Final Outcomes Report

E0161674 - Nutrien Redwater CCS Project

Prepared for:

EMISSIONS REDUCTION ALBERTA

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Nutrien is a leading global provider of crop inputs and services playing a critical role in helping growers increase food production. Nutrien has completed a Study to assess the technological feasibility, develop the preliminary engineering, and create the overall business case for the difficult-to-abate carbon emissions at the Redwater, Alberta ammonia production facility.

The Nutrien Redwater Nitrogen Operations (RNO) facility currently captures process CO_2 generated from hydrogen production. This CO_2 is compressed and transported through the ACTL for use in Enhanced Oil Recovery (EOR). This Study reviewed three decarbonization alternatives that targeted the remaining unabated emissions, ultimately determining that post-combustion carbon capture was the most technically feasible solution. Engineering deliverables were completed to support a Class 4 capital estimate and decision-making on whether this solution would be economically viable at RNO. Nutrien completed value engineering activities and engaged with multiple experienced carbon capture technology vendors and equipment vendors to develop the best business case possible. Based on the capital and operational cost estimates, Nutrien determined that the project is not economically viable at this time based on Nutrien's key economic assumptions.

Emissions Reduction Alberta ("ERA") contributed $ 2.87 MM CAD to this project through the Carbon Capture Kickstart Program. Carbon Capture Kickstart is intended to lay the groundwork for significant future investments by funding pre-construction studies for facility-specific opportunities. This investment will inspire shared learnings about the economic and emissions reduction potential of this critical technology and will position Alberta and Canada as developing CCUS technologies the world needs. For more information visit https://www.eralberta.ca/funding-technology/carbon-capture-kickstart/.

Agrium Canada Partnership ("Nutrien")'s target site for this project is its Redwater Nitrogen Operations in Redwater, AB. Nutrien is a leading global provider of crop inputs and services. Nutrien operates a world-class network of production, distribution and ag retail facilities that positions us to efficiently serve the needs of growers. https://www.nutrien.com/

International CCS Knowledge Centre ("Knowledge Centre") supported the development, review, and knowledge sharing of the Redwater Carbon Capture Project, working in partnership with Emissions Reduction Alberta and Nutrien. The International CCS Knowledge Centre is a non-profit organization founded in 2016 by BHP and SaskPower to advance large-scale carbon capture and storage projects as a critical means of managing greenhouse gas emissions and achieving the world's ambitious climate goals. The Knowledge Centre provides independent, expert advisory services for CCS projects across heavy-emitting industries. https://ccsknowledge.com/

Hatch Ltd lead the engineering of the Redwater CCS Project through Feasibility A and Feasibility B. Hatch provides professional engineering, technology, and consulting services to the metals, energy, and infrastructure market sectors. Founded more than sixty-five years ago, Hatch's global network of 10,000 professionals work on the world's toughest challenges, spanning 150 countries and approximately US$75 billion of capital projects under management at any given time. Hatch is passionately committed to the pursuit of a better world through positive change. https://www.hatch.com/

Executive Summary

Nutrien, a leading global provider of crop inputs and services, has undertaken a comprehensive study to evaluate the technological feasibility, preliminary engineering, and overall business case for reducing difficult-to-abate carbon emissions at its Redwater, Alberta ammonia operations. In the first phase of the study the three options evaluated included post-combustion capture of flue gas, the replacement of existing steam-methane reforming (SMR) with Autothermal reforming (ATR), and the installation of an ATR to generate Hydrogen for combustion displacing natural gas.

The Redwater operations already captures process CO_2 from syngas for urea production and transport through the Alberta Carbon Trunk Line (ACTL) to sequestration via Enhanced Oil Recovery (EOR). The Study explored options to expand decarbonization efforts and concluded that post-combustion carbon capture of the major equipment on site is the most technically feasible path to decarbonization.

The feasibility engineering development on post-combustion capture resulted in a Class 4 (+30% / -20%) capital and operating estimate, facilitating decision-making regarding the economic viability of the project. Despite value engineering activities, quantitative risk assessment and mitigation, and engagements with experienced carbon capture technology and equipment vendors, Nutrien determined that the project is not currently economically viable based on key economic assumptions.

Through the development of the project key risks were identified leading to the decision to not progress further in engineering development. These risks include:

- No opportunity for incremental revenue from premium pricing for low-carbon fertilizer products,
- Severe schedule risks, putting investment tax credits and incentives at risk,
- Uncertainty in the value and liquidity of carbon credits long term,
- No confirmed carbon capture space compliant with federal ITC requirements,
- Schedule and cost risks associated with building in the heart of an operating facility.

Due to these risks and the outcomes of the economic evaluation of the project no further development work will be completed on this project. The knowledge sharing activities outlined in Section 10 will be completed to disseminate lessons learned throughout the industry and to other key stakeholders.

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Abbreviations and Acronyms

Abbreviation / Acronym	Definition
AACE	Association for the Advancement of Cost Engineering
ACTL	Alberta Carbon Trunk Line
ATR	Autothermal Reformer
BOP	Balance of Plant
CAD	Canadian Dollar
CapEx	Project Capital Cost Estimate
CCS	Carbon Capture and Sequestration
CCUS	Carbon Capture, Utilization and Storage
CI	Carbon Intensity
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CS	Carbon Steel
DM	Demineralized
EOR	Enhanced Oil Recovery
GHG	Greenhouse Gas

