UNIVERSITY OF CALGARY

Feasibility of CCUS to CO_2-EOR in Alberta

by

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ABSTRACT

Carbon Capture Utilization and Storage (CCUS) is a critical mitigation technology in the fight to reduce global emissions and CO_2 utilization through Enhanced Oil Recovery (EOR) is an influential economic driver. This study presents a method and techno-economic model that considers reservoir suitability for CO_2-EOR and price conditions at which CO_2 projects become feasible and applies financial levers to identify cumulative CO_2 storage potential and incremental oil recovery in Alberta. The results demonstrate that CO_2-EOR in Alberta has the potential to store between 131Mt and 1.3Gt of CO_2 at a minimum field-delivered CO_2 price of $60/tonne. There are, however, a limited number of economic pool-clusters with material CO_2 storage potential. Financial levers can bridge the gap in CO_2 supply price and reduce economic risks for CO_2-EOR projects to promote the further deployment of CCUS to CO_2-EOR in Alberta.

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LIST OF ABBREVIATIONS AND NOMENCLATURE

AER – Alberta Energy Regulator

bbl – Stock tank barrel of oil

BTIRR – Before Tax Internal Rate of Return

BTNPV – Before Tax Net Present Value

BTNPV10 – Before Tax Net Present Value at 10% Discount Rate

CAPEX – Capital Expenditure

CO_2 – Carbon dioxide

CO_{2e} – Carbon dioxide equivalent

CCS – Carbon Capture and Storage

CCUS – Carbon Capture, Utilization and Storage

EOR – Enhanced Oil Recovery

F&D – Finding and Development Costs

Gt – Gigatonne (metric)

HCPV – Hydrocarbon Pore Volume

IEA – International Energy Agency

mmbbl – Million stock tank barrels of oil

MMP – Minimum Miscible Pressure

mscf – Thousand standard cubic feet

Mt – Million (metric) tonnes

OOIP – Original Oil in Place

OPEX – Operating Expenditure

P/I – Profitability Index

ROIP – Remaining Oil in Place

t – tonne (metric)

VRR – Voidage Replacement Ratio

WACC – Weight average cost of capital

WAG – Water-alternating Gas

WTI – West Texas Intermediate

CHAPTER 1: INTRODUCTION

In the International Energy Agency (IEA) Sustainable Development Scenario (SDS), which is aligned with the Paris Agreement, Carbon Capture Utilization and Storage (CCUS) accounts for 9% of global emissions reduction by 2050 (International Energy Agency [IEA], 2019). Carbon dioxide capture is a widely recognized and vital strategy for reducing anthropogenic carbon dioxide (CO_2) emissions. CO_2, once captured, can be injected and permanently stored in the process of enhancing recovery from oil fields.

Alberta has both oil fields amenable to CO_2-flood Enhanced Oil Recovery (CO_2-EOR) and significant direct sources of CO_2 emissions from oil sands, power generation, and other industrial activities. Yet there have been fewer than 20 CO_2-EOR projects, including pilot projects, executed in Alberta (BMO Capital Markets, 2020; Gunter & Longworth, 2013). Only one has been approved in the past 10 years (BMO Capital Markets, 2020).

Why are there so few CO_2-EOR projects? Can Carbon Capture Utilization and Storage (CCUS) through CO_2 Enhanced Oil Recovery (EOR) be commercial in Alberta in the near term? What levers can be used to promote further deployment of CO_2-EOR in Alberta? What is the resulting incremental oil recovery and CO_2 stored via CO_2-EOR?

1.1 Anchors in Sustainable Energy Development

This capstone project incorporates energy, environment, and economic dimensions of sustainable energy development for Alberta. This project is about energy because it analyzes the potential incremental oil recovery through CO_2-EOR in Alberta – the utilization component in CCUS. It also affects the environment by investigating the potential volume of CO_2 that can be geologically stored. The third dimension is the economic feasibility of CO_2 storage through CO_2-EOR and is being investigated through screening and techno-economic modelling.

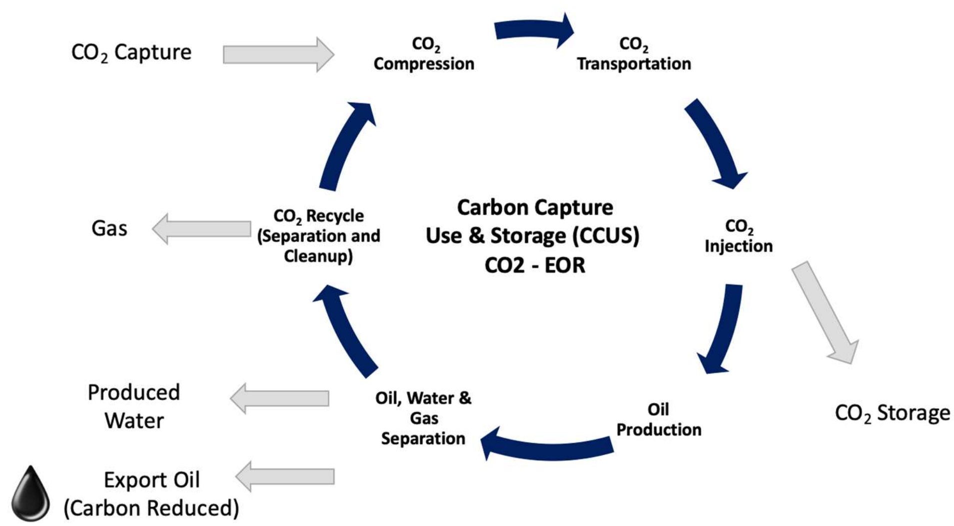
Energy production through fossil fuel extraction and processing is a cornerstone of the economy of Alberta. Canada has also committed to clear emission reduction targets under the Paris

Agreement. Advancing both agendas is only possible by finding pragmatic and economical solutions to reducing emissions. Without there being a clear economic driver, the further deployment of CCUS will be slow, as there will be no financial incentive for both industry and government to invest in future projects. CCUS is at the center of Alberta's energy, environmental, and economic issues.

1.2 CCUS to CO_2-EOR Overview

The CCUS through EOR value chain involves capturing CO_2 produced by point sources such as power plants, oil and gas extraction and processing, power generation, fertilizer plant, ethanol generation, and other industrial processes through physical or chemical absorption, adsorption, membranes, or other technologies. CO_2 is then compressed, transported, and injected into geological formations either for permanent storage or for enhanced recovery for oil fields.

Figure 1: Core functional activities used in CO_2-EOR



Source: (Author, 2020)

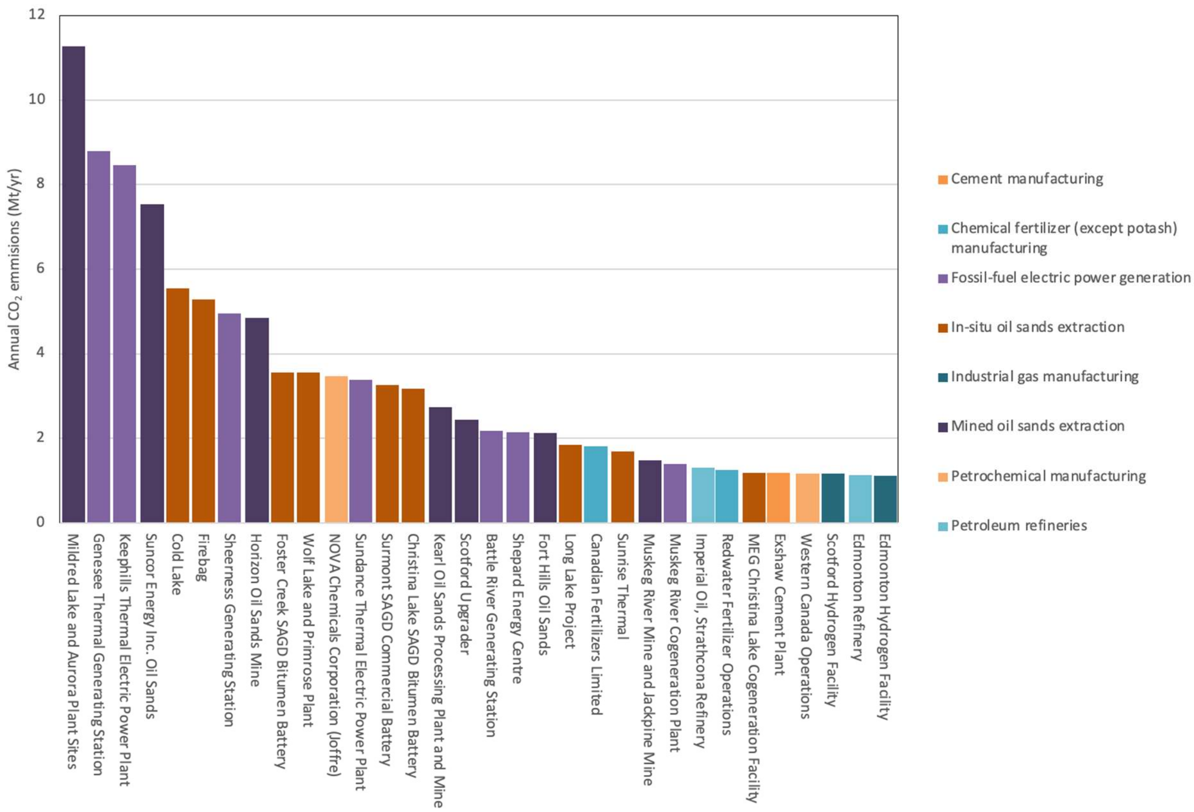
Carbon capture, utilization, and storage is one of the few feasible options for governments and private organizations to cause deep reductions of CO_2 emissions from fossil fuel use to meet future emissions targets. Enhanced Oil Recovery is the only proven utilization technology that can create a revenue stream, through produced incremental oil, while actually storing CO_2 and being deployed in the short to medium-term to handle billions of tons of captured CO_2.

There are other non-EOR uses for CO_2, but their technology readiness, scale, and commercial markets are currently limited, and many result only in the temporary storage of CO_2. Today, 18 of the 23 total global large-scale CCUS facilities in operation or under construction involve an enhanced oil recovery revenue stream (Global CCS Institute, 2019). CO_2-EOR is one of the most effective enhanced oil recovery methods, recovering an additional 7–23% of the original oil in place from the reservoirs (Bachu, 2015; Brock & Bryan, 1989; Martin & Taber, 1992).

Also, CO_2-EOR has the potential to produce oil with reduced carbon intensity. Azzolina et al. (2016) reported that the carbon intensity per barrel for CO_2-EOR using captured CO_2 could achieve less than 300kg CO_{2e}/bbl compared to a conventional barrel of approximately 500kg CO_{2e}/bbl (U.S. Department of Energy National Energy Technology Laboratory [DOE NETL], 2008; Mangmeechai, 2009). This conclusion is supported by a 2015 IEA study that reported that oil produced through CO_2-EOR is 63% less carbon intensive than a conventionally produced barrel (IEA, 2015).

Alberta has world-class geological CO_2 storage and EOR potential and material quantities of direct stationary sources of CO_2 emissions. In 2018, Alberta emitted 144.9 Mt of CO_2 from industrial sources, of which 118 Mt came from the top 50 largest emitters. Oil sands extraction operations, located around the Athabasca and Cold Lake regions of the province, emitted over 70 Mt, predominately from direct sources through steam generation and bitumen upgrading. Emissions-intensive sources in the province are concentrated in the same areas, presenting an opportunity to cluster sources, create economies of scale for carbon, capture, and storage, and reduce the investment risk (Middleton & Brandt, 2013). In addition, Alberta has an estimated 213 to 1,742 Mt CO_2 cumulative CCUS-EOR storage-related capacity with an associated incremental oil recovery of 759 to 2,858 mmbbl (Bachu, 2015).

Figure 2: 2018 Alberta CO_2 emissions by source – sources greater than 1 Mt CO_2/yr



Source: (Environment and Climate Change Canada, 2020)

There have been fewer than 20 CO_2-EOR pilot projects executed in Canada since 1980, and fewer than 15 carbon capture projects proposed (BMO Capital Markets, 2020; Gunter & Longworth, 2013; Zero Emission Resource Organisation, 2017). Table 1 shows the list of pilot and commercial CO2-EOR projects in Alberta and Saskatchewan. There are three current commercial CO_2-EOR projects operating in Alberta, Clive, Joffre, and Chigwell fields (Alberta Energy Regulator [AER], 2020). Of the carbon capture projects proposed, there are fewer than five large-scale CCUS projects currently in operation. The most recent projects are the Shell Quest CCS, a capture to permanent storage project, i.e., non-EOR, and ACTL (Alberta Carbon Trunk Line), from Alberta's Industrial Heartland to Clive EOR project, approved in 2010 and 2011 respectively.

The total estimated CO_2 capture capacity from the existing large-scale CCUS projects in Canada is 4.0 Mtpa (Global CCS Institute, 2019). No large-scale CCUS to EOR has been proposed or approved in Alberta in almost a decade. There still remains a large disconnect between the volume of industrial anthropogenic CO_2 emissions and the amount of CO_2 stored and or utilized in Alberta.

Table 1: Pilot and commercial CO_2 floods in Alberta and Saskatchewan

Field	Pool	OOIP (mmbbl)	API (°)	Pilot	Type	CO_2 Start (yr)	Current R.F. (%)	Cum. Oil Prod. (mmbbl)	Status (BMO Capital Markets, 2020; Gunter & Longworth, 2013)
Pembina	Cardium	10,576	38	X	Miscible	2005	14%	1,431	Discontinued 2010 – Technical Success
Swan Hills	Beaverhill Lake A&B	2,900	41	X	Miscible	2004	32%	929	Discontinued 2007 – Technical Success
Weyburn/Estevan	Weyburn Midale	1,500	30		Miscible	2000	35%	521	Operating - Saskatchewan
Redwater	D-3	1,300	36	x	Immisible	2008	65%	847	Discontinued 2010 – Technical Success
Swan Hills South	Beaverhill Lake A	1,084	41	X	Miscible	2008	37%	400	Discontinued 2010 – Technical Success
Judy Creek	Beaverhill Lake A&B	1,020	42	X	Miscible	2007	49%	500	Discontinued n.d. – Technical Success
Weyburn/Estevan	Midale Central Midale	730	30		Miscible	2005	22%	158	Operating - Saskatchewan
Clive	D-3A	97	40		Miscible	2019/2020	48%	47	Operating - Alberta
Joffre	Viking	89	38		Miscible	1984	48%	43	Operating - Alberta
Chigwell	Viking I & E	64	33		Miscible	2007	11%	7	Operating - Alberta
Zama	Keg River (X2X, etc)*	24	35-39	X	Miscible	2004	33%	8	Discontinued 2007 – Technical Success
Enchant	Arcs A & B	11	26	X	Miscible	2004	37%	4	Discontinued 2008 – Unsuccessful, <MMP

Source: (BMO Capital Markets, 2020)

Table 2: Large-scale CCS facilities in operation in Canada

Project	Status	Operation Date	Industry	Capture Capacity (Mtpa)	Capture Type	Storage Type
Quest	Operating	2015	Hydrogen Production for Oil Refining	1.0	Industrial Sequestration	Dedicated Geological Storage
Boundary Dam CCS	Operating	2014	Power Generation	1.0	Post-combustion capture	Enhanced Oil Recovery
Alberta Carbon Trunk Line (ACTL)	Under Construction	2020	Production/Chemical Production	0.3-0.6 (Fertilizer) 1.2-1.4 (Refinery)	Industrial separation	Enhanced Oil Recovery
Total				**3.5-4.0 Mtpa**		

Source: (Global CCS Institute, 2019)

CHAPTER 2: BACKGROUND

There have been several studies to date looking at elements of the carbon capture to CO_2-EOR in Alberta. This work has either focused on identifying reservoirs for CO_2 storage potential (Bachu & Stewart, 2002) and EOR (Bachu, 2015), or specifically on infrastructure requirements to link direct sources to storage reservoirs (Craig & Butler, 2017; Middleton & Brandt, 2013). In 2013, Middleton and Brandt presented an optimized CO_2 management infrastructure system from the Alberta oil sands to saline aquifer sinks for storage, finding that significant capture and storage occurs only above $110/tonne (t) CO_2 (Middleton & Brandt, 2013). More recently, Craig and Butler studied Alberta CO_2 pipeline hydraulics and costs, analyzing the technical parameters that would underpin an Oil Sands CO_2 pipeline network (Craig & Butler, 2017). Gunter and Longworth (2013) discussed barriers to further deployment of CCUS-EOR in Alberta, including a discussion of future business models, none of which completed a detailed techno-economic evaluation. Previous studies have highlighted the need for further understanding of economic component of CO_2-EOR utilization in CCUS. “Future work should account for the co-benefits associated with CO_2 utilization (e.g. EOR)” (Middleton & Brandt, 2013, p. 1,742).

The most recent research in Alberta has excluded the economic component of CO_2-EOR in CCUS. There has been no recent study that takes an in-depth look at Alberta CO_2-EOR project economics, the most economic places to sequester CO_2 through EOR, and the impact financial levers have on the total potential amount of CO_2 stored. The results of this capstone provide an estimation of CO_2 storage associated with CO_2-EOR in Alberta and the conditions required to unlock further storage potential.

A report released by the Alberta Economic Development Authority in 2009 recommends using financial tools like the royalty framework and utilization of public funding to augment private funding to accelerate EOR deployment (Alberta Economic Development Authority, 2009). However, no study has expanded on the subject of future CCUS-EOR in Alberta, looking specifically at business and financing levers and the economics required to produce the lowest

CO_2 emissions avoidance costs and conditions to promote the greater large-scale deployment of CCUS-EOR.

For CCUS-EOR projects to overcome high initial capital costs and the risks surrounding the price of CO_2, infrastructure requirements, the performance of CO_2-EOR, regulatory uncertainty, and general CCUS industry immaturity, innovative financing structures, and financial and policy levers need to be explored (Gunter & Longworth, 2013).

Increased public ownership can be used to decrease project risk. The federal and provincial governments can de-risk investments by taking on risk that the private sector cannot. Private sector investment in CCUS is profit-driven; governments are driven more by public good. The federal and provincial governments maybe be willing to accept smaller or even forgo profits or tax income in exchange for material reductions in emissions and reduce climate change risk. In addition, government cost of capital is lower than that of the private sector.

CCUS-EOR project economics can be improved significantly through increased revenue, reduced taxes or royalties, or reduced cost of capital, debt, or equity. Green financing instruments (such as green bonds issued by development banks, sovereign or government entities, and banks) can offer this lower cost of capital. Global green bond issuances have grown 1,600% in the past five years, with over $160 billion in issuances in 2018. The sustainable investment industry in Canada has $2.1 trillion in assets under management (BMO Capital Markets, 2020). CCUS to EOR projects in Alberta can benefit from green financing instruments.

The financial levers or tools, described above, are considered and applied to the capstone techno-economic analysis to determine the impact each has to both the economics of CO_2-EOR projects and overall CO_2 storage capacity in the province.

2.1 Fundamentals of Enhanced Oil Recovery (EOR)

Conventional oil production is usually separated into primary, secondary, and tertiary recovery techniques. Primarily, the start of production occurs through using displacement energy and reservoir pressure naturally occurring in the reservoir. Secondary recovery or production techniques are usually applied after initial production to maintain pressure in the reservoir. The most common secondary recovery techniques are waterflooding and gas injection.

Primary and secondary recovery techniques can recover up to 60% of the original oil in place (OOIP) and leave between 40–50% of oil in the reservoir (Bachu, 2015). Recovery techniques that are based on displacement mechanisms using immiscible liquids or gases are considered secondary recovery techniques. Tertiary recovery techniques are incremental production processes that include either miscible gases, chemicals, or thermal energy that are applied to displace incremental oil, usually following secondary recovery.

The term “enhanced oil recovery” (EOR) is generally applied to tertiary recovery techniques. Gas injection processes based on other mechanisms, such as oil swelling, oil viscosity reduction, or favorable phase behavior, are considered EOR processes (Bachu, 2015). Low molecular weight hydrocarbon gases (CH_4), carbon dioxide (CO_2), nitrogen, and flue gases are among the gases used in EOR processes (Green & Willhite, 2018). Gas injection is reported to be the second most popular EOR process in the world after thermal methods used in heavy oil recovery operations (Kulkarni, 2003). EOR through CO_2 is only the enhanced oil recovery technique discussed in this study.

2.2 CO_2 Enhanced Oil Recovery (EOR)

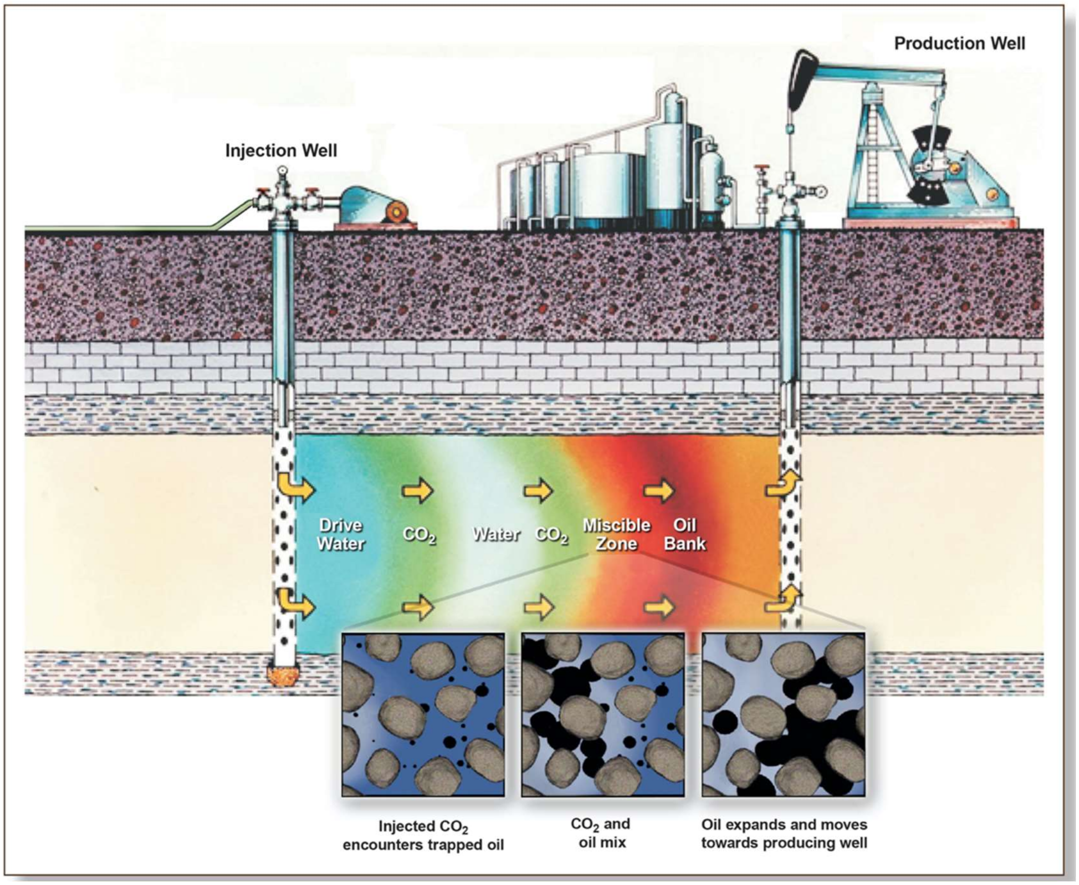
CO_2 enhanced oil recovery (CO_2-EOR) can displace oil either by an immiscible or miscible displacement process. Miscibility is where two fluids can be mixed in all proportions, forming a single fluid with no interface between them. Conversely, immiscible fluids do not form single phase when mixed. Immiscible displacement occurs when the reservoir pressure is too low or the oil composition is too heavy, and the injected CO_2 gas fails to mix with the reservoir oil (DOE

NETL, 2010). The minimum miscibility pressure (MMP) determines the minimum pressure required for the reservoir oil to be miscible with carbon dioxide at reservoir temperature.

