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Oil Sands Technology Pathway Evaluation Using Life Cycle Assessment and Mathematical Optimization

by

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Abstract

Oil sands producers must improve the environmental performance of their operations to remain competitive in the energy sector in a carbon constrained world. These improvements include both incremental changes in the existing operation to make it more efficient (e.g., by applying process integration techniques) or fundamental changes to the operation (e.g., by adopting emerging technologies). However, an individual company will consider regulatory requirements and economic feasibility prior to making decisions about investments in these technologies. This thesis investigates the potential improvements in oil sands operations through both incremental efficiency improvements (i.e., lower energy consumption per unit of energy produced) and fundamental changes in their operations. In the first part of the thesis, cost and energy savings opportunities in Steam Assisted Gravity Drainage (SAGD) (an oil sands extraction and recovery process) are assessed by applying process integration techniques through the sequential application of a water treatment system optimization followed by conventional energy pinch analysis (incremental improvement). In the second part of the thesis, the focus is on exploring fundamental improvements in the oil sands sector and identifying the optimal technology pathways for oil sands production and processing with respect to economic and environmental objectives. A comprehensive techno-economic framework is developed that considers all technological and economic input parameters that affect the performance of the oil sands supply chain in terms of total cost, total energy consumption and GHG emissions. This framework is used to: 1) find the technical, economic and policy conditions under which emerging oil sands technologies become competitive alternatives in global crude oil markets, and 2) investigate the prospect of reaching Canada’s climate goals (as it relates to the oil sands sector) by implementing available emission reduction solutions while maintaining oil sands production capacity at the current or increased level in the next three decades.

The results of this study help oil sands producers to better understand the long-term effects associated with the use of existing and emerging oil sands technologies. In addition, the results inform short- and long-term investment decision making in oil sands sector under various scenarios with different combinations of input parameters.

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List of Symbols, Abbreviations and Nomenclature

Symbol	Definition
AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
BAU	Business As Usual
BFD	Block Flow Diagram
BFW	Boiler Feed Water
BPD	Barrel per Day
CAD	Canadian Dollar
CC	Capital Cost, Composite Curve
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CEPCI	Chemical Engineering - Plant Cost Index
CO_2	Carbon Dioxide
COPTEM	Crude Oil Pipeline Transportation Emissions Model
CPF	Central Processing Facility
CSS	Cyclic Steam Stimulation
DAC	Direct Air Capture
DO	Dissolved Oxygen
ESEIEH	Enhanced Solvent Extraction Incorporating Electromagnetic Heating
FWKO	Free Water Knock Out
GCC	Grand Composite Curve
GHG	Greenhouse Gas
GHOST	GreenHouse gas emissions of current Oil Sands Technologies
HEN	Heat Exchanger Network
HLS	Hot Lime Softening
HP	High Pressure
IGF	Induced Gas Flotation
ISEU	In Situ Extraction and Upgrading
LCA	Life Cycle Analysis
MILP	Mixed Integer Linear Programming
MP	Mathematical Programming
$MtCO_2$	Million Tonnes of CO_2
MWh	Megawatt Hour
NG	Natural Gas
NPV	Net Present Value
OC	Operating Cost
ORF	Oil Removal Filter
OSTUM	Oil Sands Technologies for Upgrading Model
OTSG	Once-Through Steam Generator
PA	Pinch Analysis
PADD	Petroleum Administration for Defense District
PI	Process Integration
PRELIM	Petroleum REfinery Life cycle Inventory Model
PUB	Partially Upgraded Bitumen
SAGD	Steam Assisted Gravity Drainage

SA-SAGD	Solvent Assisted-Steam Assisted Gravity Drainage
SCO	Synthetic Crude Oil
SOR	Steam to Oil Ratio
tCO_2e	Tonnes of CO_2 equivalent
TDS	Total Dissolved Solids
TIER	Technology Innovation and Emissions Reduction
TSS	Total Suspended Solids
USD	U.S. Dollar
VROR	Vacuum Residue to Oil Ratio
WAC	Weak Acid Cation Exchanger
WN	Water Network
WTI	West Texas Intermediate

Chapter One: **Introduction**

1.1 Background

Alberta's oil sands provide a secure and reliable source of energy for North America and the world and are a vital part of the Canadian economy [1,2]. However, oil sands producers are facing important challenges, such as low oil price, that have threatened the contribution of oil sands products to global oil markets. Oil sands operations are energy intensive and costly compared to conventional oil production and generally generate more greenhouse gas (GHG) emissions than conventional oil [3]. The low prices of oil (since late 2014) pose a threat to oil sands projects and could make oil sands production uneconomic at a certain point (~US$55-60 per barrel, West Texas Intermediate benchmark) [4]. Another important challenge faced by the oil sands industry is the growing concerns over the climate impacts of fossil fuels and global demand for reducing GHG emissions from all sectors of the economy, especially the energy sector that is by far the largest contributor to GHG emissions in Canada and in the world [5,6]. As a result, oil sands operators and policy makers seek operational improvements, emission reduction solutions and investment in new low-emission technologies to improve the economic and environmental performance of oil sands production and to remain a competitive alternative in the global energy market.

There are different approaches that can be employed by oil sands producers to improve the economic and environmental performance of their operations. This thesis investigates two different approaches (not mutually exclusive) and explores the potential improvements each of these approaches can offer.

Efficiency improvements is one type of approach that could potentially improve both economic and environmental performance of oil sands operations and are achieved by making modifications to the existing technologies, for example by applying process integration techniques [7,8] without changing or replacing the technology. The oil sands industry has steadily improved the economic and environmental intensity of oil sands extraction and processing over the past five decades [9]. An analysis of long-term trends of oil sands operations calculated that the energy return (amount of energy output per energy consumed) of these operations tripled between 1970 and 2010 [9]. The impact of efficiency improvements (reducing energy consumption per unit of energy produced) has been monumental to the growth of oil sands projects in the past five decades and it continues to make oil sands operations more efficient every day. Despite the important role of efficiency improvements in keeping oil sands products competitive in the energy market, in order to contribute meaningfully to recent ambitious climate goals, emission reductions need to occur across the entire life cycle. Therefore, another type of improvements must be considered that goes beyond efficiency improvements within the existing technologies and can be achieved by introducing new technologies to replace the existing ones, i.e., by **technology substitution**. This thesis investigates these potential improvements, both **efficiency improvements** within existing technologies and improvements achieved as a result of **technology substitution**, by applying a set of process analysis and system analysis tools including process integration (PI), life cycle assessment (LCA) and mathematical optimization techniques.

Oil sands operations consist of the following stages: bitumen extraction and recovery, dilution or upgrading of bitumen and crude oil refining. Various technology options are available (or will potentially become available) for each stage of oil sands operations. Selecting the optimal technology pathway (i.e., a combination of technologies for 1) extraction and recovery of bitumen, 2) bitumen dilution/upgrading and 3) refining to produce final oil sands products) among available technology options (both existing and emerging technologies) with respect to economic and environmental objectives is complicated by the large number of input parameters in the system and requires a comprehensive techno-economic framework that considers all technological and economic input parameters that affect the performance of the entire system in terms of total cost, total energy consumption and GHG emissions. In addition, the framework must have the capability to include external factors (such as transport capacity) in the assessments. These factors do not impact the technology performance directly but can impact the scale of adoption for different technology options. This framework would be able to provide insights about the competitiveness of emerging technologies under uncertain conditions, and the impact of external factors on the scale of adoption for emerging technologies which are explored in this thesis.

1.2 Research motivation and objectives

In this section, motivation and objectives of three main chapters of this thesis (Chapters 2, 3, and 4) are explained.

1.2.1 Energy, Water, Cost, GHG Implications of SAGD Surface Facility Technologies

In the Chapter 2, cost and energy savings opportunities in Steam Assisted Gravity Drainage [10] (SAGD) (an oil sands extraction and recovery process) are assessed by applying process integration techniques through the sequential application of a water treatment system optimization followed by conventional energy pinch analysis. Process integration techniques have been used to study process design, remove inefficiencies, and investigate potential improvements in a wide range of industrial processes such as pulp and paper, petrochemical, power generation and chemicals [11,12]. However, the application of process integration to the oil sands industry has gained little attention to date and there are only a few studies [7,13,14] that explore the potential energy and cost savings in the SAGD process using process integration for energy efficiency. Chapter 2 of this thesis aims to improve the analyses performed in those studies by: 1) applying both water and heat integration to SAGD operations and 2) considering 4 combinations of technology options. The purpose of these additional analyses is to provide a broader set of insights to decision makers in the oil sands industry on potential cost and energy savings for available technology options and existing tradeoffs between cost, energy and GHG emissions.

Process integration techniques are a set of methods for combining operations within a single process or multiple processes to reduce raw material, water and energy consumption in a system [11]. Two of the most common applications of process integration techniques are energy integration via designing a Heat Exchanger Network and water integration via water minimization and designing a distributed effluent treatment system. Mathematical Programming (MP) and Pinch Analysis (PA) are two process integration techniques to improve energy efficiency and minimize water and raw material consumption of a system. These techniques can be used to improve the heat recovery in SAGD facilities, minimize external cooling and heating requirements and minimize energy consumption for water treatment.

However, process integration techniques have a narrow scope of analysis, and their focus is on one specific process within the system while the rest of the system is not considered. In addition, the environmental impacts associated with the inputs to the process (e.g., raw material) are not considered in these techniques and they lack a consistent quantification criteria for the environmental impacts associated with different kinds of process wastes. Nevertheless, the potential improvements achieved by process integration techniques can be combined with a more comprehensive approach (e.g., life cycle assessment) that considers all components of the system simultaneously, incorporates the life cycle (i.e., supply chain) impacts of the energy and material inputs to the system and includes the interconnections of the system components in the analysis. Combining incremental improvements achieved by process integration techniques with high level systems thinking offered by LCA methods is an approach to inform decision-making in energy systems. Using such holistic approach enables the decision maker to identify solutions that lead to a decrease in global environmental impact, instead of alternatives that are only able to reduce the environmental impacts locally while other negative effects over the rest of the life cycle are overlooked.

Additional tools required for analysis

Life cycle assessment has been recognized as an effective environmental management tool to quantify and evaluate the environmental and economic performance of a system from cradle to grave and provide recommendations to improve the system performance defined to include a broad set of sustainability metrics [15,16]. LCA has been used extensively for process selection, design and optimization as a decision-making tool to explore comparative performance of a set of technology options using common and consistent boundary and assumptions [17]. Chapters 3 and 4 of this thesis investigate potential improvements in oil sands operations that can be achieved by technology substitution using a LCA approach.

LCA techniques can be used to provide quantitative measures of economic and environmental performance of different process design alternatives that is required to select the best design from an economic and environmental perspective. However, when there is a large number of different possible design alternatives generated by various combinations of processes, using LCA requires generating all the possible alternatives manually and performing LCA on each of them separately. In addition, using a LCA approach becomes even more time consuming when external factors influencing performance are included in the analysis (e.g., uncertain/variable cost and policy conditions). In the absence of a systematic method to address this problem directly within the LCA, the alternatives considered is often based on intuitive and heuristic approaches which may lead to sub-optimal solutions. Mathematical optimization combined with LCA principles has the potential to inform the decision-making process by providing a structure to select among various alternatives without evaluating all possible alternatives by LCA separately.

1.2.2 Evaluation of economic and environmental performance of oil sands emerging technologies considering technological parameters uncertainty

Chapter 3 explores the potential improvements to oil sands operations using technology substitution. Life cycle stages of oil sands operations consist of bitumen extraction and recovery, dilution or upgrading of bitumen[1] (to produce a bitumen product ready for pipeline transport), bitumen product transport and refining, refinery product end-use. Different technology options (existing and emerging technologies) can potentially be employed in each stage of the operations. Employing these technology options, each with a different performance, could impact the economic and environmental performance of the entire oil sands operations. Selecting the technology options that optimize the economic and environmental performance of the oil sands operations (by maximizing the profit and/or minimizing the GHG emissions) is complicated by a large number of input parameters in the system (e.g., volatile market price of oil products). A comprehensive techno-economic framework is required that considers all technological and economic input parameters that affect the performance of the entire system in terms of total cost, total energy consumption and GHG emissions.

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[1] Bitumen dilution and upgrading technologies are currently used to produce crude oil in the form of dilbit and synthetic crude oil (SCO) (respectively) in Alberta.

Existing technologies have been widely employed by the industry and reasonable amount of operational data is available from these technologies that have been used in several studies to characterize their performance [18–20]. On the other hand, emerging technologies such as partial upgrading and solvent-assisted extraction and recovery have not been deployed at commercial scale yet and their performance is not as well understood as the existing technologies. Considering that emerging technologies are seeking to gain market share in oil sands industry, they require environmental, technological and economic evaluation prior to their uptake at commercial scale to understand the implications of adopting these technologies on GHG emissions and cost of the entire supply chain and to compare them to current technology scenarios. It is important to consider the uncertainties associated with the performance of the emerging technologies when investigating the potential impacts of their adoption on the entire supply chain. This is to ensure the expected improvement in the economic and environmental performance of oil sands operations as a result of adopting emerging technologies can in fact be achieved.

A mathematical model is developed as part of this thesis to assess the cost and GHG emissions of various oil sands production scenarios under variable and uncertain conditions with a focus on emerging oil sands production and processing technologies. This model is used to find the technical, economic and policy conditions (e.g., natural gas (NG) price, diluent price, energy use per unit flowrate of inlet crude, etc.) under which emerging oil sands technologies (e.g., solvent-assisted, and partial upgrading technologies) become competitive alternatives in global crude oil markets (compared to dilution and full upgrading technologies).

Several studies in the literature have performed economic and environmental evaluation of emerging oil sands technologies to assess their feasibility from different perspectives [19–21].

However, no study in the literature has investigated the broad set of conditions that changes the competitiveness of emerging technologies against current technology pathways from full life cycle and multi attribute perspectives (economic and environmental perspectives). Chapter 3 of this thesis aims to fill this gap. The model developed in this chapter combines life cycle assessment (LCA) and optimization techniques to more efficiently evaluate a large number of possible technology pathways to inform the investment decision making and provide insights for future research on emerging technologies by identifying the conditions (e.g., technology performance parameters, carbon price, energy price, etc.) required for a new technology to become a competitive alternative for oil sands production. This chapter aims to inform oil sands operators about the technology alternatives that can potentially make oil sands products more competitive with crude oil markets by reducing the supply chain cost and life cycle GHG emissions of oil sands operations. Results of this analysis can help oil sands producers to better understand the long-term effects associated with the use of existing and emerging oil sands technologies.

1.2.3 Role of emission reduction solutions and emerging technologies in meeting oil sands emissions reduction targets

Chapter 4 investigates a broader set of emission reduction solutions (in addition to what was included in chapter 3) and how they can be utilized to help oil sands producers achieve certain emission reduction targets while taking into account available markets for oil sands crudes, refining capacity in the target markets and transport capacity to those markets. Growing concerns over the climate change impacts of fossil fuels in Canada and in the world have put great pressure on oil sands producers to reduce GHG emissions from their operation and the entire oil sands supply chain. Oil sands producers need to utilize emissions reduction solutions in order to keep their products as competitive alternatives in the future low-carbon (or zero-carbon) energy systems.

In 2021, Canada’s 5 largest oil sands producers announced setting net-zero emissions target by 2050 [24]. Various emissions reduction solutions have been developed or are under development that can be used to reduce GHG emissions from oil sands operations. However, it is not clear whether these solutions would provide the required amount of reduction in emissions that could help achieve the ambitious reduction targets set by the oil sand producers. These emissions reduction solutions include utilization of emerging low emission intensity technologies (such as solvent assisted SAGD (SA-SAGD), In Situ Extraction and Upgrading (ISEU) and Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH)) for oil sands production and processing, implementing carbon capture and utilization/storage (CCUS) to capture CO_2 from combustion emissions sources or steam methane reforming units, and employing CO_2 removal (or negative emissions) technologies (such as Direct Air Capture and nature-based solutions) to compensate for GHGs emitted to the atmosphere. Each of these technologies have different economic and environmental performance parameters that impact the performance of the entire oil sands supply chain which complicates the selection of the optimum emissions reduction solution(s). In addition, external drivers such as transport and refining capacity could impact the choice of the technology (or technologies) to be employed for emissions reductions. Therefore, a technoeconomic framework is required that takes into account all the input parameters related to the technologies, and the external drivers and constraints and provides insights about the best possible economic and environmental performance of oil sands operations using the available technology options.

The model developed in Chapter 3 of this thesis is designed to investigate different technology pathways with a focus on uncertain and variable technology performance parameters while a limited set of external parameters that directly impact the technologies performance are considered. Other external drivers such as market demand for different qualities of crudes, refining capacity for different crude qualities, transport capacity, and availability of capital investment are not considered in that model. In Chapter 4 of this thesis, the initial model developed in Chapter 3 is modified to include a new set of constraints and emission reduction options that could provide additional insights regarding the scale of adoption for different technologies that offer emissions reductions from oil sands operations and about the set of conditions required for those technologies to become economically feasible to achieve the emission reduction targets set by oil sands producers that are in line with Canada's net-zero target by 2050 [25].

The framework developed in this study can be used to inform short- and long-term investment decision making in oil sands sector under various scenarios with different combinations of input parameters including technology availability, technology performance parameters and how they evolve over time, crude oil and transportation fuel demand forecast, energy price forecast, transport and refining capacity for target markets, future environmental policy scenarios.

1.3 Organization of this Thesis

This thesis is organized and presented in three main chapters. These chapters are preceded by an Introduction chapter (this chapter), and followed by a conclusion chapter.

Chapter 2 of the thesis investigates the implications of different technology options within SAGD surface facilities on total cost, energy and water consumption, and GHG emissions. This chapter explores water integration potential in the form of distributed effluent treatment system design as well as heat integration considerations in SAGD operations. This chapter is an example of using efficiency improvement approach for improving the performance of oil sands operations.

This chapter is published as a journal paper in *Process Integration and Optimization for Sustainability* journal. The citation is provided below.

Forshomi ZD, Carreon CE, Alva-Argaez A, Bergerson JA. Energy, Water, Cost, and Greenhouse Gas Implications of Steam-Assisted Gravity Drainage Surface Facility Technologies. Process Integr Optim Sustain 2017:1–21. https://doi.org/10.1007/s41660-017-0007-0.

In this paper, the candidate defined the problem with the help of Joule Bergerson, Alberto Alva-Argaez, and based on a previous work completed by Carlos Carreon on the heat integration opportunities in SAGD process. The candidate set up the mathematical optimization model with the help of Alberto Alva-Argaez, and selected the decision variables and constraints for the model. The candidate performed the analysis and prepared the results. All authors contributed to the interpretation of the results. The candidate prepared the manuscript and Joule Bergerson and Alberto Alva-Argaez reviewed, and critically revised the manuscript for important intellectual content.

Chapter 3 of the thesis provides a framework to assess a number of emerging technologies along with existing oil sands technologies under variable and uncertain conditions, and identifies the technical, economic and policy conditions under which emerging oil sands technologies become competitive alternatives in global crude oil markets. The proposed framework combines optimization methods with LCA principles to more efficiently assess a large number of possible technology scenarios based on their environmental and economic performance.

This chapter is submitted in the form of a journal paper to the *Journal of Cleaner Production*, and is currently under review.

Chapter 4 provides a framework to evaluate several emissions reduction solutions applicable to oil sands operations using life cycle assessment and optimization methods and investigates the role each emissions reduction solution can play in helping oil sands industry achieve ambitious emissions reduction targets during the analysis period between 2021 and 2050, while maximizing the profit per barrel bitumen produced.

This chapter is ready for submission to the *Journal of Cleaner Production.*

Chapter Two: **Energy, Water, Cost, GHG Implications of SAGD Surface Facility Technologies**

2.1 Abstract

This analysis explores the implications of technology options for SAGD surface facilities on cost, energy, GHG emissions and water consumption. Water integration in the form of distributed effluent treatment system design as well as heat integration considerations are the basis of this study. Cost savings are accomplished by sequentially employing water network optimization and energy integration techniques. Total annual cost savings of 2.7 to 7.8% are achieved at the surface facility through water integration. Additional operating cost savings of 9.2-10.2% are found due to heat integration. Of the technology options considered in this study, hot lime softening (HLS) with blowdown evaporation and HLS with blowdown recycle are the most promising when considering the tradeoffs between energy, GHG emissions and water consumption. However, these options are quite different (i.e., blowdown evaporation has lower water consumption but higher GHG emissions, whereas, blowdown recycle has lower GHG emissions but higher water consumption). Deciding between these options requires placing a value on these environmental externalities. The approach described in this work can be applied to inform decisions in the face of tradeoffs between a range of performance metrics. Similarly, the analysis framework described in this paper can be adapted to consider new technology pathways as they become available.

2.2 Introduction

Bitumen production from the Canadian oil sands resource was reported as 2.2 million bpd in 2014 [26]. Although the recent increase in global crude oil production has led to decreased oil prices and has challenged the Canadian crude oil industry, total oil sands bitumen production continues to grow albeit at a lower rate [26].

The energy intensity of the oil sands extraction process has raised concerns over the associated environmental impacts, including greenhouse gas (GHG) emissions which tend to be higher when compared to conventional oil production [18]. As such, oil sands operators are seeking new technologies and improving current techniques to reduce these environmental impacts. New technologies and improvements such as carbon capture and zero-emissions electricity are promising long-term solutions. However, near term improvements are also required.

The most prominent in situ oil sands recovery process is Steam Assisted Gravity Drainage (SAGD) that requires the generation of significant volumes of high-pressure (7,000-11,000 kPa) steam. The focus of this study is the assessment of short-term incremental improvements in the efficiency of the SAGD process using water and heat integration concepts. In SAGD, the steam is injected into the reservoir through an injection well, which heats the bitumen and reduces its viscosity allowing the resource to flow. The resulting bitumen emulsion (a mixture of oil, water, sand and clay minerals), is pumped to the surface through the production well and enters the central processing facility (CPF) [27,28]. The SAGD CPF consists of oil/water separation units, water treatment units, and steam generation in addition to storage units, pipelines, gas treatment units, oil treatment units, and other utilities. Water and oil are first separated in the CPF. The separated oil is sent to upgrading facilities or is diluted and transported to refineries for further processing. The produced water is treated in a set of water treatment units to reach the quality requirements for recycle and reuse in the steam generating boiler [29].

Process integration techniques have been used to study process design, remove inefficiencies, and investigate potential improvements in a wide range of industrial processes. Pinch analysis (PA) is a process integration technique to improve energy efficiency and minimize water and raw material consumption of a system. Pinch analysis has been shown to provide benefits in industries such as pulp and paper, petrochemical, power generation and chemicals [12,30]. However, the application of pinch analysis to the oil sands industry has not gained much attention to date and there are only a few studies [13,14] that explore the potential energy and cost savings in the SAGD process using pinch analysis for energy efficiency.

Nadella applied energy Pinch analysis to oil sands operations and used a simplified example to demonstrate the minimum energy requirement calculations for a SAGD process and proposed a heat exchanger network (HEN) [14]. However, Nadella only considered a simple SAGD configuration and did not include any process modifications.

Jacobs Consultancy conducted a study to assess the energy efficiency of SAGD operations and to evaluate the potential for reducing energy consumption and GHG emissions for a set of technology options (e.g., lime softening and evaporation) [31]. The results showed that 3.5% savings in energy consumption and 2.5% reduction in GHG emissions could be achieved through improved heat recovery. However, they only defined the energy targets and did not propose a HEN in their study to show where the energy savings would come from. Finally, they did not consider different configurations of SAGD in their analysis.

In another recent study, Carreon et al. applied heat integration to a specific configuration of the SAGD process (HLS and once-through steam generators (OTSG) with blowdown evaporation) to investigate the energy efficiency improvement (reducing energy consumption per unit of energy produced) and GHG emissions reduction potential in existing and future SAGD projects (Carreon et al., 2015). They introduced process modifications to increase energy savings beyond the maximum energy recovery identified by the pinch method. The effect of employing other technologies such as an evaporator for produced water treatment and a drum boiler for steam generation are not considered in Carreon et al.'s study. The present study aims to provide a more complete evaluation of improvement opportunities in SAGD plants by conducting both water and energy integration for a range of technology options.

There is one study that considers the application of water integration methods to the SAGD process [32] by designing a distributed effluent treatment system. Distributed effluent treatment design based on water integration and mathematical programming concepts provides the opportunity to improve water treatment networks by evaluating alternative configurations of the network without changing the treatment technologies under consideration [33]. Instead, it simply rearranges the wastewater streams in the network. Applying water integration to a water treatment network enables the design of a distributed effluent treatment system instead of conventional centralized treatment systems. This method evaluates a set of wastewater streams that could be treated for a number of contaminants in several treatment units with the possibility of partial or total bypass for each unit, in order to reach the environmental limit (or any other performance goals) for all the contaminants. Bypassing wastewater streams could potentially reduce the total system costs/energy consumption. Although conceptual methodologies are available, it has been shown that mathematical programming can assist in the design of distributed effluent treatment systems, particularly for the case where multiple contaminants are involved. In Dadashi et al.'s study, potential improvements in SAGD operations were investigated by designing a distributed effluent treatment system using mathematical programming [32]. They applied process integration techniques to minimize total cost in the water treatment system of SAGD operations. The results show up to 19.5% in cost savings in the water treatment system and up to 12% in electricity consumption savings only by diverting flows in the water treatment system [34]. However, heat integration opportunities were not in the scope of the study. Therefore, in the present study the additional savings opportunities are assessed in terms of cost and energy through the sequential application of a water treatment system optimization followed by conventional energy pinch analysis.

The area of combined water and energy integration has received increased attention in recent years. Both sequential and simultaneous approaches have been proposed. A review of recent work in this area can be found in Ahmetović et al. [35]. This review focuses on the studies that investigate the synthesis of non-isothermal water networks (WNs). Pinch analysis (PA) and mathematical programming (MP) are the two main methods used for both energy and water integration problems. PA can be applied for a sequential water and energy analysis whilst MP can be used for both sequential and simultaneous integration. The advantage of MP methods is that they are capable of exploring all the interactions between WNs and HENs. However, the overall synthesis problem is more complex when MP methods are used. PA methods reduce the complexity of the problem and give a better graphical visualization of the problem. The disadvantage of PA methods is that they are incapable of performing simultaneous energy and water integration and exploring all the interaction between WNs and HENs. It should be noted that the advantages of PA and MP methods could be combined by using a hybrid method (combined PA and MP) [35] similar to the approach followed in the present study. In the hybrid approach, it is possible to solve the WN design problem by MP first and then find the corresponding HEN design by PA. The advantage of using MP to solve the WN design problem is the capability of handling multiple contaminants in the mathematical model of the system. This feature also recognizes that the PA approach to distributed water treatment has been found to be challenging to apply for multiple contaminants.

Savulescu and Alva-Argaez reviewed different approaches that have been applied to various sectors of industry to improve energy and water efficiency using process integration considering the interactions between water and energy networks [36]. They concluded that changing the energy network usually impacts water network in different ways and vice versa especially if water is reused by water-using processes. Therefore, it is important to consider water and energy networks together in order to find sustainable solutions. The importance of water and energy networks interactions is also presented in Savulescu's study [37]. Savulescu showed that when process integration is applied to water and energy networks separately as proposed by Polley [38], it could limit water and energy savings potential. The "water path" concept has been explored in several studies (e.g., [39–41]) to improve energy efficiency of water networks when water consumption is minimized.

It has been reported that energy and water network analysis often leads to threshold problems which make it simple for the energy targets to be derived for the system [38]. However, several studies investigate Water-Energy Pinched problem such as the works of Sorin and Savulescu, Leewongtanawit and Kim, etc. [42,43]. Therefore, an in-depth analysis is required to define the type of energy problem in a simultaneous energy and water integration problem.

The most well-known approach to investigate combined water and energy integration problems is proposed by Savulesco et al. for systems with and without water reuse [44,45]. In the proposed approach by Savulescu et al., first a graphical approach is used to define water and energy target and then a two-dimensional grid diagram is implemented to design a combined water and energy integrated network. In 2011, Wan Alwi et al. improved the targeting step by introducing superimposed mass and energy curves that can assess water and energy reductions simultaneously [46].

The earliest proposed approaches to design integrated water and energy systems are based on graphical tools [44,45]. However, mathematical programming techniques were introduced later to deal with complex problems (e.g., with high number of contaminants and streams). In 1994, Papalexandri and Pistikopoulos proposed a general optimization framework to deal with heat and mass exchange networks [47] that lead to a mixed integer nonlinear programming (MINLP) problem. Papalexandri and Pistikopoulos used Generalized Benders Decomposition method to solve the MINLP problem. Since 2000, several studies attempted to improve the initial framework proposed by Papalexandri and Pistikopoulos by reformulating the mathematical model and including additional components of the system (e.g., all water allocation options and a general superstructure including both water use and heat transfer) and proposing new methods to solve the MINLP model such as generating random initial points and performing stochastic perturbations on the initial guesses [39,48,49].

In a recent study, Jagannath and Almansoori [50] propose a 2-stage sequential approach to synthesize a heat integrated water network that includes water sources, water users, water treatment units and sinks for multiple contaminants. Heat exchangers are of course part of the solution via designing a HEN for these water streams. The problem requires the definition of water sources in terms of contaminant concentrations and temperatures, water users with max inlet and outlets and mass load as well as operating temperature, sinks with its own limits on contaminants and temperature, treatment units with performance (removal ratios) and temperature requirements and cost data.

In the first stage, they used a superstructure model for water networks as reported earlier and added heaters and coolers to the interconnecting water streams. Once the water network has been designed and the stream population determined, the HEN superstructure of Yee and Grossman [51] is used to design the HEN similar to the approach followed in the present study. The non-integrated model includes only heaters and coolers to adjust the temperatures as required by the formulation. Since there is an energy cost term in the objective function, it is likely that this approach would favor non-isothermal mixing when feasible. The sequential approach is then applied to generate a set of designs and the solution with lowest cost is selected.

It must be stressed that industrial applications do not typically conform to the problem “types” defined in the literature. Heat-integrated water-using networks or WN-HEN problems as defined by Ahmetovic et al. (2015) limit the heat integration to take place among water streams only. The current case involves the design of a distributed effluent treatment network with heat integration potential for the rest of the process and the water streams.

This study aims to continue the analyses performed by Carreon et al. [13] and Dadashi et al. [32]. In Carreon et al.’s study only heat integration is applied to one set of technology options (lime softening and OTSG) and Dadashi et al. only consider water integration opportunities across different sets of technology options. The present study intends to improve those two studies by: 1) applying both water and heat integration to SAGD operations and 2) considering 4 different cases of technology options. The purpose of these additional analyses is to provide a broader set of insights on available technology options to the decision makers in oil sands industry. General Algebraic Modeling System (GAMS) and Aspen Energy Analyzer are used in this study for water and heat integration analysis respectively.

2.3 Methods

In this study, the impact of applying process integration tools is assessed using a hybrid strategy MP-PA, to selected SAGD configurations in terms of energy efficiency and GHG emissions of the SAGD process. Water integration is conducted by applying mathematical optimization and heat (or energy) integration is conducted by using conventional pinch analysis [52]. Both methods are introduced in the following sections.

2.3.1 Mathematical model for designing a distributed effluent treatment network

As mentioned earlier, Dadashi et al. [32] developed a mathematical model to design an optimized water treatment network for a SAGD plant. The model is developed in GAMS based on a superstructure model of the network that includes all components of the water treatment system (splitters, mixers, wastewater streams with known flowrates and contaminants concentrations, water treatment processes with known removal ratios, etc.) and interconnections between treatment units as shown in Figure 2-1. Cost and energy consumption of each treatment unit is assumed to be linearly related to the flow rate going through the treatment unit (Cost OR Energy = a × Flowrate + b). The model developed in Dadashi et al.'s study is used in the present study to investigate the combined effect of water and energy integration in SAGD operations.

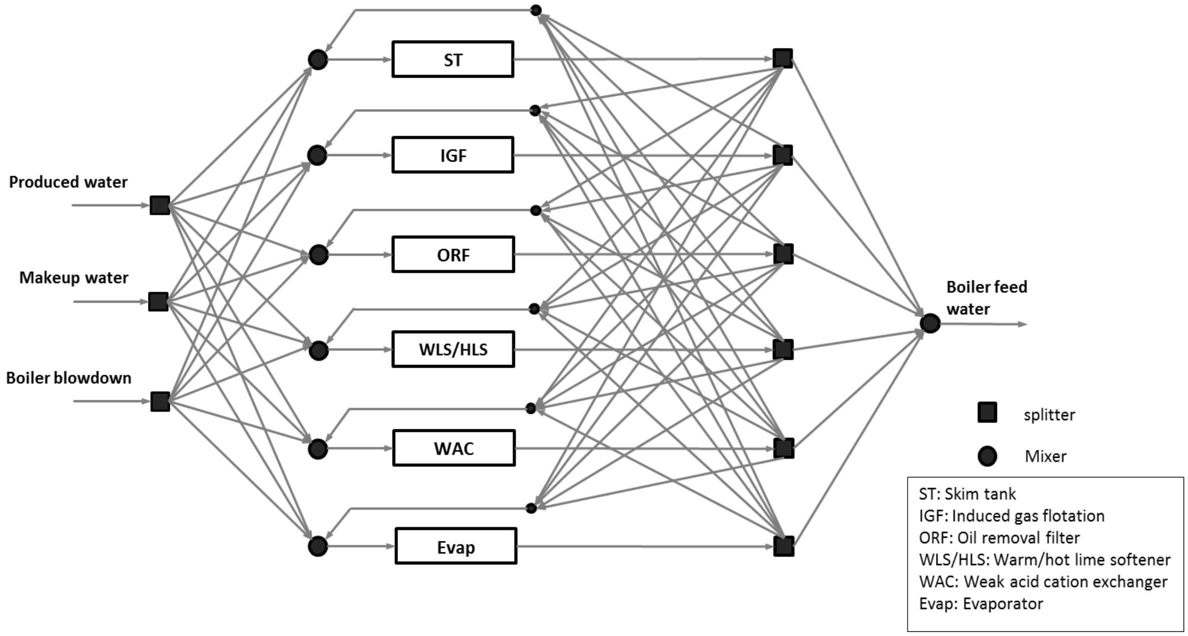

Figure 2-1 Superstructure of the system (adapted from [32])

The mathematical model is developed based on the superstructure shown in Figure 2-1 that leads to a MINLP problem. Objective function of the model is minimum total cost (or total energy consumption) of the system. For instance, cost objective function can be shown as below:

$$OF^{cost} = \sum_{tu} Cost_{tu}^{tot} + HY * \sum_{s} (F_s * \ Cost_s^{var} \ )$$

OF^{cost}	Cost objective function
$Cost_{tu}^{tot}$	Total cost of treatment unit “tu”
HY	Operating hours per year
F_s	Flowrate of water source “s”
$Cost_s^{var}$	Variable cost of water source “s”

Constraints of the mathematical model are mainly mass balance equations and some additional constraints of the system (e.g., minimum boiler feed water quality requirements). Decision variables are the flowrates of wastewater streams through each treatment process. Main mass balance constraints of the model include overall mass balance in the system, mass balance for each splitter and mixer, overall and component mass balances in each treatment unit. Additionally, each treatment unit has a maximum allowable concentration limit with respect to each component in the wastewater stream which is reflected in the constraints. Another constraint is added to the model to specify the boiler feed water quality requirement. Binary variables are added to the model to represent if a treatment process is selected by the optimization model to reach the minimum cost (or energy consumption) or not (the binary variable associated with a treatment unit assumes the value of “1” if the treatment unit is selected in the water treatment system and assumes the value of “0” if it is not selected). Binary variables are also used to assign upper and lower bounds to the streams flow rates. All constraints of the model are presented in Appendix A in equations (1) to (19).

Mathematical model of the system leads to a mixed-integer non-linear (MINLP) problem. The MINLP model is divided into two simpler sub-models: mixed integer linear programming (MILP) model and linear programming (LP) model by introducing a penalty function and projection and relaxation approaches. MILP and LP models are solved iteratively to reach an optimal solution which is then used as an initial point for MINLP problem. Then the MINLP problem is solved to find the optimal solution.

2.3.2 Pinch analysis method for heat integration

Energy Pinch analysis is a well-known process integration tool that is used to identify heat recovery potential in a system and minimize energy consumption. The first step in this type of analysis is called the targeting step where the maximum heat recovery potential and minimum hot and cold utility requirements (external heating and cooling) are identified. The next step is the design of a heat exchanger network (HEN) to reach the energy targets identified in the previous step [52]. The HENs are developed based on pinch analysis rules in Aspen Energy analyzer software [53]. The three fundamental rules to achieve maximum heat recovery when designing a HEN are:

1. No heat transfer across the pinch point
2. No external cooling above the pinch point
3. No external heating below the pinch point

Any violation of these rules leads to an energy penalty and minimum utility requirements will not be achieved.

2.3.3 Combined method

In the present study, water and heat integration are applied to the SAGD process using a sequential approach to study their combined effects in terms of energy and cost savings across a broader set of technology options. Four different configurations of the SAGD central processing facility (CPF) are investigated and compared in terms of energy and water consumption, cost and GHG emissions before and after process integration. The SAGD configurations investigated in this study are described below.

- Case 1: HLS is used for water treatment and steam is generated in an OTSG. Boiler blowdown is treated in an evaporator and the evaporator distillate is recycled directly as boiler feed water.
- Case 2: similar to the case 1, case 2 uses HLS and OTSG for water treatment and steam generation respectively. In this case however, the boiler blowdown is partially recycled back to HLS for further treatment without the evaporation step (50% recycle ratio). The remainder of the blowdown goes to deep well injection for disposal.

- Case 3: an evaporator is used for produced water treatment and steam is generated in an OTSG. Boiler blowdown is recycled back to the evaporator.
- Case 4: water is treated in an evaporator and a drum boiler is used for steam generation.

A simplified Block Flow Diagram (BFD) for case 1 is shown in Figure 2-2. In this figure, streams are numbered from 1 to 9, and the corresponding characteristics of each of these hot and cold streams are presented in Table 2-1. BFDs of the other three cases are shown in Figure 2-3 to Figure 2-5 and the streams in each case are listed in Table 2-2 to Table 2-4.

A business as usual (BAU) case is defined as a specific configuration of the SAGD process before applying water and heat integration. In other words, for each of the four cases introduced, the BAU case implements typical heat integration configurations found in industry. BAU cases are used as the basis of comparison to evaluate cost and energy savings for each selected configuration of SAGD operations.

In each case, both capital and operating costs of the water treatment units are first reduced after optimizing the water treatment network by designing a distributed effluent treatment system using the superstructure model. Additionally, the capital cost of the heat exchanger network (that includes process heat exchangers, heaters and coolers) is revised after applying heat integration and maximizing heat recovery in the system. Furthermore, applying heat integration minimizes external heating and cooling requirements which leads to lower operating costs for the system.

The required data to develop the BAU for case 1 are obtained from a SAGD Environmental Impact Assessment[2] [13,54]. This particular project has a capacity of 20,000 bpd bitumen production. The required steam flowrate in the project is approximately 490,000 kg/hr, which is the basis of all flowrate calculations in the present study. Detailed information about the facility characteristics can be found in [13]. Other BAU cases were developed using publicly available data [55].

For each BAU case, the total cost and associated energy consumption are estimated. Total cost includes capital and operating costs of water treatment units, makeup water withdrawal and wastewater disposal, capital cost of boilers and steam separators, capital cost of heat exchangers and natural gas (NG) cost. Energy consumption also includes electricity consumption. GHG emissions are calculated based on energy consumption and energy source type. For heat exchanger cost calculations in BAU cases, it is assumed that a similar HEN is designed for all BAU cases, it is noted that the required data to build the specific HEN for the BAU cases 2-4 was not available. The HEN of BAU case before water and heat integration is shown in Figure 2-6. In this figure, grey connected circles are process heat exchangers, blue circles are coolers and red circles are heaters. It must be stressed that the BAU case already has some degree of heat integration but the present study aims at improving on these current practices.

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[2] A small modification is applied and no medium pressure steam is produced from high pressure blowdown.

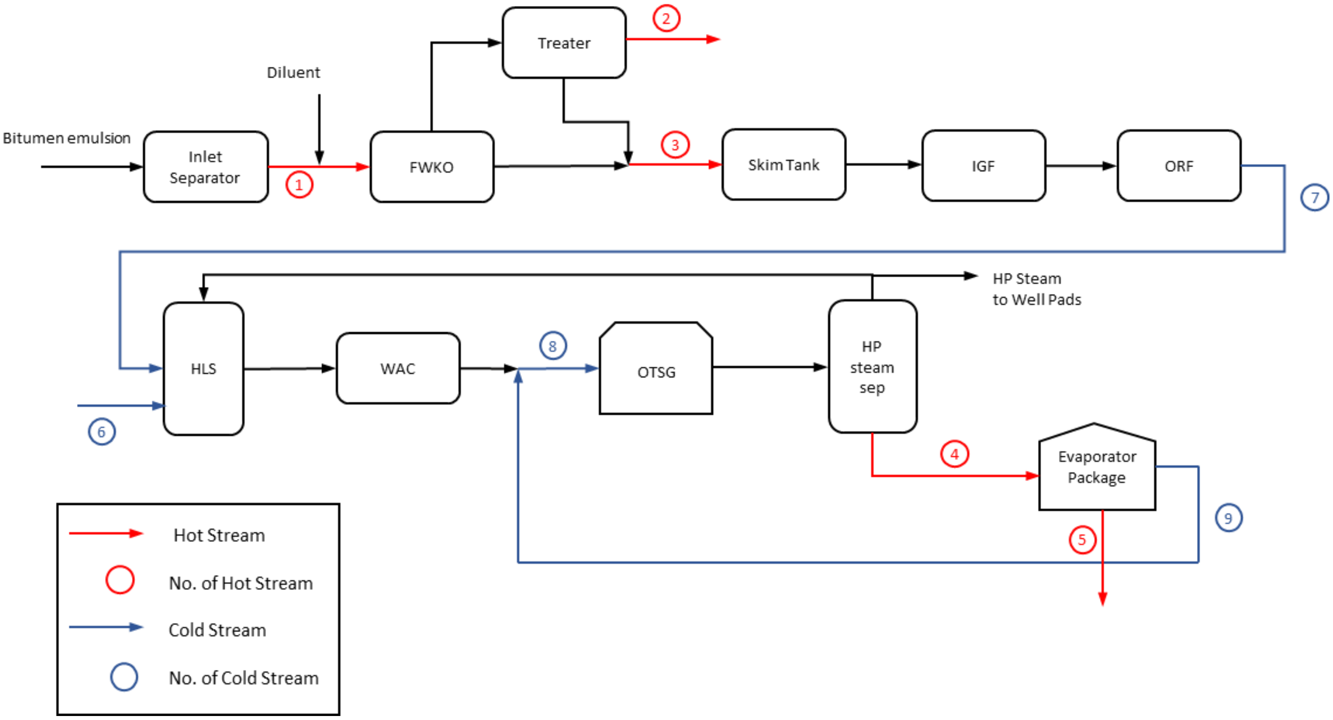


Figure 2-2 Block flow diagram of business as usual design of Case 1

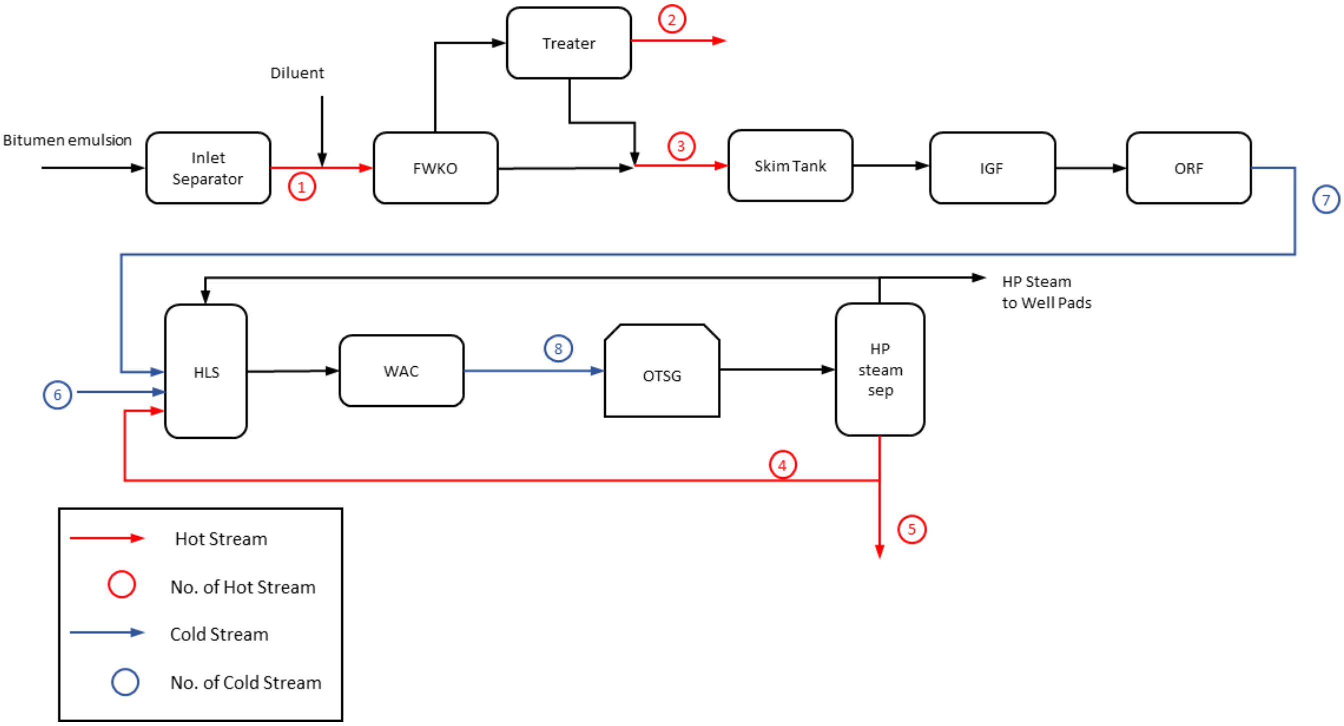


Figure 2-3 Block flow diagram of Case 2

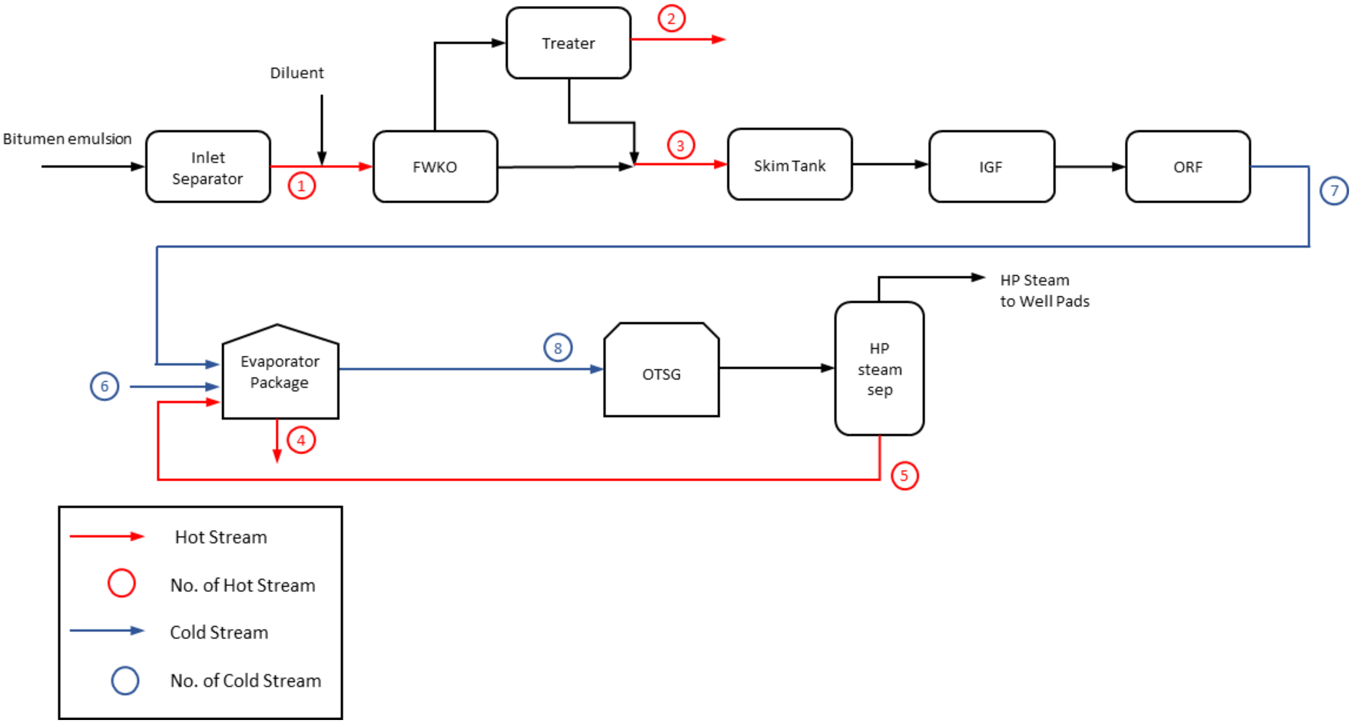


Figure 2-4 Block flow diagram of Case 3

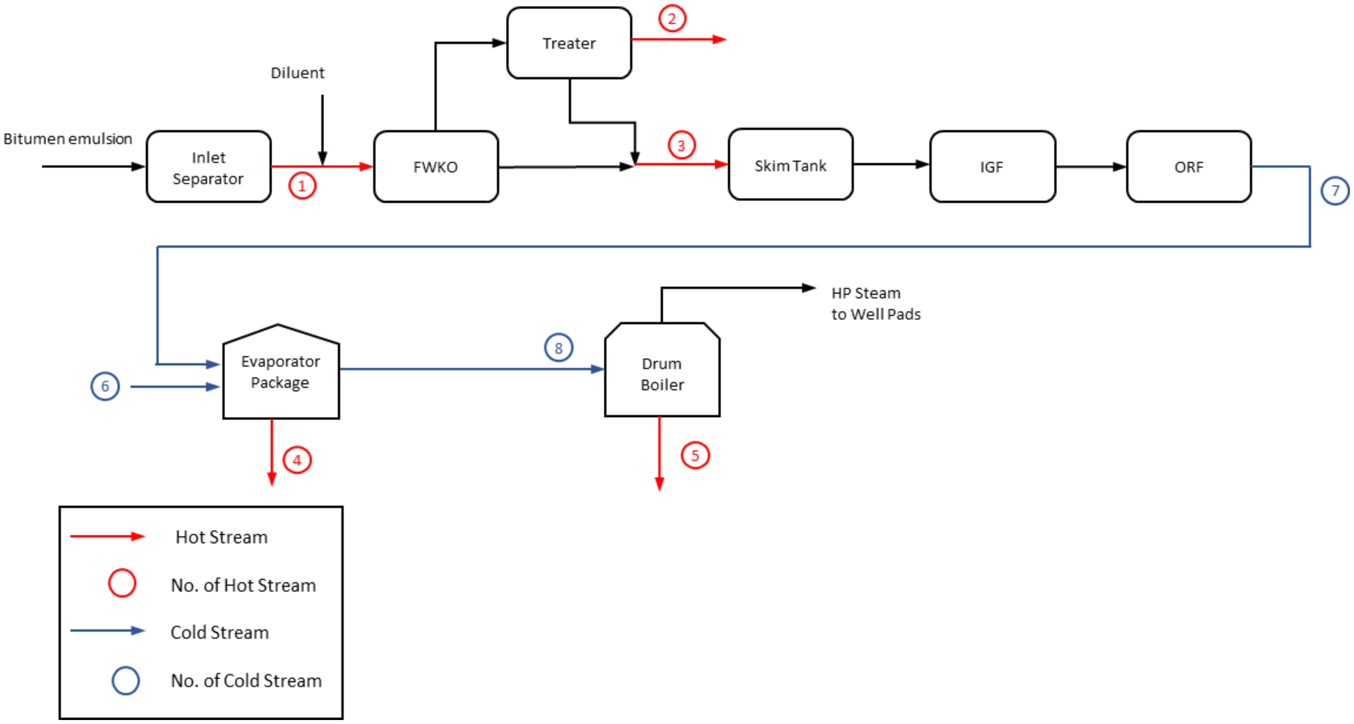


Figure 2-5 Block flow diagram of Case 4

Table 2-1 Stream data for case 1

	Stream	$T_{initial}$ (˚C)	T_{final} (˚C)	Mass flowrate (kg/hr)	Heat load (MW)
Hot streams	1 Bitumen emulsion	187	133	610,138	38.5
	2 Diluted bitumen (dilbit)	130	50	172,453	8.2
	3 Produced water form FWKO and treaters	130	85	466,960	26.2
	4 HP blowdown	310	90	125,997	35.8
	5 Evaporator blowdown	90	65	6,300	0.2
Cold streams	6 Makeup water	5	50	4,838	0.3
	7 Deoiled water to lime softener	85	95	475,463	6.0
	8 Boiler feed water	105	310	629,986	167.0
	9 Evaporator distillate	90	105	119,697	2.1
	Boiler feed water to steam conversion (latent heat)	310	310	493,658	181.0

