Emissions Reduction Alberta's Carbon Capture Kickstart Program

OCTOBER 2024

LESSONS LEARNED FROM

11 INDUSTRIAL CCS FEED STUDIES

INTERNATIONAL CCS KNOWLEDGE CENTRE

EMISSIONS REDUCTION ALBERTA

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CITING THE INTERNATIONAL CCS KNOWLEDGE CENTRE

For further information, please contact us at:

The International CCS Knowledge Centre
198 - 10 Research Drive
REGINA SK S4S 7J7
Canada

Tel: +1 (306) 565-5669
Email: info@ccsknowledge.com
www.ccsknowledge.com

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About Us

Emissions Reduction Alberta (ERA)

ERA was created in 2009 to help deliver on the province's environmental and economic goals. For 15 years, ERA has been investing revenues from the carbon price paid by large emitters to accelerate the development and adoption of innovative clean technology solutions. These technologies will lower costs, improve competitiveness, and accelerate Alberta's transformation to a low emissions economy.

The International CCS Knowledge Centre (Knowledge Centre)

The International CCS Knowledge Centre is leading the world to a sustainable future by sharing insights and expertise on carbon capture and storage (CCS) and other solutions to address climate change.

We are independent, trusted advisors with unparalleled experience developing CCS projects, fostering collaboration and the exchange of knowledge to cut greenhouse gas emissions and achieve global net-zero goals.

Executive Summary

This report summarizes key learnings from the Carbon Capture Kickstart (CCK) program, launched by Emissions Reduction Alberta (ERA) in 2022 and supported by the Government of Alberta's Technology Innovation and Emissions (TIER) fund, to accelerate large-scale carbon capture projects at industrial facilities towards a final investment decision (FID). The program was conducted in collaboration with a parallel program funded by Natural Resources Canada (NRCan). The CCK program consists of eleven Front-End Engineering Design (FEED) studies spanning 27 facilities across the oil and gas, power, cement, forestry, and fuels & chemical sectors, all operating under Alberta's TIER carbon management framework. At the outset of this study, all facilities sought to implement carbon capture and storage (CCS) on their facilities by 2030.

The program, designed to support large-scale CCS projects through FEED studies, has been instrumental in advancing carbon capture initiatives in multiple sectors. The lessons learned and technical insights that emerged from these FEED studies have value for future project developers and stakeholders as they progress toward FID and project implementation. Though the path to FID remains uncertain for many CCS facilities in the CCK program, learnings to date can help demonstrate the potential for emissions reduction and cost optimization from CCS as a decarbonization pathway.

By sharing knowledge across projects, the CCK program seeks to add value beyond the direct support for each of the innovative projects. Findings from this program can help to drive down costs, mitigate risks, and improve the feasibility of future CCS endeavors in Alberta and other jurisdictions worldwide.

Key to the success of the CCK program was fostering a culture of knowledge sharing to ensure that learnings from site selection, technology choices, and operational considerations can become accessible across sectors and stakeholders. Funded projects provided key metrics, took part in a series of lessons learned workshops, and supported the development of a levelized cost of capture (LCOC) calculator, all of which aimed to identify successful cost-saving initiatives and to standardize approaches. The LCOC calculator was used across all projects allowing for a consistent methodology in calculating capture costs and providing valuable data for future sensitivity analyses to optimize CCS project economics.

In this report, we explore many aspects of CCS projects in detail across the FEED lifecycle, with key insights and preliminary program outcomes summarized below. These represent important areas of focus for prospective CCS project developers to consider in improving design, reducing costs, mitigating operational risks and getting to FID.

Lessons Learned

SITE CONSIDERATIONS

Older facilities will require significant retrofitting to integrate CCS, particularly when considering equipment accessibility and maintenance. Proximity to infrastructure, transportation, and storage have significant cost impacts. A single-train equipment configuration is often favored for its cost savings, though it introduces constraints in operational flexibility. Reducing flue gas duct length minimizes capital expense of CCS and improves integration with the host facility.

TECHNOLOGY SELECTION

Most proponents evaluated liquid amine-based capture technology for its proven performance and ability to meet high capture rates of 90% or higher. They observed limited technical differences between vendors. Non-amine technologies like solid sorbents and cryogenic methods may offer material cost savings and environmental advantages over amine-based capture but will be challenging to implement at scale by 2030. Notably, proponents observed that cost factors for CCS are more strongly influenced by execution factors and site specifics, rather than a specific technology vendor.

FLUE GAS CHARACTERIZATION

Flue gas characterization provides crucial details necessary for the optimization of capture efficiency and the management of impurities that could degrade amine-based CCS system performance. Early flue gas characterization helps inform system design and pretreatment needs. Limited flue gas testing capabilities exist in Alberta, and there is a lack of standardized protocols, both of which highlight significant gaps in the CCS service industry.

ENERGY REQUIREMENTS

The CCK proponents indicated that thermal energy required for capture was 2.5 - 4 GJ/tCO_2, and electrical energy requirements were 80 - 300 kWh/tCO_2. Methods employed to reduce energy consumption included waste heat recovery, mechanical vapor recompression (MVR), and computational modelling of fluid flows to optimize the design of blowers. Many proponents considered auxiliary steam or power sources to avoid a significant parasitic load on their facility or due to the unavailability of the required energy at the site. However, these additional energy sources introduce additional emissions and increase the size of the capture facility.

COOLING

Cooling technology selection has a significant impact on water usage. Air cooling was the prevalent choice for cooling system among the CCK proponents, which results in net production of water from an amine-based CCS facility. Ambient temperatures, water availability, and other environmental factors influence the cooling technology choice. Cooling designs optimized for lower ambient temperatures resulted in smaller, cost-effective systems. Seasonal changes also impacted cooling demands, influencing annual operational costs.

SECONDARY EMISSIONS

Amines, aldehydes, ammonia, and nitrosamines were identified as potential secondary emissions arising from amine-based capture systems, with pretreatment of flue gas playing a critical role in reducing these emissions. Pilot testing campaigns could help identify these emissions, and optimizing operating conditions will be key to minimizing them.

WATER REQUIREMENTS

Water is required for several purposes in a CCS plant. Cooling technology choice has the largest impact on water consumption and determines whether CCS is a net producer or consumer of water. CCS could lead to new water consumption for some industries, like cement, that have a strong incentive to minimize water use and environmental impact.

SOLID AND LIQUID WASTE

Solid waste generated from amine-based CCS plants primarily consists of spent activated carbon, filters, and desiccants. Waste disposal pathways for these solid wastes exist. For those capture technologies using solid sorbents and cryogenic processes, the primary source of solid waste is spent adsorbents and filters used for contaminant removal. Recycling options for these wastes are being explored.

In an amine-based CCS facility, liquid waste can be comprised of condensed water, spent amine solution, and the liquid waste from the thermal reclaimer. Treatment options for liquid waste are available, but there are environmental challenges with many of these disposal paths, including the creation of additional byproducts. Confidentiality may play an important role in waste disposal, as it could lead to challenges in correctly identifying the waste.

CO_2 TRANSPORTATION AND STORAGE

The proponents in the CCK program evaluated distances as far as 400 km for transportation of the CO_2 product and identified saline aquifers as the permanent storage type. Proponents evaluated geological storage only, as it can accept higher volumes compared to current utilization technology, is readily available in Alberta, and unlike enhanced oil recovery, is eligible for Canada's CCUS investment tax credit. A key consideration in CO_2 transport that significantly influences the design of capture facilities is the CO_2 product specification. This remains an emergent topic as many sequestration hub projects and pipeline developers that would determine these specifications are still in the engineering phase.

EXECUTION

Alberta lacks direct access to a port, therefore equipment from overseas must travel longer distances to reach construction sites, which increases transportation costs and timelines. Technical expertise limitations within Alberta may pose challenges, and supply chain and labour shortages will likely impact project execution.

Preliminary Outcomes of the CCK Program: Costs and Emissions Reduction

The ultimate goal of FEED studies is to understand business and technical factors sufficient to reach FID, and the ultimate goal of implementing CCS projects is to achieve emissions reduction goals. While many FEED studies in the CCK program are not yet sufficiently completed to result in a FID at the time of this report's publication, estimating levelized costs and emissions reductions for the projects at this stage can inform the potential outcomes of the program, and form a basis of comparison for future CCS initiatives.

LEVELIZED COST OF CAPTURE

LCOC is a critical metric for evaluating carbon capture projects but is challenging to compare on a consistent basis between projects. The International CCS Knowledge Center developed a LCOC calculator that may be useful as a general, basic model for the purpose of comparison between projects. The sensitivity analysis from this calculator indicates that the discount rate – defined as the weighted average cost of capital – has a large impact on the final LCOC result, but the wide range of LCOC values nevertheless highlights the variability and uncertainty in cost estimates, even when consistent inputs are used.

It is also important to distinguish between levelized cost of CO_2 avoided (LCOA) vs LCOC. LCOA is an important metric as it considers only the reduction in the host facility's CO_2 emissions before and after the implementation of capture and not any CO_2 that is captured in addition to that produced by the original host facility. The LCOA was found to be approximately 20% higher than the LCOC for the projects in the CCK program. Accurate CCS costing remains an important issue that requires further analysis and ecosystem alignment. The LCOC section of this report illustrates how LCOC values change based on the various sensitivities applied.

POTENTIAL FOR EMISSIONS REDUCTION

The ultimate goal of implementing CCS is to reduce emissions. If all 27 facilities in the CCK program were to successfully reach FID, once operational, based on the data provided to date, they would collectively capture 29.6 $MtCO_2e$/yr. Note that this is slightly higher than the total current emissions of 29.4 $MtCO_2e$/yr from the host facilities. The baseline emissions would achieve a net reduction of 86%, or 25.3 $MtCO_2e$/year – slightly less than 10% of Alberta's total annual emissions. The difference between the amount of emissions reduced and the amount of emissions captured is due to the energy requirements of CCS that lead to incremental emissions and larger capture facilities. Net reductions by 2050 from all 27 facilities reaching operations by 2030 were estimated to be 508 $MtCO_2e$.

The CCK program has provided a valuable pathway for proponents to evaluate their proposed CCS projects.
As the projects advance, more data will be made available and additional learnings achieved. Ongoing knowledge sharing will remain critical to achieving emission reductions and supporting the transition to a more sustainable energy future.

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List of Abbreviations

AACE - Association for the Advancement of Cost Engineering
ATR - Autothermal Reforming
CAPEX - Capital Expenditure
CCS - Carbon Capture and Storage
CCUS - Carbon Capture Utilization and Storage
CEMS - Continuous Emissions Monitoring Systems
CFD - Computation Fluid Dynamics
CHP - Combined Heat and Power
DIN - Deutsches Institut für Normung
EOR - Enhanced Oil Recovery
EPA - Environmental Protection Agency
EPC - Engineering, Procurement, and Construction
FCCU - Fluid Catalytic Cracking Unit
FEED - Front-End Engineering Design
FID - Final Investment Decision
GHG - Greenhouse Gas
HRSG - Heat Recovery Steam Generator
LCOA - Levelized Cost of CO_2 Avoided
LCOC - Levelized Cost of Capture
MEA -Monoethanolamine
MOF - Metal Organic Frameworks
MVR - Mechanical Vapor Recompression
NGCC - Natural Gas Combined Cycle
OTSG - Once-Through Steam Generator
O&M - Operations and Maintenance
PM - Particulate Matter
SAGD - Steam-Assisted Gravity Drainage
SMR - Steam Methane Reformer
TIER - Technology Innovation and Emissions Reduction
TRL - Technology Readiness Level
ZLD - Zero Liquid Discharge

1. Introduction

Front-End Engineering Design (FEED) studies are a crucial step in large-scale Carbon Capture and Storage (CCS) project development to ensure that the project is technically and economically feasible and to enable an informed Final Investment Decision (FID). FEED studies take significant time and cost – up to 5% of the project value[i,ii]. Given that large scale CCS projects can cost hundreds of millions to several billion dollars, FEED costs are a considerable investment. Government funding to support feasibility and FEED studies accelerates learnings, reduces risk to carbon capture projects and advances them towards FID, and ultimately, creates knowledge sharing benefits that lead to material, ecosystem-wide cost savings. Importantly, organizations such as Emissions Reduction Alberta (ERA) have the ability to aggregate and anonymize data and learnings, without compromising the integrity and confidentiality of individual projects.

It is important to recognize FEED studies can have far-reaching benefits beyond informing specific project FIDs. Regardless of whether a FEED study results in a positive FID, it can generate knowledge and lessons learned. The study process is filled with decision points, each representing a possible project outcome. Navigating these decision points requires careful consideration to make informed business decisions, especially when they may necessitate operational changes or extensive retrofitting and design adjustments. Even seemingly straightforward decisions such as site selection can significantly impact cost, efficiency, and project trajectory. By integrating project learnings throughout the course of the project, rather than solely aggregating insights at project completion, valuable insights that might otherwise be lost can be captured in a timely manner. It is also worth noting that knowledge from CCS FEED is especially valuable given that lessons learned from CCS operations are yet to be fully realized due to the relatively few projects that are currently operational. By embracing a culture of continuous learning and knowledge exchange within the CCS ecosystem, we lay the groundwork for ongoing improvement and innovation, ensuring that future projects benefit from the collective learnings gained throughout the entire project lifecycle.

This report summarizes the learnings from feasibility and FEED studies that were part of the Carbon Capture Kickstart (CCK) funding program[iii], launched by ERA in 2022 and supported by the Government of Alberta's Technology Innovation and Emissions (TIER) fund, to accelerate large-scale carbon capture projects at industrial facilities towards FID and capture lessons learned. The program was conducted in collaboration with a parallel program funded by Natural Resources Canada (NRCan)[iv]. The information captured in this report is focused specifically on the capture aspect of the projects with the goal that future project developers and other stakeholders will use these insights to make decisions that optimize project outcomes and mitigate risks.

In this report, we provide:

- An overview of the CCK Program, knowledge sharing requirements for participating projects, and an overview of the types of carbon capture projects that supplied data and learnings for this analysis.
- Lessons learned to date from the participating CCK projects which span the entire FEED lifecycle, covering key areas such as site and facility considerations, technology selection, flue gas characterization, energy and cooling requirements, environmental factors including water usage, waste management, secondary emissions, insights into CO_2 transportation and storage, and execution strategies.
- A summary of anticipated outcomes of the FEED studies, including estimated levelized costs and emissions reduction benefits.
- A summary of key insights going forward, next steps for the program, and future knowledge sharing initiatives.

2. Overview of the Carbon Capture Kickstart Program

2.1 Program Background

In the spring of 2022, the Government of Alberta, through Emissions Reduction Alberta, invested CAD $40 million into 11 industrial scale carbon capture and transportation projects throughout the province of Alberta, under the Carbon Capture Kickstart Program. The studies span 27 different facilities across the oil and gas, power, cement, forestry, and fuels & chemical sectors, all operating under Alberta's TIER carbon emissions management framework. Each FEED study was subject to a minimum 1:1 private sector match requirement, and the collective value of all FEED studies was CAD $194 million. Approximately half of the FEED studies also received financial support from a parallel program via Natural Resources Canada. All projects aimed to rely on onshore geological sequestration for captured CO_2, but many did not have a confirmed pathway for the CO_2 disposal at the time they were completing their capture study. At the time of study onset, all projects aimed to complete FEED over a two-year period, reach FID in the mid-2020s, and achieve operations by 2030 to meet timelines associated with Canada's CCUS Investment Tax Credit[v].

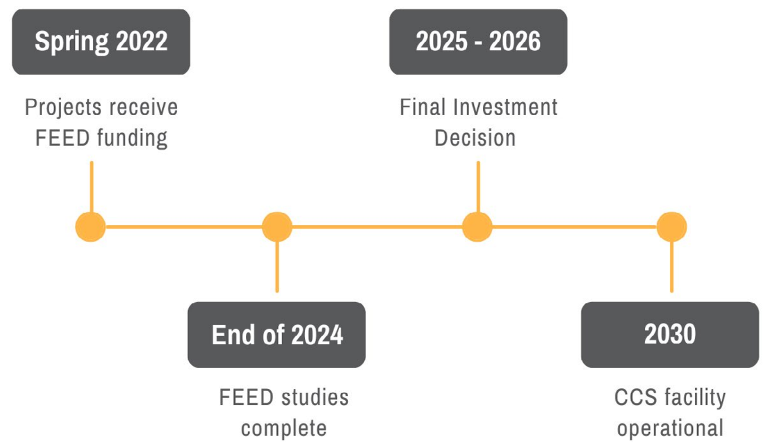


Figure-1: Original CCK Project Timeline

The program supported feasibility or FEED studies on CCS projects focused on technologies at a sufficient level of technical and commercial development given they were ready for commercial scale projects at existing industrial sites. (Refer to the International CCS Knowledge Centre's Need for FEED[i, ii] report for definitions of feasibility and FEED). Each project within the program is focused on specific existing large final emitter sites in Alberta, spanning a range of sectors.