Abbreviation / Acronym	Definition
H&MB	Heat and Material Balance
H_2	Hydrogen
Hatch	Hatch Ltd.
HAZID	Hazard Identification
HAZOPS	Hazard and Operability Study
HP	High Pressure
HRSG	Heat Recovery Steam Generators
HSS	Heat Stable Salts
IEA	International Energy Agency
IP	Intellectual Property
IPCC	Intergovernmental Panel on Climate Change
ISBL	Inside Battery Limits
KT	Kepner-Tregoe
LP	Low Pressure
MM	Million
MP	Medium Pressure
MTO	Material Take Off
MVR	Mechanical Vapor Recompression
N_2	Nitrogen
NDMA	N-Nitrosodimethylamine
NG	Natural Gas
O_2	Oxygen
OpEx	Operating cost estimate
ORP	Oxidation-reduction potential
OSBL	Outside Battery Limits
PCC	Post Combustion Capture
PD	Positive Displacement
PDP	Process Design Package
PFD	Process Flow Diagram
P&ID	Piping and Instrumentation Diagram
PSIG	Pounds per square inch gauge
QRA	Quantitative Risk Assessment
RAM	Reliability, Availability, and Maintainability
RNO	Redwater Nitrogen Operations
SCR	Selective Catalytic Reduction
SDG	Sustainable Development Goals
SDS	Safety Data Sheet
SG&A	Sales, General and Administration
SMR	Steam Methane Reformer
TEG	Tri-Ethylene Glycol
TIC	Total Installed Cost
Tonnes	Metric Tonnes
tpd	Tonnes per day
tpy	Tonnes per year
TRL	Technology Readiness Level
USGPM	US Gallons per Minute
VAT	Value Added Tax
VO	Value Opportunity

1 Project Description

1.1 Introduction & Background

Nutrien is a global agricultural solutions provider with a unique platform for generating growth and value. Nutrien is a leading provider of crop inputs and services. We operate a global network of production, distribution, and ag retail facilities that positions us to efficiently serve the needs of growers. As part of our purpose-driven culture, we strive to uphold the highest safety standards, develop respectful and positive relationships, promote responsible procurement, and contribute positively to society as a whole. Feeding the Future is our purpose, a call to action, and the reason we come to work each day. While rooted in the challenge of feeding nearly 10 billion people by the year 2050, it’s about more than food production. It means nourishing and enabling life more broadly to sustain our people and planet.

Nutrien’s Redwater Nitrogen Operations (RNO), North of Edmonton, is an integrated fertilizer production complex with the capacity to produce 951,000 tonnes of ammonia per year (Nutrien, 2023). The ammonia is produced using natural gas and Steam Methane Reforming (SMR) to produce Hydrogen which is used in the Haber-Bosch process to produce ammonia. Secondary products include urea, urea ammonium nitrate (UAN), ammonium nitrate (AN), and ammonium sulphate (AS). In 2020, 40% of the annual CO_2e production from the RNO facility was captured and used for urea production or sequestered through the Alberta Carbon Trunk Line (ACTL). The target of this study is direct emissions, including low CO_2 concentration flue gases, which are difficult to abate.

Preliminary work by Nutrien identified three potential carbon capture options for the facility. This study first undertook a trade-off assessment, referred to as Feasibility A, to identify the option to be carried forward for further engineering development. The options included: (1) post-combustion carbon capture from the flue gas from the reformer stack(s), (2) installation of an auto-thermal reformer (ATR) to replace the existing steam-methane reformer (SMR) with capture of the CO_2-rich process gas stream, and (3) installation of auto-thermal reforming with CO_2 capture to generate hydrogen fuel to replace methane as a heat source. Option 1 would involve the installation of an amine-based post-combustion carbon capture system. For Option 2, the current SMR process would be replaced by ATR technology to produce a higher concentration CO_2-rich stream for capture, thus greatly reducing the volume of flue gas. Option 3 would install ATR technology as a separate hydrogen production unit, with the resulting hydrogen replacing methane as a heating fuel source for the facility.

The results from these studies resulted in the determination that post-combustion flue gas capture is the most technically feasible solution of the three proposed options. The second phase of the study, referred focused on building the business case for this technical option, including completing a Value Optimization workshop to identify project opportunities that would improve overall capital expenditures of the project.

1.2 Project Objectives

Project objectives, as outlined at the start of the project, are as follows:

1. Develop a point of view for the technology and process options available for carbon capture at Redwater.

2. Develop the business case to justify the responsible deployment of capital, by:
    a. Concept screening study, and preliminary technology investigation of three CCS options.
    b. Quantifying technology requirements and site limitations for the deployment of carbon capture technologies.
    c. Confirm process options and advance the preliminary concept to a point that Nutrien can justify proceeding to subsequent phases of the project.
3. Develop collaborations and partnerships, with:
    a. Industry, to complete the sequestration value chain (transmission and permanent sequestration)
    b. Government and academia, for knowledge development of CO_2 capture technologies to further the overall status of carbon capture in Alberta.

2 Project Work Scope – Feasibility A

2.1 Project Scope and Boundary Limits

2.1.1 Option 1

Option 1 involved CO_2 capture from the SMR flue gas stacks located in Plant 01 and Plant 09 of the facility. Combined flue gases from each of the two sources would be collected and transported by ducts to the carbon capture facility. The design of the capture facility is approx. 2,100 – 2,200 tpd of CO_2, including the CO_2 captured from the SMRs and additional flue gas generated from the steam boiler supplying the CCS unit. The CCS unit is to be designed for a minimum 30% plant turndown, this is to ensure the operation of CCS unit when flue gas from Plant 01 is the only feed to the CCS unit.

For the purposes of the study the carbon capture facility design, including flue gas pretreatment and downstream CO_2 compression and dehydration, is provided by licensor. Hatch designed the flue gas transportation from the stacks to the Carbon Capture and Sequestration (CCS) unit battery limit, flue gas pressure boosting and Balance of Plant (BOP) which includes all the utility and offsite systems.

The overall plant would have the following processing units:

- Flue gas collection and transportation of low-pressure gas (by Hatch).
- Flue gas pressure boosting (by Licensor).
- Flue gas conditioning or pretreatment (by Licensor).
- CO_2 recovery via amine absorption and regeneration (by Licensor).
- CO_2 compression and dehydration (by Licensor).
- CO_2 transportation to an offsite location (Not in scope and by Others).
- Utility systems (by Hatch).

2.1.2 Option 2

Option 2 studied the replacement of the SMR units with auto-thermal reforming (ATR) technology. ATRs produce a high concentration CO_2 stream, instead of low concentration combustion flue gases, that is more efficient to capture for sequestration. H_2 production from the unit may also be oversized to provide H_2 as a fuel source for the ATR if target overall CO_2 recovery of the facility is not achieved with the replacement of the SMR alone. The facility capacity is based on the total H_2 production requirements of the existing Plant 01 and Plant 09 ammonia synthesis units.

The scope for the study involves the SMR unit replacement with an integrated ATR and downstream syngas purification including CO_2 capture. The project scope also includes an Air Separation Unit (ASU) to supply oxygen to the ATR unit.