Table 2-2 Stream data for Case 2

	Stream	$T_{initial}$ (˚C)	T_{final} (˚C)	Mass flowrate (kg/hr)	Heat load (MW)
Hot streams	1 Bitumen emulsion	187	133	610,138	38.5
	2 Diluted bitumen (dilbit)	130	50	172,453	8.2
	3 Produced water form FWKO and treaters	130	85	466,960	26.2
	4 HP blowdown	310	95	125,997	35.0
	5 HP blowdown to disposal	95	65	62,998	2.2
Cold streams	6 Makeup water	5	50	86,032	4.6
	7 Deoiled water to lime softener	82	95	475,463	8.8
	8 Boiler feed water	105	310	629,986	167.0
	Boiler feed water to steam conversion (latent heat)	310	310	493,658	181.0

Table 2-3 Stream data for Case 3

	Stream	$T_{initial}$ (˚C)	T_{final} (˚C)	Mass flowrate (kg/hr)	Heat load (MW)
Hot streams	1 Bitumen emulsion	187	133	610,138	38.5
	2 Diluted bitumen (dilbit)	130	50	172,453	8.2
	3 Produced water form FWKO and treaters	130	85	466,960	26.2
	4 Evaporator blowdown	90	65	27,726	0.8
	5 boiler blowdown	310	90	123,415	34.9
Cold streams	6 Makeup water	5	50	50,759	2.7
	7 Deoiled water to evaporator	82	90	521,384	5.1
	8 Boiler feed water	90	310	617,073	174.4
	Boiler feed water to steam conversion (latent heat)	310	310	493,658	181.0

Table 2-4 Stream data for Case 4

	Stream	$T_{initial}$ (˚C)	T_{final} (˚C)	Mass flowrate (kg/hr)	Heat load (MW)
Hot streams	1 Bitumen emulsion	187	133	610,138	38.5
	2 Diluted bitumen (dilbit)	130	50	172,453	8.2
	3 Produced water form FWKO and treaters	130	85	466,960	26.2
	4 Evaporator blowdown	90	65	26,512	0.8
	5 boiler blowdown	310	65	10,075	3.2
Cold streams	6 Makeup water	5	50	59,620	3.2
	7 Deoiled water to evaporator	81	90	530,245	5.8
	8 Boiler feed water	90	310	503,733	142.3
	Boiler feed water to steam conversion (latent heat)	310	310	493,658	181.0

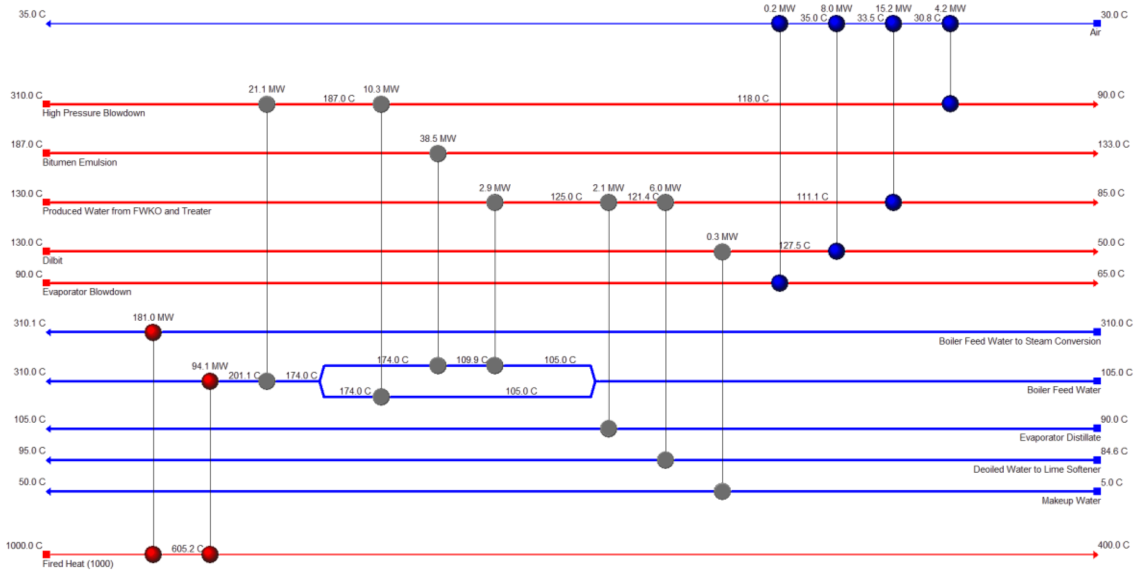


Figure 2-6 Heat exchanger network of business as usual design of Case 1

After analyzing the BAU cases, the optimization model for the water treatment system presented in [32] is used to estimate the cost savings as a result of diverting flows around treatment units. Pertinent data that are used in the mathematical model to design a distributed effluent treatment for SAGD water treatment system are presented in Table 2-5 to Table 2-9 and the results are discussed in section 2.4.1.1. The cost data for water treatment units used in this analysis are presented in Table 2-10. It should be noted that the cost data are acquired from industry partners under a confidentiality agreement, therefore, data presented in Table 2-10 are normalized to 100 (the cost data can be used as presented to reproduce the present study and it will not affect the results). Once the optimized design of the water treatment system is identified, stream data presented in Table 2-1 to Table 2-4 is used to generate composite curves and grand composite curves to find energy targets. After the energy targets are established, a heat exchanger network (HEN) is developed for each case to show how the energy targets can be achieved. Once the heat exchanger network is developed, the heat load and heat transfer area of the heat exchangers are evaluated and used for capital cost estimation and calculation of NG requirements and GHG emissions. Then the additional cost and energy savings associated with heat integration of the process are calculated. The results of heat integration and the total impact of sequential water and heat integration are presented in 2.4.1.2.

After evaluating the savings potential due to water and heat integration for each case, the results of energy consumption, total cost estimates and GHG emissions of the four cases are compared with their corresponding BAUs. Comparisons across configurations are used to identify the tradeoffs between cost, energy and emissions.

In this work, the minimum temperature approach to determine the pinch location was selected to be 13˚C. This value corresponds to the lowest temperature approach identified in any heat exchanger as reported in the base case. This selection ensures that current industrial practice is taken into consideration for the remainder of the analysis. Lower values could be explored but would likely result in excessive capital cost and is outside the scope of this paper.

Table 2-5 Concentration range for produced water contaminants

Contaminant	Concentration range (ppm)	Data Sources
Oil	1200-2000	[56–59]
TDS	800-4000	[56–62]
Hardness	15-120	[57–63]
Silica	150-260	[57–61,63]
TOC	200-400	[56–58,61,63]
TSS	25-150	[57,59,60]

Table 2-6 Concentration range for makeup water contaminants

Contaminant	Concentration range (ppm)			
	Fresh makeup water	References	Saline or brackish makeup water	References
Oil	< 1	[56,57,59]	< 1	[57,59]
TDS	2780	[56,57,59]	17708	[57,59,61]
Hardness	15-120	[57,59]	2600	[57,59,61]
Silica	5	[57,59]	8	[57,59,61]
TOC	< 1	[56,57,59]	35	[57,59,61]
TSS	< 2	[57]	< 10	[57]

Table 2-7 Deoiling processes and their oil removal efficiency

Process	Separation technology	Oil droplet size removal	Effluent oil concentration (ppm)	Approximate removal ratio
Skim tank	Gravity	> 150 µm	200-400	85-90 %
API separator	Gravity	> 150 µm	200-400	50-99 %
CPI separator	Gravity/Coalescence	> 50 µm	100	-*
DGF/IGF	Flotation	> 20 µm	10-40	90-93 %
Deoiling hydrocyclone	Centrifugal force	> 10 µm	20-40	90-93%
Filtration	Absorption	< 2 µm	1-5	90 %
Membrane	Barrier	< 1 µm	0.5-4	-*

*Accurate removal ratios could not be found in the literature.

Table 2-8 Boiler feed water quality requirements for OTSG and drum boiler

Parameter	OTSG requirement (ppm)	References	Drum boiler requirement (ppm)	References
Oil	0.5-10	[28,59,60,64,65]	0.2	[59,60]
TDS	7,000-12,000	[28,59,60,64,65]	5	[59]
TSS	<1	[59,65]	<1	[59,66,67]
Hardness	0.5-1	[28,59,60,63–65]	0.02-0.5	[59,60,63]
Silica	20-150	[28,59,60,63–65]	0.1-2	[59,60,63]
TOC	200-600	[59,63]	0.2	[59,63]
DO	0.04	[28,60,65]	0.04	[60,66,67]
Specific conductance	2,000-10,000*	[63]	150*	[60,63]

*Unit is μS/cm

Table 2-9 Contaminant concentrations of water and wastewater streams in the system used in the optimization model

Contaminant	Produced water	Fresh makeup water	Brackish makeup water
Oil (ppm)	2000	0	0
Silica (ppm)	350	15	15
TH (ppm)	20	245	2500
TSS (ppm)	50	0	5

Table 2-10 Capital and operating cost data (normalized) used in the mathematical model

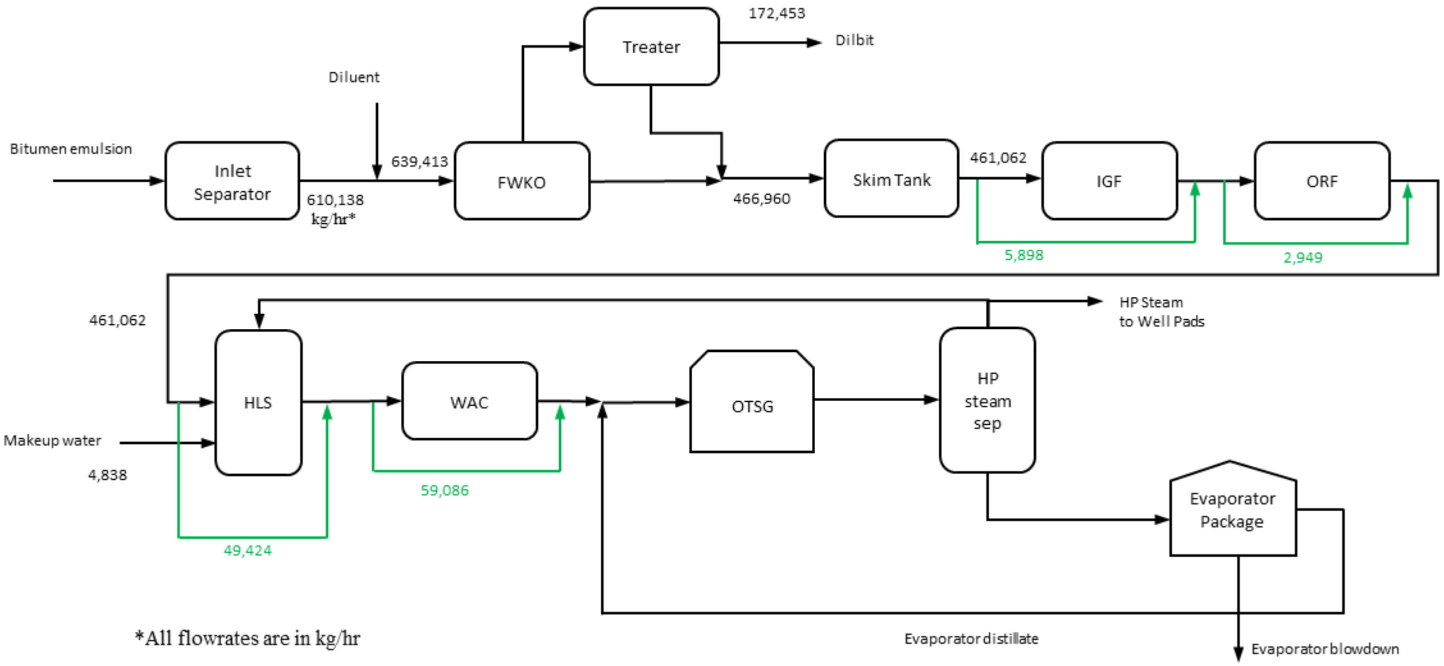
Treatment unit	Capital cost per unit flowrate ($\$.\text{tonne}^{-1}.\text{hr}^{-1}$) (normalized to 100)	Operating cost per unit flowrate ($\$.\text{tonne}^{-1}.\text{hr}^{-1}.\text{hr}^{-1}$) (normalized to 100)
Skim tank	10.69	0.29
Induced gas flotation	6.92	1.26
Oil removal filter	4.47	0
Hot lime softener	16.49	21.75
Ion exchanger	5.55	1.29
Evaporator	55.88	75.41

2.4 Results and discussion

The sequential application of water and heat integration methods to the SAGD process leads to cost and energy savings and GHG emissions reductions. By applying the mathematical model, distributed effluent treatment systems are developed for all cases. Optimized water treatment network designs and diverted flows are presented in Figure 2-7 to Figure 2-10 (diverted flows are shown in green).

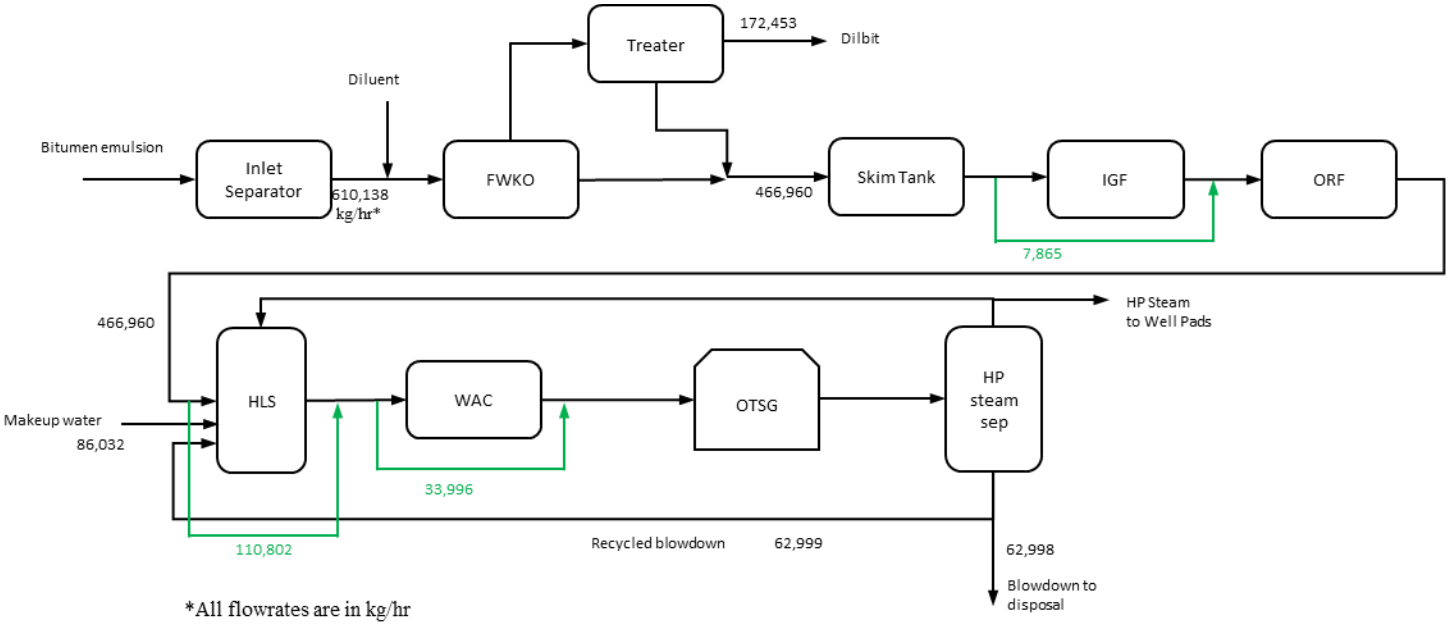
Hot and cold streams in the water treatment networks (shown in Figure 2-2 to Figure 2-5) are extracted and used to construct composite and grand composite curves. It should be noted that diverting flows will not impact stream data presented in Table 2-1 to Table 2-4. Composite curves and grand composite curves for all four cases are shown in Figure 2-11 to Figure 2-14. From the composite curves, the pinch temperature in all four cases is 180.5˚C (hot pinch temperature = 187˚C, cold pinch temperature = 174˚C). Then the HEN is developed following the pinch design method [68].

HEN of the four cases are shown in Figure 2-15 to Figure 2-18.



*All flowrates are in kg/hr

Figure 2-7 Distributed effluent treatment design for case 1



*All flowrates are in kg/hr

Figure 2-8 Distributed effluent treatment design for case 2

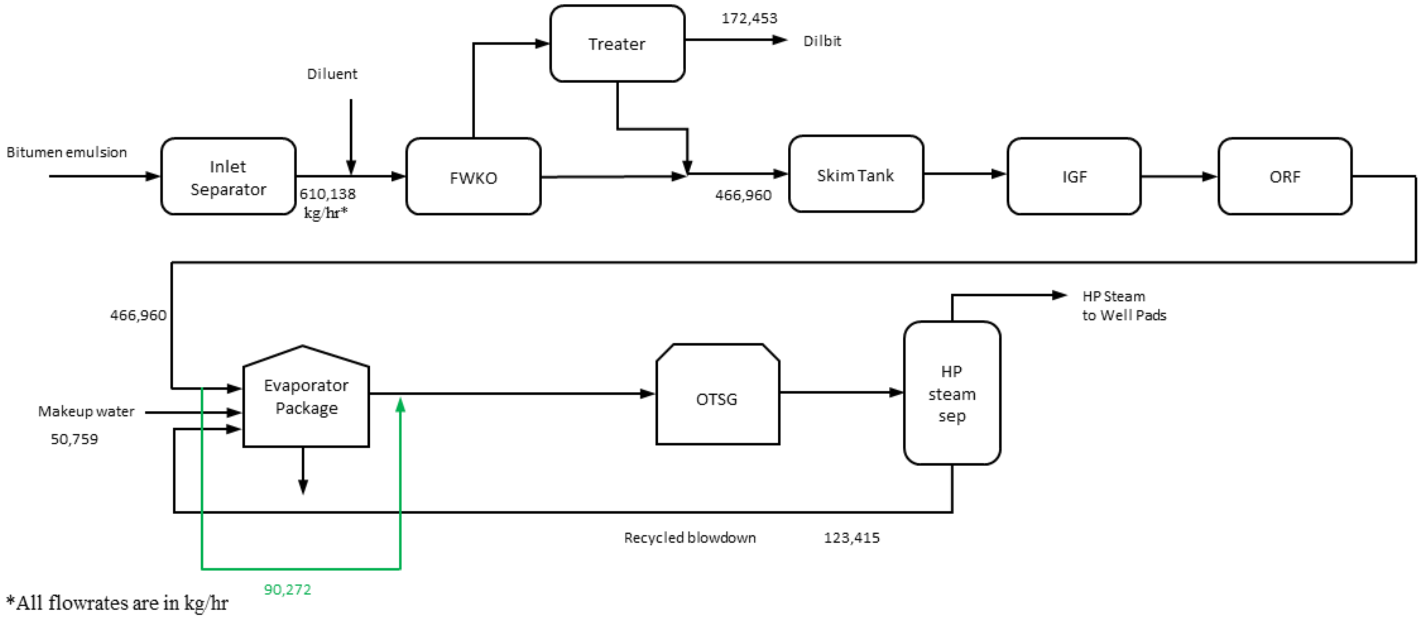


Figure 2-9 Distributed effluent treatment design for case 3

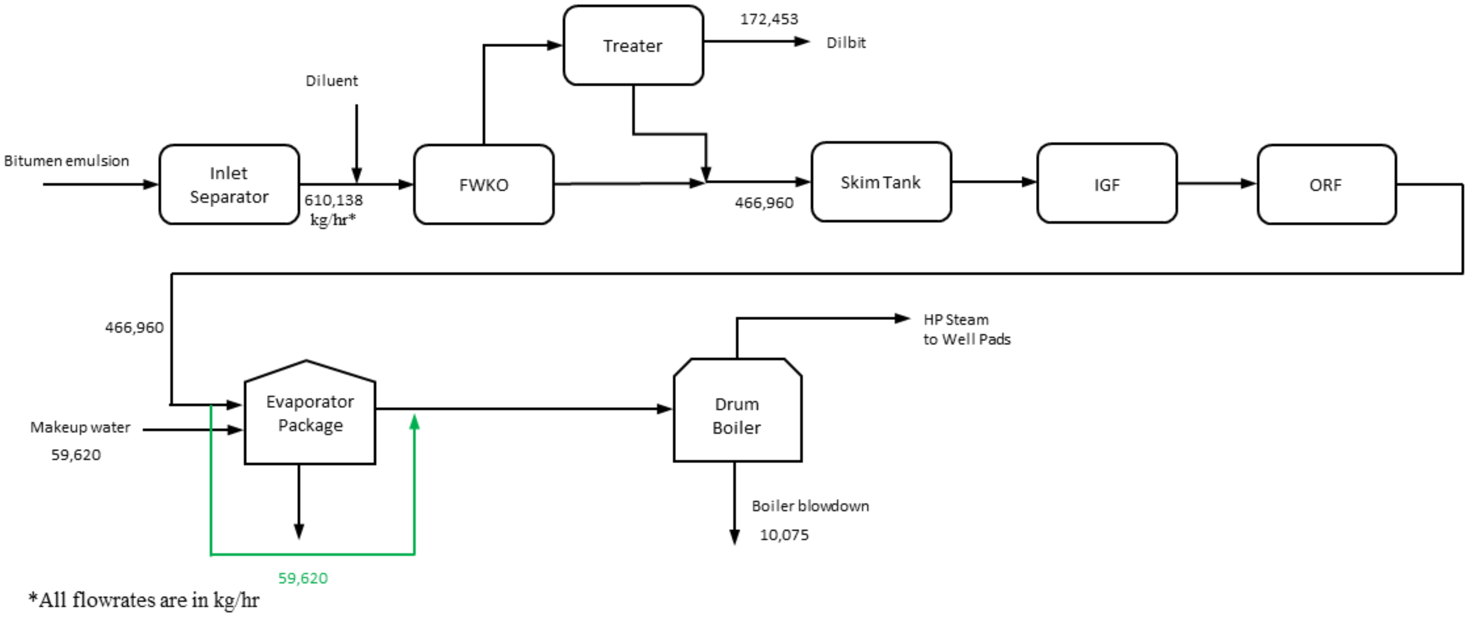


Figure 2-10 Distributed effluent treatment design for case 4

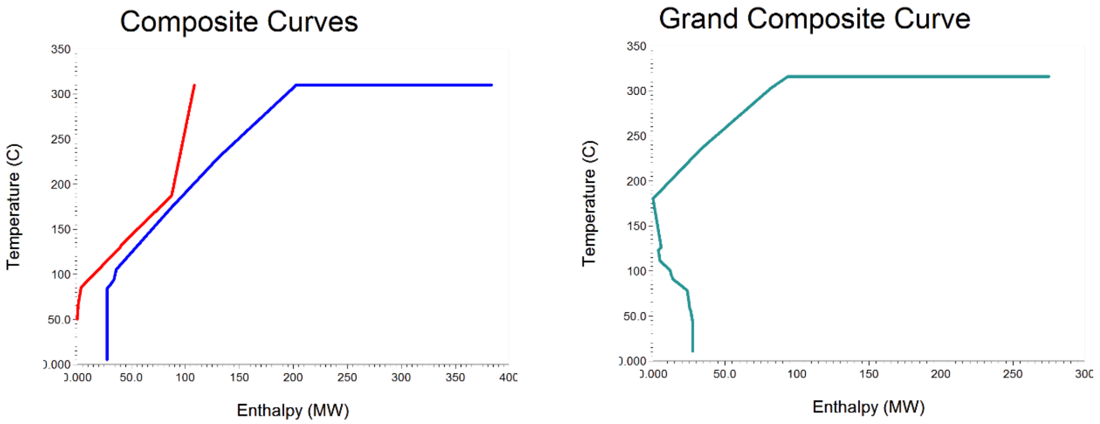


Figure 2-11 Composite curve and grand composite curve of Case 1

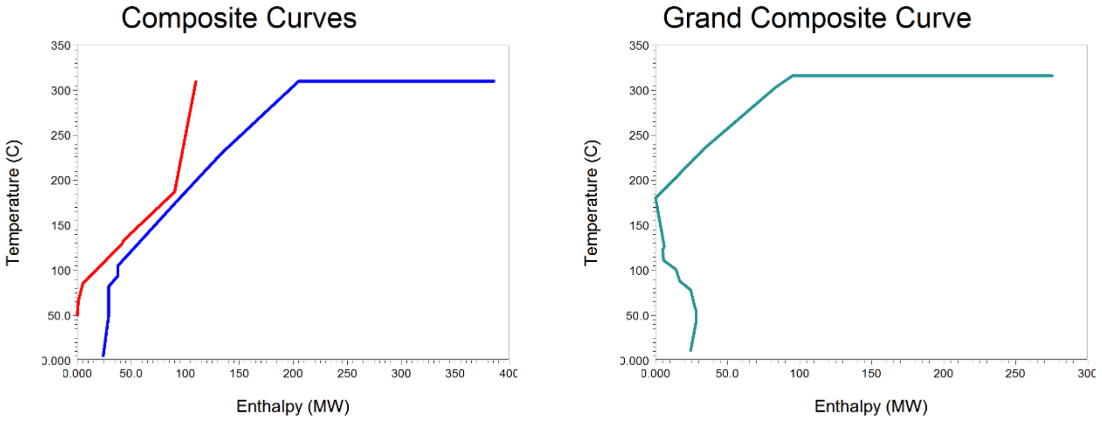


Figure 2-12 Composite curve and grand composite curve of Case 1

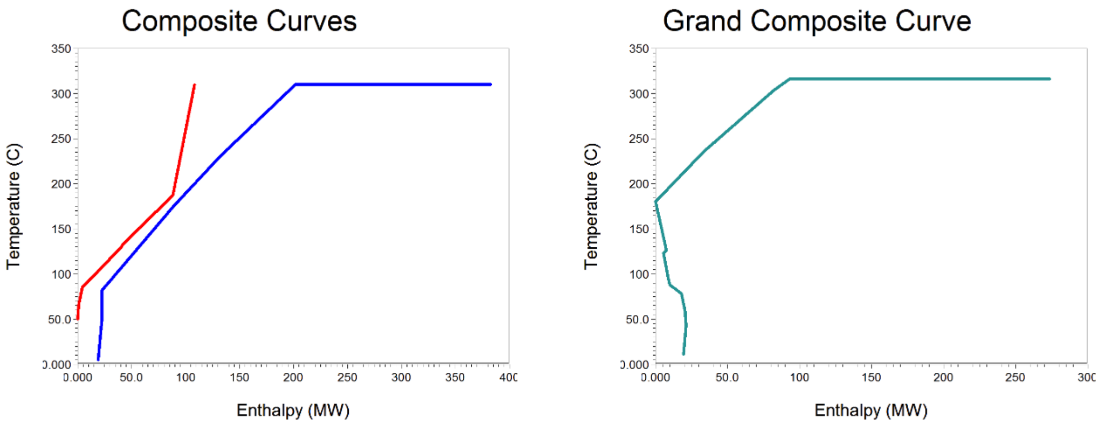


Figure 2-13 Composite curve and grand composite curve of Case 3

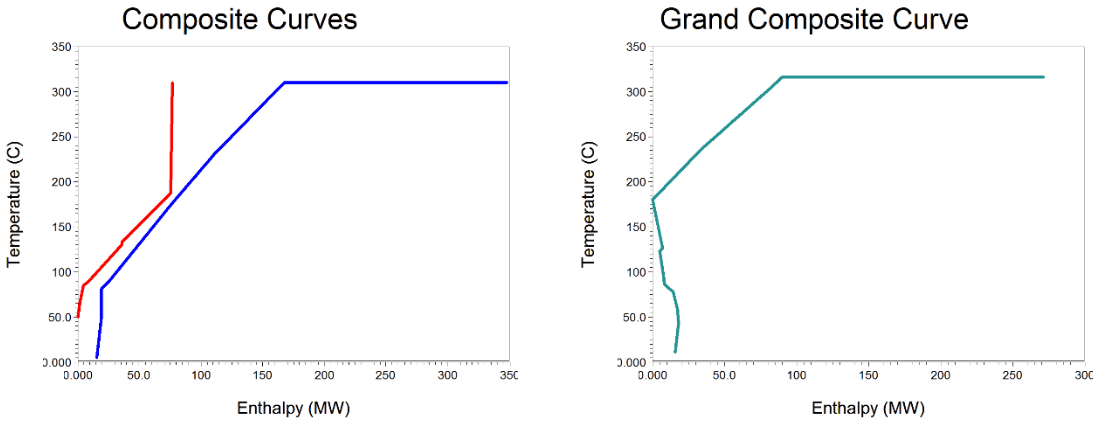


Figure 2-14 Composite curve and grand composite curve of Case 4

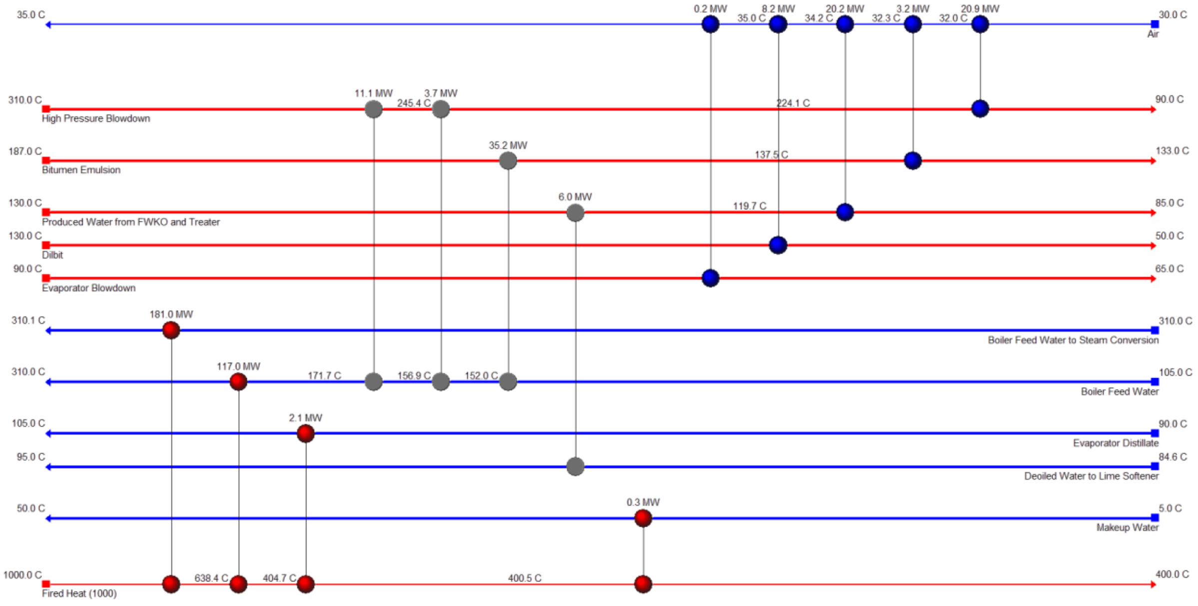


Figure 2-15 Heat exchanger network of Case 1 after water and heat integration

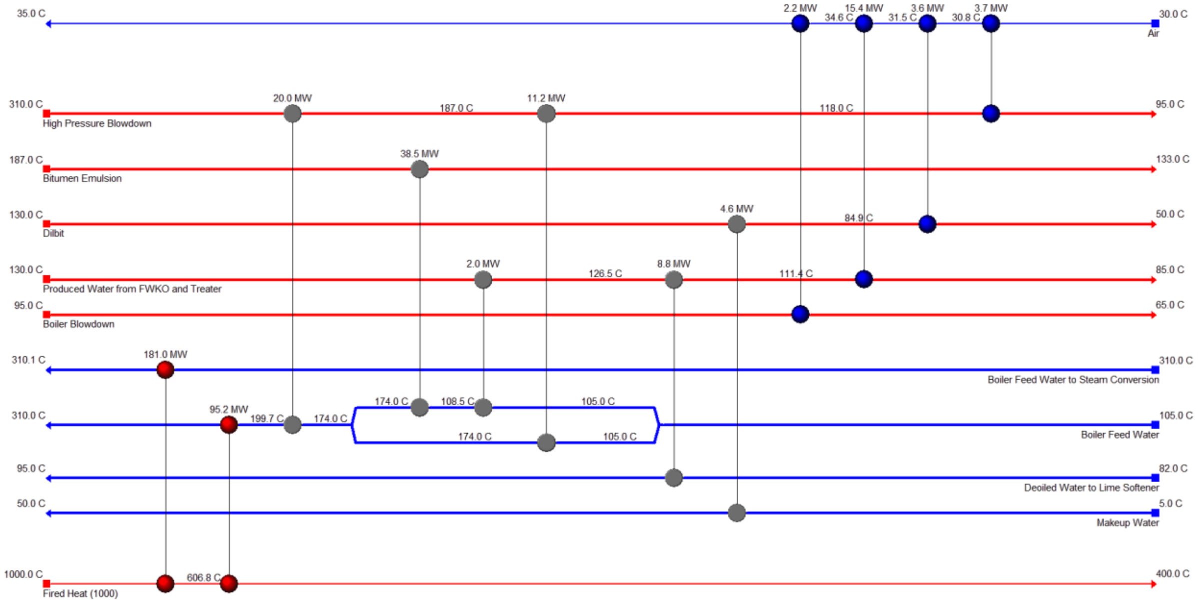


Figure 2-16 Heat exchanger network of Case 2 after water and heat integration

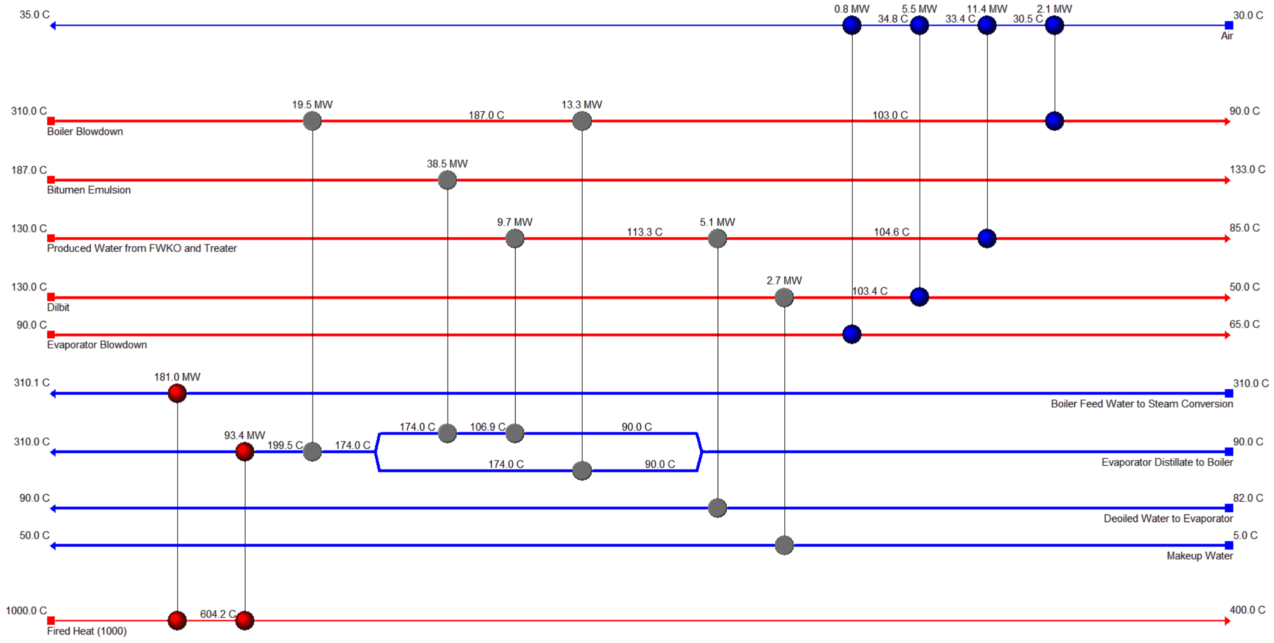


Figure 2-17 Heat exchanger network of Case 3 after water and heat integration

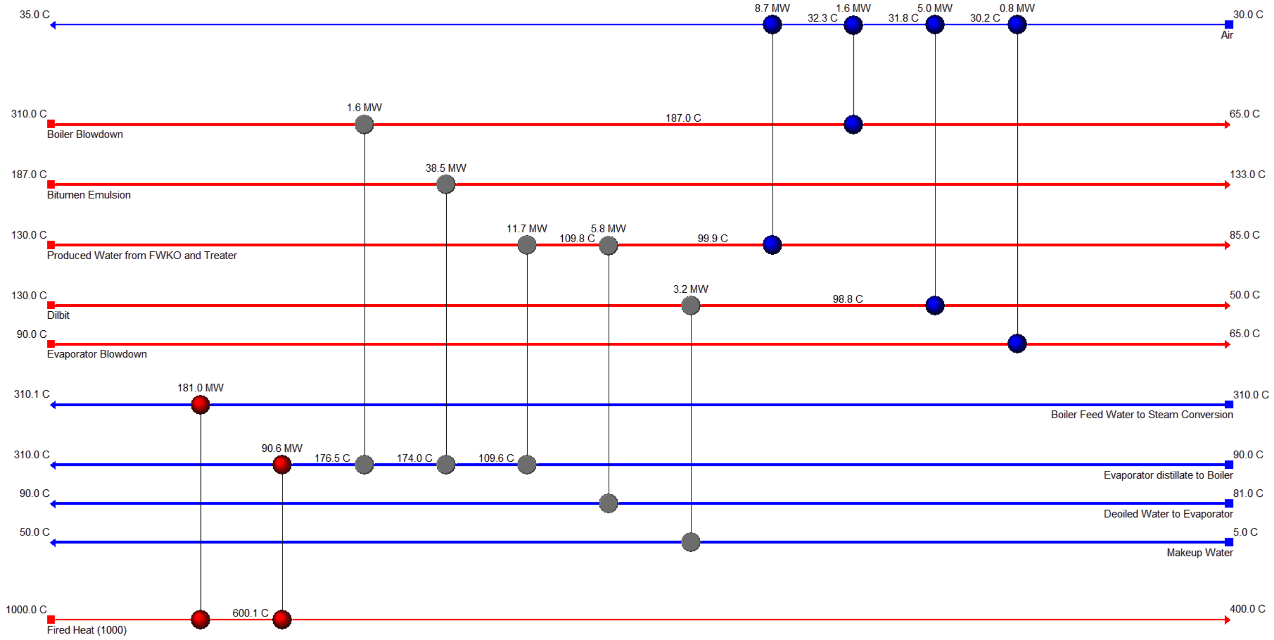


Figure 2-18 Heat exchanger network of Case 4 after water and heat integration

2.4.1 Comparison of cost, energy and GHG emissions for integrated and non-integrated (BAU) cases

Cost savings associated with water and heat integration of each case are categorized into two main sections:

1. Savings in the capital and operating costs of treatment units resulting from water integration (diverting flow around treatment units).
2. Savings in the capital cost of heat exchangers (process heat exchangers, heaters and coolers) and savings in NG consumption, resulting from heat integration of the system.

2.4.1.1 Cost savings resulting from water integration

Optimizing the water treatment network and diverting flows decrease both capital and operating cost (CC and OC) of treatment units. Cost savings as a result of water integration are shown in Table 2-10. The capital cost reductions shown in this table are due to the use of smaller treatment units handling smaller flows of wastewater. This in turn decreases electricity and chemicals consumption in the treatment units reducing operating cost. Total cost savings range from 2.7% to 7.8% of the total cost of the process. Case 3 shows the highest potential for cost reduction (compared to the BAU case associated with case 3) as a results of distributed effluent treatment design. This is due to the use of an evaporator with an OTSG. The quality of evaporator distillate is high (contaminant concentrations are approximately 10 times lower than other treatment units) and the water is treated to a quality that is cleaner than what is required in the OTSG. The difference between the evaporator treated water quality and the OTSG quality requirements provides an opportunity to bypass a large part of the evaporator inlet stream (~14%) and use a smaller evaporator for water treatment. This leads to a significant cost reduction in the evaporator (~14%).

Table 2-11 Cost savings due to water integration

	CC Savings ($/yr)	CC Savings Percentage (%)	OC Savings ($/yr)	OC Savings Percentage (%)	Total Cost Savings ($/yr)	Total Cost Savings Percentage (%)[3]
Case 1	4.14E+05	2.51%	3.22E+05	3.03%	7.37E+05	2.71%
Case 2	6.88E+05	4.22%	7.04E+05	8.09%	1.39E+06	5.57%
Case 3	9.76E+05	4.15%	1.34E+06	7.35%	3.35E+06	7.82%
Case 4	1.05E+06	4.53%	1.27E+06	7.77%	2.32E+06	5.87%

2.4.1.2 Cost and energy savings resulting from heat integration

Applying energy pinch analysis increases heat recovery in the system beyond BAU heat recovery, which results in a decrease of both cold and hot utility requirements. Table 2-11 shows both the additional recovered heat (in MW) as well as the percentage of heat recovery that occurs because of the heat integration (beyond the BAU design[4] of that case). Furthermore, makeup water consumption, wastewater disposal, capital and operating cost estimates, annual cost savings and GHG emissions reduction are also shown in Table 2-11. The results of pinch analysis show that the energy savings are comparable across the cases considered except for case 4. The energy savings potential for case 4 is significantly lower given that the high pressure blowdown used for heating boiler feed water is a very small stream in case 4 compared to the other 3 cases (because of the use of a drum boiler that produces only 2% blowdown and converts approximately 98% of boiler feed water to steam). Therefore, boiler feed water is only heated to

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[3] Cost savings due to water integration are different from Dadashi et al's study. The reason is, Dadashi et al. only included water treatment system in their cost analysis, however, in this study the cost of steam generation section is considered as well.

[4] HEN in BAU designs for cases 2, 3 and 4 are assumed to be similar to case 1, because required data were not available for BAU HEN for all cases.

approximately 176˚C using recovered heat as opposed to 200˚C in other cases and there are less opportunities to increase heat recovery in the system.

Table 2-12 Summary of energy savings, GHG emissions, cost reduction compared to BAU design due to heat integration

	Increased Heat Recovery		GHG Emissions Reduction	Makeup Water Consumption	Annualized Cost (\$ 10^6/yr)			Annual Savings
	MW	%	kg CO_2e/bbl	kg/hr	Capital	Operating	Total	\$ 10^6/yr
Case 1	23.7	41.2	6.3	4,838	17.1	55.5	72.6	5.1
Case 2	27.0	46.4	7.2	86,032	16.6	53.4	70.0	6.3
Case 3	24.5	38.1	7.5	50,759	23.4	62.1	85.5	7.4
Case 4	6.6	12.3	2.9	59,620	22.6	59.7	82.3	3.9

For cases 1-3, energy savings are significant. According to BAU designs, boiler feed water is heated up to approximately 170˚C and sent to the boiler. In the boiler, water is heated to approximately 310˚C (sensible heat) and is converted to steam at 310˚C (latent heat). In the heat integrated design of cases 1-3, boiler feed water can be heated to 200˚C by recovering additional heat from hot streams which decreases the amount of sensible heat required in the boiler and leads to lower NG consumption in the boiler.

Applying heat integration to these systems increases the number of process heat exchangers and decreases the number of heaters and coolers in the system. Total capital and installation costs of heat exchangers (process heat exchangers, heaters and coolers) are calculated for the BAU case 1 and it is assumed to be the same for BAU designs of other cases. Additionally, capital and installation costs of heat exchangers are estimated for each case after water and heat integration. Cost coefficients of heat exchangers and other equipment are extracted from [69,70]. The results are presented in Table 2-12. Heat integration results in 49-51% savings in the capital cost of heat exchangers. However, since the heat exchangers' capital cost is a small part of total capital cost of CPF (2.2-5.6%), cost savings in terms of total CPF cost are 2.1-2.9%.

Table 2-13 Capital cost of HEN before and after water and energy integration, HEN cost savings

	HEN Capital Cost ($)	HEN Capital Cost Savings ($)	HEN Capital Cost Savings Percentage (%)	HEN Annual Cost Savings ($/yr)
BAU	9.40E+06	-	-	
Case 1	4.80E+06	4.60E+06	48.9%	4.88E+05
Case 2	4.94E+06	4.46E+06	47.4%	4.73E+05
Case 3	4.77E+06	4.63E+06	49.3%	4.91E+05
Case 4	4.59E+06	4.81E+06	51.2%	5.10E+05

Heat integration to maximize heat recovery in the system leads to a decrease in external heating requirements. Assuming that heat is provided by burning NG in a fired heater, heat integration decreases NG consumption in the system. NG cost for each case before and after heat and water integration along with the resulting savings are shown in Table 2-13. Heat integration results in 11-12% savings in NG consumption. NG cost is a significant contributor to the total operating cost of the system and constitutes between 73-85% of the total CPF operating cost. Therefore, heat integration leads to 9.2-10.2% savings of the total operating cost of the system.

Table 2-14 NG consumption before and after water and heat integration for each case and NG savings within each case due to integration

	NG Cost ($/yr)	NG Savings ($/yr)	NG Savings (%)
Case 1 BAU	4.91E+07	-	-
Case 1	4.52E+07	3.90E+06	7.93%
Case 2 BAU	4.98E+07	-	-
Case 2	4.54E+07	4.44E+06	8.91%
Case 3 BAU	4.87E+07	-	-
Case 3	4.51E+07	3.58E+06	7.35%
Case 4 BAU	4.57E+07	-	-
Case 4	4.46E+07	1.09E+06	2.39%

2.4.1.3 Cost savings resulting from both water and heat integration

Figure 2-19 shows the total system cost before and after water and heat integration broken down by capital and operating cost. It shows there is a reduction in total cost for each case after water and heat integration of the process. Cost reductions range from $ 3.9 to 7.4 million/year which corresponds to $ 0.56-1.06/bbl of bitumen produced. Detailed information about the cost savings are presented in Appendix A.