At the time of study onset, it was estimated that collectively, if these projects were to reach a successful FID, they have the potential to generate over CAD $20 billion in capital expenditures, create thousands of jobs, and reduce approximately 24 million tonnes of emissions annually. This reduction is equivalent to nearly 10% of Alberta's annual industrial emissions. They also have the ability to leverage public money beyond these specific projects via effective information sharing.

Where are you on the path to CCS?

Aggressive Timeline to Deploy a CCS Project

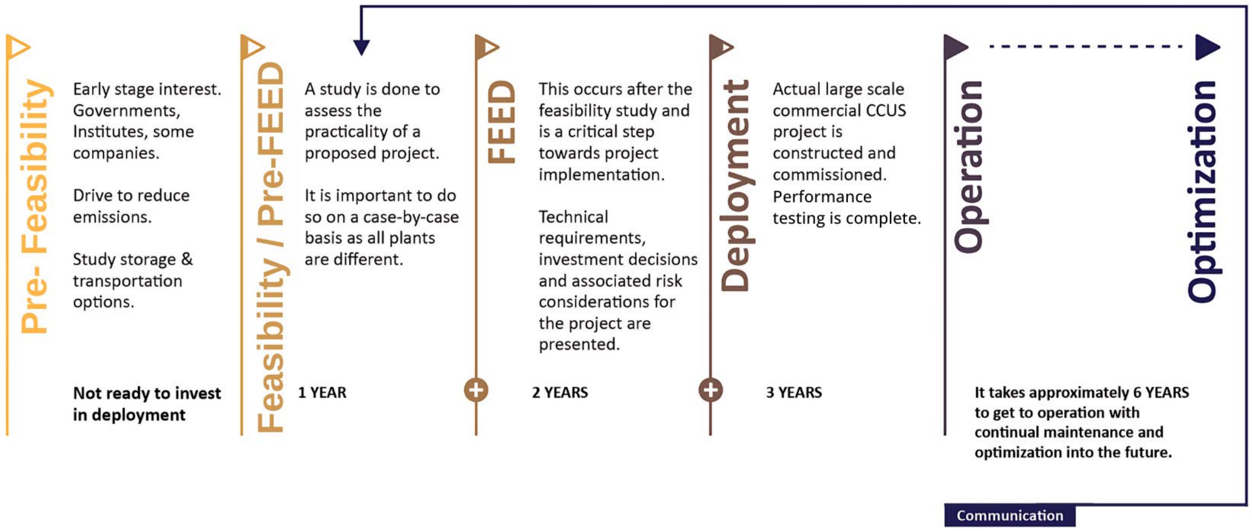


Figure-2: General CCS Project Timeline

The CCK program has the following aims:

- Improve understanding of the current costs associated with large-scale adoption of carbon capture to better inform investment decisions.
- Provide industry and government with increased lines of sight to the feasibility and integration requirements of large-scale CCS projects in Alberta.
- Collaborate with Natural Resources Canada to improve the national deployment of funding programs for CCS research and development.
- De-risk initiation of industrial-scale carbon capture projects and accelerate substantial follow-on investment for projects that have favorable study findings.
- Build Alberta's capabilities and develop a qualified workforce familiar with carbon capture technologies, enhancing Alberta's position as a leader in the industry.
- Coordinate with the Government of Alberta's carbon sequestration hub approach[vi].

2.2 CCK Program Knowledge Sharing Requirements

All FEED proponents were subject to the following knowledge sharing requirements and opportunities:

- Publication of study learnings and key outcomes following completion of study.
- Participation in knowledge sharing roundtables to discuss non-confidential lessons learned and progress.
- Provision of confidential knowledge transfer plans, detailing planned path to FID, at beginning and end of project.
- Provision of key metrics, collected on an annual basis, that may be shared in an aggregate, anonymized manner.
- Collaborate on whitepaper(s).
- (Optional) Collaboration with the International CCS Knowledge Centre.

Note that at the time of publishing this report, many of the studies are still ongoing.

Knowledge Sharing Roundtables

Proponents participated in quarterly Executive Roundtables and annual Knowledge Sharing Sessions to collect, compile, and clarify lessons learned. ERA, NRCan, and the Knowledge Centre also hosted annual knowledge sharing roundtables with ecosystem stakeholders.

Knowledge Transfer Plans

The knowledge transfer plan is a confidential document detailing knowledge transfer activities related to outputs of the funded project. It demonstrates how the completion of the FEED study will benefit the broader CCS ecosystem and would allow an understanding of the path to FID post-FEED completion.

Key Metrics Collection

It is important to have standardized key metrics when evaluating multiple host facilities to identify trends among the projects and determine FEED outcomes. During the program, the following data were collected on an annual basis for each host facility being assessed, with the ability to share the data in an aggregated, anonymized manner:

- **General Project Data:** such as host facility specifications, policy factors, permits required.
- **Greenhouse Gas and Environmental Data:** captured and avoided CO_2, secondary emissions, increased water and chemical usage, waste types and volumes.
- **Economic Data:** capital costs, operating costs, hurdle rate.
- **Technical Data:** flue gas characteristics, capture rate, technology down-selection process.

The collected key metrics and knowledge sharing roundtables with proponent participation have contributed towards this report and may contribute towards future knowledge sharing initiatives.

To align data, we worked to ensure consistency in key metrics. It is often the case that data requirements can be interpreted in different ways by different parties, therefore consistent reporting and alignment aided in ensuring results could be aggregated.

Provision of Knowledge Transfer

All proponents were offered 200 hours of support by the International CCS Knowledge Centre. This support typically took the form of workshops based on topics of the proponents' choosing and in some cases a site visit to the operating CCS facility at the Boundary Dam site. The main value was in offering proponents an unbiased, third-party perspective to project design. Most projects took full advantage of the 200 hours and found this to be a significant benefit in accelerating their FEED study.

3. Types of Projects in the CCK Program

3.1 Sectors

The projects encompass diverse industrial sectors grouped into three main categories: oil sands, power generation, and material production (including cement, fertilizer, forest products, and petrochemical) at large emitter sites across Alberta. Many of these projects are at the first stage of significantly larger overall project plans. A brief description of the various sectors is provided below:

Photo credit: Cenovus Energy, Foster Creek

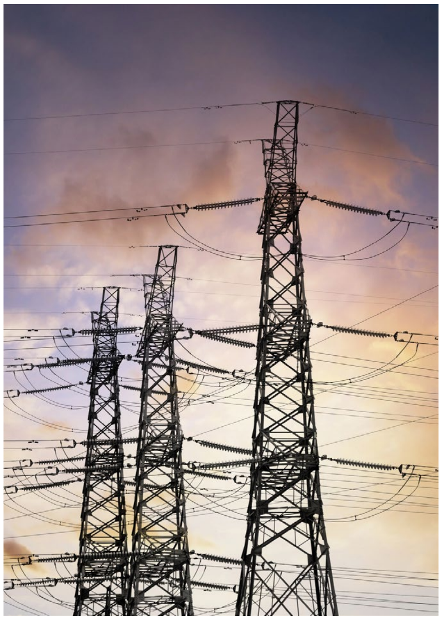
Oil Sands

Projects in the oil sands sector investigated carbon capture on a variety of natural gas burning steam and power generation equipment, including once-through steam generators (OTSGs), drum boilers, and cogeneration units, as well as on hydrogen production for use in the upgrading process. The combustion process for the OTSGs and the associated equipment to produce steam and power generate flue gases that contain CO_2. The hydrogen production process produces CO_2 via steam methane reforming (SMR).

Power Generation

The projects in power generation examined carbon capture on three types of power plants, including: natural gas combined cycle (NGCC); a coal-powered thermal plant converted to NGCC; and a coal-powered thermal plant converted to hydrogen. In the NGCC process, natural gas is combusted in a gas turbine to generate electricity. The hot flue gas goes through a heat recovery steam generator (HRSG), which produces steam to generate additional electricity. The CO_2 in the flue gas from the HRSG is captured through the carbon capture facility.

In the case of the coal thermal plant converted to hydrogen, the FEED study examined development of an on-site hydrogen production plant using autothermal reforming (ATR) technology. ATR involves a pre-combustion stream of flue gas with very high CO_2 concentrations.



Material Production

The material production sector studied the capture of CO_2 from the flue gas streams of various industrial processes. This includes flue gas from a fluid catalytic cracking unit (FCCU), a fertilizer plant, a cement plant, and a pulp mill. CO_2 emissions are generated in the following manner for these industries:

- **FCCU:** These units are used to break down heavy hydrocarbons into lighter ones and can account for 20-50% of refinery emissions[vii].
- **Fertilizer:** Fertilizer is produced by first making hydrogen, typically via steam methane reforming, and then combining it with nitrogen via the Haber-Bosch process. CO_2 is produced during the SMR process to make the hydrogen precursor.
- **Cement:** Emissions in the cement-making process arise from two main sources: (1) the energy required to heat the kiln to make cement, traditionally from combustion of fossil fuels (30-40%), and (2) the chemical reaction that occurs in the kiln to make cement (60-70%).
- **Pulp and paper:** Pulp mills may use either natural gas to power the mill, or residuals from forest product feedstocks. If the latter, emissions are considered biogenic, and do not contribute toward the facility's emissions inventory. If biogenic emissions are captured, they result in a carbon removal, or negative emissions.

A summary of the facilities in each sector and the average host facility baseline emissions can be found in Table 3-1.

Table 3-1: Industrial Sectors Analyzed

Sector	Number of Host Facilities	Host Facility Baseline Emissions ($MtCO_2e/yr$)
Oil and Gas	18	0.1 – 2.2
Power	5	0.3 – 3.5
Material Production	4	0.4 – 1.2

In addition, SMR and hydrogen production facilities comprised a subset of all three sectors, summarized below:

Sector	Number of Host Facilities	Host Facility Baseline Emissions ($MtCO_2e/yr$)
Hydrogen	5	0.7 – 2.0

3.2 Capture Technology

The CCK Program encompassed multiple types of carbon capture projects, including both pre- and post-combustion capture. Pre-combustion and post-combustion carbon capture represent distinct approaches used to reduce CO_2 emissions from industrial process. Both methods have their advantages and limitations, and the choice between them depends on factors such as the existing infrastructure, economic feasibility, and the specific emission sources being targeted.

Most of the projects in the CCK program investigated post-combustion carbon capture, with some projects also evaluating pre-combustion capture. Post-combustion capture technologies include liquid amines, solid sorbents, calcium looping, membrane-based separation, cryogenic and others. These technologies vary in materials and techniques used to separate CO_2 from flue gas, all aiming to reduce emissions after combustion. As noted in Table 3-2, Technology Suitability & Maturity, liquid amine has the highest Technology Readiness Level (TRL) of the post-combustion technologies. It also benefits from North American industry having experience handling amines, both at operational CCS facilities and in gas processing. The choice to pursue amine-based post-combustion carbon capture is also partly impacted by North American access to low-cost natural gas which can be used to generate steam for amine regeneration; in Europe, for example, there may be less focus on amines and more focus on electrically dependent technologies like cryogenic CCS.

Pre-combustion Capture

Pre-combustion carbon capture aims to reduce the CO_2 content of fuel prior to its use in the host facility. This approach yields a higher CO_2 concentration in the exit flue gas facilitating easier capture. The technology is mostly suitable in processes where syn gas (a mixture of CO, H_2, CO_2, and other trace components) is an intermediate product such as hydrogen production facilities.

Post-combustion Capture

Post-combustion capture focuses on capturing CO_2 from flue gases after fossil fuel combustion. Industries utilizing this technology implement it after pre-treating the flue gas to minimize impurities which can negatively impact the capture system. Post-combustion capture results in a lower concentration of CO_2 in the flue gas.

Table 3-2: Technology Suitability & Maturity[viii, ix, x]

Sector	Liquid Amine	Solid Adsorbent	Membrane	Calcium Looping	Cryogenic
Technology Readiness Level (TRL)	9	5-7	7 (gas permeation) 4 (contactor)	5-8	6-8
Capture Rate	95% guaranteed	>90%	80-90%	~90%	>95%
CO_2 Purity	99%	>95%	<95% & >95% (if liquid)	>99%	>99.5% (liquid)
Pretreatment Requirements	High	Medium	High (particulate)	Medium	Low
Strengths	Mature proven technology	Lower regeneration energy input	Compact & modular, easily scalable	Inexpensive sorbent. CO_2 separated easily by condensing water	Does not rely on chemical adsorption
Weaknesses	Amine degradation, waste handling, energy requirement	Robustness of metal organic framework	Not economical at higher capture rates (>85%)	Sorbent degradation	Energy intensive – cooling and compressing flue gas

Technology Readiness Level (TRL)

A qualitative scale known as the Technology Readiness Level (TRL) defines the maturity of technologies within an increasing scale of commercial deployment, as shown in Figure 3.

It may not be feasible for technologies with TRL lower than 6 to reach TRL 9 within the next 2-3 years. Given the large financial risk and other potential operating uncertainties, minimizing technical risk is one of the common sentiments expressed by those looking for near-term final investment decisions to maximize Canada's CCUS Investment Tax Credit. Therefore, project developers in the CCK program wanting to achieve short term (2030) greenhouse gas (GHG) reduction goals primarily considered liquid amine only, with a few projects open to evaluating other, lower TRL technologies.

Level 1

Basic principles of concept are observed and reported

Scientific research begins to be translated into applied research and development. Activities might include paper studies of a technology's basic properties.

Level 2

Technology concept and/or application formulated

Invention begins. Once basic principles are observed, practical applications can be invented. Activities are limited to analytic studies.

Level 3

Analytical and experimental critical function and/or proof of concept

Active research and development is initiated. This includes analytical studies and/or laboratory studies. Activities might include components that are not yet integrated or representative.

Level 4

Component and/or validation in a laboratory environment

Basic technological components are integrated to establish that they will work together. Activities include integration of "ad hoc" hardware in the laboratory.

Level 5

Component and/or validation in a simulated environment

The basic technological components are integrated for testing in a simulated environment. Activities include laboratory integration of components.

Level 6

System/subsystem model or prototype demonstration in a simulated environment

A model or prototype that represents a near desired configuration. Activities include testing in a simulated operational environment or laboratory.

Level 7

Prototype ready for demonstration in an appropriate operational environment

Prototype at planned operational level and is ready for demonstration in an operational environment. Activities include prototype field testing.

Level 8

Actual technology completed and qualified through tests and demonstrations

Technology has been proven to work in its final form and under expected conditions. Activities include developmental testing and evaluation of whether it will meet operational requirements.

Level 9

Actual technology proven through successful deployment in an operational setting

Actual application of the technology in its final form and under real-life conditions, such as those encountered in operational tests and evaluations. Activities include using the innovation under operational conditions.

Figure-3: Simplified Definitions of Technology Readiness Level for CCS Technologies

Source: Adapted from Government of Canada, Technology Readiness Level (TRL) Assessment Tool, March 25, 2021[xi].

Below we provide a summary of each of the front-running post-combustion technologies evaluated by proponents in the CCK program. Note this is not a comprehensive list of carbon capture technologies.

Liquid Amine (TRL 9)

Chemical absorption of CO_2 by aqueous amine solvents has been commercially deployed in fossil fuel power generation where the solvent is used to absorb CO_2 from the flue gas. The CO_2 rich solvent is then heated as part of a process that releases the CO_2 which is subsequently compressed and stored. The regenerated solvent is cooled and returned to the absorption column.

CCK proponents investigated both proprietary and non-proprietary amines. Proprietary amines are specific chemical compounds that are developed, patented, and sold by capture technology companies. These companies hold intellectual property rights over the chemical composition and preparation methods of these amines. Proprietary amines are generally optimized to meet capture efficiency, minimize solvent degradation and reduce the energy required for regeneration relative to non-proprietary amines.

Non-proprietary amines are not restricted by proprietary ownership. They can be sourced from various suppliers and are not limited to specific manufacturers or proprietary formulations. These amines are generally not optimized for specific applications. Non-proprietary amines such as Monoethanolamine (MEA), sometimes referred to as the conventional amines, are mostly used as benchmarks for developing new solvents to improve solvent stability and capture performance.

Solid Sorbent (TRL 5-7)

Solid sorbents are materials (physical sorbents or chemical sorbents) that selectively capture and remove CO_2 from industrial flue gases, preventing its release into the atmosphere. How the CO_2 is released from the sorbent depends on the specific technology being considered. Two of the most common methods include changing either the pressure or temperature of the material to release the CO_2.

Cryogenic (TRL 6-8)

This technology uses a physical separation method where the flue gas is cooled to extremely low temperatures, causing CO_2 to condense or solidify for easier separation from other components. This results in captured streams having a CO_2 concentration as high as 99%.

For a detailed, fulsome analysis on capture technology options and readiness, descriptions are provided in the Alberta Innovates paper titled "Carbon Capture, Utilization, and Storage (CCUS) Technology Innovation to Accelerate Broad Deployment in Alberta"[xii].

