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Genesee CCS Carbon Capture Kickstart

Non-Confidential Final Outcomes Report

Prepared for: Emissions Reduction Alberta

ERA Project ID: R0161678

Preface

This Final Outcomes Report (FOR) intends to satisfy the final reporting requirements related to the Genesee CCS FEED study, for which generous support was provided by Emissions Reduction Alberta. This FOR outlines the Project achievements and provides details on the performance of the technology as it was studied for inclusion in the project. The report includes performance metrics, lessons learned as well as GHG emissions reductions that could be expected from the Project subsequent to Final Investment Decision (FID) and construction.

List of Abbreviations

AIES – Alberta Interconnected Electrical System
AUC – Alberta Utilities Commission
B&V – Black and Veatch
BEDD – Basis of Engineering Design Document
BFD – Block Flow Diagram
B/L – Battery Limits
BOP – Balance of Plant
CAD – Canadian Dollar
CCF – Carbon Capture Facility
CCGT – Combined Cycle Gas Turbine
CCS – Carbon Capture and Storage
CCUS – Carbon Capture, Utilization and Storage
COD – Commercial Operations Date
CO2 – Carbon Dioxide
CPC – Capital Power (Carbon Capture) LP or Capital Power
DCC – Direct Contact Cooler
DTS – Demand Transmission Service
EPC(C) – Engineering, Procurement and Construction (and Commissioning)
EPEA – Environmental Protection and Enhancement Act
ERA – Emissions Reduction Alberta
FEED – Front End Engineering Design
FOR – Final Outcomes Report
GCP – Genesee Cooling Pond
GGS – Genesee Generating Station
GSU – Generator Step-Up
H2O – Water
HMB – Heat Mass Balance
HRSG – Heat Recovery Steam Generator
I&C – Instrumentation and Control
ITC – Investment Tax Credit
KM CDR – Kansai Mitsubishi Carbon Dioxide Removal
LP – Low Pressure
LSTK – Lump Sum Turnkey
MEA - Monoethanolamine
MHI – Mitsubishi Heavy Industries
MPWA – Mitsubishi Power Americas
MTBF – Mean Time Between Failures
MTPA – Million metric tonnes per year
MTTR – Mean Time to Repair
N2 – Nitrogen gas
NaOH – Sodium Hydroxide
NGCC – Natural Gas Combined Cycle
NO2 – Nitrogen Dioxide
NO – Nitric Oxide
NOx – Nitrous Oxides
NSR – North Saskatchewan River

O_2 – Oxygen gas
OE – Owner's Engineer
OEM – Original Equipment Manufacturer
O&M – Operations and Maintenance
P&ID – Piping and Instrumentation Diagram
PFD – Process Flow Diagram
ppmvd – volumetric parts per million (diluted)
RAM – Reliability/Availability/Maintainability
RBD – Reliability Block Diagram
RFCC – Residue Fluid Catalytic Cracking
SCR – Selective Catalytic Reduction
SO_2 – Sulphur Dioxide
TRL – Technology Readiness Level
WSP – WSP Global Inc.

1.0 Genesee Carbon Capture FEED Study

ERA Project ID	R0161678
Title of Project	Genesee CCS
Name and Information of Recipient Contact	Derek Ebeling, Carbon Capture Manager
Name of ERA Project Advisor	Emmanuella Sea-Nduka
Start Date of the Project	June 27, 2022
Completion Date of the Project	October 15, 2023
Technology Readiness Level (TRL) at Project Initiation	8-9
TRL at Project Completion	8-9
Total actual ERA funds received	$5,000,000
Total eligible actual Project costs	$13,860,915.62
FOR submission date	August 19, 2024
Short Project description with high level results for the ERA website	

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5.0 Executive Summary

The Genesee Generating Station ("GGS") is a ~1,300MW power facility located near Warburg, Alberta, approximately 80km southwest of Edmonton. The three Genesee units were originally designed to burn coal from the nearby Genesee mine and convert it into electricity, although Unit 3 has since been switched to burn natural gas.

Units 1 and 2, commissioned in 1994 and 1989 respectively, have been operating to provide baseload, affordable and reliable electricity to Albertans for over 30 years. Both units are currently undergoing repowering decommissioning the coal-burning components and replacing them with natural gas combined cycle ("NGCC") generation units. The transition to natural gas offers a number of advantages including significant steps towards the decarbonization of the Alberta grid by moving to high-efficiency, best-in-class J-class gas turbines in a NGCC configuration, improving the efficiency and reducing their carbon footprint by over 60%. In addition, the conversion to NGCC allows for the reuse of significant portions of the balance of plant ("BOP") equipment currently installed at Genesee to support the new facility.

The successful conversion of Genesee 1 and 2 to gas marks a historic milestone for Capital Power and Alberta, ending coal generation in the province over five years ahead of the government mandate, resulting in the reduction of carbon dioxide ("CO2") emissions from the provincial electricity grid. The next step in decarbonizing the GGS would involve the installation of post-combustion carbon capture equipment to capture 95% of the remaining CO2 emissions from the repowered facility. The intent of the recently completed front-end engineering and design ("FEED") study, which involved generous contributions from Emissions Reduction Alberta ("ERA"), was to analyze the viability of this opportunity by completing preliminary engineering and cost estimates in preparation for an investment decision.

The Genesee Carbon Capture FEED Study ("FEED" or "the Study") started at the end of the Pre-FEED work previously completed by Capital Power. During this Pre-FEED work, Capital Power selected the Mitsubishi Heavy Industries (MHI) Kansai Mitsubishi Carbon Dioxide Removal (KM CDR) process technology, as illustrated in Figure 3, for use at the Genesee Repower facility (Repower), to capture approximately 3 million tonnes per year of carbon dioxide from the flue gas of an under-construction natural gas combined cycle (NGCC) power plant. In addition to the selection of MHI as the process technology provider, Kiewit had also been selected as the EPC contractor with whom MHI would partner for overall execution of the FEED study.

Through this collaboration, the FEED involved MHI's provision of the process design for the heart of the carbon capture process while Kiewit would provide balance of plant (BOP) design and construction capabilities, for the preparation of a single overall lump sum turnkey (LSTK) engineering, procurement, construction and commissioning (EPCC) price and execution plan. In this way, the final FEED deliverable was a full EPC proposal for the imminent execution of the Project.

Throughout the FEED, MHI and Kiewit worked diligently with Capital Power and its owner's engineer (OE), Black and Veatch (B&V). Deliverables included process flow diagrams (PFDs), piping and instrumentation diagrams (P&IDs), plot plans, equipment lists, and equipment specifications, amongst others. Together, these documents were used to prepare a 3D model of the Project, and together with equipment list details, a firm price EPCC quote was prepared by the consortium. This proposal and supporting FEED engineering deliverables met Capital Power's expectations for rigor, quality and due diligence.

MHI and Kiewit went out to market participants for quotes on over one hundred different work scope packages and incorporated numerous adjustments to each proposal to account for transportation differences, minor scope discrepancies, and foreign exchange impacts to ensure that the best option was selected for each package. The agglomeration and compilation of the bid packages went through numerous senior executive reviews with both MHI and Kiewit to ensure that both organizations were comfortable submitting a lump sum, turn-key EPCC proposal.

The resulting Project is designed to capture 95% of the CO2 emitted by Repower, leveraging existing brownfield site facilities, including steam generation and electrical equipment, to minimize capital cost and to optimize the overall integration of the facility. The Project is designed to capture up to a maximum of 4.2 million tonnes of CO2 per year, but based on the expected Repower dispatch over time, on average approximately 3 million tonnes of CO2 per year would be captured over its 25-year design life. In this manner, Repower would become a source of low-carbon, baseload, dispatchable power generation with the ability to support the Alberta electricity grid for decades to come.

6.0 Project Description

Introduction

The Genesee Carbon Capture Facility (the "Project" or "CCF") Front End Engineering and Design ("FEED") study, conducted by Capital Power (Carbon Capture) L.P. ("Capital Power" or "CPC") built on earlier Pre-FEED work that was completed by Capital Power, to continue the evaluation of retrofitting a natural gas combined cycle (NGCC) facility near Warburg, Alberta, with a full-scale, post-combustion, amine-based carbon dioxide (CO2) capture system. The intent of the FEED study was to prepare a full Engineering, Procurement, Construction and Commissioning (EPCC) cost and schedule associated with a realistic execution plan from a consortium willing and ready to execute the work as the Project moves into implementation.

The FEED study started in May 2022 and was completed in June 2023, with a revised budget of $14.7 million CAD. Capital Power and Emissions Reduction Alberta (ERA) provided funding for this study, with in-kind contributions from the International CCS Knowledge Centre ("Knowledge Centre").