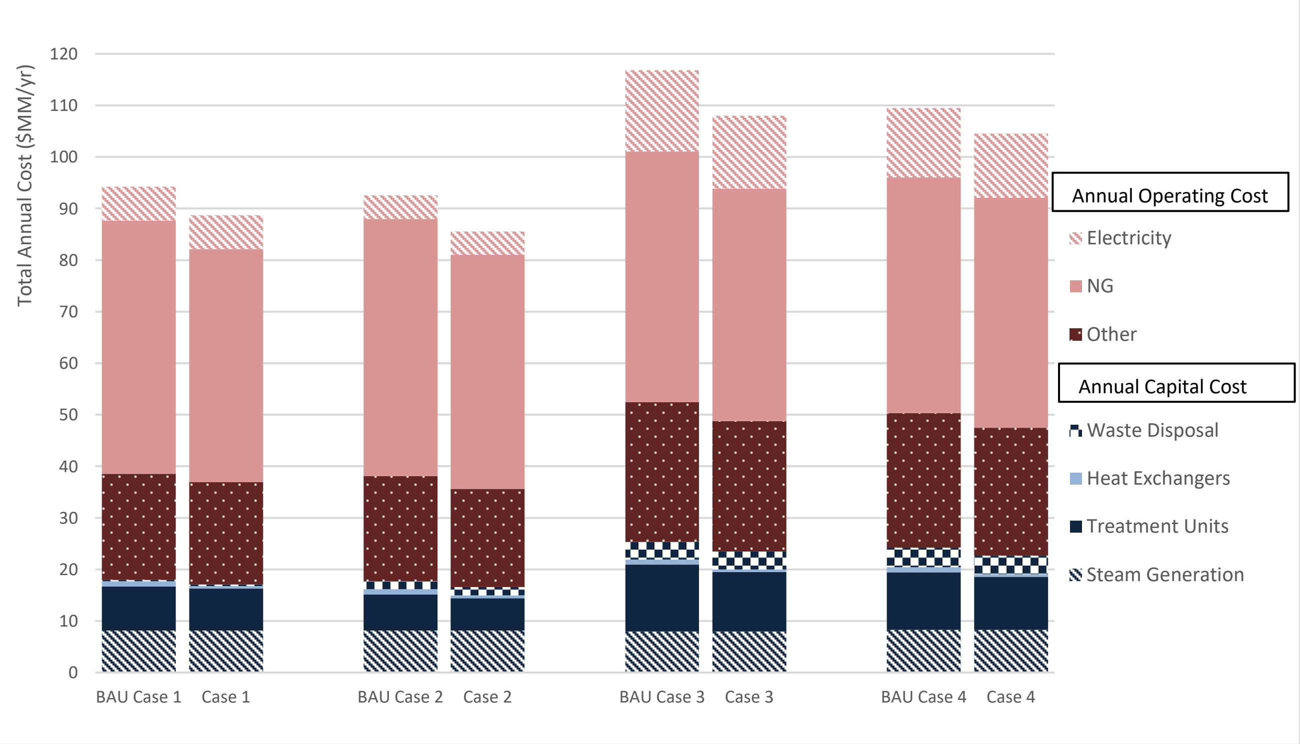

Figure 2-19 Total annual cost before and after water and heat integration for each case

Heat integration leads to larger savings than water integration in operating cost because of decreased NG consumption. Capital cost savings as a result of heat integration are not significant since heat exchangers constitute a small part of the total capital cost of the system and improving the heat exchanger network won't affect the total capital cost of the system significantly. On the other hand, water integration leads to approximately similar capital and operating cost savings in each case (order of magnitude \$$10^5$ to \$$10^6$ per year). This is due to the diversion of flows which results in smaller treatment units with lower capital and operating costs. However, the effect of water integration on operating cost savings is less significant, since the operating cost of treatment units constitutes a small part of total operating cost of the system (boilers constitute the major part of operating cost in the system which are not affected by water integration). By applying both water and heat integration techniques there are potential cost savings in both capital and operating costs of the system. Total cost savings range from \$3.9 to \$7.4 million/year and operating cost savings contribute to 74%- 82% of the total cost savings.

2.4.2 GHG emissions, makeup water consumption and total cost tradeoffs across four cases

In order to inform decisions about the selection of the preferred process option, a more complete investigation of the performance of each option is required. Figure 2-20 shows the tradeoffs between makeup water consumption, GHG emissions and total annual cost for the optimized cases 1-4. Makeup water is on the horizontal axis, GHG emissions are on the vertical axis and the size of the circles represent the total annual cost of each case (the cost differences are more visually distinguishable when the circles are larger). According to Figure 2-20, case 1 has the lowest makeup water consumption and is the second lowest in GHG emissions after case 2. Case 3 and case 4 have relatively high GHG emissions because of the use of evaporators that have high electricity consumption, but makeup water consumption of cases 3 and 4 is lower than case 2 that has the highest makeup water consumption. Additionally, cases 3 and 4 are more expensive than cases 1 and 2 because of the use of evaporators which are more expensive than lime softening and ion exchange units. However, there are no significant differences between the total annual costs of the four cases which indicates that with approximately equal cost, the process can be designed to produce different amounts of GHG emissions and to consume different amounts of makeup water. Cases 1 and 2 are overall the most promising of options. The decision between these two options will require a decision maker to apply a value to the externalities of GHG emissions versus the makeup water consumed.

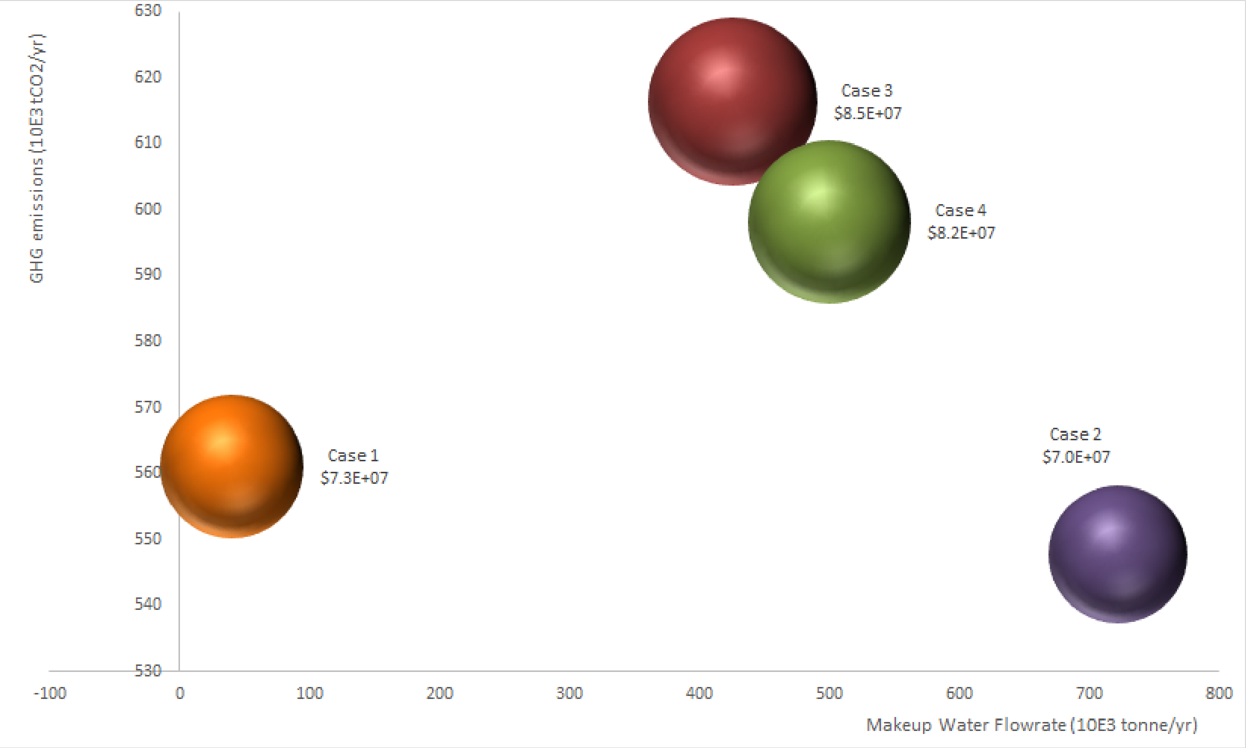

Figure 2-20 Cost, water, GHG emissions across four cases after water and heat integration (data labels show the case number and the total annual cost (bubble size) for each case)

2.4.3 Sensitivity analysis

There are a number of parameters in the system that have a significant impact on total cost and total GHG emissions such as NG price. However, these parameters tend to shift all cases proportionally in the same direction and total cost and GHG emissions of different cases would remain relatively unchanged. Therefore, sensitivity analysis for these parameters are not listed here or in Appendix A.

The quality of steam generated in the boiler is an important parameter in the SAGD process. It will affect NG consumption in the boiler, bitumen production rate and produced water flowrate. The impact of changing the OTSG produced steam quality to 90% (instead of 80% assumed in the analysis to this point) is investigated for case 3[5]. It should be noted that producing higher quality steam indicates higher quality requirements for boiler feed water (BFW) which in turn requires a smaller bypassed stream for the evaporator. A 90% steam quality requires a lower flowrate of BFW. The results of the analysis show that BFW temperature is reduced to 187˚C from 200˚C (in the original 80% quality steam case). However, this change does not affect NG consumption because of the lower flowrate of BFW. In other words, when 90% quality steam is produced, the BFW has a smaller flowrate and is heated from 187˚C to 310˚C, while in the case of producing 80% quality steam a slightly larger flowrate of BFW is heated from 200˚C to 310˚C. Calculations show that total heat load required to heat the BFW remains nearly constant ($44.8 versus $45.0 million/year). The results of this sensitivity analysis show that the total cost increases by less than 1.5%.

In the second part of the sensitivity analysis, the BFW flowrate is kept constant. This means that for the case of producing 90% quality steam, more steam is produced which in turn leads to a higher bitumen production rate. Steam generation volume is increased by 12.5% which results in a 12.5% volume increase in bitumen production. The results of the analysis show that BFW temperature is reduced to approximately 187˚C, similar to the first sensitivity analysis and since the BFW flowrate is kept constant, the required heat load to heat the BFW to 310 ˚C for steam generation increases by 10%. This in turn leads to a 10.4% increase in total NG

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[5] In case 3 OTSG is used for steam generation with an evaporator for water treatment. Therefore, there is an opportunity to generate high quality steam (higher that 80% which is the conventional quality of steam generated in an OTSG) because of the high quality of water in evaporator effluent stream.

consumption. The system cost to achieve this increased production is approximately $7.4 million/year (8.7% of total system costs) while the potential revenue from this increased production is for example $35 million/year at $40/bbl and $70 million/year at $80/bbl. Since the production increase is larger than the increase in cost, it is economic to produce 90% quality steam even if it means that higher water quality is required.

2.5 Conclusions

The analysis shows that applying water and heat integration to SAGD central processing facilities provides the opportunity to reduce the total cost of the system by between $5.1 and $7.4 million/year which is between 7.0% and 8.2% of the total cost of the system respectively. The contribution of operating cost savings to the total cost savings due to a decrease in NG consumption in the boiler is more significant than the capital cost (e.g., in case 1, the operating cost savings constitutes 82% of the total cost reduction and the capital cost savings constitutes the remaining 18%). Case 4 uses a drum boiler for steam generation and has the lowest potential for cost savings of all cases. This is due to the smaller boiler blowdown volume produced. This means that the stream provides less heat for additional potential heat recovery.

Tradeoffs between cost, water consumption and GHG emissions exist when choosing between these technology options. Use of an evaporator for produced water treatment (cases 3 and 4) increases the GHG emissions in the system significantly (~12.5%) when compared to the boiler blowdown recycle case (case 2). However, water consumption is reduced. If an evaporator is used, 2 provides the best balance between GHG emissions, water consumption and cost (compared to cases 3 and 4).

The sensitivity analysis shows that there is an opportunity to increase the profit in the case of using an OTSG with an evaporator by modifying the OTSG to produce higher quality steam. This in turn leads to a higher bitumen production rate at a relatively low cost increase due to the additional NG consumed in the boiler.

Chapter Three: **Evaluation of economic and environmental performance of oil sands emerging technologies considering technological parameters uncertainty**

3.1 Abstract

A framework is provided in this study that combines life cycle assessment and optimization methods to evaluate emerging oil sands technologies considering uncertainties associated with their performance at pre-commercial stage. Performance of three emerging technologies are evaluated and compared to existing oil sands technologies to determine the set of conditions that would make each emerging technology a competitive alternative for oil sands production in the crude oil market. The uncertainty and variability of technology performance parameters are included in the analysis using discrete probability distributions informed by reported industry data, literature data and expert consultation. The results show that all three emerging technologies can potentially improve the economic and/or environmental performance of the oil sands operations. Solvent assisted SAGD offers improvements to SAGD process by imposing small changes to the process. On the other hand, partial upgrading and in situ extraction and upgrading introduce major changes to the existing operations while impacting the performance and downstream implications of the existing operations beyond what Solvent assisted SAGD could offer. The framework developed in this study can be used to inform investment decision making and future research on emerging technologies by identifying the set of conditions required to make the technology a competitive alternative.

3.2 Introduction

Alberta's oil sands reserves supply stable and reliable energy to the world and play an important role in the Canadian economy [1]. However, the recent decline in oil prices and increasing concerns about the environmental impacts including climate change, threaten the oil sands production and its growth potential which consequently decrease the contribution of oil sands products to global oil markets. Oil sands operations are generally more energy intensive, and costly and generate more greenhouse gas (GHG) emissions compared to conventional oil production [3]. Therefore, oil sands operators and policy makers seek operational improvements and new technologies to reduce costs, energy use and emissions intensity of oil sands operations.

The oil sands industry has steadily improved the economic and environmental intensity of oil sands extraction and processing over the past five decades [9]. An analysis of long-term trends of oil sands operations calculated that the energy return (amount of energy output per energy consumed) of these operations tripled between 1970 and 2010 [9]. However, in order to contribute meaningfully to recent ambitious climate goals, emission reductions need to occur across the entire life cycle. Although some projections suggest that fossil fuels production must decrease substantially (more than 80% from today's production levels) in order to meet 2050's emission reduction goal [5], there are other scenarios that project fossil fuels (and oil sands) will remain an important part of the energy system in the world for the next two decades and even until 2050 [71]. Therefore, investigating improvements in oil sands production remains an important topic.

Life cycle stages of oil sands operations consist of bitumen extraction and recovery, dilution or upgrading of bitumen[6] (to produce a bitumen product ready for pipeline transport), bitumen product transport and refining, refinery product end-use. Various technology options including existing and emerging technologies can be employed in each stage of the operations which affect the economic and environmental performance of the operations. Selecting the technology options that optimize the economic and environmental performance of the oil sands operations (by maximizing profit and/or minimizing GHG emissions) is complicated by a large number of input parameters in the system (e.g., volatile market price of oil products). A comprehensive techno-economic framework is required that considers all technological and economic input parameters that affect the performance of the entire system in terms of total cost, total energy consumption and GHG emissions.

Steam Assisted Gravity Drainage (SAGD) is the most common bitumen extraction and recovery technology currently employed in Alberta [72]. Cyclic Steam Stimulation (CSS) and mining are two other existing bitumen extraction technologies. Delayed coking and hydrocracking are two main technology options that have been adopted for upgrading bitumen to synthetic crude oil (SCO). Several emerging technologies are introduced to oil sands operation aiming to improve the economic and environmental performance of the operations. For example, partial upgrading technologies and solvent-assisted extraction and recovery are two promising emerging technologies that are being considered for deployment in oil sands operations. These technologies have not been deployed at commercial scale yet but are seeking to gain market share. These emerging technologies require environmental, technological and economic

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[6] Bitumen dilution and upgrading technologies are currently used to produce crude oil in the form of dilbit and synthetic crude oil (SCO) (respectively) in Alberta.

evaluation prior to their uptake at commercial scale to understand the implications of adopting these technologies on GHG emissions and cost of the entire supply chain and to compare them to current technology scenarios. Understanding these implications are important to ensure the expected improvement in the economic and environmental performance of oil sands operations as a result of adopting emerging technologies can be achieved when the uncertainties associated with the performance of the emerging technologies are considered. Existing and emerging oil sands technology options in each stage of oil sands supply chain are evaluated in various studies to determine their environmental and economic performance [18,20–23,73–75]. However, in addition to the technology evaluation that is typically performed for a single technology or multiple technologies in a single stage of oil sands life cycle, the technology performance needs to be evaluated in the context of the entire supply chain. This is to ensure the full set of impacts associated with adopting a technology option for a specific stage of oil sands life cycle is captured and economic and environmental burden is not shifted to other stages of the life cycle. In addition, considering the full set of impacts of adopting a technology throughout the oil sands supply chain allows for a consistent comparison of available technology options which helps inform the investment decision making process. Additionally, variable and uncertain input parameters need to be considered in the evaluation to better understand the comparative performance of the technology alternatives under a range of uncertain and variable conditions. These uncertain and variable input parameters include technology performance parameters such as energy intensity and the quality of the output products, economic parameters such as the price of products and energy price, and policy parameters such as carbon price. Such technology assessment will provide insights for decisions makers in the oil sands industry about emerging technologies that are at pre-commercial stage in the face of uncertainty due to lack of performance and cost data in the academic and industrial publications (uncertainty in the performance of the emerging technologies when they are deployed at commercial scale and operating costs associated with their deployment). This will allow for a comparison between emerging and existing technologies. In addition, the results of this analysis provide insights about the tradeoffs between the economic and environmental impacts associated with these technology alternatives which is of great importance for investment decision making in a carbon constrained world.

A "technology scenario" in this study refers to a combination of technologies (including existing and emerging technologies) for the upstream portion of oil sands operations including extraction and recovery of bitumen, and bitumen dilution/upgrading. Downstream portion of the operations including bitumen product refining and product end use are modeled alongside the technology scenarios (upstream) to form the full life cycle of oil sands operations.

A mathematical model is developed in this study to assess the cost and GHG emissions of various oil sands production scenarios under variable and uncertain conditions with a focus on emerging oil sands production and processing technologies. This model is used to find the technical, economic and policy conditions (e.g., natural gas (NG) price, diluent price, energy use per unit flowrate of inlet crude, etc.) under which emerging oil sands technologies (e.g., solvent-assisted, and partial upgrading technologies) become competitive alternatives in global crude oil markets (compared to dilution and full upgrading technologies).

Although the economic and environmental performance of both existing and emerging oil sands technologies have been evaluated in several studies [18,20–23,73–75], no study in the literature has investigated the broad set of conditions that could change the competitiveness of emerging technologies against current technology scenarios from full life cycle and multi attribute perspectives (economic and environmental perspectives). The present study aims to fill this gap in literature using a combination of life cycle assessment (LCA) and optimization techniques. LCA techniques can be used to provide quantitative measures of economic and environmental performance of different process design alternatives that is required to select the best design from an economic and environmental perspective. However, when there is a large number of different possible design alternatives generated by various combinations of processes, using LCA requires generating all the possible alternatives manually and performing LCA on each of them separately. In addition, using a LCA approach becomes even more time consuming when external factors influencing performance are included in the analysis (e.g., uncertain/variable cost and policy conditions). In the absence of a systematic method to address this problem directly within the LCA, the alternatives considered are often based on intuitive and heuristic approaches which may lead to sub-optimal solutions. Mathematical optimization combined with LCA principles has the potential to inform the decision-making process by providing a structure to select among various alternatives without evaluating all possible alternatives by LCA separately.

Three emerging technologies are included in the scope of the present study: Solvent Assisted SAGD (SA-SAGD), Partial Upgrading, and In situ Extraction and Upgrading technology[7] (ISEU). Solvent-assisted technologies involve adding solvents (various light hydrocarbons such as gas condensate) to the steam that is injected for bitumen extraction. The addition of solvents reduces the energy and water requirements for bitumen extraction by reducing the temperature and pressure of the steam required for bitumen viscosity reduction [21].

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[7] In the literature, this technology is referred to as In Situ Upgrading Technology or ISUT [76]. In this study I refer to it as In Situ Extraction and Upgrading or ISEU.

Partial upgrading technologies upgrade bitumen to a product that has characteristics similar to medium or heavy crude in terms of liquid density, Sulphur content and metal content (compared to full upgrading that produces synthetic crude oil (SCO) that has the characteristics similar to light crude oil) at a lower cost per barrel compared to full upgrading [22]. Partial upgrading technologies require lower capital investment than full upgrading and reduce the amount of diluent required for transportation compared to bitumen dilution [21]. Partial upgrading technologies have attracted much attention in Alberta mainly because of the technology's potential for diversifying Alberta energy sector [77]. In Situ Extraction and Upgrading technology (that is referred to as ISEU) is an emerging technology developed to integrate extraction and upgrading of heavy oils [76]. The technology is based on the injection of dispersed nano-catalyst and hydrogen as upgrading agents and vacuum residue as a heat and catalyst carrier, into the reservoir (partially or fully replacing steam injection in SAGD process) to produce an upgraded synthetic crude oil (SCO) that is close to crude pipeline specifications. The produced crude might require some level of dilution but needs lower amount of diluent to reach pipeline specs compared to bitumen produced via SAGD process. In addition, the integration of extraction and upgrading stages results in decreased capital cost required specially for building an upgrader. These technologies are explained in more details in Appendix B.

Many studies have provided estimates for GHG emissions and cost of different stages of oil sands production and processing including bitumen extraction, dilution, upgrading, transportation and refining and a few of them have compared two or more alternative scenarios with respect to GHG emissions and/or cost [18–20,73,75,78–84]. The results of some of these studies are used in the present study for estimating energy consumption and GHG emissions of oil sands production and processing [19,20,73,84]. The previous studies address GHG emissions associated with one or two stages of oil sands production and do not include simultaneous upstream and downstream implications of different technologies at different stages of the production. Emerging technologies are not included in the scope of these studies. In addition, the effect of variability and uncertainty of input parameters in the context of total supply chain emissions and cost are not addressed in the previous studies.

Technology pathway selection in various industries using life cycle assessment or optimization or a combination of both tools has been introduced and studied in the literature [85–90]. These studies use both environmental and economic objective functions for selecting the optimal technology pathway. However, the previous studies do not consider the uncertainty and variability of inputs in their assessment. In addition, optimization methods for technology selection considering the entire supply chain have not been used for oil sands production pathways before.

The present study will address the gaps in the literature by proposing a new approach for evaluating and comparing existing and emerging oil sands technologies. The proposed approach considers the entire oil sands supply chain, and takes into account the variability and uncertainty of the input parameters.

3.3 Methods

A mathematical optimization model is developed in this study, using General Algebraic Modeling System (GAMS) to assess the cost and GHG emissions of various oil sands production scenarios (the entire supply chain from bitumen extraction to final product use) under variable and uncertain conditions (e.g., volatile market price of oil products). The objective of the optimization model is to identify the technology scenario (or combination of scenarios) that correspond(s) to the lowest GHG emissions and/or highest profit across the supply chain from the extraction of bitumen to the consumption of final products. The decision variables in the model are the amount of bitumen product that is processed by each technology alternative to achieve a desired amount of final products. The user can select from two objective functions: minimum GHG emissions or maximum profit. Constraints of the model include mass and energy balance equations used to describe the technologies at different stages of the operations, total desired amount of refinery products based on product slates from PRELIM model (introduced later in this section) that correspond to each crude type (e.g., dilbit, SCO), and cost and GHG calculations. The optimization model is a mixed integer linear programming (MILP) model. The model constraints, parameters and variables are presented in the Appendix B. This model is then used to find the set of input parameters (e.g., natural gas (NG) price, diluent price, energy use per unit flowrate of inlet crude, etc.) under which emerging oil sands technologies (e.g., solvent-assisted technology) become competitive alternatives for existing technologies. This is achieved by running the model multiple times with different combinations of inputs and finding the optimal pathway in each run.

Model inputs consist of technology-specific inputs, economic inputs such as energy and material price and carbon price, emission factors (e.g., combustion emission factor, electricity emission factors and upstream emission factors), bitumen product and refinery product properties (e.g., API and higher heating value) and bitumen product shipping distance. Technology-specific inputs consist of parameters that are used to estimate cost, energy intensity and GHG emissions associated with each technology. Steam to oil ratio in SAGD and SA-SAGD, diluent requirement in dilution stage, NG consumption in upgrading technologies and capital cost of different technologies are examples of these technology-specific inputs used in the model. In addition, quantity and quality of product of each technology as a function of the inlet stream are included in the model inputs.

In the base case assumptions, total cost and total GHG emissions of each scenario are presented per gigajoule of the transportation fuels produced by that pathway (functional unit is one gigajoule of transportation fuel. This means that the cost and emissions associated with different scenarios of oil sands production and processing are calculated for 1 gigajoule of transportation fuel to be produced). Alternatively, the user can run the model with a fixed volume of extracted bitumen and the results are presented per barrel of bitumen produced. This helps explore the effect of using different functional units on the choice of the lowest emission or highest profit production pathway.

Oil sands production scenarios investigated in this study consist of seven different technology scenarios from oil sands extraction to the production of transportation fuels (gasoline, diesel, and jet fuel) in a refinery. These technology scenarios include existing and emerging technology options at different stages of the production. By including existing and emerging technologies within different technology scenarios, the conditions under which the emerging technologies are selected as the most profitable or the least GHG intensive scenarios can be identified.

Figure 3-1 shows different technology options for each stage of oil sands production and how they can be combined (with each other, and with multiple potential refining options) to represent an entire supply chain. Seven scenarios include:

1. SAGD process for extraction + diluting bitumen to produce dilbit + Refining
2. SAGD process for extraction + upgrading bitumen to produce SCO + Refining

3. SAGD process for extraction + partially upgrading bitumen to produce PUB[8] + Refining
4. SA-SAGD process for extraction + diluting bitumen to produce dilbit + Refining
5. SA-SAGD process for extraction + upgrading bitumen to produce SCO + Refining
6. SA-SAGD process for extraction + partially upgrading bitumen to produce PUB + Refining
7. In Situ Extraction & Upgrading technology (ISEU) + Refining

SAGD, dilution and upgrading are the existing technologies and SA-SAGD, partial upgrading and in situ extraction & upgrading are emerging technologies in these technology scenarios. Since the focus of this study is on in situ production, mining technology is excluded from the analysis. In addition, CSS technology is excluded from the list of existing technologies because it is not being considered for new in situ projects and is mostly used in legacy projects.

For each technology scenario, one refinery configuration is selected by the model among 10 available options based on the maximum profit or minimum GHG emissions of the entire supply chain. The choice of the refinery configuration depends on the quality of bitumen product. The lower the quality of the bitumen product (for example dilbit versus SCO), the more extensive processing required in the refinery (deep and medium refining as opposed to hydroskimming). On the other hand, more extensive processing results in higher quality products but at the same time increases cost, energy and GHG intensity of the refining process. Using optimization helps select the refinery configuration that results in the overall highest profit/lowest GHG of the entire supply chain.

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[8] Partially Upgraded Bitumen

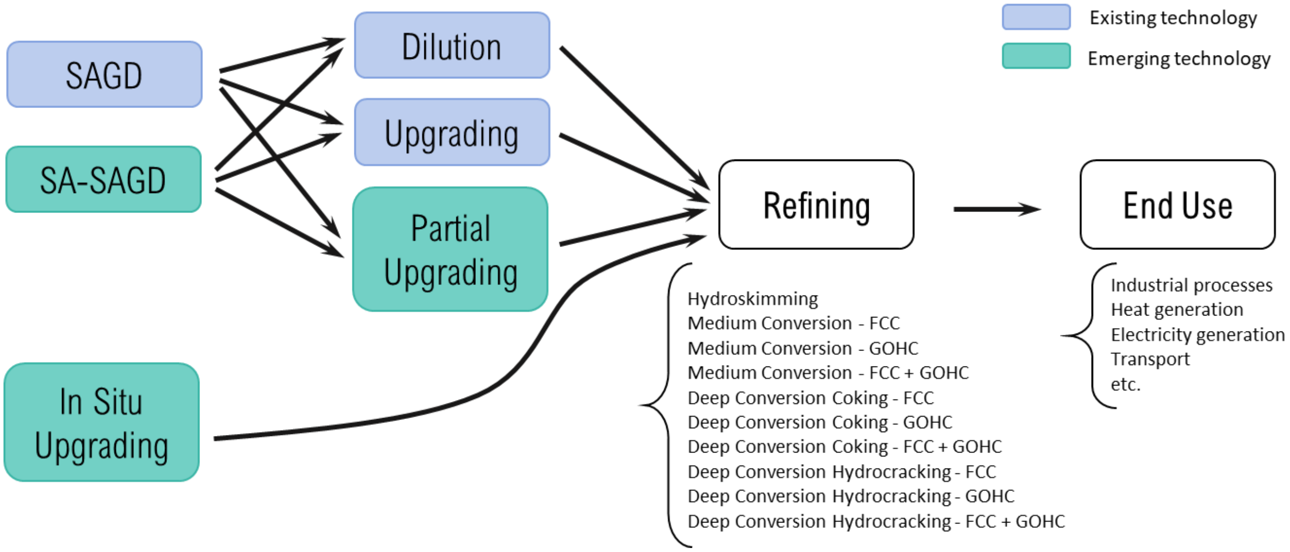

Figure 3-1 Oil Sand Production Scenarios

Life cycle GHG emissions from each scenario are estimated per unit volume of bitumen product extracted or processed by that technology using previously developed LCA models [18–20,73,78]. Each of these models provide an estimate of the GHG emissions and energy requirements for one stage within the scenario including bitumen extraction, dilution, upgrading, transport and refining. Details are provided later in this section.

In addition to estimating GHG emissions associated with each technology, cost of extraction and processing of bitumen are included in the optimization model developed in the present study. All cost estimates are adjusted using CEPCI[9] cost index tables to convert them to 2020 Canadian dollars [91]. The cost function included in the model consists of capital cost and operating costs associated with energy and material consumption. Price of carbon for upstream stages of oil sands operations (extraction and dilution/upgrading) is considered in the cost function based on Alberta's Technology Innovation and Emissions Reduction (TIER) Regulation. TIER is currently the governing greenhouse gas emissions regulation in Alberta,

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[9] Chemical Engineering - Plant Cost Index, www.chemengonline.com/site/plant-cost-index

which came into force in 2020 when carbon price was set at $30 per tonne of carbon dioxide [92]. Energy cost is estimated using energy consumption by each technology calculated by the LCA models introduced in the following and an average energy cost. Capital cost calculation for different technology options is carried out using different approaches. Capital cost for extraction technologies is estimated using published literature data and in emerging technology cases based on high level estimates provided in the literature [21,93–95].

For upgrading and refining technologies, investment cost curves (cost vs. flowrate for each process unit) from Gary et al. are used to estimate the capital cost [96] using mass balance data from OSTUM and PRELIM (two LCA models that are introduced later in this chapter). Both fixed and variable components of capital cost are estimated. Process unit cost functions are used with a range of different processing capacities to generate total cost vs. flowrate data for the entire upgrading and refining process for each technology option separately considering relevant process units for that technology option. Then a cost vs. processing capacity function is developed to predict capital cost based on the flowrate of crude processed by an upgrader or refinery. The linear cost function used in the present study is shown below:

$$\frac{Cost_C}{Cost_{Ref}} = a + b * \left(\frac{Capacity_C}{Capacity_{Ref}}\right)$$

$\text{Capacity}_{\text{Ref}}$ is the reference capacity (assumed 100,000 bbl/day in the calculations), Cost_{Ref} is the estimated capital cost for an upgrader/refinery with the reference capacity of 100,000. Cost_{c} is the capital cost of an upgrader/refinery with $\text{Capacity}_{\text{c}}$ to be estimated based on the reference cost. Although power functions are more commonly used for capital cost estimates with respect to capacity, a linear cost function is used in this study. Using a linear cost function would keep the optimization model linear which reduces the required computation power and time significantly compared to a nonlinear model while maintaining the same level of accuracy. Detailed analysis regarding the comparison of power and linear cost functions and the accuracy of a linear cost function is presented in Appendix B.

The upgrading stage is assumed to occur in Alberta and refineries are assumed to be in the US Midwest. US Midwest is currently the largest customer for Canadian heavy oil products where the refineries have the capability of processing heavy oil and is accessible by pipeline from Alberta oil sands producing regions. The location of each plant is considered in the investment cost calculations using the location factors provided by Gary et al. [96]. A 10% discount rate, and 30-year project lifetime are assumed in capital cost calculations based on the literature data [93].

3.3.1 Employment of existing LCA models

GHOST. GHOST-SE employs company-reported and publicly available data and presents a range of emissions intensities for bitumen production considering the variability of input parameters and identifies the main sources of variability in emissions intensities [19]. Default inputs and ranges in GHOST-SE are used such as SOR (or a probability distribution of inputs).

OSTUM. Three main upgrading technologies are modeled in OSTUM, including delayed coking, hydro-conversion and a combination of fluid coking and hydro-conversion [20]. Delayed coking and hydro-conversion technologies are considered in the present study. OSTUM also includes 6 different assays in its database and is run with each assay multiple times (with various input assumptions) to obtain a range of results for energy consumption and GHG emissions to be used as inputs in the optimization model developed in the present study.

COPTEM. Crude transport emissions are estimated using Crude Oil Pipeline Transportation Emissions Model (COPTEM) [78]. Variability of input parameters is considered in the model that allows for running the model for different input scenarios and generating a range of emission intensities for dilbit and SCO pipeline transport emissions. In the present study, an average emission factor is used for each type of crude in the model and the variability of transport emission intensity is not considered. This will be investigated in more detail in a future study.

The distance between the extraction site and upgrading facility is assumed to be 500 km as an average distance between the two facilities both located in Alberta. The refineries are assumed to be in PADDII (Petroleum Administration for Defense District) area, 2500 km from the upgrading facility and 3000 km from the extraction site.

PRELIM. Petroleum Refinery Life Cycle Inventory Model (PRELIM) estimates the energy consumption and GHG emissions associated with the crude oil refining stage using process-based life cycle and linear programming methods [73]. PRELIM takes into account crude properties and includes 10 main refinery configurations (based on the intensity of crude processing and the processing units employed in the refinery). PRELIM model is run with proxy assays for dilbit produced by diluting bitumen, SCO produced by bitumen upgrading process, PUB produced by partial upgrading and in situ extraction and upgrading process in all possible configurations and results of energy consumption and GHG emissions are used in the model developed in this study.

These LCA models have been populated with data provided by oil sands companies through non-disclosure agreements, publicly available data and feedback provided by industry experts. Therefore, the GHG estimates provided by these models are informed by actual operating data and not just simulation results that are presented in the environmental impact assessment documents developed to assess the environmental impacts of a project before it starts operating.

Emerging technologies investigated in this study are not included in the LCA models introduced above. Therefore, energy consumption and other relevant data are extracted directly from the two studies that investigate these emerging technologies [76,95]. Both studies use process simulation and the results of lab scale experiments to estimate the process energy, hydrogen and catalyst requirement and product specifications. Capital cost of the process are estimated in Hovespian and Marshman's studies [76,95] and the cost estimate methods and results are used in the present study.

3.3.2 Variability and Uncertainty

It is important to consider the uncertainties in the performance of emerging technologies when evaluating the cost and emissions associated with employing them. Uncertainty in the performance of emerging technologies is due to the lack of real operating data before a technology is deployed at large scale and under different operating conditions. In addition, how the technology evolves after commercialization adds to the uncertainty in the technology performance parameters. Variability in the performance of existing technologies needs to be considered as well. The variability in the performance of existing technologies corresponds to the range of performance parameters (e.g., energy intensity) of these technologies observed across different operating projects and over time. Therefore, including a range of values for the input parameters used to characterize the existing and emerging technologies instead of one single input value can provide more valuable insights regarding the comparison of different technology options. For example, this approach allows for a comparison of technologies performance (both economic and environmental performance) that are presented by probability distributions (instead of one single value) to make a conclusion about the probability of one technology scenario to outperform another scenarios while acknowledging the fact that under some conditions (albeit with lower probability), the second scenario could outperform the first one. This helps inform the investment decision making regarding the implementation of existing and emerging technology alternatives. Variability and uncertainty in the technological and economic parameters are considered in the model by assigning discrete probability distributions. In other words, a finite number of values are considered for the input parameters and one probability is assigned to each value. Values of inputs and their corresponding probabilities are informed by reported industry data, previous LCA models, Environmental Impact Assessments, government reported statistics, peer-reviewed and grey literature, and expert consultation [19,20,94,95,97,98]. For emerging technologies, the model relies on pilot experiment results, simulation results and experts consultation to define the values and probabilities of inputs [94,95]. A list of input parameters with corresponding discrete probability distributions are presented in Appendix B.

Many studies use continuous probability distribution to represent the uncertainty and variability of the input parameters. Based on the findings from previous studies that used continuous probability distributions, at least 10,000 iterations are required to completely capture the effect of variability/uncertainty of the inputs on the model outputs [97]. When this approach is combined with optimization the required computation time and power will increase (the increase in computation time can be 15 times or more depending on the type of the optimization problem and the number of variable/uncertain inputs). In this study the representation of input variability and uncertainty is simplified by using a discrete probability distribution. Test runs show that the reliability of the results is not affected using this simplified approach. Using a discrete probability distribution provides the opportunity to include the uncertainty and variability of input parameters in the analysis and ensure all possible combinations of inputs are considered while keeping the optimization problem runtime within a reasonable range (at least 15 times lower than the required runtime for Monte Carlo simulation combined with optimization). This is particularly important if nonlinear terms are added to the optimization model as part of the future work.

By including the uncertainty and variability of inputs using a probability distribution, model outputs (GHG and cost of each scenario) will be in the form of probability distributions as well. In other words, one output is calculated for each combination of input parameters that results in a series of output values for different combinations of inputs. The probability of each output value is determined by the probability of occurrence of the corresponding combination input parameters. Profit and GHG distributions are compared to determine the scenarios with highest profit and lowest GHG emissions. A pair-wise comparison of scenarios is then conducted to determine the probability of one scenario having lower GHG/higher profit than the second scenario (assume scenario 1 and scenario 2 are being compared). The comparison is done by taking random samples from each of the output distributions and comparing them (10,000 samples are taken for comparison, because the test runs showed that increasing the number of samples beyond 10,000 does not affect the final result). The number of times scenario 1 has lower GHG/higher profit than scenario 2 is counted and a percentage is calculated after 10,000 samples are taken. This percentage is the probability of scenario 1 having lower GHG/higher profit than scenario 2 and vice versa. It provides a quantitative comparison of the probability distributions that represent the economic and environmental performance of different technology scenarios under variable and uncertain conditions.

3.3.3 Sensitivity Analysis

Model input parameters that are not represented with a probability distribution are investigated in the sensitivity analysis. The parameters investigated in the profit sensitivity analysis include natural gas price, carbon price (economy-wide carbon price), price of diluent, capital cost of partial upgrading technology, capital cost of upgrading technology, annualization factor (combined effect of discount rate and project lifetime), Steam to Oil Ratio (SOR) in the SAGD and SA-SAGD processes, Vacuum Residue to Oil Ratio (VROR) in the In Situ Extraction & Upgrading process, solvent recovery rate in the SA-SAGD process, diluent requirement for diluting the product of In Situ Extraction & Upgrading process. The parameters investigated in the GHG emissions sensitivity analysis include Steam to Oil Ratio (SOR) in the SAGD and SA-SAGD processes, Vacuum Residue to Oil Ratio (VROR) in the In Situ Extraction & Upgrading process, hydrogen requirement for the ISEU process, diluent upstream emissions, and NG upstream emissions. Several other input parameters were tested and excluded from the sensitivity analysis because of the insignificant effect on the choice of the least GHG intensive scenario (e.g., solvent recovery in SA-SAGD, catalyst emissions in ISEU and partial upgrading, diluent requirement in ISEU, etc.). These parameters are not specific to one technology option and affect multiple technologies or production scenarios.

In the sensitivity analysis, parameters are varied within a specified range and the highest profit and the lowest GHG intensive pathways are determined at each level of parameter within the specified range. In this study a two-dimensional sensitivity analysis is performed [99]. A two-dimensional sensitivity analysis provides more insights compared to a regular one-dimensional sensitivity analysis by investigating the effect of two input parameters simultaneously. The sensitivity analysis results provide insights regarding the level of inputs required to make one scenario more favorable. In addition, the results provide insights about the implications of data inaccuracy by showing whether the choice of the least GHG intensive, or the highest profit pathway is affected by changing the value of input parameters.

3.4 Results

This study provides a framework to assess the cost and GHG emissions of various oil sands production scenarios under variable and uncertain conditions, and to find the technical, economic and policy conditions under which emerging oil sands technologies become competitive alternatives in global crude oil markets. Seven technology scenarios introduced in the Methods section are investigated in this study, and the set of conditions that makes one technology scenario more favorable than the alternative scenarios are identified.

3.4.1 Uncertainty and Variability Propagation

Figure 3-2 shows the profit and GHG distribution of the seven technology scenarios when both uncertainty and variability of input parameters are considered.

According to Figure 3-2 (left), although some scenarios are more likely to generate higher profit per unit of product, none of the scenarios is clearly superior to others in terms of profitability given that the profit distribution for all technology scenarios overlap.

In the comparison of different scenarios, partial upgrading scenarios are generally more profitable than full upgrading scenarios which is mainly due to the higher capital cost required for the full upgrading process. The product derived from the full upgrading process (Synthetic Crude Oil or SCO) is of higher quality compared to the product of partial upgrading (Partially Upgraded Bitumen or PUB) and consequently requires less energy in the refining process. However, the higher energy required for full upgrading process compared to partial upgrading leads to higher life cycle energy requirement (when combining partial/full upgrading and refining stages) for full upgrading scenario. Therefore, the overall impact of partial upgrading versus full upgrading is a lower cost of production and processing of oil sands bitumen to produce the same amount of transportation fuel. This results in higher profit per unit of transportation fuel produced.

Additionally, the results show that solvent assisted SAGD (SA-SAGD) is generally more profitable than conventional SAGD because solvent injection reduces the steam to oil ratio of the extraction process and consequently reduces natural gas required for the process. Solvent requirement in SA-SAGD adds to the operating cost of the extraction process compared to SAGD, however, for this additional cost (makeup solvent cost) to make SA-SAGD more expensive than SAGD, solvent cost must be ~2-3 times higher than the current solvent cost (which is 60-80 USD per barrel), depending on solvent recovery rate and percent SOR reduction in SA-SAGD compared to SAGD. This is further investigated in the sensitivity analysis.

The range of estimated profit for the In Situ Extraction and Upgrading (ISEU) scenario is comparable to partial upgrading which is due to the uncertainty of emerging technologies performance parameters (e.g., capital and operating costs, hydrogen consumption, diluent requirement). Dilution pathways show a wide range of estimated profit which is due to variability (e.g., different types of diluent (e.g., condensate, naphtha, SCO) in dilution scenarios) and uncertainty (e.g., fraction of diluent mixed with bitumen) of input parameters. Also, two upgrading technologies considered in this study (delayed coking and hydrocracking) with variable inputs (e.g., different energy and hydrogen requirements), lead to the wide range of profit observed for upgrading pathways. Separating the impact of variability and uncertainty of inputs show that the range of profit per gigajoule of transportation fuel for different scenarios is more heavily affected by input uncertainty than the variability of the inputs. The detailed results are presented in Appendix B.

If technology input parameters are defined with higher certainty, the choice of the most profitable scenario can be more clearly determined. However, the input uncertainty is an important challenge that is inevitable especially when emerging technologies are investigated. Similar to the profit distribution results, there are large overlaps between the GHG distribution of different oil sands production scenarios per unit of transportation fuel as well (Figure 3-2 (right)). This means that emerging technology scenarios will not transform the environmental and economic performance of oil sand operations, they will rather introduce incremental improvements under specific conditions.

Dilution scenarios seem to be generally less emissions intensive than upgrading and partial upgrading which is mainly due to the absence of an additional processing step (upgrading or partial upgrading) in dilution scenario. The more intensive refining process required for dilbit compared to SCO and PUB does not make the total emissions of dilution scenario higher than upgrading and partial upgrading. In addition, SA-SAGD scenarios have slightly lower life cycle emissions than SAGD (e.g., comparing SAGD + Upgrading with SA-SAGD + Upgrading or SAGD + P. upgrading with SA-SAGD + P. upgrading shows a slight shift to the left when SAGD is replaced with SA-SAGD). This is due to the lower NG combusted in the SA-SAGD process (because of lower SOR) which is not completely compensated with the additional indirect emissions of the solvent lost in the reservoir in the SA-SAGD process.

Figure 3-3 shows the results of pair-wise comparison of scenarios based on their economic and environmental performance. These two figures provide insights about the likelihood of one scenario having higher profit or lower life cycle emissions than the others.

According to Figure 3-3 (left) SA-SAGD with partial upgrading has higher total profit than the other scenarios with 75% or more probability when input uncertainty and variability are considered, except when compared to SA-SAGD with dilution scenario that shows a ~40% probability of generating a higher profit than SA-SAGD with partial upgrading. The pairwise comparisons also show generally that SA-SAGD routes are usually more profitable than equivalent SAGD routes; diluent and partial upgrading are usually more profitable than full upgrading; and ISEU is usually more profitable than all SAGD routes or SA-SAGD + upgrading.

Solvent assisted SAGD reduces the natural gas requirement for the bitumen extraction process compared to regular SAGD while producing a product with similar quality to SAGD. On the other hand, SA-SAGD involves the injection of solvent into the reservoir which results in the loss of a fraction of the injected solvent and leads to an additional cost compared to the regular SAGD process, but the results show that the overall effect of adding solvent to the SAGD process is a reduction in the cost of the extraction process. Therefore, the technology scenarios with SA-SAGD as the extraction process have a higher profit compared to the same scenarios with SAGD as the extraction process.

For dilution and ISEU scenarios, refining is a larger contributor to the total cost (~30 – 33%) compared to upgrading and partial upgrading scenarios (~20 – 27%). In dilution scenarios, purchase of the required diluent is a significant part of the total cost as well. Diluent purchase can contribute to up to 45% (on average) of the total cost of the production from extraction to refining.

As expected, the results show that partial upgrading scenarios reduce the cost of upgrading. Refining cost for PUB is higher than SCO, but the magnitude of cost increase in the refining stage is lower than the magnitude of cost decrease in the partial upgrading stage.

Therefore, partial upgrading shows lower total cost and consequently higher profit per unit of transportation fuel.

In upgrading and partial upgrading scenarios, extraction cost is generally higher than dilution, because the volume ratio of SCO/PUB to bitumen is lower than the ratio of dilbit to bitumen (because diluent is added to bitumen to produce dilbit). In other words, for the same amount of crude produced by partial/full upgrading and dilution scenarios, a higher volume of bitumen is required for the partial/full upgrading scenario compared to dilution.

According to Figure 3-3 (right), the probability of the SA-SAGD with dilution scenario to have lower life cycle emissions than the other 6 scenarios is between 79% and 100% and SAGD with dilution is the least emission intensive scenario after that. SAGD with upgrading is the most emissions intensive scenario. Partial upgrading scenarios are between dilution and upgrading in terms of the total life cycle emissions. Aside from the dilution scenarios, In Situ Extraction and Upgrading has the best environmental performance among the remaining scenarios with SA-SAGD + partial upgrading being the closest competitor.

In all the technology scenarios, GHG emissions associated with product end use (i.e., combustion of transportation fuel) is the largest contributor (67 – 75%) to the total GHG emissions. Refining and transportation emissions contribute to 7 – 11% and 1 – 3% of the total emissions. Dilution and ISEU scenarios are in the higher range of refining and transportation emissions, because of the lower quality of crude compared to upgrading and partial upgrading scenarios. Partial upgrading scenarios reduce the upgrading emissions compared to full upgrading, but result in higher refining emissions.

In upgrading and partial upgrading scenarios, GHG emissions associated with the extraction process is generally higher than dilution (up to 60%), for the same reason that extraction cost is higher for these scenarios as explained earlier; for the same amount of crude produced by partial/full upgrading and dilution scenarios, a higher volume of bitumen is required for the partial/full upgrading process compared to dilution.

More insights derived from the comparison of scenarios are presented in Appendix B.