It is envisaged that Option 2 will include all new equipment, with an alternative option to check the hydraulics and catalytic performance of the existing units with the new flows as a future optimization engineering exercise.

The overall plant is envisaged to have the following processing units:

- ASU (by Others; Licensor to include ASU in CapEx estimate).
- Pre-Reformer (by Licensor).
- Integrated Autothermal Reformer Unit (ATR) (by Licensor).
- Fired Heater (by Licensor).
- Shift Unit (by Licensor).
- CO_2 Capture Unit (by Licensor).
- CO_2 compression and drying (by Hatch).
- Supporting Units, Utilities & Offsites or Balance of Plant (by Hatch).
- CO_2 transportation to an offsite location (Not in scope and by Others).

2.1.3 Option 3

The scope of Option 3 starts with the receipt of natural gas and fuel gas mixture from the existing Plant 01 and Plant 09 source and terminates with hydrogen (H_2) at the required specification and conditions to be used as fuel in the existing SMR unit. High concentration CO_2 from the ATR is captured and H_2 production from the proposed facility will replace the fuel gas feed to the primary reformer for heating. The facility capacity is based on the heating duty required to replace the current fuel source.

The scope for the study involves the new ATR unit and associated downstream shift, CO_2 capture, and syngas purification unit. The project scope also includes an ASU to supply oxygen to the ATR unit.

Option 3 would include all new equipment, with an alternative option to check the hydraulics and catalytic performance of the existing units with the new flows as a future optimization engineering exercise.

The overall plant is envisaged to have the following processing units:

- ASU (by Others; Licensor to include ASU in CapEx estimate).
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- Shift Unit (by Licensor).
- CO_2 Capture Unit (by Licensor).
- CO_2 compression and drying (by Hatch).
- Supporting Units, Utilities & Offsites or Balance of Plant (by Hatch).
- CO_2 transportation to an offsite location (Not in scope and by Others).

2.2 Risk Analysis

A risk analysis was conducted to review the technical and business risks associated with the various scopes and technology, and mitigation measures to reduce the severity and likelihood of its occurrence. The major risks identified for each option are listed in the sections below.

2.2.1 Option 1

- **Presence of flue gas contaminants:** Various flue gas impurities including NO_x and SO_x species in flue gas can increase the oxidative degradation of the amine and build-up of Heat Stable Salts (HSS), causing an inefficiency in operation and higher solvent consumption/makeup leading to increasing the operating cost. Routine flue gas testing at site is conducted for environmental reporting purposes. A detailed flue gas characterization for feed to an amine-based carbon capture unit will require additional testing to analyze other components that can impact the amine solvent.
- **Emissions from CO_2 absorber:** Depending on the proprietary solvent used in the absorption process, different type of nitrosamines and other amine degradation products can be released to the atmosphere from the absorber along with the CO_2 depleted flue gas. NDMA, for example, is toxic as defined in Section 64 of the Canadian Environmental Protection Act and is likely to be carcinogenic at relatively low levels (Environment Canada, Health Canada, 2001).
- **Corrosion in equipment and piping:** Corrosion is accelerated in the presence of oxygen and contaminants in the flue gas that can react with amine to form corrosive compounds. Inappropriate material selection, operation at high temperature and presence of high concentration of CO_2 in the amine solution leading the solution pH to drop can also increase corrosion.
- **Plant reliability:** There is no sparing of pumps incorporated in the Feasibility A design, which can reduce plant reliability.
- **Absorber and quencher tower design:** The selection of a rectangular tower design for the Absorber and Quencher presents potential issues with the mechanical integrity of square joints over time, especially after repeated thermal cycles. An alternative option would be to use cylindrical towers, which may require the use of two absorber and quencher trains instead of just one.
- **Transportation and fabrication:** There are potential challenges associated with transportation of absorber and quencher columns, in addition to the on-site fabrication required for these columns in rectangular design.
- **Construction access road:** These larger equipment pieces may also be too big to transport underneath the existing pipe racks within the Redwater facility.
- **Increasing demand for carbon capture technology:** As industries progress carbon capture solutions to mitigate their environmental impact, the surge in demand may create bottlenecks and limitations in lead times and design capacity.

2.2.2 Option 2

- **Living Out Allowance (LOA) costs:** due to the number of units and complexity of integration with the existing Plant 01 and Plant 09 systems, the number of personnel on-site during construction will be much higher for Option 2 compared to the other options. Living out allowance and accommodation during construction has not been considered in the Feasibility A cost estimate.

- **Construction access road:** Option 2 has several large pieces of equipment (ATR, CO_2 absorber and stripper) and limited available plot area for construction access. Therefore, this option is likely to require an additional access road to the new facility to allow for more flexibility during construction.
- **Limited ATR licensor:** If this option is selected, a technology licensor selection will need to be conducted. Market demand for ATR technology licensors may limit technology selection and impact the project execution schedule.
- **Replacement of SMR with ATR:** In Option 2, the SMR process is replaced with an ATR process. This presents higher risks to the existing ammonia production at the Nutrien Redwater site due to the replacement of a core process and extensive utility integration with the existing utility systems. Therefore, there is a higher risk of negative cascading impacts to the production should there be delays or issues with the implementation of the ATR process.
- **Firewater System:** The current design assumes the existing firewater system is adequate for the requirements of this option. However, due to the complexity, number of equipment, and extensive plot area, there is a risk the existing fire water system on-site is not adequate for the capacity of this option.

2.2.3 Option 3

- **Burner conversion:** Option 3 targets to replace the natural gas fuel of the SMR fired heaters with hydrogen. Although the burner vendor has indicated the burners should be capable of switching fuel sources, there is a risk that further investigation into the burners yields unsatisfactory results and the burners of the SMR fired heater must be replaced. The cost to modify or replace burners has not been included in the cost estimate at this stage.
- **Construction access road:** Option 3 has several large pieces of equipment (ATR, CO_2 absorber and stripper) and limited available plot area for construction access. Therefore, this option is likely to require an additional access road to the new facility to allow for more flexibility during construction.
- **Limited ATR licensor**: If this option is selected, a technology licensor selection will need to be conducted. Market demand for ATR technology licensors may limit technology selection and impact the project execution schedule.
- **Firewater System:** The current design assumes the existing firewater system is adequate for the requirements of this option. However, due to the complexity, number of pieces of equipment, and extensive plot area, there is a risk the existing fire water system on-site is not adequate for the capacity of this option.

