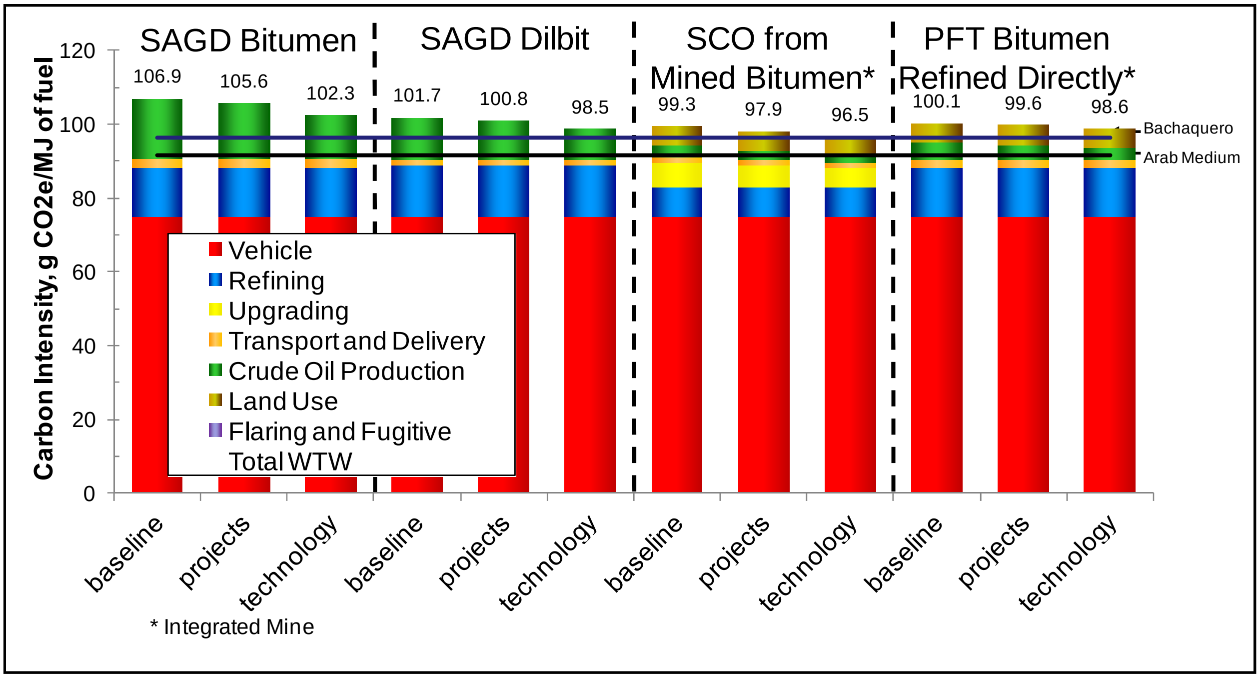
The results from Figure 8-9 are summarized in Table 8-1, which shows the impact of projects and technology on reducing the CI of diesel for the four bitumen pathways evaluated. The percent change is from each pathway's baseline.

Table 8-1.
Impact of Projects and Technology on Reducing Gasoline WTW CI

Crude Oil for Producing Gasoline	Change in WTW CI from Baseline due to:	
	Projects	Technology
SAGD Bitumen	-1.2%	-4.2%
SAGD Dilbit	-0.9%	-8.3%
SCO from Integrated Mining and Extraction	-1.4%	-8.2%
PFT Bitumen Refined Directly	-0.5%	-7.6%

The potential impact of the identified energy efficiency projects and technology opportunities on the LCA CI of diesel from bitumen produced by the four pathways are shown in Figure 8-10. The upper horizontal line on the figure shows the CI for diesel from Bachaquero; the lower horizontal line is the CI for diesel from Arab Medium.

Figure 8-10.
Impact of Energy Efficiency Improvement on WTW CI of Diesel



The results from Figure 8-10 are summarized in Table 8-2, which shows the impact of projects and technology on reducing the CI of diesel for the four bitumen pathways evaluated. The percent change is from each pathway's baseline.