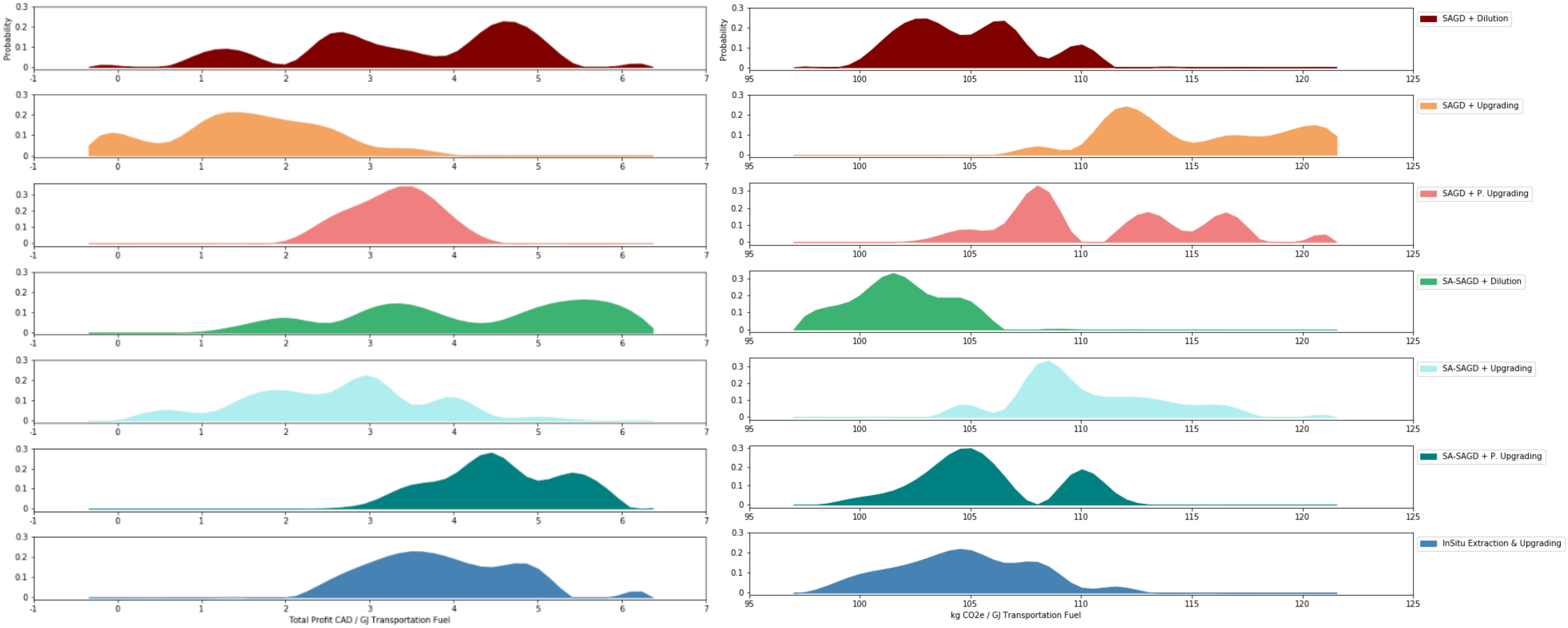

Figure 3-2 Profit distribution of technology scenarios (left), GHG distribution of technology scenarios (right)

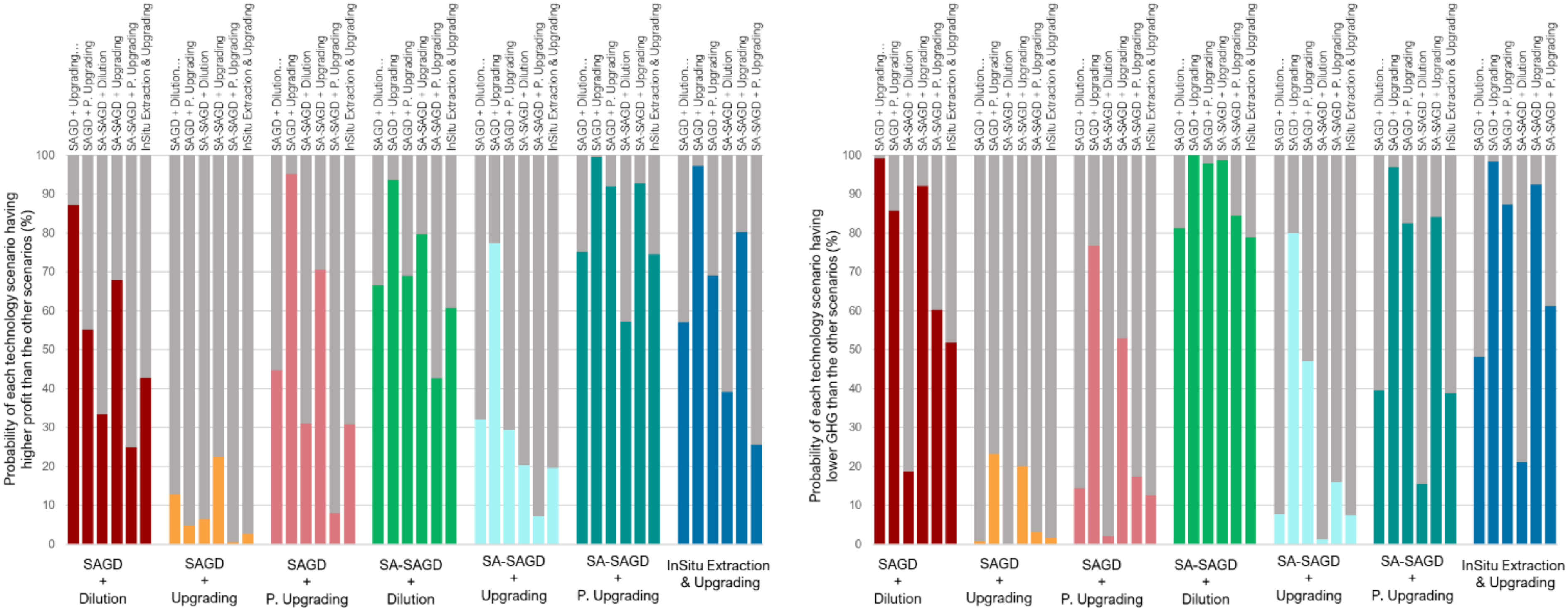

Figure 3-3 Comparison of technology scenarios' economic performance (left), Comparison of technology scenarios' environmental performance (right)

3.4.2 Profit / GHG trade-offs

To understand the trade-offs between economic and environmental performance of different scenarios, profit and GHG distributions for all scenarios are presented in one graph in Figure 3-4. According to this figure, if SAGD scenarios (SAGD + Dilution/Upgrading/Partial Upgrading) are compared to the corresponding SA-SAGD scenarios, a slight upward shift is observed in the profit distribution and a downward shift is observed in the GHG distribution. In other words, a change from SAGD to SA-SAGD as extraction technology seems to improve both economic and environmental performance of the entire supply chain when input uncertainty and variability are considered. A similar observation is made when comparing Upgrading scenarios (SAGD/SA-SAGD + Upgrading) to Partial upgrading scenarios. Partial upgrading is shown to improve both economic and environmental performance of the operations over Upgrading.

The comparison between dilution and partial upgrading scenarios is more complicated. Dilution scenarios have better environmental performance compared to Partial upgrading under a wide range of input assumptions, but the economic performance of Dilution can be highly uncertain particularly due to the uncertainty in diluent cost that is an important contributor to the total cost of the operation from extraction to refining. The higher capital cost of partial upgrading compared to dilution is a significant barrier for adopting this scenario for oil sands production. However, the benefits of producing a higher value product in Alberta instead of diluting and exporting lower quality bitumen, combined with the lower operating cost of partial upgrading could provide an incentive for building partial upgrading plants in the province. The effect of pipeline capacity and available market for each type of crude (i.e., dilbit, partially upgraded bitumen, etc.), need to be considered as well for making a decision between different scenarios.

This study is focused on comparing technology scenarios assuming there is no constraint on pipeline capacity and market demand, but the effect of these factors is recommended to be investigated in future work.

The economic and environmental performance of In Situ Extraction and Upgrading scenario is very similar to SA-SAGD + Partial upgrading when the probability distributions are compared. However, the range of profit is slightly lower for ISEU. Performing a sensitivity analysis (presented in the next section) will provide more insights for comparing these two scenarios.

Overall, the results show that emerging technologies have the potential to improve the performance of the existing technologies by employing innovative solutions. Injecting solvent to the reservoir can reduce cost and environmental impacts of the extraction process with minimal changes to the initial process design for the SAGD process. Unlike SA-SAGD, ISEU and Partial upgrading are associated with significant changes to the existing production scenarios. This makes the adoption for these technologies more challenging, but at the same time offers more substantial improvements. For example, as explained earlier, partial upgrading diversifies the market for Alberta oil sands products and can somewhat address the pipeline transport constraint faced by oil sands producers in Alberta.

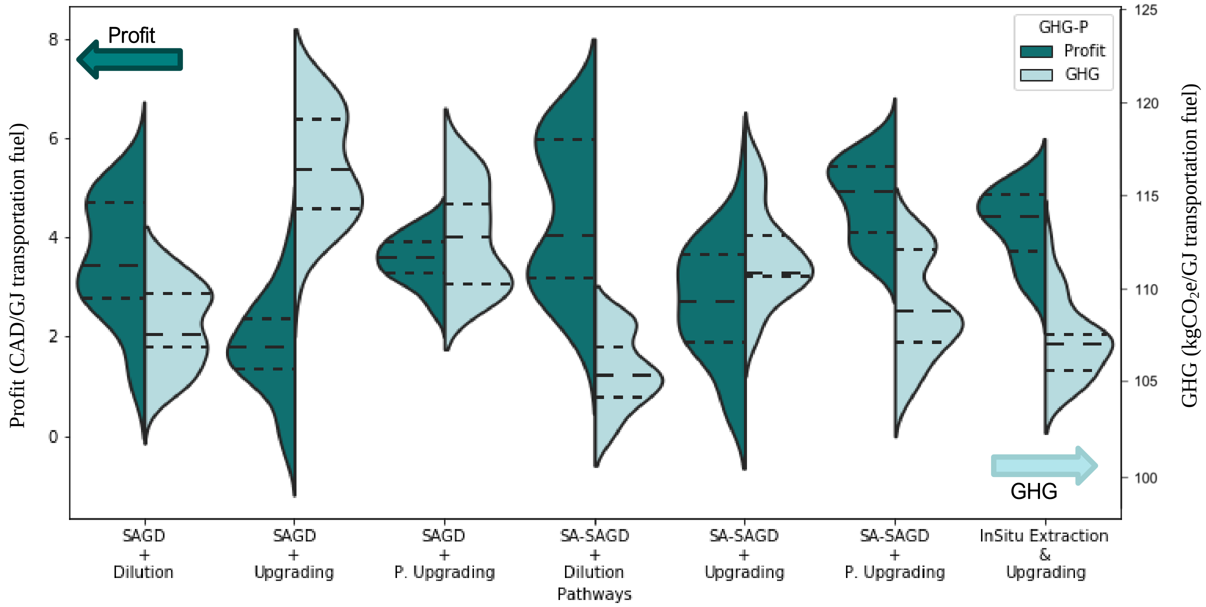

Figure 3-4 Economic and environmental performance trade-offs

Sensitivity Analysis

As explained in the methods section, sensitivity analyses are performed to understand the effect of input parameters on the choice of the least GHG intensive and the highest profit scenario. Several input parameters are tested and the parameters with the largest effect on the output (profit or GHG) are selected and investigated in the sensitivity analysis.

Figure 3-5 and Figure 3-6 show the results of the sensitivity analysis on the choice of the technology scenario with the highest total profit per unit transportation fuel and the technology scenario with the lowest total GHG per unit transportation fuel respectively. These figures highlight the conditions under which each of the technology scenarios are economically or environmentally competitive for oil sands extraction and processing. Each block in the grid is broken down into sections and each square within each block represents the result of optimization holding two parameters constant and varying the remaining parameters using their probabilities. Each color represents one scenario and different shades of one color are indications of the magnitude of difference between the first- and second-best scenario (darker colors show a larger difference between the first and the second scenario).

According to Figure 3-5, the difference between the first and the second best scenarios under a wide range of uncertain and variable inputs seem to be relatively small (i.e., light shades of the colors appear in this figure, which represent a smaller difference than $1/GJ of transportation fuel based on the 80th percentile). However, the results show the boundaries of each input that can make one scenario or another (e.g., SA-SAGD + Partial Upgrading), the preferable technology scenario. Understanding these input boundaries is useful to inform the future research and investment decisions (e.g., understanding whether it is worth spending money and resource improving solvent recovery). The large uncertainty associated with emerging technologies and future price of energy and products marks the importance of using such a tool for evaluating the existing and emerging technology scenarios.

Three out of the seven scenarios investigated in this study, including SA-SAGD + Dilution, SA-SAGD + Partial upgrading and In Situ Extraction & Upgrading (ISEU) are the most frequently selected scenarios under a wide range of input parameters. The remaining four scenarios including all SAGD scenarios (SAGD + Dilution/Upgrading/Partial upgrading) as wells as SA-SAGD + Upgrading only appear as the highest profit alternative under extreme values of some of the input parameters, for example very low capital cost for upgrading, or very low SOR values for SAGD.

The results indicate that solvent assisted SAGD is more economically attractive than regular SAGD under a wide range of possible input parameters. The results of the sensitivity analysis provide several interesting insights that are discussed below.

Overall, SA-SAGD with Partial Upgrading seems to be the dominant scenario under most combinations of input parameters, consistent with findings from Figure 3-2 and Figure 3-3. SA-SAGD with dilution and ISEU become competitive under certain conditions as well. SA-SAGD with upgrading becomes competitive only at very low capital cost of upgrading, below 9 billion CAD for a 100,000 barrel per day upgrader, which is much lower than the average capital cost of building an upgrader in Alberta (~14 billion as of 2018) [100].

As expected, high future natural gas prices favor the ISEU scenario. The reason is the lower natural gas required for this extraction method (as a result of eliminating the need for steam production compared to SAGD and SA-SAGD), therefore, high natural gas price accentuates the advantage of this technology against SA-SAGD extraction. Depending on the value of other input parameters, ISEU becomes competitive at NG prices above \$4/GJ to \$9/GJ (compared to the 2021 price of ~\$2.8/GJ). Additionally, at low diluent requirement for ISEU (<4% diluent for dilution, compared to the current best guess of 10%), the ISEU scenario becomes competitive at any NG price.

Generally, at low NG prices, SA-SAGD with partial upgrading is the most competitive option, but at diluent cost lower than \$65-\$70/barrel, SA-SAGD + Dilution becomes more competitive than SA-SAGD + Partial upgrading. In addition, at high discount rate and short project lifetime (that bring the annualization factor above ~0.12, which is equivalent to 12% discount rate when project lifetime is 30 years, or 18 years project lifetime when discount rate is

10%), Dilution has advantage over Partial upgrading, even at low NG price. The reason is the higher capital cost associated with Partial upgrading scenarios compared to Dilution that makes the Partial upgrading scenarios less attractive at high discount rates. Considering the current NG price (~$3/GJ), SA-SAGD + Partial upgrading is the most profitable scenario under most combinations of inputs, except for: 1) low diluent cost and high annualization factor that makes Dilution more profitable (as explained above), and 2) low diluent requirement in ISEU scenario that make this scenario more profitable than Partial upgrading.

Diluent requirement for ISEU scenario is the most important parameter that affects the competitiveness of this scenario against SA-SAGD + Partial upgrading. If the required diluent to make the product of In Situ Extraction and Upgrading process meet the pipeline specifications is 6% (6 bbl diluent/bbl final product) or lower, ISEU becomes the most competitive alternative unless 1) SOR of the SA-SAGD process is less than 1.2, or 2) capital cost of partial upgrading is less than $4.5B (for a reference 100k bpd plant), or 3) diluent cost is less than $55/bbl. In the first two cases, SA-SAGD with Partial upgrading and in the third case SA-SAGD + Dilution become the most profitable scenarios.

The main parameters that affect the competitiveness of SA-SAGD + Dilution are the price of diluent and the annualization factor. At diluent prices lower than $70/bbl diluent, Dilution becomes more competitive than Partial upgrading regardless of the value of other parameters, except at low capital cost of Partial upgrading; when Partial upgrading capital cost for a reference 100k bpd plant is less than $5B.

High carbon price (economy wide carbon price is assumed), is in favor of Dilution scenario compared to partial upgrading, but the carbon price must be higher than $250 per tonne to make dilution more profitable than partial upgrading when other inputs are fixed.

When economy wide carbon pricing is implemented in the model, ISEU becomes more economically attractive compared to the conditions that regulatory carbon price is implemented. For example, at very low solvent recovery rate in SA-SAGD (<60%), ISEU is more profitable than SA-SAGD + Partial Upgrading at any carbon price. In addition, at low VROR values (<0.9), ISEU is the most profitable scenario when carbon price is $50 per tonne or higher. The impact of implementing an economy wide carbon price on the economic competitiveness of the new technologies such as ISEU (as opposed to implementing regulatory carbon price based on the current regulation in Alberta), shows the importance of the GHG emissions standards and policies on adopting emerging technologies and achieving emissions reduction targets. While the current carbon pricing policies might not provide the required incentive for developing new low emission technologies, an increased price on carbon emissions could provide the opportunity to move towards innovative and sustainable solutions to reduce oil sands environmental impacts.

According to Figure 3-6, Dilution scenarios are the least GHG intensive ones among the 7 technology scenarios investigated in this study. In Dilution scenarios, SA-SAGD is normally the preferred option over SAGD because of the lower SOR and consequently the lower NG consumption. The figure shows SAGD as the less emission intensive scenario compared to SA-SAGD when SAGD SOR is lower than 3, and SA-SAGD SOR is higher than 3.5. Since SA-SAGD SOR is always lower than SAGD SOR (at the same reservoir conditions), those conditions will not happen in reality (even though some combinations of inputs might not happen in reality, the ranges are included in the analysis to show the impact of all possible combinations of inputs). High upstream emissions of diluent can make alternative scenarios to become less emission intensive than Dilution; if diluent upstream emissions are higher than 11 gCO_2e/MJ, partial upgrading can be a competitive scenario as the lower GHG intensive scenario.

In addition, ISEU can become a competitive alternative to Dilution if the hydrogen requirement is lower than ~50 m^3 hydrogen/m^3 vacuum residue injected.

Upgrading scenarios are associated with high emissions intensity and are not competitive with other scenarios even under extreme conditions.

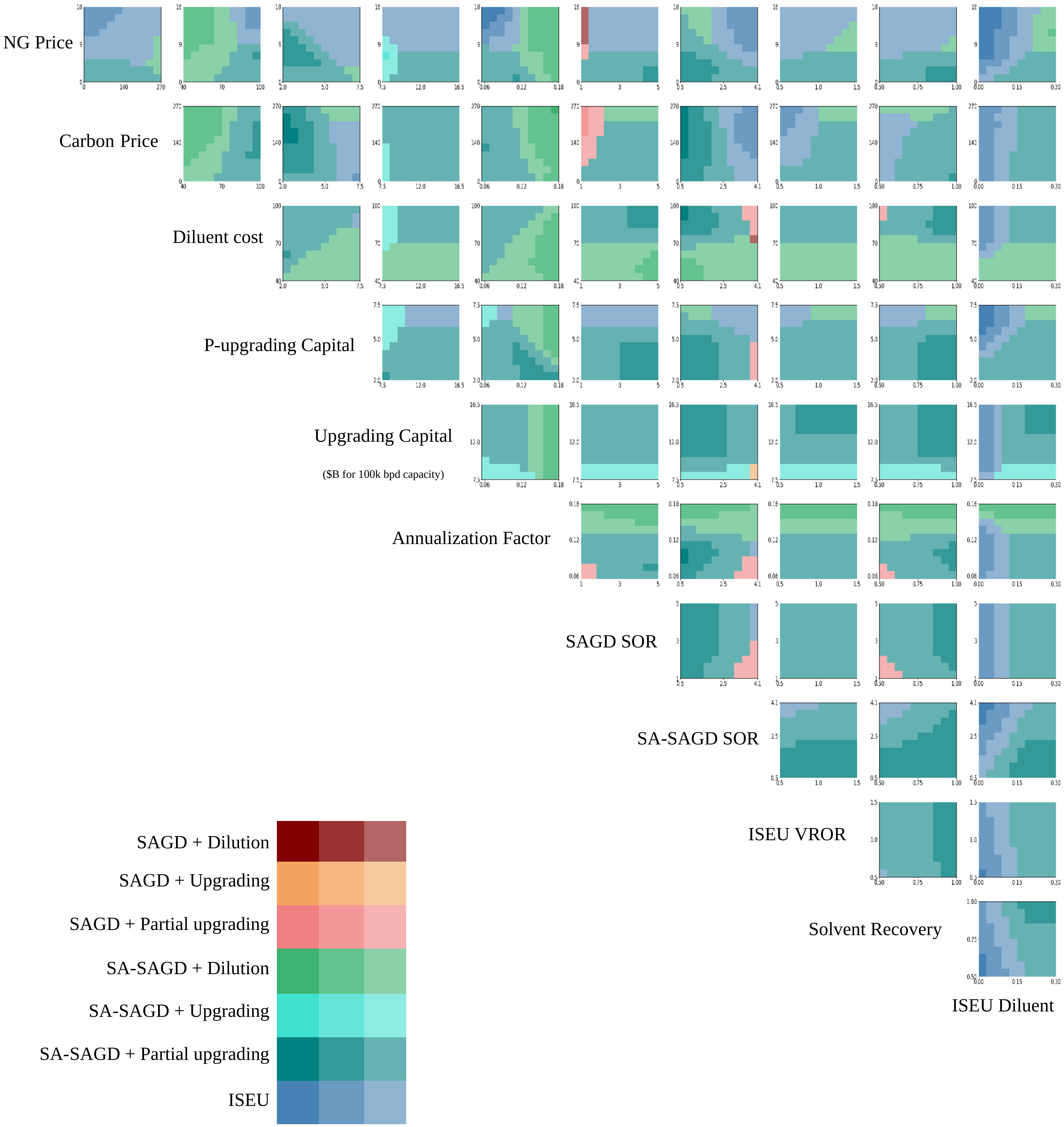

Figure 3-5 Sensitivity analysis for total profit of the scenarios. Each block or square in the grid is broken down into sections and each square within each block represents the result of optimization, i.e., the most profitable technology scenario, holding two parameters constant and varying the remaining parameters using their probabilities.

Each color represents one technology scenario. Different shades of one color are indications of the magnitude of difference between the first and second best scenario. Darker colors show a larger difference between the first and the second scenario.

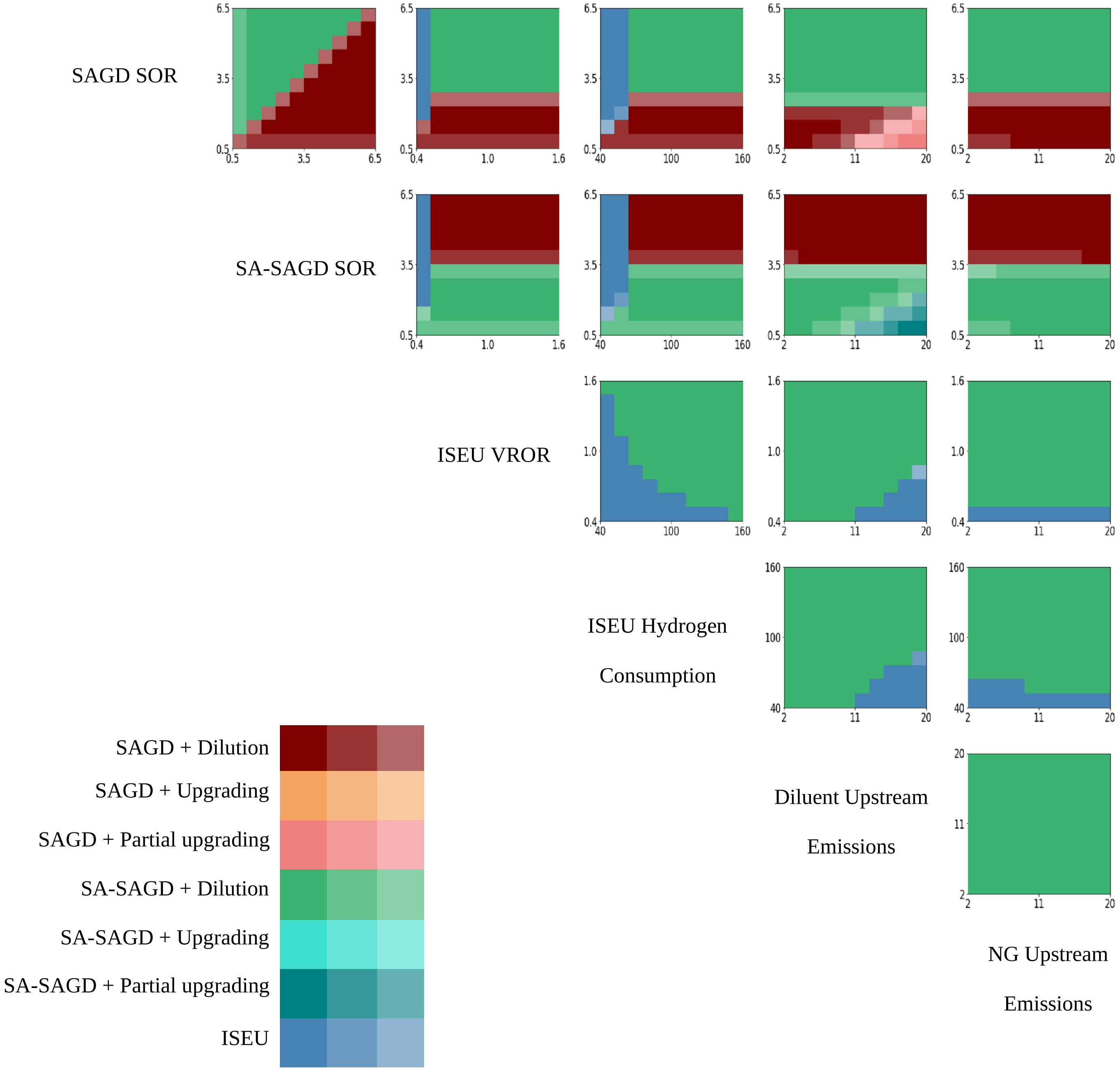

Figure 3-6 Sensitivity analysis for total GHG emissions of the scenarios. Each block or square in the grid is broken down into sections and each square within each block represents the result of optimization, i.e., the least GHG intensive technology scenario, holding two parameters constant and varying the remaining parameters using their probabilities.
Each color represents one technology scenario. Different shades of one color are indications of the magnitude of difference between the first and second best scenario. Darker colors show a larger difference between the first and the second scenario.

The effect of different functional units on the results of the analysis was investigated as well. One alternative functional unit is one barrel of bitumen extracted. Using this functional unit slightly affects the comparison between the economic performance of different scenarios. Upgrading and partial upgrading are negatively affected, while Dilution and ISEU are positively affected by this change. In other words, Dilution and ISEU scenarios have higher profit per barrel of bitumen produced compared to Upgrading and Partial upgrading. The reason is that in Upgrading and Partial upgrading scenarios, the volume of final crude sent to the refinery after processing the bitumen is smaller than the initial volume of bitumen extracted. On the other hand, in Dilution and ISEU scenarios, the volume of crude is larger than the volume of bitumen because diluent is added to bitumen in Dilution and because of the swelling factor associated with the ISEU product. This means that lower volumes of final products (gasoline, diesel, etc.) are produced for one barrel of bitumen extracted in Upgrading/Partial upgrading compared to Dilution/ISEU. This results in a higher profit for Dilution/ISEU scenarios. This functional unit affects the comparison between the environmental performance of different scenarios as well. Upgrading/Partial upgrading have lower GHG emissions per barrel of bitumen compared to Dilution/ISEU. The reason is similar to the reason behind the change in the economic performance of these scenarios. Larger volume of crude in Dilution/IESU leads to higher refining and end use emissions for one barrel of bitumen extracted compared to Upgrading/Partial upgrading.

The second alternative functional unit investigated in this study is one gigajoule of all refinery products (including heavier and less valuable products such as liquid heavy ends, instead of 1 gigajoule of transportation fuels only, as the most valuable refinery products). The results show that such change in the functional unit does not affect the overall comparison between the economic performance of technology scenarios significantly. On the other hand, the GHG results are slightly affected by this change in the functional unit. Since the emission factor (on a per gigajoule basis) is lower for heavier products, the model selects less intensive refining options that lead to producing a higher volume of heavy products (and lower volume of transportation fuels). Therefore, the technology scenarios are affected differently when this functional unit is used. The most significant change observed was an increase in the range of GHG emissions for ISEU scenario.

3.5 Discussion

A novel method is developed for uncertainty analysis combining LCA, scenario analysis, sensitivity analysis and optimization. This method allows for an investigation of the role that uncertainty plays in the comparison of mature and emerging technologies. The novel approach proposed in this study that uses optimization methods with LCA, allows for the evaluation of a broad set of possible scenarios without the need to select the scenarios beforehand. In other words, using optimization helps identify the best possible scenarios (based on their economic or environmental performance) considering the uncertainty and variability in their performance while eliminating the need to include all possible scenarios (that might be not competitive under any conditions) in the analysis. This helps reduce the time and effort required to analyze all possible scenarios only using LCA methods if optimization was not used. This is particularly helpful when variable external factors (e.g., price of raw material as a function of supply and demand) are included in the analysis. The proposed method utilizes discrete probability distribution for inputs (as part of the optimization model). This compromise (as compared to the continuous probability distributions typically used in Monte Carlo Simulation) allows more flexibility to explore extensive scenario and sensitivity analysis which becomes impractical when many uncertain parameters are included and the nature of these distributions are not well characterized (e.g., early stage technologies). This then provides more detail to decision makers about the impact of the variability and uncertainty of inputs on the choice of the most competitive technology scenario while keeping the computation time within a reasonable range.

The proposed method is used to evaluate the impact of adopting emerging technologies on the environmental and economic performance of the oil sands production. The results show that all three emerging technologies have the potential to improve the performance of oil sands production. However, there are some differences between the magnitude of impacts and the risks associated with adopting each technology option. The results of the sensitivity analysis identify the conditions that could make each technology option the highest-profit or lowest-GHG scenario.

Converting SAGD to SA-SAGD offers improvements in both economic and environmental performance of the operations, but the magnitude of changes is small. There is an advantage in improving the performance of the operations without imposing significant changes to the process and with little or no increase in the required capital cost, because it reduces the usual risks associated with adopting a new technology. On the other hand, since the change from SAGD to SA-SAGD doesn’t change the quality of the crude bitumen product, it doesn’t provide any new market opportunities for the product of the new technology.

Building a partial upgrader to replace bitumen dilution can improve the economic performance of the operations, but not necessarily the environmental performance. Partial upgrading will likely improve both economic and environmental performance of oil sands operations compared to full upgrading. Adopting partial upgrading technologies creates significant changes to the process of oil sands production by adding/changing a major step in the operations (adding a major step compared to dilution scenario, and changing a major step compared to full upgrading scenario). Capital investment is required for adopting this technology which will increase the risks of the technology uptake. On the other hand, the product of this technology has higher quality than dilution scenario which can provide new market opportunities for oil sands production. In addition, it can be beneficial to the Canadian producers to generate an added value product in the province of Alberta (that can improve the profit margin for the Canadian producers) instead of exporting low quality dilbit to the destination refineries.

In situ extraction and upgrading technology offers improvements in the economic and environmental performance of the operations as well (under some conditions). Similar to partial upgrading, ISEU creates significant changes to the entire operations by introducing a completely different in situ extraction method (compared to SAGD) that eliminates the need for steam generation and uses vacuum residue as the extraction agent. This technology offers the opportunities associated with creating a different quality product (although the product is still of lower quality compared to partial or full upgrading) as well which can be beneficial by creating diversity in the potential markets. On the other hand, adopting this new technology is associated with higher risk that partial upgrading and SA-SAGD as it is not similar to any of the previously deployed technologies for oil sands production.

Full upgrading does not seem like an attractive technology option compared to the other existing and emerging scenarios, unless the demand for the Canadian heavy and medium crude oil (e.g., dilbit and partially upgraded bitumen respectively) disappears.

The tool developed in this study can help set performance targets for emerging technology developers (e.g., percent energy intensity reduction target compared to existing technologies) and provide insights about the comparative performance of each specific emerging technology against existing or other emerging technologies. The results of the analysis help the oil sands producers understand the supply chain impacts of adopting new technologies and the new technologies' potential to keep the oil sands competitive in the global market. Close-to-commercial technologies investigated in this study show promise to reduce cost and emissions, and could all become viable options. However, on a life cycle basis this is modest compared to long term climate goals, so additional technologies must be developed and deployed. This framework can be adapted to represent the increased uncertainty associated with earlier stage technologies.

This study has improved upon the previous LCA studies of oil sands processes and technologies by including the emerging technologies along with the uncertainty of key inputs in the scenario comparison. The framework developed in this study can be used to include market conditions and capacity constraints in the analysis as well. Those constraints are not included in the scope of the present study, but are recommended to be investigated in the future work.

3.6 Conclusion

Emerging technologies are introduced to oil sands operations aiming to help Canada's move towards reducing GHG emissions and meeting the country's climate change targets. The implications of adopting these emerging technologies on the environmental and economic performance of the oil sands' entire supply chain need to be understood prior to their uptake at commercial scale. This study provides a framework to assess these emerging technologies along with existing oil sands technologies under variable and uncertain conditions, and identifies the technical, economic and policy conditions under which emerging oil sands technologies become competitive alternatives in global crude oil markets. The proposed framework combines optimization methods with LCA principles to more efficiently assess a large number of possible technology scenarios based on their environmental and economic performance.

The results of the analysis show that all three emerging technologies investigated in this study (SA-SAGD, Partial upgrading, and ISEU) have the potential to improve the oil sands operation. The conditions that make each technology a competitive alternative for oil sands production are identified and explained in details in the results section. Utilizing SA-SAGD instead of conventional SAGD offers improvements in the economic and environmental performance of the oil sands operations by imposing minor changes to the SAGD process. On the other hand, Partial upgrading and ISEU introduce major changes to the existing operations (dilution and full upgrading), while at the same time impacting the performance of the existing operations beyond what SA-SAGD offers. An example is the different quality of the crude produced by Partial upgrading and ISEU (unlike SA-SAGD product that is similar to SAGD) that diversifies the market for Alberta oil sands.

Although economic and environmental performance improvements can be obtained by employing emerging oil sands technologies, additional measures and technologies are still required (e.g., large scale carbon capture and sequestration/utilization projects) to achieve long term climate goals. These additional emission reduction opportunities are recommended to be investigated in the future work.

The results of this study provide insights for investment decision making and future research on emerging technologies by identifying the conditions (e.g., technology performance parameters, carbon price, energy price, etc.) required for a new technology to become a competitive alternative for oil sands production. In future work, other emerging technologies can be added to the model to broaden the scope of the analysis by including additional pathways in the model.

Chapter Four: **Role of emission reduction solutions and emerging technologies in meeting oil sands emissions reduction targets**

4.1 Abstract

A technoeconomic framework is developed using life cycle assessment and optimization methods to evaluate potential emissions reduction solutions for oil sands supply chain and the role each can play in helping the oil sands industry achieve ambitious emissions reduction targets while maximizing the profit per barrel bitumen produced. The results show that setting mandatory emissions reduction targets (on upstream direct emissions), that are in line with Canada's net zero by 2050 target, can incentivize retrofitting existing oil sands projects to employ emissions reduction solutions such as carbon capture and storage. It can also lead to shutting down parts of the existing projects and building new projects that employ emerging technologies with lower GHG emissions impacts. CO_2 removal technologies such as Direct Air Capture can be employed to prevent the shut down of existing projects, but the price of CO_2 removal must decrease (to ~\$100/tonne) through technology improvement and large scale deployment for their deployment to become economically feasible. Setting emissions reduction targets on the entire supply chain emissions (upstream and downstream including end-use) will make investments in new oil sands projects uneconomic because of the high cost of removing equivalent amount of CO_2 from the atmosphere to compensate for end-use emissions. In addition, the results of the study provide insights about the scale of emerging technologies deployment under different scenarios.

4.2 Introduction

4.2.1 Background

According to the data published by the Government of Canada, Canada's total greenhouse gas emissions in 2019 were 730 $MtCO_2e$ [101]. Oil and gas production accounted for 26% of the GHG emissions in 2019 (191 $MtCO_2e$). Oil sands emissions contributed to 43% of oil and gas emissions and 11% of total GHG emissions in Canada (83 $MtCO_2e$) [101]. Oil sands emissions include emissions from mining and in situ oil sands extraction as well as oil sands upgrading. In situ oil sands extraction accounted for 42.7 $MtCO_2e$ in 2019.

Canada has taken serious actions to reduce GHG emissions and mitigate the impact of climate change since signing the Paris Agreement in 2015 [102,103]. Policies and measures have been put in place to move towards achieving a net-zero economy in 2050 [104,25]. Canada's short-term plan for emissions reduction includes a 40-45% reduction below 2005 levels by 2030 (increased from the initial plan to reduce by 30% below 2005 levels) [71,105].

In Canada, ~82% of total GHG emissions come from energy (energy use in different sectors including transportation, residential, industrial, commercial and agriculture) [6]. Decarbonizing the energy sector is crucial for meeting Canada's climate goals. Therefore, great effort is made for transitioning the energy system towards low intensity fuels (renewable electricity, biofuel, hydrogen, etc.). Similar plans for decarbonizing the energy sector has been set by other countries in the world, most importantly by the United Sates, as the largest importer of Canada's oil sands crudes [106]. As such, oil sands producers have started to set emissions reduction targets for their operations in an attempt to remain a part of Canada's future energy system and to maintain their market share in the U.S. [24,107].

The emissions reduction targets set by oil sands producers often include the upstream portion of the supply chain emissions only (i.e., crude refining and final product end-use are not included) [24]. To understand the potential life cycle emissions impacts as a result of the planned upstream emissions reduction, the entire supply chain emissions must be considered. This is especially important because meaningful reduction must occur in the entire supply chain emissions (not just upstream emissions) to ensure the oil sands products can remain competitive alternatives in the energy sector. It should be noted that even though downstream emissions are usually outside the operational boundary of oil sands producers (i.e., the emissions occur in facilities that are not operated or controlled by oil sands producers, for example in refineries in the U.S.), and therefore on-site emissions reduction cannot be achieved by oil sands producers, negative emissions solutions can be adopted by them to compensate for downstream emissions and result in higher net reductions throughout the supply chain (compared to the case where only upstream emissions are considered in reduction targets). In addition, oil sands producers can purchase carbon offset credits (generated from other emissions reduction projects that are eligible for offset credit generation in Alberta) to complement their on-site emissions reductions and help them achieve their emissions reduction goals.

Life cycle stages of oil sands operations consist of bitumen extraction and recovery, dilution or upgrading of bitumen[10], bitumen product transport and refining, and refinery product end-use [108]. Various technology options (which are at different stages of development) can be employed in each stage of the operation. These technology options offer different economic and

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[10] Bitumen dilution and upgrading technologies are currently used to produce crude oil in the form of dilbit and synthetic crude oil (SCO) respectively in Alberta. Dilbit and SCO are crudes that are ready for pipeline transport

environmental performance that impact the performance of the entire oil sands operation. In addition, they produce crude oil with different qualities. Selecting the optimum technology option(s) is complicated by technology performance parameters and several external drivers. The main performance parameters impacting the technology selection decision include potential emissions reduction offered by each technology, cost of utilizing the technology and the quality of crude produced by the technology. The main external drivers that could impact the choice of technology include crude demand in the target market(s), available refining capacity compatible with the crude quality, transport capacity, emissions reduction targets and climate goals, and available capital investment. Therefore, a technoeconomic framework is required that takes into account all the input parameters related to the technologies, and the external drivers and constraints and provides insights about the best possible economic and environmental performance of oil sands operations using the available technology options.

In this study, optimization methods are used to investigate the emerging technologies and emissions reduction solutions available (or potentially available in the future) to oil sands producers and determine how they can be used to meet certain emissions reduction goals while providing the best economic benefit throughout the entire oil sands supply chain considering the constraints on transport and refining capacity in the target markets.

A “technology pathway” in this study is defined as a combination of technologies (including existing and potential future technology options) for the upstream portion of oil sands operations that includes extraction and recovery of bitumen, and bitumen dilution/upgrading. Downstream portion of the operations that include refining of the bitumen product and product end-use are modeled alongside the technology pathways (upstream) to form the full life cycle of oil sands operations.

This study is focused on *in situ* oil sands operations in Alberta (oil sands mining is not included in the scope). Oil sands production data for 2019 and 2020 shows approximately 1,350,000 BPD bitumen is currently produced by in situ projects [109]. About 92% of the in situ production is by using the two main steam based extraction methods; Steam Assisted Gravity Drainage (SAGD) is used for 77% of the production and Cyclic Steam Stimulation (CSS) is used for 15% of the production. In the present model, SAGD is used as the “baseline” extraction method in the analysis and it is assumed that 100% of the current in situ bitumen is produced using SAGD. This is a simplifying assumptions that is justified based on similar sources of GHG emissions and similar ranges of emissions from SAGD and CSS production methods [3,18]. It is also assumed that SAGD bitumen from the existing projects is diluted and sold in the market as dilbit. I acknowledge that there are four upgrading facilities currently operating in Alberta; Scotford, Horizon, Mildred Lake and Suncor upgrader [110,111]. However, feedstocks to these upgraders are mostly bitumen produced by mining operations, and only one facility, Suncor upgrader, processes bitumen from in situ projects which is approximately 15% of the total bitumen produced from in situ operations in Alberta [109]. Therefore, dilution (along with SAGD as the extraction method) is used as the “baseline” production pathway for existing operation in the model since it accounts for ~85% of the in situ production. So the baseline production pathway used to model the existing bitumen production capacity is SAGD + Dilution. The reduction targets are set against this baseline production pathway.

New in situ projects could potentially be built during the analysis period, 2021 to 2050. There is a range of technology options that can be employed for these new projects. In addition, existing projects could potentially be retrofitted to reduce GHG emissions. Different technology options as well as available retrofit options and how they are incorporated in the model are explained in the Methods section.

4.2.2 Market and Crude Transport

Market and transport capacity are two important external factors that are considered in the analysis. U.S. is currently the main importer of Canada's crude oil. More than 75% of the total crude oil produced in Canada is exported to the U.S. (based on 2019 and 2020 data) [112,113]. The remaining 25% (which is mainly light crude oil) is processed within Canada. More than 93% of the dilbit produced in Alberta is currently exported to the U.S. (100% of Alberta's dilbit export), which makes Canada the largest foreign supplier of crude oil to the U.S. [112–114]. Market growth for Canadian crude oil in the U.S. is limited by available transport (pipeline and rail) capacity.

Adding new pipeline capacity for transporting crude oil over long distances has been a controversial topic for a long time, and the debate over the positive and negative impacts of building new pipeline has escalated over the past decade as concerns over the climate change impacts of fossil fuel increase. There are currently 840,000 km of pipeline across Canada [115]. Major crude oil export pipelines provide a total capacity of ~4 million barrels per day of crude oil transport from Alberta. There are three main pipelines that transport crude oil from Alberta to U.S. PADDs; TC Energy Keystone, Enbridge Mainline, and Enbridge Express. In addition, Enbridge Line 3 replacement pipeline has recently been completed and added to the current transport capacity. More details about the capacity and destination of each pipeline are presented in the Appendix C.

Another major pipeline that transports crude oil from Alberta to West Coast in Vancouver (and provides access to offshore markets from there) and to Washington State is Trans Mountain pipeline. In addition, a new pipeline, Trans Mountain Expansion, is being constructed and will be added to the transport capacity in 2023 [116]. Trans Mountain Expansion will twin the existing Trans Mountain pipeline.

There are several other pipelines that carry smaller volumes of crude oil to U.S. markets. More details about those pipelines are presented in Appendix C [113,116].

Rail transport is a more expensive alternative to pipeline transport. Using rail to transport crude oil from Alberta to U.S. markets has increased in the past three years (~120% increase on average compared to 2017 and before) since the current pipeline transport capacity for exporting Alberta oil sands products to U.S. refineries is saturated [117].

U.S. PADD 2 (Mid-west) is currently the largest customer of crude oil from Alberta oil sands, importing ~60% of total crude oil exports from Canada (equal to 2.13 million barrels per day in 2020) [113], and there is not much potential for market growth for oil sands. U.S. PADD 3 (Gulf coast) is another customer of Alberta oil sands crude (importing 0.73 million barrel per day in 2020) [113]. PADD 3 currently receives heavy crudes from Venezuela and Mexico, however, the supply of heavy crude from those two countries has declined in the past 8 years. Canadian heavy crude provides the best alternative to replace the declined supply of heavy crude from Venezuela and Mexico and even compete with the current imports from those two countries. However, the success of Canadian heavy crude in reaching PADD 3 refineries depends on new pipeline capacity being added in the future. U.S. PADD 5 (West coast) is another market that has a potential for additional import of Alberta oil sands crude. PADD 5 has large refining capacity to process Canadian heavy oil, but currently receives only 7% of the total Canadian crude export to the U.S. The additional pipeline capacity provided by Trans Mountain Expansion could potentially increase oil sands crudes transport to U.S. PADD 5.

Another potential market for oil sands products is the Asia-Pacific region, especially China. China has a large refining capacity for heavy crude oil [118,119]. Similar to limitations that exist for market growth in the U.S., accessing Asia-Pacific markets requires additional transportation capacity as well. Transporting crude oil to China is possible via tankers from the West Coast terminals. Therefore, Trans Mountain and Trans Mountain Expansion pipelines play an important role to help Canadian heavy crude oil reach Chinese refineries.

These market and transport constraints could potentially impact the choice of technologies used for oil sands production (e.g., based on type of refineries in each target market, and the quality of crude being transported) and therefore, are included in the analysis.

4.2.3 Literature

Other studies in the literature have investigated the economic and environmental performance of various oil sands technologies [18–20,73,75,78–80,82–84,120]. The results of some of these studies are used in the present analysis [19,20,73,84]. The previous studies do not provide a comparison of the economic and environmental impacts of existing and emerging technologies throughout the oil sands supply chain. In addition, the impacts of market and transport capacity constraints on the adoption of existing and emerging technologies are not addressed in the previous studies. None of the studies in the literature have investigated the emissions reduction targets set by oil sands producers and how they could impact the choice of technology pathways for oil sands production.

Technology pathway selection in various industries using life cycle assessment or optimization or a combination of both tools has been introduced and studied in the literature [85–90]. These studies use both environmental and economic objective functions for selecting the optimal technology pathway. However, optimization methods for technology selection considering the entire supply chain have not been used for oil sands production pathways before.

In a previous study by Dadashi et. al., a framework is provided to assess several emerging technologies along with existing oil sands technologies under variable and uncertain conditions, to identify the technical, economic and policy conditions under which emerging oil sands technologies become competitive alternatives in global crude oil markets [108]. The proposed framework combines optimization methods with LCA principles to more efficiently assess a large number of possible technology scenarios based on their environmental and economic performance. However, that study investigates different technology pathways only based on the technology performance parameters and explores the impacts of a limited set of external parameters (e.g., NG price and carbon price) on the choice of technology pathway(s) in the sensitivity analysis. The external factors are not considered in the previous study, namely market and transport capacity constraints, GHG emissions reduction targets, and availability of capital investment. The present study will address the gaps in the literature by including a broad set of constraints and technology types in the analysis.

4.3 Methods

4.3.1 Model overview

A mathematical optimization model is developed in this study to investigate the emerging technologies and emissions reduction solutions for oil sands production and processing and how they can be employed to help the oil sands industry maintain and increase production while meeting Canada's short- and long-term climate targets. The model developed in this study is based on a model proposed in a previous study by Dadashi et.al. [108], and is expanded to include additional constraints and analysis. Similar mass and energy balance equations are used in this study, but unlike the previous study, a 30-year analysis period, 2021 – 2050, is considered in the present study. In other words, a time component is added to the model that allows for the expansion of the model to include the 30-year period in the analysis. The objective of the model is to identify the mix of emissions reduction solutions and technology pathways for future oil sands projects that correspond to the best economic performance for the oil sands' entire supply chain while meeting the constraints on GHG emissions targets, refining and transport capacity limits, capital investment availability and other requirements and conditions (that are explained in more details later in this section). Extraction, dilution, and upgrading stages are assumed to occur in Alberta, and refining is assumed to occur in the markets outside of Canada.

The optimization model is a mixed integer linear programming (MILP) model. Model inputs, constraints and objective function are explained in the following sections.

4.3.2 Objective Function and decision variables

Decision variables of the model are the volume of bitumen produced or processed by each technology option for each technology pathway in each year during the analysis period in the model. In other words, decision variables are a representation of the size of each new (greenfield project, explained in section 4.3.5) or retrofit project that are built between 2021 and 2050 and the year the projects are built.

The objective function of the optimization model is maximizing the Net Present Value[11] (NPV) of all the projects (project types are explained in section 4.3.5) during the analysis period. In addition to NPV, the impact of maximizing royalties is investigated (paid by the oil sands producers to the Crown) as part of the objective function of the model. To do this, a linear combination of NPV and the present value of royalties paid during the analysis period is used as the objective function of the model. By using a combination of the two values in the objective function, the projects' high level economic performance as well as the profit generated for Alberta public (which can be an important factor in making investment and policy decisions in the oil and gas sector) are taken into account simultaneously.

4.3.3 Technology options

Several technology options are considered in the model. The technology options are categorized into four main categories:

1) Existing technologies

This category includes technology options that are currently utilized or are ready to be adopted at commercial scale. Technology options in this category include SAGD, dilution (even though dilution is not a "technology", it is treated as a technology option for life cycle modelling purposes), full and partial upgrading.

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[11] Payback period is another parameter that can be used as the objective function. However, since the impact of various input parameters such as carbon price, NG price, etc. is investigated during the analysis period (2021-2050), NPV is used to allow for the evaluation of the technology pathways during a specified period of 30 years.

2) Incremental improvement technologies

This category includes technology options that can provide incremental improvements to the existing in situ operations by reducing GHG emissions and/or enhancing economic performance of the operations. These technologies are past demonstration phase, but are still not adopted at large scale. The technology options in this category include solvent assisted SAGD (SA-SAGD) and carbon capture and storage (CCS) (post-combustion CCS is considered in this study) technologies.

3) Intermediate technology

This is a generic technology option considered in the model. This technology option is considered to have an innovative component that differentiates it from the two previous categories. This technology option is assumed to offer potential improvements to the environmental and/or economic performance of oil sands operations, but is still a few years away from being ready for adoption at commercial scale. In addition, there are uncertainties associated with the technology performance (e.g., energy intensity and cost of the technology when scaled up) that need to be considered. Two technologies are included in this category in the model; Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH) and In Situ Extraction and Upgrading (ISEU). Literature has suggested that ESEIEH technology provides improved economic and environmental performance compared to SAGD based on pilot scale results [121]. This technology uses a combination of electromagnetic energy and a light hydrocarbon solvent to heat and mobilize bitumen in the reservoir. ISEU technology is based on the injection of dispersed nano-catalyst and hydrogen as upgrading agents and vacuum residue as a heat and catalyst carrier, into the reservoir (partially or fully replacing steam injection in SAGD process) to produce an upgraded synthetic crude oil (SCO) that is close to crude pipeline specifications. More details about both technologies are provided in Appendix C.

4) Breakthrough technology

Similar to the intermediate technology option explained above, breakthrough technology is another generic technology option considered in the model and is assumed to be a possibility in the future (available in 15-20 years). This technology option is assumed to provide a significant reduction in GHG intensity of the oil sands operation. There is no specific technology considered for this category. The purpose of including this technology option in the model, is to investigate the possibility of adopting such technologies (if and when they become available) and the role they might play in meeting Canada's climate goal (as it relates to oil sands sector) by 2050.