The FEED work was completed by a consortium of Mitsubishi Heavy Industries ("MHI") and Kiewit Construction Services ULC ("Kiewit"). Significant steam integration work was also completed by Mitsubishi Power Americas ("MPWA"), via the MHI partner of the consortium. Numerous additional original equipment manufacturer ("OEM") vendors were involved in the steam integration work as well. Owner's Engineer ("OE") support was provided by Black and Veatch Canada ("B&V"). ERA funding was associated with 200 hours of Knowledge Centre support which was also leveraged. In parallel with the execution of the FEED, Capital Power led the preparation of environmental permitting applications with the support of WSP.

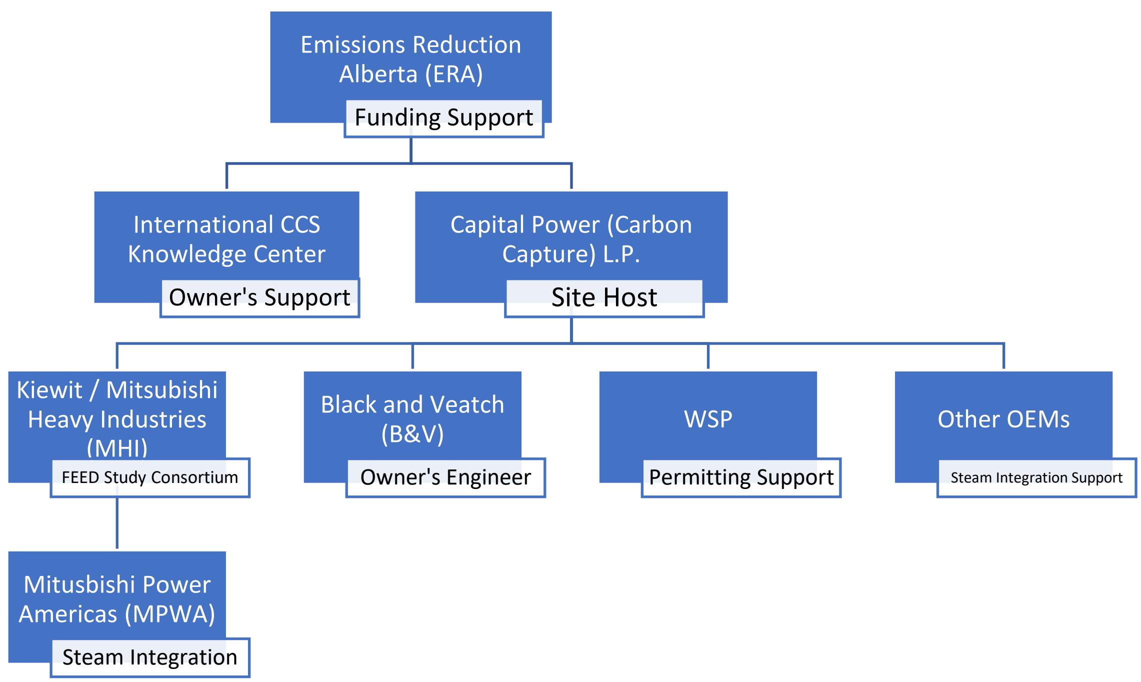

Figure 1 – Project Organization Chart

Genesee Repower Overview

The Genesee Repower project consists of a repowering effort of the original Genesee units 1 and 2, coal-fired subcritical power generation units dating from the late 1980s/ early 1990s. As part of Capital Power's decarbonization journey, this repowering effort includes the installation of two new, state-of-the-art, advanced class, high efficiency Mitsubishi gas turbines and heat recovery steam generators ("HRSGs"), in addition to the reuse of existing steam turbine and balance of plant equipment, as shown in Figure 2. The Repower project is currently under construction and is expected to enter commercial operations in 2024. When complete, the Repower project will supply approximately 1,338MW of power to the Alberta Interconnected Electrical System ("AIES").

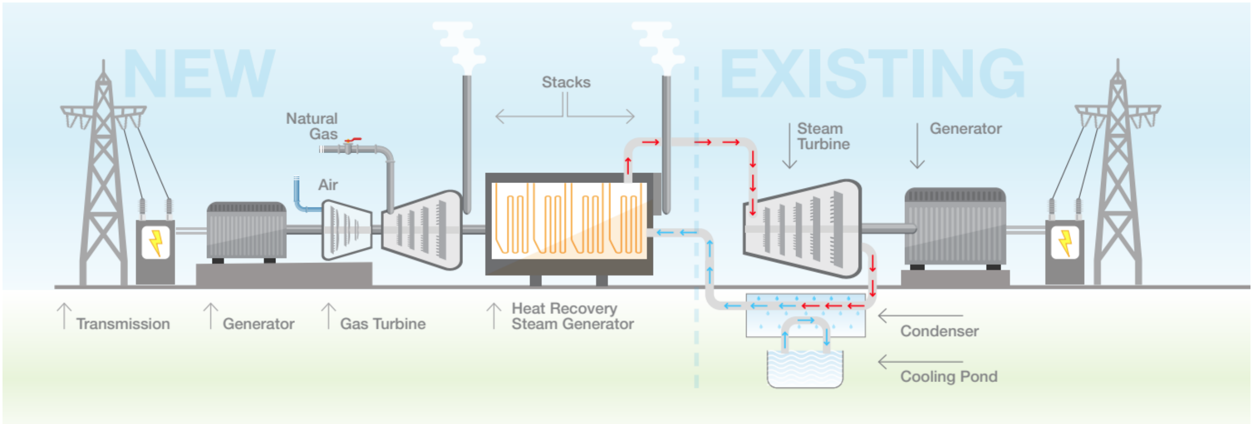

Figure 2 – Genesee Unit 1 and 2 Natural Gas Combined Cycle (Repower) Configuration

For further emission reductions, Capital Power pursued the installation of a post-combustion carbon capture and storage (CCS) facility at this Repower site.

The carbon capture facility (CCF) includes the installation of Mitsubishi Heavy Industry (MHI) proprietary technology, namely the Kansai-Mitsubishi Carbon Dioxide Removal (KM CDR) post-combustion amine capture technology, which leverages MHI's state-of-the-art KS-21 amine-based solvent. In consortium with Kiewit Energy Canada (Kiewit), the Project has now completed an 11-month front end engineering and design (FEED) study (the Study) to validate the cost and performance expectations for the Project.

Background of the Project

The Project's main goal is the cost-effective decarbonization of the Genesee Repower facility, currently under construction. In line with Capital Power's strategic goals for net zero by 2045, the installation of CCS technology at Genesee is a critical component to cutting CO2 emissions while maintaining reliable, base-load generation to support the Alberta electricity grid.

Between 2021 and 2022, Capital Power completed feasibility and Pre-FEED studies to analyze alternative technologies prior to launching the FEED study. The feasibility study analyzed alternatives for low-carbon dispatchable baseload power generation at Genesee, which included a comparison between the installation of blue hydrogen facilities (i.e. conversion of natural gas to blue hydrogen for burning in the existing Repower gas turbines, capturing CO2 in the process), and post-combustion carbon capture using amine-based technologies. This feasibility study showed that the levelized cost of carbon required for a blue hydrogen facility would be materially higher than for a post-combustion carbon capture facility. The Pre-FEED leveraged the results of the feasibility study to further narrow down the analysis of different post-combustion capture technologies.

Leveraging the results of this feasibility study and selecting post-combustion capture due to its greater readiness for commercial deployment at the 3 million tonnes per year (MTPA) scale, technologies with demonstrated commercial experience at this scale were reviewed in detail during the Pre-FEED phase of work. This assessment was based on criteria developed during Pre-FEED and is shown below in Table 1. This technology assessment resulted in the selection of MHI's Kansai Mitsubishi Carbon Dioxide Removal (KM CDR) technology as the preferred amine-based post-combustion capture solution for the Project.