Miscible and immiscible displacement process involves several mechanisms to enhance oil recovery: oil swelling, reduction in oil viscosity, and contribution to a solution gas drive production (Bachu, 2015). Oil swelling occurs when carbon dioxide is dissolved into the crude oil and the volume of the oil increases. As the volume of oil increases, oil is displaced from the pore space leading to enhanced oil recovery (Mungan, 1981). As carbon dioxide is dissolved into the crude oil, the oil density and viscosity is also reduced, improving the mobility of the oil. CO_2 can also provide a solution gas drive effect where CO_2 provides additional reservoir drive energy. Both in immiscible and miscible displacement processes, the injected CO_2 changes the residual oil properties to make it more mobile and producible (Lake, 1989). It has been reported that CO_2 can partially dissolve in oil even when full miscibility is not achieved (Rojas, Zhu, Dyer, Thomas, Ali, 1991).

Oil recovery is limited in an immiscible displacement process, and miscible displacement through CO_2 is preferred. During immiscible CO_2 flooding, some oil remains trapped and immobile and does not move into the flowing stream due to capillary forces that prevent the passage of oil through the pore throats. If miscibility is achieved, the interfacial tension or forces between the in-place oil and water phase is reduced, liberating trapped oil, improving the displacement efficiency, and in turn, improving the oil recovery (Green & Willhite, 2018). Also, in immiscible displacement processes, the displacement efficiency and oil recovery is impacted by the large density difference between CO_2 and reservoir oil and also to the adverse mobility ratio between the displacing CO_2 and displaced fluid oil causing fingering and channelling in the reservoir (Bachu, 2015). The miscible CO_2 injection process is shown in Figure 3.

Figure 3: Miscible CO_2 injection process



Source: (DOE NETL, 2010)

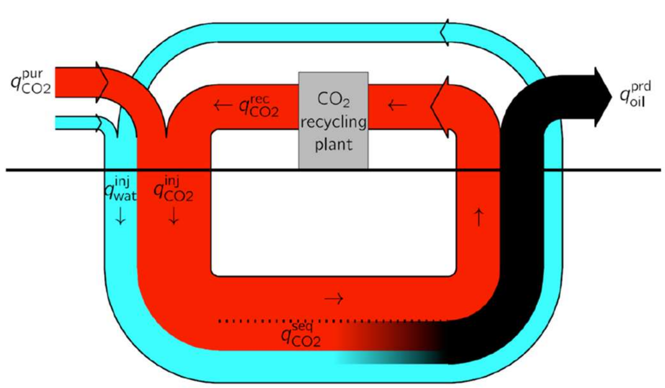
The miscible displacement process is best applied to light- and medium-density oil, and the immiscible displacement process may apply best to heavier oils (Hashemi Fath, 2014). Miscible CO_2-EOR projects have shown incremental oil recovery rates between 7% and 23% (Bachu, 2015; Brock & Bryan, 1989; Martin & Taber, 1992).

Alternating injection of volumes of water and CO_2 is called a water-alternating gas (WAG) process and often used in CO_2-EOR schemes (Azzolina et al., 2015; Green & Willhite, 2018). Over 90% of the CO_2-EOR projects around the world have employed WAG processes (Merchant, 2017). WAG oil recovery processes are employed to improve the oil recovery of miscible flooding processes. Water is injected intermittently with the EOR gas. The displacing water typically has a lower mobility, higher viscosity, and prevents the lower viscosity CO_2 from channelling ahead of the displaced oil. This process improves volumetric sweep efficiency or displacement efficiency over that obtained with just CO_2 injection. Sweep efficiency is the effectiveness of the injected CO_2 contacting the volume of the reservoir where oil resides (Green & Willhite, 2018).

Carbon dioxide is delivered, usually via pipeline, to the CO_2-EOR site. During the process, a volume of relatively pure CO_2 is injected into the reservoir where the CO_2 comes in contact with the reservoir crude oil, forming a miscible phase and mobilizes and displaces the oil. Incremental oil, water, and some CO_2 are then produced through production wells, with CO_2 separated, dried, re-compressed and re-injected at surface.

Not all carbon dioxide is recycled; more than 30% of the CO_2 is retained in the reservoir pore space through capillarity, dissolution in formation water and oil, and structural or stratigraphic trapping mechanisms (Azzolina et al., 2015; Bachu, 2015; Hadlow, 1992; Nuñez-Lopez & Moskal, 2019; Olea, 2015). The remainder of the purchased CO_2 is produced together with oil and water and other hydrocarbon gases. The produced CO_2 is then separated and recycled. There are often some CO_2 surface losses related to surface processing; however, more than 90–95% of purchased CO_2 remains trapped based on industry experience (Azzolina et al., 2015; DOE NETL, 2010; Melzer, 2012).

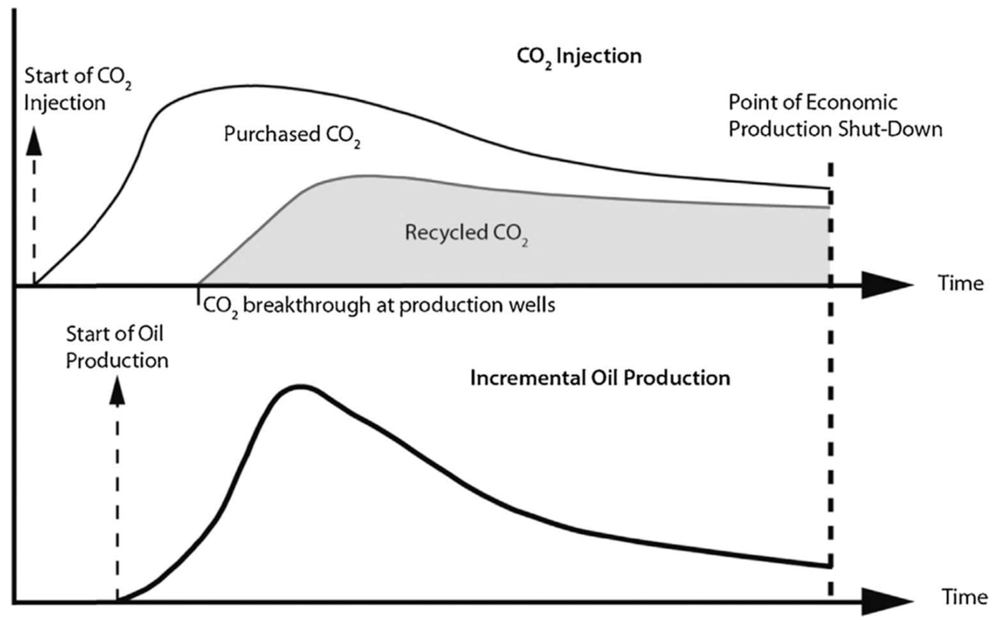
Figure 4: Schematic of fluid flows in CO_2-EOR project



Source: (Azzolina et al., 2015)

To make up for the portion of CO_2 retained in the reservoir, additional CO_2 is purchased. Over the production life of the reservoir, CO_2 gas is recycled with additional CO_2 purchased to offset the gas retained in the reservoir (Azzolina et al., 2015). Figure 4 shows a schematic of CO_2 and oil and water flows in a CO_2-EOR project.

Figure 5: Example of production and injection volumes from a typical CO_2-EOR project



Source: (Bachu, 2015)

CHAPTER 3: METHODOLOGY

The study is divided into several sequential steps. A comprehensive literature review is completed to gather a complete view on current status and understanding CCUS to EOR in Alberta. The study aggregates all emissions and oil reservoir data in Alberta from public sources such as Alberta Energy Regulator (AER) and Environment and Climate Change Canada. Directly applicable results and analysis in related literature are used. A thorough analysis of reservoirs suitable for CO_2-EOR, for example, has been completed in earlier studies (Bachu, 2015).

The study investigates and compiles the cost of capturing CO_2 in Alberta to determine indicative supply cost for CO_2 for EOR. Geographic locations, volumes of Alberta CO_2 emissions, and emissions types were gathered from Environment and Climate Change Canada (Environment and Climate Change Canada, 2020). Reported CO_2 emissions are based on 2018 data. Indicative capture costs were calculated based on a United States capture cost model from Pilorgé et al. (2020).

The multi-regression model from Pilorgé et al. (2020) produces the cost of carbon capture ($/t) as a function of capture rate, flue gas CO_2 concentration, and volumetric flow. The currency-adjusted Pilorgé et al. (2020) model was applied to the Alberta CO_2 emission data set. The concentration of the CO_2 emissions source is dependent on the industrial process where the emission is produced. Table 3 shows the assumed concentration of CO_2 by industrial emission type. As CO_2 concentration in the emissions stream increases, the energy and related cost required for its separation at the high purity required for CO_2-EOR decreases (Pilorgé et al., 2020). There are few pure sources of CO_2 in Alberta. Most CO_2 emissions sources are post-combustion flue gasses with high temperature, atmospheric pressure, and low CO_2 concentration, adding to the cost of capture (Bains et al., 2017).

Table 3: CO_2 emissions type and CO_2 concentration

Emission Type	Flue Gas CO_2 Conc. (mol %)	Source	Comment
Cement manufacturing	30%	Pilorgé et al., 2020	
Chemical fertilizer manufacturing (Ammonia)	45%	Pilorgé et al., 2020	
Coal fired power generation (PC)	13%	Pilorgé et al., 2020	
Gas Plant & Petroleum refineries (FCC)	15%	P. Bains et al., 2017	Fluid catalytic cracker (regeneration of catalyst)
In-situ oil sands extraction (OTSG)	9%	Middleton & Brandt, 2013	Steam generation
Industrial gas manufacturing (H2)	18%	P. Bains et al., 2017	Pressure Swing Abdorption Priocess
Mined Oil Sands Coke - Plant use	13%	Middleton & Brandt, 2013	Assumed consumed in coking unit (some combustion for hot water and steam occurs)
Mined Oil Sands Natural Gas - Further processing	19%	Middleton & Brandt, 2013	Assumed consumed for for hydrogen production.
Mined Oil Sands Natural Gas - Plant use	9%	Middleton & Brandt, 2013	Assumed for steam and hot water generation
Mined Oil Sands Process Gas - Further processing	19%	Middleton & Brandt, 2013	Assumed consumed for for hydrogen production.
Mined Oil Sands Process Gas - Plant use	9%	Middleton & Brandt, 2013	Assumed for steam and hot water generation
Natural Gas fired power generation (GT)	4%	Pilorgé et al., 2020	Natural Gas Combined Cycle
Non-ferrous metal smelting and refining	23%	P. Bains et al., 2017	
Other basic organic chemical manufacturing (Glycol)	15%	P. Bains et al., 2017	
Other basic organic chemical manufacturing (Methanol)	99%	P. Bains et al., 2017	
Petrochemical manufacturing	15%	Pilorgé et al., 2020	

Source: (Author, 2020)

A techno-economic model was built to evaluate the project economics of each suitable pool for CO_2-EOR. The compiled results demonstrate the cost of CO_2 to EOR in Alberta and the resulting CO_2 emission avoidance through CO_2 storage. The capstone techno-economic model will build on, and adapt, recent state-of-the-art (SOA) models (Azzolina et al, 2015; Fukai, Mishra, Moody, 2016; DOE NETL, 2018).

The features of this capstone project methodology and techno-economic model include:

- Aggregating publicly available CO_2 emissions and oil pool reservoir data;
- Screening and ranking oil pools for CO_2-EOR suitability;
- Grouping pools into clusters for production and economic optimization;
- Generating CO_2 purchased and recycled volumes and the resulting incremental oil production volumes using the Azzolina et al. regression model (2015);
- Creating an economic model using the Fukai et al. (2016) CO_2-EOR cost model to run CO_2 -EOR project economics by cluster;
- Applying sensitivities, including financial levers, to the economic model, and
- Running economic scenarios, break-even CO_2 price and fixed CO_2 price scenarios and generating cost curves, evaluating the field-delivered price of CO_2 in Alberta as a function of CO_2 emissions avoided or cumulative CO_2 stored through CO_2-EOR.

The most novel features of the capstone are the analysis of the CO_2-EOR of the CCUS value chain and the building and analysis of the resulting CO_2 supply cost curves.

The capstone results incorporate revenue from EOR, project capital and operating cost, cost of capital, and potential value generation from carbon offsets or credits. The capstone identifies under what conditions CO_2-EOR is most economically viable, the amount of CO_2 storage potential available through CO_2-EOR, and pools where CO_2 storage through CO_2-EOR is most economical. All results are presented in 2019 CAD dollars.

3.1 Modelling Methodology

The following section describes in detail the methodology, models, and inputs used to screen and rank pools for CO_2-EOR suitability, generate purchased CO_2, production and injection volumes, and evaluate indicative project level economics.

3.1.1 CO_2-EOR Screening Criteria

Identifying and screening oil reservoirs for CO_2-EOR suitability is a common practice. There is sufficient historic reservoir performance data from global CO_2-EOR projects to determine the criteria for a successful CO_2-EOR project. The first commercial CO_2-EOR project commenced in 1972 in the U.S (Shaw & Bachu, 2002).

The screening criteria used in the study is based on Buchu (2015) and Koottungal (2014) and can be applied to identify oil reservoirs suitable for CO_2-EOR in any given jurisdiction using information usually available in public databases (Bachu, 2015). Koottungal (2014) performed a global survey to derive a set of screening criteria for identifying oil reservoirs suitable for miscible CO_2-EOR. A comparison of this study's screening criteria against previously published studies is shown in Table 4.

Table 4: Comparison of CO_2 suitability criteria

Screening Criteria	Criteria used for study Bachu (2015)	Koottungal (2014)	Kovscek (2002)	Shaw & Bachu (2002)	Taber, Martin, Seright (1997)	King, Blevins, Britton (1984)	Taber & Martin (1983)	Stalkup (1983)	Carcoana (1982)	OTA (1978)	Iyoho (1978)	McRee (1977)	Lewin and Associates (1976)	Geffen (1973)
ρ (◦API)	27-45	27-45	>22			>25	>26	>27	>40	>27	30-45	>35	>30	>30
μ (mPas)	0.4-6	0.4-6			<10		<15	<12	<2	<12	<10	<5	<12	<3
K (md)	Not Used	1-4500							>1		>10	>5		
Temperature (◦C)	28-127	28-127		31-120					<91					
Depth (m)	500-4100	487-3600			>762		>607		<2987		>762	>607	>914	
Porosity (%)	Not Used, Incomplete Dataset	30-Apr												
Initial oil saturation (%)	Not Used, Incomplete Dataset	26.5-89		>0.25	>0.2		>0.3	>0.2	>0.3		>0.25	>0.25	>0.25	>0.25
Oil saturation at start of CO2-EOR (%)	Not Used, Incomplete Dataset	5-50												
P/MMP	>1			>0.95		>1								

Source: (Author, 2020)

This study applies the following 10 screening criteria to a total of 14,671 pools using pool and reservoir data from the 2018 Alberta Energy Regulator pool and pressure databases (AER, 2019). Data not directly available from the public oil databases, such as minimum miscibility pressure and viscosity, are calculated from correlations (Beggs & Robinson, 1975; Holtz, Núñez-López, Breton, 2005) described in the Bachu (2015) study.

3.1.2 Ranking and Clustering

A weighting factor was applied to each criteria and a total ranking score calculated for each pool. No weighting factor was attributed to those criteria that fell below the criteria threshold. The higher the weight, the higher the importance of the criteria. The most important screening criteria are the current pressure being above the minimum miscibility pressure (MMP) and the oil gravity and oil viscosity of the pools. Miscibility and the optimal oil gravity and viscosity are all critical for a successful miscible CO_2-EOR project to ensure the highest oil recovery through improved oil mobility and high reservoir sweep efficiency. The ranking weight applied was based on the Bachu (2015) study and the author's professional experience. The maximum total ranking score is 22.

Pools were screened based on a score of 16 or above. A total score of 16 was set to ensure all pools met the minimum miscibility requirement, allow some flexibility for oil pools that where either abandoned or commingled, and pass a large enough number of pools to generate best-case clusters.

Table 5: CO_2-EOR screening criteria and ranking

Criteria	Threshold	Ranking Weight
Active Pool	Pool not Abandoned	1
Commingled Pool	Pool not Commingled	1
Suitable Depth (m)	>500 m, <1400 m	1
Oil Gravity (°API)	>22, <45	5
Temperature (ºC)	>27, <127	1
Oil Viscosity (mPa.s)	>0.4, <6	3
Current Pressure > MMP Pressure	Current Pressure > MMP	5
$P_{initial}$ > MMP	$P_{initial}$ > MMP	1
Initial Oil in Place (mmbbl)	12.5	1
Remaining Oil in reservoir (mmbbl)	5	3
Total		22

Source: (Author, 2020)

Both abandoned and commingled pools are not ideal candidates for CO_2-EOR. Abandoned pools require reactivation that can be capitally intensive and unsuccessful depending on the condition of the wells. Commingled oil pools are pools that are produced from multiple, often vertically stacked, individual reservoirs and brought to surface using a common wellbore (AER, n.d.).

These pools can be problematic for CO_2-EOR projects given the uncertainty around CO_2 flood front conformance and identifying what volume of CO_2 is being injected into what pool (Bachu, 2015). While abandoned and commingled pools are not ideal, these are not disqualifying factors. Other screening criteria for previous studies such as porosity and permeability thresholds were not included because of data unavailability.

Once pools were screened and ranked, the pools were clustered using a 10-km radius. Clustering the pools commingles vertically-stacked pools and consolidates production in a given area to optimize infrastructure. Reducing the number of pools into 10-km clusters prevents over-estimating infrastructure costs for those pools in close proximity and helps better to identify target areas for CO_2-EOR potential rather than individual pools.

3.1.3 Production Modelling

Purchased and recycled CO_2 volumes and incremental oil volumes were calculated based on a model presented by Azzolina et al. (2015). Azzolina et al. (2015) analyzed oil production and CO_2 injection data from 31 miscible water-alternating gas CO_2-EOR projects in the United States. The analysis showed a pattern across each project of increasing oil recovery with an increasing volume of injected CO_2 (HCPV) until stabilizing at hydrocarbon pore volume (HCPV) injection percentage above 200%.

Azzolina et al. (2015) also analyzed the net CO_2 utilization ratio as a function of HCPV injected. The net CO_2 utilization ratio is the purchased and stored CO_2 volume per barrel of incremental oil production and is expressed as mscf of CO_2 per barrel of oil produced (mscf/bbl). The recycled component in the CO_2 volume is not included in the calculation (Azzolina et al., 2015). Azzolina et al. (2015) also showed the net utilization factor increases for lower percentage HCPV (HCPV%) injected, meaning a greater proportion of CO_2 is retained in the reservoir while less incremental oil is recovered (Bachu, 2015). Azzolina et al. then fitted a nonlinear curve as a function of total cumulative volume of (CO_2 +H_2O) injected in HCPV% to describe the overall shape of the CO_2 storage and incremental oil profile across the 31 sites (Azzolina et al., 2015; Bachu, 2015).

Azzolina et al. (2015) modelling allows for the estimation of CO_2 retention, incremental oil recovery, and net CO_2 utilization in CO_2-EOR projects from HCPV% injected, original oil in place (OOIP), and from parameters from the Azzolina et al. (2015) fitted curves.

Pool depth, pressure, and temperature are inputted to calculate gas and oil properties. A volumetric balance is performed to calculate the fractional component of produced, retained, and recycled CO_2, produced incremental oil, and produced and injected water as a function of

HCPV%. Production and injection volumes are then converted to units as a function of time from the dimensionless HCPV% units using an assumed HCPV% injected per year. The fitted parameters used in the Azzolina et al. (2015)-based volumetric balance model are the median values from the 31-site dataset.

The Azzolina et al. (2015) study did not incorporate produced and injected water volumes. The volumetric balance in this study includes produced and injection water volumes using an assumed water-alternating gas (WAG) ratio and voidage replacement ratio (VRR). A water-alternating gas ratio (WAG) is assumed to 2 to 1, where two volumes of water are injected followed by one volume of gas, CO_2. The VRR is expressed as the HCPV% of total fluids produced per HCPV of CO_2 plus water injected and is assumed to be 1 for this study. The study does not explicitly consider the impact of WAG ratio and VRR on incremental oil recovery and CO2 storage volume. This may be an area of sensitivity for future studies.

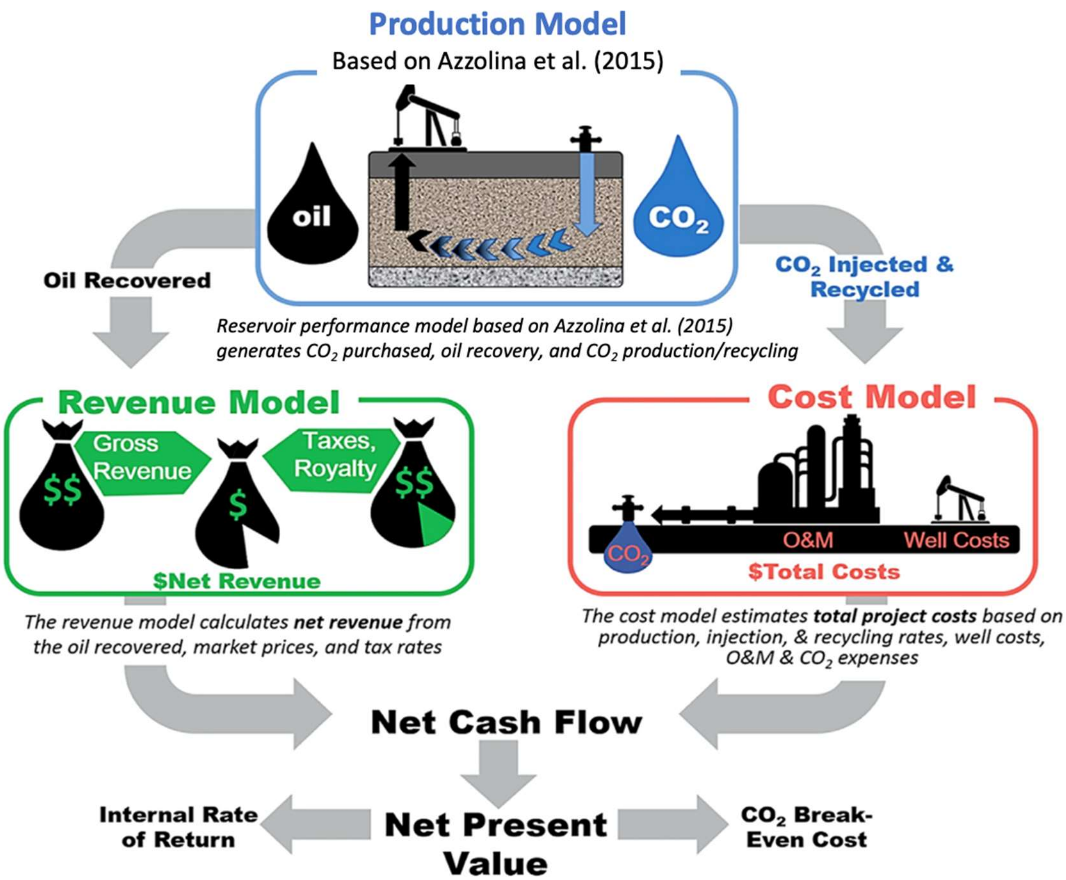
The produced and injected water volumes are important components, as there are costs associated with producing water. The operating costs in this study do include produced water costs. Also, given the maturity of many Alberta pools, there should be an expectation that the water cuts—the ratio of produced water per total produced liquid—are fairly high.