2.3 Project Achievements

Feasibility A resulted in a complete AACE Class IV factored estimate for all three options. The estimated CapEx (project capital cost estimate) and OpEx (operating cost estimate) outcomes developed during the Study are presented in Table 1.

Table 1 Feasibility A Estimates

Case description		Option 1: With SCR[1]	Option 1: Without SCR[1]	Option 2	Option 3
CapEx (CAD, Q2 2023)					
Direct Cost	MMCAD	$ 363,274,620	$ 357,378,620	$ 1,092,327,893	$ 520,049,240
Indirect Cost	MMCAD	$ 138,412,850	$ 136,607,530	$ 337,806,958	$ 160,256,944
Total Base Cost	**MMCAD**	**$ 501,687,470**	**$ 493,986,150**	**$ 1,430,134,851**	**$ 680,306,184**
Contingency[2], Escalation and Owner's Cost	MMCAD	$ 209,498,910	$ 206,142,300	$ 614,861,759	$ 293,246,742
Total Installed Cost	**MMCAD**	**$ 711,186,380**	**$ 700,128,450**	**$ 2,044,816,610**	**$ 973,552,925**
OpEx (CAD, Q2 2023)					
Total OpEx[3]	**CAD/y**	**$ 47,249,411**	**$ 46,090,555**	**$ 73,736,627**	**$ 83,890,850**
Variable Costs	CAD/y	$ 23,407,673	$ 22,558,441	$ 13,050,482	$ 48,082,748
Direct Fixed Costs	CAD/y	$ 16,729,878	$ 16,530,834	$ 40,237,979	$ 26,072,572
Allocated Fixed costs	CAD/y	$ 7,111,860	$ 7,001,280	$ 20,448,166	$ 9,735,529

Notes:

1. CapEx and OpEx are estimated for two cases: Base case includes Selective Catalytic Reduction (SCR) whereas sensitivity case is without SCR with NO_2 and NO levels in the flue gas based on the stack test results.
2. Contingency based on standard recommended cost estimating contingency of 30% given the level of accuracy.
3. OpEx estimated based on TIC including 30% contingency.

Feasibility A successfully fulfilled the objectives of this phase in supporting the decision making required to develop a point of view for the technological opportunities for carbon capture at Redwater and completed the concept screening study needed to build a business case for decarbonization. A pre-FEED level of evaluation was completed for all three technical options.

2.4 Analysis of results

2.4.1 Option 1

A pre-FEED level of development for post-combustion carbon capture of flue gases from SMRs Plant 01 & 09 and additional flue gas from steam generation in the CCS plant was conducted to reduce the carbon footprint at the Nutrien Redwater facility with the following findings:

- Option 1, as per the inputs provided by the Technology Licensor for the carbon capture area and the design of BOP to support the carbon capture unit, represents a feasible option.

- Proposed plot area of 176,420 ft^2/ 16,400 m^2 is deemed sufficient for Option 1.
- CO_2 recovery of 95% is expected to be achieved capturing 2,047 tpd CO_2 including the CO_2 captured from new boiler flue gas.
- Net reduction of 90% of in scope CO_2e emissions is achieved.
- Total capital cost estimated (including contingency, escalation, and owner's cost) is $711 MMCAD (including SCR) and $700 MMCAD (excluding SCR).
- Total annual operating cost estimated is $47 MMCAD (including SCR) and $46 MM CAD (excluding SCR).

2.4.2 Option 2

A pre-FEED level of development for the replacement of the existing Plant 01 and Plant 09 SMR with an ATR process was conducted to reduce the carbon footprint at the Nutrien Redwater facility with the following findings:

- Option 2, as per the inputs provided by the Technology Licensor for the ATR process and the design of BOP to support the ATR unit, represents a feasible option.
- The plot area requirement for Option 2 is 707,318 ft^2 / 65,712 m^2. Proposed plot area is not sufficient for Option 2. However, it was determined there is sufficient plot area available for this option within the Nutrien Redwater site boundary limits.
- Approximately 4,873 tpd CO_2 is captured in the carbon capture unit, with net 1,671 tpd CO_2 sent to pipeline for transportation to sequestration on top of existing utilization and export.
- Net reduction of 90% in overall CO_2 emissions is achieved.
- Total capital cost estimated (including contingency, escalation, and owner's cost) is $2,044 MMCAD.
- Total annual operating cost estimated is $74 MMCAD.

2.4.3 Option 3

A pre-FEED level of development for the addition of an ATR process to produce H_2 as fuel for the existing Plant 01 and Plant 09 SMR fired heaters was conducted to reduce the carbon footprint at the Nutrien Redwater facility with the following findings:

- Option 3, as per the inputs provided by the Technology Licensor for the ATR process and the design of BOP to support the ATR unit, represents a feasible option.
- The plot area requirement for Option 3 is 371,150 ft^2 / 34,481 m^2. Proposed plot area is not sufficient for this option. However, it was determined there is sufficient plot area available within the Redwater site boundary limits.
- Approximately 1,873 tpd CO_2 is captured in the carbon capture unit and sent to pipeline for transportation to sequestration.
- Net reduction of 90% in overall CO_2 emissions is achieved.
- Total capital cost estimated (including contingency, escalation, and owner's cost) is $974 MMCAD.
- Total annual operating cost estimated is $84 MMCAD.

2.4.4 Options Analysis

Based on the technical deliverables of Feasibility A, an options ranking workshop was conducted to rank the three options evaluated. A summary of the criteria used for ranking, respective weightage of each criterion and results from the ranking workshop is outlined in Table 2. Any criteria that was scored equally among all three options was dropped to a 0% weightage. These criteria are still included in Table 2 to show all factors that were considered in the evaluation.