Additional information on various CCS technologies can be found in a recently released compendium issued by the Global CCS Institute titled "State of the Art: CCS Technologies 2024"[xiii]. The compendium highlights:

- Insights into the latest CCS advancements and solutions.
- Details on performance and applications of new CCS technologies.
- A snapshot of the range of industries where available technologies are being applied.

4. Lessons Learned

Most industries have a deep understanding of how to operate their core industrial processes. However, carbon capture technology represents a relatively new area with unique challenges that many industries are still learning to navigate. As the FEED studies progressed, numerous technical learnings emerged that can be used to inform future designs and optimize performance.

This section discusses lessons learned from the following aspects of FEED, based on knowledge sharing sessions and roundtables and key metrics collection from CCK projects:

- Site considerations
- Capture technology selection
- Flue gas characterization
- Energy requirements
- Cooling technology
- Water requirements
- Solid and liquid waste
- Secondary emissions
- CO_2 transportation & storage
- Execution considerations

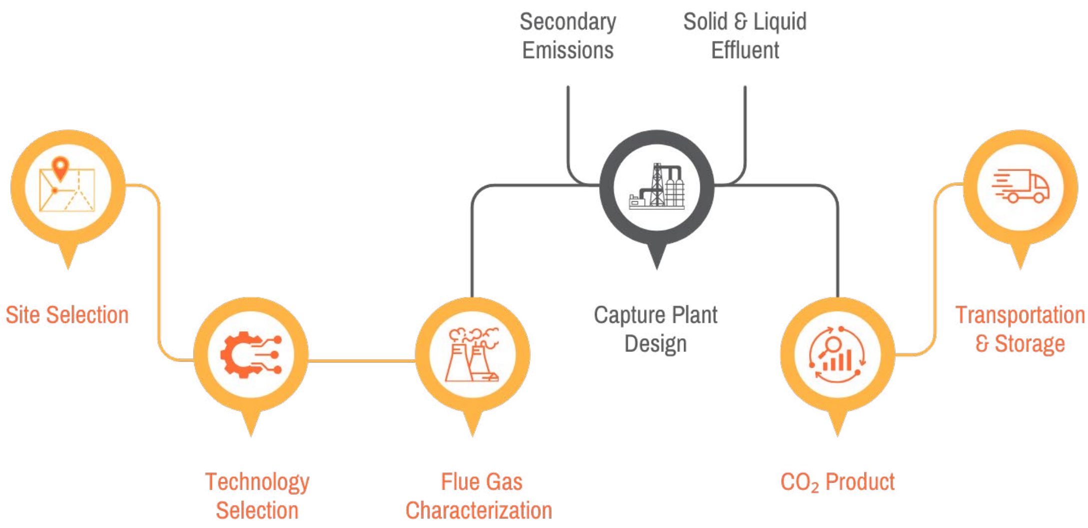


Figure-4: Key Technical Considerations for Carbon Capture Projects

A note on data integrity:

The data presented in this report reflects the status of the projects as of July 1, 2024. The data is preliminary and does not in all cases represent final results, as the majority of FEED studies were not yet complete at this time. However, overarching trends at this stage in the projects have been identified.

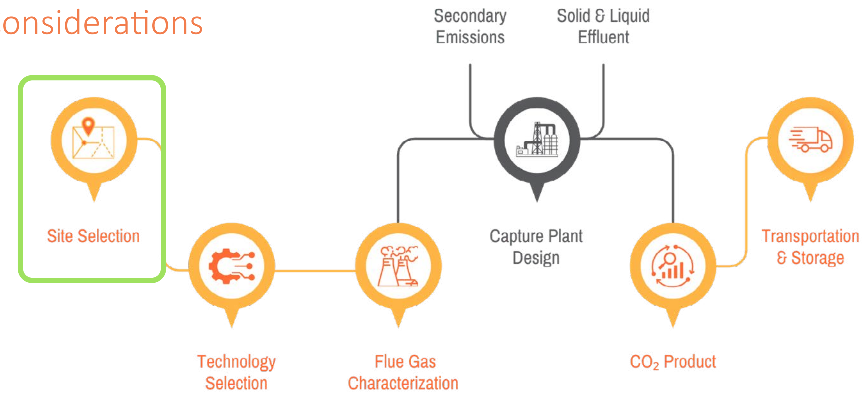
The data, collected from project proponents during the feasibility or FEED studies, spans 27 individual facilities and was categorized into three sector types – oil and gas, power generation, and materials production. To ensure confidentiality of individual projects, all project-specific details have been anonymized.

The dataset includes information submitted in the Key Metrics Template, as detailed in section 2.2.

Projects adhered to an Association for the Advancement of Cost Engineering (AACE) Class 5 Cost Estimate at a minimum, but ranged significantly in terms of accuracy. There are challenges associated with consolidating and comparing data sets with different degrees of uncertainty; however, a concentrated effort was made to present the data in a manner that highlights trends and ranges effectively.

A standardized levelized cost of capture (LCOC) calculator was provided to proponents to provide a basis of cost estimation that could allow for comparison among projects. Further detail on the LCOC calculator is provided in Section 5.1.

4.1 Site Considerations



In this section, we provide an overview and discuss lessons learned pertaining to site considerations. Where a capture facility will be built is an integral part of any design assessment. Some of the main factors when considering site specifics include age of the existing, or host, facility, geographic location, and space requirements. Any large industrial facility will, over its lifetime, require maintenance and modifications. When it comes to industrial processes, older facilities tend be less efficient and smaller, with less of a remaining lifetime and/or higher costs to refurbish. These are important economic considerations for CCS application because capital costs are incurred not only to build a CCS facility, but also to modify the facility to which it will be attached.

The availability of space for the CCS plant footprint is also a factor in determining a suitable location. Not only is being near suitable transport and storage locations an important consideration, but also the distance between the host facility and the capture facility can result in significant capital expenditures for interconnections. In addition, greater physical distance between the CCS facility and its host makes integration of the operations more complex and less effective. Proximity to available water, cooling or reliable electricity must also be considered, which are discussed in greater detail later in this report. All project designs in this program involve retrofitting a CCS facility to the host facility based on the project developers' emission reduction plan. Each of the projects will collect flue gas from various point sources and direct it through a carbon capture facility, with the number of point sources ranging from one to fourteen across the various CCK projects.

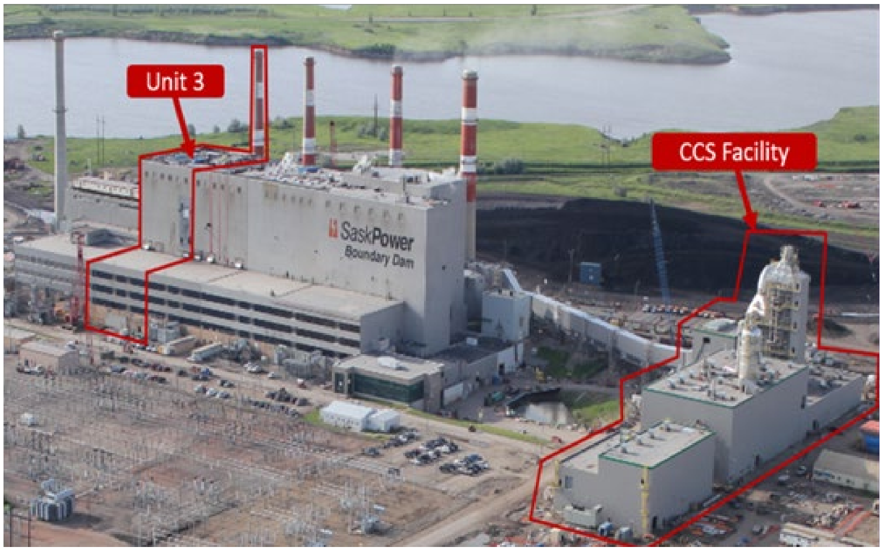


Figure-5: Boundary Dam Power Station and the CCS Facility

A typical CCS facility includes flue gas pretreatment, carbon capture technology, CO_2 compression and dehydration, CO_2 terminal point to the pipeline (or other transportation mechanics), cooling system, water treatment plant, associated power and water utility supply, and effluent discharge. Interfaces with the host plant include flue gas ducting and can also include steam and condensate piping, and other utilities. The retrofit plot size required for CCS facilities can be large, often times similar in size to the original site footprint. Figure 5 is an image of an amine-based carbon capture facility at the Boundary Dam Power Station. Although this was not part of the CCK program, this site provides insight into the plot requirements for a CCS facility.

Key Insights

- **The age of a host facility impacts its operational efficiency and refurbishment needs.** Older facilities tend be smaller and operationally less efficient due to the age of equipment, with less of a remaining lifetime and/or higher costs to refurbish. Installation of a CCS facility will likely require significant refurbishment of the host facility.

- **Proximity to existing infrastructure is a crucial consideration in project planning.** Proponents considered the proximity to adjacent roads and buildings for the potential impact of plumes resulting from cooling towers, for permitting purposes, and for construction risks.

- **Proximity to transportation and storage impacts project cost.** Selecting a site closer to transportation and storage facilities will reduce the overall cost of the project.

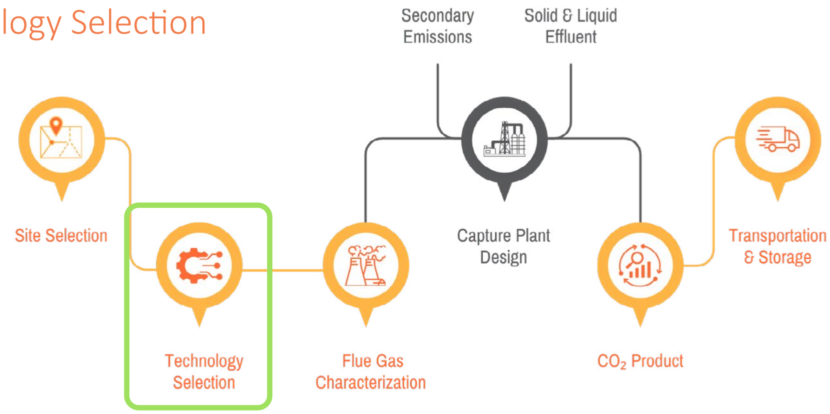
- **Site integrity is essential for placement of new equipment.** Geotechnical data is needed to confirm the suitability of the site for new equipment placement. This is particularly important for CCS facilities that include equipment with large footprints and significant height.

- **Placement of CCS equipment should consider accessibility for installation, maintenance, and for loading and unloading of material.** Collaboration between the project developer, the technology licensor, and the balance of plant developer is critical to optimize site layout.

- **Multi-train and single train construction approaches each have advantages and disadvantages.** Initially, some project developers considered a multi-train approach where, rather than installing a single larger unit of equipment such as the absorber, multiple smaller units in parallel were considered. Subsequently, cost savings and efficiencies were realized in the design by moving to a single train approach which also offers a significantly smaller footprint compared to a multi-train configuration. However, a single train approach leads to considerations around transportation of materials and on-site assembly due to the increased size of the equipment. For processes that expect significant and sustained turndown operation a further consideration is that a single train approach reduces operational flexibility for turndown and maintenance.

- **Ducting is a major source of CAPEX for CCS projects.** Reducing ducting requirements is thus an important aspect of cost savings. The configuration of the ducting is also important to minimize pressure losses throughout the duct and to mitigate potential erosion caused by particulates in the flue gas. Greater physical distance between the CCS facility and its host makes integration of the operations more complex and less effective.

4.2 Technology Selection



This section intends to expand on section 3.2 and highlights findings from the proponents related to capture technology choice. Various types of technologies exist for capturing carbon ranging across the TRL scale.

There is a drive to have projects planning to capture CO_2 by 2030 to maximize benefits from the Canadian federal government's CCUS investment tax credit. These time constraints, coupled with layered business and financial risks, have resulted in most proponents choosing to minimize technical risk by assessing liquid amine technologies at TRL 9 and conducting FEED with one or more proprietary amine vendors.

Amines have proven operational experience in North America, but there are still some technical risks associated with their use; namely, the impact of flue gas composition on performance and efficiency. The presence of certain components of the flue gas can alter amine chemistry and reduce its effectiveness. Given that amine technologies are mainly proprietary, if vendors are unwilling to share the chemical composition of their amine due to intellectual property considerations, it can be difficult to gain an understanding of expected rates of amine degradation, and therefore operating costs.

Multiple proponents exploring liquid amines shared that, to date, they see limited difference in emission reduction representations between technology vendors.

Overall CCS facility cost and performance are strongly influenced by other factors, such as site and facility specifics. However, some vendors were found to be more focused on amine chemistry as the major factor influencing CCS performance and have found optimizations through use of proprietary next-generation amines. Other vendors were found to have instead focused on the reclaiming of the amine (maintaining amine health). Technology guarantees often accompany the sale and use of proprietary amines, which is not the case for non-proprietary amines. This enables a level of assurance that they will work as promised or a financial or "make-right" remedy will be available but is expected to come with a higher cost when compared to non-proprietary amines. All proponents generally aimed to achieve capture rates of 90% or higher, and commercial vendors have broadly committed to meet this level of performance.

Assessment of other (TRL 7+) technologies

Of the proponents who chose to assess technologies other than liquid amine, assessments were focused on cryogenic carbon capture and solid sorbents, which are around the TRL 7 range. Two proponents opted to assess cryogenic as a "backup" option for detailed engineering, to mitigate risks associated with liquid amines, and with the potential of offering significant cost advantages.

Cryogenic capture is more electrically dependent, whereas amine technology is more natural gas (heat) dependent, so potential cost advantages partly depend on future prices for these different sources of energy. Preliminary technoeconomic analysis suggests that energy consumption and capital costs could be approximately 33% and 40% lower respectively using cryogenic capture vs post combustion amine capture[xiii]. After 2030, some companies believe cryogenic capture technology could effectively enter the marketplace at commercial scale, especially in jurisdictions with higher natural gas prices.

Another proponent evaluated a metal organic framework (MOF) capture design. The process works by introducing flue gas into filters, where CO_2 is captured by the adsorbent surface. The remaining flue gas, primarily consisting of N_2, O_2, and H_2O, is discharged as spent or exhaust gas. The CO_2-rich filters are then regenerated using steam, releasing a stream mainly composed of CO_2 and steam. This particular technology works best if source CO_2 concentrations are in the range of 10-20%[viii]. This technology eliminates potential secondary emissions from the capture process, is able to take advantage of low-grade or waste heat on site, can handle flexible operating conditions, and has equipment with reduced heights compared to amine-based capture plant towers, which may be advantageous for some site locations. However, at a TRL of 7, this technology has not yet been deployed on a full commercial scale.

It was noted there may be opportunities in non-amine capture systems that have a lower TRL but also a potentially lower LCOC. On a forward-looking 2050 trajectory, versus a near-term 2030 constrained timeframe, there would be ample opportunities to explore alternative technologies. Some companies noted, however, that unlike other decarbonization technologies that may result in production efficiencies and cost reduction (i.e. solvents for in-situ oil sands production), CCS is always an added cost that reduces production efficiency. The exception to this is biogenic CO_2 capture which results in CO_2 removals. Therefore, it is difficult for companies to spend limited innovation dollars investing in next-generation capture technologies. Despite this, even if amines continue to be the dominant technology through 2030, due to the associated challenges mentioned above, technologies such as membranes, MOFs, and solid sorbent should continue to be assessed for technical, cost, and environmental advantages.

Pre-combustion capture

Hydrogen production facilities are different from most industrial facilities in that they could potentially explore and implement retrofitting the facility with pre-combustion or post-combustion capture or a combination of the two. In the SMR process, natural gas (CH_4) reacts with steam (H_2O) to produce a mixture of hydrogen (H_2), carbon monoxide (CO), and a small amount of CO_2. In the subsequent step, the water-gas shift reaction, the carbon monoxide reacts with additional steam to produce more hydrogen and a higher concentration of CO_2. Pre-combustion CO_2 capture occurs at this stage, where the CO_2 is separated from the hydrogen product stream before the hydrogen is combusted or utilized. Since the CO_2 is at a higher concentration and partial pressure in this stream, the separation is more efficient compared to post-combustion processes. Additional CO_2 arises from combustion of natural gas to heat the reformer (post-combustion); therefore a combination of pre-and post-combustion capture is needed to fully address emissions associated with SMR hydrogen production when natural gas is used as the fuel source[xiv]. For greenfield hydrogen production sites, autothermal reforming with pre-combustion capture could potentially be the most efficient option as, during normal operation, only one gas stream is generated with a very high CO_2 purity, which facilitates easier capture of the CO_2.

Key Insights

- **Proprietary amine technologies are best suited to meet near-term implementation timeframes.** To maximize benefit from the CCUS investment tax credit and to minimize technical risk, most proponents chose to evaluate liquid amine technology and conducted FEED with one or more proprietary technology vendors.