Also, for the purpose of this study, CO_2 surface losses are calculated as 1% in the volumetric balance; industry experience suggests that total losses from these are <5% (Azzolina, 2015). This volumetric balance can then be applied to the ranked and screened pool data set due to the required CO_2 miscibility criteria. Sensitivities can be performed on volumetric models, as WAG ratio, VRR, HCPV% injected per year and resulting cumulative HCPV% injected, and CO_2 surface losses are all variables.

3.1.4 Economic Modelling

As part of this study an economic model was created that was adapted from the Fukai et al. (2016) process illustrated in Figure 7. The aggregated cluster incremental oil, produced water, CO_2 purchased and recycled volumes, generated from the Azzolina et al. (2015) volumetric model, are inputted in the economic model along with maximum area size of the reservoir, average pool depth, and oil density (heavy or light).

Figure 6: Illustration of adapted economic model inputs and outputs



Source: Adapted from Fukai et al., 2016

Revenue and net cash flows are generated from the economic model using the economic input assumption and cost model described in the next section. Net cash flow is discounted to produce the before-tax net present value (BTNPV). All economic analyses in this study are performed on a before-tax basis. Internal corporate tax structures can be complicated, with corporations having unique tax efficient structures and tax pools, so a before-tax basis was chosen for simplicity of analysis.

3.1.5 Economic Input Assumptions

Table 6: Base case economic inputs

	Weighted Average Cost of Capital (WACC)/Discount Rate (%)	Annual Inflation (%)	Royalty Rate Pre-Payout (%)	Royalty Rate Post-Payout (%)	WTI Oil Price ($/bbl)	Field Delivered CO_2 Price ($/tonne)	CO_2 Credit ($/tonne)	Hydrocarbon Pore Volume Inj. (CO_2+H_2O)	Project Life (yrs)
Base case	10%	2%	5%	20.7%	$50	$60	-	150%	30

Source: (Author, 2020)

3.1.5.1 Oil Price

West Texas Intermediate (WTI) is the benchmark for crude oil pricing within North America. The economic modelling uses a $50/bbl WTI oil price. A discount is applied the WTI price to account for the currency exchange rate and Canadian heavy and light oil discount. The discount from the WTI Spot price to Canadian Light Sweet (based on the 12-month average from June 2019 to May 2020) was calculated to be 10%. The same calculation was performed for a Canadian heavy oil, assumed to be priced as Hardisty Heavy, yielding a discount of 25%.

3.1.5.2 CO_2 Purchase Cost

The net CO_2 field-delivered purchased price of $60/t was defined as the base case. $60/t was determined to be a reasonable CO_2 delivery price as a starting point for analysis. This is discussed further under the Scenario Analysis in Section 5.2.

3.1.5.3 Weighted Average Cost of Capital

The base case weighted average cost of capital (WACC), or discount rate, as presented in Table 6, is 10%. Weighted average cost of capital is used in the economic modelling as a proxy for discount rate. The simplified WACC formula is shown in Eq. (1).

$$WACC = Cost\ of\ Equity \times \%\,Equity + Cost\ of\ Debt \times \%\,Debt \qquad (1)$$

Oil and gas companies require a return or a premium beyond WACC to manage risk. The impact of weighted average cost of capital (WACC) on CO_2-EOR project economics was also evaluated. Weighted average cost of capital is considered the minimum discount rate a company would accept in evaluating projects.

The mean WACC for medium to large upstream oil and gas companies is 7.14% according to a NYU Stern School of Business analysis in January 2020. This is calculated from the cost of equity of 9.6%, cost of debt of 2.75%, and debt-to-debt plus equity of 36% for a WACC of 7.14% (NYU Stern School of Business, 2020). Cost of capital will be higher for smaller companies with higher equity component because they cannot access the lower cost debt markets. If 10% is considered the discount rate, it would only include a nominal return if the WACC is assumed to be 7.14% as reported by the NYU Stern School of Business analysis.

3.1.5.4 Carbon Credit

The base case assumptions exclude any government grants, subsidies, or benefits from carbon credits or offsets.

3.1.5.5 Royalty Rate

The royalty rate assumptions used in the economic model are based on the Alberta Enhanced Hydrocarbon Recovery Program (EHRP) that was introduced to promote incremental production to account for higher costs associated with enhanced recovery methods such as gas flooding, including CO_2-EOR (Government of Alberta, n.d.). Under the program, a company will pay a flat royalty rate of 5% on crude oil produced for a limited benefit period. After that benefit period ends, the enhanced recovery project will be subject to normal royalty rates. For the purpose of this study, a royalty rate of 5% is applied until payout and 20.7% after that (BMO Capital Markets, 2020; Government of Alberta, n.d.).

3.1.5.6 Cost Model Inputs

Table 7: Cost model inputs, equations, and references

Cost Model Input	Cost Equations (a)	Cost Inflation (2014-2019)	Currency (CAD/USD)	Study Referenced
Well Cost				
Drilling & Completion (D&C)	$\$65{,}703e^{(0.0004\ x\ depthft)}$ (2)			Fukia et al. (2016)
Production Well Equipment	$\$10.12 \times depthft + \$20{,}210$ (3)			Fukia et al. (2016)
Injection Well Equipment	$\$18.33 \times depthft + \$11{,}626$ (4)			Advanced Resources International [ARI] (2006), Godec (2014), Kuuskra et al. (2011), DOE NETL (2014)
CO_2 Costs				
CO_2 Transportation & Distribution	$\$220{,}000\ per\ 40\ acre$ (5)			Fukia et al. (2016)
CO_2 Recycling Plant	$\$877{,}264 + MaxCO_2$recyclingrateMMscf/day (6)	6%	1.3	ARI (2006), Godec (2014), Kuuskra et al. (2011), DOE NETL (2014)
CO_2 Recycling O&M	$0.01 \times \frac{USD}{STBoil} \times CO_2$recycledMMscf (7)			ARI (2006), Godec (2014), Kuuskra et al. (2011), DOE NETL (2014)
Total O&M Costs				
Periodic O&M	$\$33{,}684e^{(0.0001\ x\ depthft)} \times no.\,of wells$ (8)			McCoy (2008), McCoy & Rubin (2009)
Liquid Lifting Costs	$\$0.25 \times (producedbblswater + oil)$ (9)			ARI (2006), Godec (2014), Kuuskra et al. (2011), DOE NETL (2014)
General & Administrive (G&A)	$0.20 \times (\$O\&M + \$LiquidLifting)$ (10)			ARI (2006), Godec (2014), Kuuskra et al. (2011), DOE NETL (2014)
Monitoring, Measurement & Verification (MMV)	$\$2/t$	None	CAD	North West Redwater Partnership et al. (2019)
Injection Well Maintenance	$\$1/t$	None	CAD	North West Redwater Partnership et al. (2019)

(a) Values reported in 2014 USD unless otherwise specified

Source: (Author, 2020)

Capital cost assumptions are based primarily on a United States inflation and exchange rate-adjusted cost model from Fukai et al. (2016) described in Table 7. The cost inflation from 2014 to 2019 is based on the Chemical Engineering Plant Cost Index (CEPCI). Drilling and completion costs are calculated based on average depth of the cluster, maximum cluster pool area, and the assumption that one new well is drilled per 40 acres. An average of the production and injection well equipment is applied to each well. CO_2 transportation and distribution costs are applied to 50% of the maximum cluster pool area, given that the spatial extent of infrastructure is unlikely to cover the entire area of the cluster pool area. Descriptions of cost model inputs are in Appendix A.

There is a possibility that capital costs assumptions do not fully reflect actual present-day Alberta capital and operating costs. The net effect is that the break-even CO_2 price calculated using the economic model may be a lower bound. Capital and operating cost sensitivities are performed to account for this uncertainty.

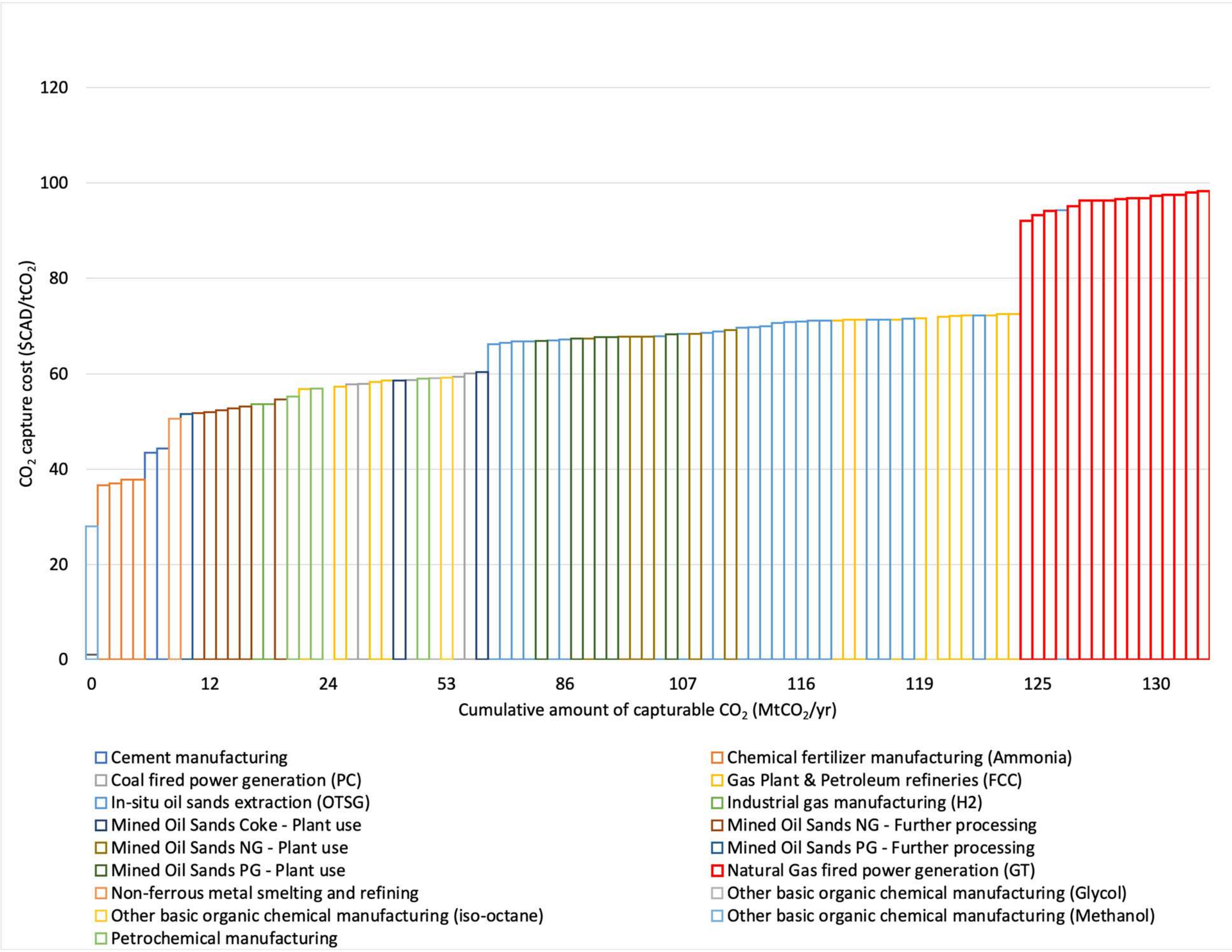
CHAPTER 4: MODEL RESULTS

The Results and Findings are broken into three sections: Alberta Stationary CO_2 Sources and Emissions, Pool CO_2-EOR Suitability, and Single Cluster Production and Economic Summary. The Results and Findings chapter provides the inputs and basis for the analysis of CO_2-EOR feasibility in Alberta.

4.1 Alberta Stationary CO_2 Sources and Emissions

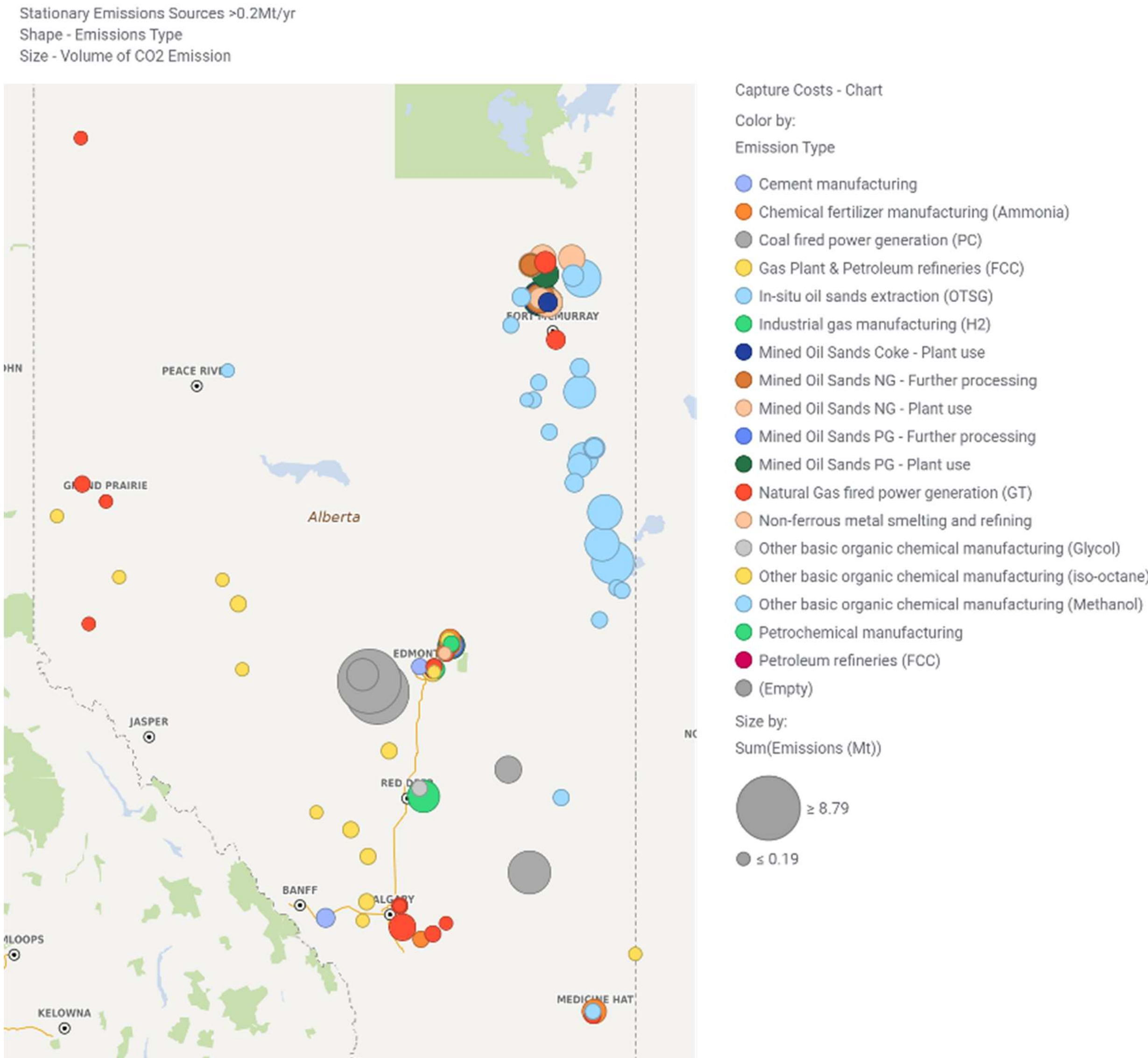
Estimated capture costs were calculated using the methodology from Pilorgé et al. (2020) and Middleton and Brandt (2013), combined with Environment and Climate Change Canada (2020) emissions data. Figure 7 shows the cumulative CO_2 emissions by source and type. The emissions are filtered for stationary sources producing greater than 200,000 tonnes per year to identify only the material sources of emissions. Figure 8 demonstrates that there is approximately 100 Mt/y CO_2 capturable for \$60/t to \$80/t. The majority, 70 Mt/yr of CO_2 in 2018, of CO_2 emission sources are concentrated in northeast Alberta, from oil sand in situ and mining extraction.

Figure 7: Comparison of capture costs and amount of CO_2 available for different CO_2 sources and types



Source: (Author, 2020)

Figure 8: Map of stationary CO_2 sources in Alberta producing greater than 200,000 t/year



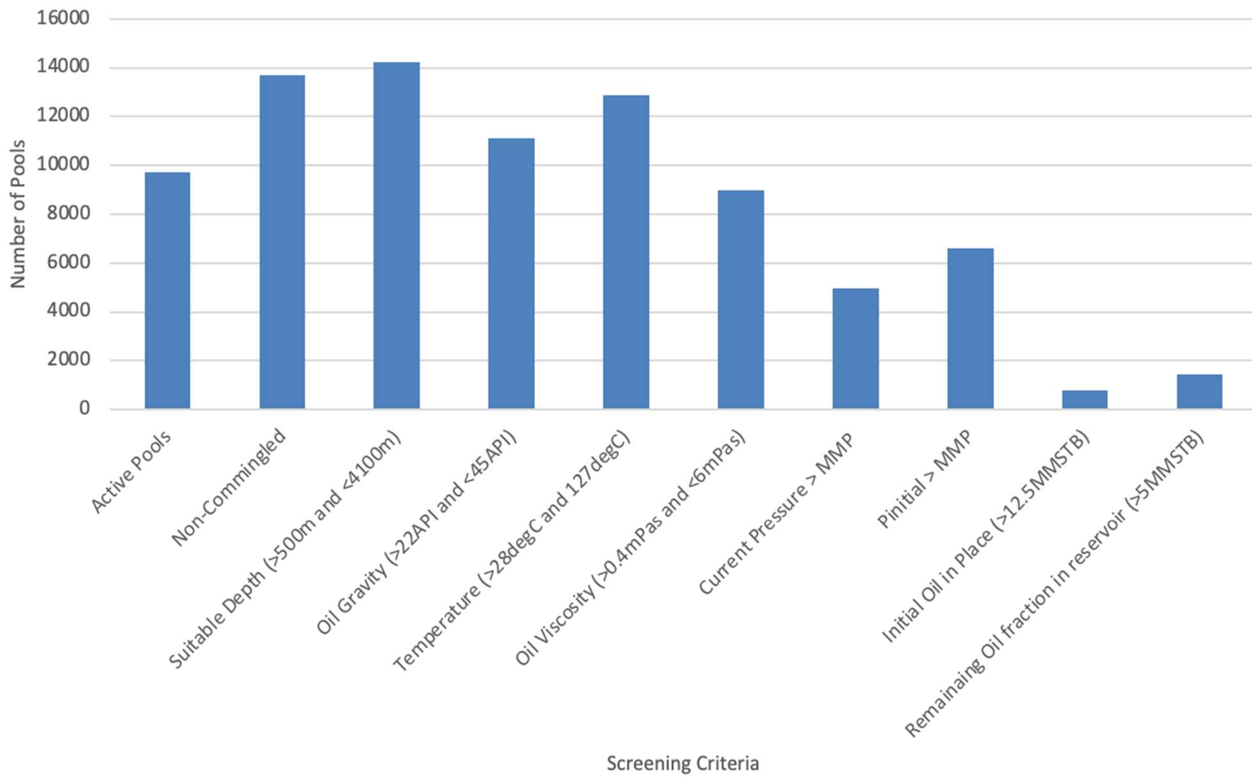
Source: (Author, 2020)

4.2 Pool CO_2-EOR Suitability

Per the Alberta Energy Regulator 2018 crude oil pool database, there are 14,677 oil pools in Alberta (AER, 2019). The analysis shows that highest impact screening criteria are minimum miscibility pressure (MMP) and original and remaining oil in place (OOIP and ROIP, respectively).

Of the 14,677 oil pools in Alberta, 802 pools have an OOIP of greater than 12.5 mmbbl and 4,954 have a current pressure greater than the MMP.

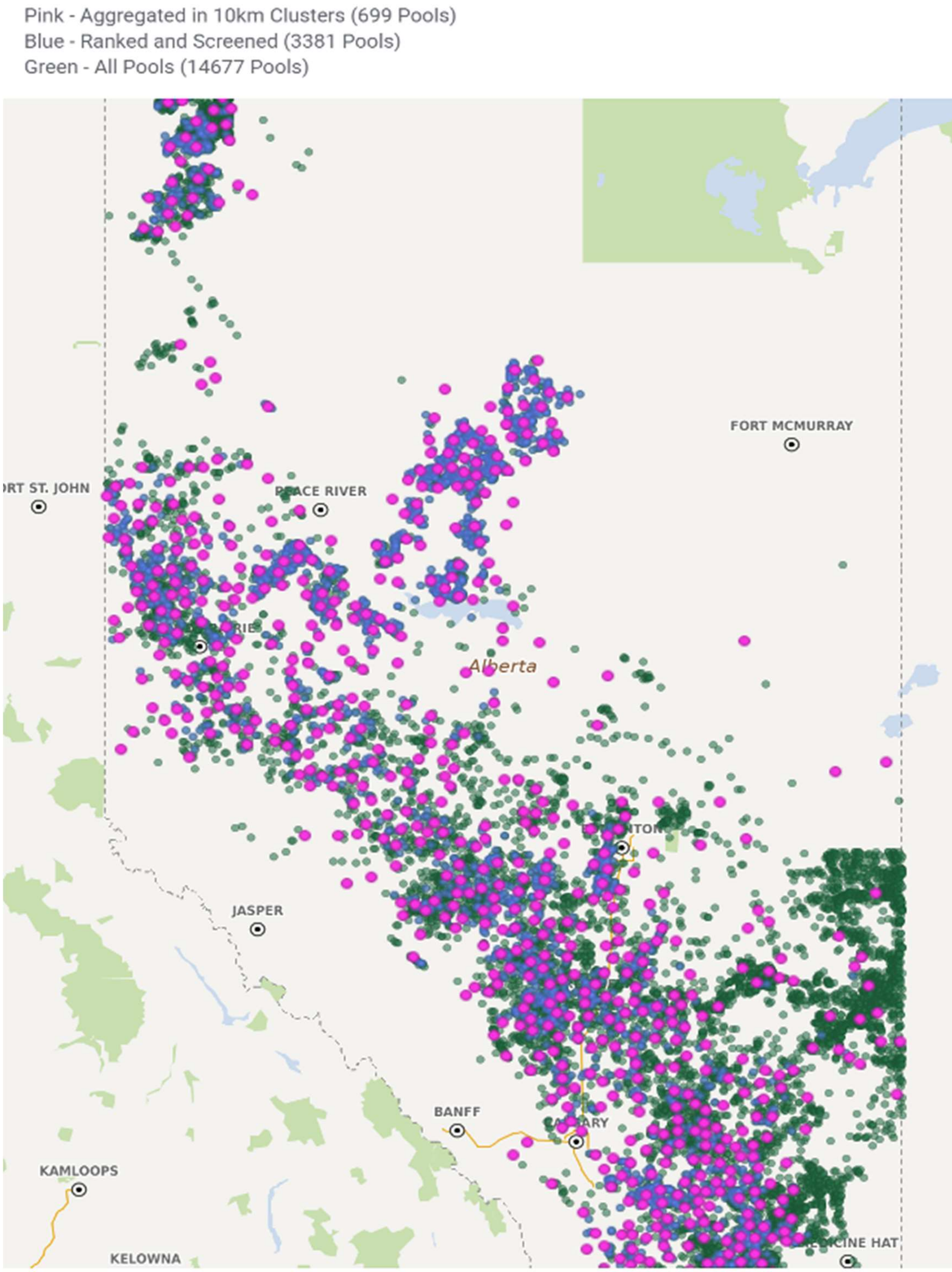
Figure 9: Number of oil reservoirs suitable for CO_2-EOR in Alberta



Source: (Author, 2020)

Applying the screening and ranking process described in the Methodology section reduced the total number pools from 14,677 to 3,381 pools. 97 of the 14,671 total pools scored a maximum weighted ranking of 22, with 3,381 pools passing the ranking score of 16 or higher. The 3,381 ranked and screening pools are reduced to 699 clusters when clustered using a 10-km radius. Figure 10 displays the location of all pools, screened and ranked pools, and the clusters that are fed into the production model.