Table 2 Options Ranking Criteria

Criteria		Weight	Weighted Value		
			Option-1	Option-2	Option-3
1.	**Process Performance**				
A	Target or desired CO_2 Recovery Achieved	0%	0.0	0.0	0.0
B	CO_2 to Sequestration	2%	0.6	1.6	1.0
C	Raw water import	2%	2.0	0.2	1.0
D	Turndown Capability	4%	4.0	0.4	0.4
E	Plant availability/reliability				
E.1	*Shutdown frequency and duration*	3%	2.4	3.0	3.0
E.2	*Complexity/risk of unplanned shutdown*	3%	2.4	0.9	1.5
E.3	*Catalyst and chemical availability*	1%	0.8	1.0	0.3
2.	**Technology Risks**				
A	Risk				
A.1	*Technology performance*	0%	0.0	0.0	0.0
A.2	*Level of deviation from standard design*	0%	0.0	0.0	0.0
A.3	*New Process/Operating Conditions or New Chemicals/Catalysts*	0%	0.0	0.0	0.0
A.4	*Process integration (Impact on existing operation)*	15%	15.0	1.5	7.5
3.	**Costs**				
A	Capital Costs	15%	15.0	1.5	12.0
B	Total Operating Cost				
B.1	*Power import*	5%	5.0	2.5	0.5

Criteria		Weight	Weighted Value		
B.2	*Natural Gas import*	5%	1.5	5.0	0.5
B.3	*Catalysts and chemicals, Operating consumables, waste disposal*	3%	1.5	3.0	2.4
B.4	*Maintenance and insurance*	5%	5	0.5	4.0
B.5	*Staffing*	3%	2.7	3.0	0.3
4.	**Project Execution**				
A	Logistics and modularization	3%	0.3	2.4	2.4
B	Shutdown requirement for tie-in	2%	2.0	1.0	0.2
C	Business model flexibility	2%	0.4	2.0	2.0
D	Ease of Integration with existing facility	3%	3.0	0.3	1.5
E	OSBL integration (substation requirements)	1%	0.8	0.1	0.5
F	Project Schedule and demolition requirements.	10%	2.0	5.0	5.0
G	Start-up complexity	6%	6.0	0.6	0.6
5.	**Environmental and safety**				
A	Gaseous emissions	2%	0.2	2.0	2.0
B	Effluent Discharge	2%	1.0	0.6	1.0
C	Solids disposal	2%	2.0	0.2	1.0
D	Process Safety	1%	0.7	0.5	0.3
Overall Score					
Total Weighted Score		**100**	**76.3**	**38.8**	**50.9**

Option 1 is preferred based on a number of key aspects evaluated:

- Lowest CapEx.
- Lowest OpEx.
- Lowest plot plan requirements (and potential to further reduce the required plot area when switching to water cooling).
- Lowest level of process integration.
- Highest ranking from the Options Ranking workshop.
- Fit the available footprint on the brownfield site
- Lowest level of Plant downtime to integrate the new equipment into the existing facility

From a business perspective, Options 2 and 3 in theory have flexibility to provide additional H_2 and N_2 to the existing facility by pre-investing capital and oversizing production from those options. This may present debottlenecking opportunities, resulting in additional ammonia production or further reduction in greenhouse gas emissions by replacing imported natural gas or power. Option 1 would be limited by the fact that cost (CapEx and OpEx) will start to disproportionally increase at capture rates higher than 95%. Some economy of scale benefit is still possible for Option 1 in that power import may be replaced by increasing the size of the boiler to produce additional steam for power generation, through use of either a saturated steam turbine (which has a lower efficiency) or by superheat of the steam followed by a conventional turbine.

Option 2 will also present OpEx and sustaining CapEx savings opportunities from decommissioning of the existing SMRs which have not been accounted for in the current analysis. Having said that, the high CapEx requirement for Option 2 is expected to far exceed any such sustaining CapEx reduction opportunities.

Nitrogen, oxygen, or hydrogen import from a third-party site may be considered as alternatives to Options 2 and 3. This would eliminate many of the brownfield integration penalties of having to construct within a limited available plot space on site and the associated long interconnecting pipelines, although significant product pipelines will still be required to transport any supply gas to site.

It can be concluded that from a pure carbon mitigation objective of achieving ~90% CO_2 mitigation as set out at the start of the project, Option 1 will be the most economical option. On the other hand, Options 2 and 3 may present additional business opportunities that may be considered in Nutrien's overall economic evaluation. They are also likely to have more flexibility in shifting CapEx to OpEx through gas supply by third parties, thereby reducing Nutrien's investment requirements.

2.4.5 Financial Analysis

Table 3 Feasibility A Economic Summary

Parameter	Units	Option 1	Option 2	Option 3
Technical and Performance				
CO_2 captured for sequestration[1]	tpd	2,047	1,671	1,873
CO_2 recovery	%	95%	99%	99%
Economics				
Capital Expense	Millions CAD (P50-P90)	\$765 - \$1,091	\$2,018 - \$2,956	\$939 - \$1,358
Operating Expense	CAD/tonne CO_2	\$65 - \$75	\$125 - \$148	\$125 - \$140

Notes:

1. Total CO_2 to sequestration, including emissions generated by the capture plant and auxiliary boilers.

2.5 Feasibility A Conclusion and Recommendations

Following completion of the tasks and technical deliverables of Feasibility A, additional lines of inquiry to strengthen the project deliverables were identified. Nutrien determined that additional information was required to properly build the business case for the options studied in Feasibility A before moving forward to selecting one option for Feasibility B. These studies are:

- Inclusion of a co-generation unit for heat and power in the flue gas capture plant in Option 1.
- Technical requirements of replacing fuel source of onsite direct fired emissions with hydrogen, from natural gas.

The results from these studies solidified the determination that post-combustion flue gas capture is the most technically feasible solution of the three proposed options as well as the most economically viable option.

Although all three options were not economically viable according to Nutrien's internal assumptions and hurdles, it was recommended to progress into Feasibility B with Option 1 Flue Gas Capture. The scope of Feasibility B was to build the business case for the project through further engineering development, discussions with potential funding partners, value optimization, and qualitative risk assessment.