Assessment Category	Scale-up Risk from Existing Facilities, including Technology Risk	License Agreement Readiness, Fees and Previous Negotiation Experience with Licensor	Cost of CO_2 Capture	Capex	Solvent Supply Risks	EPC Partnership Approach
Description and Questions to Consider	*<u>Scale-up Risk</u> - at what scale has the technology been deployed, and how much larger is our deployment (i.e., 1x, 10x, 100x) <u>Technology Risk</u> - has the technology been deployed on similar processes and flue gases (i.e., low-CO2 concentration flue gas), and how adaptable is the process to our deployment*	*What are the initial terms on the license agreement to use the technology, including the fee schedule. Does Capital Power have experience working with and negotiating with the counterparty, and what does that experience lead us to expect.*	*Lifetime Levelized cost Including: capex, opex, solvent supply, license costs*	*How does the representative capex compare, for example more capex means more capital to raise and deploy meaning higher risk.*	*How and under what terms could a long-term supply agreement look like. Does the licensor supply directly, where is it manufactured, and at what cost is it delivered.*	*What is the EPC approach proposed for FEED. Can the licensor self-perform the full FEED, do they have a partner, or does Capital Power need to find an EPC partner. If they or a partner can perform, what is their experience, for example in Western Canada, or with Capital Power.*
Licensor A	Comparable to the others	Reasonable license fee, shown early flexibility	Marginally lower	Marginally higher	Supply risk low	EPC Wrap available
Licensor B	Comparable to the others	Reasonable license fee, shown early flexibility	Middle levelized cost	Marginally higher	Supply risk moderate	EPC Wrap available
Licensor C	Comparable to the others	Most flexibility on license fee terms	Marginally higher	Lowest	Supply risk moderate	EPC Wrap available
Weighting	*15%*	*5%*	*50%*	*15%*	*5%*	*10%*

Table 1 – Technology Selection Assessment Criteria at the End of Pre-FEED

Subsequent to this technology selection, MHI noted that they had significant North American experience with Kiewit as an EPC partner on carbon capture projects. This experience included the execution of the Petra Nova carbon capture facility near Houston, Texas, as well as numerous FEED and Pre-FEED studies executed by Kiewit/MHI. Together, this made a joint FEED proposal from MHI and Kiewit an attractive option. Other options included using a different EPC company to partner with MHI, or alternatively focusing on the process design with MHI first, and subsequently working on an EPC proposal with Kiewit or other EPC companies. After reviewing alternatives, Capital Power chose to execute the FEED on the Kiewit-MHI basis, which included a clear delineation of deliverables, work scope, team members, schedule and budget between the Kiewit and MHI entities[1].

[1] Capital Power advances carbon capture project at Genesee - Capital Power

In addition to Kiewit and MHI, the FEED study leveraged other expert contractors for support. This included Black and Veatch as Owner's Engineer, as well as providing dedicated full-time engineering support personnel. WSP (formerly operating as Golder Associates) worked diligently in the environmental consultant role to prepare the environmental and regulatory applications, in addition to performing environmental assessment work, both field- and desktop-based, such as noise, air emissions and water quality analysis.

General Electric and Mitsubishi Power Americas, amongst others, supported the FEED in the analysis of the steam integration scope to determine the viability of extracting large quantities of steam from the Repower bottoming cycle for use in the Project. Finally, the International CCS Knowledge Center provided support to the FEED study through the review and recommendations of various operational considerations including commissioning and the transition to operations which was helpful in the consideration of the overall operating and maintenance plan for the Project.

In May 2022, the FEED kickoff meeting was held.

Project Objectives

As per the original Contribution Agreement, the original objectives of the Project were as follows:

1. Front End Engineering and Design (FEED) study for the post-combustion capture of CO2 from the Genesee Repower units 1 and 2.
2. Engineering deliverables typical of a FEED study, including engineering documentation like P&IDs, equipment list, plot plans and project execution documentation such as execution plan, and implementation schedule.
3. Preparation of regulatory applications (EPEA and AUC) and progression of CO2 offtake.
4. EPC (engineering, procurement, and construction) estimate and scope to support Final Investment Decision, currently anticipated for mid-2023, pending other contingent factors including regulatory and policy matters outside of this direct scope.

While these objectives did not change over the course of the Project, the following minor amendments were made to the Milestone Deliverables and Schedule A of the Contribution Agreement.

- CO2 absorber drawing was not provided to ERA due to confidentiality issues;
- Total project costs were revised from $15,752,172 to $14,710,328 in the Milestone Two Reporting Documents. The cost revision was a result of the reallocation of labour costs from Capital Power to subcontractors. This was due in part to a) increased reliance on subcontractors who provided labour and engineering expertise, and b) most of the FEED deliverables being undertaken as subcontract work.

Additionally, while no formal amendments were made to either the Milestone Deliverables or Contribution Agreement, the Final Investment Decision for the CCF, initially expected in mid-2023 has not yet been achieved. Capital Power announced at Q2 results in August 2023 that while technical work to date is positive, progressions on carbon assurances with the federal government are moving slower than anticipated. Capital Power continued efforts to secure carbon assurances, until more recently in May 2024[2], when Project discontinuation on account of project economics was formally announced.

[2] Capital Power announces first quarter 2024 results

Capture Technology Description

MHI's KM CDR process is an amine-based CO2 capture process which uses MHI's proprietary KS-21 solvent. The CO2 capture system is capable of recovering 95% of the CO2 from the flue gas and compressing the treated CO2 to adequate pipeline conditions. Figure 3 below shows a block flow diagram of the CO2 capture facility.