Figure 10: Map of screening and ranked oil pools and clusters. Pink circles indicate the locations of the aggregated clusters that pass the screening criteria and ranking.



Source: (Author, 2020)

The most important screening criterion is current pressure above minimum miscible pressure (MMP) and is applied the highest ranking weight (5) as a result. Because of this ranking weight, it is possible for a pool to achieve a ranking score of 16 or higher without meeting the miscible pressure criteria. This often means the current reservoir pressure is lower (and in some cases a lot lower) than the miscible pressure. The pools that fail to meet the MMP requirement account for 210 of the 3,381 total screened and ranked pools. Reservoir pressure in the lower pressure pools could be raised either through water or CO_2 injection, depending on the impact on the project economics, to reach MMP prior to production.

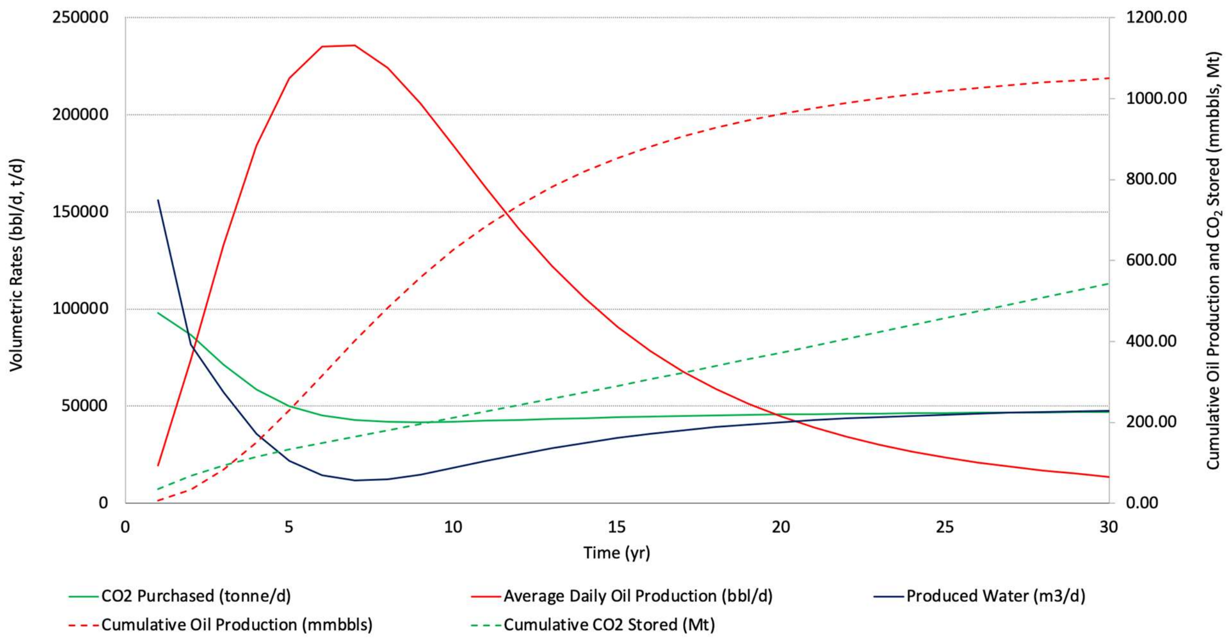
These pools pass the screening criteria and are fed into the Azzolina et al. (2015)-based volumetric production model as clusters. These low-pressure pools have a low calculated CO_2 density that in turn reduces the CO_2 storage capacity. There are a few examples in the dataset of pools, through the Azzolina et al. (2015)-based volumetric model, that have a high estimated incremental oil recovery because of a larger OOIP and low CO_2 storage capacity resulting from low reservoir pressure and low CO_2 density. This results in a very low net CO_2 utilization ratio, low CO_2-related capital and operating expenses, and very positive project economics. These pools with low pressure and strong economics need to be taken into consideration when analyzing the best performing CO_2-EOR pools in Alberta. Because of the aggregation of pools through the clustering process, the effect of these low-pressure pools on cluster project economics is minimized.

4.3 Single Cluster Production and Economic Example

Purchased and recycled CO_2, incremental oil, and water volumes are calculated for each cluster from the Azzolina et al. (2015)-based volumetric model assuming a 150% HCPV. Figure 11 shows the single cluster production and injection rates of the Pembina-Cardium cluster as an example.

Pembina-Cardium is the largest pool cluster in the province, with 10.6 billion barrels of original oil in place. As such, the Pembina-Cardium cluster is unique, and the incremental oil recovery and the before-tax net present value (BTNPV) are high compared to the other clusters in the province. The Pembina-Cardium results presented in this section are intended to illustrate the single cluster volumes and CO_2-EOR project economics generated for each of the 699 clusters from the modelling in this study.

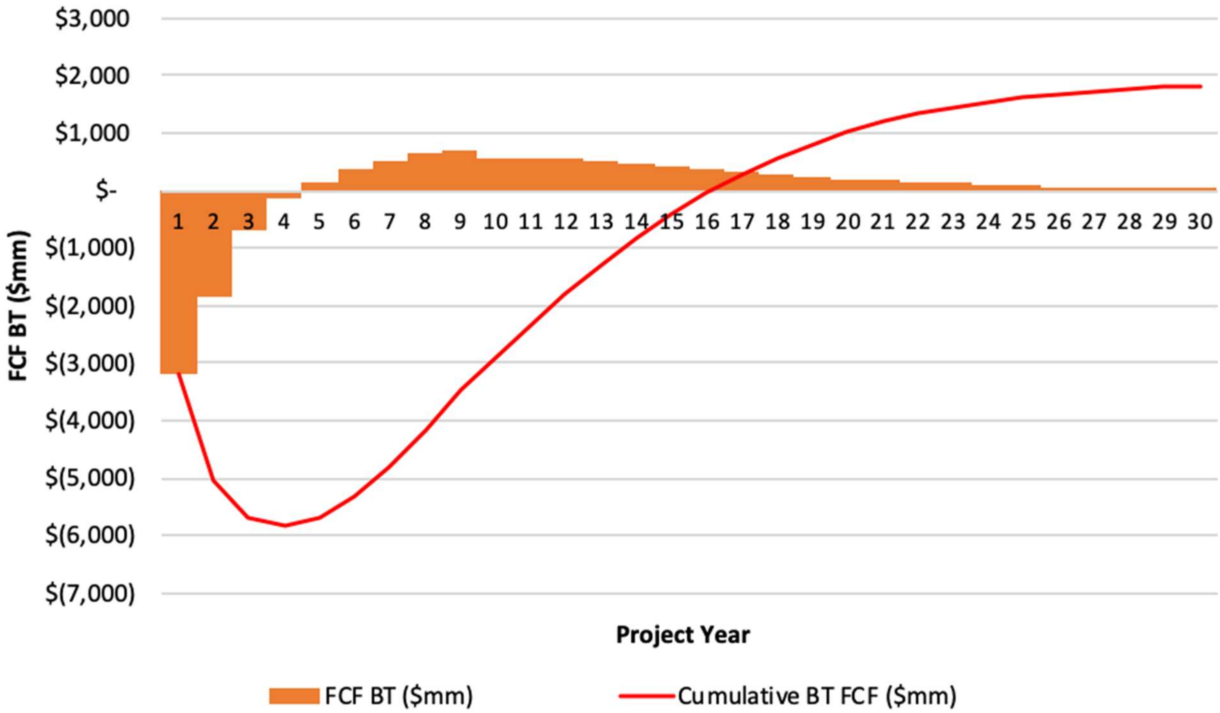
Figure 11: Illustrative production and injection volumes, Pembina-Cardium cluster



Source: (Author, 2020)

Figure 11 shows the general profiles of production and injection volumes of oil, water and CO_2 for each cluster. The cumulative oil production rate increases as the injected HCPV% increases over time. The volume of CO_2 purchased decreases and plateaus as more CO_2 volumes are recycled.

Figure 12: Illustration of before-tax free cash flow, Pembina-Cardium cluster



Source: (Author, 2020)

In this study, all cluster production and capital spending starts January 1st, 2020 to normalize and simplify project economics. The project life is assumed to be 30 years, with the projects ending at the end of 2050. The Pembina-Cardium cluster before-tax free cash flow in Figure 12 illustrates the shape of a normal CO_2-EOR project cash flow. The before-tax cash flow presented are the CO_2-EOR project earnings (losses) before interest, tax depreciation (EBITDA). There is a large initial capital investment followed by a long payback period. Table 8 shows the economic indicators generated from the economic modelling.

Table 8: Economic indicators, Pembina-Cardium cluster

Pembina-Cardium CO_2-EOR Economic Indicators		
Incremental Oil	850.9	mmbbls
Incr. Recovery Factor	8	%
Total Stored CO_2	289	Mt
Net Utilization Factor	6.59	mcf CO_2/bbl
Total Capital	3,747	$mm CAD
NPV10 (BT)	1,823	$mm CAD
IRR (BT)	13%	
P/I Ratio (BT)	0.49x	
Payback Period (BT)	15	years

Source: (Author, 2020)

CHAPTER 5: SCENARIO ANALYSIS

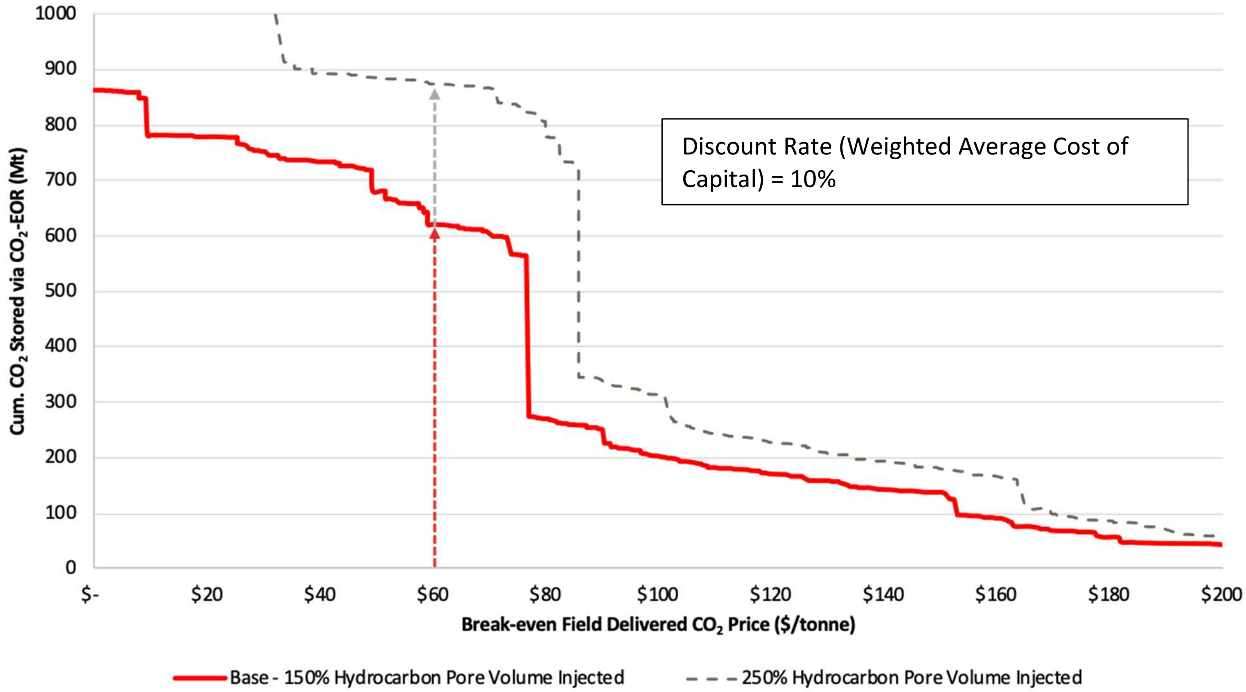
5.1 CO_2 Break-Even Price

The CO_2 break-even price is the field delivered CO_2 price, in \$/t, paid by the upstream oil producer that results in a Before Tax Net Present Value (BTNPV), at a 10% discount rate, equal to zero. This is the maximum CO_2 price an oil producer can pay to return the value equal to the weighted cost of capital, the “affordable price” of CO_2. If the BTNPV of the project is negative, the project is cash flow negative and not a viable project. In reality, investors may require a higher return and, consequently, a lower break-even CO_2 price for EOR projects depending on the risk they assume. The CO_2 break-even price is calculated for a number of scenarios: HCPV% injected, capital and operating costs sensitivities, and WTI oil price.

Figure 13 shows the cumulative CO_2 stored against the break-even field delivered CO_2 price. The lower the field delivered CO_2 price, the greater number of cluster CO_2 -EOR projects have BTNPV at 10% discount rate equal to zero, and a greater amount of CO_2 can be stored through CO_2 -EOR. At high field-delivered CO_2 prices, few clusters achieve a BTNPV equal to zero, and less cumulative CO_2 is stored through CO_2 -EOR.

621 Mt of CO_2 can be stored at a field-delivered price of \$60/tonne at base case inputs. The average break-even CO_2 price was calculated from the sum product of the net CO_2 price by cluster and total CO_2 stored. At a weighted average cost of capital of 10%, the average volume weighted field delivered break-even price was found to be \$69/t at a WTI oil price of \$50/bbl. The figure shows a significant increase in total cumulative CO_2 stored, from 280Mt to 621Mt, between a break-even CO_2 price of \$80/tonne and \$60/tonne. The largest contribution to the jump in cumulative CO_2 stored is a single large cluster, Pembina-Cardium, with a break-even CO_2 price of \$77/tonne and total CO_2 stored of 290 Mt.

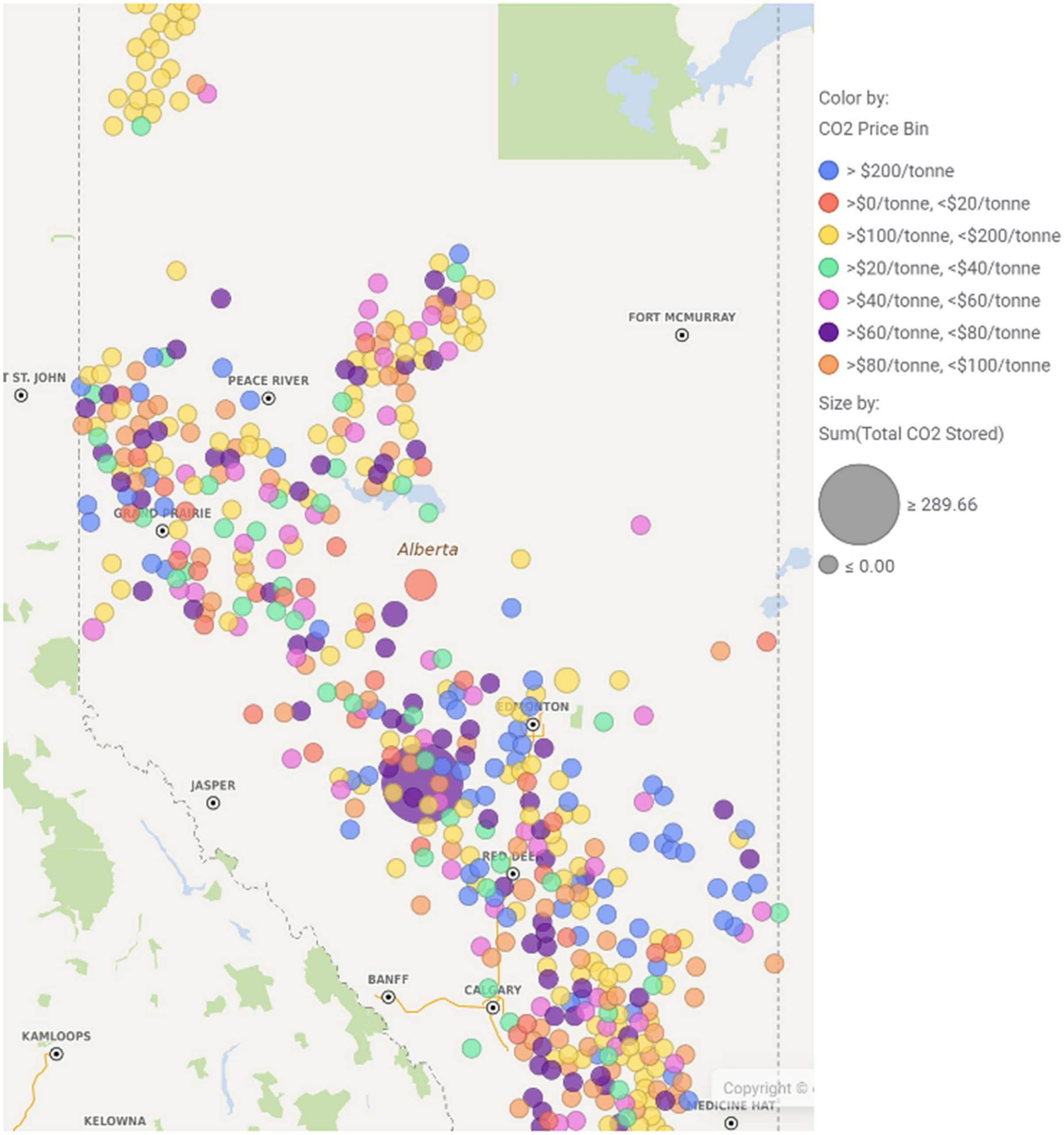
Figure 13: Cumulative CO_2 stored (Mt) vs. break-even field-delivered CO_2 price



Source: (Author, 2020)

Figure 14 shows a map with the locations of the clusters and the break-even field-delivered CO_2 price. A high break-even field-delivered CO_2 price indicates a tolerance to higher CO_2 prices. What is notable about this map is the number of clusters that have a break-even CO_2 price of $60/tonne or above at WTI $50/bbl. The Pembina-Cardium cluster can be identified in west-central Alberta by the larger cumulative CO_2, signified by the larger shape radius. No particular area of the province has a large concentration of high break-even field-delivered CO_2 price clusters. There are a number of clusters in the north-west of the province (Rainbow field clusters) that have high break-even; however, these clusters are mainly smaller, with lower OOIP, lower CO_2 storage potential, and incremental oil recovery from CO_2-EOR.

Figure 14: Break-even field-delivered CO_2 price, BTNPV10=$0, $50/bbl WTI



Source: (Author, 2020)

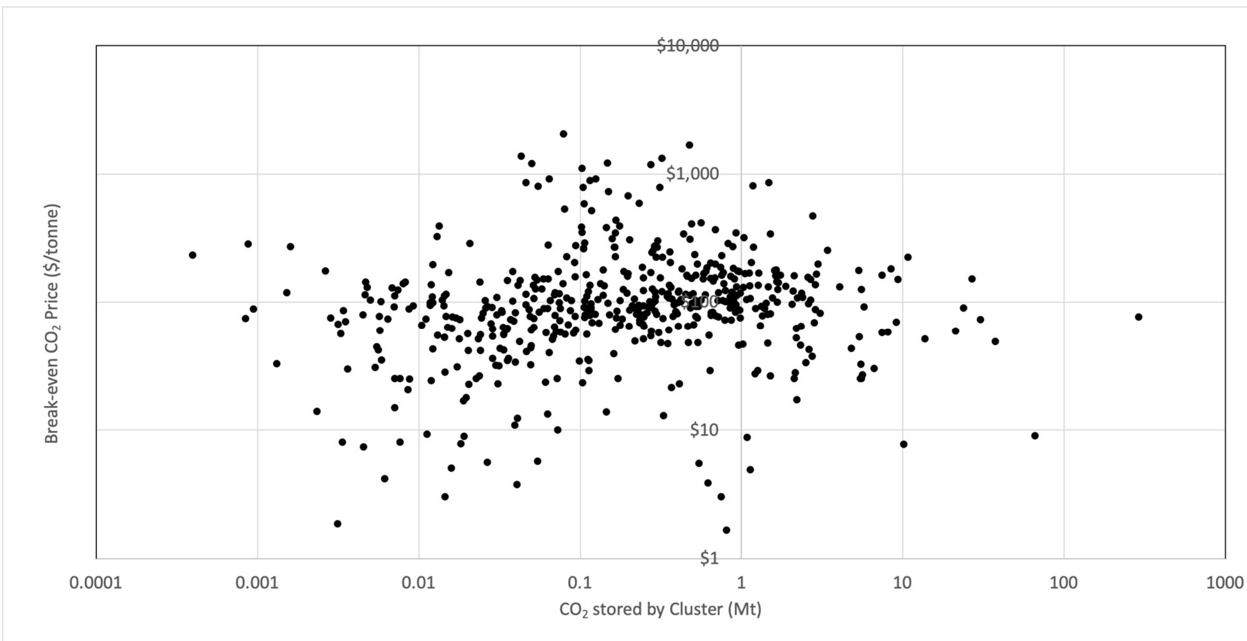
Table 9: Top 10 clusters based on break-even CO2 price ($/t), storage greater than 5 Mt

Field-Pool Cluster	Pools in Cluster	Active Wells (2018)	Cluster Area (ha)	Total OOIP (mmbbls)	Total Capital ($mm)	CO_2 Utilization Factor (mscf/bbl)	Total CO_2 Stored (Mt)	Total Incr. Oil (mmbbls)	Incr. Recovery Factor (%)	Break-even CO_2 Net Purchase Cost ($/tonne)
LEDUC-WOODBEND - D-3 B	26	142	11392	900	$229	3.0	11	70	7.8%	$225
RAINBOW - MUSKEG M	14	55	1195	473	$45	4.2	8	39	8.3%	$182
RAINBOW - SULPHUR POINT B	16	20	733	308	$26	4.3	5	24	7.9%	$177
WIZARD LAKE - D-3 A	4	2	1075	408	$37	4.6	7	31	7.7%	$163
REDWATER - D-3	1	346	17236	1245	$295	4.5	27	117	9.4%	$152
VALHALLA - COMMINGLED POOL 035	5	120	9810	342	$196	3.8	6	29	8.4%	$126
LOON - COMMINGLED POOL 002	25	89	4890	211	$95	5.8	6	19	9.1%	$91
JUDY CREEK - COMMINGLED POOL 004	8	133	19223	1099	$442	5.7	24	81	7.4%	$90
PEMBINA - CARDIUM	12	4135	175000	10579	$4,424	6.6	290	852	8.0%	$77
JUDY CREEK - BEAVERHILL LAKE A	5	144	12298	1113	$354	7.2	30	81	7.3%	$73

Source: (Author, 2020)

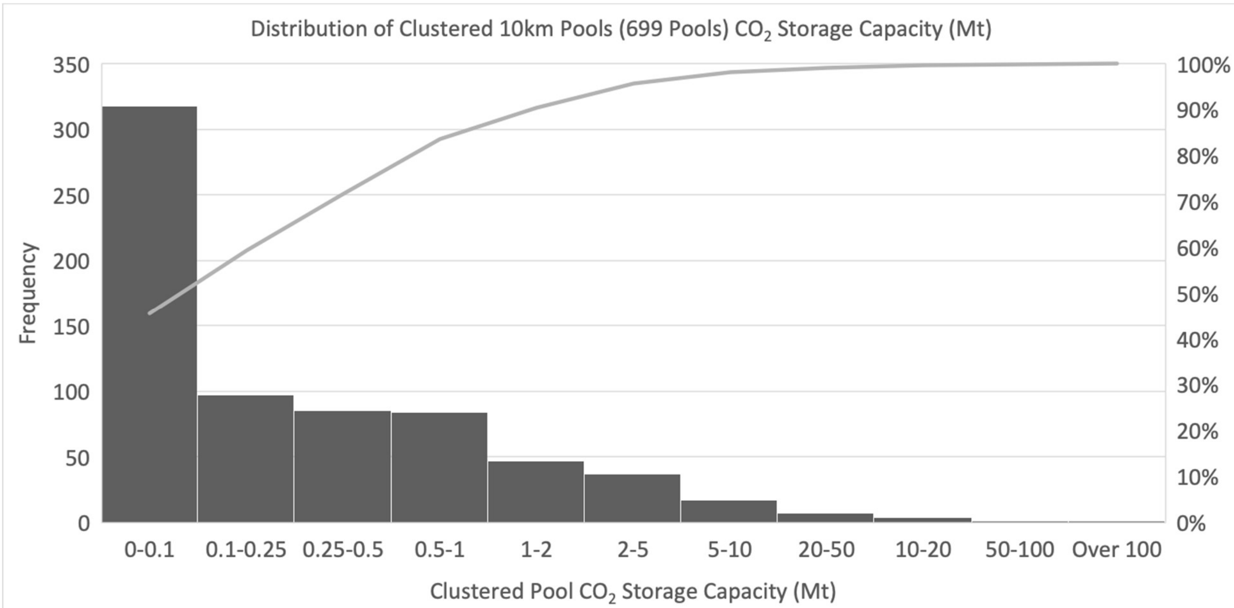
The top 10 clusters based on break-even CO_2 price are shown in Table 9. These clusters are ranked by CO_2 break-even price (BTNPV10=$0), and filtered by cumulative CO_2 stored greater than 5 Mt. At the 5 Mt storage potential, the approximate initial annual purchased CO_2 volume is 0.3 Mt/yr and declines thereafter. Those clusters with the lowest CO_2 utilization, requiring less CO_2 per incremental barrel of oil produced, can tolerate higher net CO_2 prices. Pembina-Cardium and Redwater field-pools are commonly referred to in published studies as having the best CO_2 storage potential for CO_2-EOR projects in Alberta (Bachu, 2015; BMO Capital Markets, 2020; Gunter & Longworth, 2013).