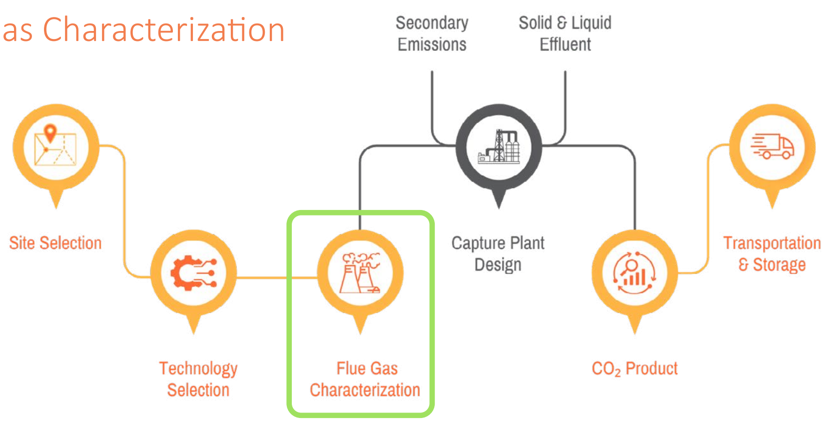
- **Liquid amines have certain technical risks related to how flue gas composition affects amine health and the formation of amine degradation products.** Liquid amines have a high TRL but their compatibility with the specific flue gas constituents must be carefully evaluated. It is also important for amine vendors to be transparent about amine chemistry to create understanding of possible degradation products.

- **Multiple proponents exploring liquid amines see limited difference in amine chemistry performance between vendors.** All proponents generally aimed to achieve capture rates of 90% or higher, and commercial vendors have committed to broadly meet this level of performance. Some vendors focus more on amine chemistry, whereas others focus on maintaining amine health.

- **Non-amine technologies present potential advantages but require longer timescales.** Of the proponents who chose to assess technologies other than liquid amine, assessments were focused on solid sorbent (MOF) and cryogenic technologies, which are considered to have a TRL of around 7. This represents a challenge for achieving decarbonization targets by 2030.

- **There is value in continuing to invest in next generation TRL carbon capture technologies.** On a forward-looking 2050 trajectory, versus a near-term 2030 constrained timeframe, there would be ample opportunities to explore alternative technologies, such as calcium looping, cryogenic, membranes, and solid adsorbents.

4.3 Flue Gas Characterization



Flue gas characterization is critical for the effective design and operation of a carbon capture system, as various components within the flue gas can adversely affect operational, environmental, and health and safety outcomes. It is important to note that flue gas has historically been treated as a waste stream, with conventional flue gas testing solely conducted to satisfy environmental regulatory requirements. When it comes to carbon capture, however, this waste stream now becomes a process input to a multi-million, if not multi billion-dollar project. Early characterization of flue gas helps identify potential issues and informs decisions about pretreatment units, capture types and technology providers. Therefore, understanding what goes into this complex chemical process is crucial.

The optimal functioning of the capture system is dependent on the flue gas composition and the relationship that exists between operational variations in the upstream facility and the resulting fluctuations in flue gas components. Variations in operational conditions at the host facility should be considered during the flue gas testing period to identify any resulting changes in flue gas composition. These operational variations include changes in fuel type, process conditions, and other routine activities that can alter the flue gas properties. Sectors that use varying types of feedstocks, such as cement and oil and gas, will have variations in the resulting flue gas due to changes in feedstock. Recognizing how the flue gas composition changes with varying operational conditions helps in designing a robust system that can handle these fluctuations.

Notably, there are very limited capabilities in the province to fully perform a thorough analysis on the flue gas components relevant to CCS. Even trace amounts of certain contaminants (e.g., sulfur compounds and certain metals) can have detrimental effects on CCS equipment and processes.

In addition, there is a lack of standardized protocols and guidelines for flue gas characterization specific to CCS applications. This can lead to inconsistencies in data collection and analysis across different projects. To more accurately determine flue gas composition in the context of CCS systems, researchers and engineers have adopted existing U.S. Environmental Protection Agency (EPA), Deutsches Institut für Normung (DIN), and other European methods. These modifications, though not yet standardized, involve tailoring conditions to match the specific operational requirements of CCS facilities. Development of standardized protocols and guidelines for flue gas characterization specific to CCS would improve data quality and facilitate comparisons across projects.

CO_2 Concentration

The capture cost and efficiency of implementing a CO_2 capture technology is influenced to a great degree by the CO_2 concentration in the flue gas stream. In amine-based capture, the concentration of CO_2, expressed as its partial pressure, is the driving force for absorption of the CO_2 by the amine. A higher concentration of CO_2 in the flue gas stream facilitates easier capture as the CO_2 will transfer more easily into the solvent. This higher reactivity results in a shorter absorber column which translates to significant savings in equipment cost.

However, capturing CO_2 becomes more challenging with lower CO_2 concentrations. To maintain capture efficiency in these cases, the following approaches can be taken:

- **Increase Solvent Circulation:** By circulating more solvent relative to the CO_2 amount, the driving force is maintained. However, this approach requires more energy for solvent regeneration.
- **Reduce Lean Loading:** By reducing the CO_2 content in the lean solvent sent to the absorber, the driving force for absorption increases. Achieving this requires additional energy to regenerate the solvent to lower CO_2 levels.

Both approaches increase energy consumption for solvent regeneration, so an optimal balance of solvent flow rate and lean loading is necessary to minimize regeneration energy in cases of lower CO_2 concentrations.

There is an optimal range of CO_2 concentration in which amine technology is most effective. CO_2 capture from flue gases with concentrations below 3% is possible with amines, but the process becomes less efficient and more expensive with lower CO_2 concentration. In these cases, alternative technologies or process modifications might be more suitable. Flue gases with CO_2 concentrations exceeding 30% can also be captured using amine technology, however, specific considerations and optimizations might be needed for the process to remain efficient and cost-effective.

Flue Gas Impurities

Flue gas impurities are often defined as any component in the flue gas other than CO_2. These impurities typically include oxygen (O_2), nitrogen (N_2), sulfur dioxide (SO_2), sulfur trioxide (SO_3), nitrogen oxides (NOx), particulate matter (PM), and metals, and can degrade the solvents used in post-combustion carbon capture systems and reduce capture efficiency in other technologies. In amine-based carbon capture, for example, SO_3 can form aerosols that absorb the solvent and pass through the CO_2 absorber, causing some of the solvent to exit the system. Similarly, SO_2 can lead to the formation of heat stable salts and NO_2 can accelerate amine degradation and lead to the formation of nitrosamines. Particulates can cause fouling in heat exchangers and vessel packing, which increases maintenance costs and reduces capture efficiency. The levels at which these components become impactful depends on the type of capture technology selected, as well as what other components are present in the flue gas. Some components only become problematic in the presence of other components.

The initial design benefit of examining the impurities present in the flue gas stream is to know what type of pretreatment is required for efficient operation of the capture technology. Removal systems for NOx, SOx, particulate matter, and trace metals can be installed to reduce solvent degradation induced by these impurities, and to ensure efficient operation of the capture facility. It is important to note that pretreatment equipment will not completely remove the impurities in the flue gas stream but will significantly reduce their concentrations. Particulate matter and many transition metals, even when present in small quantities, can build up in the capture system over time.

A significant challenge in flue gas characterization for CCS arises when dealing with upstream facilities that are still in the design or construction phase. Flue gas composition is dynamic and can fluctuate due to variations in fuel quality, combustion efficiency, and operational factors. For completed upstream systems, continuous monitoring of flue gas composition is key to identifying changes that could impact CCS performance and developing appropriate solutions. However, this presents a challenge for systems under development since flue gas composition can only be inferred through process simulation and reference to flue gas conditions at other similar facilities that are operational.

It is important to work with the technology licensor early in the project to determine what components impact their system design. This collaboration will guide the flue gas testing campaign.

Table 4-1: Flue Gas Considerations by Sector

	Power Generation	Oil and Gas	Material Production
CO_2 flue gas composition before pretreatment (vol%)	NGCC: 3 – 7	OTSG: 8-12 Hydrogen: 9-18	Non-hydrogen: 12-17 Hydrogen: 9
Trace Flue Gas Impurities	NOx, SOx, PM	NOx, SOx	NOx, SOx, PM, VOCs
Challenges	Variable flue gas flow based on load demands	Variability in feedstock, VOCs	High concentrations of metals and wide variations in flue gas composition, variability in feed stock

Each of the sectors has unique considerations for their flue gas. Power producers using commercial natural gas generally are less likely to have variability in feedstock, but this was nonetheless identified by a proponent as a potential concern. Variability in load demands impact the flue gas flow to the capture plant which may impact the design. There may be metals or other degradation catalysts carried into the process which would affect the performance of the capture facility.

The oil and gas sector uses produced gas, pipeline natural gas, and recovered vapors as fuel sources for combustion. The resulting flue gas may contain SO_2, SO_3, and Volatile Organic Compounds (VOCs) which could all affect capture performance and impact the emissions from the absorber tower.

Finally, the material production sector covers a range of industrial processes. The flue gas from the cement production process is highly variable and contains a wide range of impurities. Some of these impurities, such as SO_3, can be challenging to measure reliably. Ammonia is also often present in these flue gases, and in combination with SO_3 and other components can result in a significant risk of aerosols forming which can have a negative impact on CCS processes.

In nitrogen fertilizer production, carryover of the catalyst from the hydrogen reformer is a concern from a CCS perspective. Finally, in pulp and paper, biomass feedstock contains lignin, which when combusted, could lead to the production of hydrocarbons and VOCs in the flue gas.

More data on flue gas composition from different sectors will enable new project developers to better understand key sector-specific components. This will allow them to develop more effective and targeted flue gas testing campaigns.

Key Insights

- **There are limited local testing capabilities.** There are very limited capabilities in Alberta to fully perform a thorough analysis on the flue gas components relevant to CCS.

- **There is a need to develop standardized protocols and guidelines for flue gas characterization.** Standardized protocols and guidelines specific to CCS would improve data quality and facilitate comparisons across projects.

- **CO_2 concentration impacts the optimal type of capture technology that can be used.** For amine-based capture, higher CO_2 concentrations typically result in smaller towers and more efficient capture. However, after a point CO_2 concentration could become too high for efficient amine-based capture.

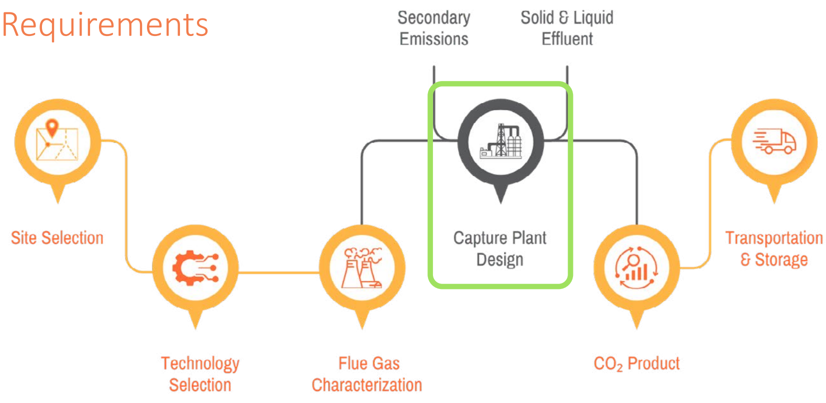
- **Flue gas impurities can have significant cost and performance implications if not properly addressed**. In the case of an amine-based capture process, particulates can cause fouling in heat exchangers and vessel packing, which increases maintenance costs and reduces capture efficiency. Additionally, failure to quantify components like SOx, NO_2, O_2, or metals can accelerate amine degradation, leading to higher costs for thermal reclaiming, amine makeup, and waste handling.

- **Early detailed characterization of flue gas should inform facility design and can mitigate cost and performance issues.** This is critical to identify potential issues and inform pretreatment and capture facility design.

- **Greenfield host facility construction creates challenges for proper flue gas characterization.** A significant challenge in flue gas characterization for CCS arises when dealing with upstream facilities that are still in the design or construction phase, as testing on the flue gas is not possible.

- **Each of the sectors in the program have unique considerations for flue gas characterization.** This is based on the feedstock used, and the impact of the upstream process.

4.4 Energy Requirements



The amount of energy required by the carbon capture process directly influences both operating costs and overall system efficiency. High energy demands can significantly increase the cost of carbon capture. The energy requirements discussed in this section are based on the CO_2 capture, compression and conditioning process associated with amine-based carbon capture as this was the capture technology evaluated by almost all proponents in the program. It is important to note that energy requirements will be different for various CO_2 capture technologies.

The main consumers of energy in an amine-based CO_2 capture technology are the CO_2 compressor, reboilers for amine regeneration, booster fan, heat rejection including circulation pumps and cooling fans, and, where applicable, the CO_2 mechanical vapor recompression (MVR) unit. Amine-based CO_2 capture technology requires thermal energy to regenerate the solvent at the CO_2 regenerator reboilers and for the operation of the thermal reclaimer package. Designs proposed by many technology licensors utilize heat exchangers to optimize energy usage throughout the capture plant. Electrical energy is used to operate equipment such as pumps, compressors, fans, heat tracing and heaters, if required, within the capture facility. The type of energy required for the CO_2 compressor depends on whether the compressor is driven by a steam turbine or by an electric motor.

Sources of Thermal & Electrical Energy

Thermal and electric energy can be sourced from the host site if there is heat and electricity available at the facility. If this energy is sourced from the host facility, it will result in a parasitic load. Waste heat from the existing host site may provide thermal or electrical energy to the capture plant. Individual projects would need to assess the costs and operational impact of using waste heat or thermal or electrical energy that is available at the site as modifications to the existing facility would be required to source this energy and transport it to the capture plant.

If additional thermal energy is required beyond what can be supplied by the host facility, auxiliary boilers may be used. As an alternative to an auxiliary boiler, some project developers have evaluated the addition of a combined heat and power (CHP) plant. The CHP plant provides the steam required for the CO_2 capture plant, while having the additional benefit of generating power which can be used in the capture plant and the host facility, with the potential for excess power being sold to the electrical grid. Alternatively additional electrical energy required for the capture facility can be sourced from the grid, which may require expansion of the existing electrical transmission network.

Introducing an auxiliary boiler or a CHP plant into the facility will create additional emissions due to the combustion of fuel. The additional emissions may be directed through the capture plant, which impacts the design and cost of the capture plant and associated balance of plant design.

Proponents may wish to continue operating the CHP plant during routine maintenance of the host plant or, when possible, vary the CHP plant load to optimize returns from the sale of power to the grid. This will broaden the required operating range of the capture facility. A thorough analysis of the integration of the thermal energy source will ensure the capture plant is designed appropriately for the additional, potentially variable, flue gas flow.

The incremental combined thermal and electrical energy required for the CCS plants for the CCK proponents is shown in Table 4-2. The data indicates that while integration opportunities may exist with the host facility, there is still a significant amount of energy required. There can be a substantial range in the amount of incremental thermal or electrical energy required by the CCS plant due to the type of capture technology used as well as the selection of the CO_2 compressor, which can be steam or electrically driven. The proponents indicated that thermal energy required for capture was 2.5 - 4 GJ/tCO_2, and electrical energy requirements were 80 - 300 kWh/tCO_2. For clarity, these values include capture and compression only, and do not include energy consumption associated with transportation and storage.

Table 4-2: Incremental Energy by Sector

Sector	Incremental energy for CCS (GJ/tCO_2 captured)
Oil and Gas	2.9- 4.4
Power	3.3 – 4.4
Material Production	3.6- 3.7

In addition, hydrogen production facilities comprised a subset of all three sectors:

Sector	Incremental energy for CCS (GJ/tCO_2 captured)
Hydrogen	2.9- 4.4

There was a notable variation in the energy sources used by the CCK proponents in their designs. Many used natural gas to generate thermal energy for CO_2 capture, with some proponents importing this natural gas, and others sourcing it through existing operations. Similarly, there was diversity in power source, where some projects relied on imported power from the grid, and others sourced power through their existing operations.

Where proponents identified a parasitic load, values ranged from 9% to 40%. To optimize utility costs and usage, some projects are considering a CHP plant to provide energy for the CCS, with potential power available for sale to the grid or for use in their existing facilities. Proponents noted that their assumptions around energy costs have large implications on project economics.

It is also important to note that these incremental utilities required for CCS may require additional infrastructure to the project sites, which must be factored in the cost and timeline of the project.

Approaches for improving energy efficiency in CCS

While CCS is energy-intensive, proponents found a number of methods to optimize energy usage.

An area of energy savings is in the flue gas blower which provides the necessary differential pressure for the flue gas to transit through the absorber in the CO_2 capture plant. Computational fluid dynamics (CFD) modelling has been used by proponents in the CCK program to optimize the energy requirements of the flue gas blower.