Table 8-2.
Impact of Projects and Technology on Reducing Diesel WTW CI

Crude Oil for Producing Diesel	Change in WTW CI from Baseline due to:	
	Projects	Technology
SAGD Bitumen	-1.2%	-4.3%
SAGD Dilbit	-0.9%	-7.8%
SCO from Integrated Mining and Extraction	-1.4%	-9.7%
PFT Bitumen Refined Directly	-0.5%	-7.7%

Conclusions – Life Cycle Analysis

- Although the reduction in GHG emissions due to energy efficiency improvements may appear small on a WTW basis, the impact of the improvements due to energy efficiency are significant on a well-to-tank (WTT) basis, considering the bitumen production and processing steps which were the focus of this Study.

Table 8-3.
Total Potential Reduction in GHG Emissions

	GHG Reduction	
	Crude Production	**Well-to-Tank**
In Situ (dilbit) → Refinery	30% (12% projects / 20% technology)	13%
Mining and Extraction → Upgrader →Refinery	35% (7% projects / 30% technology)	9%

- Similar opportunities for improving the energy efficiency of refining, transportation and delivery could be pursued as part of a separate study.
- Industry input is needed to reduce the uncertainty in the LCA. Areas of focus include but are not limited to:
    - Land use
    - Refining
    - Flaring
    - Transportation and delivery
- The pathways to produce bitumen significantly impact the GHG intensity of the final products.

References

1. Yeh S., Jordaan S., Brandt A.R., Merritt R. Turetsky, Spatari S., Keith D.W., *Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands*, Environmental Science and Technology, 2010
2. *Life Cycle Assessment Comparison of North American and Imported Crudes,* Jacobs Consultancy for AERI (now Alberta Innovates Energy and Environment Solutions), 2009
3. *EU Pathway Study: Life Cycle Assessment of Crude Oils in an European Context*, Jacobs Consultancy for the Alberta Petroleum Marketing Commission, March 2012
4. *ST60b, Upstream Petroleum Industry Flaring and Venting*, ERCB, Sept 2011
5. World Bank/NOAA Study, *Estimated Flared Volumes from Satellite Data, 2006-2010*, World Bank, 2010

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Section 9.

Conclusions and Recommendations

Key Conclusions

- **Project Impact on Reducing GHG Emissions—**Implementation of economically viable operational and capital projects can improve the energy efficiency and reduce the GHG emissions from existing oil sands operations. The estimated reduction in GHG emissions is summarized by bitumen production and processing facility in Table 9-1.

Table 9-1.
Potential GHG Reduction—Project Summary

	In Situ	Mining & Extraction	Upgrading	Timing - Uncertainty
Operational Improvements	3%	2%	2%	-Near term (1-3 years) -low risk
Capital Improvements	9%	5%	6%	-Mid term (3-5 years) -moderate risk

Note: The improvements are relative to the baseline GHG intensity of each facility; the impact on the WTT GHG intensity will be lower because there are other contributors to WTT GHG intensity.

- **Technology Impact on Reducing GHG Emissions—**Technology developments for improving energy efficiency offer significant potential to close the GHG intensity gap between crude oils derived from bitumen and heavy crude oils produced outside of Alberta. Potential energy efficiency improvement and GHG intensity reduction over a timeframe greater than 10 years are shown in Table 9-2 by bitumen production and processing facility.

Table 9-2.
Potential GHG Reduction—Technology Summary

	In Situ	Mining & Extraction	Upgrading	Timing - Uncertainty
Technology Improvements	20%	30%	10%	-Long term (10+ years) -higher risk

Note: The improvements are relative to a baseline GHG intensity of each facility; the impact on the WTT GHG intensity will be lower because there are other contributors to WTT GHG intensity.