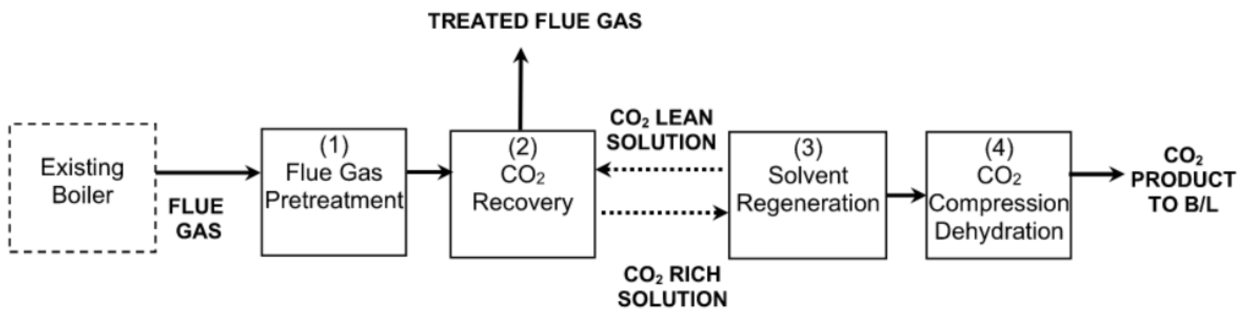

Figure 3 – Block Flow Diagram of the CO2 Capture Facility

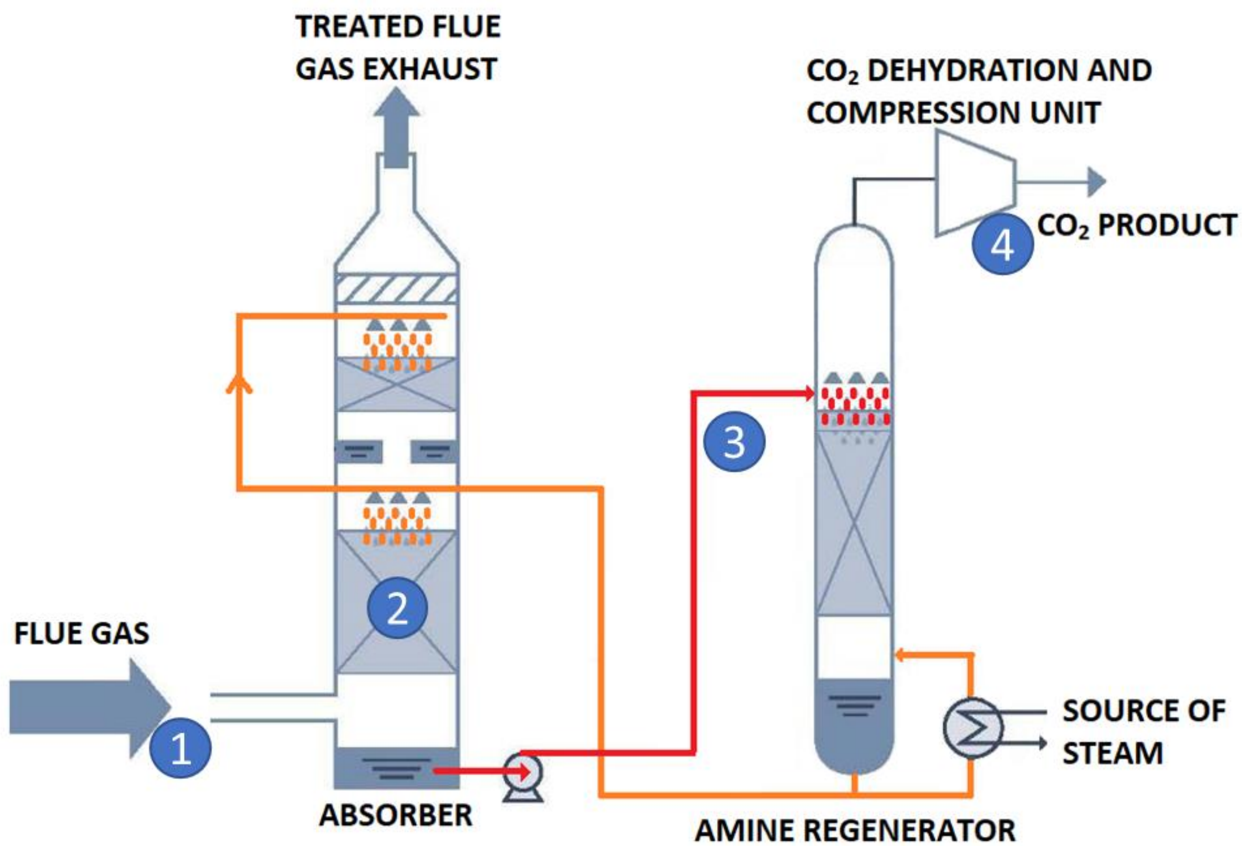

Figure 4 – Illustrative Diagram of the CO2 Capture Facility

In flue gas pretreatment (Step (1) in Figure 4 above), the flue gas temperature is cooled through direct contact with cooled circulation water. The circulation water is injected with caustic soda to reduce the amount of SO2 in the flue gas entering the amine system. Flue gas blowers are installed downstream of the flue gas quencher to overcome the pressure drop across the flue gas quencher and CO2 absorber.

In CO2 recovery (2), the cooled flue gas from the flue gas quencher is introduced at the bottom of the CO2 absorber. The flue gas moves upward through the packing while the CO2-lean solvent is supplied at the top of the absorption section where it flows down onto the packing. The flue gas contacts with the solvent on the surface of the packing where CO2 in the flue gas is absorbed by the solvent. The CO2-rich solvent from the bottom of the CO2 absorber is sent to the regenerator. The CO2-lean flue gas exits the absorption section of the CO2 absorber and enters the flue gas washing section of the CO2 absorber. The flue gas contacts with circulating water to reduce the amount of amine that is emitted from the top of the CO2 absorber with the treated flue gas which now contains approximately 5% of the CO2 with which it entered.

In solvent regeneration (3), rich solvent is first heated by the hot lean solvent extracted from the bottom of the regenerator in a heat exchanger. The pre-heated rich solvent is then introduced into the upper section of the regenerator and flows down over the packing where it contacts with stripping steam. As it flows down the column, the rich solvent is steam stripped and regenerated into lean solvent. The steam in the regenerator is produced by the reboiler where low pressure (LP) steam is used to heat the lean solvent. The lean solvent is then further cooled to the optimum absorption temperature before being sent to the CO2 absorber again. The overhead vapor leaving the regenerator is cooled, and the condensed liquid from this unit is then returned to the system.

Finally, the CO2 is compressed (4) through a multi-stage gas compressor, and treatment such as O2 removal or dehydration may be necessary to meet pipeline and storage guidelines. The process produces a >99% pure CO2 gas stream.

Various balance of plant (BOP) systems are also required to provide support for the core carbon capture systems. These BOP systems include:

- Open cooling water system
- Closed cooling water system
- Steam and condensate system
- Compressed air system
- Fire protection system
- Utility water system
- Potable water system
- Demineralized water system

New BOP systems are required for all of these except for the demineralized water and fire protection systems, which can leverage connections to the existing Repower facility.

Capture Plant Sizing

The Project was sized to be able to capture CO2 across all reasonable operating modes of the Repower host facility. This included being able to operate the CCF from 50% load on the Repower gas turbines all the way up to 100% gas turbine load including HRSG duct-firing. These three modes, as shown in Table 2 below, form the basis for design conditions for the CCF as well as the performance guarantee points.

	Case 1001	Case 1002	Case 30

Case Description	Winter full load	Summer duct fired	Summer part load
Ambient Temp (°C)	-26.2	25.4	25.4
Atmosphere Pressure (bar)	0.924	0.924	0.924
Ambient Relative Humidity (%)	64%	50%	50%
HRSG Duct Firing	Off	On	Off
Gas Turbine Load (%)	100%	100%	50%
Flue Gas Constituents (mol %)			
CO2	4.96	6.53	4.39
H2O	9.21	14.13	9.80
N2	74.39	71.69	73.53
O2	10.51	6.75	11.36
SO2, ppmvd	0.00001	0.00001	0.00001
NOx, ppmvd @15% O2	3	3	3
Stack Flow (per stack) (kg/h)	2,479,743	2,440,383	1,577,293
Stack Flow (per stack) (Nm3/h)	1,955,997	1,952,033	1,249,318
Stack Flow Temperature (°C)	98	72	87
Ammonia Slip from Repower SCR (ppmvd @15% O2)	5	5	5

Table 2 – Host Facility Flue Gas Design Conditions

Site Conditions

The site conditions are well characterized given that significant industrial development has taken place over the course of 40+ years the Genesee site has been delivering power to the Alberta grid. Table 3 below summarizes key aspects of these site conditions.

Site Elevation (m)	734.5
Atmospheric Pressure (bara)	0.9245
Plant Design Life	25 years
Dry Bulb Max / Min Temperatures (°C)	36.0 / -43.8

Table 3 – Genesee Site Conditions

Other Design Considerations

Steam Integration

Significant work was undertaken during the FEED study to validate the opportunity to utilize steam from the Repower bottoming cycle. This steam would then be used to regenerate the amine solvent, releasing its CO2 load, before the condensed steam returns to the bottoming cycle. Due to the high efficiency nature of the Repower facility, this represents a highly cost-effective manner of sourcing steam for the CCF. In short, this analysis showed that steam integration with the host unit was viable at minimal capital cost and with an acceptable level of risk. This design was incorporated into the remainder of the FEED study. Despite this, a commercial decision was made late in FEED (driven in part by a change in ITC legislation) to explore external steam supply, such as through a combined heat and power plant (Cogen) with CCS. Given the timing of this decision, it was not possible to update the FEED results for this change, meaning that all completed FEED works were done on the basis of steam integration.

Redundancy

A reliability/availability/maintainability (RAM) study was completed on both the process equipment and balance of plant (BOP) equipment to determine which areas of the plant design would benefit from equipment redundancy and which areas were not worthwhile. The RAM analysis is based on a reliability block diagram which compares the mean time between failures (MTBF) and mean time to repair (MTTR) times for each EQUIPMENT component to derive an overall availability for the Project based on alternate potential redundancy configurations. The analysis also considers the planned outage rate to determine the overall optimal configuration of redundancy. In these results, "N+0" indicates that redundancy for the equipment component is not included, i.e. that N units will be sufficient with 0 redundancy. "N+1" implies that N units would have a net positive cost-benefit result from having 1 additional unit installed for redundancy purposes, and thus was selected to include said redundancy. That analysis resulted in the equipment redundancy selected in Table 4.

Item	**Redundancy Selected**
Carbon Capture Process Island	
Flue Gas Blower	2x50% per train
CO2 Compressor	2x50% per train
Main process pumps	2x100% per train
Balance of process pumps	N+0
Small pumps	N+0
Process heat exchanger	N+0
Balance of Plant	
Cooling water heat exchanger	N+1
Open Cycle Cooling Pumps	4x25% for total CCF
Closed Cycle Cooling Pumps	2x50% per train
Air Compressors	3x50% for total CCF
General Service Pumps	N+1

Table 4 – Design Basis for Equipment Redundancy

Performance/Success Metrics Identified in the Contribution Agreement

The performance/success metrics identified in the Contribution Agreement are shown in Table 5.

Success Metric	**Project Execution Metrics**	**Study Metrics**	**Achievements Prior to Execution of Contribution Agreement**
Capture Rate	95%	95%	
Ultimate Project Target Capital Cost	$2,100 ($M)	$2,100 ($M)	Working to validate if targets are achievable.
Levelized Opex/Tonne	$90/tonne	$90/tonne	Working to validate if targets are achievable.

Table 5 – Performance/Success Metrics Identified in the Contribution Agreement

Over the course of the FEED study, more detailed analysis was completed in all three areas of these metrics, to confirm their viability.

Capture Rate

At the initiation of the FEED study, MHI had confirmed that a 95% target capture rate was achievable. The latest generation KS-21 solvent used by MHI in their KM CDR process has been proven to be able to meet or exceed these targets in testing at a specialized CO2 capture testing facility, Technology Center Mongstad in Norway, as seen below in Table 6.