A significant amount of energy is used in the reboilers for amine regeneration. Therefore, it is necessary to work with the technology licensors to optimize the regeneration process using a representative flue gas CO_2 concentration. The operating pressure of the CO_2 regenerator has an impact on the CO_2 compression requirements. As the regenerator pressure increases, the temperature and, therefore, energy and cost of amine regeneration increases as well. However, the increase in regenerator pressure translates to a higher inlet pressure to the compressor thereby decreasing compression load and power costs.

Amine degradation temperatures will determine the degree to which regenerator pressure and reboiler temperature can be increased. An analysis of the relationship between operating conditions of the regenerator and the CO_2 compressor would assist in determining the optimal operating conditions.

The design of a capture plant may incorporate an MVR unit to enhance energy efficiency by reducing the amount of external thermal energy required. The vapors from the hot, lean amine exiting the regenerator are flashed in the MVR unit, and the resulting steam is compressed and reintroduced into the regenerator. While the MVR contributes to energy savings by using available heat in the lean amine, it consumes electricity, which necessitates a thorough analysis to assess the overall economic benefit of this design.

Waste heat recovery from the existing process may be considered to minimize the amount of energy needed from new sources. As an example, two potential areas for heat recovery within a cement plant have been identified in a previous study conducted by the CCS Knowledge Centre[xv]. The first area is from the flue gases exiting the pre-heater tower, and the other is the clinker cooler exhaust air. While this study indicated that the waste heat recovered would not be sufficient to supply the energy requirements of the CCS plant, the study explored the option of utilizing the waste heat to offset the use of an auxiliary boiler. By conducting a thorough analysis of waste heat recovery from the existing process, and optimizing energy usage in the CCS plant, project developers can reduce CCS operating costs.

Utilization of a CHP plant for thermal and electric energy could benefit project economics. While having a higher initial capital cost than an auxiliary boiler, this method of steam and power generation has been found to improve the business case for the installation of a CCS facility due to the lower cost of self-supplied power used at the site, and from revenue due to the sale of the power[xvi]. If many facilities select this approach, there could be broader implications for the electricity grid as a whole.

Key Insights

- **Where proponents identified a parasitic load, values ranged from 9% to 40%.** The proponents indicated that thermal energy required for capture was 2.5 - 4 GJ/tCO_2, and electrical energy requirements were 80 - 300 kWh/tCO_2.

- **Introducing an auxiliary boiler or a CHP plant into the facility can reduce parasitic energy loads but will create additional emissions due to the combustion of fuel.** The additional emissions may be directed through the capture plant, which impacts the design and cost of the capture plant and associated balance of plant design.

- **Proponents noted energy costs have a large impact on project economics.** However, in many cases, these costs have a high level of uncertainty, such as the future price of electricity.

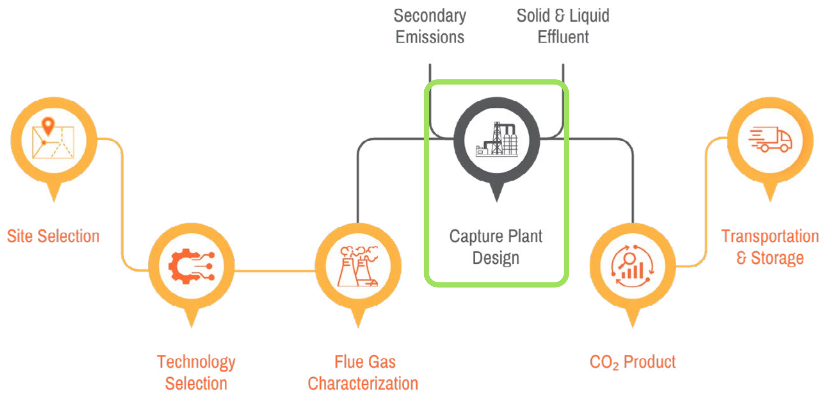
- **Proponents observed several energy saving tools and methodologies:**
  - » Computational fluid dynamics (CFD) modelling has been used in the CCK program to optimize the energy requirements of the flue gas blower.
  - » Operating conditions of the regenerator and CO_2 compressor can be optimized for energy usage. An analysis of the relationship between operating conditions of the regenerator and the CO_2 compressor would assist in determining the optimal operating point.
  - » An MVR may reduce steam required by the CCS process but will result in increased electric load. Heat exchangers within the system utilize waste heat generated within the capture process.
  - » Utilizing waste heat recovery from the host facility may reduce the incremental energy required from new sources.

- **Drivers for the CO_2 compressor have a significant impact on energy usage.** Most proponents started their evaluation with an electrically driven compressor. As the projects developed, the optimal source of energy to drive the compressor was evaluated, with some proponents now examining a steam turbine for driving the compressor.

- **High energy needs of carbon capture are driving companies to take a more holistic view of their business.** CCS FEED is driving some facilities to integrate energy production (ie: power production from a CHP plant) and the host facility material production, aiming to reduce emissions and produce near net zero electricity.

- **High energy needs of carbon capture may have broad implications to the grid as a whole.** Upgrades to electrical transmission lines or natural gas lines may be required to supply the additional utility requirements for the CCS facility. Early engagement with the utility provider will reduce the schedule risk associated with ensuring adequate supply of utilities to site and provide valuable planning information around sourcing of incremental energy needs.

4.5 Cooling



In an amine-based CCS facility, cooling is needed to ensure the required process conditions for both the flue gas and amine solvent are met. As explained in more detail below, from the cooling of flue gas prior to it entering the absorber tower to intercooling between absorption stages and the cooling of lean amine after regeneration, cooling plays an important role throughout the capture process and has a significant impact on the water usage of the plant. Depending on the cooling technology selected, CCS may either be a net water producer or consumer.

The flue gas from the host facility undergoes a cooling step prior to entering the absorber tower. This enhances the absorption efficiency of the solvent as amines operate best in a relatively narrow temperature range. Flue gas cooling is often achieved, at least in part, through direct contact cooling with water.

Due to the heat of absorption released by the reaction of amine and CO_2 in the absorber, the solvent temperature rises. This increase in temperature reduces the capacity of the amine to absorb CO_2. To restore the capture capacity and allow for higher rich loading, the amine is intercooled between absorber stages, typically utilizing water as the cooling medium. This temperature management ensures a favorable condition for CO_2 capture and contributes to the overall efficiency of the amine-based CCS process.

The rich amine solvent from the absorber exchanges heat with hot lean amine from the regenerator which lowers the lean amine temperature for further absorption. In some cases, the lean amine undergoes further cooling using air or water as cooling medium before entering the absorber to increase the capture capacity of the amine in the absorber. The heat recovered by the rich amine in this process provides significant energy savings by reducing the reboiler heat required for CO_2 release in the regenerator.

The CO_2 product leaving the amine regeneration process is cooled prior to entering the CO_2 compressor. As the CO_2 is compressed, its temperature rises due to the increase in pressure. Cooling of the CO_2 between compression stages helps manage the temperature, and reduces the volume of CO_2 to be compressed, minimizing the work required for compression.

Beyond its crucial role in establishing optimal process conditions for absorption and regeneration, cooling is equally essential for maintaining the operational integrity of various components within the amine-based CCS facility. Pumps, compressors, and other equipment rely on effective cooling to prevent overheating and ensure reliable and continuous operation.

Typical cooling types employed in CCS systems include air cooling, water cooling and hybrid systems.

The availability of water, ambient temperature, potential for environmental impact, regulatory requirements, and specific process needs, such as temperature targets and integration with existing infrastructure, are factors that influence the final decision on the choice of cooling type used in the capture facility.

Facilities near abundant water sources may opt for water cooling due to its feasibility and cost-effectiveness. Additionally, in regions with high ambient temperatures, air cooling might be less efficient, necessitating hybrid systems or reliance on water cooling. Water scarcity concerns and potential water use restrictions in some areas can make air cooling a more attractive option. Plant size and capacity also factor into the decision, as large-scale facilities may require hybrid cooling to meet higher demands, while smaller plants might favour simpler air or water cooling for cost reasons.

Types of Cooling[xvii]

Table 4-3: Comparison of Cooling Methods

Cooling Type	Water Cooling	Air Cooling	Hybrid Cooling
Cooling Medium	Water	Air	Air and Water
Comparative Energy Requirement	Lower	Higher	Moderate
Preferred Conditions	High heat loads, large plants, ample water supply, moderate temperatures	Smaller plants, limited water availability	Variable climate, large plants
Pros	High efficiency, mature technology	No/low water usage, favorable for zero liquid discharge (ZLD) requirement	Flexible, reduced water usage compared to water cooling
Cons	High water usage, higher CAPEX, requires water treatment, suitability for ZLD requires closed water loop	Lower efficiency, high energy consumption, large footprint	More complex design, higher initial cost than air cooling

Key Insights

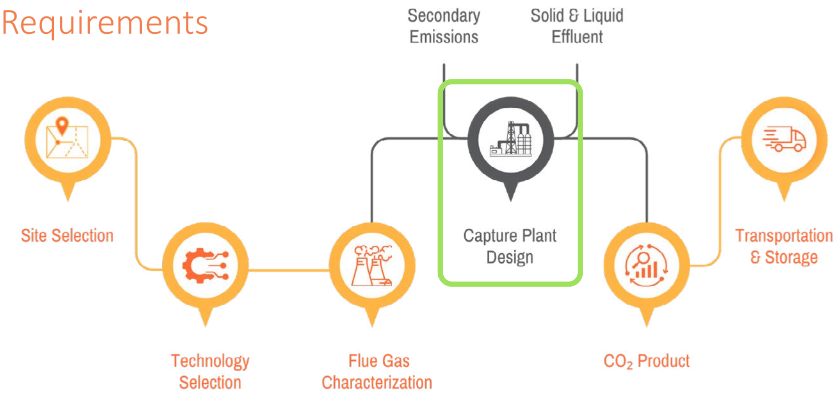
- **Cooling technology selection has a large impact on water usage in amine-based capture systems.** Proponents identified all three types of cooling – hybrid, air, and water cooling – as their cooling technology of choice. Air cooling was the prevalent cooling system identified, which results in the CCS facility being a net producer of water.

- **Several site-specific factors influence the optimal choice of cooling technology.** The availability of water, ambient temperature, environmental impact, regulatory requirements and specific process needs, such as temperature targets and integration with existing infrastructure, are factors that influence the final decision on the choice of cooling type used in the capture facility.

- **Ambient temperature for cooling design may be optimized.** Designing the cooling system for lower than maximum ambient temperature is expected to reduce the footprint and cost. The trade-off is reduced cooling on the hottest days of the year which results in reduced CO_2 capture efficiency during that period. This is based on an investigation that included assessing the potential loss of capture efficiency and this was found to be acceptable in the overall yearly operating scheme when considering the footprint and cost savings from designing for lower ambient temperatures.

- **Seasonal considerations impact representative operating costs.** Cooling tower fan and water demand fluctuates throughout the year. In normal operation the average annual demand factor in a Western Canadian climate should be confirmed through modeling at various ambient conditions. This will provide a design that is more representative of the annual operating cost of the system.

4.6 Water Requirements



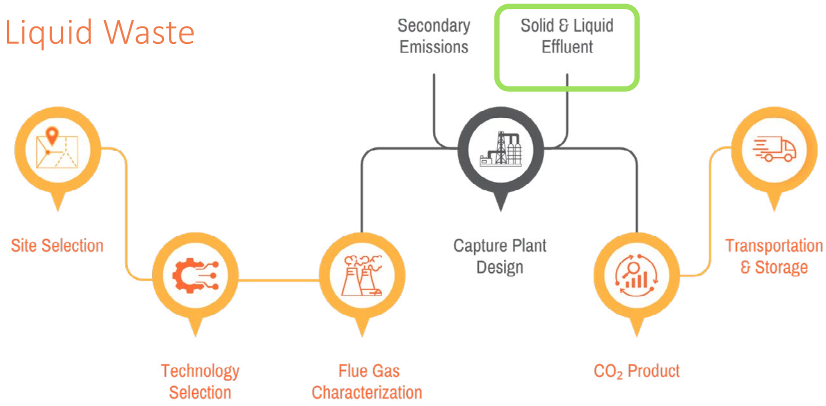
In addition to hybrid or water cooling being a major consumer of water in amine-based CCS plants, water is also used for other purposes within the CCS process. Water plays a role in flue gas pretreatment, such as cooling the flue gas in the direct contact cooler. Amine-based CCS plants require demineralized water for solvent preparation and conditioning when regulating amine concentration. Demineralized water is water that has undergone treatment to remove almost all of its mineral ions (e.g., sodium, calcium, chloride, sulfate, magnesium etc.). The removal of these ions prevents undesired reactions of the mineral ions with the amine solution and prevents scale deposit on equipment surfaces. Additionally, water is also used in the wash water section (located downstream of the absorption process in the amine plant) to reduce contaminants and entrained amine in the treated flue gas before it exists the system. Amine regeneration also utilizes water in the form of steam, which helps in stripping the captured CO_2 from the rich amine. Furthermore, during amine regeneration, water may be lost with the CO_2 that leaves the tower. To compensate for this loss and maintain the required amine concentration, makeup water is added to the system.

Key Insights

- **CCS could lead to additional water consumption for some industries.** For example, the cement industry does not currently consume large amounts of water as part of their operations. Introduction of CCS means they may need to construct new infrastructure and tie-ins to accommodate this additional water usage and must consider the source of the additional water required.

- **Cooling technology has a significant impact on water usage – and CCS can be either a "net consumer" or "net producer" of water.** Cooling of the flue gas may result in significant water condensation which can be treated and used within the CCS process. Where dry cooling was employed, proponents indicated that they may be a net producer of water. Where wet or hybrid cooling was used, the additional raw water required was sourced from nearby water sources.

4.7 Solid & Liquid Waste



CCS facilities produce both solid and liquid waste, and CCK proponents provided information on waste types, volumes and disposal/recycling pathways.

Solid waste generated from amine-based CCS plants primarily consists of spent activated carbon, filters, and desiccants. These components are used to purify amine solutions and to reduce moisture and contaminants in the treated flue gas. Solid waste is also generated during periodic cleaning of equipment (reboilers, heat exchangers) due to fouling. Packing materials used in CCS units (predominantly absorbers) are another contributory source of solid waste in CCS plants during replacement periods.

The thermal amine reclaiming process, which purifies the amine solution by removing degradation products based on their boiling points, can also generate solid waste. This waste typically accumulates at the bottom of the reclaimer and must be disposed of in accordance with established procedures.

In other capture technologies using solid sorbents and cryogenic processes, the primary source of solid waste is spent adsorbents and filters used for contaminant removal.

Knowing the composition of the waste material and their generation sources will assist in creating targeted strategies for better waste management. At this stage of the design study, only a small number of proponents have identified the expected solid waste which included filter media. Most proponents will determine this in a later study phase.

In an amine-based CCS facility, liquid waste can be comprised of condensed water, spent amine solution, and the liquid waste from the thermal reclaimer[xviii]. Aside from the process generated waste streams, additional liquid waste may arise from blowdown from various units in plants (e.g. quencher, scrubber, cooling towers), equipment cleaning, and maintenance activities.

There were a wide range of liquid waste stream volumes identified by the CCK proponents, from 41 – 8000 tonnes/year. As the FEED studies progress, more details will become available on the volume and composition of the liquid waste streams. The composition of the waste stream is highly influenced by the type of amine solvent used and associated volumes of degraded amine. In most amine-based CCS facilities, the liquid waste streams may be comprised of various compounds, including ammonia, amines, aldehydes, and nitrosamines. Where possible, the liquid waste can be treated in a wastewater treatment system for reuse within the capture process.

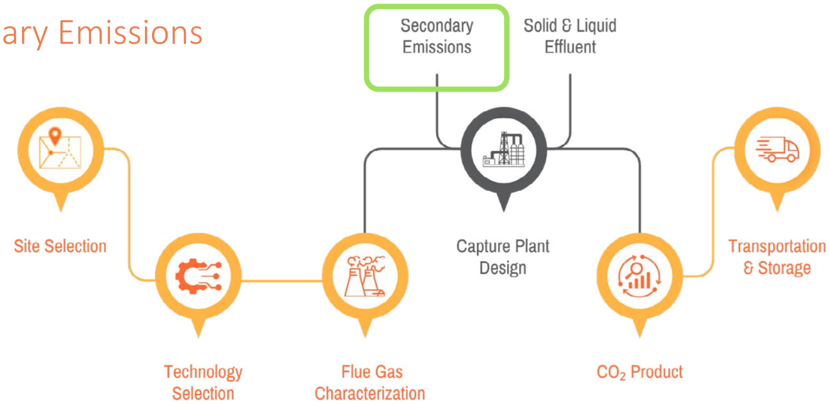
Treatment options for liquid waste streams generally comprise the use of incineration (direct incineration, cofiring with fuel), ion exchange, nitrification or denitrification in a bioreactor. While these options exist, burning amine waste directly or as fuel is not recommended due to the potential increase in harmful NOx emissions, which could violate air quality permits. Additionally, ion exchange treatment may not be suitable for liquid waste streams with high levels of total dissolved solids, as it would require frequent regeneration of the ion exchange resin. Biological treatment may be an option for liquid waste generated from CCS since its by-products are mostly nitrogen and solid filter cake which can be disposed in a landfill[xix]. Where water treatment is not possible, as in the case of liquid waste generated from the thermal reclaimer, characterization of liquid waste (hazardous, non-hazardous) is a significant undertaking to determine the right permits for discharge or disposal requirements.