2.6 Additional Studies

2.6.1 Combined Heat and Power

For the Feasibility A design, a steam boiler was considered as the base case to meet the heat requirements for the Post-Combustion Capture (PCC) plant. Nutrien previously conducted a separate study for a cogen plant to supply some of the power and steam requirements of the existing site. As part of this study, results of those two separate projects were combined to determine if the integrated flow scheme brings an overall benefit. Instead of the boiler, the cogen was sized to fully supply steam to the existing facility and the PCC, and power to the PCC system while also supplying some of the existing facility's requirements. Also, for this case, the flue gas from the cogen unit will be sent to the PCC for additional CO_2 capture.

Multiple gas turbines configurations have been identified and developed as suitable to meet the power and steam demands of the existing facility as well as the additional demands of the PCC equipment. All of the options evaluated result in similar reduction of CO_2 emissions when compared to using an auxiliary boiler and grid power, from a base case of 771 tpd to a range of 273-324 tpd. Flue gas flow rates and CO_2 concentrations varied, and the impact of this variance on the cost and performance of the PCC facilities have been considered as part of the overall cost, electricity production, and emissions.

The cogen flue gas represents a higher percentage of the total flue gas feed to the PCC unit (48% - 62%) compared to the LP steam boiler flue gas (18%) when compared to the Base Case. This is a benefit to the integrated cogen + PCC configuration as the turndown required for the PCC unit is less severe when one of the flue gas sources is down, allowing a target design turndown of 40% instead of 30%.

An increase in the P50 TIC of 248 MMCAD from Option 1 in Feasibility A was estimated and used in the economic evaluation, with recommendations to get further vendor details and specifications in Feasibility B. Despite the increase in capital cost, an incremental economic evaluation was completed and determined that the addition of a cogen plant to the base PCC plant was an overall net benefit to the project due to the increase in CO_2 captured and benefit of low-carbon power and steam to the Redwater site. A summary of these economic results is in Table 4.

Table 4 Economic Evaluation of Combined Heat & Power Study

Incremental Capital Cost (MMCAD)	Incremental Operating Expense (MMCAD/y)	NPV of Cogen (MMCAD)
$ 248	($ 12)	$ 77

The inclusion of a cogeneration unit with HRSG was taken as the base case for Feasibility B.

2.6.2 Hydrogen to Replace Natural Gas as Fuel

The study looked at fuel-switching or the replacement of natural gas fuel with hydrogen in key equipment:

- NH_3 II - Reformer Fuel (LP Gas)
- NH_3 II (Plant 09) Startup Heater
- NH_3 I - Reformer Fuel (LP Gas)
- NH_3 I (Plant 01) Startup Heater
- Nitric Acid – Tail Gas Stack
- Utilities - Boiler #1
- Utilities – Boiler #2
- Utilities – Boiler #3
- Utilities – NH_3 Flare

After completing the review of the existing equipment, conversion appears to be technically feasible, as replacement burners have been identified for key equipment which are capable of operating on 100% H_2 fuel. While significant uncertainty remains, this option has a significantly lower CapEx, assuming imported Hydrogen, when compared to the post-combustion CCS.

However, there are significant risks presented by H_2 fuel gas as a result of the combustion characteristics including higher flame temperature and propagation characteristics. Risks to the process include:

- Process performance risk for process heaters and reformers resulting from the conversion of existing equipment to Hydrogen.
- Current condition of equipment, metallurgical characteristics, remaining useful life, and possible impacts of hydrogen conversion on useful life.
- Limited experience converting equipment to use Hydrogen as a fuel.
- Increased rate of NO_x in exhaust gas with use of Hydrogen as fuel, both in a blend with natural gas or 100% H_2.

Furthermore, while the initial CapEx estimate is low, the high operational costs, notably the price of hydrogen fuel, is expected to result in significantly increased overall project costs and the capital cost estimate is not encompassing of all the elements involved and is likely to increase significantly once all unknowns are addressed.

The cost of hydrogen has not been predicted in this study but is expected to be significantly higher than natural gas. For reference, during the previous phase of study the CapEx estimate for producing 1,105 MMBtu/hr of net blue hydrogen to the Plant 01 and Plant 09 SMR's was $997 MMCAD and the OpEx was $9 CAD /MMBTU. This cost may be reduced somewhat in a greenfield setting with additional layout optimization but is representative.

Hydrogen fuel-switching appears technically feasible based on the evaluation of the burners. There is insufficient information to confirm the changes in process operating parameters and equipment life will fit within allowable ranges and existing expectations. From a process risk perspective, PCC is a relatively less invasive bolt-on process which does not introduce additional risk to existing equipment performance. Fuel-switching was not recommended for continued evaluation in Feasibility B.

2.6.3 Logistics and Transportation Study

The Logistics Study investigated the options of shipping equipment to various ports identified as potential shipping envelopes, assessing their capabilities, and developing a high-level route survey for the port that Hatch determined would best service the project. Hatch's Logistics Team has determined, from a cost and service perspective, the two most efficient entry ports into Canada for oversize freight from Asia. These ports are the Port of Vancouver or the Port of Prince Rupert, both located in British Colombia (BC). A detailed logistics execution plan will need to be developed to describe how the overall logistics activities will be performed. The Logistics Execution Plan will outline the logistics approach for the Nutrien Redwater Carbon Capture Project and will provide a framework for the transport of materials and equipment from vendors located overseas and within North America.

2.6.4 Modularization and Constructability Study

A Modularization Study was conducted to confirm if the challenges related to cost, schedule, and labour availability that increases cost and schedule uncertainty could be mitigated through a modularized execution strategy. The results of this study indicate that parts of the facility could be assembled in a module yard located in Alberta, transported to site and installed. Using this approach, the established module yards reduce uncertainties regarding cost and schedule, labour availability and productivity as compared to work executed at site.

A module vs. stick build cost trade-off study was completed to determine the savings the modularization strategy could bring to the project. The following base assumptions were used:

- Module yard labour rate of $130 per hour and productivity multiplier factor of 1.0
- Site labour rate of $175 per hour and productivity multiplier factor of 1.60
- 15% increase to structural steel by modularization

A total of 20% of site hours were estimated to be removed, approximately 125,000 hours and a savings of $11.4 million.

A Constructability Study was prepared with the purpose of developing the draft construction sequence during the early stage of the project planning process. It has been developed to allow the project stakeholders to determine their paths of development during the next stage of project development. Some of the risks identified as part of this study included: potential delays due to long lead items delivery, limited site footprint, parallel installation of compressor unit and process building as well as availability of laydown and subassembly areas.