- **CCS Impact on Reducing GHG Emissions—**CO_2 capture and Storage (CCS) offers the potential for significant GHG reductions from both in situ, non-integrated mining and extraction, and upgrading facilities. However, current CCS technologies are too expensive to be economically viable at the current cost of avoided CO_2 or captured CO_2.
- **Energy Efficiency Metrics—**A set of energy efficiency metrics have been proposed to help evaluate and potentially benchmark the energy efficiency of bitumen production and processing facilities.
- **Bitumen Production Pathway—**The pathway chosen to extract, upgrade, and refine crude oils derived from bitumen significantly affects the overall well-to-wheels GHG intensity of diesel and diesel refined from these crude oils, which can vary by as much as 10-30% on a well to tank (WTT) basis.

Additional Conclusions

- Integrating co-generation plants with new bitumen production facilities can reduce energy use and GHG emissions and has the potential to reduce WTT GHG intensity of producing diesel and diesel by up to 5 percent.
- Integrating low-level waste heat sources from Upgraders or on-site power generation with Mining and Extraction can reduce the GHG intensity of bitumen extraction by 30-50% over stand-alone Mining and Extraction that uses natural gas to generate hot water for extraction. It is important to note that most existing Mining and Extraction facilities already have a high degree of integration to use low-level waste heat.
- Upgrading and then refining bitumen to finished products versus processing the bitumen directly in a refinery to finished products adds approximately 10-30% to the GHG intensity, on a WTT basis.
- Resource constraints and timing of planned maintenance outages continue to be barriers to implementation of energy efficiency opportunities. In addition, depressed natural gas prices adversely affect the economic viability of these opportunities.
- A life cycle assessment of energy inputs to producing finished products and GHG emissions from producing these products (including refining) is needed to properly evaluate and compare the GHG intensity of intermediate products produced in Alberta (including SCO and bitumen). Comparing individual facility performances to each other without considering product type/quality and downstream emissions can lead to inaccurate comparisons.