The technology is assumed to use electricity as the energy source (this is consistent with electrification solutions in net-zero scenarios in Canada and the world [5,25]). Two levels of cost are considered for this technology:

- High cost which is 40-50% higher than the average cost of current oil sands operation
- Medium cost that is up to 20% higher than the average cost of current oil sands operations.

4.3.4 Negative emissions and emissions offset credits

Carbon dioxide removal or negative emissions projects (projects that remove carbon dioxide from the atmosphere) are considered to play an important role in meeting the global climate goals [122,123]. Carbon dioxide removal can be achieved through natural or technological solutions. Direct Air Capture technology is a method of removing carbon dioxide from the atmosphere using chemical reactions. DAC technologies typically use a liquid solvent or a solid sorbent to remove CO_2 from the ambient air. The solvent and sorbent then go through a regeneration process to separate CO_2 and are re-used in the capture process. The captured and separated CO_2 can be used in different products and applications or can be permanently stored in a geological formation [123]. Solvent-based and sorbent-based methods have different energy requirements and costs associated with them. A range of energy consumption and cost for DAC technologies is available in the literature [124,125]. A 2018 study by Keith et al. presents detailed results including mass and energy balance and cost estimates of a DAC unit at a pilot plant [124]. The results of Keith's study are used to model the DAC technology in the present study. The main data point to model DAC technology in the model is the cost per tonne of captured CO_2, which ranges between 138 and 340 CAD/tonne CO_2 captured in the present analysis. In addition, the upfront capital investment required to install a DAC unit is taken into account.

One of the advantages of DAC solutions is location flexibility. DAC projects don't need to be located close to any emissions sources and can be built in an area close to a geological storage to reduce transportation cost.

In addition to DAC technology, nature-based solutions can be used to remove CO_2 from the atmosphere as well. Nature-based solutions remove CO_2 from the atmosphere by conserving and restoring ecosystems or sustainably managing them [126]. Examples of nature-based solutions include but are not limited to restoring and protecting forests and wetlands, protecting or restoring coastal ecosystems (mangroves, reefs and salt marshes), and regenerative agricultural practices. There are some limitations and challenges associated with nature-based CO_2 removal solutions. For example, carbon sequestration by nature-based solutions can be reversible and the captured carbon can be released back into the atmosphere in case of wildfires or changes in land management. In addition, there are concerns regarding the additionality of nature-based carbon removal projects and how much of the carbon absorption claimed as negative emissions would have occurred anyway. Also, emissions leakage can occur with projects like forest protection, when protecting a forest in one location can shift logging to another forest in a different location and consequently result in zero negative emissions [127]. In this study, the focus is on DAC technology for negative emissions solution, and nature based solutions are not in the scope of the analysis.

Emissions offset credits can be generated by projects that voluntarily reduce GHG emissions (i.e., emissions reduction is not required by the regulations) and follow the requirements set out by the Alberta Emission Offset System [128]. Offset credits are owned by the owner/operator of the facility (or facilities) where the offset project takes place. Emissions offset credits can be purchased by other companies/operators (as emissions credits or negative emissions) who need to become compliant with various regulations that require them to reduce GHG emissions, but can’t achieve the desired emissions reduction at their own facilities. Offset credits are usually sold at a 10-15% discount to the prevailing carbon price (consultation with industry experts). The offset credits are assumed to be sold at 10% discount to the carbon price.

DAC projects explained above are one type of offset projects, but there are many other types of projects that can generate offset credits in Alberta. A list of eligible project types can be found on the Alberta emissions offset webpage [128]. One important difference between offset projects in general and DAC projects is that other offset projects generate emissions credits by preventing the release of GHGs to the atmosphere (avoided emissions) and don't remove CO_2 from the atmosphere similar to what DAC projects offer. Therefore, the emissions offset credits and DAC negative emissions are treated differently in the model. As the environmental regulations become more stringent, more emissions reduction activities become required by law (i.e., are not voluntary) and consequently fewer projects will be eligible to generate offset credits. Therefore, a tightening limit is put on the amount of offset credits that can be purchased by oil sands producers to offset their GHG emissions. Details are provided in Appendix C.

4.3.5 Project types

Two main types of projects are modeled that can be built during the analysis period.

1) Greenfield projects

New projects can be built during the analysis period using any of the available technology options introduced earlier. Figure 4-1 below shows different technology options for each stage of oil sands production and how they can be combined (with each other, and with multiple potential refining options) to represent an entire supply chain. Expansion projects (for existing projects) are considered under this project type as well.

For each technology pathway, one refinery configuration is selected by the model among 10 available options based on the maximum profit or minimum GHG emissions of the entire supply chain. The choice of the refinery configuration depends on the quality of bitumen product. The lower the quality of the bitumen product (for example dilbit versus SCO), the more extensive processing required in the refinery (deep and medium refining as opposed to hydroskimming). On the other hand, more extensive processing results in higher quality products when but at the same time increases cost, energy and GHG intensity of the refining process. Using optimization helps select the refinery configuration that results in the overall highest profit/lowest GHG of the entire supply chain.

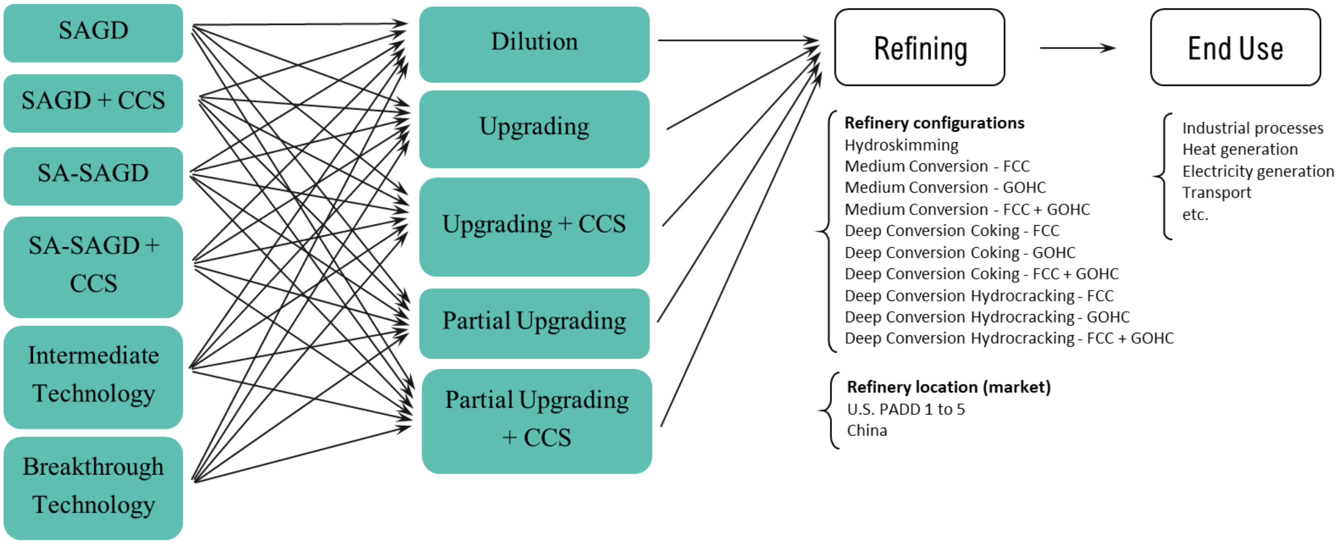

Figure 4-1 Oil sand technology pathways

2) Retrofit projects

There is an option in the model for existing pathways to be modified and converted to lower GHG intensive pathways using available technology options. Below is the list of possible retrofit options for existing SAGD + Dilution to be converted to:

- Installing CCS on existing SAGD projects to capture CO_2 from NG combustion flue gas
- Adding solvent injection equipment to the existing SAGD facilities to convert them to SA-SAGD
- Changing dilution to full or partial upgrading by building upgrading facilities with or without CCS technology

4.3.6 Markets and transport

Two major markets are assumed to be the destination for crude oil produced from oil sands in Alberta; United States (5 PADDs) and China. The refining capacity in each market is obtained from literature and used to put a constraint on the amount of crude oil that can be sold and processed in each market [118,129]. Also, the available transport capacity (pipeline and rail) to each market is used to put a constraint on the amount of crude that can be transported to each market [113,115,116].

4.3.7 GHG Emissions and Cost Calculation

Life cycle GHG emissions (both direct and indirect emissions) for each technology pathway are estimated using various data sources. For some of technologies, energy consumption data (fuel and electricity) and other emissions data (vent and fugitive emissions) from previously developed LCA models are used; GHOST model for SAGD (and with some modifications for SA-SAGD) [18,19], OSTUM for upgrading [20], COPTEM for pipeline transport [78], and PRELIM for refining [73]. For technologies that are not included in these models, data from LCA studies in the literature are used for estimating GHG emissions [76,95,124,130]. For CCS technology, energy consumption data is obtained from literature and through consultation with experts [131–133].

The cost calculations in the model take into account both capital cost and operating costs (energy and material cost, carbon emissions cost). Energy and material costs (e.g., NG, electricity, diluent, solvent) are calculated using energy and material consumption calculated by the model and the energy and raw material price forecast. This is further explained in section

4.3.8. Price of carbon is estimated based on different scenarios for carbon price forecast. More detail is provided in section 4.3.8.

Capital cost calculation for different technology options is completed using different approaches. Capital cost for extraction technologies is estimated using published literature data and high level estimates provided in the literature for emerging technologies [21,93–95]. For upgrading and refining technologies, investment cost curves (cost vs. flowrate for each process unit) from Gary et al. are used to estimate the capital cost using mass balance data from OSTUM and PRELIM [96,108]. For DAC and CCS technologies data from literature are used for the cost calculations [124,132,133].

4.3.8 Other inputs and constraints

4.3.8.1 Bitumen production forecast

Bitumen production forecast scenarios from Canada's Energy Future 2020 report published by CER are used in the present model [134]. In the base case scenario bitumen production is forecasted to increase continuously during the analysis period by expanding existing projects and building new projects. In addition to base case scenario, a low case scenario is included in which a lower increase in bitumen production is forecasted due to a lower demand for crude oil (and fossil fuels in general) in the target markets which is in line with the forecasted decline in fossil fuel use in IEA's net zero pathways [5]. Both scenarios' data are provided in Appendix C.

4.3.8.2 Annual capital investment

Three cases are considered for total annual capital available for investment in oil sands in situ production. Base case is based on forecast data provided in AER ST98 [135]. High and low case are derived from base case data and through expert consultation. The high and low cases are intended to provide the upper and lower bounds on the capital investment in the oil sands sector for possible future scenarios and are not based on any forecast data. In the low investment case, it is assumed that investment in the oil sands sector starts decreasing (compared to the base case) in 2030 until it eventually reaches zero in 2050. In the high investment case, it is assumed that the investment increases compared to the base case up to 2015 levels by 2030, and remains at that level until 2050. The impacts of both high and low cases are investigated in the sensitivity analysis. The three cases are shown in Figure 4-2 below.

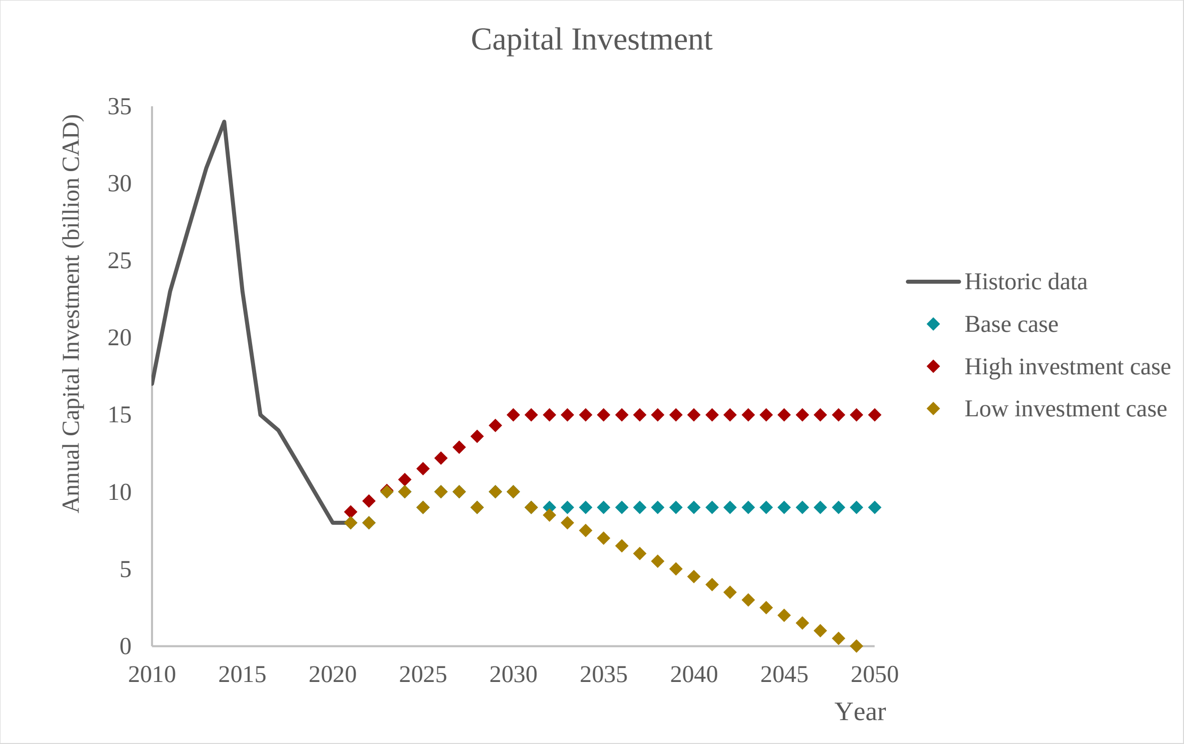

Figure 4-2 Annual capital investment in oil sands sector

4.3.8.3 GHG reduction targets

GHG reduction targets are set for each year during the analysis period with reference to baseline emissions in 2020. Three different paths for GHG reduction are considered: base case, delayed reduction case, and early reduction case. All three paths are designed to reach zero emissions by

2050. Base case reduction path is determined based on Canada's current GHG targets for 2030 and the emissions reduction goals announced by major oil sands producers (~20% reduction from 2020 levels) [24,25], and a steady annual reduction between 2030 and 2050. Delayed reduction path is based on an assumption of gentler reduction between 2021 and 2030 (compared to base case reduction) and steeper reduction between 2030 and 2050. Early reduction case is the opposite of delayed reduction, with steep reduction between 2021 and 2030 and gentle reduction between 2030 and 2050. The three GHG reduction paths are shown in Figure 4-3 below:

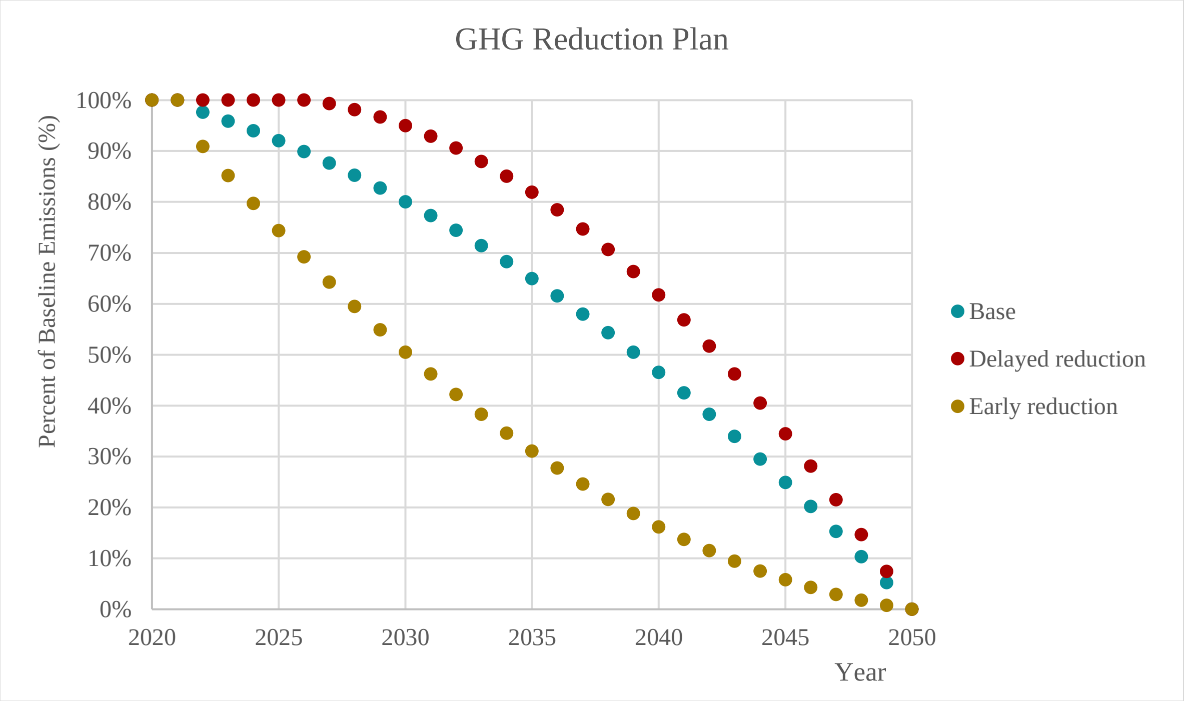

Figure 4-3 GHG reduction paths

4.3.8.4 Carbon price

Three scenarios for carbon price during the analysis period are included in the model. Base case scenario is based on the current carbon price schedule announce by the Government of Canada, in which carbon price will increase from $50/tonne in 2022 to $170/tonne in 2030 (increasing

$15/tonne per year) and remains at $170/tonne after that [136]. Two additional scenarios for carbon price are included in the model; high and low cases. In high carbon price scenario carbon price will increase to $170/tonne by 2030 and will increase by $10 per year to reach $370/tonne in 2050. In low carbon price scenario, carbon price will remain fixed at $50/tonne after 2022. These two scenarios are aimed to provide lower and upper bounds for the carbon price during the analysis period, and are not based on any specific plans announced by the Government of Canada.

4.3.8.5 Grid emission intensity

Alberta grid emission intensity has declined in the past 5 years as a result of phasing out coal from the power generation sector and increasing the share of renewable electricity for power generation [137]. Grid intensity in 2019 was ~0.57 tCO_2e/MWh [138]. Alberta Electric System Operator (AESO) forecast scenarios are used to estimate grid intensity during the analysis period and include it in the model. Based on the forecast scenario, grid intensity in 2050 will be 0.185 tCO_2e/MWh. Detailed data are provided in Appendix C.

4.3.8.6 Energy and crude price forecast

Price forecast data for NG (in U.S. and Canada), electricity, diluent (condensate), and WTI benchmark are obtained from available forecast reports including Annual Energy Outlook reports published by Alberta Energy Regulator (AER) (ST98), and by U.S. Energy Information Administration [135,139]. Details are provided in Appendix C.

4.3.8.7 Royalty calculation

Oil sands operators pay royalties on the crude bitumen produced in Alberta. Royalty rates for oil sands Royalty Projects (a Royalty Project is an approval issued by the Government of Alberta that allows the oil sands operators to pay royalties under the oil sands royalty regime) are determined based on different factors including oil price, pre-payout and post-payout period of the project, projects costs and revenues [140,141]. According to oil sands royalty guidelines, royalties are calculated based on project gross revenue in pre-payout phase and project net revenue in post-payout phase.

- In the pre-payout phase, the royalty rate is 1% of the gross revenue for WTI price of \$55/barrel or lower, and 9% for WTI price of \$120/barrel or higher. Between \$55/barrel and \$120/barrel, the royalty rate increases linearly with the WTI price from the minimum (1%) to the maximum (9%).
- In the post-payout phase, the royalty rate is 25% of the net revenue for WTI price of \$55/barrel or lower, and 40% for WTI price of \$120/barrel or higher. Between \$55/barrel and \$120/barrel, the royalty rate increases linearly with the WTI price from the minimum (25%) to the maximum (40%).

More details about the oil sands royalty rates can be found in [141].

Since the length of payback period is variable across different oil sands projects, the pre and post-payout periods for each project cannot be accurately predicted. Therefore, a “modified approach” is used to calculate the royalties based on the project’s gross revenue for all projects using a simplified calculation procedure. The data from 2016 to 2020 reporting years are reviewed and a correlation between royalty as a percentage of gross revenue and WTI price is found. Figure 4-4 below shows the modified approach used in this study for calculating oil sands royalties. As shown in this figure, royalty rates range between 6 and 18% of project gross revenue.

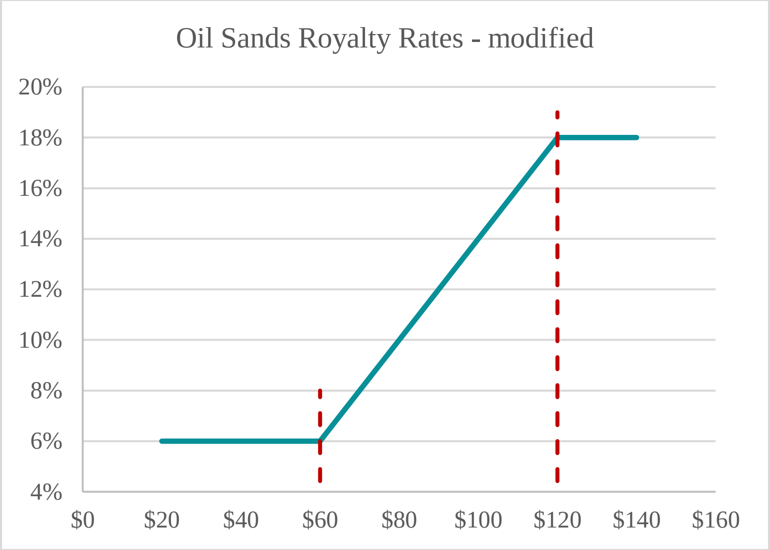

Figure 4-4 Oil Sands Royalty Rates - modified approach

After all the model constraints are added and different cases for input parameters are built into the model, the model described in this section is run with various sets of input parameters and assumptions, then the results of each run are presented, and the impacts of different inputs on the results are discussed in the Results section. Each set of input parameters used to run the model is called a "Scenario". Out of more than 100 scenarios investigated and analyzed, the results of 5 main scenarios (along with a number of sub-scenarios) are presented in the Results section that provide the most interesting insights derived from the analysis. More information on several other scenarios is provided in Appendix C.

4.4 Results and Discussion

This study provides a framework to investigate the effectiveness of emissions reduction solutions and emerging technologies (with lower emission intensity compared to existing technologies) in reducing GHG emissions from oil sands in situ operations and helping oil sands producers reach emissions reduction targets that are in line with Canada’s net-zero pathway by 2050. The results of this study are used to determine the combination of technologies and solutions that provide the best economic performance for in situ oil sands production while achieving emissions reduction that are in line with Canada’s climate plan. The results provide insights about the technologies and solutions in which investments could be made during the analysis period (which is from 2021 to 2050) to provide the highest economic benefit throughout the oil sands supply chain. Decision variables reflect the size and start date of greenfield and retrofit projects as well as the technology pathway for each project. In addition, the required performance parameters for emissions reduction solutions to become economically feasible are investigated.

4.4.1 Scenario 1

Scenario 1 represents the business as usual (BAU) scenario with the set of input parameters as described below. The first set of results is obtained using the assumptions listed below regarding the availability of different technologies:

Availability of different technology categories described in the Methods section is set up in the model as explained below:

1) Incremental improvements technologies (including addition of solvent to steam for extraction and installing carbon capture units) are available to be implemented today,
2) Building upgrading and partial upgrading projects is possible today,
3) Intermediate technologies that are past the demonstration phase will become available for being adopted at commercial scale in 5 years,
4) Breakthrough technologies are not considered a possibility in the future

In Scenario 1 (BAU scenario) implementation of carbon emissions pricing as presently imposed by the Federal and Provincial Governments (base case carbon price scenario explained in the Methods section) is the only mechanism in place to force the transition of oil sands sector towards less emission intensive production methods (i.e., there are no specific caps on emissions). List of the main inputs for scenario 1 is provided below:

- Upstream carbon price: base case
- Downstream carbon price: 0
- Capital investment: base case
- Bitumen production forecast: base case
- CCS capital cost: $60/tonne
- Carbon offset price: 90% of carbon price
- Carbon offset availability: base case

The objective function of the model in Scenario 1 is a linear combination of NPV of all projects (using cash flows for 2021 to 2050), and the "present value of royalties" paid by the producers between 2021 and 2050, referred to as *NPV* and *royalty* respectively, hereafter.

The results of scenario 1 are shown in Figure 4-5. In this figure, the X axis shows the years in the analysis period (2021 to 2050), the left-Y axis shows the volume of bitumen produced by each technology pathway, and the right-Y axis shows the total life cycle emissions, upstream emissions, offset and DAC credits (same axes are used for Figure 4-6 to Figure 4-9 in this section). The technology pathways are shown by stacked area with different colors in the figure. Life cycle and upstream emissions, offset and DAC credits are shown by lines with different colors in the figure. The results show that in the absence of mandatory GHG emissions reduction targets, and with current carbon pricing scenario (increase to \$170/tonne by 2030 and remaining at this level after that), it is economically favorable to build new oil sands projects in 2021 onwards to meet the forecasted bitumen production volumes (which is based on the increased demand for oil sands bitumen production).

New projects that are built before 2025 (when the intermediate technologies are assumed to become ready for adoption at the commercial scale) use solvent-based extraction technology (SA-SAGD) to take advantage of early investment opportunities. Solvent-based extraction technologies offer incremental GHG emissions reduction and efficiency improvement (e.g., lower SOR) to traditional SAGD. Approximately 57% of bitumen produced via SA-SAGD use dilution pathway to produce dilbit and the remaining 43% go through a partial upgrading process to produce partially upgraded bitumen (PUB).

When the intermediate technologies become available in 2025, all the added production capacity is built using those technologies. Roughly 40% of the bitumen production volume by intermediate technologies use dilution and the remaining 60% are coupled with partial upgrading equipped with CCS units.

In addition to the new projects being built in 2021 onwards, 50% of the existing SAGD + dilution (baseline technology pathway, explained in the Methods section) projects are converted to partial upgrading. Overall, the results suggest that installing new partial upgrading units to process bitumen produced from new projects as well as part of the existing bitumen production is an economically attractive option under the assumptions of scenario 1.

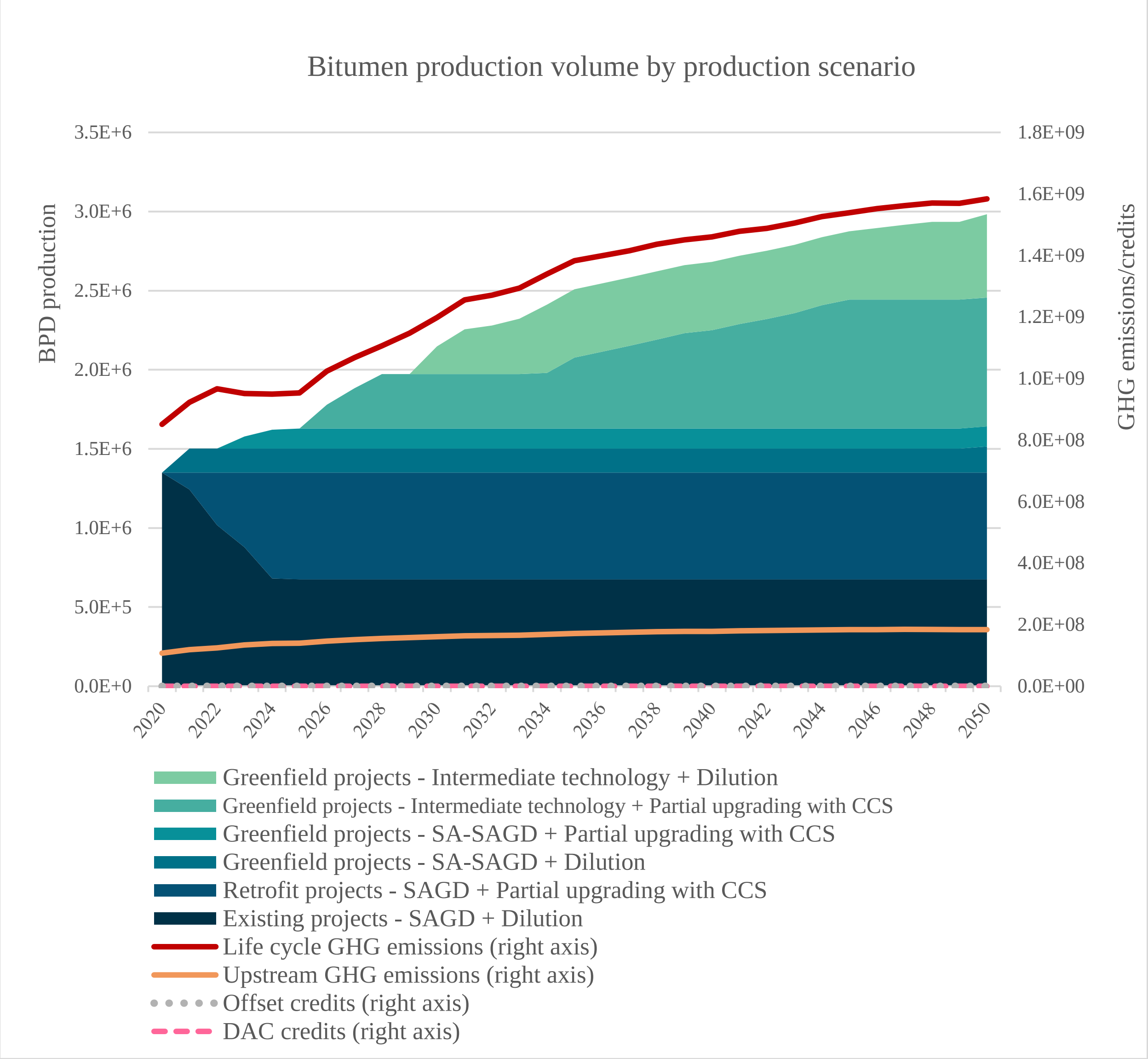

Figure 4-5 Bitumen production pathways under Scenario 1

Using the same input parameters listed for Scenario 1, if the model is run with NPV (which considers total supply chain costs and revenues) as the objective function (i.e., if royalty is excluded from the objective function) (referred to as Scenario 1-1), the mix of technologies implemented for greenfield projects is slightly changed and partial upgrading is adopted more widely for greenfield projects. This is an indication of the better economic performance of partial upgrading pathway compared to dilution when the entire supply chain is considered. The main reason for partial upgrading not being adopted as widely when royalty is maximized (as part of the objective function) is because of the higher cost of partial upgrading that could potentially decrease the total profit generated in Alberta. Even though the share of partial upgrading might decrease when maximizing royalty, it still contributes to 55% of total production capacity at the end of the analysis period (2050), compared to 75% when only NPV is considered. The profit generated per MJ of final transportation fuel is ~10% higher in Scenario 1-1 (when NPV is maximized) compared to Scenario 1 (when NPV and Royalty are maximized) (profit per barrel bitumen is ~7% higher in scenario 1-1 compared to Scenario 1). Total bitumen production growth remains almost the same (~2% decrease) in Scenario 1-1 compared to Scenario 1. Detailed results are presented in Appendix C.

If availability of the intermediate technologies for adoption at commercial scale is delayed (to 2030 instead of 2025) (Scenario 1-2), it results in the wider utilization of SA-SAGD technology coupled with partial upgrading with CCS for building new projects prior to 2030 and a smaller share of the intermediate technology in total production capacity in 2050. Delaying investment and waiting for a new technology to become ready for adoption does not provide economic benefits unless the new technology offers more than 25% reduction in cost per barrel of bitumen produced.

4.4.2 Scenario 2

In the next step, the impact of implementing mandatory emissions reduction targets (i.e., by putting a cap on the total emissions from oil sands sector to achieve the ambitious net zero goal by 2050) on direct upstream emissions are examined (direct emissions occurring in Canada). In this scenario, the CO_2 removal technologies (i.e., Direct Air Capture (DAC)) are assumed to be employed to remove emissions from the atmosphere (negative emissions) to compensate for any GHG emitted to the atmosphere from oil sands upstream operations. In addition, emissions offset credits (generated from other emissions reduction projects that are eligible for offset credit generation in Alberta) can be purchased by oil sands producers to offset (part of) the GHG emitted to the atmosphere. Because of the limited amount of offset credits generated in the province, a limit is put on the amount of offset credits that can be purchased by oil sands producers to offset GHG emissions. The limits on offset credits is further explained in Appendix C. Price of offset credits are determined based on the regulated carbon price. The offset credits are assumed to be sold at 10% discount to the prevailing carbon price (consultation with industry experts). Other assumptions for Scenario 2 are similar to Scenario 1.

The results, presented in Figure 4-6, show that after adding the emissions reduction targets to the model constraints, when maximizing NPV, total bitumen production volume at the end of the analysis period will be smaller than Scenario 1. The reason is that implementing low emissions intensity technologies is not sufficient to achieve the net zero targets, because the emissions reduction technologies (e.g., CCS) are not 100% effective and a portion of emissions will remain that must be eliminated in some way. Offset credits and CO_2 removal technologies can be employed to eliminate the remaining emissions after available emissions reduction technologies are implemented. Offset credits are utilized first because they have lower cost. DAC technologies have not been adopted at large scale yet, mostly because of the high cost of the technology. The cost of DAC in the model is \$340/tonne (there is a wide range of cost per tonne CO_2 removal in the literature, which is between \$140 to \$500/tonne. In this study a

$340/tonne is used based on a comprehensive study published in 2018 by Keith et al. [124]), but it’s expected to reduce as the technology improves and gets more widely adopted. The high cost of the DAC solutions slows down the production growth and even results in shutting down part of the existing production. The results also show that part of the existing production is retrofitted from dilution to partial upgrading with CCS starting 2021, and greenfield projects are started as soon as the intermediate technologies become available in 2025. In the late 2020s, production volume from the existing SAGD + Dilution projects start to decline while the projects that adopted intermediate technologies are expanded. The results indicate that with high cost DAC being the only option to reduce total direct emissions to zero in 2050 (in the present model, offset credit are available for purchase during the first half of the crediting period (2021-2035), but as the regulations become more stringent, less offset credits are generated across different projects), deployment of the lower emission intermediate technologies in the late 2020s (by building new projects) is economically more attractive than keeping the high emission intensity existing projects.

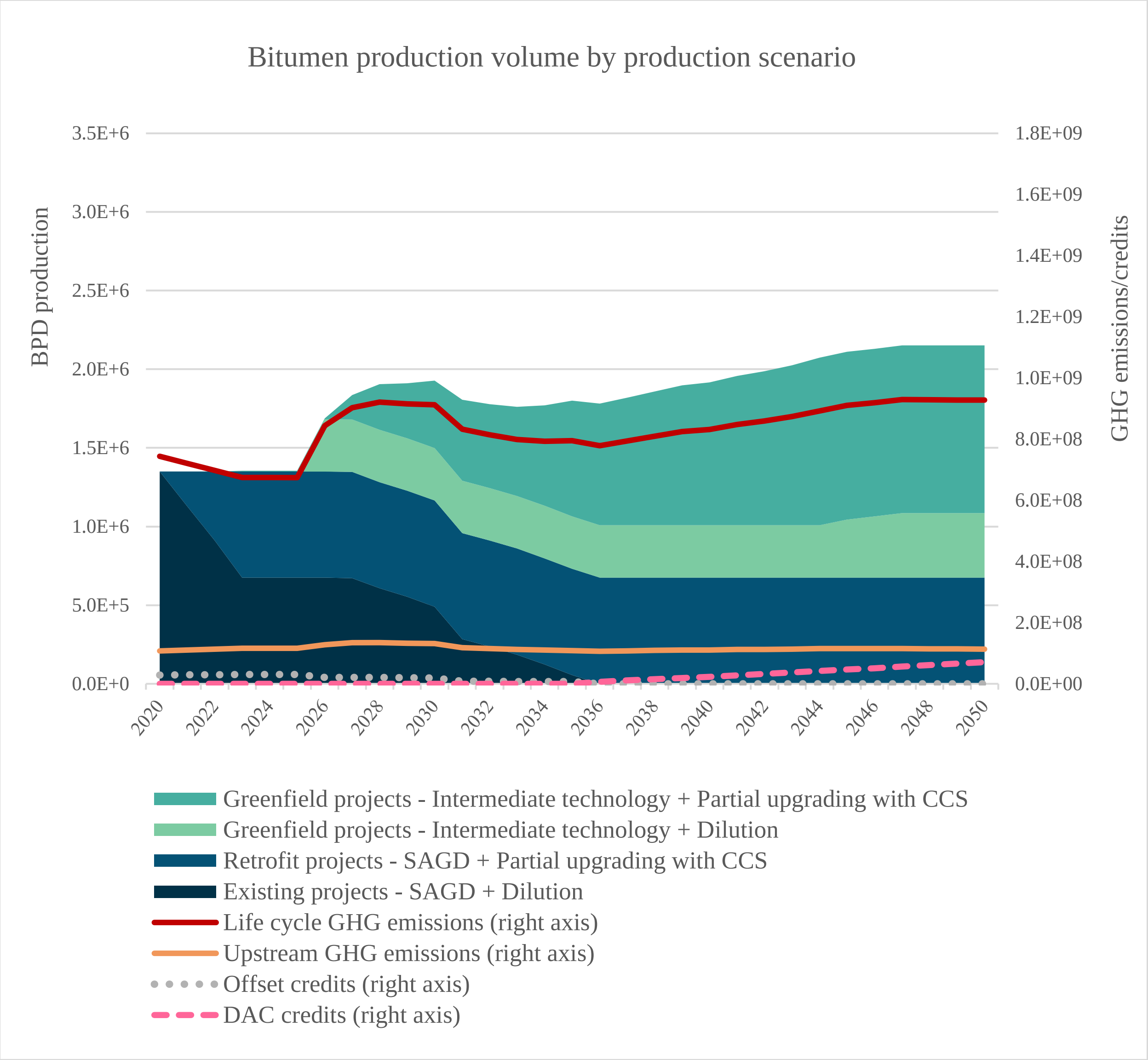

Figure 4-6 Bitumen production pathways under Scenario 2

There is a limit in the model for the total annual capacity of the new projects that are built in 2021 onwards. If the potential new projects built in 2021 onwards are assumed to replace the existing production capacity (capacity of the existing projects) to go beyond the aforementioned capacity limit in the model (scenario 2-1), total production can increase more than what is shown in Figure 4-6, up to the levels shown in Figure 4-5. This means that with intermediate technologies offering lower emission intensity per barrel of bitumen produced (compared to existing SAGD + dilution), total production can increase even with a cap on total emissions and at high DAC cost. However, there is a difference in the contribution of technologies to the total production. While in scenario 1 intermediate technologies contribute to ~45% of total production in 2050, in Scenario 2-1 (considering the assumptions explained above) that contribution is increased to 70% and investment in new projects is delayed until the intermediate technologies become available. The NPV per barrel of bitumen produced is ~10% lower in scenario 2-1 compared to Scenario 1.

If the availability of intermediate technology for adoption at commercial scale is delayed to 2030 while the rest of the assumptions from Scenario 2-1 are kept (Scenario 2-2), contribution of intermediate technology is decreased to 50% (compared to 70% in Scenario 2-1) and SA-SAGD contributes 20% of total production (increased from ~5% in Scenario 2-1). This means that a portion of the investment in new projects is shifted from the intermediate technology to the proven SA-SAGD technology to benefit from the opportunities of early investment. However, even though investing in SA-SAGD will provide the best economic performance under the assumptions of Scenario 2-2, NPV per barrel of bitumen produced is ~12% lower than Scenario 2-1.

Under the assumptions used for Scenario 2, if DAC cost decreases as more projects are deployed (Scenario 2-3), at approximately \$100/tonne, it will become economically feasible to deploy DAC to compensate for the remaining emissions from existing production and production decline will not be necessary to achieve the net zero target in 2050 (details are presented in Appendix C).

Based on the results of Scenarios 2-2 and 2-3, there are two sets of conditions that allow for total oil sands production volume to be maintained and/or to increase by building new projects all the way through 2050:

1) If existing production capacity that has been shut down is replaced with new projects that employ intermediate technologies that are assumed to become available for adoption at commercial scale between 2025 and 2030.
2) If the cost of Direct Air Capture is reduced to below $100/tonne.

Both of these sets of conditions are associated with high levels of uncertainty. However, the result of the analysis can be used to help identify the area of research to focus on as well as the level of technological improvement required for oil sands production to remain economically feasible under stringent environmental regulations.

Under the assumptions of Scenario 2, if the objective function is changed from maximizing NPV to maximizing NPV + royalties (Scenario 2-4), even at $500/tonne for DAC, production growth is similar to scenario 1 (even with the mandatory emissions reduction targets). The reason is that to maximize royalty as part of the objective function, increasing total production is favorable even at lower profit margins. In this scenario, NPV is ~50% lower than scenario 1 (per bbl bitumen and per MJ of transportation fuel). Therefore, the projects might not be economically attractive, but they provide the highest revenue for Alberta public.

4.4.3 Scenario 3

For Scenario 3, a breakthrough technology is assumed to become available for deployment at commercial scale in 2035. At high cost (cost levels explained in the methods section), the technology will not be adopted even after 2035. The results show that it would make more sense to invest in intermediate technologies earlier and expand those later rather than delaying investment for the breakthrough technology to become available. This will not change even if implementing emissions reduction targets are delayed. However, at medium cost (i.e., ~20% higher than the average cost of current oil sands), delaying part of the investment in intermediate technologies until the breakthrough technologies become available becomes a potentially favorable option (Scenario 3-1). Breakthrough technology can contribute to up to 17% of the total added production capacity between 2021 and 2050. The results of this scenario is presented in Figure 4-7.

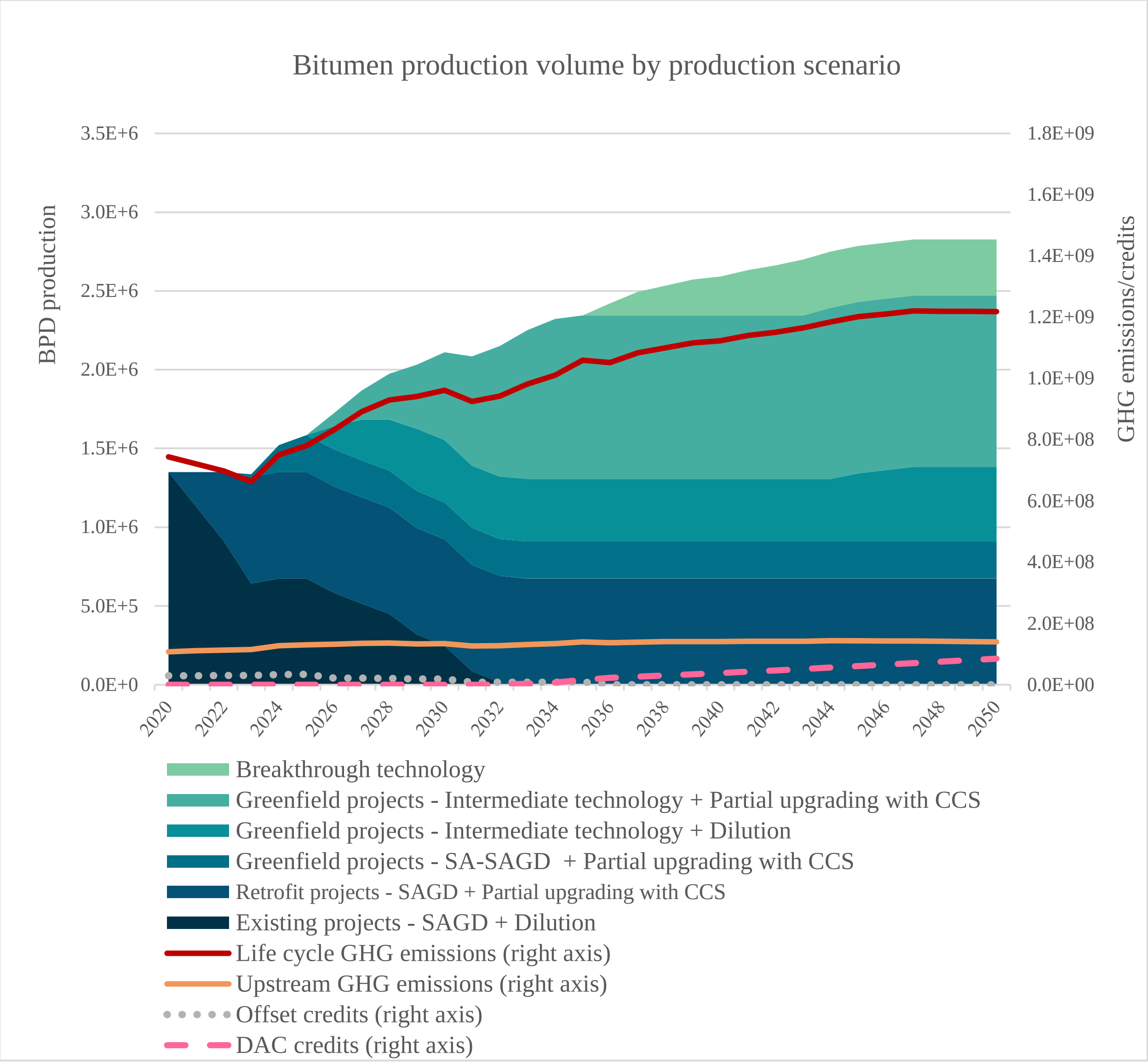

Figure 4-7 Bitumen production pathways under Scenario 3-1

4.4.4 Scenario 4

In this scenario the impact of implementing mandatory emissions reduction targets for both upstream and downstream direct emissions are explored. Reducing downstream emissions can be achieved by installing CCS on refineries (with constraints such as the percent reduction achievable by CCS technology), or by employing CO_2 removal technologies (DAC) to compensate for GHGs emitted to the atmosphere, or by reducing production if capture technologies are economically infeasible. The results show that to maximize profit (considering the entire supply chain costs and revenue), even at \$100/tonne cost of DAC, maintaining current production is not economically feasible. The reason is that end-use emissions (as part of downstream direct emissions) represent ~65-80% of the total supply chain emissions, and offsetting that amount of GHG emissions by DAC will impose such high cost to the supply chain that makes the production uneconomic. The cost of DAC must be at most ~\$2/tonne for the production to become economically feasible, which doesn't seem to be possible even after the potential future improvements and wide deployment of the DAC technology that could lead to a reduction in the cost of CO_2 capture.

If end-use emissions are excluded from the downstream emissions and only consider refining and transport emissions are considered (Scenario 4-1), existing projects can continue production and even new projects can be built. So, if oil sands products are to be used for end-use purposes other than combustion (e.g., petrochemicals) it might be possible to see an increase in oil sands demand while staying compliant under a net zero scenario, assuming the cost of DAC would go down to ~\$100/tonne in the next 5-10 years. Figure 4-8 below shows the results of Scenario 4-1.

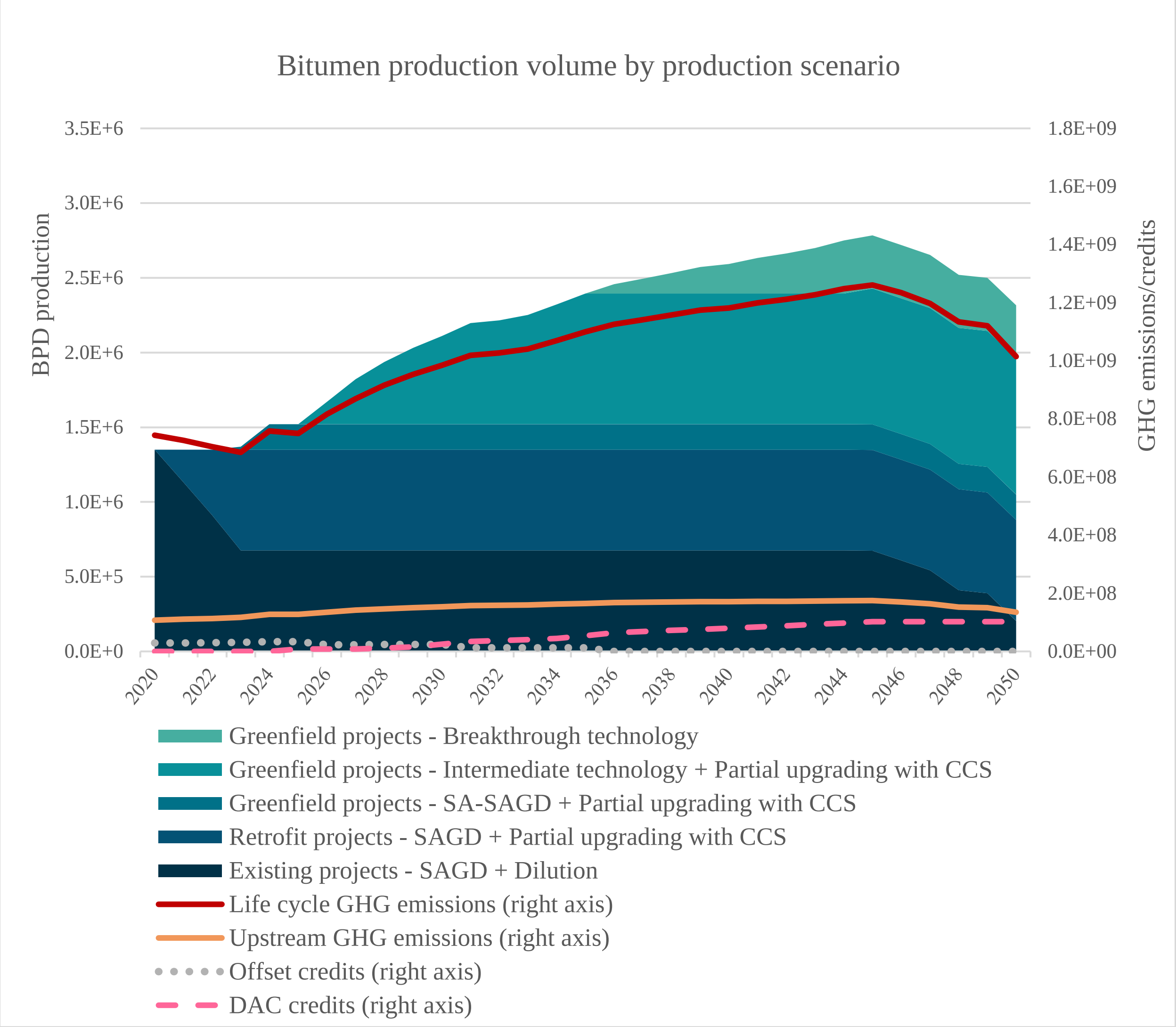

Figure 4-8 Bitumen production pathways under Scenario 4-1

Using the same assumptions as scenario 4-1, if the possibility of additional available capacity for building new projects is considered when existing projects are shut down (Scenario 4-2), the results show that replacing existing production by building new projects that employ intermediate or breakthrough technologies provides slightly higher NPV per barrel of bitumen extracted and per MJ of transportation fuel produced (5% and 7% respectively). In addition, in Scenario 4-2, total production in 2050 is 15% higher than Scenario 4-1, mainly because the existing SAGD + Dilution projects will eventually need to partially shut down (starting in 2045) to meet the zero emissions target in 2050, and investing in building new projects using intermediate and breakthrough technologies at that time is not economically favorable. Figure 4-9 shows the results of scenario 4-2.