Confidentiality may play an important role in waste disposal, as it could lead to challenges in correctly identifying the waste. Third party waste management firms may need to sign non-disclosure agreements. Hazard information sheets for each of the waste products may need to be developed to cover the hazards associated with spent solvent or reclaimer wastes. Disposal certificates may be required not only for environmental reasons but also for legal proof of the compliance with confidentiality agreements. These extra steps could result in additional costs and introduce delays, if not considered at the planning phase.

Key Insights

- **Solid waste generated from amine-based CCS plants primarily consists of spent activated carbon, filters, and desiccants.** Waste disposal pathways for these solid wastes exist.
- **In capture technologies using solid sorbents and cryogenic processes, the primary source of solid waste is spent adsorbents and filters used for contaminant removal.** Recycling options for these wastes are being explored.
- **A wide range of liquid waste streams volumes were identified by the CCK proponents, from 41 – 8000 tonnes/year.** While these results are preliminary, this highlights that site-specific factors could have a strong influence on waste volumes.
- **Treatment options for liquid waste are available but face environmental challenges, such as the creation of additional byproducts.** More work is needed to identify sustainable pathways for some of these wastes.
- **Confidentiality may play an important role in waste disposal, as it could lead to challenges in correctly identifying the waste.** This should be evaluated during FEED in partnership with capture technology vendors.

4.8 Secondary Emissions



CCS facilities are designed to be highly effective at removing large amounts of CO_2 from industrial flue gas streams. Additionally, amine-based carbon capture, by design, provides the added benefit of significantly reducing the emissions of other harmful flue gas components[xx]. This process may also result in low levels of secondary emissions that form due to the chemical processes involved in the capture of CO_2 and exit with the gas that leaves via the absorber vent. Secondary emissions include the release of very small amounts of SOx, NOx, CO, particulate matter, amines and their nitrosamines and nitramines, aldehydes, amides, ketones, ammonia, and other volatile organic compounds. Secondary emission profiles will vary by facility, depending on the type of amine solvent being used, the type and concentration of flue gas impurities, as well as the host facility and capture facility operating conditions.

Key Insights

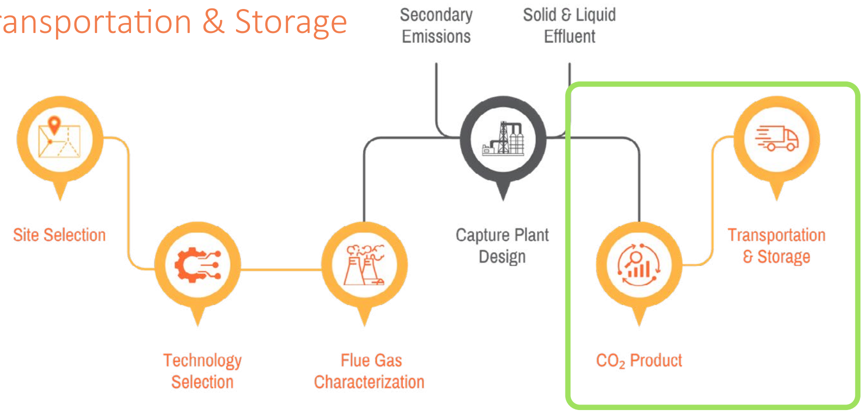
- **CCS facilities result in clean-up of the flue gas.** CCS facilities not only remove large amounts of CO_2 from industrial flue gas streams, but they also provide the added benefit of significantly reducing emissions of SOx, NOx, CO, and particulate matter.

- **Liquid amine-based CCS plants produce secondary emissions that must be characterized.** An understanding of the interplay of the flue gas constituents, amine reactivity, and expected operating conditions is useful towards gaining a better understanding of secondary emission profiles. An appropriately designed pilot testing campaign can assist in identifying the potential secondary emissions.

- **All sectors identified amines and aldehydes as potential secondary emissions.** Material production and the oil and gas sectors additionally named ammonia, nitrosamines, NOx, SOx, VOCs, CO, and particulate matter as other possible emissions. The new secondary emissions formed due to the carbon capture process are:
  - » **Amines** may be emitted as aerosols.
  - » **Aldehydes** are typically formed from the oxidative degradation of MEA and have been detected in the gas phase in the absorber.
  - » **Ammonia** is a by-product of many carbon capture solvents. As a result, monitoring of ammonia levels on carbon capture systems is important for both operational and environmental purposes.
  - » **Nitrosamines** are formed not only due to direct emissions to air, but also from the emissions of amine, which can result in the formation of nitrosamines in the atmosphere by reaction with NO_2.

- **Flue gas pretreatment to remove impurities can reduce the impact of secondary emissions.** Secondary emissions stem from the reaction between amines and flue gas impurities. Therefore, the pretreatment of flue gas to remove impurities such as NOx and SOx is crucial towards minimizing the release of secondary emissions from the stack of the absorber.

4.9 CO_2 Transportation & Storage



Captured CO_2 must be transported to sites where it can be injected for permanent storage. The proponents in the CCK program evaluated distances as far as 400km for transportation of the CO_2 product and identified saline aquifers as the storage type. Transportation of the CO_2 product can be done via rail, truck or pipeline, and each method has specific advantages and considerations. The International CCS Knowledge Centre, together with GLJ Ltd., issued a guide titled "Alberta Carbon Capture and Storage (CCS) Landowner Information Guide"[xxi] with more details on transportation considerations. Further technical analysis of transportation and storage options in Alberta can also be found in Alberta Innovates' CCUS whitepaper[xii].

A key consideration pertaining to CO_2 transport that significantly impacts capture facility design, however, is CO_2 product specification. Depending on the intended use of the CO_2 product, the type and level of impurities allowable in the CO_2 product stream may vary[xxii, xxiii]. For instance, in enhanced oil recovery (EOR) applications, the primary concerns over impurities are overheating at the injection point because of the reaction between oxygen and oil, the likely release of toxic components at the production well if there is a CO_2 breakthrough, and an increase in the minimum miscibility pressure for oil extraction. For underground storage, the possibility of geochemical reactions can lead to reduced permeability, corrosion, hydrate formation and elevated pore pressure, all of which are undesirable.

In both cases, pipeline safety is of critical importance. To ensure pipeline safety, the CO_2 product specification would minimize the risk of free water formation and its related consequences, such as hydrate formation, pipeline corrosion and subsequent pipeline rupture or sudden leakages. Additionally, lower levels of impurities such as inert gases, allow for a reduction of discharge pressure and compression work needed for maintaining CO_2 in a dense phase for transportation[xxiv]. The CO_2 production specification will impact the compression and conditioning areas of the carbon capture system design to meet the required temperatures, pressures, and composition of the CO_2 product.

Existing Product Specifications

Table 4-4 provides a summary of typical CO_2 product specifications for different off takers as well as that provided in literature. This table illustrates the differences that exist in current pipeline specifications. The limits for the various components are largely dependent on design and operational requirements, and health and safety considerations.

Table 4-4: CO_2 Product Specifications

Parameters	Unit	CO_2 Product Specifications			
		ACTL[1] [xxv]	EBTF[2] [xxvi]	EU's DYNAMIS Project[xxvii]	Literature[xxii]
Intended Use		EOR	Generic	Generic	Generic
CO_2	mol %	≥95	>90	>95.5	>95
N_2	mol %	<1[3]	<4 (All non-condensable gases)	<4 (All non-condensable gases)	<4 (All non-condensable gases)
Ar	mol %	<1[3]			
H_2	mol %	<1[3]			
O_2	ppmv	<1000	<100	100-1000[4]	<10
H_2O	lbs/mmscf ppmv	10 215	<23.3 <500	23.3 500	23.3 500
SO_2	ppmv	Not provided	Not provided	Not provided	Not provided
SOx	ppmv	<100	<100	100	<50
NOx (No, NO_2, or N_2O_4)	ppmv	<100	<100	100	<100
CO	ppmv	<1 mol %	<2000	2000	<2000
Hydrocarbons	mol %	<2[5]	Not provided	Not provided	<2
CH_4	mol %	<1[3]	<2	<4 for aquifer <2 for EOR	Not provided
NH_4	lbs/mmscf	≤ 3	Not provided	Not provided	Not provided
Amines	lbs/mmscf	≤ 3	Not provided	Not provided	Not provided
Glycol	lbs/mmscf	≤ 3	Not provided	Not provided	Not provided
Methanol	lbs/mmscf	≤ 3	Not provided	Not provided	Not provided
Ethanol	ppmv	Not provided	Not provided	Not provided	Not provided
H_2S	ppmv	<10	<200	200	< (10-50)
Total Sulfur	ppmv	≤16	Not provided	Not provided	Not provided
Mercury	ppbv	<100	Not provided	Not provided	Not provided
Particulates	ppmw	No solid particles	Not provided	Not provided	Not provided

[1] Alberta Carbon Trunk Line. The CO_2 shall be delivered at less than 40 °C (104 °F) and 17,926 kPag (2,600 psig) with no free liquids including lube oils or glycol. The ACTL limits for SOx and NOx reads as "Less than 100 ppm for SOx or NOx by volume," and KC's interpretation is that the limit applies to each component.

This observation is similar to that provided for NH_3, amines, glycol and methanol.[xxv]
[2] European Benchmarking Taskforce.
[3] For non-condensable components (N_2, O_2, H_2, CH_4 and Ar), the total amount should be limited to less than 4 mol%.
[4] For EOR applications. For aquifer < 4 mol%.
[5] Dewpoint not to exceed -20 °F (-7 °C).

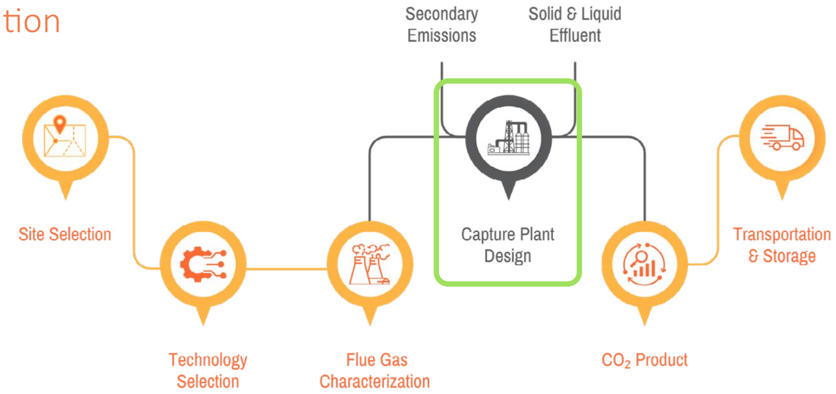
At the Knowledge Sharing Roundtables in which CCK proponents participated, CO_2 product specification was identified as an important consideration for the design of the capture plant, but this topic remains emergent, as many sequestration hub and pipeline projects that would determine these specifications are still in the engineering phase.

Key Insights

- **Proponents evaluated geological storage only, as it can accept higher volumes compared to current utilization technology, is readily available in Alberta, and unlike enhanced oil recovery, is eligible for Canada's CCUS investment tax credit.** The proponents evaluated distances as far as 400km for transportation of the CO_2 product and identified saline aquifers as the permanent storage type.

- **CO_2 product specification for pipelines and intended uses is a key consideration influencing the design of capture facilities.** CO_2 product specification is an emergent topic because many sequestration hub and pipeline projects that would determine these specifications are still in the engineering phase.

4.10 Execution



The CCK proponents identified a number of execution challenges in their carbon capture and storage initiatives, primarily due to high uncertainty regarding facility costs and potential penalties associated with non-compliance.

Proponents noted that there is minimal difference in performance between amine suppliers, and that site considerations and execution strategy generally have a larger impact on the design of the capture plant than specific amine choice.

There is a shortage of technical experts in the province of Alberta specifically trained in capture technology, as most vendors are based outside the province. One proponent that operates on a global scale estimates costs in Alberta to be 15-20% higher compared to similar projects in Europe, largely due to the province's lack of access to tidewater for shipping equipment. This geographic disadvantage could be a challenging factor for Alberta to compete for CCS funding against international projects. Additionally, the nature of CCS projects as mega ventures compounds risks and uncertainties, including potential supply chain and labour shortages arising from concurrent large-scale projects. Furthermore, there are concerns about the functionality of CCS plants post-startup, particularly in coordinating maintenance and turnaround activities between upstream processes and capture facilities.

Some companies have determined the best approach to optimize costs is to modularize construction as much as possible by building equipment elsewhere and transporting it to site. This would also allow them to take advantage of potentially lower labour rates elsewhere, avoid bottlenecks with shop space, and reduce schedule risk. However, other projects are taking the opposite approach using a combination of shop and field construction. As an example, to address the transport issues associated with large towers, proponents are considering constructing steel sections at shops that are then delivered to the site for assembly. As noted in section 4.1, consideration is being given to both single train and multi-train design approaches to determine the most effective method of execution.

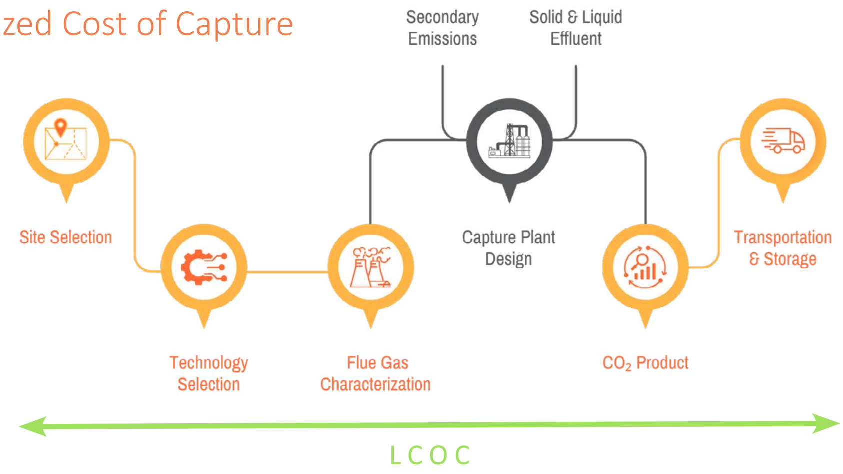
Proponents noted that compressors are increasingly difficult to source given the limited number of suppliers who can provide compressors at the size and power required for CCS resulting in long lead times. Proponents who are further along in their FEED studies have considered multiple compressor types and recommend making a selection that optimizes heat integration and is best for the specific site.

Key Insights

- **There is a need to increase local CCS technical expertise.** There is currently a shortage of technical experts in the province of Alberta specifically trained in capture technology, as most vendors are based outside the province.
- **Lack of access to tidewater creates a geographic disadvantage.** Alberta does not have access to tidewater for shipping, increasing transportation costs for equipment.
- **Supply chain is seen as a significant risk for implementing CCS projects.** Supply chain and labour shortage risks may arise from concurrent large-scale projects. An example of this is CO_2 compressors, which can be difficult to source in certain size ranges.
- **Proponents are approaching execution in different ways.** Some companies are aiming to modularize by prefabricating equipment offsite and then ship to site for assembly, while others are combining both shop and field construction approaches. Rectangular structures are being considered where sections are fabricated offsite, shipped, and then assembled on site.
- **Post start-up operation and maintenance should be considered for CCS facility design and operation.** Proponents noted they have concerns about coordinating maintenance and turnaround activities between upstream processes and capture facilities post-startup.

5. Preliminary Outcomes of the CCK Program

5.1 Levelized Cost of Capture



The levelized cost of capture (LCOC) represents the average dollar price per tonne of CO_2 that would be required over the life of the plant to cover all capital, operation and maintenance expenditures. To account for the time value of money, future cashflows are discounted to provide present value.

While LCOC is a critical metric for evaluating carbon capture projects, it is challenging to compare on a consistent basis between projects. This is a challenge globally for industry, government, and the broader CCS ecosystem. Currently, many different frameworks around LCOC methodologies are used by policymakers, think tanks, academia, and industry, and assumptions may not always be provided to justify results. Below are some examples of factors that lead to inconsistency when comparing LCOCs:

- Time-sensitive or jurisdictional factors like taxes and incentives.
- Engineering class of cost estimate, and differences between industries in how these classes are used.
- What is included in the cost estimate, for example:
    - » Facility upgrades if required.
    - » Pretreatment/effluent treatment.
    - » CO_2 transportation and sequestration.
    - » Contingency.
- Changing project development timelines.
- Key assumptions that may be industry or site specific, such as discount rate, rate of return, and escalation rates on capital expenditure (CAPEX) and operating & maintenance (O&M or OPEX) costs.