CO2 Source	Combined Cycle Gas Turbine (CCGT), Residue Fluid Catalytic Cracking (RFCC) Flue Gases
Solvent	KS-21 ™ Solvent, KS-1 ™ Solvent
Flue gas flow rate (Sm3/h)	30,400 – 55,000
Flue gas CO2 content (%)	CCGT 4-4.3, 14 ; RFCC 12.6 (10 days)
Regenerator pressure (barg)	0.30 – 1.58 barg, adjusted
CO2 capture rate (%)	95 – 99.8%, adjusted

Table 6 – MHI Demonstration Test Results of KS-21(TM) Solvent at Technology Center Mongstad, Norway, Courtesy MHI

These tests proved this capture rate on flue gases with a wide variety of flue gas compositions, including low CO2 and high oxygen concentrations as are expected in the Repower flue gas. They also showed that MHI's newest solvent, KS-21™, was also a strong opportunity to replace the former KS-1™ solvent given that it exhibited several improved economic performance parameters compared to the original. These improvements, including performance improvements compared to a simple monoethanolamine (MEA) solvent are shown below in Table 7.

Parameters Relative to KS-1™	MEA	KS-1™	KS-21™
Volatility	100	100	50-60
Thermal Degradation Rate	200	100	30-50
Oxidation Rate	500->1000	100	70
Heat of Reaction	>120	100	85

Table 7 – Comparison Between KS-21(TM) and KS-1(TM) Solvents for the KM CDR Process, Courtesy MHI

Commercial and technical discussions with MHI further provided comfort that these capture rates would be expected, achievable, and guaranteed during the performance testing period subsequent to construction and commissioning.

Ultimate Project Target Capital Cost

The original target capital cost as shown above was $2.1B CAD for the facility, based on cost information from the Feasibility and Pre-FEED studies. A key deliverable of the FEED was the compilation of an Engineering, Procurement, Construction and Commissioning (EPCC) cost estimate proposal, which was provided by Kiewit and MHI in consortium. This proposal was prepared after the completion of engineering deliverables which defined the majority of the quantities, equipment sizes and specifications, layouts, equipment redundancy and other aspects of the front-end engineering design. Multiple quotes were solicited for the majority of major equipment items, as well as for bulk equipment and materials. Placement rates, labour rates and productivities based on Kiewit's significant experience across the Alberta construction market were also allocated to the Project scope.

The Project is expected to be eligible for material Investment Tax Credit (ITC) support from the federal government, however this support requires that projects meet various eligibility criteria. At the time of the estimate preparation, the eligibility criteria were not available for the CCUS ITC, but were available for other ITCs such as the clean energy ITC. During preparation of the Project capital cost estimate Kiewit confirmed that, should the CCUS ITC requirements be equivalent to the clean energy ITC requirements, then the Project estimates would indeed meet the CCUS ITC eligibility criteria. In recent months, since the completion of the FEED study, a draft of the CCUS ITC details has been made available and confirms that the Project cost estimate will meet these eligibility criteria, i.e. the capital cost is not expected to increase as a result of these CCUS ITC requirements, should they be approved as drafted.

The selection of an execution strategy was a key consideration informing the overall capital cost. As the basis for the FEED estimate, and as part of the FEED execution strategy, we selected MHI as the technology provider and Kiewit as BOP engineer and constructor, working together as a consortium. Kiewit and MHI would share responsibility for procurement, with MHI procuring key process equipment and Kiewit providing the remainder of the equipment. There are material benefits to this strategy that outweigh any potential drawbacks. Most important of these is the ability to obtain the highest possible performance assurances from the consortium post-construction. Since Capital Power will be responsible for the long-term operations and maintenance of the facility and will wear the risk associated with performance shortfalls long into the operating future of the facility after construction is complete, the assurance that the plant would perform in line with expectations was critically important to the overall economics of the project. This factor gains further importance given that so few operating carbon capture facilities – especially at this size, with this technology, and with this flue gas – exist elsewhere in the world.

As part of the FEED scope of work with Kiewit and MHI, a firm-priced lump-sum turnkey capital cost proposal was provided for execution of the Project in June 2023. While the estimate has not been directly classified, based on the level of detail of the engineering, and estimating methodology used, it is reflective of a typical Class 2 level cost estimate. Including Owner's Costs and potential additional optimizations, both through scope optimization and contract optimization, Capital Power believes the range of EPC cost for the overall project is between $2.3 - $2.5 billion CAD.

Levelized Opex per Tonne

The main drivers of opex per tonne comprise the following:

- Cost of steam, for amine regeneration
- Cost of power, for operating blowers and CO_2 compressors
- Cost of operating and maintenance expenses, to operate and maintain the facility during regular operations as well as outages
- Cost of solvents and chemicals, associated with the flow of CO_2 being captured
- Capacity factor of the host facility, which drives the annual CO_2 volumes captured

Various efforts were undertaken to minimize the levelized opex per tonne, which are summarized below.

As discussed in the Milestone 4 Steam Integration Report, the integration of steam supply between the host facility and the carbon capture facility (CCF) was a critical component of the FEED study. The steam generated by the Repower facility is some of the most efficiently produced steam in Alberta, given that the source of heat is the high-efficiency gas turbines being installed at site. As such, this steam requires less energy (sourced from natural gas) to produce and therefore minimizes the operating cost per tonne. As noted in the preceding section on steam integration, while a commercial decision was made to explore external steam supply, such as through a cogeneration facility, this decision was made late in FEED meaning it was not possible to update FEED works for this design change. This means that the costs described in this report are based on the steam integration configuration.

Similarly to the steam integration, various options for the provision of electrical power to the CCF were considered. The option that was ultimately selected was based on feeding power from the high side of the gas turbine generator step-up (GSU) transformers (i.e. from both Repower units), feeding to a common CCF electrical bus which subsequently distributes power at various voltage levels throughout the facility. Although this option minimized the overall capex associated with providing power – i.e. by avoiding the installation of a new electrical switchyard – it also served to minimize opex associated with alternative arrangements, such as Demand Transmission Service (DTS) charges if a grid connection were used instead.

Based on their experience at Petra Nova and other facilities, Kiewit and MHI prepared a high-level recommendation regarding the operating and maintenance labour manpower expected for the facility. Based on this preliminary view, further discussions were held with Genesee site operators and leadership to understand how existing Genesee resources could be leveraged to minimize the incremental CCF staff. In this manner, O&M expenses were optimized and ultimately reduced.

Solvents and chemicals form a large portion of the consumption costs for the operations of the facility which are largely driven by the replacement amine and other chemicals (e.g. NaOH, anti-foaming agents) that are consumed. These costs are included in the overall Opex figures shown in this report, but due to specific confidentiality provisions with the technology provider, the amine solvent cost cannot be broken out and shown independently.

The capacity factor of the CCF is determined based on the proportion of time that the facility is online and operating. A higher capacity factor leads directly to a higher volume of CO2 captured, upon which fixed operating costs are amortized – as such, efforts to increase the expected capacity factor can lead to a lower operating cost per tonne. This calculation reflects the reliability of the CCF as well as the host Repower facility, but also the dispatch of the Repower facility itself – i.e. whether the Repower units are dispatched on or off, and when on, whether they are loaded to 50% vs 100% capacity. Although Repower dispatch is dependent upon the forecasted needs of the Alberta electricity grid on an hour-to-hour basis and is therefore out of the control of the CCF design, optimizing the reliability and availability of the CCF can support a higher overall capacity factor. To achieve this high reliability of the CCF, significant effort was put into completing a reliability/availability/maintainability (RAM) analysis to confirm the preferred level of redundancy for certain critical components of the CCF.

The final operating expenses, on a $/tonne basis, are estimated to be in the range of $70 – 115/tonne.

Project Changes

During the lifecycle of the ERA funded project scope, there were no material changes to the corporate structure of the company, nor to the Project consortium partners or contractors.

Technology Risks

At the beginning of the Project, several technology risks were identified. Core among these was the integration of steam between the bottoming cycle of the host Repower facility and the carbon capture facility. Risks related to steam integration stem from the lack of experience proving the concept at scale, and other operating challenges and risks, especially considering the original design did not contemplate steam offtake in this fashion. To assess this, a preliminary study and change of use study was completed as part of the FEED and it was concluded that managing these risks would be feasible.

A second key risk that the Study intended to assess was related to the dispatch of the carbon capture facility (CCF). The CCF requires steam (for the solvent regeneration process) and electricity (for major process electrical loads such as the CO2 compressors). Since the CCF is tightly integrated with the steam and power generated by the Repower facility, the CCF needs the Repower facility to operate in order for the CCS to operate. As such, it was critical to determine how quickly the CCF can ramp up and down in response to the Repower facility being dispatched in the Alberta power market. In addition, understanding the unabated CO2 emissions that would be released during Repower startups prior to the CCF coming online were critical risks to the economic modeling of the facility. Since these unabated startup emissions need to be offset economically, they have a significant impact on the overall Project economics. This risk is especially acute given that current forecasts for Repower dispatch are expected to incur more numerous startups per year in the later years of the Project life, as more renewables come online on the Alberta grid.