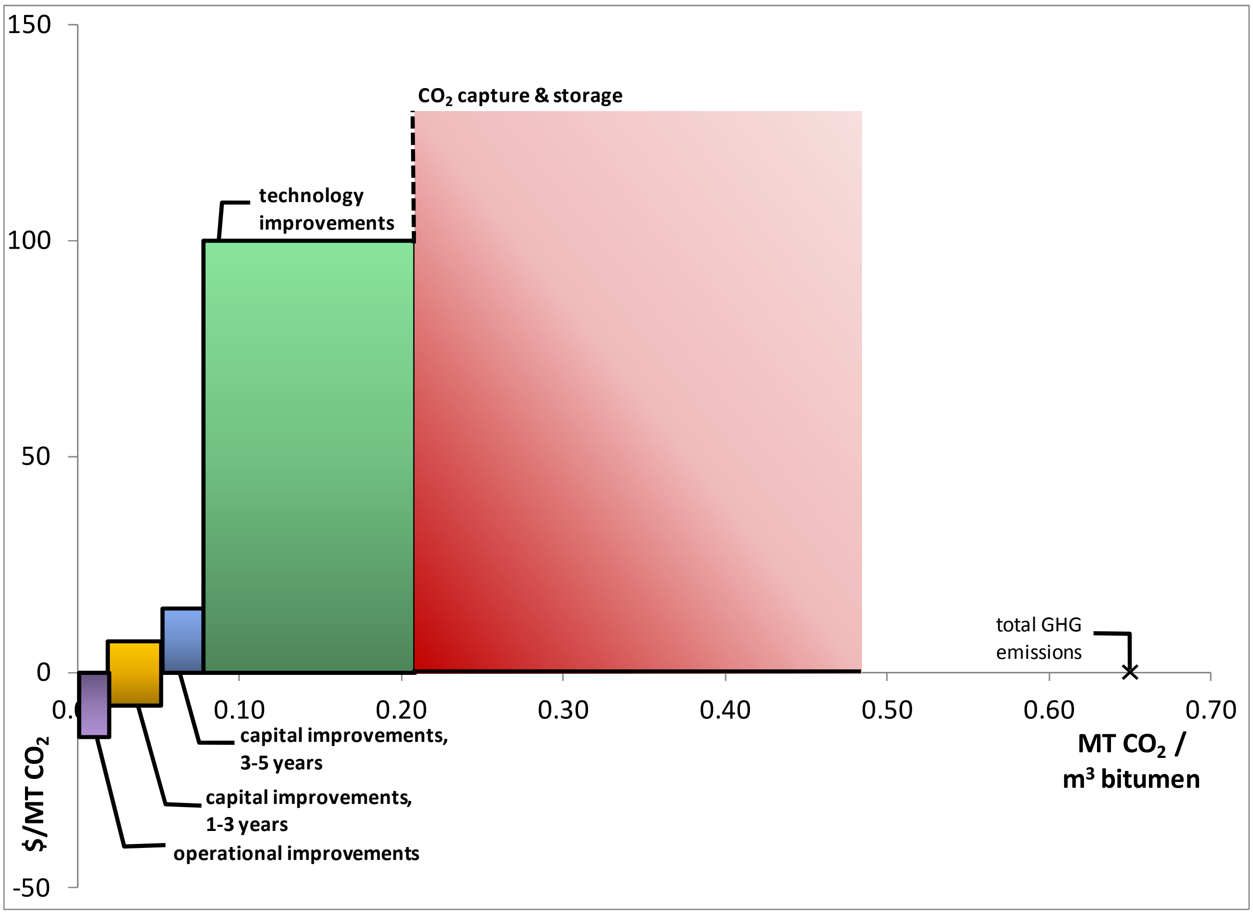
Roadmaps

The project and technology options evaluated in this Study for reducing energy consumption and GHG emissions can be put into a roadmap to guide implementation. The potential reductions, timing and risks were summarized in Tables 9-1 and 9-2. In the following paragraphs we show the cumulative impact of GHG emission reduction and costs for the projects and technologies considered.

In Situ GHG Reduction Roadmap

Figure 9-1 represents a potential roadmap for GHG reduction from In Situ bitumen production resulting from projects and technology. The horizontal axis is the amount of CO_2 reduction per cubic metre of bitumen produced; the vertical axis is CO_2 pricing.