Proponents in the CCK program emphasized that aligning on a standardized method for calculating levelized costs would benefit the entire industry. It is worth noting that working groups like the International Energy Agency Greenhouse Gas R&D (IEAGHG) CCS cost network are specifically dedicated to addressing this topic.

Developing a generalized calculator

For this analysis, the Knowledge Centre developed a LCOC calculator intended as a generally applicable, basic model for the purpose of comparison between projects. Individual project factors could influence these costs. It is still valuable, however, to compare costs between projects, and understand sensitivities to inputs that have the greatest impact on cost.

The calculator was based on a modified version of the National Energy Technology Laboratory (NETL) calculator provided in NETL-PUB-22580 (Sept. 2019)[xxviii].

The calculator used costs for the capture plant and excluded transportation and storage. Figures 6 and 7 illustrate the capital and O&M costs included in the LCOC.

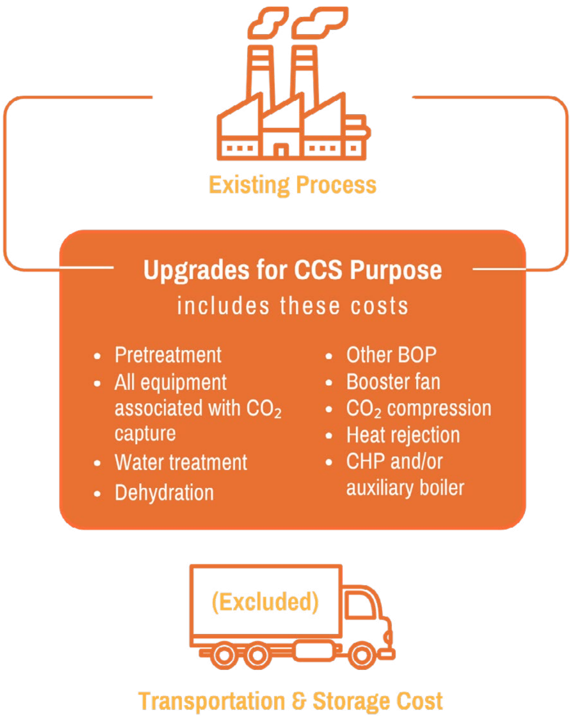


Figure-6: Capital Costs Included in LCOC Calculation

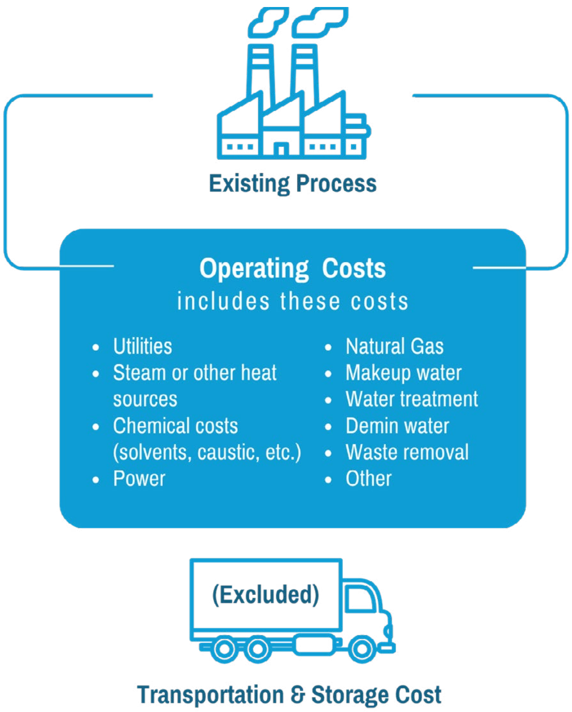


Figure-7: Operating Costs Included in LCOC Calculation

The levelized cost was expressed in terms of CO_2 captured and CO_2 avoided. The levelized cost of CO_2 captured was based on the total amount of CO_2 being captured, which includes CO_2 from the host facility flue gas that was previously being emitted to the atmosphere, and any CO_2 produced due to the operation of systems that support capture (e.g. CO_2 from an auxiliary boiler or CHP plant). The levelized cost of CO_2 avoided (LCOA) is based on the amount of net CO_2 reductions, which considers the amount of CO_2 that is 'avoided' from the previous operating state but does not include in the calculation any CO_2 that may be produced to support the capture of host facility CO_2. Consequently, LCOA is always greater than LCOC for a given scenario with all other parameters being held constant.

Figure 8 represents the sensitivity analysis done on the LCOC case. The base case in Figure 8 included the following assumptions:

- Construction of the capture plant was set to begin in 2028 and finish commissioning by the end of 2030.
- Capital cost distribution 2028/2029/2030 – 20%, 50%, 30%.
- Escalation of capital costs - 3%.
- Escalation of fixed and variable O&M costs - 3%.
- Discount Rate (defined as the weighted average cost of capital) - 8%.
- Interest During Construction - 8%.
- Operational Period- 25 years.

For each sensitivity, one variable was changed with all others remaining fixed at the base case values. This analysis indicates that the discount rate used in the LCOC calculation has the largest impact on the final LCOC result. The discount rate is defined as the weighted average cost of capital and directly influences the present value of future costs and revenues, meaning that even small changes in the discount rate can lead to large variations in the overall cost calculation. It is important to note that sectors have significant variance in inputs such as discount rate and capital expenditure profile. For projects with higher discount rates, the LCOC will be higher, making it more challenging to justify the investment in a business case. Escalation rate of the capital and O&M costs impact the LCOC to a lesser degree, while variables related to the operational period and interest during construction have very little impact on the LCOC. Capital expenditure period did not affect the LCOC significantly as projects with a longer spend profile spent the bulk of the capital in a 3 to 4 year period, with a small amount of expenditure prior to and after the main capital spend period.

Figure 8 is a statistical box and whisker plot that represents the aggregated data from all sectors. The bottom line in each data set represents the minimum LCOC for that category, the box represents data between the first and third quartiles, or 50% of the data, and the top line represents the maximum value. The longer the box and whiskers, the greater the variability of the data distribution.

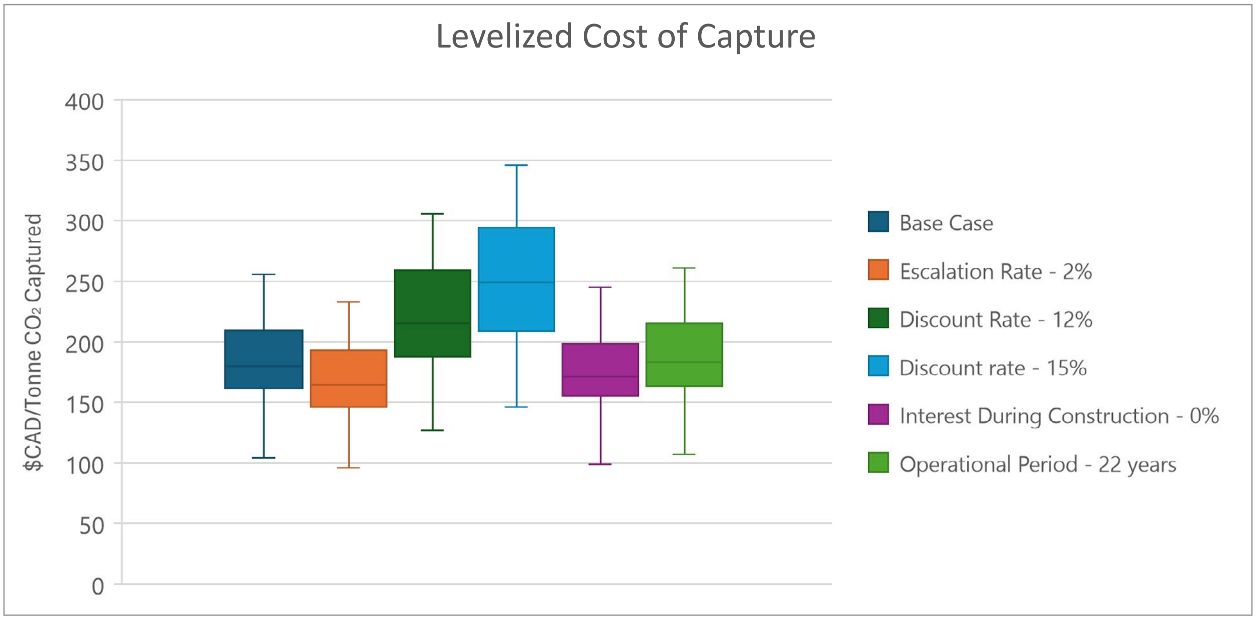


Figure 8: Sensitivity Analysis of Levelized Cost of Capture

Levelized cost of CO_2 avoided is also an important metric. As the CAPEX and OPEX remain the same, but the volume of CO_2 captured that is considered is smaller, levelized cost of CO_2 avoided will be higher than LCOC, as illustrated in Figure 9.

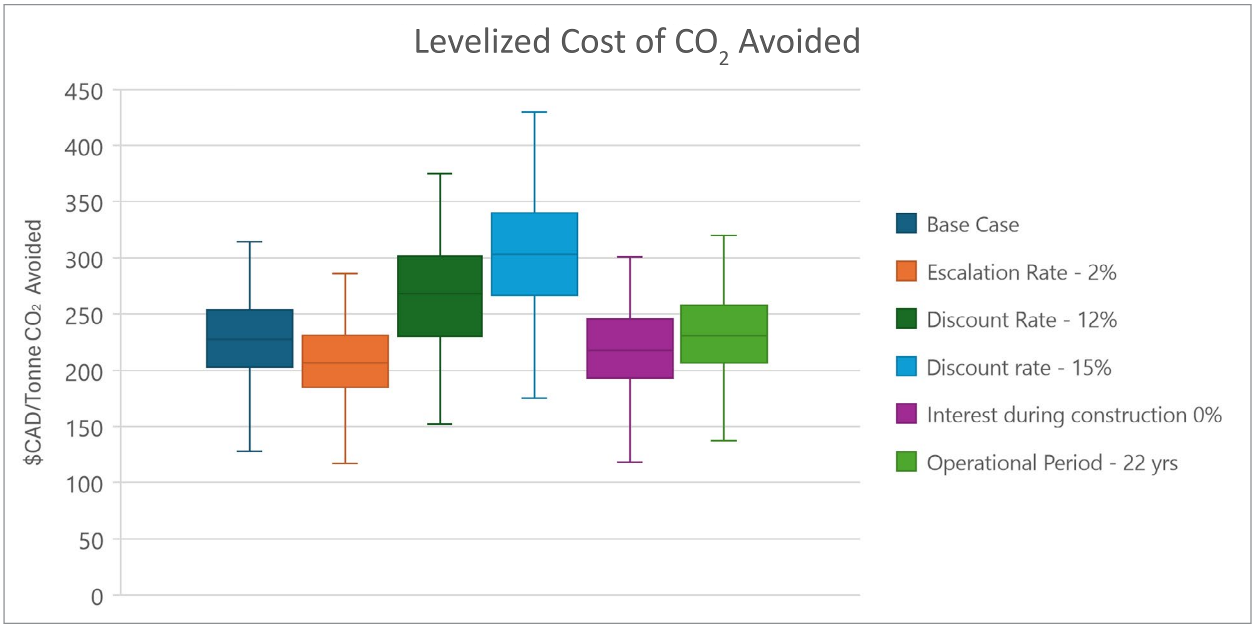


Figure 9: Sensitivity Analysis of Levelized Cost of CO_2 Avoided

The wide range of LCOC and LCOA values highlights the variability and uncertainty in cost estimates, even when consistent inputs are used. This variability can significantly impact project planning, investment, and decision-making, emphasizing the need for careful consideration of project-specific factors. Evaluating sector-specific LCOCs and LCOAs would provide a more representative value to base decisions on. However, sector-specific cost analysis has not been included as part of this report. This was done to maintain confidentiality given that certain sectors supported by the program were represented by a small number of proponents and sector-specific cost information could risk revealing sensitive information about individual companies.

Key Insights

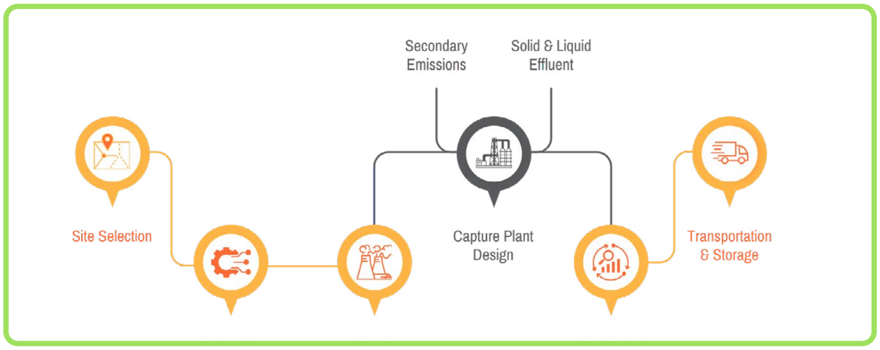
- **The sensitivity analysis indicates that the discount rate used in the LCOC calculation has a significant impact on the final result.** For projects with higher discount rates, the LCOC will be higher, making it more challenging to justify the investment in a business case. The escalation rate of capital and O&M costs, as well as capital expenditure period had comparatively less effect on the LCOC.

- **It is important to distinguish between levelized cost of CO_2 avoided vs levelized cost of capture (LCOA vs LCOC).** Levelized cost of CO_2 avoided is an important metric as it considers only the reduction in the host facility's CO_2 emissions before and after the implementation of capture and not any CO_2 that is captured in addition to that produced by the original host facility, therefore represents the cost of emissions reduction. The levelized cost of CO_2 captured will be higher than the levelized cost of CO_2 avoided.

- **The wide range of LCOC values highlights the variability and uncertainty in cost estimates, even when consistent inputs are used.** In the base case, LCOC values ranged from \$105 - \$260 CAD/tCO_2 captured. The levelized cost of CO_2 avoided was approximately 20% higher, ranging from \$125 - \$315 CAD/tCO_2 avoided.

- **CCS costing remains an important issue that requires further analysis and ecosystem alignment.** The IEAGHG hosts workshops that bring together international experts from across the CCS ecosystem to share and discuss the most current information available on the cost of CCS.

5.2 Emissions Reduction



The ultimate goal of implementing CCS is to reduce emissions. The baseline emissions of all 27 facilities that participated in the CCK program amounted to 29.4 MtCO_2e/yr, or approximately 10% of Alberta's total emissions. It is important to recognize that potential emissions reductions are not a simple calculation of applying the capture rate to the baseline emissions. This is because of the high incremental energy requirements of CCS which is in the range of 2.9 – 4.4 GJ/tCO_2 captured. This energy can sometimes be supplied directly by the host facility, which would not alter the total amount of CO_2 to be captured but would impose a parasitic load to the host facility. Alternatively, if additional energy is provided by the addition of a new auxiliary boiler or CHP plant, the overall emissions to be captured would increase from the baseline. Therefore, it is important to recognize that total captured CO_2 is thus not the same as net reduced CO_2, because additional CO_2 is often generated beyond the baseline as part of the capture process.

Table 5-1: Program Emissions Reduction

Program	Current Program Emissions ($MtCO_2e/yr$)	Program Reductions ($MtCO_2e/yr$)	% of Baseline Emissions Reduced
Total	29.4	25.3	86

If all projects in the CCK program were to go to successful FID, the province of Alberta would see emissions net reductions of 25.3 $MTCO_2e/yr$, which represents an 86% reduction in baseline emissions. However, it is important to note the total emissions captured would be 29.6 $MTCO_2e/yr$, slightly higher than the baseline emissions, due to the capture of additional CO_2 from auxiliary equipment used for the CCS facilities.

Of the 27 facilities, 17 assume they will be operational before 2030, resulting in an estimated 27.3 $MtCO_2e$ net reductions in total by 2030 if those facilities proceed as planned to FID.

All facilities could be operational by 2040, resulting in an estimated 279 $MtCO_2e$ net reductions in total by 2040 if all facilities proceed as planned to FID, and 508 $MtCO_2e$ net reductions by 2050. Of note, at this time, at least several CCK proponents have indicated they will not proceed as the CCS landscape is dynamic; this is a hypothetical scenario only. All captured CO_2 was assumed to be permanently sequestered (without further end use) in saline aquifers or other types of geological formations.

In addition to these reductions, a project evaluated capturing and sequestering biogenic emissions. These emissions are not included in the overall reductions since they are currently considered zero emissions due to their natural origin. Instead, capturing and storing these emissions would be classified as a removal, effectively taking existing carbon out of the atmosphere rather than simply reducing new emissions.