3 Value Optimization

From the Value Optimization workshop, twenty possible cases combining various flue gas sources, steam generation units, and column configurations were defined. This included nine cases in which the flue gas from Plant 01 is not processed in the carbon capture unit. Hatch performed a preliminary analysis on the cases, and it was decided to remove the cases where Plant 01 flue gas is not processed and cases where the flue gas processing capacity is similar. In total, four opportunities were selected for further investigation in trade-off studies.

Two primary design cases were used for the trade-off studies, shown in Table 5.

Table 5 Design Cases for Trade-off Studies

Flue Gas Property	Units	Case 1A – Aux Boiler	Case 2B – Cogen
		Feasibility A Capacity	Additional Studies Capacity
Temperature	°F	399	383
Pressure	psig	0	0
Nominal Flowrate	lb/hr (tpd)	1,461,903 (15,915)	2,396,356 (26,087)
CO_2 in flue gas	lb/hr (tpd)	197,929 (2,155)	266,483 (2,945)

3.1 Absorber Tower Design

3.1.1 Design Basis

The post-combustion carbon capture design in Feasibility A was estimated based on a single rectangular quencher/absorber tower with an auxiliary steam generation boiler. However, a rectangular column design is not preferable due to the challenges associated with on-site field fabrication at the Redwater location and concerns over the mechanical integrity of squared joints during long-term operation. In Feasibility B, a trade-off study was completed to investigate the cylindrical column design including a one-train and two-train configuration. A two-train configuration would be beneficial for transportation to site and can over more flexible operation and lower turndown rates. The following options were evaluated in the trade-off comparison:

- Rectangular columns (Feasibility A basis) vs. cylindrical columns
- 1 train (Feasibility A basis) vs. 2 trains for both the quencher and absorber
- Evaluation of the feasibility of compressing the flue gas to a higher pressure to process the flue gas in a single cylindrical column

Two design cases were used in this trade-off study, shown in Table 5, above.

3.1.2 Results and Recommendation

3.1.2.1 Rectangular vs Cylindrical Columns

Feasibility A included a rectangular quencher and absorber. The installed cost of the rectangular quencher and absorber columns is comparatively high due to onsite fabrication. The large dimensions of the rectangular columns also meant that significant, large cranes are needed to lift the pieces of the column into place. If fabricated onsite, manpower and labour costs would also contribute to a much higher total installed cost.

It was recommended at end of Feasibility A to investigate cylindrical columns which can be shop-fabricated in a controlled environment and transported to site at a lower cost. Although the maximum allowable transportation limits to the Redwater site limit the size of columns that can be considered, the savings from shop-fabrication vs. field-fabrication is expected to vastly outweigh the potential cost of adding second process train.

There are also added advantages of cylindrical columns. The Plant 19 site, selected as the location for the post-combustion capture unit, has significant space constraints. The rectangular columns require an assembly and laydown area which is not available close to the installation location. Having an assembly and laydown area away from the installation site will add additional cost for transportation and double handling. The field-fabrication of the rectangular columns will only be able to start after the completion of the foundations, which could lead to a longer construction schedule. Whereas the cylindrical columns could be fabricated in the shop in parallel with the foundation work at site, resulting in overall construction schedule savings while minimizing site labour hours.

It was decided that the Project would proceed with cylindrical columns. The rest of this trade-off study reflects this decision and is based on cylindrical columns for the quencher and absorber.

3.1.2.2 Transportation Limits for Columns

A logistics study was conducted by Mammoet Canada Western Ltd. to determine the maximum allowable transportation limits for cylindrical vessels to the Redwater site by road. The maximum transportation limits were as follows:

- Maximum vessel weight should be 550 tonnes (excluding saddles and transport steel)
- Length/height of the vessel should be 45m to 65m
- Vessel diameter (ID) should not exceed 10m

3.1.2.3 2 Trains vs. 1 Train Configuration

The technology licensor provided dimensions and weight of each vessel to capture 95% of the total CO_2 flow rate in each design case (Table 5, above) in a two-train configuration, and optimize dimensions to capture maximum CO_2 in a single train configuration while maintaining the dimensional limits specified in Section 3.1.2.2.

A third case was also provided (Case 2B – Supplementary) in which the flooding approach (FA) was increased to try to meet the vessel transportation weight limit of 550 tonnes (606 short tons). In this supplementary case there are additional power requirements in the blower, quencher circulation pump, and 1st wash water pump due to increased flooding approach.

The post-combustion carbon capture unit is not capable of processing 100% of either design case in a single-train maximum diameter cylindrical quencher, absorber and regenerator configuration. Given both options will require two trains to capture the full flue gas amount from either the boiler or cogen unit, there is no significant capital cost advantage for the boiler option.

Selecting Case 2B – Cogen as the design case and cylindrical columns for the absorber and quencher, three configurations were considered:

- Option 1: 1 quencher, 1 absorber
- Option 2: 2 quenchers, 2 absorbers
- Option 3: 2 quenchers, 1 absorber

A major contributor to the differences in the three configurations is the carbon tax paid due to not capturing all CO_2 in the flue gas in the single absorption column cases. The CO_2 emitted in Option 1 and 3 increase by 951tpd and 312tpd, respectively, compared to the dual-train configuration in Option 2.

Although the configuration with 2 quenchers and 2 absorbers had the highest TIC, the significant savings in the net total annual operating costs due to increased generation of carbon tax credits makes this option the preferred design to carry forward.

3.1.2.4 Sensitivity for flue gas compression

Two sensitivity cases were analyzed to investigate the possibility of compressing the flue gas to reduce the volume going through the absorber, increasing the absorber capacity:

- Reducing the flue gas volume by half
- Increasing the Flooding Approach (FA) and reducing the flue gas volume such that 100% of the flue gas can be processed through the absorber

In both configurations there would be two quencher columns and one absorber column with flue gas compression downstream of the quencher.

Table 6 Flue Gas Compression

Description	Unit	Reduce flue gas volume by half	Single train, increased FA
Absorber Inlet Pressure	psig	15.0	3.1
Additional Power for Compression	MW	24	6
Additional Cooling Duty	MMBTU/hr	98	22

Due to the additional power, cooling duty, and associated size increase of compressor and cooling tower, compressing the flue gas was not considered as a practical option.