Figure 15: Break-even CO_2 price vs. CO_2 stored by cluster



Source: (Author, 2020)

Figure 16: Distribution of storage capacity of clusters



Source: (Author, 2020)

When the cluster CO_2 stored capacity is plotted against the break-even CO_2 price in Figure 15, the uneven distribution of the CO_2 storage capacity by cluster becomes clear. Figure 16 histogram of clusters storage volume shows only 20%, or 66 of the 699 total clusters, have storage capacity of 1 Mt or greater.

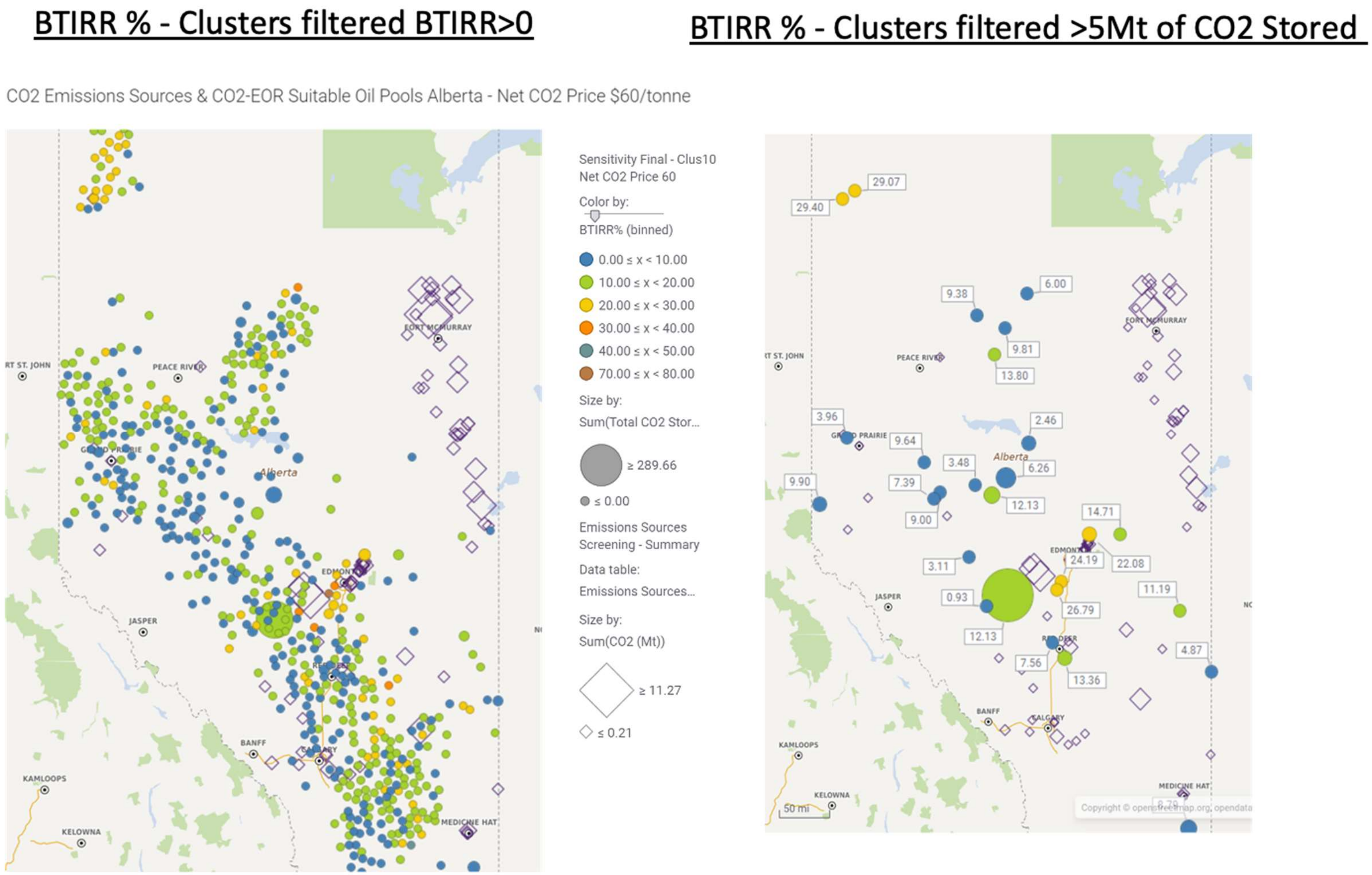
5.2 Revenue and Before Tax Internal Rate of Return Analysis (BTIRR)

Net present values (NPV) at different discount rates, internal rates of return (IRR), and ratios of net present values to investment and payback periods are all commonly calculated to aid in investment decisions (Kemp & Stephen, 2018). Revenue and Before-Tax Internal Rate of Return Analysis (BTIRR) analysis was performed at fixed field-delivered CO_2 prices with the base case at \$60/t. \$60/t was felt to be a reasonable initial field-delivered CO_2 price estimate for analysis considering the average estimated current carbon capture costs of between \$40 and 80/tonne, seen in Figure 7, and allowing for transportation cost of a few dollars to tens of dollars per tonne – depending on transport distance, field demand, and configuration of the system (National Energy Technology Laboratory, 2018).

The results show the Before-Tax Net Present Value (BTNPV) and Before Tax Internal Rate of Return (BTIRR) for each cluster. Clusters with the highest and lowest BTNPV and BTIRR, indicating the best and worst project economics, can be identified at a given CO2 price and discount rate.

Figure 17 displays the geographic location of the CO_2 -EOR clusters, BTIRR percent at a field delivered CO2 price of $60/tonne, and WTI oil price of $50/bbl. Figure 18 shows a considerable number of clusters with sufficient BTIRR for a potential CO2-EOR project, with BTIRR greater than 10%. Most clusters, 305 of the 699 total, have a BTIRR of between 10–20% at $50/bbl WTI. However, when clusters are filtered for cumulative 5 Mt of CO2 stored over the life of the project, the number of clusters is reduced from 392 to 30. There are a limited number of material, economic clusters at a field-delivered CO2 price of $60/tonne. Also, few of the clusters reaching the CO2 storage threshold of 5 Mt are in direct proximity of locations of the stationary sources of CO2 emissions, displayed by the purple diamonds in Figure 18.

Figure 17: Map of clusters BTIRR%, net CO_2 price \$60/t



Labels – Before Tax Internal Rate of Return (BTIRR) %, Size – CO_2 Stored (Mt)

Source: (Author, 2020)

Indicative investment hurdles were also applied to screen the economic modelling results to identify those volumes of CO_2 and oil that might be potentially economical. Investment hurdles employed in the oil and gas industry are not generally made available publicly. Individual companies have different investment hurdles, and these hurdles are dependent on the weighted average cost of capital for the company and risk profile of the investment. For example, for larger companies with lower WACC, a lower BTIRR giving them a return above their WACC may be sufficient. However, that may not be sufficient for an investor.

The threshold of greater than 10% BTIRR indicates those projects that have a positive BTNPV. Given the base case weighted average cost of capital of 10%, an indicative BTIRR 15% and 20% hurdles were chosen to identify projects that exceed BTNPV of zero. This can been seen as applying a 5% or 10% risk premium to the WACC as effectively a sensitivity. The number of clusters that pass the specific investment hurdles are shown in Table 10. Further work to assess an appropriate investment hurdle rate will be required when risk structure of CCUS to CO_2-EOR is better understood.

Table 10: Clusters passing economic thresholds at field delivered CO_2 price $60/t

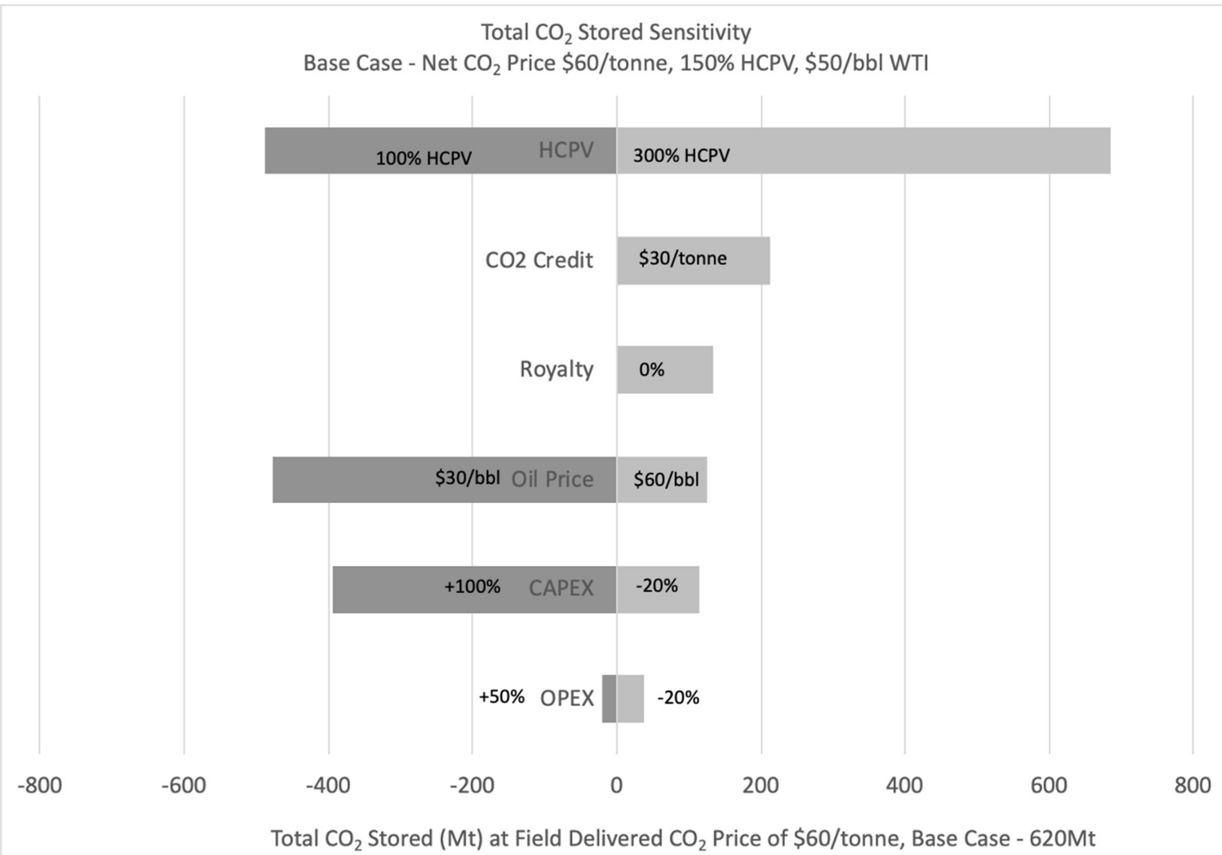
	Number of Clusters passing Threshold (Total - 699 Clusters)	
	$50/bbl WTI	$40/bbl WTI
BTNPV10>$10mm CAD	154	99
BTIRR>15%	207	117
BTIRR>20%	100	50
CO_2 Stored >5Mt	30	30
Incremental Oil Recovered > 10mmbbls	54	54

Source: (Author, 2020)

5.3 Sensitivity Analysis

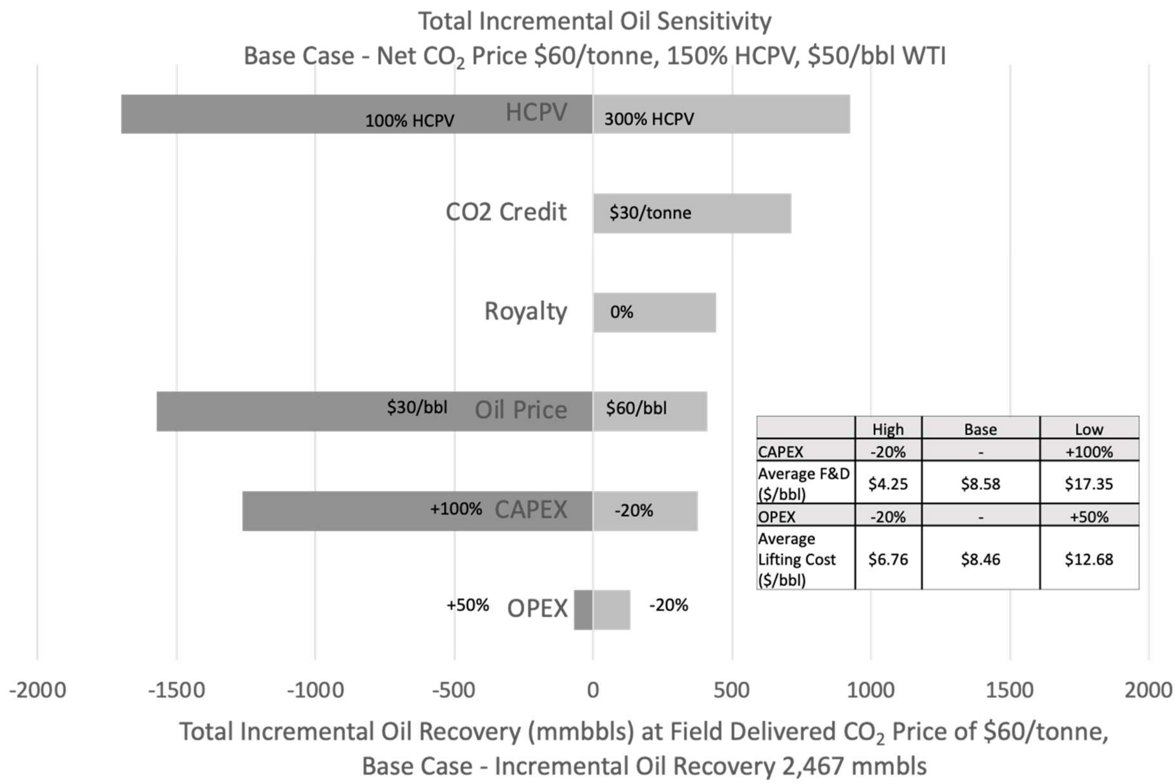
Figure 20 and Figure 21 sensitivity analysis tornado diagrams show the base case model resulting in an incremental oil recovery of 2,467 mmbbls and 629 Mt of CO_2 stored. The horizontal axis shows the net oil recovery (mmbbls) and CO_2 stored (Mt) as a function of percent change in the input parameter from the base case. The most sensitive inputs are hydrocarbon pore volume injected and oil price.

Figure 18: Tornado diagram of the CO_2 stored sensitivity analysis



Source: (Author, 2020)

Figure 19: Tornado diagram of incremental oil sensitivity analysis

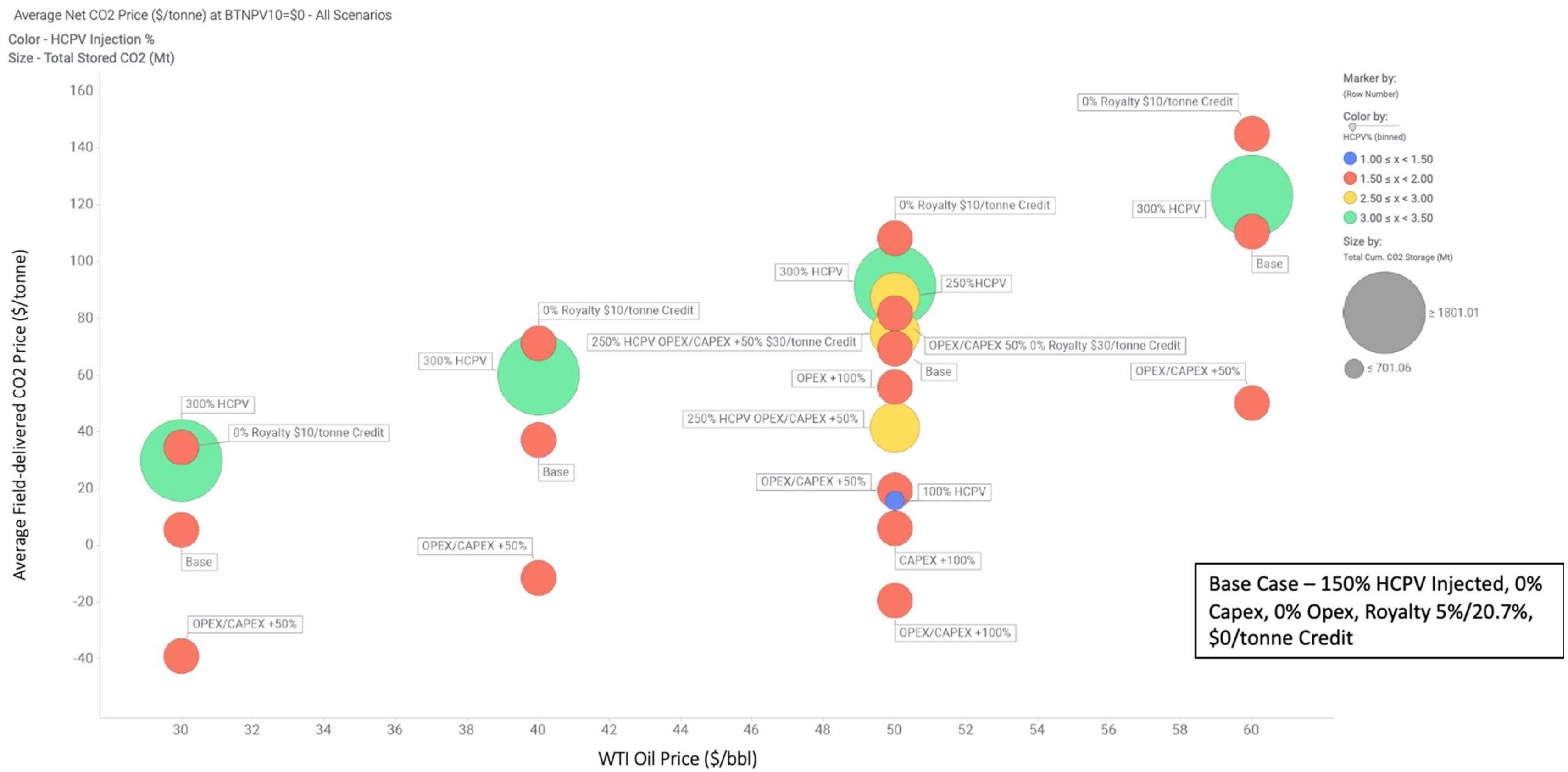


Source: (Author, 2020)

In addition, a doubling of the capital cost, increasing the average finding and development cost (F&D) from \$8.58/bbl to \$17.35/bbl, reduces the incremental oil recovery and CO_2 stored by 1441 mmbbls and 394 Mt respectively. The operating costs, including CO_2 recycling and the measurement, monitoring, and verification costs related to CO_2 storage have little impact on the overall economics. This results mainly from the smaller magnitude operating cost sensitivity range compared to other sensitivities. The CO_2 storage volume and incremental oil recovery are more sensitive to capital costs because these costs are upfront, beginning of field life, costs that have a larger impact on the BTNPV of cluster project economics due to time value of money. Operating costs are spread over the life and have a less impact on the BTNPV. Also, the large swings in sensitivity results are driven predominately by a handful of larger clusters. If operating costs were to increase by 100%, instead of 50%, several of the larger cluster's BTNPV would become negative and the incremental oil recovery and CO_2 stored volume would be reduced by a similar magnitude to the capital sensitivity.

Figure 20 shows the average volume weighted field-delivered break-even CO_2 price against a WTI oil price range of $30 to $70/bbl and plots each sensitivity performed in this study. The figure demonstrates the range in break-even prices and the conditions required to raise the average break-even field delivered CO_2 price or alternatively the tolerance to capital and operating cost sensitivities. For example, at $50/bbl WTI, the average break-even price ranges from negative values, meaning operators need to receive payment for delivered CO_2, to being able to tolerate up to over $100/t CO_2 price.

Figure 20: Average field-delivered break-even CO_2 price ($/tonne)



Source: (Author, 2020)

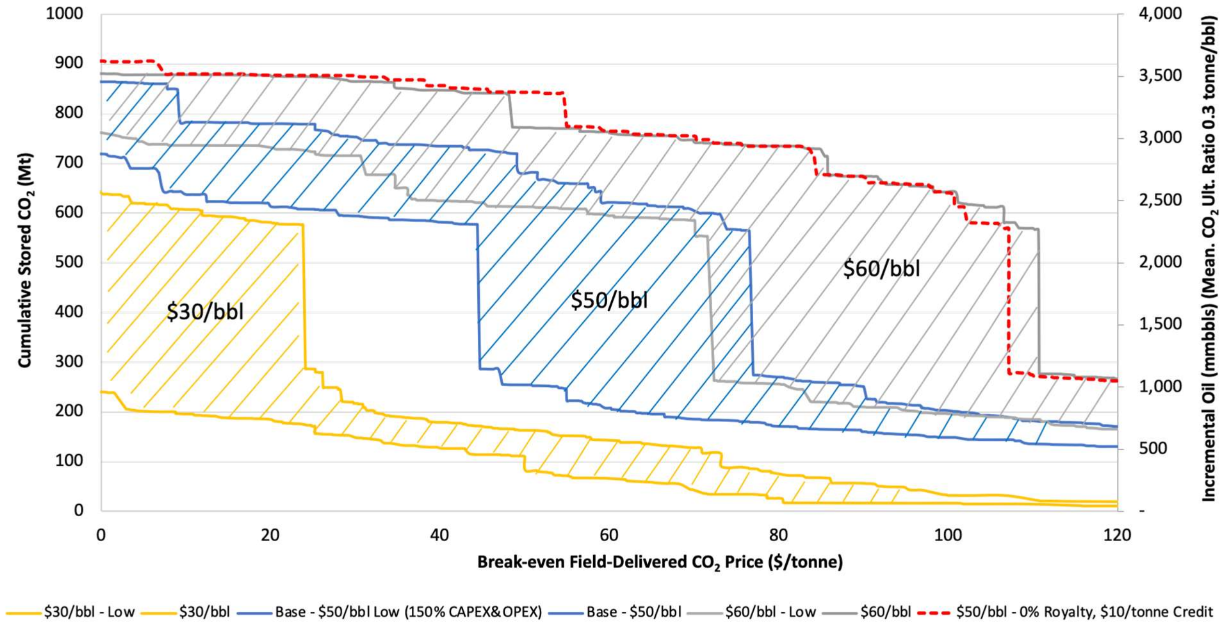
At today's oil price of approximately \$40/bbl WTI, on average across all clusters, operators need CO_2 supplied at a field-delivered cost of \$37/t to break even.