The assessment of this unabated emissions risk included detailed transient analysis of the startup process of the CCF, to understand what actions were required prior to the energization of various equipment components, as well as the time required for the warm-up of, for example, the regenerator vessel. The warm-up time for these components varies depending upon the amount of time that has passed since the equipment was shutdown. For example, in the event of a short-term CCF outage (i.e. one that is expected to last only 1-2 hours), the operators could expect to maintain the equipment running and warm such that when repairs were completed, the CCF could quickly restart without having to complete the startup sequence from the beginning. However, if a longer shutdown was required, then a “cold” startup sequence may be required.

Once this analysis was complete, the startup sequence and timings were mapped against the projected startup times for the Repower facility, to indicate approximately how long Repower would operate with unabated emissions. These results were incorporated into the overall financial model, based on their material implications on the dispatch, run hours and overall capacity factor of the Repower facility.

7.0 Project Work Scope

Experimental Procedures/Methodology

The methodology of the execution of the FEED study is generally summarized below.

During the kickoff for the FEED study, results from the Pre-FEED were reviewed and used as the preliminary basis of design, sizing and operating parameters, so that the facility definition could be complete. This included high-level assumptions about the facility, such as the sizing for the facility (i.e. that it be sized for the full, duct-fired capacity of the host Repower facility), the expected high-level dispatch of the facility (i.e. including the hours during which it would be expected to turn down to 50% gas turbine load and still be able to capture 95% of the CO2 emitted by Repower), and other items. These design basis items were incorporated into Kiewit/MHI’s Basis of Engineering Design Document (BEDD), amongst other aspects of the design of the facility, such as site and ambient conditions, design standards, and a high-level summary of the various utilities available on site such as firewater, cooling water, electricity, steam and others. This document was also maintained as a "living document" and updated throughout the FEED study, while other process optimization aspects of the Project were completed to inform the content of the BEDD. This BEDD also laid the groundwork for discipline-specific documents to be prepared, such as mechanical/piping, electrical, instrumentation and control (I&C), structural and civil design criteria.

Preparation of the block flow diagram (BFD), subsequent process flow diagrams (PFDs), and heat and mass balances (HMBs) formed the next stage of the FEED study, sequenced in this manner so that as further process engineering definition was complete the results of these analyses were captured. As this process definition was completed, work continued to bifurcate into various sub-streams. Additional process engineering was completed to support the dynamic simulations, RAM analysis, piping and instrumentation diagrams (P&IDs). These results fed into other engineering documentation such as equipment sizing and specification, which led to the analysis of loading and sizing so that civil engineering design and plot plans could be started. While this work progressed, additional deliverables, including the modularization strategy, transportation strategy, winterization strategy and procurement strategy, could also be prepared.

Once this engineering was completed, cost estimating efforts could be initiated through three main avenues. As noted above, MHI's scope of supply for the execution of the Project includes procurement of major equipment components, including the CO2 compressors, regenerator vessels and absorber vessels, amongst others. This equipment, now that it had been specified, sized and validated against local building codes, was circulated for quotation amongst top-tier equipment vendors both in Canada, North America and for some critical items, across the rest of the world.

In parallel, Kiewit prepared a list of other key equipment components within their balance of plant (BOP) scope, as well as major bulk materials such as large bore piping, structural steel and instrumentation components. Over 100 of these estimate packages were prepared and circulated to the market for quotations. Finally, Kiewit leveraged its in-house cost databases for remaining bulk materials, inflation, escalation and unit labour rates in order to compile an overall cost estimate. Given that the FEED study was based on an open-book cost estimate process, a detailed review of the estimate was held between Capital Power, MHI and Kiewit as part of the review process. This led to the clarification of a number of assumptions and identification of "bridging period" items where further analysis would be required during the next phase of detailed engineering execution. This overall process is illustrated in the schematic figure shown in Figure 5.

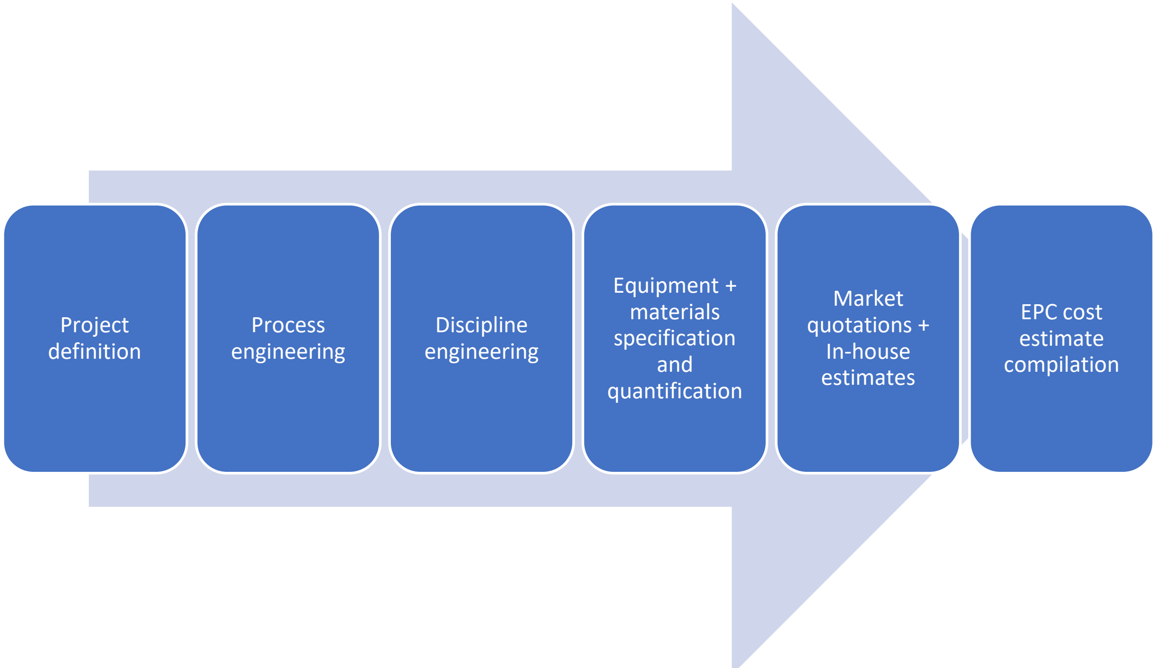

Figure 5 – FEED Study Methodology Flow Chart

Technology Development, Installation and Commissioning Description

This Study did not include the development, installation or commissioning of any technology or equipment.

Overall Project achievements relative to stated objective and performance metrics

The aspirational metrics identified in the Contribution Agreement are noted below, as compared to the achieved metrics.

Success Metric	Study Metrics	Achieved Metrics
Capture Rate	95%	95%
Ultimate Project Target Capital Cost	$2,100 ($M)	$2,300 – 2,500 ($M)
Levelized Opex/Tonne	$90/tonne	$70-115/tonne[3]

Table 8 – Achievement of Performance/Success Metrics Originally Identified in the Contribution Agreements

Analysis of results

The results of the Study show a number of key findings relevant to the goals pursued. The viability of a post-combustion carbon capture facility with at least 95% capture rate based on flue gas from a natural gas combined cycle facility was shown to be an effective solution for decarbonization of the Genesee Repower facility. The 95% level of capture was also shown to be able to be commercially guaranteed by technology licensors and constructors. The price of the Project was also determined and incorporated a Lump Sum Turnkey (LSTK) price and schedule guarantee.

[3] Excludes capex and varies with facility dispatch.

Finally, although operating expenses could not themselves be fully guaranteed, steam and power consumption guarantees could be provided which forms a large part of the basis of the operating costs for the facility. Furthermore, refinement of the expected operations and maintenance labour and expenses forecast allowed us to obtain greater certainty regarding the expected overall operating costs per tonne.

8.0 Commercialization

The selected MHI technology is typically considered to have a Technology Readiness Level (TRL) of 8-9, where a TRL of 9 is required to be considered for the technology to enter "normal commercial service"[4] and a TRL level of 8 is considered to have demonstrated "Commercial demonstration, full-scale deployment in final form". Given that the MHI technology (using an earlier version of the KS-21 solvent, namely KS-1) has been proven at the ~1 MTPA scale at Petra Nova facility near Houston, Texas, we expect there to be minimal risk related to the scale-up of the technology to meet the needs of the Project. Indeed, that minimal risk is one of the critical factors which informed the decision to select this technology prior to initiation of the Study. However, there remain scale-up risks associated with the technology, especially given that the flue gas under consideration – with relatively low CO2 concentrations and high O2 concentrations – has not been proven at commercial scale elsewhere in the world. However, with the successful completion of the FEED study, this work advances the commercialization potential of the technology in this application.