Key Insights

- **Because of the high energy requirements of CCS, more CO_2 may be captured than was originally being produced.** If all 27 facilities in the CCK program were to go to successful FID, once operational, based on the data provided to date, they would collectively capture 29.6 $MtCO_2e/yr$. Note this is slightly higher than the total current emissions from the host facilities, 29.4 $MtCO_2e/yr$. The baseline emissions would achieve a net reduction of 86%, or 25.3 $MtCO_2e/year$ – slightly less than 10% of Alberta's total annual emissions.

- **Net reductions by 2050 from all 27 facilities reaching operations by 2030 or shortly thereafter was estimated to be 508 $MtCO_2e$, assuming all facilities were to proceed to FID.** Note that the future of CCS projects in the CCK program remains uncertain, but this gives a sense of the ultimate potential emissions reduction.

6. Conclusions

This report highlights the lessons learned from the ERA Carbon Capture Kickstart program as of July 2024. Knowledge sharing is a key element in the advancement of CCS, helping to mitigate risk and lower cost for future projects and is especially important given the high capital cost of CCS and the relatively limited operational knowledge to date.

Throughout the program, the shared experiences and lessons learned have provided invaluable insights into overcoming the technical and operational challenges associated with CCS. The insights provided in this report span the full range of the technical study phase of a CCS facility. Learnings were shared from site selection through to technology selection, flue gas characterization, and throughout the technical design considerations of CCS plant design. Most proponents were not at a stage to share information regarding transportation and storage, so the main focus remained within the CCS facility and the associated balance of plant design. A levelized cost of capture calculator was developed to standardize the inputs and the methodology of calculating the LCOC. A sensitivity analysis determined the factors that influenced the results of the calculation.

Through this initiative, knowledge has been shared from multiple projects, while maintaining individual project confidentiality.

The CCK program has provided a valuable pathway for proponents to evaluate their CCS projects to FID. As the projects advance their FEED studies, more data will be made available and additional learnings can be achieved. While the studies were initially intended to be complete by end of 2024, the majority will now be completed by end of 2025. At the time of completion, all projects will publish final public reports summarizing FEED outcomes. Final metrics, including costs and emissions reductions, will be collected, analyzed, and disseminated. As the industry continues to evolve, ongoing knowledge sharing will remain critical to achieving global carbon reduction targets and supporting the transition to a more sustainable energy future.

7. Key Insights from CCK Program Summarized

SITE CONSIDERATIONS

- **The age of a host facility impacts its operational efficiency and refurbishment needs.** Older facilities tend be smaller and operationally less efficient due to the age of equipment, with less of a remaining lifetime and/or higher costs to refurbish. Installation of a CCS facility will likely require significant refurbishment of the host facility.

- **Proximity to existing infrastructure is a crucial consideration in project planning:** Proponents considered the proximity to adjacent roads and buildings for the potential impact of plumes resulting from cooling towers, for permitting purposes, and for construction risks.

- **Proximity to transportation and storage impacts project cost.** Selecting a site closer to transportation and storage facilities will reduce the overall cost of the project.

- **Site integrity is essential for placement of new equipment.** Geotechnical data is needed to confirm the suitability of the site for new equipment placement. This is particularly important for CCS facilities that include equipment with large footprints and significant height.

- **Placement of CCS equipment should consider accessibility for installation, maintenance, and for loading and unloading of material.** Collaboration between the project developer, the technology licensor, and the balance of plant developer is critical to optimize site layout.

- **Multi-train and single train construction approaches each have advantages and disadvantages.** Initially, some project developers considered a multi-train approach where, rather than installing a single larger unit of equipment such as the absorber, multiple smaller units in parallel were considered. Subsequently, cost savings and efficiencies were realized by moving to a single train approach which also offers a significantly smaller footprint compared to a multi-train configuration. However, a single train approach leads to considerations around transportation of materials and on-site assembly due to the increased size of the equipment. For processes that expect significant and sustained turndown operation a further consideration is that a single train approach reduces operational flexibility for turndown and maintenance.

- **Ducting is a major source of CAPEX for CCS projects.** Reducing ducting requirements is thus an important aspect of cost savings. The configuration of the ducting is also important to minimize pressure losses throughout the duct and to mitigate potential erosion caused by particulates in the flue gas. Greater physical distance between the CCS facility and its host makes integration of the operations more complex and less effective.

TECHNOLOGY SELECTION

- **Proprietary amine technologies are best suited to meet near-term implementation timeframes.** To maximize benefit from the CCUS investment tax credit and to minimize technical risk, most proponents chose to evaluate liquid amine technology and conducted FEED with one or more proprietary technology vendors.

- **Liquid amines have certain technical risks related to how flue gas composition affects amine health and the formation of amine degradation products.** Liquid amines have a high TRL but their compatibility with the specific flue gas constituents must be carefully evaluated. It is also important for amine vendors to be transparent about amine chemistry to create understanding of possible degradation products.

- **Multiple proponents exploring liquid amines see limited difference in amine chemistry performance between vendors.** All proponents generally aimed to achieve capture rates of 90% or higher, and commercial vendors have committed to broadly meet this level of performance. Some vendors focus more on amine chemistry, whereas others focus on maintaining amine health.

- **Non-amine technologies present potential advantages but require longer timescales.** Of the proponents who chose to assess technologies other than liquid amine, assessments were focused on solid sorbent (MOF) and cryogenic technologies, which are considered to have a TRL of around 7. This represents a challenge for achieving decarbonization targets by 2030.

- **There is value in continuing to invest in next generation TRL carbon capture technologies.** On a forward-looking 2050 trajectory, versus a near-term 2030 constrained timeframe, there would be ample opportunities to explore alternative technologies, such as calcium looping, cryogenic, membranes, and solid adsorbents.

FLUE GAS CHARACTERIZATION

- **There are limited local testing capabilities.** There are very limited capabilities in Alberta to fully perform a thorough analysis on the flue gas components relevant to CCS.

- **There is a need to develop standardized protocols and guidelines for flue gas characterization.** Standardized protocols and guidelines specific to CCS would improve data quality and facilitate comparisons across projects.

- **CO_2 concentration impacts the optimal type of capture technology that can be used.** For amine-based capture, higher CO_2 concentrations typically result in smaller towers and more efficient capture. However, after a point CO_2 concentration could become too high for efficient amine-based capture.

- **Flue gas impurities can have significant cost and performance implications if not properly addressed.** In the case of an amine-based capture process, particulates can cause fouling in heat exchangers and vessel packing, which increases maintenance costs and reduces capture efficiency. Additionally, failure to quantify components like SOx, NO_2, O_2, or metals can accelerate amine degradation, leading to higher costs for thermal reclaiming, amine makeup, and waste handling.

- **Early detailed characterization of flue gas should inform facility design and can mitigate cost and performance issues.** This is critical to identify potential issues and inform pretreatment and capture facility design.

- **Greenfield host facility construction creates challenges for proper flue gas characterization.** A significant challenge in flue gas characterization for CCS arises when dealing with upstream facilities that are still in the design or construction phase, as testing on the flue gas is not possible.

- **Each of the sectors in the program have unique considerations for flue gas characterization.** This is based on the feedstock used, and the impact of the upstream process.

ENERGY REQUIREMENTS

- **Where proponents identified a parasitic load, values ranged from 9% to 40%.**

- **Introducing an auxiliary boiler or a CHP plant into the facility will create additional emissions due to the combustion of fuel.** The additional emissions may be directed through the capture plant, which impacts the design and cost of the capture plant and associated balance of plant design.

- **Proponents noted energy costs have a large impact on project economics.** However, in many cases, these costs have a high level of uncertainty, such as the future price of electricity.

- **Proponents observed several energy saving tools and methodologies:**
    - » Computational fluid dynamics (CFD) modelling has been used in the CCK program to optimize the energy requirements of the flue gas blower.
    - » Operating conditions of the regenerator and CO_2 compressor can be optimized for energy usage. An analysis of the relationship between operating conditions of the regenerator and the CO_2 compressor would assist in determining the optimal operating point.
    - » An MVR may reduce steam required by the CCS process but will result in increased electric load. Heat exchangers within the system utilize waste heat generated within the capture process.
    - » Utilizing waste heat recovery from the host facility may reduce the incremental energy required from new sources.

- **Drivers for the CO_2 compressor have a significant impact on energy usage.** Most proponents started their evaluation with an electrically driven compressor. As the projects developed, the optimal source of energy to drive the compressor was evaluated, with some proponents now examining a steam turbine for driving the compressor.

- **High energy needs of carbon capture are driving companies to take a more holistic view of their business.** CCS FEED is driving some facilities to integrate energy production (ie: power production from a CHP plant) and the host facility material production, aiming to reduce emissions and produce near net zero electricity.

- **High energy needs of carbon capture may have broad implications to the grid as a whole.** Upgrades to electrical transmission lines or natural gas lines may be required to supply the additional utility requirements for the CCS facility. Early engagement with the utility provider will reduce the schedule risk associated with ensuring adequate supply of utilities to site and provide valuable planning information around sourcing of incremental energy needs.

COOLING

- **Cooling technology selection has a large impact on water usage.** Proponents identified all three types of cooling – hybrid, air, and water cooling – as their cooling technology of choice. Air cooling was the prevalent cooling system identified, which results in the CCS facility being a net producer of water.

- **Several site-specific factors influence the optimal choice of cooling technology.** The availability of water, ambient temperature, environmental impact, regulatory requirements and specific process needs, such as temperature targets and integration with existing infrastructure, are factors that influence the final decision on the choice of cooling type used in the capture facility.

- **Ambient temperature for cooling design may be optimized.** Designing the cooling system for lower than maximum ambient temperature is expected to reduce the footprint and cost. The trade-off is reduced cooling on the hottest days of the year which results in reduced CO_2 capture efficiency during that period. This is based on an investigation that included assessing the potential loss of capture efficiency and this was found to be acceptable in the overall yearly operating scheme when considering the footprint and cost savings from designing for lower ambient temperatures.

- **Seasonal considerations impact representative operating costs.** Cooling tower fan and water demand fluctuates throughout the year. In normal operation the average annual demand factor in a western Canadian climate should be confirmed through modeling at various ambient conditions. This will provide a design that is more representative of the annual operating cost of the system.

WATER REQUIREMENTS

- **CCS could lead to additional water consumption for some industries.** For example, the cement industry does not currently consume large amounts of water as part of their operations. Introduction of CCS means they may need to construct new infrastructure and tie ins to accommodate this additional water usage and must consider the source of the additional water required.

- **Cooling technology has a significant impact on water usage – and CCS can be either a "net consumer" or "net producer" of water.** Cooling of the flue gas may result in significant water condensation which can be treated and used within the CCS process. Where dry cooling was employed, proponents indicated that they may be a net producer of water. Where wet or hybrid cooling was used, the additional raw water required was sourced from nearby water sources.

SOLID AND LIQUID WASTE

- **Solid waste generated from amine-based CCS plants primarily consists of spent activated carbon, filters, and desiccants.** Waste disposal pathways for these solid wastes exist.

- **In capture technologies using solid sorbents and cryogenic processes, the primary source of solid waste is spent adsorbents and filters used for contaminant removal.** Recycling options for these wastes are being explored.

- **A wide range of liquid waste streams flowrates were identified by the CCK proponents, from 41 – 8000 tonnes/year.** While these results are preliminary, this highlights that site-specific factors could have a strong influence on waste volumes.

- **Treatment options for liquid waste are available but face environmental challenges, such as the creation of additional byproducts.** More work is needed to identify sustainable pathways for some of these wastes.

- **Confidentiality may play an important role in waste disposal, as it could lead to challenges in correctly identifying the waste.** This should be evaluated during FEED in partnership with capture technology vendors.

SECONDARY EMISSIONS

- **CCS facilities result in clean-up of the flue gas.** CCS facilities not only remove large amounts of CO_2 from industrial flue gas streams, but they also provide the added benefit of significantly reducing emissions of SOx, NOx, CO, and particulate matter.

- **Liquid amine-based CCS plants product secondary emissions that must be characterized.** An understanding of the interplay of the flue gas constituents, amine reactivity, and expected operating conditions is useful towards gaining a better understanding of secondary emission profiles. An appropriately designed pilot testing campaign can assist in identifying the potential secondary emissions.

- **All sectors identified amines and aldehydes as potential secondary emissions.** Material production and the oil and gas sectors additionally named ammonia, nitrosamines, NOx, SOx, VOCs, CO, and particulate matter as other possible emissions. The new secondary emissions formed due to the carbon capture process are:
    - » **Amines** may be emitted as aerosols.
    - » **Aldehydes** are typically formed from the oxidative degradation of MEA and have been detected in the gas phase in the absorber.
    - » **Ammonia** is a by-product of many carbon capture solvents. As a result, monitoring of ammonia levels on carbon capture systems is important for both operational and environmental purposes.
    - » **Nitrosamines** are formed not only due to direct emissions to air, but also from the emissions of amine, which can result in the formation of nitrosamines in the atmosphere by reaction with NO_2.

- **Flue gas pretreatment to remove impurities can reduce the impact of secondary emissions.** Secondary emissions stem from the reaction between amines and flue gas impurities. Therefore, the pretreatment of flue gas to remove impurities such as NOx and SOx is crucial towards minimizing the release of secondary emissions from the stack of the absorber.

CO_2 TRANSPORTATION AND STORAGE

- **Proponents evaluated geological storage only, as it can accept higher volumes compared to current utilization technology, is readily available in Alberta, and, unlike enhanced oil recovery, is eligible for Canada's CCUS investment tax credit.** The proponents evaluated distances as far as 400km for transportation of the CO_2 product and identified saline aquifers as the permanent storage type.

- **CO_2 product specification for pipelines and intended uses is a key consideration influencing the design of capture facilities.** CO_2 product specification is an emergent topic because many sequestration hub and pipeline projects that would determine these specifications are still in the engineering phase.

EXECUTION

- **There is a need to increase local CCS technical expertise.** There is currently a shortage of technical experts in the province of Alberta specifically trained in capture technology, as most vendors are based outside the province.

- **Lack of access to tidewater creates a geographic disadvantage.** Alberta does not have access to tidewater for shipping, increasing transportation costs for equipment.

- **Supply chain is seen as a significant risk for implementing CCS projects.** Supply chain and labour shortage risks may arise from concurrent large-scale projects. An example of this is CO_2 compressors, which can be difficult to source in certain size ranges.

- **Proponents are approaching execution in different ways.** Some companies are aiming to modularize by prefabricating equipment offsite and then ship to site for assembly, while others are combining both shop and field construction approaches. Rectangular structures are being considered where sections are fabricated offsite, shipped, and then assembled on site.

- **Post start-up operation and maintenance should be considered for CCS facility design and operation.** Proponents noted they have concerns about coordinating maintenance and turnaround activities between upstream processes and capture facilities post-startup.

LEVELIZED COST OF CAPTURE

- **The sensitivity analysis indicates that the discount rate used in the LCOC calculation has a significant impact on the final result.** For projects with higher discount rates, the LCOC will be higher, making it more challenging to justify the investment in a business case. The escalation rate of capital and O&M costs, as well as capital expenditure period had comparatively less effect on the LCOC.

- **It is important to distinguish between levelized cost of CO_2 avoided vs levelized cost of capture (LCOA vs LCOC).** Levelized cost of CO_2 avoided is an important metric as it considers only the reduction in the host facility's CO_2 emissions before and after the implementation of capture and not any CO_2 that is captured in addition to that produced by the original host facility, therefore represents the cost of emissions reduction. The levelized cost of CO_2 captured will be higher than the levelized cost of CO_2 avoided.

- **The wide range of LCOC values highlights the variability and uncertainty in cost estimates, even when consistent inputs are used.** In the base case, LCOC values ranged from \$105 - \$260 CAD/tCO_2 captured. The levelized cost of CO_2 avoided was approximately 20% higher, ranging from \$124 - \$314 CAD/tCO_2 avoided.

- **CCS costing remains an important issue that requires further analysis and ecosystem alignment.** The IEAGHG hosts workshops that bring together international experts from across the CCS ecosystem to share and discuss the most current information available on the cost of CCS.

EMISSIONS REDUCTION

- **Because of the high energy requirements of CCS, more CO_2 may be captured than was originally being produced.** If all 27 facilities in the CCK program were to go to successful FID, once operational, based on the data provided to date, they would collectively capture 29.6 MtCO_2e/yr. Note this is slightly higher than the total current emissions from the host facilities, 29.4 MtCO_2e/yr. The baseline emissions would achieve a net reduction of 86%, or 25.3 MtCO_2e/year – slightly less than 10% of Alberta's total annual emissions.

- **Net reductions by 2050 from all 27 facilities reaching operations by 2030 or shortly thereafter was estimated to be 508 MtCO_2e, assuming all facilities were to proceed to FID.** Note that the future of CCS projects in the CCK program remains uncertain, but this gives a sense of the ultimate potential emissions reduction.

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