The required price of CO_2 for CO_2-EOR projects from published studies ranges from \$17USD to \$50USD/t (Martin et al.,2017). A CO_2 price for EOR of \$40USD/t or 2% of the price of a barrel of WTI per million cubic feet of CO_2 are commonly referenced in other studies (Kuuskraa et al., 2011; Middleton, 2013; Núñez-López & Moskal, 2019). Traditionally CO_2 price has been tied to oil price as the suppliers of CO_2 have wanted equity ownership the EOR project and to benefit from rising oil prices. The prices of CO_2 for EOR are expected to be lower than those calculated in the above mentioned studies given the higher assumed WTI oil price. Kuuskraa et al. (2011) assumed a WTI oil price of \$85/bbl, and Middleton (2013) assumed \$81/bbl. Consideration also needs to be taken for assumed currency conversion and return on investment; however, the average volume weighted break-even CO_2 prices presented in this capstone project (Figure 20) does fit within these price ranges from other relevant studies.

5.3.1 Oil Price Scenarios

Several economic scenarios were examined to better understand the impact of oil price of the potential for CO_2-EOR storage projects in Alberta.

Figure 21: CO_2-EOR storage potential and incremental oil recovery vs. WTI oil price



Source: (Author, 2020)

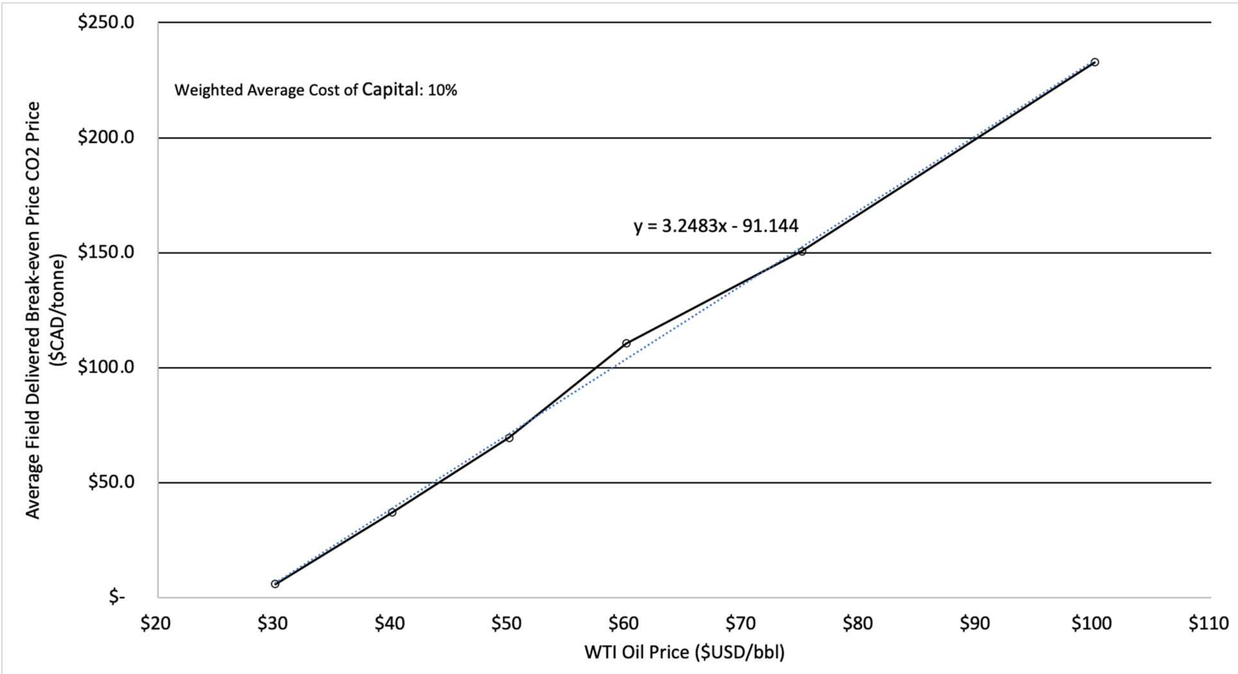
Figure 21 shows the range in potential CO2 stored at a given CO2 break-even price and WTI oil price. The total cumulative CO_2 stored (Mt) is on the vertical axis, and the break-even field delivered CO_2 price ($/t) is on the horizontal axis. The secondary horizontal axis shows the equivalent incremental oil recovery using an all cluster average net CO_2 utilization ratio of 0.3 tonne of CO_2/bbl. The WTI oil price sensitivity is shown in shaded colour bands from $30/bbl to $60/bbl. The incremental oil recovery value is indicative only as each cluster has a unique net CO_2 utilization ratio value. The coloured band high ends are defined by the base case inputs (150% HCPV, WACC 10%), and the low ends are a capital sensitivity of 150% applied to the base case. The coloured bands reflect uncertainty related to capital cost assumptions.

The range in values of total cumulative CO_2 stored and incremental oil recovered is broad depending on the break-even CO_2 price, WTI oil price, and capital cost. Within the range of values plotted in Figure 24, cumulative CO_2 stored varies between 19Mt at $30/bbl WTI to 879Mt at $60/bbl. Figure 24 shows how sensitive the total amount of cumulative CO_2 stored and incremental oil recovery is eroded with the lower oil price, higher CO_2 price, and higher capital costs.

A sensitivity case where royalties are eliminated, and a \$10/t CO_2 credit is applied is also plotted on Figure 24 as a dashed red line. This sensitivity shows how large the \$50/bbl band can expand and how much additional CO_2 storage potential and incremental oil can be added when these financial levers are applied. At a field-delivered break-even price of \$80/t, the impact of these levers is sizeable, with the cumulative CO_2 stored increasing by 465 Mt.

Both Figure 21 and Figure 22 show that the cumulative CO_2 stored and break-even field delivered CO_2 price are sensitive to WTI oil price. If the base case WTI oil price drops by \$10/bbl, from, \$50/bbl to \$40/bbl, the volume weighted average CO_2 break-even price decreases by \$32.5/t. WTI oil price of \$100/bbl, the break-even CO_2 price is \$232/t. As the oil price increases, the CO_2 price required to break-even, or CO_2 price the CO_2-EOR project can tolerate increases. Some caution should be taken using the average break-even CO_2 price from all the clusters as each of the 699 clusters evaluated have discrete project economics.

Figure 22: Average CO_2 break-even price vs. WTI oil price

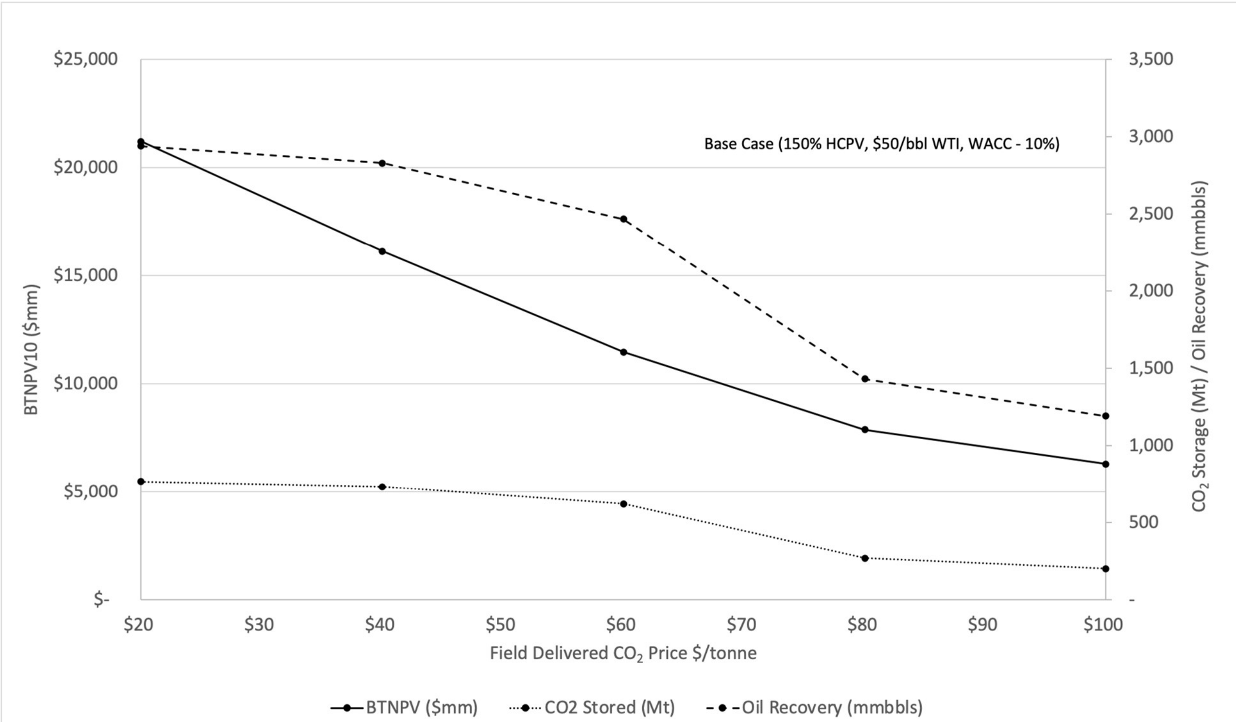


Source: (Author, 2020)

5.3.2 CO_2 Price Scenarios

Field-delivered CO_2 price is one of the largest barriers to large-scale CCUS-EOR deployment in Alberta. Figure 23 shows how sensitive cumulative BTNPV, CO_2 stored and oil recovered are to field-delivered CO_2 price. Figure 23 also shows the significant impact, both in terms of BTNPV and CO_2 stored, reducing the field delivered price from $80/t to $40/t can have. 465 Mt of economic storage is unlocked between a field-delivered CO_2 price of $80/t and $40/t. Also, for every incremental $20/tonne reduction in CO_2 price, between $3.5 and $5 billion in BTNPV is generated.

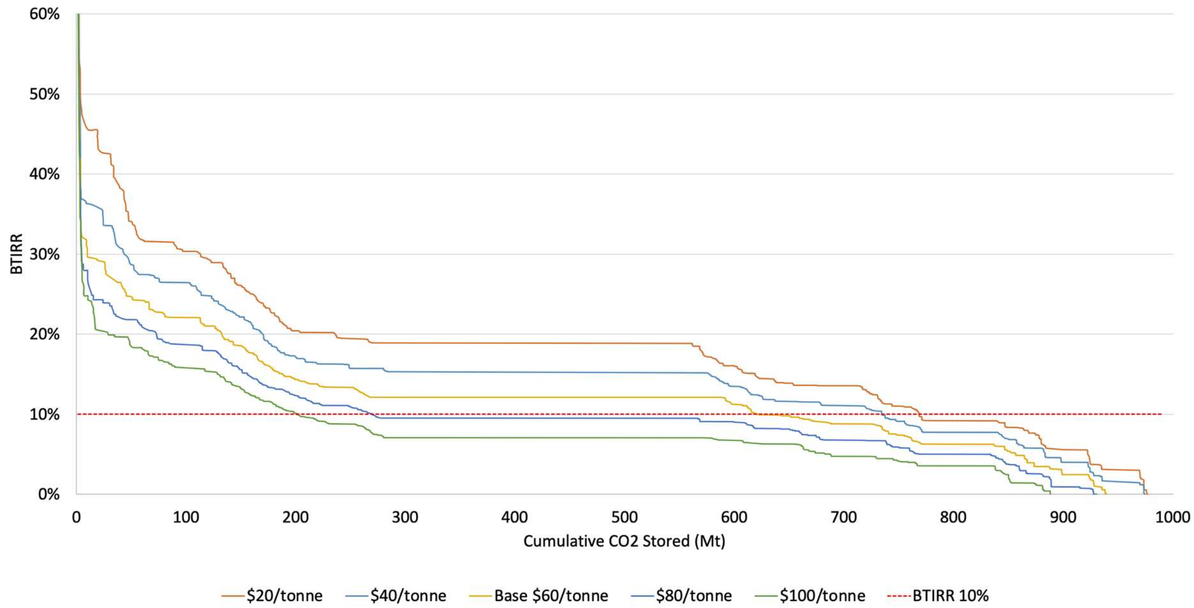
Figure 23: BTNPV and CO_2 stored vs. field-delivered CO_2 price



Source: (Author, 2020)

Figure 24 shows that for any given cumulative CO_2 storage volume a $20/t price drop is the equivalent to approximately 3% BTIRR. Also, at a breakeven BTIRR of 10%, a $20/t reduction in field-delivered CO_2 price adds between 34 and 353Mt of CO_2 stored. Volume of CO_2 stored is highly sensitive to BTIRR required by the investor. In the $60/t case, if the investor requires a 20% BTIRR, rather than 10%, the potential volume of CO_2 stored drops from 600Mt to 130 Mt.

Figure 24: BTIRR vs Cumulative CO_2 stored, field-delivered price sensitivity



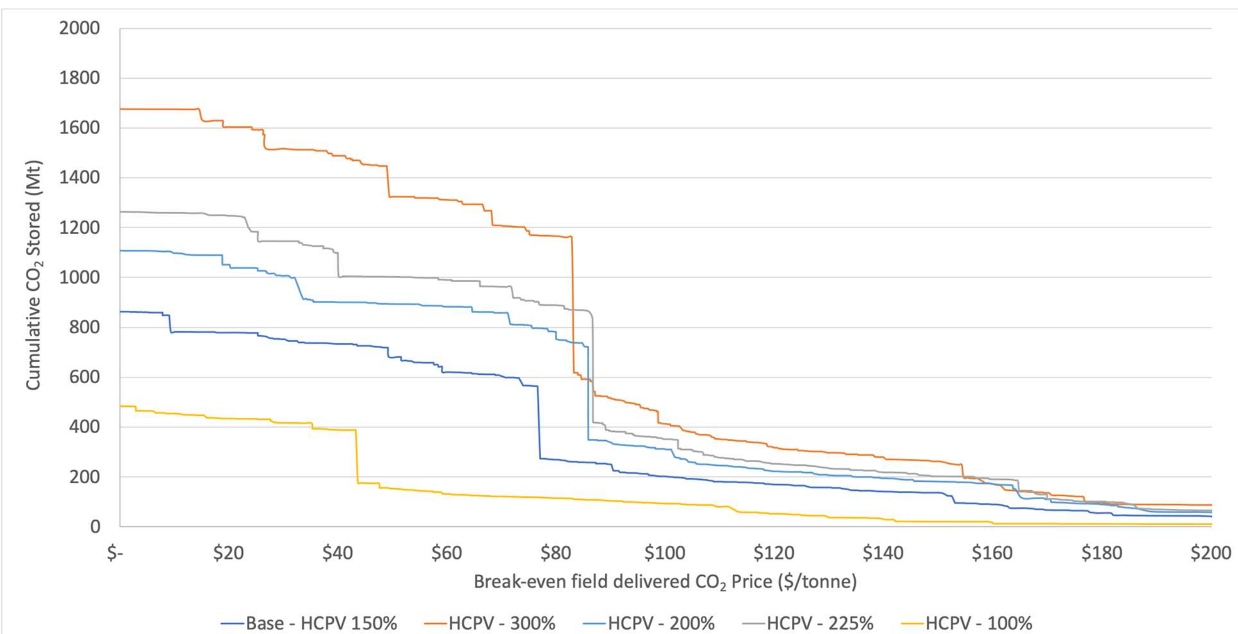
Source: (Author, 2020)

5.3.3 Hydrocarbon Pore Volume Injected (HCPV)

Incremental oil recovery and net CO_2 utilization ratio are dependent on the percentage of the hydrocarbon pore volume of CO_2+H_2O injected (HCPV%) and represent uncertainty in the economic results (Azzolina et al., 2015). The uncertainty in HCPV% injected produces uncertainty in the estimates of CO_2 stored. Sensitivities were performed to evaluate the impact of HCPV% on the CO_2-EOR project economics. These HCPV% sensitivities ranged from the lower bound of 100% HCPV to the upper bound of 300% HCPV based on Azzolina et al. (2015) and other field studies. The median HCPV% based on the available dataset from the 31 United States sites used in the Azzolina et al. (2015) study is 242.1% HCPV. It is estimated that Enhance Energy is proposing injecting 150% HCPV of CO_2 into their Clive CO_2-EOR project in Alberta (North West Redwater Partnership et al., 2019). Gunter and Longworth (2013) reported that the Alberta Joffre Viking CO_2-EOR project total HCPV% of 76%. Also, the HCPV% sensitivity range is consistent with other studies. For example, the Merchant (2010) study applied a 80% to 190% HCPV injection sensitivity range to model CO_2-EOR performance.

The sensitivities show that both the total incremental oil production and CO_2 stored are very sensitive to HCPV% injected. Total CO_2 stored increases by 685 Mt, and incremental oil recovery increases by 923 mmbbls when HCPV% injection volumes are increased from 150% from 300%. The more CO_2 that is injected, the higher the incremental oil recovery. The results show that the incremental recovery increases from 8.3% at 150% HCPV to 10% at 300% HCPV injected. These incremental recovery factor values fit within the range of 7–23% presented earlier in the study (Brock & Bryan, 1989; Martin & Taber, 1992). These recovery factors also are supported by the range of values (5–25%) reported by Merchant (2010).

Figure 25: Break-even price vs. cumulative CO_2 stored, HCPV% injection sensitivity

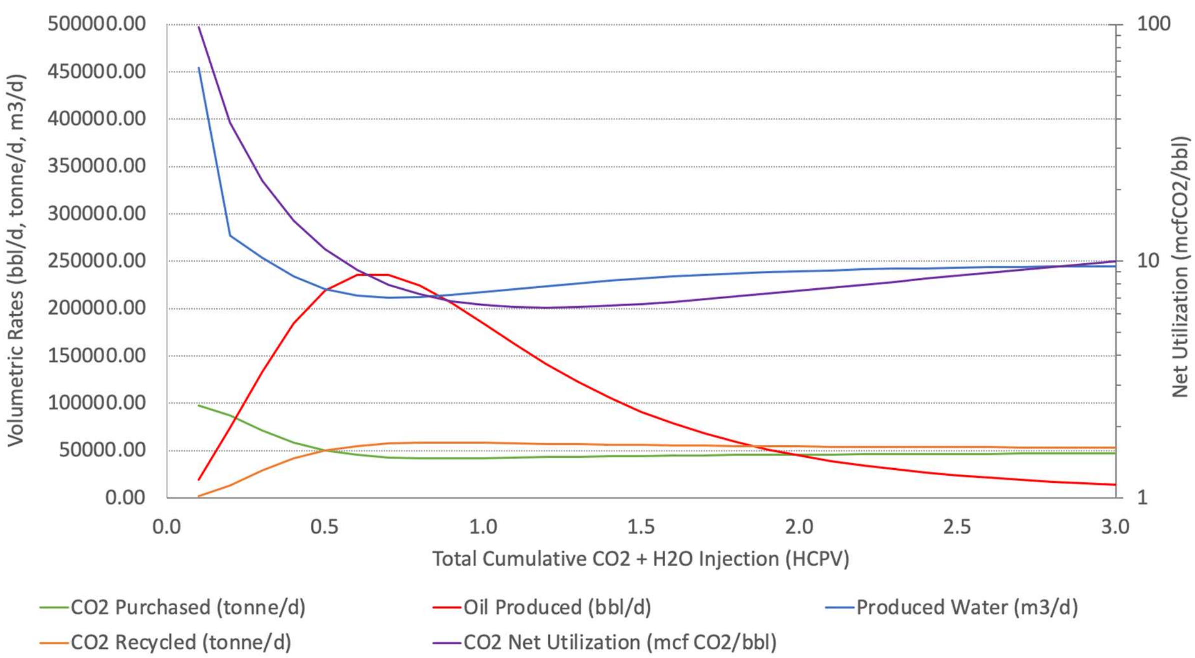


Source: (Author, 2020)

However, it can be observed from Figure 26 that with the incremental oil, additional volumes of water and recycled CO_2 are produced as the net CO_2 utilization increases in the later part of field life and the HCPV% approaches 300% and beyond. With higher net CO_2 utilization brings increased cost-related CO_2 recycling and produced water.

The result of this is a diminishing rate of return with increasing HCPV% as injection approaches 300%. For example, the Pembina-Cardium cluster, at base case conditions, returns a BTIRR of 8.3% at 100% HCPV injected, 15% at 200%, and 20% at 300%. The overall net CO_2 utilization rates show the optimal economic HCPV injection percent between 200% and 300% HCPV based on the Azzolina et al. (2015) model. The Pembina-Cardium cluster net CO_2 utilization at 100% HCPV is 6.5mscf/bbl, dropping to 4.7mscf/bb at 200%, and increasing to 10mscf/bbl at 300% HCPV.

Figure 26: Production and injection volumes vs. HCPV% injected, Pembina-Cardium cluster

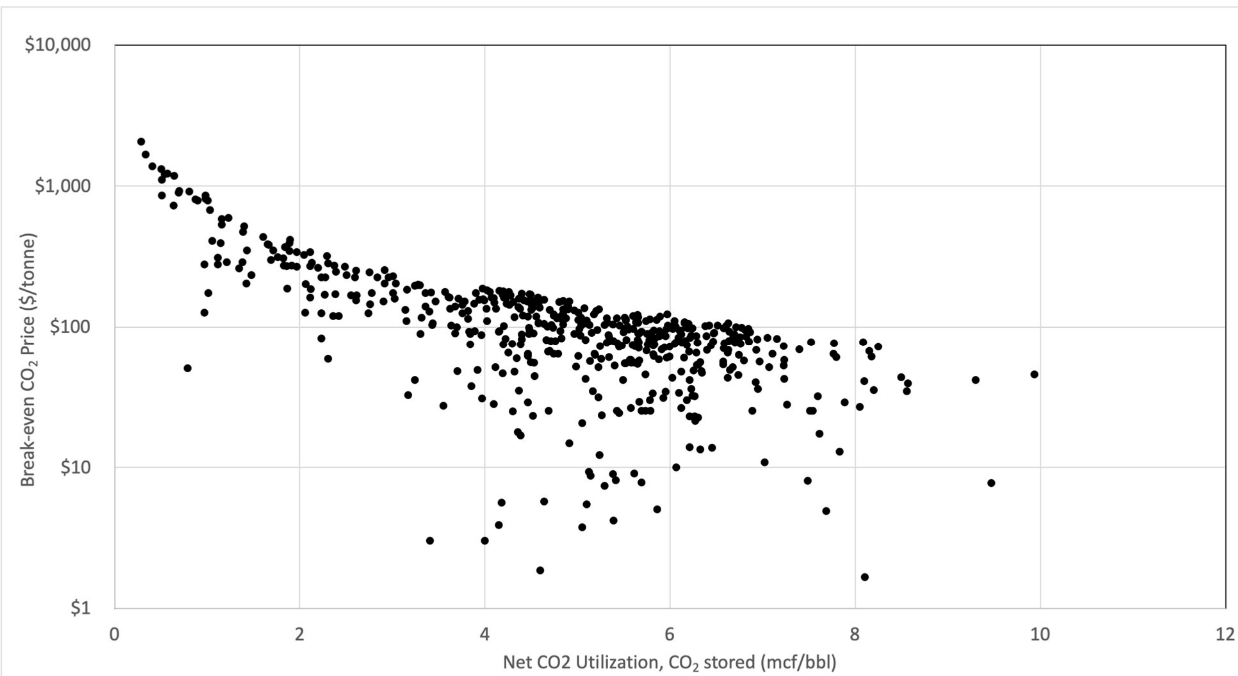


Source: (Author, 2020)

5.3.3.1 Net CO_2 Utilization Factor

The economic viability of CO_2-EOR projects is dependent on the net and gross CO_2 utilization ratio. The net CO_2 utilization factor indicates the amount of CO_2 stored per incremental barrel of oil produced. The lower the net CO_2 utilization factor the greater the amount of oil recovered per mscf of CO_2 stored. The break-even price of CO_2 or affordable price of CO_2 increases with a decreasing CO_2 utilization factor as shown in Figure 28. Net CO_2 utilization factor is also a key determinant of the life cycle GHG foot print for a barrel of oil produced through EOR (Cooney et al, 2015).