9.0 Lessons Learned

Completion of the Study resulted in a number of lessons learned, including both technical and non-technical aspects.

From a technical perspective, the Study showed that steam integration between a carbon capture facility and an operating NGCC facility is feasible, and depending on the specific details of the NGCC, such integration may be feasible at minimal capital cost. Consequently, this shows that cost-minimization for a carbon capture facility similar to the Project is feasible through the avoidance of additional steam generation equipment. However, one lesson learned is the importance of the integration study and ensuring that sufficient time is available to complete the work so the results can be fully incorporated into the final deliverables of the FEED, including specifically the impacts on capital and operating costs, maintenance requirements, as well as performance and scope guarantees.

A lesson learned regarding the non-technical aspects of the FEED study includes the recommendation for detailed flue gas analysis prior to the initiation of future FEED studies. In the case of the Project, since Repower was under construction during the execution of the FEED, it was not possible to obtain a gas sample of the flue gas emissions from Repower to validate the range of expected compositions and contaminants prior to the design of the various flue gas-handling equipment as part of the CCF. This required assumptions to be made, based on detailed engineering calculations stemming from the Repower design engineering team. In addition, assumptions for particulate matter were made based on comparable combined cycle units of similar sizes in operation across North America. However, in the execution of future FEED studies of this

[4] (Kearns, Liu, & Consoli, March 2021)

kind, if such flue gas samples are available, a detailed analysis would be recommended across a range of host facility operating conditions to confirm the design range for the carbon capture facility.

During the execution period of the FEED study, numerous discussions were ongoing across the political and social landscape about the role of CCS in Canada's energy transition. This included the introduction of Federal ITC-based incentives, the drafting of the Canadian Clean Electricity Regulations, as well as various discussions with different Federal bodies seeking to incent the construction of Canadian CCS facilities through the use of dedicated financing or innovative commercial structures. Since these commercial supports were in flux during the FEED study, assumptions were made regarding reasonable expectations for e.g. carbon capture rate guarantees, construction labour requirements, economic life, as well as the viability of using cogeneration facilities for the provision of steam and electricity to feed the carbon capture process. Each of these assumptions has material impacts on the overall design, redundancy and EPC structure considerations of the Project, and each such assumption comes with capital or operating cost impacts. Given the evolving nature of these discussions, it would be difficult to kickoff the FEED study after such considerations have been finalized. However, in an ideal world, it would be recommended that the commercial structure be finalized to the fullest extent possible prior to the kickoff of FEED engineering to avoid any re-work based on a changing regulatory landscape.

Another lesson learned relates to the use of a proven CCS provider. Given the magnitude of the size and scale (both economically and emissions-wise) of the Project, it was important to choose a technology provider with proven operations at the size of the capture facility considered. This importance led the Project to strongly lean towards the selection of one of the major amine-based technology providers for the execution of the FEED study, and away from some of the numerous other technology providers. While there are numerous vendors in the carbon capture industry, with more entering every year, not all vendors have the experience, scale or ability to execute FEED projects that more established vendors have. The selection of MHI and Kiewit proved to be beneficial not just because of their experience with the Petra Nova project, but also because of their deep bench strength in the ability to bring engineers, procurement teams and project management staff together to prepare not just a successful FEED study but also a feasible EPC execution plan. Matching the size and needs of a project with the capabilities and technology readiness level of a vendor is critical to successfully moving these complex carbon capture projects forward.

Finally, it was critical to align the internal Project team with external contractors to ensure clear lines of communication, clear delineation of responsibilities and aligned executive expectations to successfully meet the FEED schedule and objectives. With many vendors involved, including MHI and Kiewit, WSP, Black and Veatch as well as numerous other vendors supporting work such as the steam integration study, a strong and competent project management team is critical to ensuring that information, direction and responsibility flows clearly and effectively throughout the FEED study. Regular coordination meetings, schedule reviews and regular discussions surrounding objectives and course adjustments are strongly recommended.

10.0 Environmental Benefits

10.1 Emissions Reduction Impact

The Project would have resulted in significant emissions reductions at the Genesee Repower facility. With a 95% capture rate, the project would have been expected to cut CO2 emissions from roughly 12,000 tonnes per day (tpd) to 600 tpd during full, duct-fired load of the host facility. This 95% capture rate was also guaranteed at lower load levels, down to 50% load of the Repower gas turbines. At this load level, approximately 2,500 tpd of CO_2 are captured, out of the approximately 2,600 tpd of CO_2 that is created. While the CCF was designed to capture approximately 4.2 million tonnes of CO_2 per year, the actual expected captured volumes would have depended on the dispatch of the host facility over the year, and over its economic life. As such, the expected volume of captured CO_2 over the life of the Project was 40 – 60 million tonnes, while producing up to 124 TWh of electricity.

10.2 Other Environmental Impacts

To achieve the significant carbon emission mitigations noted above, there are other environmental impacts that were considered as part of the Project.

Land Reclamation

As noted above, the Project would have been installed on brownfield areas immediately adjacent to the existing Genesee facility, which in some areas would have also included the demolition of parts of the original Genesee facility to make way for the Project. During Project construction, the Project would also require construction and materials laydown areas near to the Genesee site – these areas would also be used during operations for turnaround/maintenance periods. At the end of the Project life, these areas would be reclaimed. This reclamation plan would be included in the AUC application when submitted.

Water

The use of water at Genesee was a critical consideration in the design of the CCF. Genesee currently uses the Genesee Cooling Pond (GCP) for all on site water needs and leverages flows from the North Saskatchewan River (NSR) to balance the chemistry within the GCP. These Genesee uses include process cooling (open cooling water), internal cooling processes (closed cooling water) as well as other water services such as firewater. The CCF intended to use the GCP in the same ways. Cooling water is used in the CCF for major and minor cooling loads – the majority of which is in the direct contact cooler (DCC) whereby the flue gas is cooled prior to entry into the absorber vessel. Additionally, significant volumes of cooling water would have been used to cool the intercoolers of the CO_2 compressors as the final product CO_2 is compressed from close to atmospheric pressure up to the 15MPa required for pipeline transportation. GCP water would also have been used for the CCF firewater system, and demineralized GCP water is leveraged for amine solvent dilution, with some blowdown being returned to the cooling pond as is the current practice for the rest of the Genesee facility. All these incremental water uses were considered in the updated environmental permit application, which noted that no further withdrawal from the NSR would be required to support the CCF.

Aldehyde

During the carbon capture process, an aqueous amine solution comes into direct contact with the flue gas to chemical bind the amine and the CO_2 molecules. However, as the amine solution degrades over time and contacts other minor contaminants in the flue gas, some small portion of this amine solution is transformed into other species which are measured at the absorber stack as aldehyde emissions. These net new aldehyde emissions have been incorporated into the environmental permit applications and engineering controls have also been incorporated into the design, by way of water wash equipment near the top of the absorber stack, to minimize these emissions further. Significant air quality modelling was performed as part of the Study to ensure that these emissions would meet or exceed any ambient air quality guidelines, whether such guidelines already existed or were expected to be adopted from other jurisdictions into the Alberta standards.

NOx flowthrough

Nitrous oxide (NOx) emissions were not expected to be impacted by the installation of the CCF. As NOx is produced in the Repower gas turbines, it is subsequently abated using a selective catalytic reduction (SCR) installation downstream of the duct burners in the Repower heat recovery steam generators (HRSGs). This reduces the NOx present in the Repower flue gas, and such reduction is completed upstream of the area of the HRSG where the flue gas is extracted towards the CCF. The specific interactions between NOx and the amines in the CCF system are minimal based on the NO2/NO ratio present in the flue gas, and as such NOx emissions essentially flow through the CCF system with no further mitigation or aggregation.

Footprint

The design of the Project was carefully planned so that the entire footprint of the CCF would have been situated on "brownfield" lands around the existing Genesee facility. This required the Project to include as part of its scope the demolition of large portions of the original coal-fired Genesee units 1 and 2, including the coal handling plant, ash management facilities and electro-static precipitators currently installed at site. The boiler house, which contains the original boiler heat exchangers for coal-fired operation, was expected to remain without demolition to minimize the impact on site operations during construction of the Project.

Wetlands

In addition to focusing the Project footprint on the brownfield area of the existing site, additional care was given to avoid construction in any wetlands in the area. Such construction could have impacted wetland species. To avoid these areas, cooling water pipelines were designed to be routed from the Genesee cooling pond to the process heat exchanger area using angled pipes rather than straight line routing.