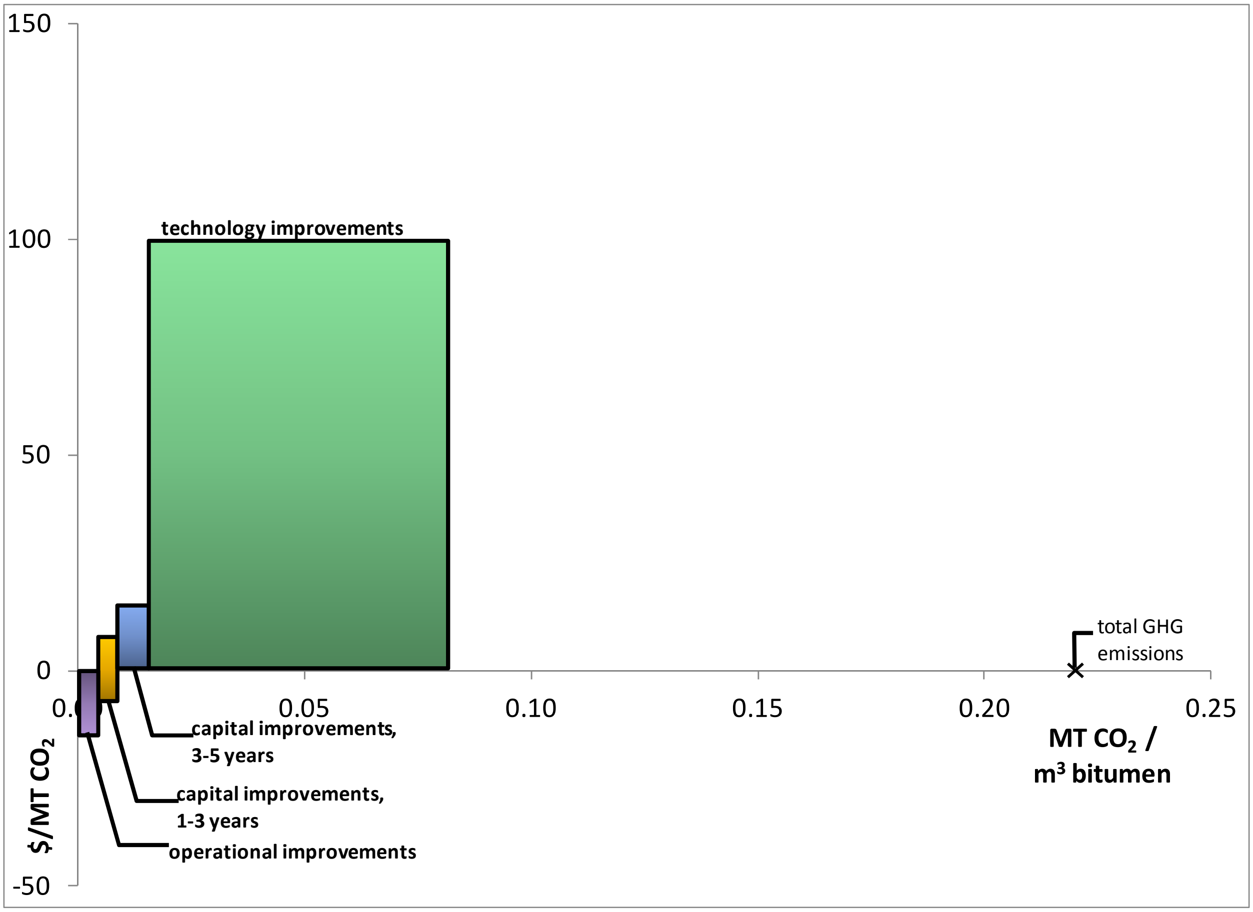
Figure 9-1.
In Situ—Potential GHG Roadmap



Mining and Extraction GHG Reduction Roadmap

A similar roadmap was developed for Mining and Extraction (Figure 9-2). Because the typical mining and extraction facility uses waste heat to generate hot process water, there are no boilers used specifically for mining and extraction, and therefore no direct applications for CCS. The gap that remains between technology improvements and the total GHG emissions from a typical mining and extraction facility is comprised of mobile emissions from the heavy haulers and from electricity.