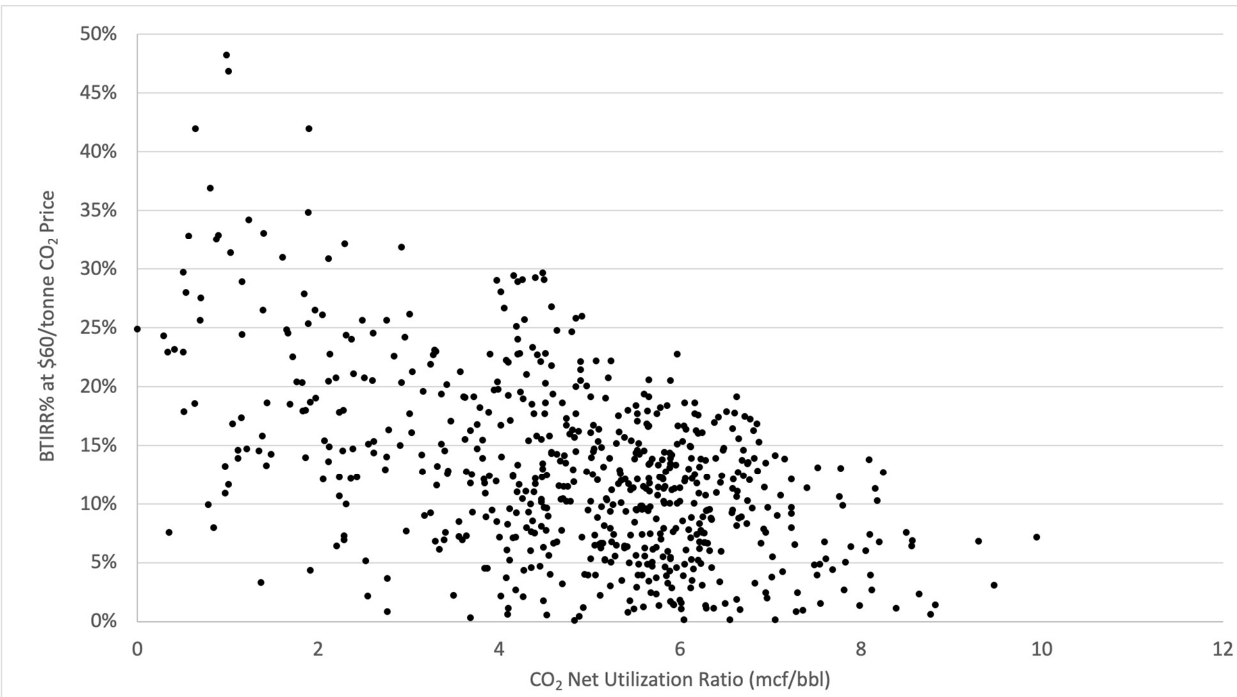
Figure 27: Cluster break-even CO_2 price vs. net CO_2 utilization ratio



Source: (Author, 2020)

The average net CO_2 utilization value for all clusters is 5.9 mscf/bbl. Azzolina et al. (2015) calculated a P10 to P90 range of 4.8mscf/bbl to 10.5mscf/bbl from the CO_2-EOR projects included in their study. The P10 or P90 value indicates there is a 10% or 90% probability that value is less than the P10 or P90 value. The net CO_2 utilization range in this study also compares well with other published studies and field data. The Merchant (2010) study of CO_2-EOR projects reported a net CO_2 utilization range of 1 mscf/bbl to 10 mscf/bbl. In Saskatchewan, the Weyburn CO_2-EOR project's CO_2 net utilization averages around 8 mscf/bbl with a range of 4–15 mscf/bbl (BMO Capital Markets, 2020).

Figure 28: Cluster BTIRR% at CO_2 \$60/tonne vs. net CO_2 utilization ratio



Source: (Author, 2020)

From a CO_2-EOR project economics perspective, a lower net CO_2 utilization, meaning less CO_2 required to produce an incremental barrel of oil, is preferable (Azzolina et al. 2015). The highest cost incurred for CO_2-EOR project is the purchase cost of CO_2 and the expenses related to CO_2 injection and recycling. Figure 28 shows that the lower the net CO_2 ratio, the higher BTIRR. Operators should target clusters where they can achieve low net CO_2 utilization ratios, the use of CO_2 is optimized, and CO_2 purchases are minimized (Núñez-López & Moskal, 2019).

It should be noted that this approach to CO_2-EOR project economics is a more traditional approach, and it competes with the more progressive view to reduce GHG emissions. There is an opportunity to potentially target higher net CO_2 utilization ratio clusters and generate an alternative revenue stream through carbon offsets from CO_2 stored to offset the cost of higher CO_2 utilization. Figure 23 shows that between a field-delivered CO_2 price of $40/t and $80/t there is a total BTNPV difference of $8,240mm. The equivalent CO_2 credit or offset, based on the CO_2 storage volume difference of 465 Mt and WTI price of $50/bbl, is $18/t.

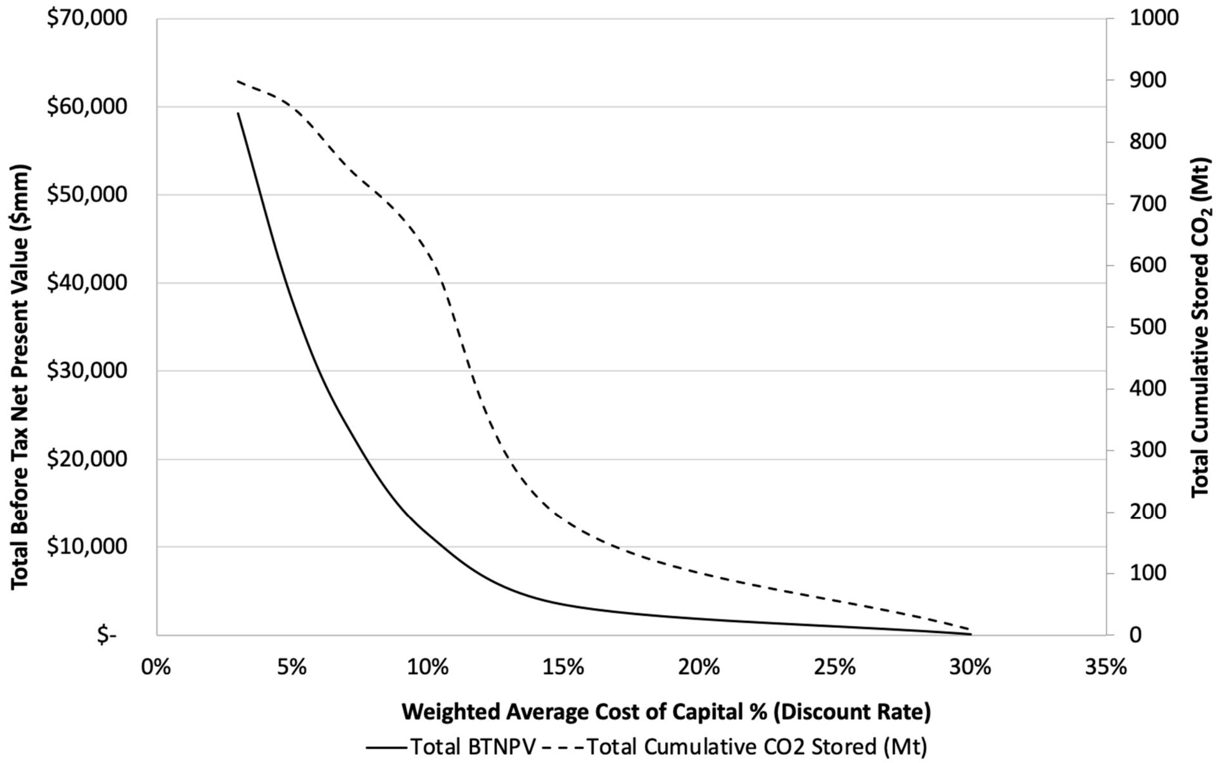
5.3.4 Financial and Policy Levers

Financial and policy levers and tools are critical to encouraging investment in CCUS-EOR projects. Sensitivities were performed on weighted average capital of capital, royalty rates, and carbon credits to demonstrate the high-level impact these tools can have on CO_2-EOR project economics and cumulative CO_2 stored in the province.

5.3.4.1 Weighted Average Cost of Capital

Weighted average cost of capital (WACC) or discount rate sensitives were modelled to demonstrate the impact of cost of capital on project economics and CO_2 storage volume. The economic model WACC sensitivities ranged from 3% to 30%, with the lower bound case representing project financing using low cost debt financing, e.g., government-backed low-interest loans or green bonds, and the higher bound used to reflect what might be required for equity financed higher risk projects.

Figure 29: Total BTNPV and CO_2 stored vs. weighted average cost of capital



Source: (Author, 2020)

Figure 29 shows the BTNPV profile dropping quickly as the weighted average cost of capital is increased, reflecting its effect on the long-term CO_2-EOR projects and emphasising the capital-intensive nature of these types of projects. The potential CO_2 volume stored is highly sensitive to the weighted average cost of capital required by the investor. On the other hand, Figure 29 shows the potential to store large volumes of CO_2 and generate billions in BTNPV if the right investment environment can be created.

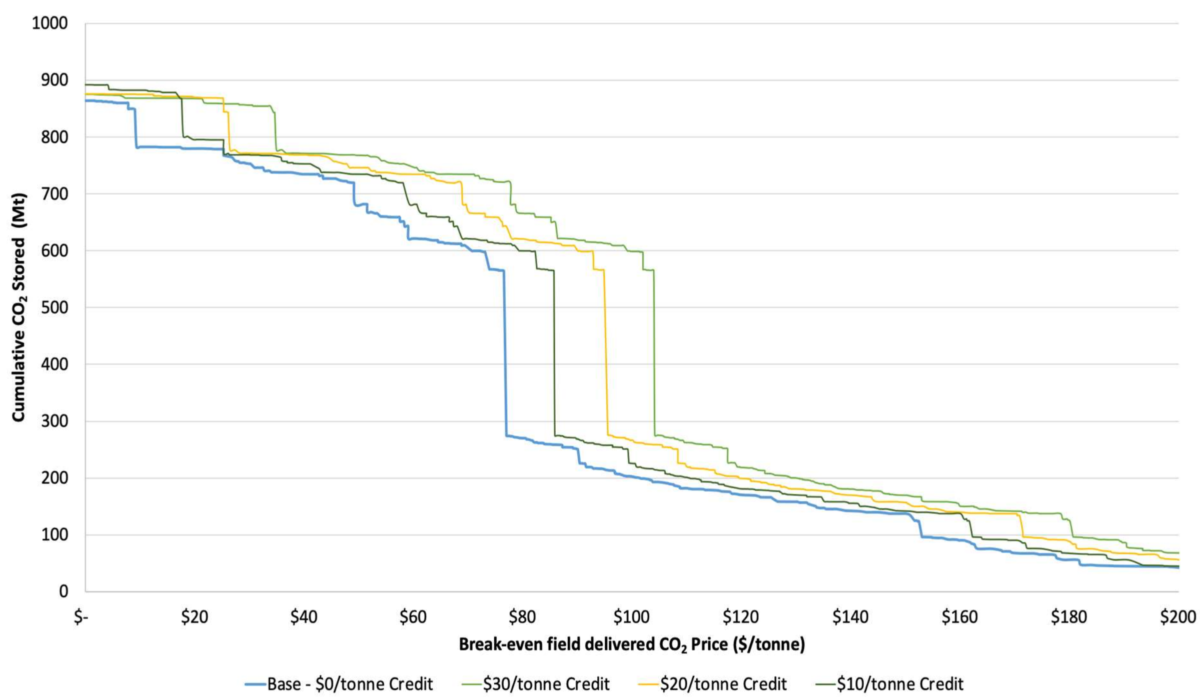
5.3.4.2 Carbon Credit

Carbon credits were applied to the economic model as a proxy for carbon or offset credits or a tax credit to see the impact of these types of financial incentives on the CO_2-EOR project economics and broader cumulative CO_2 stored in the province. Carbon offset credits can be generated from projects that reduce greenhouse gas emissions or increase stored carbon through activities such as CCS through CO_2-EOR.

With the anticipated increase in federal carbon tax from \$30/t in 2019 to \$50/t in 2022, the value of carbon offsets generated is expected to increase (Environment and Climate Change Canada, 2019). The value or portion of the carbon offset credits received is dependent on the arrangement or sharing agreement between the emitter and CO_2-EOR operator. The base case economics assume the operator managing the CO_2-EOR project and storing CO_2 receives no carbon credit. In reality, the CO_2-EOR operator would receive some portion of the Alberta carbon offset credit; this will go to offsetting the cost of the CO_2 purchase.

By applying a \$30/t carbon credit to the base case, the total cumulative CO_2 increases by 212 Mt and incremental oil recovery increases 711 mmbbls.

Figure 30: Break-even field-delivered CO_2 price vs. cumulative CO_2 stored, CO_2 credit sensitivity

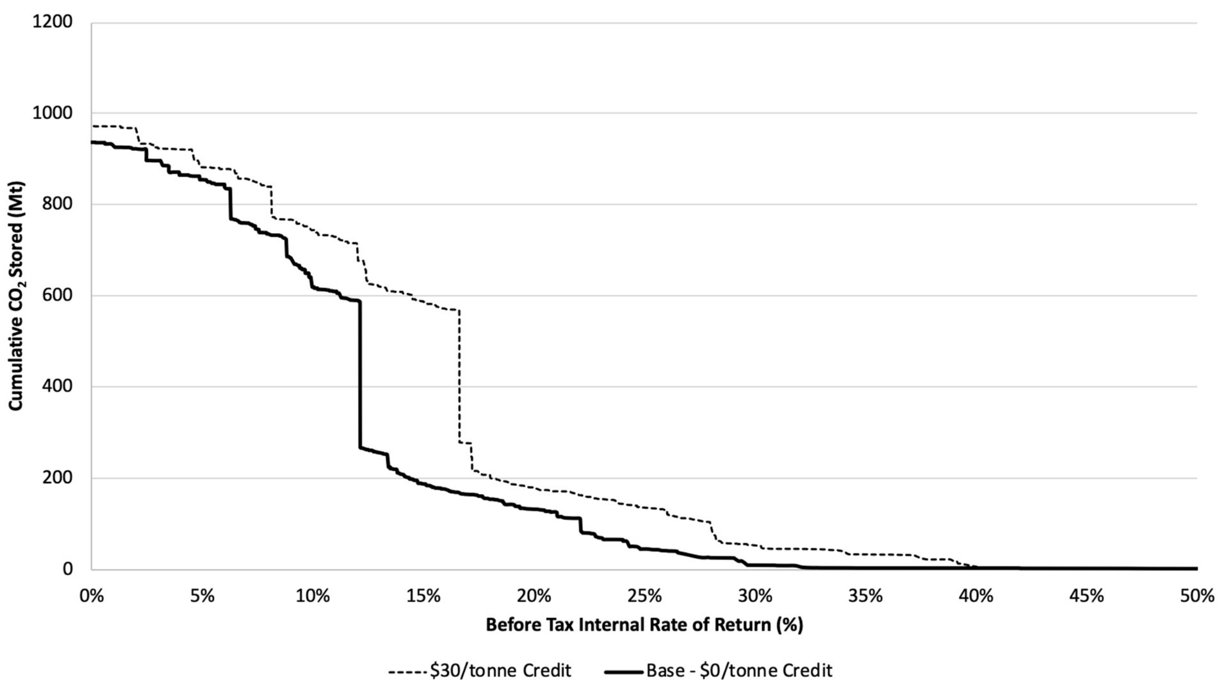


Source: (Author, 2020)

It is assumed that the carbon credit can be used to reduce the net cost of CO_2 purchases, increasing the break-even CO_2 price by the given credit amount. Figure 30 shows that there is an opportunity within the break-even CO_2 price window of between \$60/t and \$90/t, after applying a \$30/t carbon credit, to add a significant amount of CO_2 storage. This is a due to the Pembina-Cardium cluster's size and estimated economic performance. At \$90/t break-even CO_2 price, a \$30/t credit could potentially unlock an additional 392 Mt of viable CO_2 storage, from 249 Mt to 641 Mt.

Figure 30 shows that the volume of potential CO_2 stored is not materially sensitive to CO_2 credits up to \$30/t at both the high and low break-even CO_2 price ranges. This means projects with poorer project economics, requiring lower field delivered CO_2 prices to reach a BTNPV of zero, are smaller in terms of volume of CO_2 stored and require significant CO_2 credits to make them viable. On the other end, those projects with high break-even CO_2 prices have a high tolerance to CO_2 price and require a significant increase in price to become uneconomic. The potential volume of CO_2 stored is, however, sensitive to CO_2 credits in the midrange, \$60/t to \$90/t.

Figure 31: Cumulative CO_2 stored vs. BTIRR%, CO_2 credit sensitivity



Source: (Author, 2020)

From Figure 31, most of the CO_2-EOR clusters have a BTIRR of between 10% and 20%. A carbon credit of $30/t can add 5% to the BTIRR%.

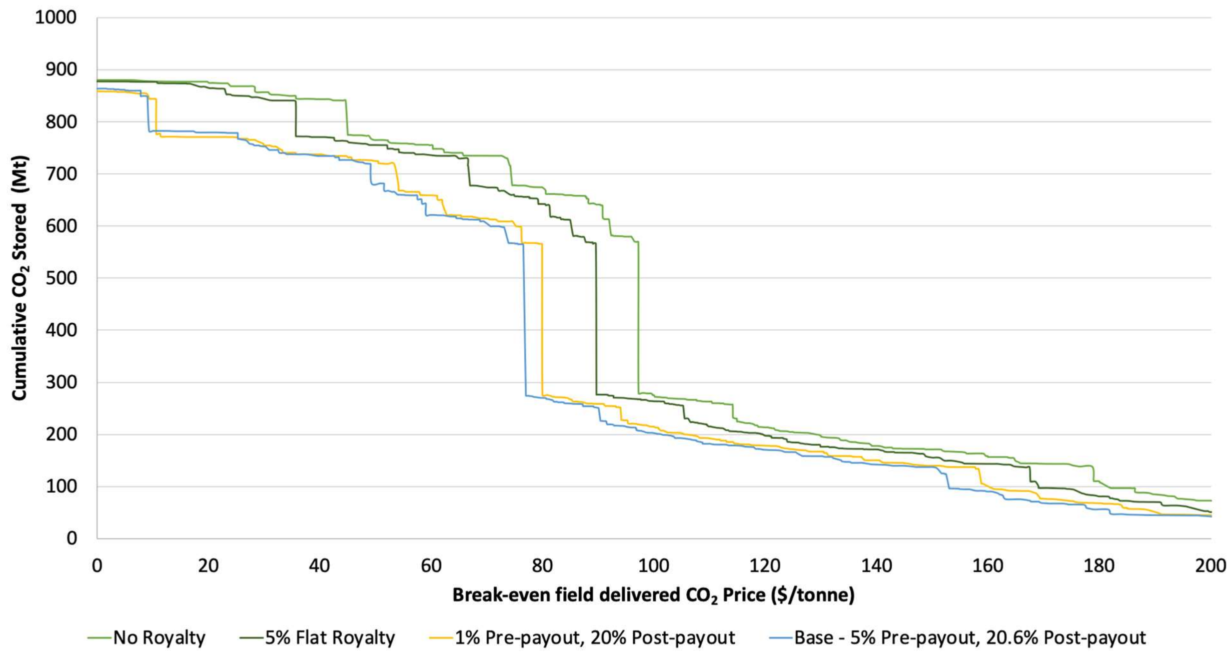
A recent 45Q tax credit in the United States has generated interest in Carbon Capture and Storage (CCS) and CO_2-EOR. The 45Q tax credit allows projects to eventually receive $50USD/t CO_2 for geologic storage and $35USD/t CO2 for enhanced oil recovery. It provides a stable and predictable value on carbon, addressing one of the most significant uncertainties for CO_2-EOR projects.

The Global CCS Institute reported that 45Q has already led to a series of project announcements since the tax code was reformed in 2018 (Beck, 2020). Both Figure 30 and 31 show that carbon credits are a powerful tool to incentivise further deployment of CCUS to CO_2-EOR.

5.3.4.3 Royalty Rates

Regulatory incentives like royalty relief or elimination can improve CO_2-EOR project economics significantly. Although Alberta currently has the Alberta Enhanced Hydrocarbon Recovery Program (EHRP) royalty program to incentivise incremental production from enhanced recovery methods, there exists an opportunity for further royalty reduction to encourage greater CO_2-EOR development. For example, Saskatchewan has a lower royalty rate than Alberta on incremental production from a new enhanced oil recovery (EOR) projects. Saskatchewan uses a pre- and post-payout structure similar to Alberta, with a royalty rate of 1% of gross revenue applying to projects pre-payout and a 20% royalty on net revenues post-payout (Government of Saskatchewan, 2019).

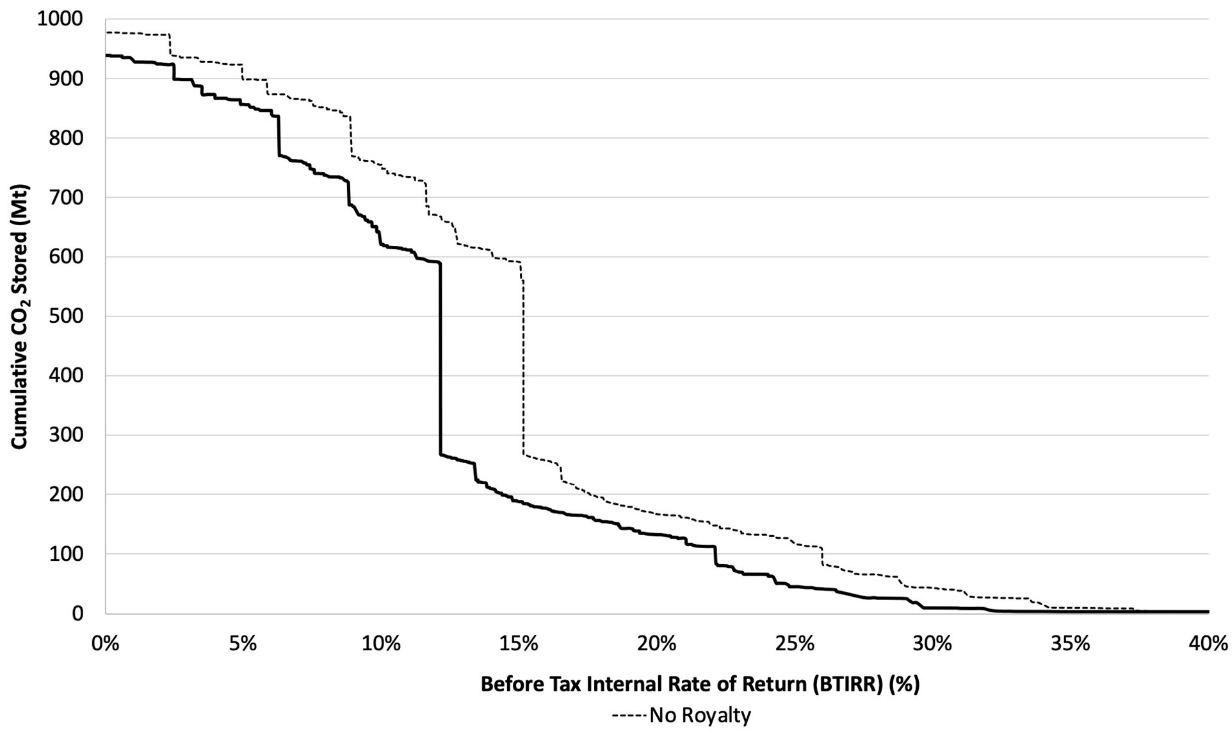
Figure 32: Cumulative CO_2 stored vs. break-even field-delivered CO_2 price, royalty rate sensitivity



Source: (Author, 2020)

Reducing the Alberta royalty rate to something comparable to Saskatchewan has little impact to the overall affordability of CO_2, increasing the break-even CO_2 price by $2–3/t. However, reducing the royalty rate to a flat 5% or eliminating the royalty entirely can increase the break-even CO_2 price by $15–20/t. At a break-even CO_2 price of $60/tonne, an elimination of royalties can add 134 Mt of CO_2 potential storage and an incremental oil production of 440 mmbbls.