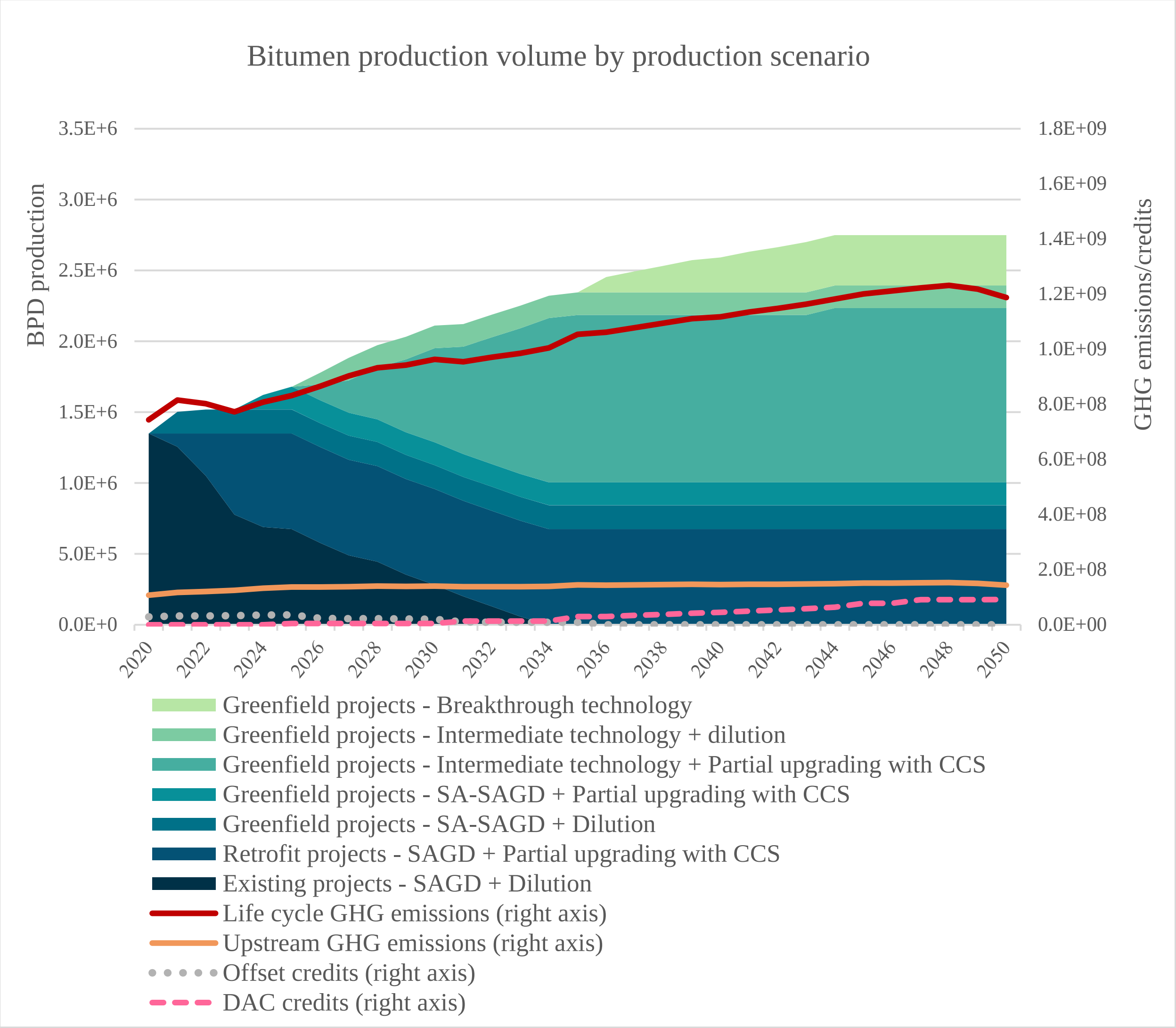

Figure 4-9 Bitumen production pathways under Scenario 4-2

4.4.5 Scenario 5

In the next scenario, the impact of reduced demand for oil sands crudes on the potential production pathways is investigated. As countries that import Canadian crude oil move towards reducing their direct GHG emissions by transitioning their energy system (i.e., replacing fossil fuels with renewable and other low carbon fuels (e.g., hydrogen and biofuel)), demand for Canadian crude could diminish. In this scenario, the cost of DAC is set at $340/tonne, and other assumptions are similar to Scenario 3. To maximize NPV in a low demand scenario half of the existing SAGD + Dilution pathway is converted to SAGD + Partial upgrading, and new projects utilizing SA-SAGD and Partial upgrading are built to supply the additional crude needed in the first few years, and the remaining demand is satisfied by building new projects employing intermediate technologies when the technologies become available.

If the shut down capacity of existing projects are assumed to be replaced with new projects that employ intermediate technologies (Scenario 5-1), a higher NPV is obtained if existing projects are slowly replaced by new projects employing emerging technologies. This will increase the NPV by ~6% on a per barrel of bitumen basis, so if other barriers could be encountered for shifting from existing to intermediate technology that are not considered in the model, the 6% improvement in NPV might not provide enough incentive to shut down existing projects and build/expand new projects to replace them.

4.4.6 Other scenarios

Several other input parameters are investigated in this section and a summary of the main findings regarding how they impact the results are presented here.

Modifying the refining capacity constraint does not impact the technology pathway selection under most scenarios. For example, even when the majority of the available refining capacity is deep conversion refining (suitable for heavy crude oils), it won’t shift the production pathway towards producing more heavy crude (i.e., dilbit) instead of medium crude (i.e., partially upgraded bitumen). On the other hand, changing available transportation capacity can impact the result in some cases. For example, with limited pipeline transport capacity available, upgrading and partial upgrading pathways are preferred over dilution. The reason is diluent that is mixed with dilbit to make it ready for pipeline transport, takes pipeline space and is then separated from bitumen at the refinery and shipped back to Canada, and is not converted to useful products, while in PUB and SCO case, the whole transported crude is processed in the refinery and turned into useful products.

Modifying the capital investment constraint in the model impacts the mix of technology pathways in different scenarios. The results show that when more capital is available, more partial upgrading capacity is built and the contribution of dilution pathways decrease. This result is consistently seen across different scenarios.

Based on the results of different scenarios, it is observed that retrofitting the existing projects to use CCS (either by installing CCS for SAGD projects or by switching from dilution to partial upgrading equipped with CCS) seems to be a more cost effective option for reducing emissions than retrofitting to SA-SAGD. Retrofitting SAGD to SA-SAGD is a low cost option, however, the emissions reduction impact is not sufficient to achieve the reduction targets and CCS will still be required to achieve those targets. In other words, if one of the retrofit options between SA-SAGD and CCS had to be selected, going with CCS seems to be more economically favorable in the long term considering the strict reduction targets. On the other hand, SA-SAGD is the best technology option for new projects that are built before intermediate or breakthrough technologies become available.

The contribution from employing low emission intensity technologies (e.g., SA-SAGD, CCS, intermediate and breakthrough technologies) and direct air capture in reducing direct upstream GHG emissions below business as usual case (SAGD + dilution) is investigated across all scenarios. The results show that each emissions reduction solution (low emission technologies and DAC) contribute to ~50% of the total reduction on average. At the low range of DAC cost considered in different scenarios (i.e., \$100/tonne), contribution of DAC to total emissions reduction can increase to 65% (from 50%).

4.5 Conclusions

Growing concerns over the climate change impacts of fossil fuels in Canada and in the world have put great pressure on oil sands producers to reduce GHG emissions from their operation and the entire oil sands supply chain. Oil sands producers need to utilize emissions reduction solutions in order to keep their products as competitive alternatives in the future low-carbon (or zero-carbon) energy systems. Various emissions reduction solutions have been developed or are under development that can be used to reduce GHG emissions from oil sands operations. The choice of the optimum reduction solution(s) is complicated by the technology performance parameters and external drivers. This study provides a framework to evaluate several emissions reduction solutions applicable to oil sands operations and how they can be used to help oil sands producers achieve voluntary/mandatory emission reduction targets.

The results of the study show the scale of adoption for intermediate and breakthrough technologies is impacted by the technology cost and the year the technologies become ready for adoption at commercial scale. For example, under most scenarios, delaying investment in available technologies (such as SA-SAGD) until intermediate technologies become available is not economically justified, unless the cost of intermediate technologies are more than 25% lower than available technologies on average.

When mandatory emission reduction targets are set on direct upstream emissions with a net-zero target in 2050, part of the existing projects must be shut down in order to achieve those targets. However, if the cost of DAC technologies is reduced to ~$100/tonne by 2030), negative emissions could help maintain production from existing projects. If emission reduction targets are set on direct emissions from the entire supply chain (upstream and downstream including end-use), the high cost of negative emissions required to compensate end-use emissions (from the combustion of refinery products, that contribute to ~65-80% of total supply chain emissions) makes the operations economically infeasible, even at low cost of negative emissions. In other words, with a net-zero target on total supply chain emissions, producing transportation fuels from oil sands crudes becomes very expensive to the point that the products will not be able to compete with other low- or zero-emission energy sources (such as renewable electricity).

Investing in partial upgrading facilities is an economically favorable decision across different scenarios. For most of the new projects and all the retrofit projects, partial upgrading is selected as part of the technology pathway. Compared to dilution pathways, partial upgrading provides the advantage of lower pipeline capacity requirement as well.

The framework developed in this study can be used to inform short- and long-term investment decision making in oil sands sector under various scenarios with different combinations of input parameters including technology availability, technology performance parameters and how they evolve over time, crude oil and transportation fuel demand forecast, energy price forecast, transport and refining capacity for target markets, future environmental policy scenarios.

Chapter Five: **Conclusions and Future Work**

This thesis investigates potential improvements in the economic and environmental performance of oil sands operations by applying a set of process analysis and systems analysis tools including process integration (PI), life cycle assessment (LCA) and mathematical optimization techniques. Two types of improvements are investigated; 1) incremental improvements within existing technologies by increasing the efficiency of the operations (Steam Assisted Gravity Drainage (SAGD) technology is studied for efficiency improvements) using process integration methods, and 2) improvements achieved by technology substitution and employing emissions reduction solutions that capture CO_2 emissions using a combination of life cycle assessment and mathematical optimization methods. Improving the economic and environmental performance of oil sands operations is critical for oil sands products to remain competitive alternatives in the low emission intensity energy markets that are anticipated to emerge as a response to the growing climate change concerns.

Chapter 2 investigates different technology options within SAGD surface facilities and the impacts of each technology on GHG emissions, water consumption, and cost. The analysis completed in Chapter 2 shows that there is a potential to reduce the total cost of SAGD operations by $5.1 to $7.4 million/year by applying water and heat integration to SAGD central processing facilities. This help achieve 7.0% to 8.2% reductions in the total cost of the system. Operating cost savings have a larger contribution to the total cost savings compared to capital cost. The main driver of the operating cost savings is the decrease in NG consumption in the boiler (for example in case 1, the contribution of operating cost and capital cost savings are 82% and 18% of the total cost savings respectively). In case 4 where a drum boiler is used for steam generation, the lowest potential for cost savings is observed among all cases. This is because of the smaller volume of boiler blowdown that consequently provides less potential for heat recovery in the system.

Trade-offs between water consumption, GHG emissions, and cost must be considered when choosing between different technology options. In cases 3 and 4, using an evaporator for produced water treatment would increase the GHG emissions in the system by approximately 12.5% compared to case 2 in which the boiler blowdown is recycled. On the other hand, water consumption in cases 3 and 4 are reduced compared to case 2. Overall, when an evaporator is used for water treatment, case 2 provides a better balance between water consumption, GHG emissions, and cost compared to cases 3 and 4.

The results of the sensitivity analysis show that total profit can potentially increase when an OTSG and an evaporator are used in the system by modifying the OTSG to generate steam with higher quality. This results in a higher bitumen production rate with a small increase in total cost because of the additional NG consumption in the boiler.

In Chapter 3, a more comprehensive approach is used to evaluate the potential improvements in SAGD operations (in addition to the incremental improvements achieved in Chapter 2) in the context of the entire supply chain and by implantation systems analysis methods.

Chapter 3 provides a framework to evaluate emerging oil sands technologies considering uncertainties associated with their performance at pre-commercial stage. The results show that all three emerging technologies investigated in this chapter (SA-SAGD, Partial upgrading, and ISEU) have the potential to improve the oil sands operation. The conditions that make each technology a competitive alternative for oil sands production are identified and explained in detail in Chapter 3.

Converting SAGD to SA-SAGD offers improvements in both economic and environmental performance of the operations, but the magnitude of changes is small. There is an advantage in improving the performance of the operations without imposing significant changes to the process and with little or no increase in the required capital cost, because it reduces the usual risks associated with adopting a new technology. On the other hand, since the change from SAGD to SA-SAGD does not change the quality of the crude bitumen product, it does not provide any new market opportunities for the product of the new technology.

Building a partial upgrader to replace bitumen dilution can improve the economic performance of the operations, but not necessarily the environmental performance. Partial upgrading will likely improve both economic and environmental performance of oil sands operations compared to full upgrading. Adopting partial upgrading technologies creates significant changes to the process of oil sands production by adding/changing a major step in the operations (adding a major step compared to dilution scenario, and changing a major step compared to full upgrading scenario). Capital investment is required for adopting this technology which will increase the risks of the technology uptake. On the other hand, the product of this technology has higher quality than dilution scenario which can provide new market opportunities for oil sands production. In addition, it can be beneficial to the Canadian producers to generate an added value product in the province of Alberta (that can improve the profit margin for the Canadian producers) instead of exporting low quality dilbit to the destination refineries.

In situ extraction and upgrading technology offers improvements in the economic and environmental performance of the operations as well (under some conditions). Similar to partial upgrading, ISEU creates significant changes to the entire operations by introducing a completely different in situ extraction method (compared to SAGD) that eliminates the need for steam generation and uses vacuum residue as the extraction agent. This technology offers the opportunities associated with creating a different quality product (although the product is still of lower quality compared to partial or full upgrading) as well which can be beneficial by creating diversity in the potential markets. On the other hand, adopting this new technology is associated with higher risk that partial upgrading and SA-SAGD as it is not similar to any of the previously deployed technologies for oil sands production.

The results of Chapter 3 help the oil sands producers understand the supply chain impacts of adopting new technologies and the new technologies' potential to keep the oil sands competitive in the global market. Close-to-commercial technologies investigated in this chapter show promise to reduce cost and emissions, and could all become viable options. However, on a life cycle basis this is modest compared to long term climate goals, so additional technologies must be developed and deployed. This framework can be adapted to represent the increased uncertainty associated with earlier stage technologies.

In Chapter 4, additional external constraints are added to the framework developed in Chapter 3 and a broader set of emissions reduction solutions are evaluated. In addition, a time component is added to the model that allows the model to expand and include a 30-year period in the analysis. In Chapter 4, uncertainties associated with the performance of emerging technologies are not directly implemented in the model using probability distributions, rather those uncertainties and their impacts on the oil sands supply chain are investigated through the analysis of various technology scenarios.

The results of Chapter 4 show the scale of adoption for intermediate and breakthrough technologies is impacted by the technology cost and the year the technologies become ready for adoption at commercial scale. For example, under most scenarios, delaying investment in available technologies (such as SA-SAGD) until intermediate technologies become available is not economically justified, unless the cost of intermediate technologies are more than 25% lower than available technologies on average.

When mandatory emissions reduction targets are set on direct upstream emissions with a net-zero target in 2050, part of the existing projects must be shut down in order to achieve those targets. However, if the cost of DAC technologies is reduced to ~$100/tonne by 2030), negative emissions could help maintain production from the existing projects. If emission reduction targets are set on direct emissions from the entire supply chain (upstream and downstream including end-use), the high cost of negative emissions required to compensate end-use emissions (from the combustion of refinery products, that contribute to ~65-80% of total supply chain emissions) makes the operations economically infeasible, even at low cost of negative emissions. In other words, with a net-zero target on total supply chain emissions, producing transportation fuels from oil sands crudes becomes very expensive to the point that the products will not be able to compete with other low- or zero-emission energy sources (such as renewable electricity).

Investing in partial upgrading facilities is an economically favorable decision across different scenarios. For most of the new projects and all the retrofit projects, partial upgrading is selected as part of the technology pathway. Compared to dilution pathways, partial upgrading provides the advantage of lower pipeline capacity requirement as well.

Carbon capture and utilization/storage expectedly plays an essential role in helping oil sands projects comply with emissions reduction targets. More than 75% of the new production from oil sands (from 2021 onwards) must adopt technologies that would either rely on low-emission (or zero-emission) electricity as the main source of energy (for example the emerging technologies that use electricity instead of fuel combustion) or are equipped with carbon capture technology from the start, in order to satisfy the expected mandatory emissions reduction targets. Part of the emissions that are not captured from the start of the project would need to be offset by negative emissions (e.g., direct air capture) as the reduction targets become more stringent towards the end of the analysis period (year 2050).

While carbon capture technology and low-emission electricity provide solutions for reducing emissions associated with oil sands extraction and processing, end-use emissions of oil sands products (e.g., combustion of transportation fuels) still pose a great challenge to the oil sands projects (and more broadly fossil fuel production) in a carbon-constrained world. Offsetting end-use combustion emissions using direct air capture is economically infeasible. Therefore, it is of utmost importance for oil sands producers to consider other potential end-use for their products (other than the combustion of transportation fuels) when evaluating new oil sands projects (and the risk of oil sands projects becoming stranded assets). Other potential end-use for oil sands products can be investigated in future work.

The framework developed in Chapter 4 can be used to inform short- and long-term investment decision making in oil sands sector under various scenarios with different combinations of input parameters including technology availability, technology performance parameters and how they evolve over time, crude oil and transportation fuel demand forecast, energy price forecast, transport and refining capacity for target markets, future environmental policy scenarios.

The analysis frameworks and results presented in Chapters 2 to 4 of this thesis present a new set of tools that can be used for evaluating oil sands operations from different perspectives and to inform government, industry and policy decision making about the emissions reduction and economic improvement solutions for oil sands operations. As part of the future work, it is recommended to evaluate oil sands operations performance against other low emissions energy system scenarios, such as biofuels, electricity and hydrogen or a combination of those, using similar frameworks developed in this thesis.

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Appendix A: Supporting Information I

A.1. Constraints of the mathematical model

Overall mass balance[12]

$$\sum_{s} F_s - F^{BFW} = \sum_{tu} F_{tu}^{loss} \tag{1}$$

Mass balance around splitters and mixers

$$F_s = \sum_{tu} F_{s,tu} \qquad \forall\, s \in S \tag{2}$$

$$\sum_{s} F_{s,tu} + \sum_{tu'} F_{tu',tu} = F_{tu}^{in} \qquad \forall\, tu \in TU \tag{3}$$

$$F_{tu}^{out} = \sum_{tu'} F_{tu,tu'} + F_{tu}^{exit} \qquad \forall\, tu \in TU \tag{4}$$

$$\sum_{tu} F_{tu}^{exit} = F^{BFW} \tag{5}$$

Mass balance of each treatment unit

$$F_{tu}^{in} - F_{tu}^{out} = F_{tu}^{loss} \qquad \forall\, tu \in TU \tag{6}$$

Component mass balance in each treatment unit

$$\left(1 - RR_{tu,c}\right) * ML_{tu,c}^{in} - ML_{tu,c}^{out} - F_{tu}^{loss} * C_{tu,c}^{loss} = 0 \qquad \forall\, tu \in TU\,, c \in C \tag{7}$$

$$ML_{tu,c}^{in} - ML_{tu,c}^{out} - ML_{tu,c}^{rem} - F_{tu}^{loss} * C_{tu,c}^{loss} = 0 \qquad \forall\, tu \in TU\,, c \in C \tag{8}$$

Equations (9) and (10) show the mass balance for each contaminant in each treatment unit when the performance of the treatment unit is specified by a fixed removal ratio and a fixed outlet concentration respectively.

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[12] All mass balance equations are for water and the contaminants.

Definition of inlet and outlet mass loads of contaminant c in treatment units

$$\sum_{tu'}\left(F_{tu',tu} * C_{tu,c}^{out}\right) + \sum_{s}\left(F_{s,tu} * C_{s,c}\right) - ML_{tu,c}^{in} = 0 \qquad \forall\, tu \in TU\,, c \in C \tag{9}$$

$$C_{tu,c}^{out} * \left(\sum_{tu'} F_{tu',tu} + \sum_{s} F_{s,tu} - F_{tu}^{loss}\right) - ML_{tu,c}^{out} = 0 \qquad \forall\, tu \in TU, c \in C \tag{10}$$

Concentration limit for inlet stream to treatment units

$$ML_{tu,c}^{in} \leq C_{tu,c}^{in,max} * F_{tu}^{in} \qquad \forall\, tu \in TU, \quad c \in C \tag{11}$$

Discharge concentration limit to meet boiler feed water quality requirements

$$\sum_{tu}\left(F_{tu}^{exit} * C_{tu,c}^{out}\right) \leq C_{c}^{target} * \sum_{tu} F_{tu}^{exit} \qquad \forall\, c \in C \tag{12}$$

Total mass load of contaminant c to be removed from the system

$$\sum_{tu} ML_{tu,c}^{rem} + \sum_{tu}\left(RR_{tu,c} * ML_{tu,c}^{in}\right) \geq ML_{c}^{rem} \qquad \forall\, c \in C \tag{13}$$

$$ML_{c}^{rem} = \sum_{s} F_{s} * \left(C_{s,c} - C_{c}^{target}\right) \qquad \forall\, c \in C \tag{14}$$

Cost of treatment units

$$Cost_{tu}^{tot} = Cost_{tu}^{var} * F_{tu}^{in} + Cost_{tu}^{fix} \qquad \forall\, tu \in TU \tag{15}$$

The mathematical model described above is a nonlinear problem (NLP). Nonlinearities are in the form of bilinear terms in equations (11), (12) and (14) where both flow rate and concentration are unknown variables.

Binary variables are added to the model to represent if a treatment process is selected by the optimization model to reach the minimum cost (or energy consumption) or not (the binary variable associated with a treatment unit assumes the value of “1” if the treatment unit is selected in the water treatment system and assumes the value of “0” if it is not selected). Binary variables are also used to assign upper and lower bounds to the streams flow rates. By adding additional constraints including binary variables, the problem is converted to a mixed-integer non-linear (MINLP) problem. Additional constraints including binary variables are presented here:

Eliminating the cycles

$$B_{tu,tu'} + B_{tu',tu} \leq 1 \qquad \forall\, tu \text{ and } tu' \in TU \;\; (tu \neq tu') \tag{16}$$

Assigning upper and lower bounds to the streams flow rate

$$F - B * Bound^{up} \leq 0 \tag{17}$$

$$F - B * Bound^{low} \geq 0 \tag{18}$$

This constraint is applied to all streams (F variables and corresponding binary variable) in the model. The maximum flow rate that can exist in the system is the sum of all inlet streams (water sources) as shown in Equation (21). The minimum flow rate is defined based on the system specifications.

$$Bound^{up} = \sum_{s} F_s \tag{19}$$

The MINLP model is divided into two simpler sub-models: mixed integer linear programming (MILP) model and linear programming (LP) model by introducing a penalty function and projection and relaxation approaches. MILP and LP models are solved iteratively to reach an optimal solution which is then used as an initial point for MINLP problem. Then the MINLP problem is solved to find the optimal solution.

A.2. Total cost savings

Table A-1 Total cost savings associated with water and heat integration in SAGD process ($/year)

	Capital Cost Savings ($/yr)	Operating Cost Savings ($/yr)	Total Cost Savings ($/yr)
Case 1	9.02E+05	5.80E+06	5.12E+06
Case 2	1.16E+06	6.00E+06	6.30E+06
Case 3	1.47E+06	7.03E+06	7.42E+06
Case 4	1.56E+06	7.33E+06	3.92E+06

Table A-2 Total cost savings associated with water and heat integration in SAGD process ($/bbl)

	Capital Cost Savings ($/bbl)	Operating Cost Savings ($/bbl)	Total Cost Savings ($/bbl)
Case 1	0.13	0.60	0.73
Case 2	0.17	0.73	0.90
Case 3	0.27	0.79	1.06
Case 4	0.22	0.34	0.56

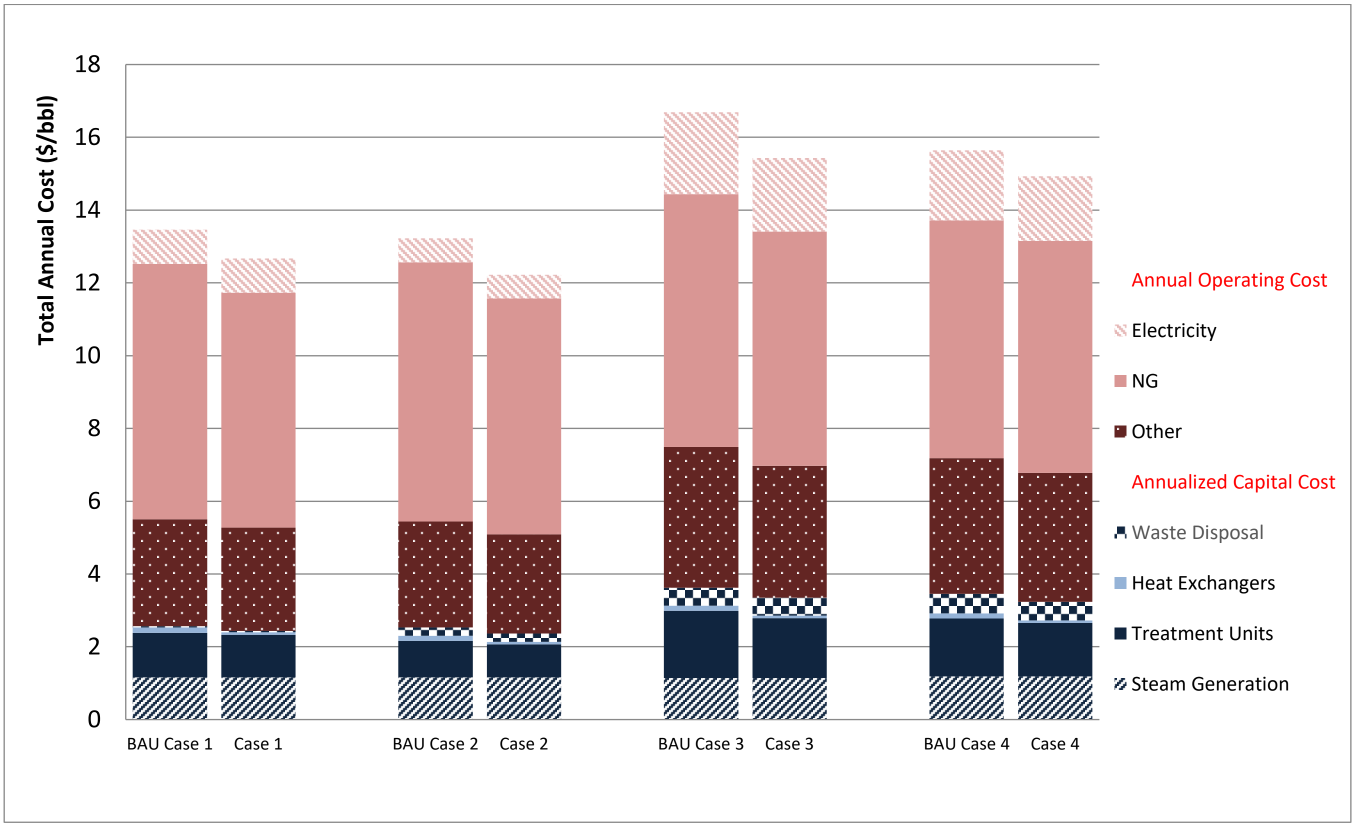

Figure A-1 Total annual cost before and after water and heat integration for each case

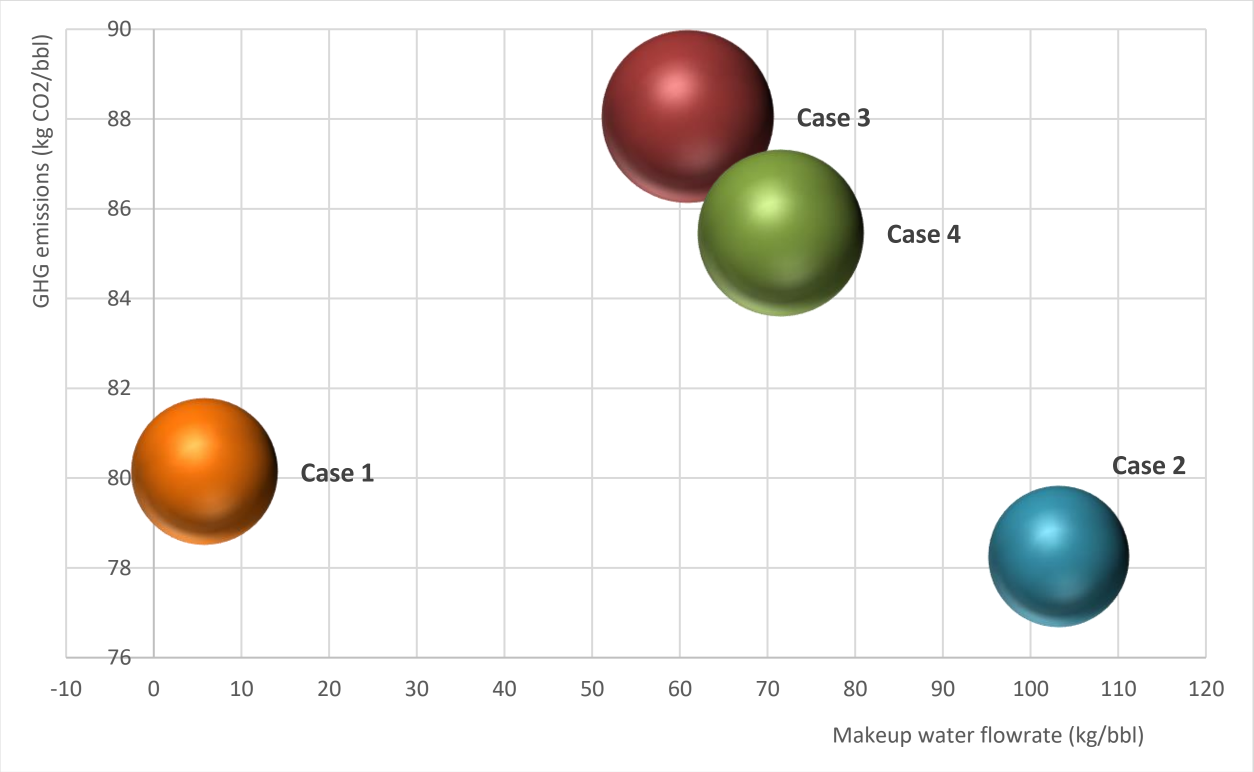

Figure A-2 Cost, water, GHG emissions across four cases after water and heat integration

A.3. Nomenclature

Index

c	contaminant
tu	treatment unit
s	water source

Parameters

Flow rates

F_s	Flow rate of water source s ∈ S
F_{tu}^{loss}	Flow loss in treatment unit tu ∈ TU
F^{BFW}	Boiler feed water flow rate

Concentrations

$C_{s,c}$	Concentration of contaminant c ∈ C in water stream s ∈ S
$C_{tu,c}^{out,fix}$	Fixed outlet concentration of contaminant c ∈ C from treatment unit tu ∈ TU
$C_{tu,c}^{in,max}$	Maximum allowable inlet concentration of contaminant c ∈ C to treatment unit tu ∈ TU
$C_{tu,c}^{loss}$	Contaminant c concentration of stream that is lost in treatment unit tu ∈ TU
C_c^{target}	Target concentration required at discharge
$C_{s,tu,c}$	Concentration of contaminant c ∈ C in the stream between water source s ∈ S and treatment unit tu ∈ TU
C_c^{ave}	Average concentration of contaminant c ∈ C in the system

Mass loads

ML_c^{rem}	Mass load of contaminant c ∈ C to be removed from the system
ML_c^{tot}	Total mass load of contaminant c ∈ C in the system

Cost parameters

$Cost_s^{var}$	Variable cost of water stream s ∈ S
$Cost_s^{fix}$	Fixed cost of water stream s ∈ S
$Cost_{tu}^{var}$	Variable cost of treatment unit tu ∈ TU
$Cost_{tu}^{fix}$	Fixed cost of treatment unit tu ∈ TU

Other parameters

$RR_{tu,c}^{fix}$	Fixed value for the removal ratio of contaminant c ∈ C in treatment unit tu ∈ TU
$RR_{tu,c}$	Removal ratio of contaminant c ∈ C in treatment unit tu ∈ TU
$Bound^{up}$	Upper bound for streams flow rate
$Bound^{low}$	Lower bound for streams flow rate
NS_{tu}^{max}	Maximum number of streams that can go through treatment unit tu ∈ TU
HY	Number of hours of operation per year

Variables

Flow rates

$F_{s,tu}$	Flow rate of the stream from water source s ∈ S to treatment unit tu ∈ TU
$F_{tu,tu'}$	Flow rate of the stream from treatment unit tu ∈ TU to treatment unit tu′ ∈ TU (tu′ ≠ tu)
F_{tu}^{exit}	Flow rate of the stream from treatment unit tu ∈ TU to discharge point

F_{tu}^{in}	Flow rate of inlet stream to treatment unit tu ∈ TU
F_{tu}^{out}	Flow rate of outlet stream from treatment unit tu ∈ TU
Concentration	
$C_{tu,c}^{in}$	Concentration of contaminant c ∈ C in inlet stream to treatment unit tu ∈ TU
$C_{tu,tu',c}$	Concentration of contaminant c ∈ C in stream from treatment unit tu ∈ TU to treatment unit tu′ ∈ TU (tu′ ≠ tu)
$C_{tu,c}^{exit}$	Concentration of contaminant c ∈ C in the stream from treatment unit tu ∈ TU to the discharge point
$C_{tu,c}^{out}$	Outlet concentration of contaminant c ∈ C from treatment unit tu ∈ TU
C_{c}^{BFW}	Discharge concentration of contaminant c ∈ C (at discharge point)
Mass load	
$ML_{tu,c}^{rem}$	Mass load of contaminant c ∈ C that is removed in treatment unit tu ∈ TU specified with a fixed outlet concentration
$ML_{tu,c}^{in}$	Mass load of contaminant c ∈ C entering the treatment unit tu ∈ TU
$ML_{tu,c}^{out}$	Mass load of contaminant c ∈ C exiting the treatment unit tu ∈ TU
$ML_{tu,c}^{gain}$	Slack variable for mass load of contaminant c ∈ C in treatment unit tu ∈ TU
$ML_{tu,c}^{loss}$	Surplus variable for mass load of contaminant c ∈ C in treatment unit tu ∈ TU
Cost and energy variables	
$Cost_{tu}^{tot}$	Total cost of treatment unit tu ∈ TU
$Cost^{op}$	Operating cost of the system
$Cost^{cap}$	Capital cost of the system

$Cost^{tot}$	Total cost of the system
$energy_{tu}^{var}$	Total energy consumption of the system

Appendix B: Supporting Information II

B.1. Emerging technologies

Three emerging technologies are included in the scope of the present study: Solvent Assisted SAGD (SA-SAGD), Partial Upgrading, and In situ Upgrading Technology (ISUT). These technologies are briefly explained in the following.

SA-SAGD.

Solvent-assisted technologies involve adding solvents (various light hydrocarbons such as gas condensate) to the steam that is injected for bitumen extraction. The addition of solvents reduces the energy and water requirements for bitumen extraction by reducing the temperature and pressure of the steam required for bitumen viscosity reduction [21]. Using solvent in the bitumen extraction process is investigated in several experimental studies to understand different aspects of the process such as the best thermodynamic conditions for solvent assisted extraction, the effect of solvent on the phase behavior inside the reservoir and the quality of the product [142–145]. Solvent can be used alone or combined with steam in the extraction process. In this study, solvent assisted SAGD or SA-SAGD is included in the analysis. SA-SAGD is based on the use of a light hydrocarbon (e.g., condensate or butane) as solvent combined with steam (5%-20% solvent concentration in steam by volume) to facilitate the extraction process and to reduce steam to oil ratio and consequently energy requirement in the process.

Partial Upgrading.

Partial upgrading technologies upgrade bitumen to a product that has characteristics similar to medium or heavy crude in terms of liquid density, Sulphur content and metal content (compared to full upgrading that produces synthetic crude oil (SCO) that has the characteristics similar to light crude oil) at a lower cost per barrel compared to full upgrading [22]. Partial upgrading technologies require lower capital investment than full upgrading and reduce the amount of diluent required for transportation compared to bitumen dilution [21]. Partial upgrading technologies have attracted much attention in Alberta mainly because of the technology's potential for diversifying Alberta energy sector [77]. A number of partial upgrading technologies have been developed in lab or pilot scale such as MEG HI-Q®, Catalytic Steam Cracking and Visbreaking technology [146]. In the present study, the Catalytic Steam Cracking (CSC) technology information is used to model the partial upgrading stage. Catalytic Steam Cracking (CSC) is a partial upgrading technology that was studied by Marshman [7]. Marshman developed a pilot plant of the technology and used process simulation and LCA to estimate the life cycle GHG emissions of this new technologies. The results of Marshman's study are used in the mathematical model developed in the present study.

In Situ Extraction & Upgrading (ISEU).

In Situ Upgrading technology (that is referred to as ISUT) is an emerging technology developed to integrate extraction and upgrading of heavy oils and is studied by researchers in the University of Calgary [76]. The technology is based on the injection of dispersed nano-catalyst and hydrogen as upgrading agents and vacuum residue as a heat and catalyst carrier, into the reservoir (partially replacing steam injection in SAGD process) to produce an upgraded synthetic crude oil (SCO) that is close to crude pipeline specifications. The produced crude might require some level of dilution but needs lower amount of diluent to reach pipeline specs compared to bitumen produced via SAGD process. In addition, the integration of extraction and upgrading stages results in decreased capital cost required specially for building an upgrader. Hovsepian et al. studied the In Situ Upgrading process in a two dimension bench scale experimental simulation and the results of the study are used in the present analysis to demonstrate a high level model of the process (e.g., energy and mass balance, quality of the product, etc.) as one of the emerging oil sands production pathways.

B.2. LCA Models

GHOST. GHOST-SE employs company-reported and publicly available data and presents a range of emissions intensities for bitumen production considering the variability of input parameters and identifies the main sources of variability in emissions intensities [19]. Default inputs and ranges in GHOST-SE are used such as SOR (or a probability distribution of inputs).

OSTUM. Three main upgrading technologies are modeled in OSTUM, including delayed coking, hydro-conversion and a combination of fluid coking and hydro-conversion [20]. Delayed coking and hydro-conversion technologies are considered in the present study. OSTUM also includes 6 different assays in its database and is run with each assay multiple times (with various input assumptions) to obtain a range of results for energy consumption and GHG emissions to be used as inputs in the optimization model developed in the present study.

COPTEM. Crude transport emissions are estimated using Crude Oil Pipeline Transportation Emissions Model (COPTEM) [78]. Variability of input parameters is considered in the model that allows for running the model for different input scenarios and generate a range of emission intensities for dilbit and SCO pipeline transport emissions. In the present study, an average emission factor is used for each type of crude in the model and the variability of transport emission intensity is not considered. This will be investigated in more detail in a future study.

The distance between the extraction site and upgrading facility is assumed to be 500 km as an average distance between the two facilities both located in Alberta. The refineries are assumed to be in PADDII (Petroleum Administration for Defense District) area, 2500 km from the upgrading facility and 3000 km from the extraction site.

PRELIM. Petroleum Refinery Life Cycle Inventory Model (PRELIM) estimates the energy consumption and GHG emissions associated with crude oil refining stage using process-based life cycle and linear programming methods [73]. PRELIM takes into account crude properties and includes 10 main refinery configurations (based on the intensity of crude processing and the processing units employed in the refinery). PRELIM model is run with proxy assays for dilbit produced by diluting bitumen, SCO produced by bitumen upgrading process, PUB produced by partial upgrading and in situ upgrading process in all possible configurations and results of energy consumption and GHG emissions are used in the model developed in this study.

These LCA models have been populated with data provided by oil sands companies through non-disclosure agreements, publicly available data and feedback provided by industry experts. Therefore, the GHG estimates provided by these models are informed by actual operating data and not just simulation results that are presented in the environmental impact assessment documents developed to assess the environmental impacts of a project before it start operating.

Emerging technologies investigated in this study are not included in the LCA models introduced above. Therefore, energy consumption and other relevant data are extracted directly from the two studies that investigate these emerging technologies [76,95].

B.3. Literature studies

Many studies have provided estimates for GHG emissions and cost of different stages of oil sands production and processing including bitumen extraction, dilution, upgrading, transportation and refining and a few of them have compared two or more alternative scenarios with respect to GHG emissions and/or cost.

Charpentier et al. developed a life cycle-based model, Greenhouse gas emissions of current Oil Sands Technologies (GHOST), to assess the direct and indirect energy use and GHG emissions associated with the recovery, extraction, dilution, transportation, and upgrading of oil sands bitumen [18]. A statistically enhanced version of GHOST (GHOST-SE) was later developed by Orellana et.al [19] to assess the variability of GHG emissions associated with the bitumen extraction process using in situ techniques. Pacheco et al. developed another life cycle-based model, Oil Sands Technologies for Upgrading Model (OSTUM), to estimate energy use and GHG emissions associated with upgrading technologies at the process unit level [20]. GHOST and OSTUM methods, inputs and results are used in the present study for estimating energy consumption and GHG emissions of oil sands extraction and upgrading process, respectively. Choquette-Levy et al. developed a first-principles, fluid mechanics-based model, COPTEM, to estimate the GHG emissions associated with crude oil pipeline transport using crude oil characteristics, pipeline dimensions and a set of external factors [78]. Choquette-Levy's model is used in the present study for transport GHG emissions. Another oil sands transportation model was developed by Tarnoczi to compare pipeline and rail transport emissions [79]. Tarnoczi applied the model to several existing and potential oil sands transportation routes to investigate the variability of oil sands transport emissions under various conditions and the effect of several parameters such as regional electricity grid and train engine efficiency. Petroleum Refinery Life Cycle Inventory Model (PRELIM), developed by Abella and Bergerson, estimates the energy consumption and GHG emissions associated with crude oil refining stage using process-based life cycle and linear programming methods [73]. PRELIM takes into account crude properties and includes 10 main refinery configurations (based on the intensity of crude processing and the processing units employed in the refinery). Each of these studies address GHG emissions associated with one or two stages of oil sands production and do not include simultaneous upstream and downstream implications of different technologies at different stages of the production.

Nimana et al. developed a fundamental engineering principles-based model to estimate GHG emissions of upgrading and refining of oil sands bitumen [80]. A technoeconomic model is developed by Sapkota et al. to estimate the overall supply chain costs of oil sands products for a specific production and processing capacity including the cost of extraction, processing and transportation as well as shipping the crude oil to the Asia-Pacific region [81]. Emerging technologies are not included in the scope of these studies. In addition, the effect of variability and uncertainty of input parameters in the context of total supply chain emissions and cost are not addressed in the previous studies.

Ordorica-Garcia developed an energy optimization model (EOM) for oil sands production to identify the mix of SCO and bitumen production pathways that results in minimum energy supply cost when CO2 emissions constraints are considered [82]. SAGD and mining are included as extraction technologies, and refining stage is not included in this study. The model output is the optimal combination of power and hydrogen plants required for oil sands production at different levels of CO_2 reduction constraints. Betancourt-Torcat developed another energy optimization model to investigate the effect of CO_2 mitigation strategies, SOR and NG price on the economics of oil sands operations [83]. Extraction and dilution/upgrading stage of oil sands production are included in Betancourt-Torcat's model. Three main production pathways are included in the study; Mining + upgrading, SAGD + upgrading and SAGD + dilution. Total production capacity is used as model input and the model output provides the production capacity by each pathway in order to minimize the annual energy cost. The economic performance of oil sands extraction was investigated by Rui et al., but their analysis was limited to SAGD technology [75]. They used historical data from 35 SAGD projects in Alberta and examined the effect of several parameters such as reservoir characteristics and production capacity on the economic feasibility of the SAGD process. None of these studies investigate the GHG emissions and cost of the entire oil sands supply chain and are limited to either one specific technology or part of the total production cost (e.g., energy cost).

Technology pathway selection in various industries using life cycle assessment or optimization or a combination of both tools has been introduced and studied in the literature [85,86]. Garcia and You developed an optimization model to identify the most environmentally sustainable and cost effective technology pathways for biofuel generation [87,88]. They explored the trade-offs between economic and environmental performance of different technology pathways and made recommendations about the choice of the best production pathway under different conditions. However, uncertainty and variability of inputs are not considered in their studies. Marvin et al. developed a mixed integer linear programming optimization model to determine the most economic choice of technology and location for biomass processing facilities considering the biofuel supply chain [89]. Biofuel production pathways are explored in another study by Murillo-Alvarado et al. [90]. They considered multiple feedstock, products and processing steps in an optimization model developed to determine the production pathways with maximum net profit and minimum GHG emissions. Optimization methods for technology selection considering the entire supply chain have not been used for oil sands production pathways before. The present study will address this gap in the literature by proposing a new approach for evaluating and comparing oil sands existing and emerging technologies.

B.4. Capital Cost Estimate – upgrading and refinery plants

Capital cost of upgrading and refining facilities are calculated as a function of the size (or capacity) of the facility using Gary et al. cost data [96] and based on the capital cost of a reference facility with 100,000 BPD capacity. A power cost function along with a simplified linear function for cost vs. capacity are presented. The linear cost function is used in the present model to keep the optimization model linear, and the data to show that the linear function is an accurate representation of the cost function based on the R squared values is presented.

Below are the power and linear cost functions:

$$\boldsymbol{Power\ function}: \quad \frac{Cost_C}{Cost_{Ref}} = a\left(\frac{Capacity_C}{Capacity_{Ref}}\right)^b$$

$$\boldsymbol{Linear\ function}: \quad \frac{Cost_C}{Cost_{Ref}} = a + b * \left(\frac{Capacity_C}{Capacity_{Ref}}\right)$$

$Capacity_{Ref}$ is the reference capacity (assumed 100,000 bbl/day in the calculations), $Cost_{Ref}$ is the estimated capital cost for an upgrader/refinery with the reference capacity of 100,000. $Cost_c$ is the capital cost of an upgrader/refinery with $Capacity_c$ to be estimated based on the reference cost.

Cost functions for two types of upgrading facilities are presented in Figure B 1 and Figure B 2. Cost data for different capacities show that even though cost fits a power function perfectly, a linear function provides a good fit to the cost data as well, with R squared values above 0.98.