11.0 Economic and Social Impacts

Had the Project continued, the projected economic impacts from the Project on the Warburg region and on Alberta as a whole would have been significant. In addition to a $2.3 – 2.5 billion capital investment in Alberta's Capital region the Project was expected to produce significant ongoing economic benefits. Property taxes alone were expected to exceed $5 million per year, with these revenues expected to be invested into the surrounding area starting in the year of Project COD (commercial operations date). Further, between 20 and 30 incremental well-paying engineering, operations and maintenance jobs were expected for the long-term operations of the facility. Construction of the facility itself would have leveraged provincial labour expertise to the extent possible, and local and Indigenous spend would also be critical metrics for project success. Although specific Indigenous spend metrics were not determined, apprentice hours would have been expected to be at least 10% of total Red Seal trade labour hours, and wages would meet or exceed prevailing wage requirements in the region. Approximately 3.0 million on-site labour hours would have been expected to be required for the project, with a peak site workforce of up to 850.

The Project would have required the addition of between 10-20 full-time staff, who would have been required in order to operate and maintain the facility over its lifetime. These staff would require appropriate training both on the operation of the overall Project as well as the technical intricacies of the MHI carbon capture process technology. This training would have contributed to the overall knowledge level of carbon capture facilities within the industry as well as within Alberta specifically. It was expected that these personnel would be sourced from Edmonton and the surrounding area, leveraging knowledge and skills from engineers and technologists in process plants, acid gas recovery facilities and the petrochemical industry local to the Industrial Heartland region.

Capital Power also explored a partnership with local Indigenous group(s), for equity participation in the ownership of the Project.

12.0 Scientific Achievements

Through the execution of the FEED Capital Power and its subcontractors followed scientific processes and methodology typical of a FEED study to hypothesize, test and evaluate the technology and methods that could be deployable at Genesee.

There have been no applied for or obtained patents, published books, journal articles or student theses based on work conducted during the Project. Conference presentations given include overall summary presentations related to the project at the following venues:

- Carbon Capture Canada Conference, Sept 12-14, 2023

  Between September 12th and 14th, the city of Edmonton hosted the Carbon Capture Canada Conference, which brought together over 4,000 attendees, 100 exhibiting companies and more than 150 expert speakers to discuss carbon capture projects across the country. International delegates also joined, including numerous state representatives. The event also included an awards gala where the Project was the recipient of the Carbon Capture Project Award.

- CarbonNEXT Conference, January 2022 and January 2023

  A collaboration between Foresight Canada and Carbon Management Canada, CarbonNEXT is Canada's carbontech commercialization hub, dedicated to driving development and scaling of Canadian carbon capture, utilization and storage ventures. CarbonNEXT leverages Canada's leadership in CCUS technology, including the Project, to support new carbon ventures. Capital Power was asked to participate to give an overview of the Project as well as provide guidance to new technology entrants regarding potential commercialization challenges, as well as high-level lessons learned and areas for technology advancement in CCS technology.

- IPPSA, March 2023

  The Independent Power Producers Society of Alberta (IPPSA) is an industry group which serves as a forum for dialogue amongst Alberta's power producers, including through hosting an annual conference. In March 2023 Capital Power representatives presented the Project as a case study for how CCS could be deployable in the power sector, sharing lessons learned with other industry participants and other proponents considering the potential to deploy CCS technology at other facilities.

- World Petroleum Congress – Carbon Tech Expo, September 2023

  The World Petroleum Congress is an international network of energy professionals across various energy industries and sectors. At the 2023 exposition in Calgary, Alberta, Capital Power representatives had the opportunity to present on CCS and the technology to interested industry participants on learnings, as well as to present a case study on the potential to deploy CCS in the power sector.

- Various Investor Day presentations, 2022-2023 (see Capital Power website[5] for details)

13.0 Overall Conclusions and Project Outcomes

The Study for the Project was a success, proving that carbon capture can be designed for retrofit installation on a natural gas combined cycle facility. Further, achieving a 95% capture rate provides confidence that approximately three million tonnes of CO2 per year, and 40 – 60 million tonnes over the Project life, can be captured from the Repower facility through the installation of a carbon capture facility. This achievement can be met while providing a reliable, dispatchable, baseload power supply to the Alberta electricity grid, with a near-zero emissions intensity.

14.0 Next Steps

At this time, Capital Power has discontinued all work on the Project on account of project economics[6]. Were the Project continuing to proceed, or should it be re-started at some point in the future, the following steps would be taken.

The Project is based on three pillars which are required to be aligned to take the Project from FEED study into execution. These three pillars are:

1. Certainty regarding the commercial structure, funding and "bankability" of the Project, inclusive of mitigating the "stroke of pen" risk to carbon price and policy,
2. Contractual certainty regarding the sequestration capability of nearby sequestration zones, as well as having a commercial agreement in place for the long-term offtake of CO2 including transportation and sequestration,
3. Finalization of any outstanding FEED study components (such as final terms and conditions of an EPC agreement), revisions to the FEED study based on any revisions in technical scope, and capital cost certainty.

The timing of each of these next steps is uncertain and depends on a variety of factors. Commercial structure discussions between Capital Power and the Federal government are ongoing at the time of writing. Although progress has been made regarding an alignment between parties of the desired structure, the details of such an agreement are still required before additional progress can be initiated on the remaining steps.

Once a commercial structure is in place, additional work is required to finalize the details of the CO2 offtake agreement between Capital Power and its sequestration partner. It is expected that this work would not kick off until after the overall Project commercial structure has been finalized, and that this could take between three to nine months.

Although the FEED work provided a lump-sum turnkey EPC price for the Project, this price came with a bid validity period that has since expired. Additional work would be required to reprice this scope, which would also not be kicked off until after the Project commercial structure is in place. It is expected that the repricing effort would take approximately three months. Finally, if the ultimate commercial structure for the Project or changes to the various commercial supports, such as the Investment Tax Credit or other federal funding, implies that improved project economics could result from an updated technical scope, then this updated

[5] Capital Power Website
[6] Capital Power announces first quarter 2024 results

design work would also need to be completed prior to repricing. Depending on the scope of such an update, this work could take anywhere between two to eight months.

15.0 Communications Plan

To date, knowledge-sharing regarding the Study has been limited to solely within Capital Power. However, there have been significant communications activities externally which have included a variety of public-facing information sessions taking various forms. As part of the draft AUC application, a preliminary Participant Involvement Program (PIP) was developed to outline the stakeholder communications plan and activities to date. Preliminary stakeholders were identified as:

- Occupants, residents and landowners within 2,000m of the project area requiring direct notification
- Companies with operations on the Genesee plant site
- Municipal government including elected and unelected representatives from Leduc County and the Village of Warburg
- Local Indigenous communities who have been included in previous notifications for Genesee regulatory applications

In January 2023, Capital Power hosted an in-person meeting at the Genesee Generating Station with several representatives of local First Nations communities to share information about the Project, as well as to discuss a First Nations equity partnership as noted previously. A pre-consultation assessment, prior to the submission of the environmental application, was submitted on February 2, 2023 with the Aboriginal Consultation Office.

In addition, a project-specific information package newsletter was circulated to local Treaty 6 communities on February 22, 2023, including the Paul First Nation, Alexander First Nation, Alexis Nakota Sioux Nation and Enoch Cree Nation 135. Multiple follow-up communications were also circulated in subsequent months to seek out questions or concerns related to the Project.

Regular meetings with municipalities are held between Capital Power and local municipal leaders, including annual or semi-annual “Good Neighbour” touch base meetings with Leduc County and Village of Warburg officials. These meetings have discussed the Project since June 2022, with status updates being provided at each subsequent meeting, including the latest meetings on April 12, 2023 and November 21, 2023.

Most significantly, on April 12, 2023, a community open house was hosted at the Genesee Community Hall to discuss the Project in detail. Presentation materials were provided both by the Project as well as by Enbridge regarding the transportation and sequestration aspects downstream of the Project. While most of the discussion centered around the safety of the subsurface aspects, there were also healthy discussions regarding the air quality modelling results as well as potential job opportunities for local indigenous groups during the construction of the Project.

A variety of materials from these stakeholder communications are available online:

- Genesee Generating Station: Carbon Capture Project Newsletter: February 2023
- News releases including:
  - November 2021 announcement of Memorandum of Understanding between Capital Power and Enbridge
  - June 2022 announcement of partnership with MHI and Kiewit on the FEED study

- December 2022 announcement of limited notice to proceed for the Project

Further stakeholder engagement materials, including open house presentations and other related materials were previously delivered to stakeholders and published online. With the Project's discontinuation, these materials have since been removed from the Capital Power website to ensure messaging is consistent and up to date for all interested parties and stakeholders.

16.0 Literature Reviewed

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