Figure 33: Cumulative CO_2 stored vs. BTIRR%, royalty rate sensitivity



Source: (Author, 2020)

Also, at a net field-delivered CO_2 price of $60/t, eliminating royalties adds approximately 3% to BTIRR% CO_2-EOR cluster project economics. Depending on the weighted average cost of capital of the company, this could mean the difference between a viable CO_2-EOR project and not.

Reducing or eliminating royalty payments for a CO_2-EOR project comes with significant loss of government royalty revenue. The results show an estimated $9.4 billion in net present royalty revenues at base case conditions would be lost if royalties were eliminated. However, this can be offset by the benefit of increased economic activity in the province. The estimated net present royalty revenue lost reduces to $0.9 billion is the case of adopting the Saskatchewan CO_2-EOR royalty regime.

CHAPTER 6: DISCUSSION

There is a material amount of CO_2 storage potential and incremental oil production opportunity at base case conditions. The results are encouraging for the province in that almost 2.5 billion bbls of oil could be recovered, and around 620 Mt of CO_2 potentially stored. This compares to a technical potential of 759 to 2,858 mmbbls and 213 to 1,742 Mt CO_2 estimated by Bachu (2015).

At first glance, these CO_2-EOR project clusters are economically viable and cumulatively present a strong value creation opportunity. Over 50% of the CO_2-EOR clusters (699 total clusters) have a positive BTNPV at a 10% weighted average cost at base case conditions. Also, CO_2 supply price is becoming more affordable, with approximately 50% of the total cumulative CO_2 storage potential (451 Mt, at base case) economically viable in the \$60/t to \$120/t CO_2 price range. The average price of CO_2, across all identified clusters, at which EOR becomes an economically viable option for storage, i.e., break-even at 10% weighted average cost of capital, is \$69/tonne. However, these projects are very sensitive to oil price and cost of capital, as oil price decreases or investors require greater return on investment, the break-even CO_2 price drops significantly. Alternatively, as the weighted average cost of capital is reduced, with low-interest loans or other low-cost financing, the average break-even price or tolerance to higher CO_2 supply price increases.

The size of the prize for investors, companies, and the province in incremental oil produced, CO_2 stored, royalties, and taxable revenue is large. There is substantial upside incremental oil recovery and CO_2 stored potential. At 300%HCPV injection, there is up to 1.3Gt of CO_2 storage, 3.3 billion bbls of incremental oil recovered, and \$11.5 Billion in BTNPV. Further deployment of CO_2-EOR can also provide both increased royalty and tax revenue to the province. At base case conditions, \$9.4 billion would be returned to the Alberta treasury in royalties. Other benefits include extending the life of mature oil fields in the province, providing employment including redeployment of skilled workers, and tax revenue to Alberta and rural municipalities.

The current cost and geographical locations of CO_2 supply in the province is an issue. The results show the majority of stationary CO_2 emissions in Alberta at a capture cost of between $40/t and 80/t. This cost of capture will continue to come down as capture technology advances. However, these sources are generally located in the northeast of the province and are not in direct proximity to the most viable clusters for CO_2-EOR. Also, at present, there is no infrastructure to connect this concentration of CO_2 emissions sources to the central and west Alberta CO_2-EOR clusters. The high-level cost for CO_2 transportation and compression from the emission source to the CO_2-EOR site in Alberta is estimated between a few dollars to tens of dollars per tonne – depending on transport distance, field demand, and configuration of the system (National Energy Technology Laboratory, 2018). This transportation cost can be added to the capture cost range with an assumed carbon offset credit between $10/t and 15/t to reach a range of delivered CO_2 price of between $55/t and $80/t. This supports the initial base case field-delivered CO_2 supply cost assumption of $60/t. There would also likely be an economies of scale effect where larger CO_2-EOR projects with higher CO_2 purchase volume would have lower CO_2 supply cost. Many CO_2-EOR projects are well within the range of viability when considering the estimated field delivered CO_2 prices with the CO_2 break-even prices calculated from this study.

Beyond the challenges of aggregating emissions sources, CO_2 transportation, and bringing down the supply capture cost, there is the added complexity of how to deliver CO_2 from large emitters to the many small clusters for CO_2-EOR. The analysis shows that the majority CO_2 storage potential is concentrated amongst only a few clusters. At base case inputs, 57% of the total available CO_2 storage potential of 991 Mt is among 10 clusters. 289 Mt of CO_2 storage potential is in a single cluster, Pembina-Cardium. Figure 17 shows that only 30 clusters have the potential to store 5 Mt of CO_2 or greater. The Figure also shows how geographically dispersed the locations of these clusters are. Maximizing CO_2 storage requires the less material CO_2-EOR clusters to be developed. Building the infrastructure needed to unlock the full CO_2 storage potential through CO_2-EOR will be a challenge. To achieve full-scale CO_2 storage through CO_2-EOR more pipeline infrastructure is required.

There are many uncertainties and barriers to consider in the development of CCUS to CO_2-EOR in Alberta. These include technical uncertainties, e.g., reservoir performance and net CO_2 utilization factors, and economic and commercial risks, such as high upfront capital costs, commodity price, CO_2 supply and cost. Also, political and regulatory uncertainty exists that can impact the oil and gas industry through policies such as royalty regimes and carbon tax and offset programs.

For the most part, technical uncertainties can be addressed or mitigated through detailed reservoir characterization, numerical simulation, and CO_2-EOR pilots or demonstration projects. This is discussed briefly in Section 7.1 Limitations and Future Research. Other uncertainties are more irreducible and can benefit from policy intervention. Policy interventions or levers to reduce or mitigate against these uncertainties can include low-interest government back loans, grants, royalty rates reduction or elimination, carbon credits (tax, offset credits), and tax programs for accelerated capital depreciation. Levers are required to provide more project certainty, de-risk the project economics, and provide quicker returns to incentivise the further deployment of CO_2-EOR.

There are only a few commercial CO_2-EOR projects currently operating in Alberta. The complexity of delivering CO_2 from the province's high emission sources to the areas with most attractive CO_2-EOR project economics coupled with the uncertainties identified above have meant that deployment of CO_2-EOR has been slow. In addition, CO_2-EOR project economics are often challenging from an investment or funding standpoint. CO_2-EOR projects have large upfront capital expenditures similar to that of oil sands projects in the order of magnitude for Capex, the shape of cash flow, and longer capital recovery or payback periods. The WACC sensitivity in Figure 29 demonstrates how capital-intensive these types of projects are. Also, CO_2-EOR projects also have higher CO_2 purchase costs earlier in the project life, as net CO_2 utilization ratios are high and CO_2 recycle rates are low.

There is still a disconnect between carbon price required for viable CO_2-EOR projects and capture costs, especially when considering the cost of transportation and the current oil price. Levers or financial tools can be applied to bridge the gap in CO_2 price and reduce economic risks for CO_2-EOR projects to promote the further deployment of CCUS to CO_2-EOR in Alberta.

Government and industry focus should be on promoting financial tools and incentives to reduce external uncertainties that can not be mitigated by individual companies. These uncertainties for CO_2-EOR projects are primarily in price and commercial risk, specifically price certainty, oil and CO_2, and the upfront capital cost to reach full commercial scale. Financial tools that can be specifically used to reduce front-end capital expenditures or accelerating recovery of front-end capital are direct grants, accelerated depreciation of capital, or carbon offset or tax credits that can be realized early in the project life or for pilot projects. These financial tools are especially crucial to reaching full-scale CO_2 storage in the province.

Pilot CO_2-EOR projects are necessary to mitigate technical and economic risk prior to moving to commercial-scale operations. Early adopters have been penalized for early action in the past and left with stranded or worthless assets (Alberta Economic Development Authority, 2009). Grant or loan programs to cover design studies and tax breaks or public-private partnerships for pilots to reduce upfront project de-risking costs should be promoted.

The results of this study demonstrate that economic incentives or policy levers that have the largest impact are those that can help reduce the project weighted average cost of capital or carbon credits (tax, offset credits) that can be used to offset the supply cost of CO_2. Figure 29 shows how sensitive the cumulative potential CO_2 stored and incremental oil recovery is the WACC. Billions of dollars of BTNPV can be generated and hundreds of Mt of CO_2 can be stored through access to lower cost of capital, reducing the project WACC by a couple percent. Access to low cost capital is critical for companies pursuing CO_2-EOR projects given the high initial capital cost of the projects, especially for small companies. As previously noted, the majority (83%) of the suitable clusters for CO_2-EOR have a CO_2 storage potential of less than 1 Mt. These clusters account for 662 mmbls of total incremental oil recovery. Individually, these clusters are not material for large companies. Large companies often have a broader resource base with more attractive targets for their budget dollars than CO_2-EOR (Gunter and Longworth, 2013). Small companies are necessary to exploit the smaller, less material, CO_2-EOR opportunities to reach the full CO_2 storage potential through CO_2-EOR.

Companies and, in particular, smaller producers, may have challenges accessing lower cost of capital debt or credit. Policies that lower the cost of capital for these projects is a potential lever for federal or provincial governments to use in order to encourage CCUS to CO2-EOR in Alberta (and other provinces). Financing options and incentives need to target and promote the development of these less material clusters by smaller companies. The government can play a significant role in removing or reducing this obstacle for smaller companies by assisting in projects on the front end (Alberta Economic Development Authority, 2009).

Carbon credits are also shown to have significant impact on the volume of potential CO_2 stored and economics of CO_2-EOR projects. Tax credits or other carbon credits, such as offset credits, can go towards offsetting the supply cost of CO_2. A $30/t carbon credit can add 212 Mt of CO_2 storage potential and incremental oil recovery of 711 mmbbls. Tax credits for CO_2 stored through CO_2-EOR have been successful in incentivising CO_2-EOR projects in the United States with the implementation of the 45Q tax credit. Implementing tax policies similar to the 45Q tax credit, providing a $35USD/t to $50USD/t tax credit for CO_2 stored through CO_2-EOR, will help bridge the gap in CO_2 supply cost and promote further deployment of CO_2-EOR.

Royalty rates are another policy tool that can have some impact on incentivising CO_2-EOR deployment. As discussed above, accelerating capital recovery is essential to improving the economics of CO_2-EOR projects. Reducing pre-payout royalty rate can allow companies to generate greater cash flow in the early years of the project. For example, Saskatchewan has a 1% pre-payout royalty rate for CO_2-EOR projects compared Alberta's pre-payout royalty rate of 5%. The results show that reducing the pre-payout royalty to 1% can add 37Mt of CO_2 storage potential and 133mmbbls of incremental oil. A CO_2-EOR royalty incentive can improve the CO_2-EOR project economics through the acceleration of capital recovery.

Eliminating CO_2-EOR royalties, although unrealistic, not surprisingly, is a more impactful lever. The CO_2 price equivalent to eliminating royalties is over $20/t. This is important because the high-level capture cost analysis shows that CO_2 capture costs are within $20/t of the break-even CO_2 price for most clusters. Eliminating royalties for CO_2-EOR projects is beneficial to operators, but the government does forgo royalty revenue of $9.4 Billion in net present value at $50/bbl

WTI. Increased corporate tax from incremental CO_2-EOR project revenue could go some way to offsetting any loss of royalty revenue.

Financial and policy levers such as government grants and loans, royalty relief, and clean energy standards can work in conjunction with 45Q type tax credits to further leverage private sector investment into CO_2-EOR projects. All financial tools and levers should be promoted, however, those that can reduce initial capital cost or accelerate capital cost recovery such as direct grants, or access to lower cost of capital financing and carbon credits are the most impactful.

Another aspect that needs to be considered is the net impact of CCUS CO_2-EOR on emissions reduction. This study demonstrates that CO_2-EOR can be one vehicle to generate a revenue stream to offset the cost of CO_2 capture, and thus avoid emissions of CO_2 from point sources. In the base case, the 620 Mt of CO_2 that is stored through CO_2-EOR is CO_2 not emitted from Alberta industrial sources. The actual CO_2 emissions abated would be slightly less due to the energy penalty of CO_2 capture. This, thus, supports Alberta's and Canada's near-term climate goals. The longer-term potential for CCUS to CO_2-EOR to contribute to emissions reduction is more complex, as the emissions associated with use of produced oil as a transport fuel (and predominantly used in other countries) will become more important. Moreover, absent incentives for CO_2-EOR (or other means of tertiary recovery), smaller CO_2-EOR suitable oil fields may have to shut-in. This highlights the need for careful economic modeling and life cycle analysis that assesses the net impact of emissions resulting from hydrocarbon extraction to CO_2 capture through CO_2 storage under different potential policy scenarios.

This capstone will be of interest to regulators, government, oil and gas companies, and environmental scientists. The results can help regulators and policymakers understand the size of the CO_2 storage potential through CO_2-EOR in Alberta and where the CO_2 supply price needs to be to unlock further storage potential and the impact of financial and policy levers. This study will hopefully generate discussion and inform future policy, whether it be carbon pricing, government grants or incentives, or public and private financing models, that will promote the large-scale deployment of CCUS to enhanced oil recovery projects in Alberta. This study can also provide companies with a screening tool for potential CO_2-EOR opportunities and help prioritize clusters to focus on; those with the highest returns and that can utilize existing facilities and infrastructure. Finally, standalone CCUS through CO_2-EOR is shown to be viable in this study, but CO_2-EOR can also be seen as a stopgap until CO_2 price, regulation, or policies can make dedicated geological CO_2 storage and blue hydrogen (hydrogen from methane) more viable.

CHAPTER 7: CONCLUSION

Utilization is crucial to making CCS economically viable; CO_2-EOR is one of the only proven, mature, scalable, and economic value-added utilization options for CO_2 in the near term. The need for carbon capture and storage deployment at an accelerated rate globally and in Alberta is clear. Alberta is uniquely positioned, given the province's world-class geological CO_2 storage potential and large in place oil in mature reservoirs, and has an opportunity to be a world leader. The study estimated that CCS through CO_2-EOR could economically store between 130 to 1,310 million tonnes over the next 30 years.

The results of this study provide an estimation of the economic CO_2 storage potential and incremental oil production through CO_2-EOR operations in Alberta. This study presents an integrated modelling methodology, with CO_2-EOR pool suitability screening criteria and ranking based on Bachu (2015), incremental oil production and CO_2 storage estimation based on Azzolina et al. (2015), and economic and cost models from Fukai et al. (2016) and others (Advanced Resources International [ARI], 2006; Godec, 2014, Kuuskra et al., 2011; McCoy, 2009; McCoy & Rubin 2009; North West Redwater Partnership et al., 2019).

Carbon Capture Utilization and Storage (CCUS) through CO_2 Enhanced Oil Recovery (EOR) can be viable in Alberta in the near term. At a field-delivered break-even CO_2 price of \$60–120/t, and WTI oil price of \$50/bbl, there is 451 Mt of CO_2 storage potential and 362 mmbbls of incremental oil. The estimated of range of CO_2 storage potential is between 130 Mt and 1,310 Mt, with up to \$11.5 billion BTNPV, at 10% discount rate, to be created.

Although the cumulative opportunity is large, few clustered pools in Alberta offer both material CO_2 storage potential and strong economics. Financial and policy levers such as low-interest government-backed loans, accelerated capital depreciation, reduced royalty rates, and carbon credits (tax, offset credits) can be used to promote further deployment of CO_2-EOR in Alberta, targeting the less material pool clusters.

This screening methodology and economic model presented in the study can help identify the most suitable oil pools for CO_2-EOR in Alberta and the most economically viable clusters for CO_2 storage through CO_2-EOR. Also, the methodology used in this study can be applied as a techno-economic screening tool to other jurisdictions to calculate high-level CO_2-EOR economics and both estimated economic CO_2 storage capacity and CO_2 break-even prices.

7.1 Limitations and Future Research

This capstone project has assessed and confirmed the potential viability of CCUS to EOR for CO_2 storage in Alberta. The limitations of this study and areas of future research for consideration are the following:

- Integrating this work with the capture and transportation elements of CCUS value chain,
- Detailed evaluation of financial and policy levers,
- Expanding the geographic area of study,
- Greater consideration of CO_2-EOR project development uncertainty.

This study takes a relatively simplistic approach to modelling the financial and policy levers available to CO_2-EOR projects. Detailed after-tax financial modelling is required to understand better the impact of financing options, private and public partnerships, and other lever that the government could use to accelerate deployment of CCUS to CO_2-EOR. Specifically, levers to reduce CO_2-EOR project risks through royalty relief, tax credits, financing, and loan guarantees. After-tax financial modelling will allow for sensitivities of more complicated financial levers and instruments. This detailed financial modelling should also update the cost modelling to reflect the present-day cost of CO_2-EOR in Alberta more accurately.

To fully evaluate the viability of CCUS to CO_2-EOR projects in Alberta, the methodology and modelling described in this capstone needs to be integrated with the capture and transportation elements of the CCUS value chain, expanding on work performed by Middleton and Brandt (2013) and Middleton and Yaw (2018).

The proximity of the CO_2 source to the suitable CO_2-EOR clusters was not considered in the screening and ranking criteria. Future studies should include:

- Identifying the required CO_2 infrastructure to connect emission sources and suitable CO_2-EOR oil fields presented in this study,
- Building scenarios: the selection of sources and CO_2-EOR clusters to maximize the overall profit from CO_2 to EOR,
- Techno-economic modelling of CO_2 capture, compression, transportation alternatives, and enhanced oil recovery to obtain full CCUS value chain economics.

Break-even CO_2 price analysis and financial and policy levers sensitivities can be applied similarly to this study.

Future studies should consider expanding the emissions source and CO_2-EOR feasibility evaluation into East British Columbia and Saskatchewan. There are large industrial sources of emissions and pools suitable for CO_2-EOR in these areas. One of the largest carbon storage through CO_2-EOR projects exists in the Weyburn-Midale oil pools in Saskatchewan (BMO Capital Markets, 2020). There is opportunity to optimize CCUS to CO_2-EOR economics across the borders of the provinces.

This capstone project is intended to be a high-level tool to screen and quantify economic CO_2 storage via CO_2-EOR in Alberta. The screening and weighed ranking methodology should be refined to eliminate erroneous low pressure pools. Another opportunity for improvement is the ranking and screening methodology. While assigning a single score to each pool on the basis of their performance on discrete screening criteria has been previously used (Bachu, 2015), ad-hoc weighting factors were used. Structured methods to develop weighting factors (e.g. pairwise comparisons) could be considered in future studies.

The Azzolina et al. (2015)-based volumetric CO_2-EOR model used in this study doesn't capture geological heterogeneity, water-alternating gas ration and voidage replacement ratio influence, and other factors that may impact CO_2-EOR performance and storage potential. CO_2 retention is highly dependent on specific pool geology. Detailed reservoir characterization and numerical simulation are required to assess pool-level CO_2 stored capacity and incremental oil recovery accurately. Also, the Azzolina et al. (2015) model uses a dataset that reflects only water-alternating gas CO_2 floods within the continental United States and may not be analogous to pools in the Western Canadian Sedimentary Basin.

CO_2-EOR cluster economics performed in this study reflect success case economics, meaning there is no consideration for chance and cost of project failure. No chance of success or cost of pilot projects are incorporated into the economic evaluation. In reality, pilot projects are required prior to the move to commercial scale in order to adequately de-risk the technical and commercial risks.

Decision tree and Expected Monetary Value (EMV) analysis should be performed to accurately present CO_2-EOR project value. Some downside CO_2-EOR performance risk is considered in the HCPV% injected sensitivity in this study. Also, downside incremental oil recovery is reflected in the parameters used in the Azzolina et al. (2015) volumetric model that uses the median values of the 31-site dataset.

Future studies could perform statistical analysis using the range of fitted parameters generated by Azzolina et al. (2015). There are also sensitivities used in this study to reflect risks surrounding cost, oil and CO_2 price, and high discount rates can be used as a proxy for technical risk. Also, project economics are optimistic due to the assumed project timelines. In this study, all cluster production and capital spending starts January 1st, 2020; however, CO_2-EOR projects, in reality, will be much more staggered, with production commencing later and the project life likely being shorter. Timelines need to be adjusted to reflect actual project delivery timeline, and consideration needs to be made for matching purchased CO_2 rates and supply of captured CO_2.

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APPENDIX A – CO_2-EOR Project Cost Definitions

Cost Category	Definition (Fukai et. al, 2016)
Well Cost	
Drilling & Completion (D&C)	Tangible and intangible costs associated with on-site drilling and completion phases for production and injection wells. Items include lease hold costs, site preparation, surface and downhole drilling, casing, cementing, well perforating, and all labour associated.
Production Well Equipment	Capital costs of tangible and, to a lesser extent, intangible items associated with production well equipment and installation. Items include surface and subsurface production well equipment: tubing, rods, down-hole pump, well-head, and well-site metering.
Injection Well Equipment	Capital costs of tangible and, to a lesser extent, intangible items associated with injection well equipment and installation. Items include surface and subsurface injection well equipment: tubing, rods, injection pump, well-head, and well-site metering.
CO_2 Costs	
CO_2 Transportation & Distribution	Fixed and variable capital costs associated with transporting the volume of CO_2 required for injection from the regional pipeline to the EOR site, as well all manifolds and flow lines required for on-site CO_2 distribution.
CO_2 Recycling Plant	Capital costs of a recycling facility of sufficient size to facilitate CO_2 separation from produced fluids during peak production and recycling operations. Items include separators, fluid distribution lines, gas stream flow lines, CO_2 compression equipment, flow controls, and other processing equipment.
CO_2 Recycling O&M	Expenses related to operation of the recycling facility corresponding to the rate of production, recycling, and injection simulated for a specific time period, with the energy required for CO_2 surface management, treatment and compression generated on-site. Energy required for for recycling facility operations including power for separation, processing, and CO_2 compression costs.
Total O&M Costs	
Periodic O&M	Costs associated with operation and maintenance of a CO_2-EOR surface site including surface repairs/remediation, maintenance and replacement.
Liquid Lifting Costs	Operational costs of pumping (to surface), managing, and (re)distributing liquids produced during a given time period of CO_2-EOR operation, with the required energy generated on-site

General & Administrative (G&A)	Other expenses associated with routine activities and processes required for effective operation of the overall project, but not directly related to the production of marketable goods and services.
Monitoring, Measurement & Verification (MMV)	Monitoring plan for the injection facilities, the storage site (including the CO_2 plume) and the surrounding environment. Assess behaviour of the plume with predicted behaviour of the plume through dynamic modelling. Detect and identify potential unintended migration of CO_2 or other irregularities. Quantify volumes of CO_2 associated with leakage or unintended migration.