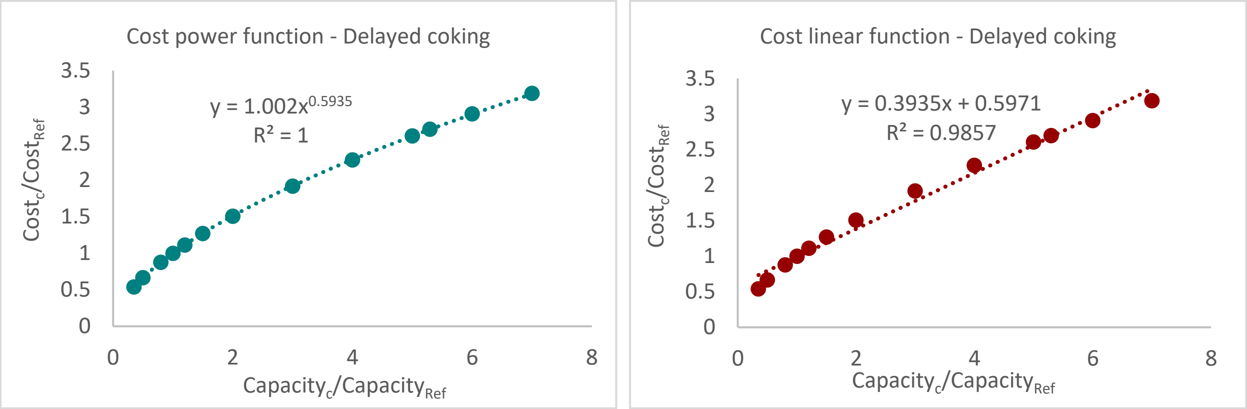

Figure B 1 Power and linear cost functions, delayed coking upgrading

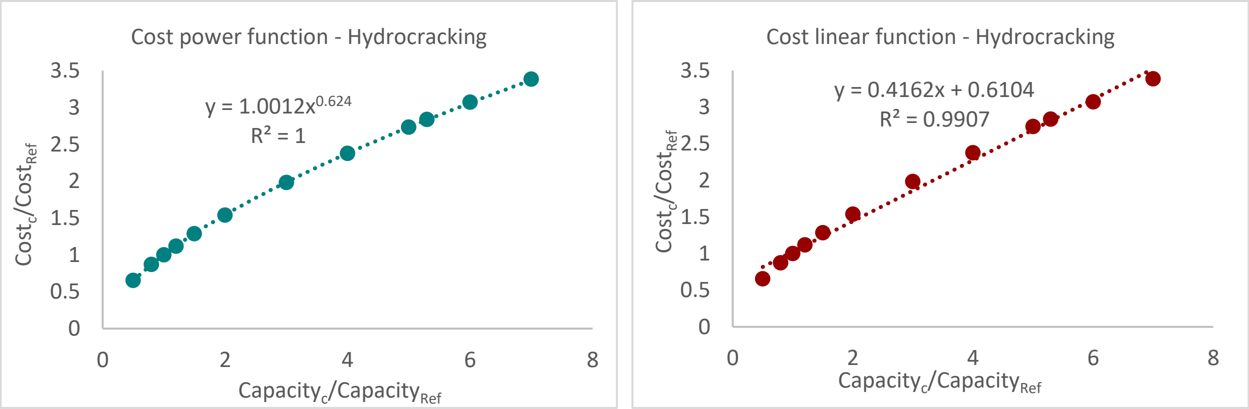

Figure B 2 Power and linear cost functions, hydrocracking upgrading

Cost functions for 10 different refinery configurations are presented in Figure B 3 to Figure B . Similar to upgrading cost functions, linear function provides a good fit to the refining capital cost data versus refining capacity.

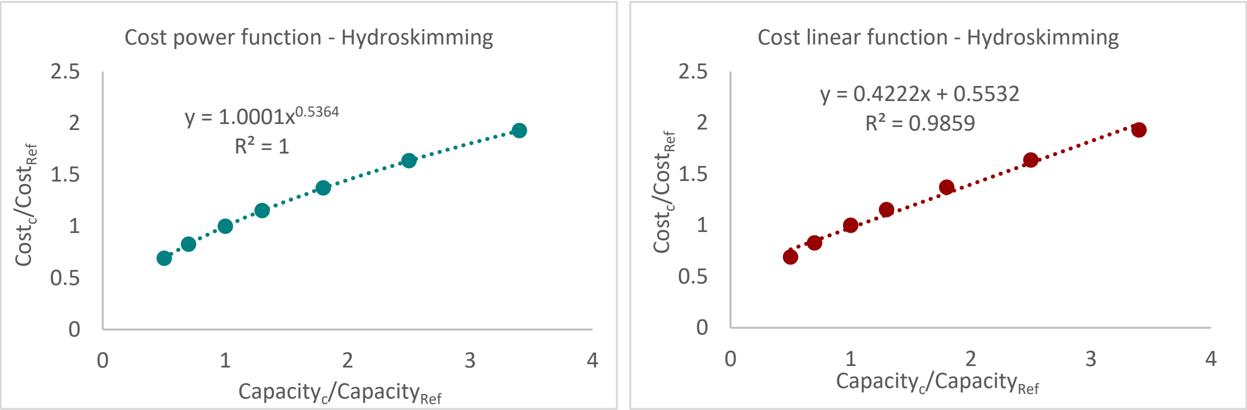

Figure B 3 Power and linear cost functions, hydroskimming refining

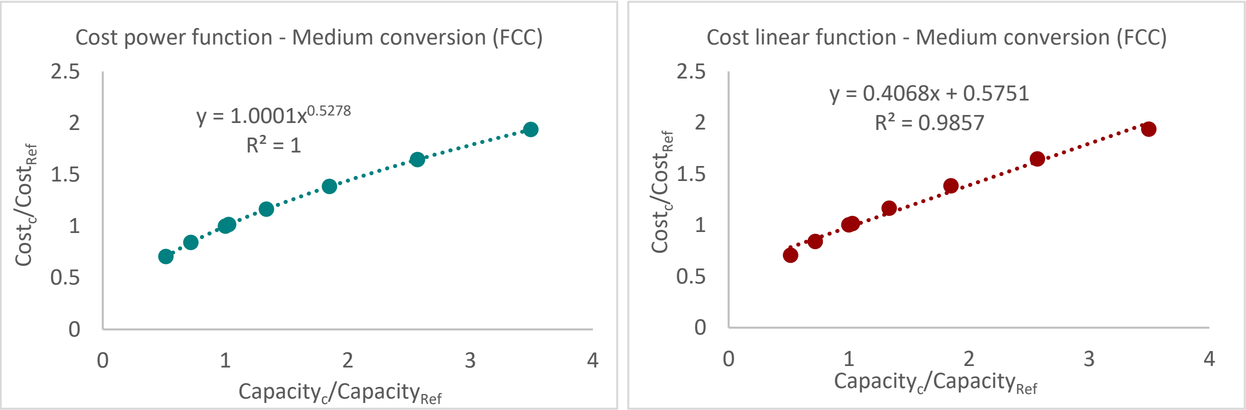

Figure B 4 Power and linear cost functions, medium conversion refining (FCC)

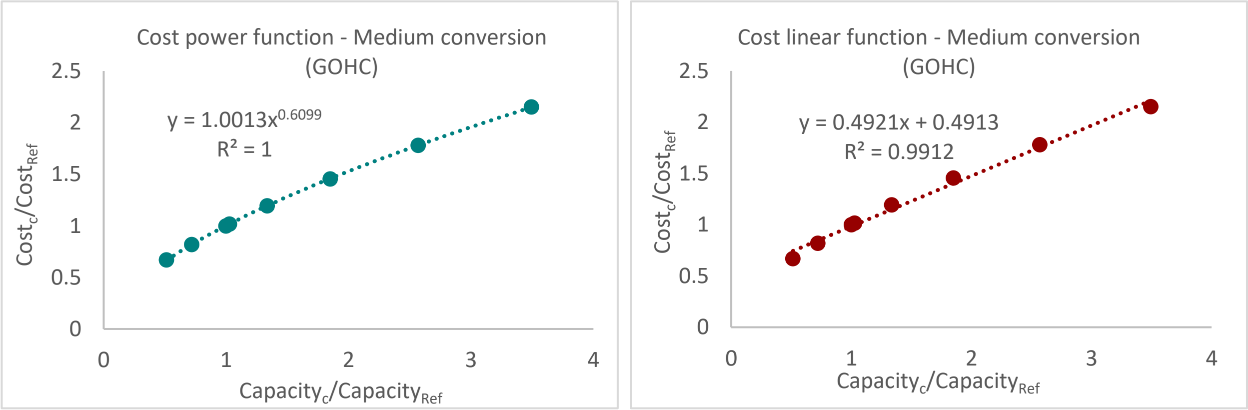

Figure B 5 Power and linear cost functions, medium conversion refining (GOHC)

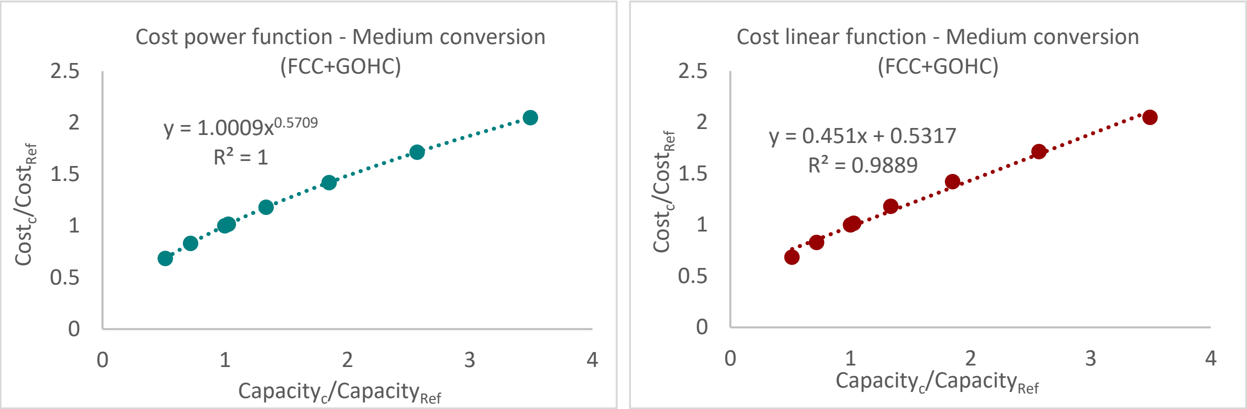

Figure B 6 Power and linear cost functions, medium conversion refining (FCC+GOHC)

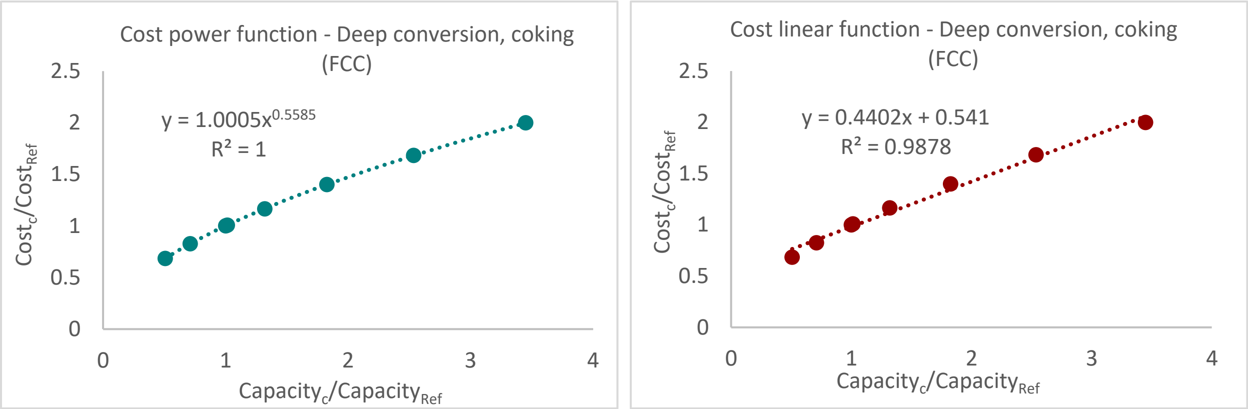

Figure B 7 Power and linear cost functions, deep conversion, coking refining (FCC)

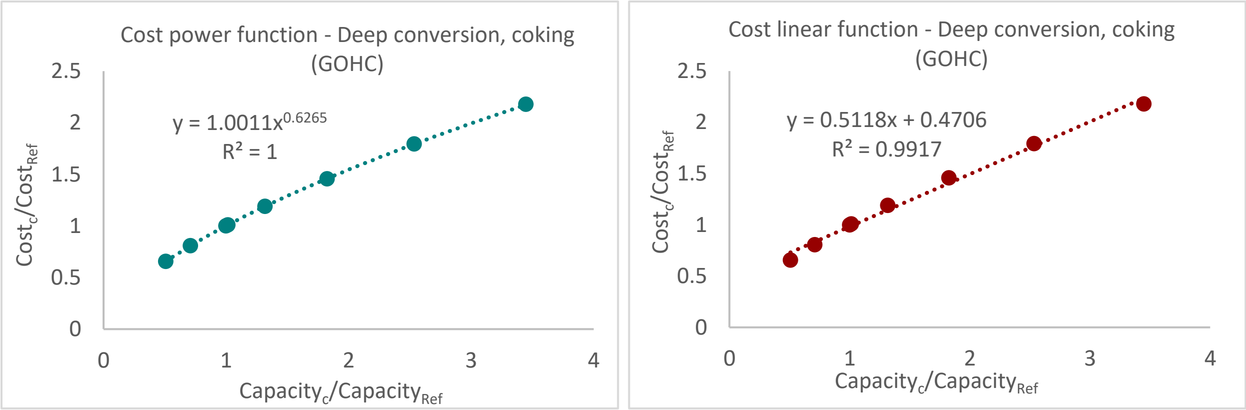

Figure B 8 Power and linear cost functions, deep conversion, coking refining (GOHC)

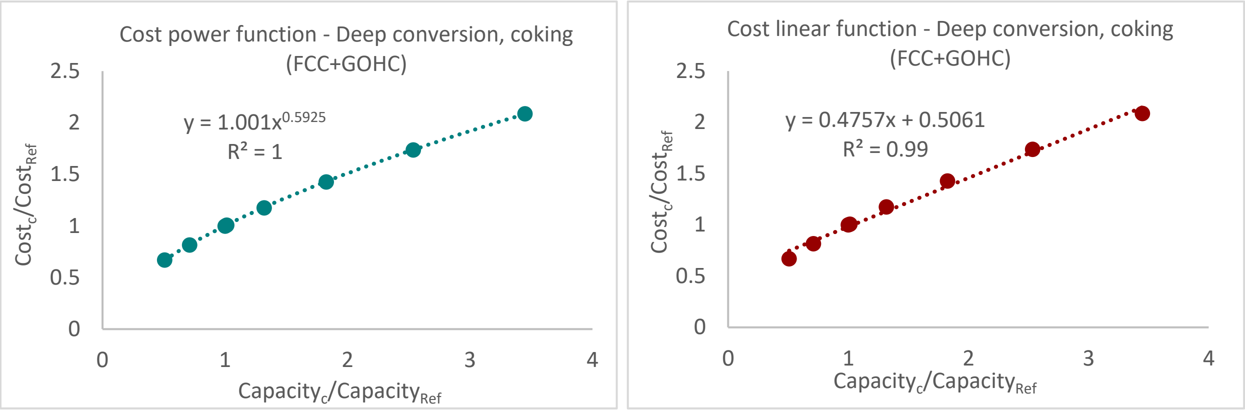

Figure B 9 Power and linear cost functions, deep conversion, coking refining (FCC+GOHC)

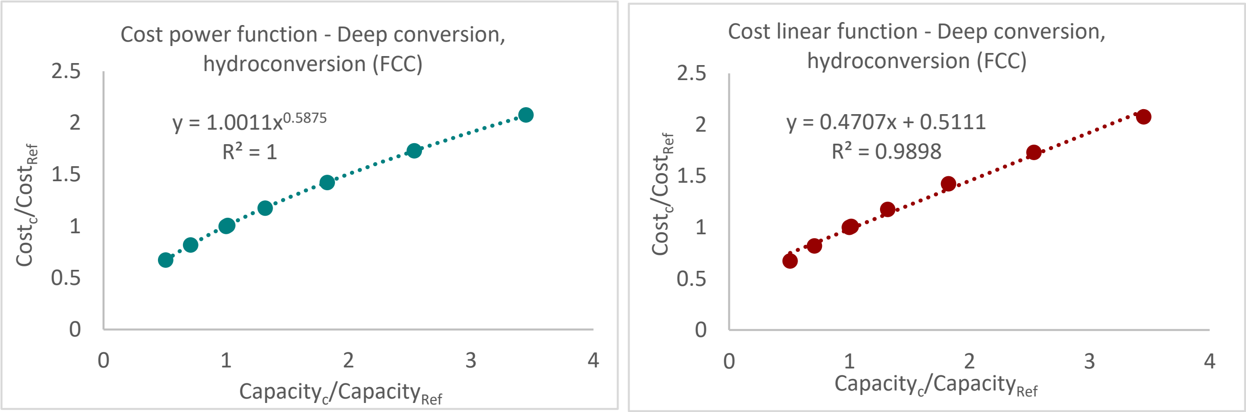

Figure B 10 Power and linear cost functions, deep conversion, hydroconversion refining (FCC)

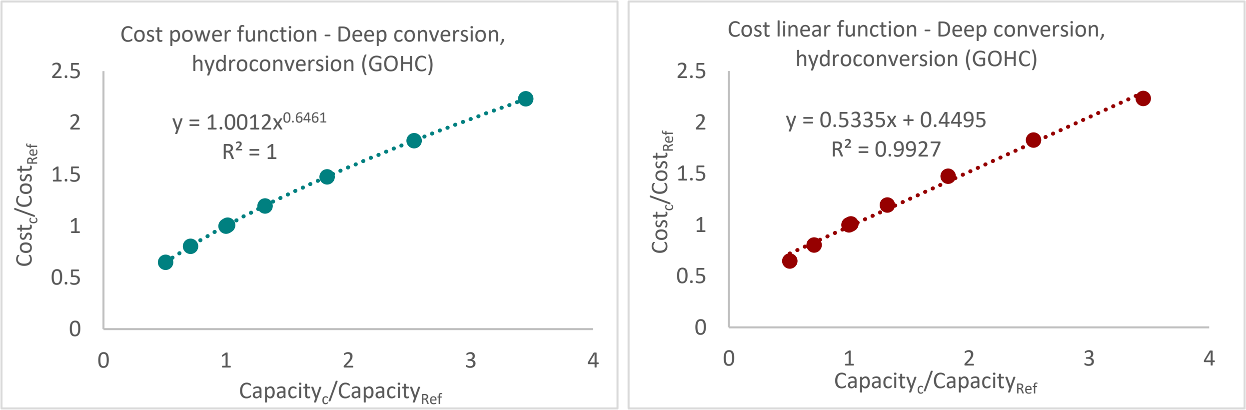

Figure B 11 Power and linear cost functions, deep conversion, hydroconversion refining (GOHC)

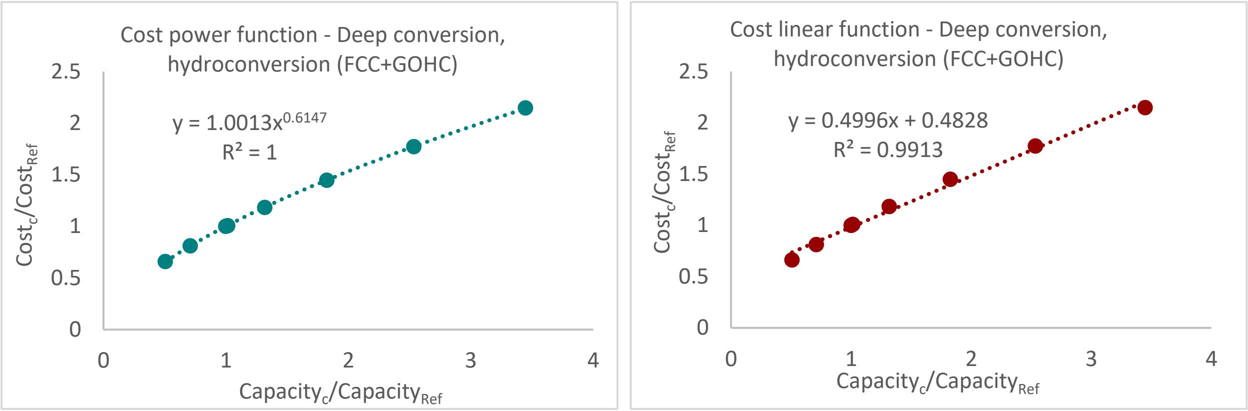

Figure B 12 Power and linear cost functions, deep conversion, hydroconversion refining (FCC+GOHC)

B.5. Inputs and probabilities

Technology	Variable Input	Unit	Value	Probability
SAGD	SOR	m3 steam/ m3 bitumen	2	0.1
			2.6	0.44
			3.4	0.23
			4	0.23
	Operating Cost (excl. NG & electricity)	CAD/bbl bitumen	6.2	0.1
			6.97	0.6
			8	0.3
SA-SAGD	SOR	m3 steam/ m3 bitumen	1.5	0.15
			2.1	0.6
			3	0.25
	Solvent Recovery	fraction	0.9	0.15
			0.8	0.6
			0.7	0.25
	Capital Cost	CAD/bbl bitumen	12.5	0.5
			16.36	0.5
ISEU	VROR	m3 steam/ m3 bitumen	0.8	0.15
			1	0.6
			1.2	0.25
	Hydrogen consumption	m3 H/ m3 VR	70	0.15
			100	0.6
			130	0.25
	Diluent use	m3/m3 bitumen	0.1	0.5
			0.2	0.5
Delayed coking - upgrading	Capital Cost	billion CAD for a 100,000 bpd facility	6	0.1
			7.5	0.6
			9.1	0.3
Hydro-conversion - upgrading	Capital Cost	billion CAD for a 100,000 bpd facility	7	0.1
			8.8	0.6
			10.5	0.3
Catalytic steam Cracking – partial upgrading	Capital Cost	billion CAD for a 100,000 bpd facility	3.2	0.33
			3.6	0.34
			4.3	0.33

B.6. Sets, Variables, and Parameters

Sets

E	Extraction technology options
D	Dilution options
U	Upgrading technology options
R	Refining configurations
RF	Types of refinery feed
RP	Refinery products

Parameters

$DilbtoBit$	Dilbit to bitumen volume ratio for each dilution option
$SCOtoBit$	SCO to bitumen volume ratio for each upgrading technology
$Fmax$	Upper bound on the flow through each process
$Fmin$	Lower bound on the flow through each process
NG_E	NG consumption in each extraction process
$Elec\_E$	Electricity consumption in each extraction process
$Solvent\_E$	Solvent consumption in each extraction process
H_E	Hydrogen consumption in each extraction process
$GHGother\_E$	Other GHG emissions for each extraction process (e.g., vent, flare)
GHG_D	Upstream emissions for each type of diluent
NG_U	NG consumption in each upgrading process
FG_U	Fuel gas consumption in each upgrading process
$Elec\_U$	Electricity consumption in each upgrading process
$GHGother\_U$	Other GHG emissions for each upgrading process (e.g., vent, flare)
NG_R	NG consumption in each refining process and each refinery feed type
FG_R	Fuel gas consumption in each refining process and each refinery feed type
$Elec\_R$	Electricity consumption in each refining process and each refinery feed type

$GHGother\_R$	Other GHG emissions for each refining process and each refinery feed type
$GHGT\_Dilb$	Transport GHG emissions for dilbit
$GHGT\_PUB$	Transport GHG emissions for partially upgraded bitumen
$GHGT\_SCO$	Transport GHG emissions for SCO
$EF_{NG-direct}$	NG combustion emissions
$EF_{NG-indirect}$	NG upstream emissions
$EF_{Elec-AB}$	Grid electricity emissions intensity, Alberta
$EF_{Elec-US}$	Grid electricity emissions intensity, U.S. average
EF	Refinery product combustion emissions factor
$Dist_{EtoU}$	Distance between extraction and upgrading stages
$Dist_{EtoR}$	Distance between extraction and refining stages
$Dist_{DtoR}$	Distance between dilution and refining stages
$Dist_{UtoR}$	Distance between upgrading and refining stages
$CapCostE$	Capital cost of each extraction technology
$NGprice$	Price of NG
$ElecPrice$	Price of electricity
$SolvPrice$	Price of solvent
$HPrice$	Price of hydrogen
$CarbonPrice$	Price of carbon emissions
$Cost\_D$	Price of diluent
$PlantComp$	Plant complexity, for each upgrading and refining technology
$ProcComp$	Process complexity, for each upgrading and refining technology
$LocFactor$	Location factor (for Alberta), for capital cost estimates
AF	Annualization factor, for capital cost estimates
$OpCostF$	Fixed operation cost, as a percentage of capital cost
$Cost\_ref$	Reference cost for each upgrading and refining technology
$CostU\_a$	Capital cost factor “a” for each upgrading technology
$CostU\_b$	Capital cost factor “b” for each upgrading technology

$CostR\_a$	Capital cost factor “a” for each refining technology
$CostR\_b$	Capital cost factor “b” for each refining technology
$ProdComp$	Refinery product slate for each refinery configuration and feed type
$PriceP$	Price of refinery final products
LHV	Lower heating value of each refinery product

Variables

F_{crude}	Total volume of crude extracted from all extraction technologies
F_{EtoD}	Volume of crude sent from each extraction technology to each dilution option
F_{EtoU}	Volume of crude sent from each extraction technology to each upgrading technology
F_{EtoR}	Volume of crude sent from each extraction technology to each refinery type
F_{DtoR}	Volume of crude sent from each dilution option to each refinery type
F_{UtoR}	Volume of crude sent from each upgrading technology to each refinery type
F_{in}	Volume of crude entering each technology option in each stage
F_{out}	Volume of crude exiting each technology option in each stage
F_{inR}	Volume of each crude type entering each refinery configuration
F_{RProd}	Volume of each product from each refinery configuration
$Bupg$	Binary variable for upgrading technology options
$Bref$	Binary variable for refining technology options
GHG_{ext}	Total GHG estimated for the extraction stage
GHG_{dil}	Total GHG estimated for the dilution stage
GHG_{upg}	Total GHG estimated for the upgrading stage
GHG_{ref}	Total GHG estimated for the refining stage
$GHG_{transport}$	Total GHG estimated for the transportation stage
$GHG_{end-use}$	Total GHG estimated for end-use stage
GHG_{total}	Total life cycle GHG emissions
$CapCost_{ext}$	Capital cost of the extraction stage

$OpCost_{ext}$	Operating cost of the extraction stage
$OpCost_{dil}$	Cost of the dilution stage
$CapCost_{upg}$	Capital cost of the upgrading stage
$OpCost_{upg}$	Operating cost of the upgrading stage
$CapCost_{ref}$	Capital cost of the refining stage
$OpCost_{ref}$	Operating cost of the refining stage
$Cost_{transport}$	Cost of the transportation stage
$Cost_{total}$	Total life cycle costs
$Revenue$	Total revenue from the sale of refinery products
$Profit$	Total profit

B.7. Mathematical Formulation

Mass Balance Equations

Overall Mass Balance

$$\sum_{E,D} F_{EtoD}(E,D) + \sum_{E,U} F_{EtoU}(E,U) + \sum_{E,R} F_{EtoR}(E,R) = F_{crude}$$

Extraction Stage

$$F_{out}(E) = \sum_{D} F_{EtoD}(E,D) + \sum_{U} F_{EtoU}(E,U) + \sum_{R} F_{EtoR}(E,R)$$

Dilution Stage

$$F_{in}(D) = \sum_{E} F_{EtoD}(E,D)$$

$$F_{out}(D) = \sum_{R} F_{DtoR}(D,R)$$

$$F_{in}(D) \times DilbtoBit(D) = F_{out}(D)$$

Upgrading Stage

$$F_{in}(U) = \sum_{E} F_{EtoU}(E, U)$$

$$F_{out}(U) = \sum_{R} F_{UtoR}(U, R)$$

$$F_{in}(U) \times SCOtoBit(U) = F_{out}(U)$$

Refining Stage

$$\sum_{RF} F_{inR}(R, RF) = \sum_{E} F_{EtoR}(E, R) + \sum_{D} F_{DtoR}(D, R) + \sum_{U} F_{UtoR}(U, R)$$

$$F_{RProd}(R, RP) = \sum_{RF} F_{inR}(R, RF) \times ProdComp(R, RP, RF)$$

$$F_{in}(R) = \sum_{RF} F_{inR}(R, RF)$$

$$F_{out}(R) = \sum_{RP} F_{RProd}(R, RP)$$

Upper and Lower Bounds

$$F_{in}(U) \leq Bupg(U) \times Fmax$$

$$F_{in}(U) \geq Bupg(U) \times Fmin$$

$$F_{inR}(R, RF) \leq Bref(R, RF) \times Fmax$$

$$F_{inR}(R, RF) \geq Bref(R, RF) \times Fmin$$

Defining Refinery Feed Types

$$F_{inR}(R, \text{"}Dilbit\text{"}) = \sum_{D} F_{DtoR}(D, R) \quad , \quad D \in \{naphtha, condensate\}$$

$$F_{inR}(R, \text{"}Synbit\text{"}) = \sum_{D} F_{DtoR}(D, R) \quad , \quad D \in \{SCO\}$$

$$F_{inR}(R,"SCO") = \sum_{U} F_{UtoR}(U,R) \quad , \qquad U \in \{DC, HC\}$$

$$F_{inR}(R,"PUB") = \sum_{U} F_{UtoR}(U,R) \quad , \qquad U \in \{CSC\}$$

$$F_{inR}(R,"ISEU\_PUB") = \sum_{E} F_{EtoR}(E,R) \quad , \qquad E \in \{ISEU\}$$

Emissions

$$\begin{aligned} GHG_{ext} = \sum_{E} \Big[& F_{out}(E) \\ & \times [NG\_E(E) \times [EF_{NG-direct} + EF_{NG-indirect}] + Elec\_E(E) \times EF_{Elec-AB} \\ & + \ GHGother\_E(E)]\Big] \end{aligned}$$

$$GHG_{dil} = \sum_{D} \left[F_{out}(D) \times \left[1 - \frac{1}{DilbtoBit} \right] \times GHG\_D(D) \right]$$

$$\begin{aligned} GHG_{upg} = \sum_{U} [& F_{out}(U) \\ & \times [NG\_U(U) \times [EF_{NG-direct} + EF_{NG-indirect}] + FG\_U(U) \times EF_{NG-direct} \\ & + Elec\_U(U) \times EF_{Elec-AB}] + \ GHGother\_U(U)] \end{aligned}$$

$$\begin{aligned} GHG_{ref} = \sum_{R,RF} \Big[& F_{inR}(R,RF) \\ & \times [NG\_R(R,RF) \times (EF_{NG-direct} + EF_{NG-indirect}) \\ & + FG\_R(R,RF) \times EF_{NG-direct} + Elec\_R(R,RF) \times EF_{Elec-US} \\ & + \ GHGother\_R(R,RF)]\Big] \end{aligned}$$

$$
\begin{aligned}
GHG_{transport} = {} & GHGT\_Dilb \\
& \times \left[\sum_{E,U} F_{EtoU}(E,U) \times Dist_{EtoU}(E,U) + \sum_{D,R} F_{DtoR}(D,R) \times Dist_{DtoR}(E,R)\right] \\
& + GHGT\_PUB \times \sum_{E,R} F_{EtoR}(E,R) \times Dist_{EtoR}(E,R) \\
& + \ GHGT\_SCO \times \sum_{U,R} F_{UtoR}(U,R) \times Dist_{UtoR}(E,R)
\end{aligned}
$$

$$GHG_{end-use} = \sum_{R,RP} F_{RProd}(R,RP) \times EF(RP)$$

$$GHG_{total} = GHG_{ext} + GHG_{dil} + GHG_{upg} + GHG_{ref} + GHG_{transport} + GHG_{end-use}$$

Costs

$$CapCost_{ext} = \sum_{E} [F_{out}(E) \times CapCostE(E) \times AF]$$

$$
\begin{aligned}
OpCost_{ext} = {} & \sum_{E} \Big[F_{out}(E) \\
& \times [NG\_E(E) \times NGprice + Elec\_E(E) \times ElecPrice \\
& + Solvent\_E(E) \times SolvPrice \ + H\_E(E) \times HPrice + \ Costother\_E(E)]\Big] \\
& + GHG_{ext} \times CarbonPrice
\end{aligned}
$$

$$OpCost_{dil} = \sum_{D} \left[F_{out}(D) \times \left[1 - \frac{1}{DilbtoBit}\right] \times Cost\_D(D)\right] + GHG_{dil} \times CarbonPrice$$

$$
\begin{aligned}
CapCost_{upg} = {} & \sum_{U} \left[\frac{PlantComp(U)}{ProcComp(U)} \times LocFactor \times Cost\_ref(U) \right. \\
& \left. \times [CostU\_a(U) \times F_{out}(U) + Bupg(U) \times CostU\_b(U)] \times AF \right]
\end{aligned}
$$

$$OpCost_{upg} = \sum_{U} \Big[F_{out}(U) \times [NG\_U(U) \times NGprice + Elec\_U(U) \times ElecPrice]$$

$$+ OpCostF(U) \times CapCost_{upg} \Big] + GHG_{upg} \times CarbonPrice$$

$$CapCost_{ref} = \sum_{R,RF} \left[\frac{PlantComp(R)}{ProcComp(R)} \times LocFactor \times Cost\_ref(R) \right.$$

$$\left. \times [CostR\_a(R) \times F_{inR}(R,RF) + Bupg(R,RF) \times CostR\_b(R)] \times AF \right]$$

$$OpCost_{ref} = \sum_{R,RF} \Big[F_{inR}(R,RF) \times [NG\_R(R,RF) \times NGprice + Elec\_R(R,RF) \times ElecPrice]$$

$$+ OpCostF(R) \times CapCost_{ref} \Big] + GHG_{ref} \times CarbonPrice$$

$$Cost_{transport} = CostT$$

$$\times \left[\sum_{E,U} F_{EtoU}(E,U) \times Dist_{EtoU}(E,U) + \sum_{E,R} F_{EtoR}(E,R) \times Dist_{EtoR}(E,R) \right.$$

$$\left. + \sum_{D,R} F_{DtoR}(D,R) \times Dist_{DtoR}(E,R) + \sum_{U,R} F_{UtoR}(U,R) \times Dist_{UtoR}(E,R) \right]$$

$$Cost_{total} = Cost_{ext} + Cost_{dil} + Cost_{upg} + Cost_{ref} + Cost_{transport}$$

Revenue and Profit

$$Revenue = \sum_{R,RP} F_{RProd}(R,RP) \times PriceP(RP)$$

$$Profit = Revenue - Cost_{total}$$

Required Product Limit

$$\sum_{R,RP} F_{RProd}(R,RP) \times LHV(RP) = 100 \text{ (arbitrary number,does not impact the results)},$$

$$RP \in \{BlendGas, ULSD, JetFuel\}$$

B.8. Variability vs. Uncertainty

Figure B shows the profit distribution of technology scenarios considering uncertainty of inputs only. Figure B shows the profit distribution of technology scenarios considering variability of inputs only.

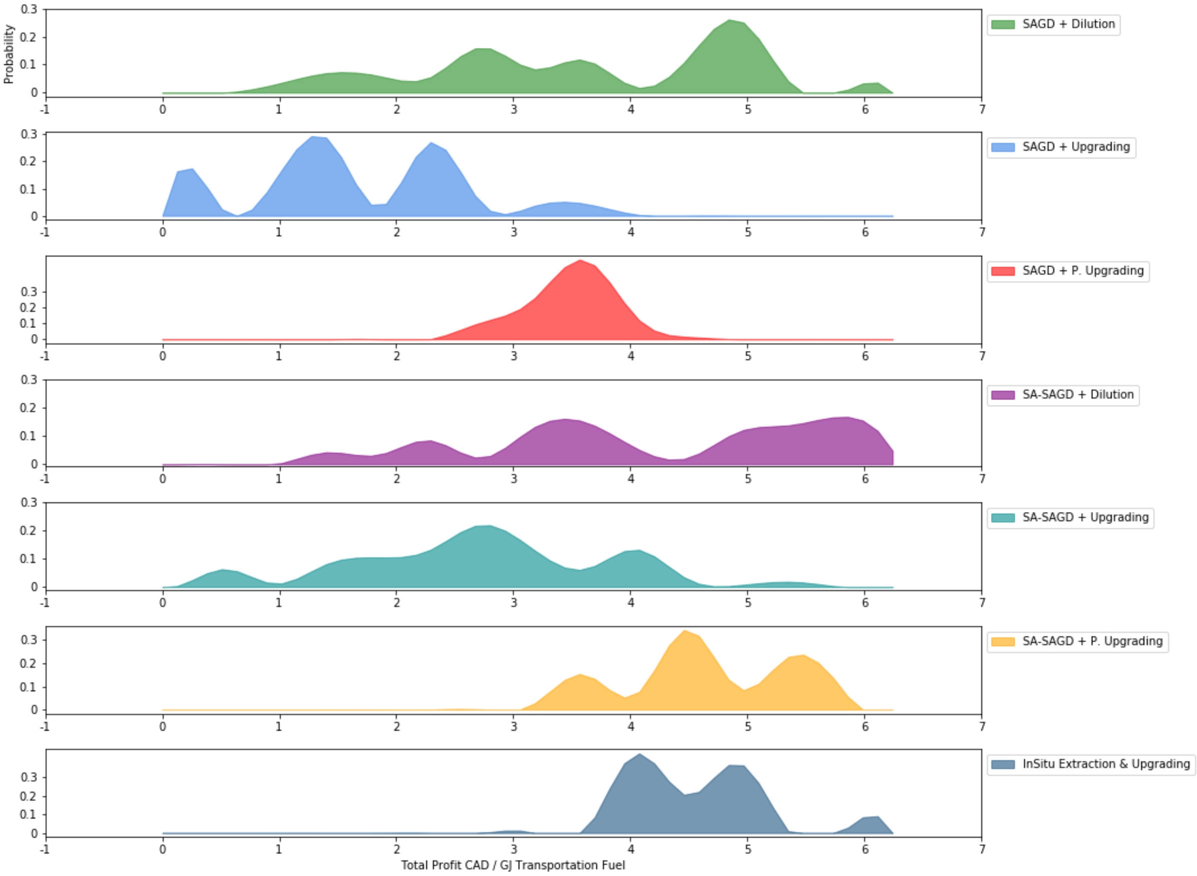

Figure B 13 Profit distribution of technology scenarios, considering uncertainty of inputs only

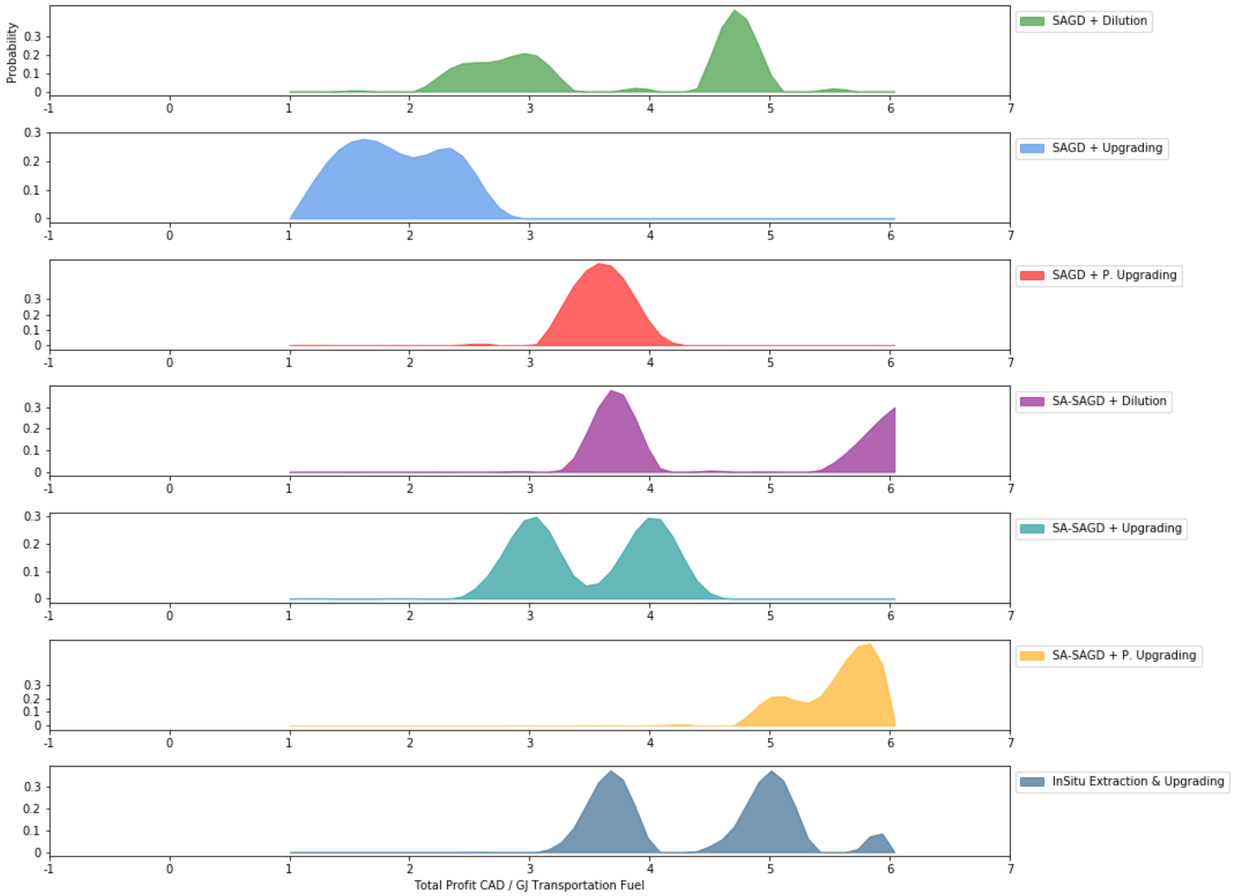

Figure B 14 Profit distribution of technology scenarios, considering variability of inputs only

B.9. pair-wise comparison of scenarios – additional insights

As mentioned in the main content, partial upgrading process has lower capital cost compared to full upgrading and even though the partially upgraded bitumen has lower quality than synthetic crude oil (the product of full upgrading process), and consequently requires a more extensive refining process, partial upgrading is still more favorable than upgrading when looking at the total supply chain cost. The same is true for a comparison between dilution and upgrading. Capital cost required for the dilution process is minimal, but the quality of dilution product (dilbit) is lower than SCO and requires a higher level of refining. However, dilution scenario is more profitable than upgrading scenario when the total supply chain cost is considered. In Situ Extraction and Upgrading scenario shows higher probability of a better economic performance compared to Upgrading scenarios and SAGD scenarios. ISEU combines the extraction and upgrading in one stage. The economic performance of ISUE technology and how it compares to the other scenarios are affected by several factors. ISEU has higher capital cost than SAGD and SA-SAGD extraction technologies, but it reduces or eliminates the need for dilution and does not require a separate upgrading process. ISEU does not require steam generation as SAGD and SA-SAGD do. On the other hand, it requires hydrogen to upgrade the bitumen in the reservoir. Overall, the probability of ISEU having the best economic performance is lower than SA-SAGD + Dilution and SA-SAGD + Partial upgrading scenarios.

Figure B and Figure B below show the results of pair-wise comparison of scenarios based on their economic and environmental performance. These figure present similar data to the figures for pair-wise comparison of scenarios in the main content using a different method of representing the results.

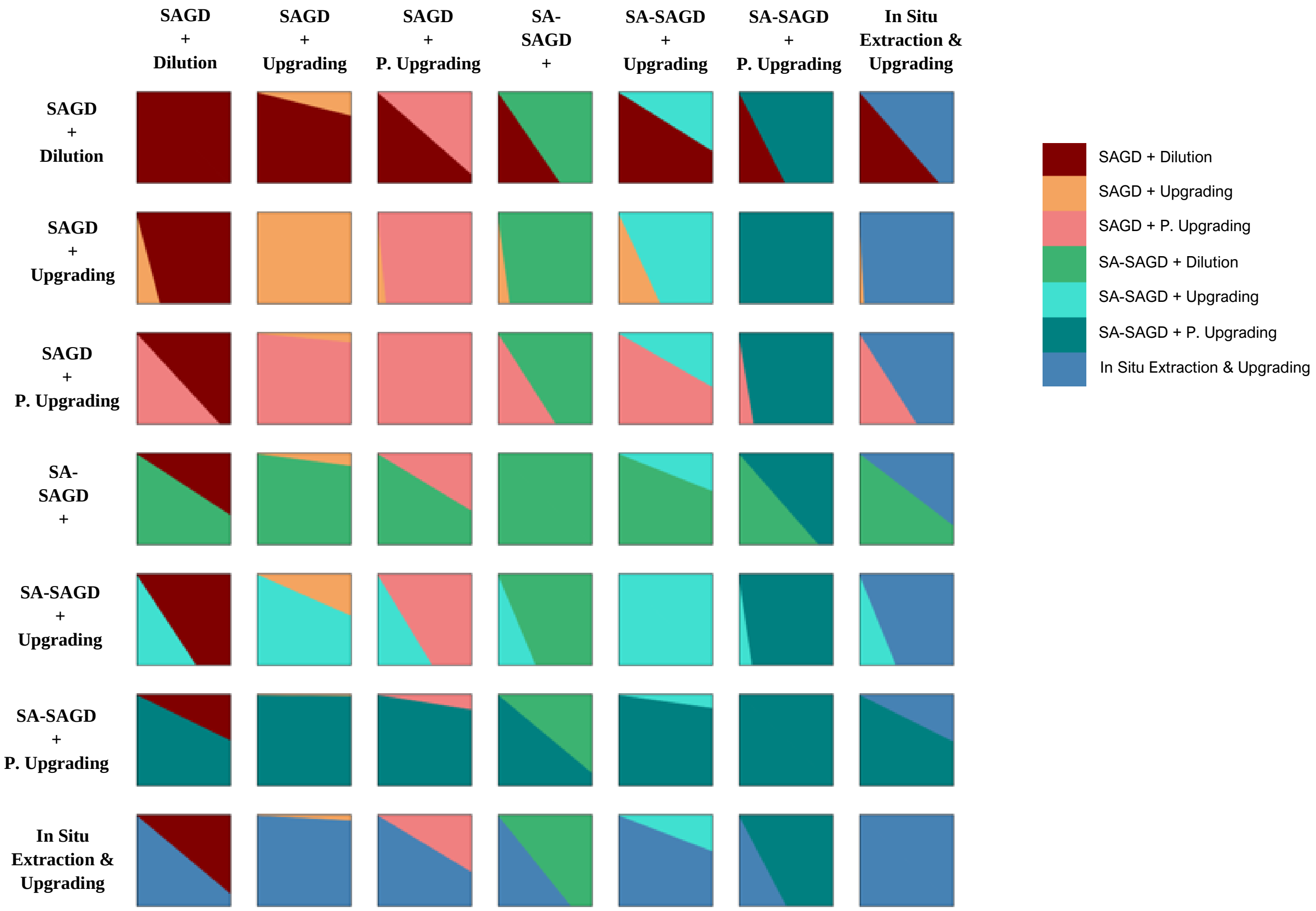

Figure B 15 Comparison of technology scenarios' economic performance

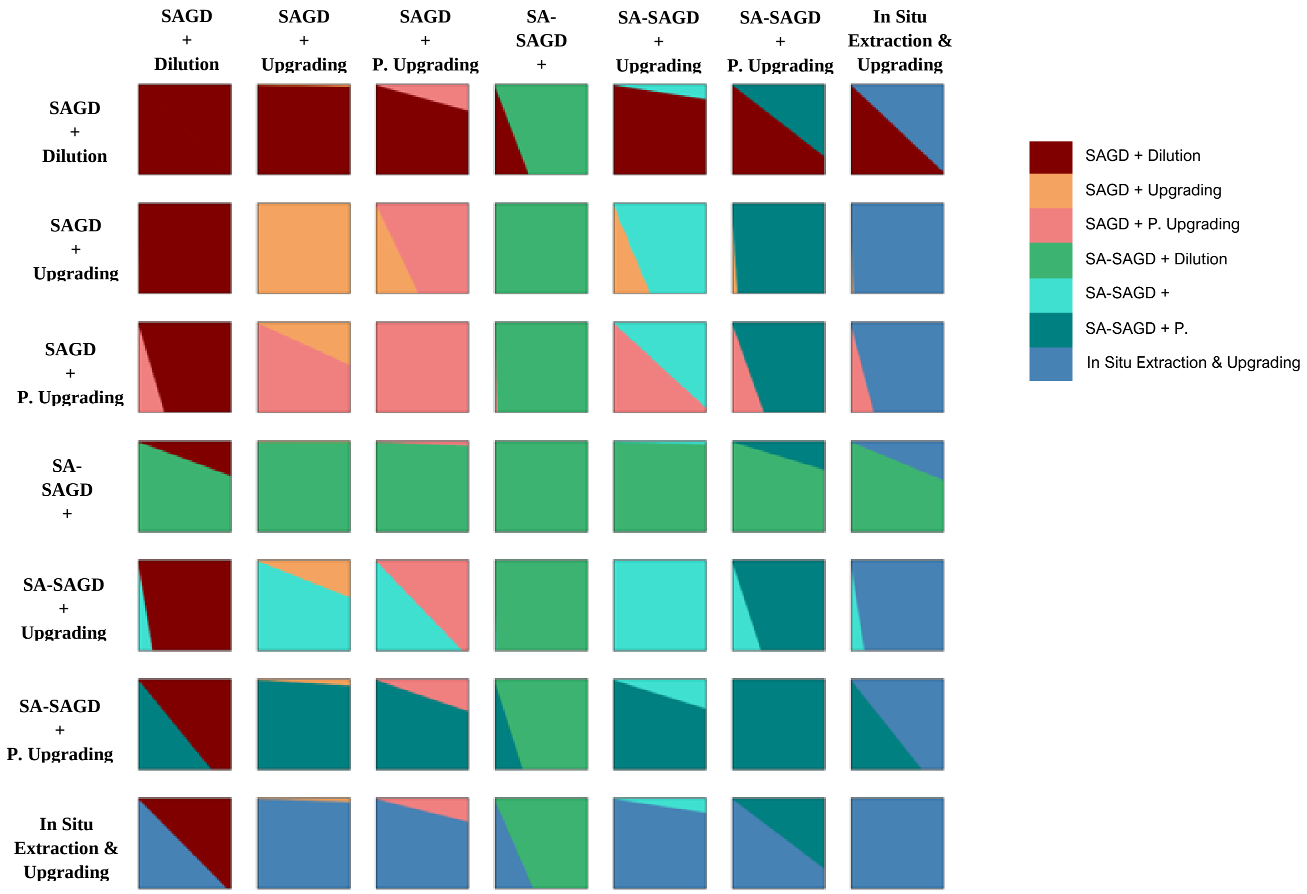

Figure B 16 Comparison of technology scenarios' environmental performance

B.10. Sensitivity Analysis – additional insights

The results indicate that solvent assisted SAGD is more economically attractive than regular SAGD under a wide range of possible input parameters. The results of the sensitivity analysis provide several interesting insights that are discussed below.