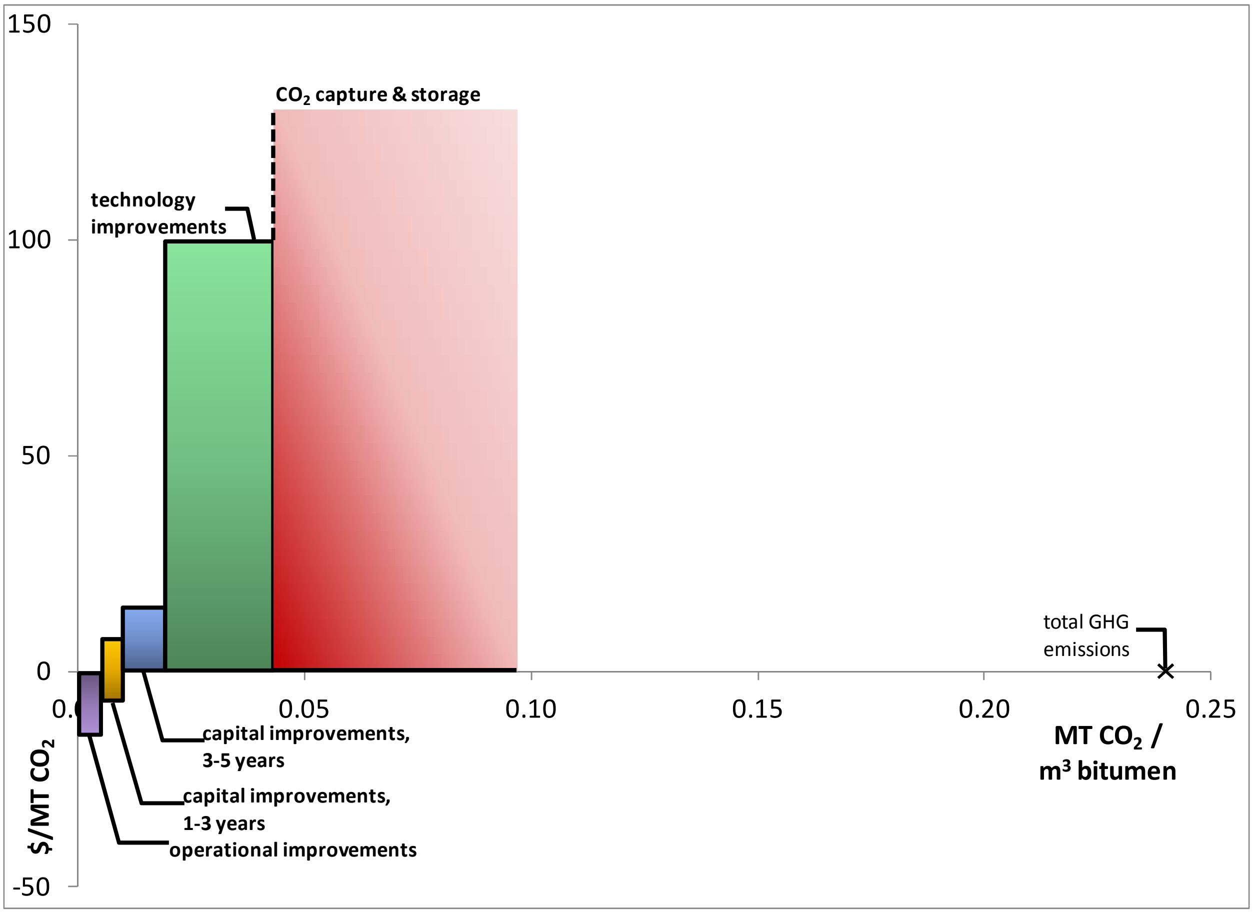
Figure 9-2.
Mining and Extraction—Potential GHG Roadmap



Upgrading GHG Reduction Roadmap

Figure 9-3 shows the roadmap developed for upgrading.

Figure 9-3.
Upgrading—Potential GHG Roadmap



Recommendations

- Due to the lower cost of incorporating energy efficiency improvements in new facility construction, the following elements should be evaluated early in the design of any new bitumen facility:
    - Gap between industry-established best practices and proposed design
    - Impact of integration with low-level heat sources, as applicable
    - Role of cogeneration facilities in the proposed design

- Because all bitumen production and processing pathways have different GHG emissions, life cycle analysis should be used to compare the impact of different pathways and technology options, including:
    - Refining bitumen vs. upgrading bitumen and Refining SCO
    - Impact of land use
    - Ability to recycle diluent

  Note: To support future LCA efforts, the uncertainty of the data should be reduced by collaboration to provide data, especially for the refining of SCO and diluted bitumen in determining the impact of land use.
- All improvement projects and their potential benefits identified in this Study require a more detailed evaluation before they can be considered for implementation.
- Further validation from a broader section of the industry is needed before these metrics can be used as benchmarks.
- Because the majority of future bitumen production will be In Situ-based, and because In Situ production offers the greatest opportunity for improvement in energy efficiency, the development of new technology to improve energy efficiency and reduce GHG emissions should be primarily focused on In Situ bitumen production.
- Joint industry, academic and government collaboration could further accelerate the rate of development and deployment of new energy efficiency technologies, including CCS.