Overall, SA-SAGD with Partial Upgrading seems to be the dominant scenario under most combinations of input parameters. SA-SAGD with dilution and ISEU become competitive under certain conditions as well. SA-SAGD with upgrading becomes competitive only at very low capital cost of upgrading, below 9 billion for a 100,000 barrel per day upgrader, which is much lower than the average capital cost of building an upgrader in Alberta [100].

As expected, high future natural gas prices favor the ISEU scenario. The reason is the lower natural gas required for this extraction method (as a result of eliminating the need for steam production compared to SAGD and SA-SAGD), therefore, high natural gas price accentuates the advantage of this technology against SA-SAGD extraction. Depending on the value of other input parameters, ISEU becomes competitive at NG prices above \$4/GJ to \$9/GJ. Additionally, at low diluent requirement for ISEU (<4% diluent for dilution), the ISEU scenario becomes competitive at any NG price.

Generally, at low NG prices, SA-SAGD with partial upgrading is the most competitive option, but at diluent cost lower than \$65-\$70/barrel, SA-SAGD + Dilution becomes more competitive than SA-SAGD + Partial upgrading. In addition, at high discount rate and short project lifetime (that bring the annualization factor above ~0.12), Dilution has advantage over Partial upgrading, even at low NG price. The reason is the higher capital cost associated with Partial upgrading scenarios compared to Dilution that makes the Partial upgrading scenarios less attractive at high discount rates. Considering the current NG price (~\$3/GJ), SA-SAGD + Partial upgrading is the most profitable scenario under most combinations of inputs, except for: 1) low diluent cost and high annualization factor that makes Dilution more profitable (as explained above), and 2) low diluent requirement in ISEU scenario that make this scenario more profitable than Partial upgrading.

Diluent requirement for ISEU scenario is the most important parameter that affects the competitiveness of this scenario against SA-SAGD + Partial upgrading. If the required diluent to make the product of In Situ Extraction and Upgrading process meet the pipeline specifications is 6% (6 bbl diluent/bbl final product) or lower, ISEU becomes the most competitive alternative unless 1) SOR of the SA-SAGD process is less than 1.2, or 2) capital cost of partial upgrading is less than $4.5B (for a reference 100k bpd plant), or 3) diluent cost is less than $55/bbl. In the first two cases, SA-SAGD with Partial upgrading and in the third case SA-SAGD + Dilution become the most profitable scenarios.

The main parameters that affect the competitiveness of SA-SAGD + Dilution are the price of diluent and the annualization factor. At diluent prices lower than $70/bbl diluent, Dilution becomes more competitive than Partial upgrading regardless of the value of other parameters, except at low capital cost of Partial upgrading; when Partial upgrading capital cost for a reference 100k bpd plant is less than $5B.

High carbon price (economy wide carbon price is assumed), is in favor of Dilution scenario compared to partial upgrading, but the carbon price must be higher that $250 per tonne to make dilution more profitable than partial upgrading when other inputs are fixed.

When economy wide carbon pricing is implemented in the model, ISEU becomes more economically attractive compared to the conditions that regulatory carbon price is implemented. For example, at very low solvent recovery rate in SA-SAGD (>60%), ISEU is more profitable than SA-SAGD + Partial Upgrading at any carbon price. In addition, at low VROR values (<0.9), ISEU is the most profitable scenario when carbon price is $50 per tonne or higher. The impact of implementing an economy wide carbon price on the economic competitiveness of the new technologies such as ISEU (as supposed to implementing regulatory carbon price based on the current regulation in Alberta), shows the importance of the GHG emissions standards and policies on adopting emerging technologies and achieving emissions reduction targets. While the current carbon pricing policies might not provide the required incentive for developing new low emission technologies, an increased price on carbon emissions could provide the opportunity to move towards innovative and sustainable solutions to reduce oil sands environmental impacts.

According to Figure 3-6, Dilution scenarios are the least GHG intensive ones among the 7 technology scenarios investigated in this study. In Dilution scenarios, SA-SAGD is normally the preferred option over SAGD because of the lower SOR and consequently the lower NG consumption. The figure shows SAGD as the less emission intensive scenario compared to SA-SAGD when SAGD SOR is lower than 3, and SA-SAGD SOR is higher than 3.5. Since SA-SAGD SOR is always lower than SAGD SOR (at the same reservoir conditions), those conditions will not happen in reality (even though some combinations of inputs might not happen in reality, the ranges are included in the analysis to show the impact of all possible combinations of inputs). High upstream emissions of diluent can make alternative scenarios to become less emission intensive than Dilution; if diluent upstream emissions are higher than 11 gCO_2e/MJ, partial upgrading can be a competitive scenario as the lower GHG intensive scenario.

In addition, ISEU can become a competitive alternative to Dilution if the hydrogen requirement is lower than ~50 m^3 hydrogen/m^3 vacuum residue injected.

Upgrading scenarios are associated with high emissions intensity and are not competitive with other scenarios even under extreme conditions.

Appendix C: Supporting Information III

C.1. In Situ Extraction and Upgrading (ISEU) Technology

In Situ Upgrading technology (that is referred to as ISUT) is an emerging technology developed to integrate extraction and upgrading of heavy oils and is studied by researchers in the University of Calgary [76]. The technology is based on the injection of dispersed nano-catalyst and hydrogen as upgrading agents and vacuum residue as a heat and catalyst carrier, into the reservoir (partially replacing steam injection in SAGD process) to produce an upgraded synthetic crude oil (SCO) that is close to crude pipeline specifications. The produced crude might require some level of dilution but needs lower amount of diluent to reach pipeline specs compared to bitumen produced via SAGD process. In addition, the integration of extraction and upgrading stages results in decreased capital cost required specially for building an upgrader. Hovsepian et al. studied the In Situ Upgrading process in a two dimension bench scale experimental simulation and the results of the study are used in the present analysis to demonstrate a high level model of the process (e.g., energy and mass balance, quality of the product, etc.) as one of the emerging oil sands production pathways.

C.2. Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH) Technology

Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH), uses radio frequency to heat the reservoir and adds a solvent which facilitates the movement of the bitumen to the surface. Electromagnetic (EM) heating uses a radio frequency antenna that converts electricity to radio frequency energy. The antenna is placed inside a reservoir to heat the bitumen by vaporizing the formation connate water. ESEIEH is considered to require a relatively lower solvent-to-oil ratio than solvent-based extraction and operates at a lower temperature than EM heating. Furthermore, it could have a higher oil recovery factor than CSS and SAGD.

C.3. Western Canadian Crude Oil Export Pipelines

Table C 1 List of crude oil export pipelines from Western Canada [147]

Company	Name	Start-up	Origin	Destination	Distance km	Capacity bbl/day	Status
TRANS MOUNTAIN CORPORATION	Trans Mountain	1953	Edmonton, AB	Burnaby, BC	1147	300,000	Operating
	TM Expansion	Q2/2022	Edmonton, AB	Burnaby, BC	1150	+590,000	Under construction
TC ENERGY	Keystone	2010	Hardisty, AB	Steele City, NE Cushing, OK Nederland, TX	4324	590,000 + 50,000	Operating
	Keystone XL	-	Hardisty, AB	Steele City, NE	1947	+830,000	Cancelled
	Energy East	-	Hardisty, AB	Saint John, NB	4500	+1,100,000	Cancelled
ENBRIDGE	Express	1997	Hardisty, AB	Casper, WY	1,265	305,000 + 25,000	Operating
	Mainline						Operating
	• Line 1	1950	Edmonton, AB	Superior, WI	1,767	237,000	
	• Line 2	1957	Edmonton, AB	Superior, WI	1,774	442,000	
	• Line 3	1968	Edmonton, AB	Superior, WI	1,767	390,000	
	• Line 4	2002	Edmonton, AB	Superior, WI	1,770	796,000	
	• Line 65	2010	Cromer, MB	Clearbrook, MN	504	186,000	
	• Line 67	2010	Edmonton, AB	Superior, WI	1,790	800,000	
	• Total					**2,850,000**	
	Mainline Optimization	2019 2021	Edmonton, AB	Superior, WI	1,660	125,000 +25,000	Operating
	Line 3 Replacement	2021	Edmonton, AB	Superior, WI	1,660	+370,000	Operating
	Northern Gateway	-	Bruderheim, AB	Kitimat, BC	1,178	+525,000	Cancelled
PLAINS ALL AMERICAN CANADA	Milk River		Milk River, AB	Glacier County, MT	16.5	97,900	Operating
	Rangeland		Carway, AB	Cutbank, MT	0.75	11,000	Operating
TOTAL ESTIMATED EXPORT CAPACITY						4,279,900	
CAPACITY UNDER CONSTRUCTION						1,060,000	

C.4. Bitumen Upgraders in Alberta

Table C 2 List of bitumen upgraders in Alberta

Facility	Start-up	Feedstock	SCO Capacity (bbl/day)
Shell - Scotford	2003	Diluted bitumen from Muskeg River and Jackpine	320,000
CNRL - Horizon	2009	Bitumen from Horizon Froth Treatment	250,000
Suncor upgrader	1967	Bitumen from Base Plant + Firebag	357,000
Syncrude Mildred Lake upgrader	1978	Bitumen from Mildred Lake	350,000

C.5. Mathematical Formulation

Mass Balance Equations

Overall Mass Balance

For greenfield and expansion projects:

$$\sum_{E,D} F_{EtoD}(E,D,PT,Y) + \sum_{E,U} F_{EtoU}(E,U,PT,Y) + \sum_{E,R} F_{EtoR}(T,E,R,PT,M,Y)$$

$$= F_{crude-GF}(PT,Y) \ + [F_{crude-exi}(Y) - F_{crude-real-exi}(Y)] \quad ,$$

$$PT \in \{GF, Exp\}$$

For retrofit and existing projects:

$$\sum_{E,D} F_{EtoD}(E,D,PT,Y) + \sum_{E,U} F_{EtoU}(E,U,PT,Y) + \sum_{E,R} F_{EtoR}(T,E,R,PT,M,Y)$$

$$\leq F_{crude-Exi}(Y) \quad , \quad PT \in \{Ret, Exi\}$$

Mass Balance of Existing and Retrofitted Volumes

$$F_{crude-ret}(Y) = \sum_{E,D,PT} F_{EtoD}(E,D,PT,Y) + \sum_{E,U,PT} F_{EtoU}(E,U,PT,Y)$$

$$+ \sum_{E,R,PT} F_{EtoR}(T,E,R,PT,M,Y) \quad , \quad PT \in \{Ret\}$$

$$F_{crude-exi}(Y) \ = \ F_{bitumrn-2020} - F_{crude-ret}(Y)$$

$$F_{crude-real-exi}(Y)$$

$$= \sum_{E,D,PT} F_{EtoD}(E,D,PT,Y) + \sum_{E,U,PT} F_{EtoU}(E,U,PT,Y)$$

$$+ \sum_{E,R,PT} F_{EtoR}(T,E,R,PT,M,Y) \quad , \quad PT \in \{Exi\}$$

Constraint of New and Retrofit Projects

$$F_{EtoD}(E,D,PT,Y) \geq F_{EtoD}(E,D,PT,Y') \ , \quad PT \in \{GF, Exp\}, \qquad Y > Y'$$

$$F_{EtoU}(E,U,PT,Y) \geq F_{EtoU}(E,U,PT,Y') \ , \quad PT \in \{GF, Exp\}, \qquad Y > Y'$$

$$F_{EtoR}(T,E,R,PT,M,Y) \geq F_{EtoR}(T,E,R,PT,M,Y') \ , \quad PT \in \{GF, Exp\}, \qquad Y > Y'$$

Extraction Stage

$$F_{out}(E,PT,Y) = \sum_{D} F_{EtoD}(E,D,PT,Y) + \sum_{U} F_{EtoU}(E,U,PT,Y) + \sum_{R} F_{EtoR}(T,E,R,PT,M,Y)$$

$$F_{out-add}(E,PT,Y) = F_{out}(E,PT,Y) - F_{out}(E,PT,Y'), \qquad Y' = Y - 1$$

Dilution Stage

$$F_{in}(D,Y) = \sum_{E,PT} F_{EtoD}(E,D,PT,Y)$$

$$F_{out}(D,Y) = \sum_{T,R,M} F_{DtoR}(T,D,R,M,Y)$$

$$F_{in}(D,Y) \times DilbtoBit(D) = F_{out}(D,Y)$$

Upgrading Stage

$$F_{in}(U,Y) = \sum_{E,PT} F_{EtoU}(E,U,PT,Y)$$

$$F_{out}(U,Y) = \sum_{T,R,M} F_{UtoR}(T,U,R,M,Y)$$

$$F_{in}(U,Y) \times SCOtoBit(U) = F_{out}(U,Y)$$

$$F_{in-add}(U,Y) = F_{in}(U,Y) - F_{in}(U,Y'), \qquad Y' = Y - 1$$

$$F_{out-add}(U,Y) = F_{out}(U,Y) - F_{out}(U,Y'), \qquad Y' = Y - 1$$

Refining Stage

$$\sum_{RF} F_{inR}(R,RF,M,Y)$$

$$= \sum_{T,E,P} F_{EtoR}(T,E,R,PT,M,Y) + \sum_{T,D} F_{DtoR}(T,D,R,M,Y)$$

$$+ \sum_{T,U} F_{UtoR}(T,U,R,M,Y)$$

$$F_{RProd}(R,RP,M,Y) = \sum_{RF} F_{inR}(R,RF,M,Y) \times ProdComp(R,RP,RF)$$

$$F_{in}(R,Y) = \sum_{RF,M} F_{inR}(R,RF,M,Y)$$

$$F_{out}(R,Y) = \sum_{RP,M} F_{RProd}(R,RP,M,Y)$$

Upper and Lower Bounds

$$F_{in}(U,Y) \leq Bupg(U,Y) \times Fmax$$

$$F_{in}(U,Y) \geq Bupg(U,Y) \times Fmin$$

$$F_{in-add}(U,Y) \leq Bupg_{add}(U,Y) \times Fmax$$

$$F_{in-add}(U,Y) \geq Bupg_{add}(U,Y) \times Fmin$$

$$F_{inR}(R,RF,M,Y) \leq Bref(R,RF,M,Y) \times Fmax$$

$$F_{inR}(R,RF,M,Y) \geq Bref(R,RF,M,Y) \times Fmin$$

Defining Refinery Feed Types

$$F_{inR}(R,\text{"}Dilbit\text{"},M,Y) = \sum_{T,D} F_{DtoR}(T,D,R,M,Y)$$

$$F_{inR}(R,\text{"}SCO\text{"},M,Y) = \sum_{T,U} F_{UtoR}(T,U,R,M,Y) \quad , \quad U \in \{DC,HC\}$$

$$F_{inR}(R,\text{"}PUB\text{"},M,Y) = \sum_{T,U} F_{UtoR}(T,U,R,M,Y) \quad , \quad U \in \{CSC\}$$

$$F_{inR}(R,\text{"}ISEU\_PUB\text{"},M,Y) = \sum_{T,E,PT} F_{EtoR}(T,E,R,PT,M,Y) \quad , \quad E \in \{ISEU\}$$

Emissions

Similar to Appendix B.

Costs

Similar to Appendix B.

GHG related constraints

$$GHG_{total}(Y) = GHG_{ext}(Y) + GHG_{dil}(Y) + GHG_{upg}(Y) + GHG_{ref}(Y) + GHG_{transport}(Y) + GHG_{end-use}(Y)$$

$$GHG_{total-dir}(Y) = GHG_{ext-dir}(Y) + GHG_{upg-dir}(Y) + GHG_{ref-dir}(Y) + GHG_{transport}(Y) + GHG_{end-use}(Y)$$

$$GHG_{total-ups}(Y) = GHG_{ext}(Y) + GHG_{dil}(Y) + GHG_{upg}(Y)$$

$$GHG_{total-ds}(Y) = GHG_{ref}(Y) + GHG_{transport}(Y) + GHG_{end-use}(Y)$$

$$GHG_{total-dir-ups}(Y) = GHG_{ext-dir}(Y) + GHG_{upg-dir}(Y)$$

$$GHG_{total-dir-ds}(Y) = GHG_{ref-dir}(Y) + GHG_{transport}(Y) + GHG_{end-use}(Y)$$

$$GHG_{total-offsetted}(Y) = GHG_{total}(Y) - offset(Y)$$

$$GHG_{total-dir-offsetted}(Y) = GHG_{total-dir}(Y) - offset(Y) - DAC(Y)$$

$$GHG_{total-dir-ups-offsetted}(Y) = GHG_{total-dir-ups}(Y) - offset_{ups}(Y) - DAC_{ups}(Y)$$

$$GHG_{total-dir-ds-offsetted}(Y) = GHG_{total-dir-ds}(Y) - offset_{ds}(Y) - DAC_{ds}(Y)$$

$$GHG_{total-dir-offsetted}(Y) \leq GHG_{target} \times GHG_{baseline}$$

$$GHG_{total-dir-ups-offsetted}(Y) \leq GHG_{target} \times GHG_{baseline-ups}$$

$$GHG_{total-dir-ds-offsetted}(Y) \leq GHG_{target} \times GHG_{baseline-ds}$$

Offset constraint

$$Offset(Y) \ \leq offset_{limit} \times GHG_{total-dir}(Y)$$

$$offset_{ups}(Y) \ \leq offset_{limit-ups} \times GHG_{total-dir-ups}(Y)$$

$$offset_{ds}(Y) \ \leq offset_{limit-ds} \times GHG_{total-dir-ds}(Y)$$

Cost related constraints

$$Cost_{total}(Y) = Cost_{ext}(Y) + Cost_{dil}(Y) + Cost_{upg}(Y) + Cost_{ref}(Y) + Cost_{transport}(Y)$$

$$\begin{aligned} Cost_{total+offset}(Y) & \\ &= Cost_{total} + offsetPrice \times \left[offset_{ups}(Y) + offset_{ds}(Y)\right] \\ &+ DACCost \times \left[DAC_{ups}(Y) + DAC_{ds}(Y)\right] \end{aligned}$$

$$Capital_{total}(Y) \leq AnnualCapital(Y)$$

$$\sum_{RF} F_{inR}(R, RF, M, Y) \leq RefCapacity(R, M)$$

$$\sum_{E,R,PT} F_{EtoR}(T, E, R, PT, M, Y) + \sum_{D,R} F_{DtoR}(T, D, R, M, Y) + \sum_{U,R} F_{UtoR}(T, U, R, M, Y)$$

$$\leq TransCapacity(T, M)$$

Required Product Limit

$$\sum_{R,RP} F_{RProd}(R, RP) \times LHV(RP) = 100 \text{ (arbitrary number,does not impact the results)},$$

$$RP \in \{BlendGas, ULSD, JetFuel\}$$

C.6. Model Inputs

The value of input parameters of the model are presented in X to Y.

Table C 3 below shows the maximum amount of offset credits that can be used to offset a project emissions to achieve the reduction targets. Offset limit is presented as a fraction of total project's emissions.

Table C 3 Offset credits limit as a fraction of a project's total emissions

Year	Offset limit	Year	Offset limit	Year	Offset limit
2021	0.3	2031	0.1	2041	0
2022	0.3	2032	0.1	2042	0
2023	0.3	2033	0.1	2043	0
2024	0.3	2034	0.1	2044	0
2025	0.3	2035	0.1	2045	0
2026	0.1	2036	0	2046	0
2027	0.1	2037	0	2047	0
2028	0.1	2038	0	2048	0
2029	0.1	2039	0	2049	0
2030	0.1	2040	0	2050	0

Table C 4 shows the volume of bitumen production forecast for greenfield and expansion projects between 2021 and 2050. Forecast data is extracted from Canada's Energy Future 2020 report published by CER [148].

Table C 4 Bitumen production forecast, base case and low case scenarios

Year	Bitumen production – base case (BPD)	Bitumen production – low case (BPD)	Year	Bitumen production – base case (BPD)	Bitumen production – low case (BPD)
2021	152,307	152,307	2036	1,106,448	705,837
2022	188,261	183,717	2037	1,144,384	702,415
2023	228,662	217,623	2038	1,182,612	697,333
2024	270,878	251,263	2039	1,222,988	691,621
2025	330,157	298,280	2040	1,241,747	672,256
2026	429,566	377,722	2041	1,281,995	663,101
2027	533,203	455,980	2042	1,313,299	647,592
2028	623,321	518,002	2043	1,350,253	633,222
2029	682,329	550,569	2044	1,399,441	622,510
2030	761,181	595,821	2045	1,435,608	603,945
2031	846,808	642,406	2046	1,455,832	577,313
2032	865,917	636,001	2047	1,476,775	549,971
2033	901,022	640,037	2048	1,495,234	520,754
2034	972,237	667,156	2049	1,526,181	494,693
2035	1,069,609	708,155	2050	1,532,725	459,817

Table C 5 shows a forecast of Alberta grid electricity emission intensity forecast between 2021 and 2050, based on AESO's Clean Tech Scenario [149].

Table C 6 shows NG price (AECO-C base price) forecast in Canada, extracted from Alberta Energy Outlook published by the Alberta Energy Regulator (ST98) [135].

Table C 7 shows NG price (Henry Hub) forecast in the U.S., for Reference and Evolving Scenarios from [150].

Table C 5 Alberta grid emission intensity forecast

Year	AB Grid Intensity (g/kWh)	Year	AB Grid Intensity (g/kWh)	Year	AB Grid Intensity (g/kWh)
2021	545.8	2031	244.4	2041	222.9
2022	441.1	2032	245.5	2042	218.4
2023	361.2	2033	242.7	2043	214.0
2024	300.5	2034	242.1	2044	209.7
2025	282.5	2035	234.4	2045	205.6
2026	269.7	2036	237.4	2046	201.4
2027	264.6	2037	234.0	2047	197.4
2028	254.4	2038	234.4	2048	193.5
2029	249.1	2039	230.9	2049	189.6
2030	246.9	2040	223.3	2050	185.8

Table C 6 Natural gas price forecast in Canada, AECO-C base price

Year	NG Price – Canada (CAD/GJ)			Year	NG Price – Canada (CAD/GJ)		
	Low case	Base case	High case		Low case	Base case	High case
2021	2.28	2.83	3.52	2036	3.38	4.20	5.22
2022	2.4	2.99	3.71	2037	3.42	4.26	5.29
2023	2.45	3.05	3.79	2038	3.47	4.31	5.36
2024	2.54	3.16	3.94	2039	3.51	4.37	5.43
2025	2.64	3.29	4.09	2040	3.55	4.42	5.50
2026	2.68	3.33	4.14	2041	3.58	4.46	5.54
2027	2.78	3.46	4.3	2042	3.60	4.48	5.57
2028	2.89	3.59	4.47	2043	3.63	4.51	5.61
2029	3	3.73	4.64	2044	3.64	4.53	5.63
2030	3.11	3.87	4.81	2045	3.67	4.57	5.68
2031	3.15	3.93	4.88	2046	3.69	4.59	5.70
2032	3.20	3.98	4.95	2047	3.71	4.62	5.74
2033	3.24	4.04	5.02	2048	3.73	4.64	5.77
2034	3.29	4.09	5.08	2049	3.75	4.67	5.80
2035	3.33	4.15	5.15	2050	3.78	4.70	5.84

Table C 7 Natural gas price forecast in U.S., Henry Hub price

Year	NG Price – U.S. (USD/GJ)		Year	NG Price – U.S. (USD/GJ)	
	Reference Scenario	Evolving Scenario		Reference Scenario	Evolving Scenario
2021	1.94	1.94	2036	3.60	3.40
2022	2.32	2.32	2037	3.65	3.44
2023	2.37	2.35	2038	3.70	3.48
2024	2.46	2.42	2039	3.74	3.52
2025	2.54	2.48	2040	3.79	3.55
2026	2.66	2.60	2041	3.82	3.55
2027	2.80	2.71	2042	3.84	3.55
2028	2.93	2.82	2043	3.87	3.55
2029	3.06	2.95	2044	3.89	3.55
2030	3.18	3.06	2045	3.91	3.55
2031	3.32	3.18	2046	3.93	3.55
2032	3.36	3.21	2047	3.96	3.55
2033	3.41	3.25	2048	3.98	3.55
2034	3.46	3.29	2049	4.00	3.55
2035	3.51	3.33	2050	4.03	3.55

Table C 8 Condensate price forecast

Year	Condensate Price (CAD/bbl)		Year	Condensate Price (CAD/bbl)	
	Base Case	Low Case		Base Case	Low Case
2021	82.3	82.3	2036	96.9	96.9
2022	82.4	82.4	2037	98.9	98.2
2023	78.7	78.7	2038	100.8	99.5
2024	75.0	75.0	2039	102.9	100.8
2025	76.6	76.6	2040	104.9	102.0
2026	78.3	78.3	2041	107.0	102.8
2027	80.0	80.0	2042	109.2	103.3
2028	81.8	81.8	2043	111.3	104.1
2029	83.6	83.6	2044	113.6	104.6
2030	85.4	85.4	2045	115.8	105.3
2031	87.2	87.2	2046	118.2	105.9
2032	89.1	89.1	2047	120.5	106.6
2033	91.1	91.1	2048	122.9	107.1
2034	93.0	93.0	2049	125.4	107.6
2035	95.0	95.0	2050	127.9	108.4

C.7. Additional Scenarios Results

Results of additional scenarios are presented in Figures C 1 to C 8.

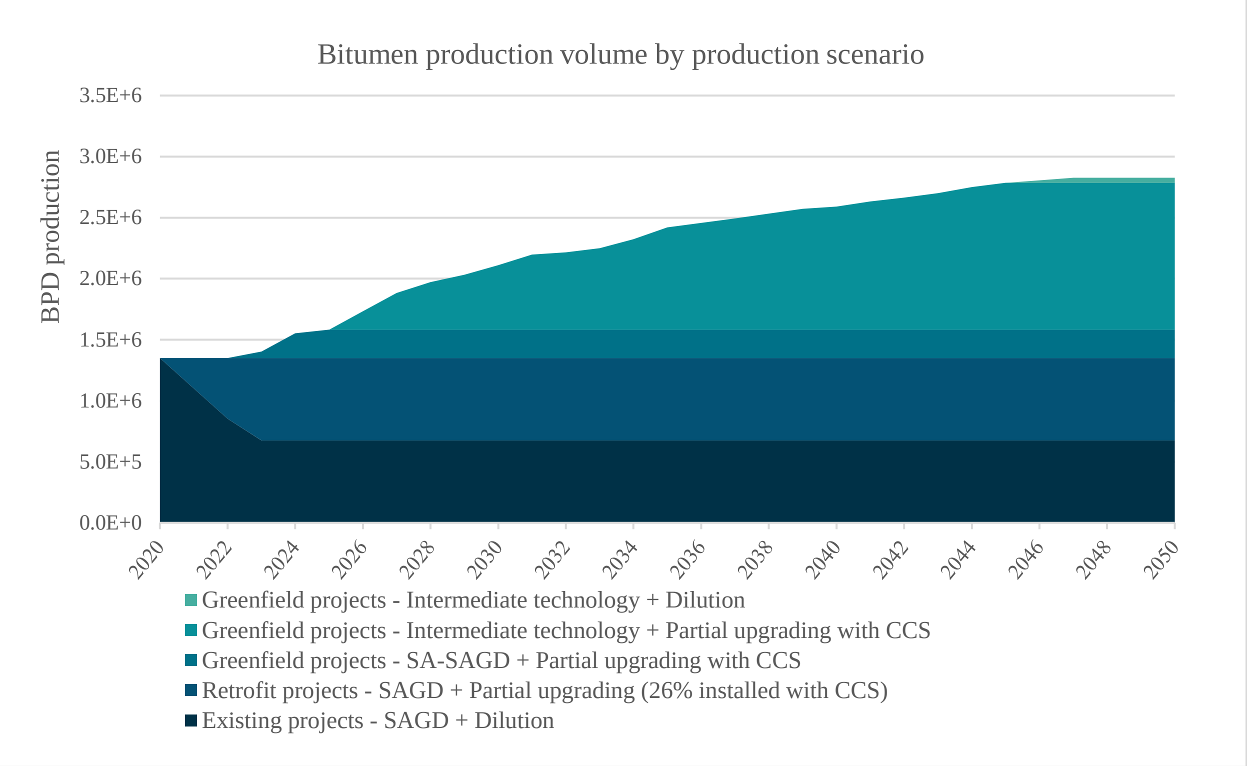

Figure C 1 Bitumen production pathways under Scenario 1-1

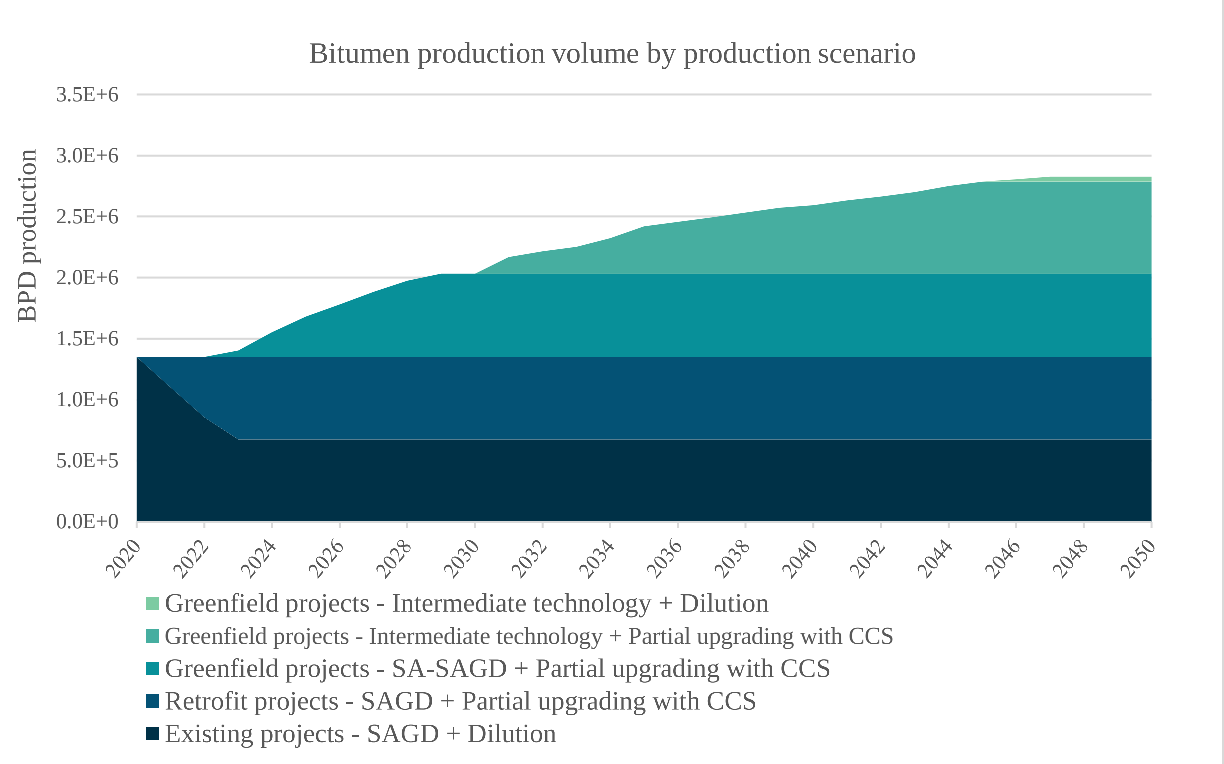

Figure C 2 Bitumen production pathways under Scenario 1-2

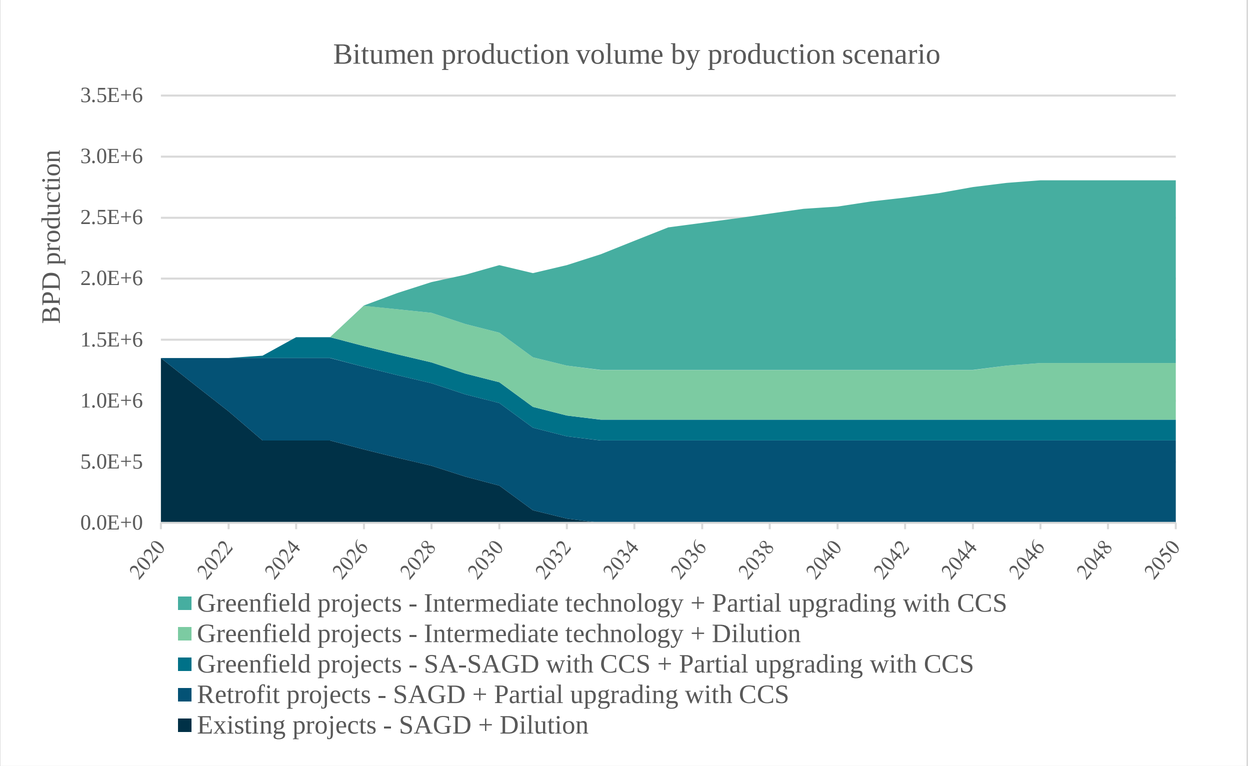

Figure C 3 Bitumen production pathways under Scenario 2-1

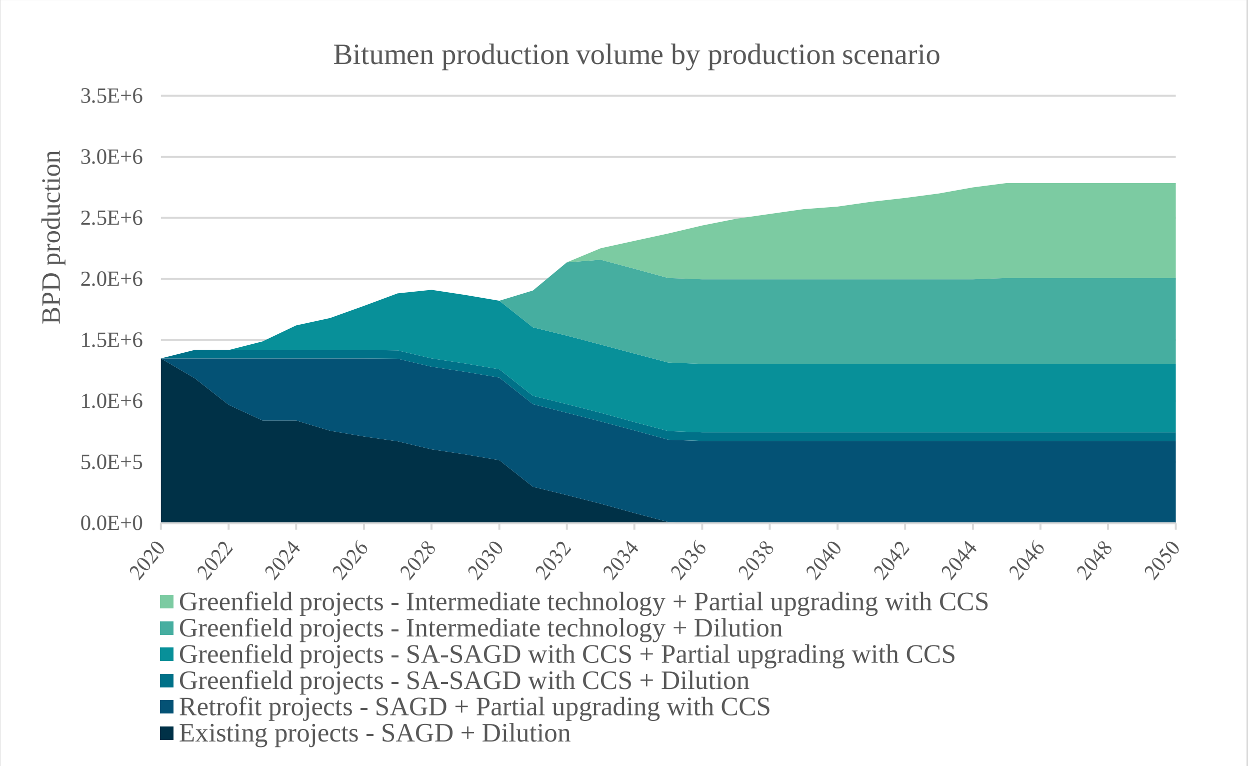

Figure C 4 Bitumen production pathways under Scenario 2-2

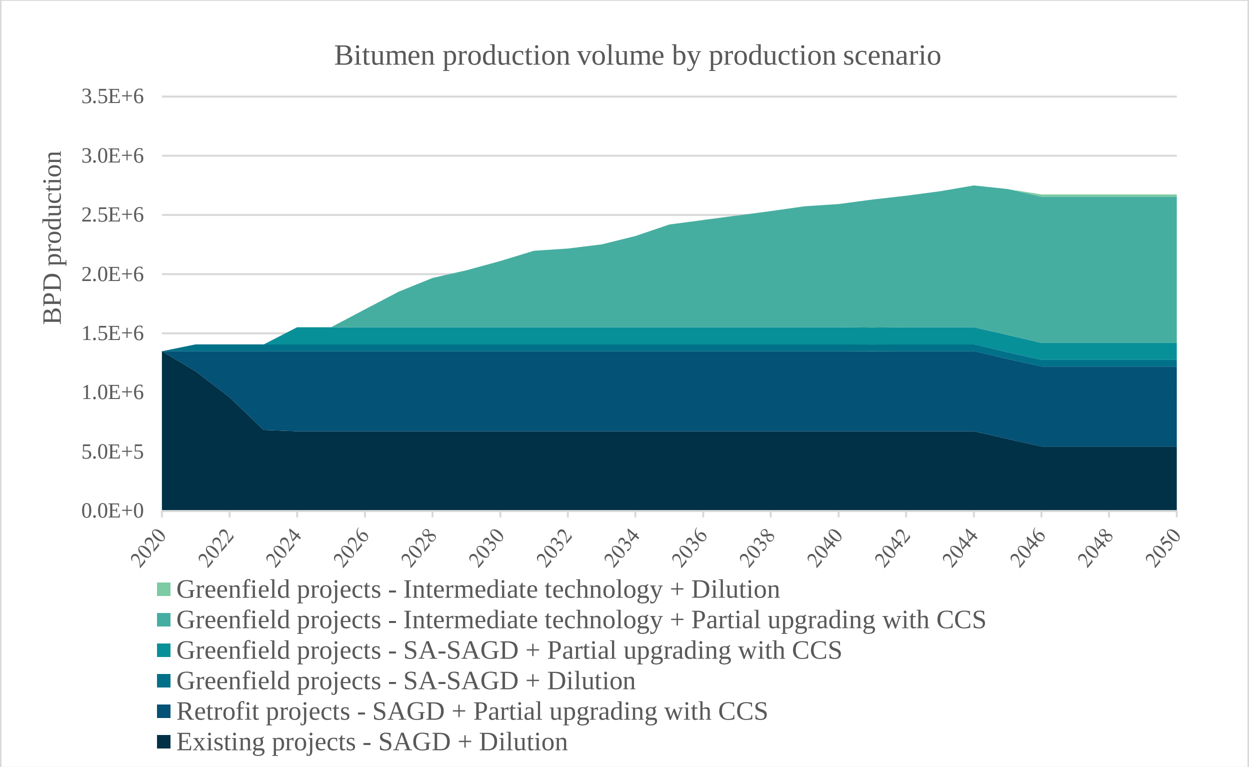

Figure C 5 Bitumen production pathways under Scenario 2-3

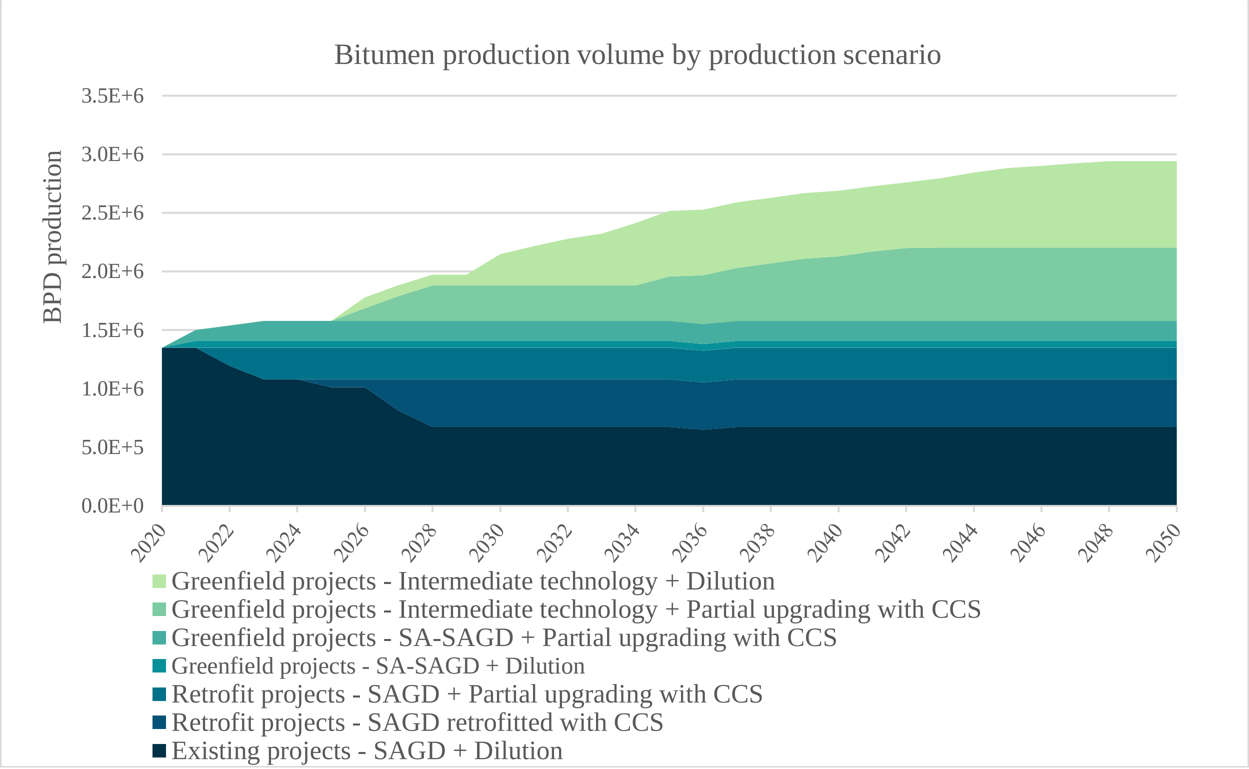

Figure C 6 Bitumen production pathways under Scenario 2-4

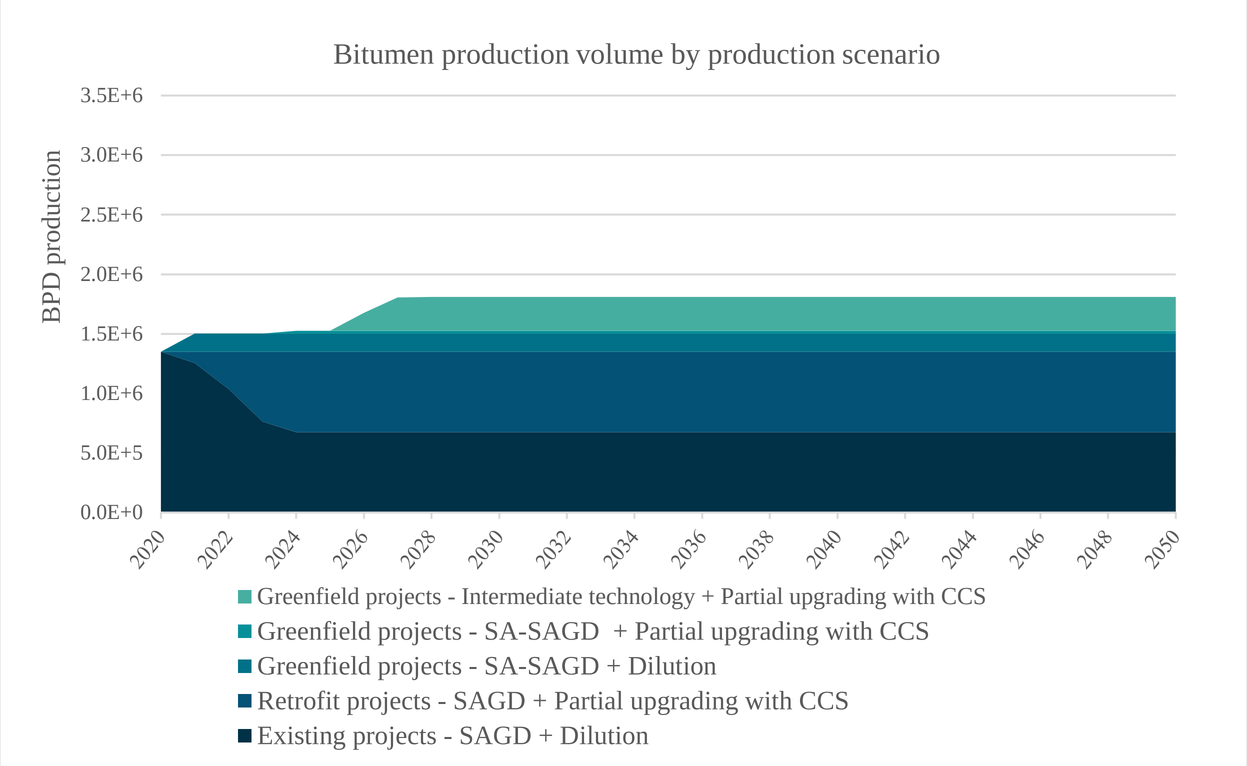

Figure C 7 Bitumen production pathways under Scenario 5

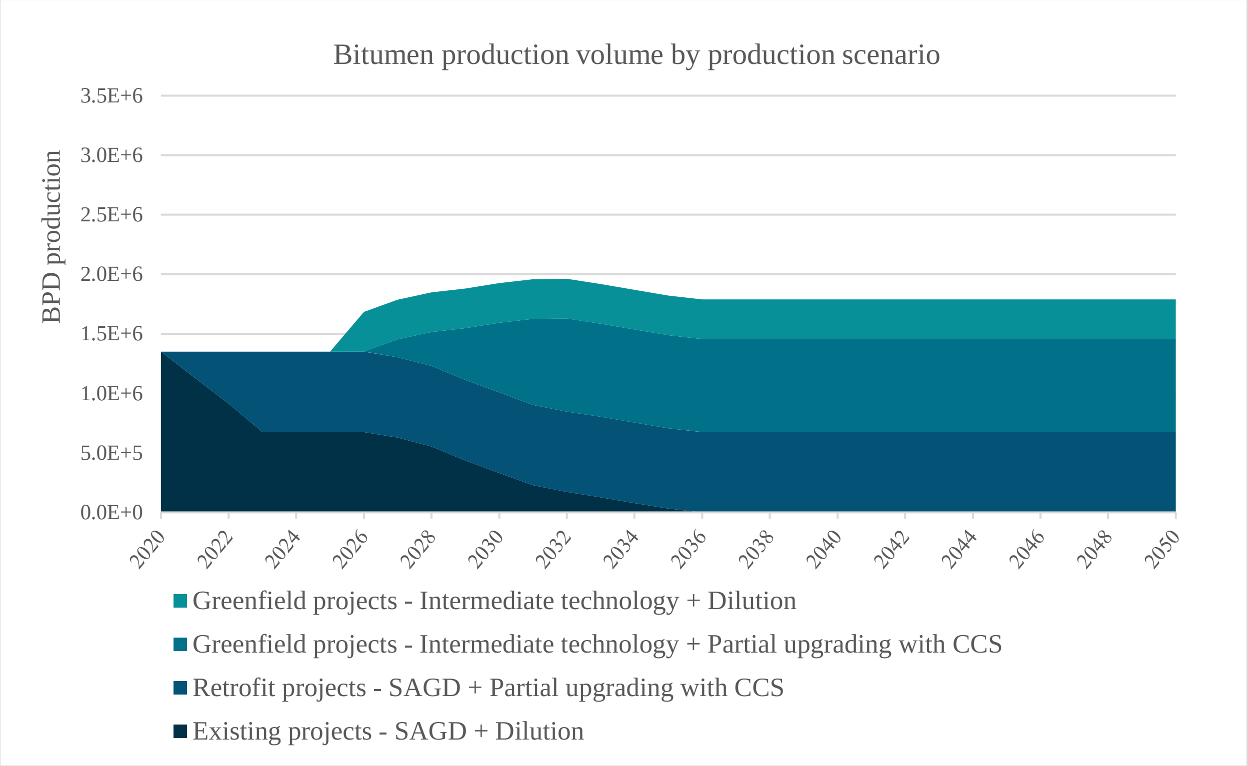

Figure C 8 Bitumen production pathways under Scenario 5-1