3.2 Air vs. Water Cooling

3.2.1 Design Basis

In Feasibility A, it was assumed that insufficient water was available from the existing Redwater facility and air cooling was maximized to avoid cooling water (CW) use. A trade-off analysis was conducted to compare air cooling vs. water cooling with two potential cooling systems considered:

- Air cooler design based on dry bulb temperature of 80°F
- Cooling water system

The preliminary design dry bulb temperature for air cooling was 80°F in Feasibility A, based on the Redwater site design criteria. Following an internal review, it was decided to keep this design condition for the trade-off study. The trade-off study design basis is Case 1A.

For water cooling, a dedicated new cooling water system was designed to meet the cooling water requirements. Process conditions of open recirculation cooling water at the plant battery limit and design basis for water cooled heat exchangers are in Table 7.

Table 7 Cooling Water Process Conditions and Design Basis

Property	Units	Cooling Water
Supply Temperature	°F	75
Return Temperature	°F	93 – 105
Supply Pressure	psig	65
Return Pressure	psig	35
Normal ΔT in Coolers	°F	18
Max. Pressure Loss	psi	30

Pressure Drop in Heat Exchangers	psi	10 - 14
Design Temperature (Vessels/Piping)	°F	650 / 156
Design Pressure	psig	125

From the capture technology licensor, five coolers were used in the design for the trade-off study:

- Quencher Cooler (E-001)
- Wash Water Cooler (E-002)
- Reflux Cooler (E-004)
- Lean Cooler (E-006)
- HP Discharge Cooler (E-102)

Key design criteria used by the technology licensor for both air and water cooling are in Table 8

Table 8 Design Criteria for Air vs. Water Cooling

Property	Units	Air Cooling	Water Cooling
Design Temperature	°F	80	75
Process Liquid Temperature Approach for Water Cooler (E-001/002)	°F	18	6
Process Liquid Temperature Approach for Solvent Cooler (E-004/005/006)	°F	27	11

3.2.2 Results and Recommendation

Cooling water can achieve a lower temperature approach than air cooling, which leads to lower process temperatures (i.e. for E-001 and E-002, the duties, process water flowrates, and process inlet/outlet temperatures are much less for water cooling than air cooling). This can have a slight benefit on the absorption process since the CO_2 reaction with amines is exothermic, making it more efficient and increasing the CO_2 loading in the amine solvent. Although the difference is not significant, slightly less solvent needs to be circulated to achieve the same CO_2 capture rate with lower process temperatures. Additionally, there is a corresponding reduction in solvent consumption and amine emissions with lower process temperatures. Smaller column diameters in the base case are also achieved with cooling water compared to air cooling due to the associated reduction in gas volume at lower temperatures.

To estimate the bare equipment costs cooling water system, budget pricing from vendors was factored based on the duty required and approximate installation factor. The same TIC to direct cost ratio was used as in Feasibility A to calculate an estimate total installed cost. The total installed cost associated with water cooling is estimated to be approximately 17% lower than air cooling, based on the Feasibility A flue gas capacity (Case 1A), $71 MMCAD compared to $85 MMCAD. Note that this is not representative of the overall TIC of the capture unit at the conclusion of Feasibility B due to the design case used. The operating costs for the cooling water system is approximately 2% lower than air cooling, $18.2 MMCAD compared to $18.6 MMCAD. Although increased power demand for air coolers is offset by the additional raw water import costs to make-up water to the cooling tower.

The plot area requirement for the air-cooling system was estimated to be 43,520ft² / 4043m², compared to 8,064ft² / 750m² for the cooling tower. An additional benefit is that the cooling tower can be located to the east of Plant 19, which will also minimize congestion in Plant 19 during construction and operations.

Considering the significant reduction in plot area requirements within Plant 19 and slight savings in capital and operating costs, it was recommended and decided to process with the cooling water system design in Feasibility B.

3.3 Regenerator Operating Conditions

3.3.1 Design Basis

A trade-off study was complete to optimize the regenerator operating pressure, the design case for this study was Case 2B, with a CO_2 recovery rate of 95%. Information from the technology licensor was provided, ranging the regenerator pressure.

3.3.2 Results and Recommendations

The results of the trade-off study show that higher regenerator pressure reduces the reboiler duty, regenerator diameter, and compressor shaft work. When considered in isolation, higher regeneration pressure is generally expected to increase the required reboiler duty however the resulting reduction may be due to indirect effects such as increase in the feed inlet temperature. Operating the regenerator at higher pressure can lead also to improved heat exchange in the Lean-Rich Amine Exchanger. Amine degradation increases with higher regeneration pressure, resulting in a higher chemical cost per tonne of CO_2.

The increase in operating costs at higher pressure due to higher solvent loss is offset by the decrease in in natural gas costs associated with reduced steam consumption. Additionally, operating the regenerator at a higher pressure can offer capital cost savings due to a smaller regenerator diameter, lower reboiler duty, and reduced CO_2 compression requirements. For these reasons, the results of the trade-off study were to increase the operating pressure for the regenerator.

4 Project Work Scope – Feasibility B

4.1 Project Scope and Boundary Limits

The Redwater Carbon Capture facility scope starts at the transportation of flue gas off the stack from each of the two sources (Plant 1 and Plant 9 SMR flue gas) and terminates with vent gas and carbon dioxide (CO_2) at the required specification and conditions at site boundary.

The carbon capture facility design including flue gas pretreatment is provided by licensor. Downstream CO_2 compression and dehydration system design may be provided by licensor or included within Hatch scope. Hatch is to design the flue gas transportation from the stacks to the PCC unit battery limit, and Balance of Plant (BOP) which includes all the utility and offsite systems. If flue gas pressure boosting is located at the source, flue gas blowers are included as part of the Hatch scope. An alternate option is to locate flue gas blower downstream of the quencher, in which case, it would be part of the licensor scope.

In addition, the facility is configured to be self-sufficient in terms of power and steam generation. Cogeneration units with HRSGs to supply sufficient heat are included as part of Hatch scope to produce steam and power. The flue gases from the cogen plant are directed to the carbon capture facility together with Plant 1 and Plant 9 SMR flue gases.

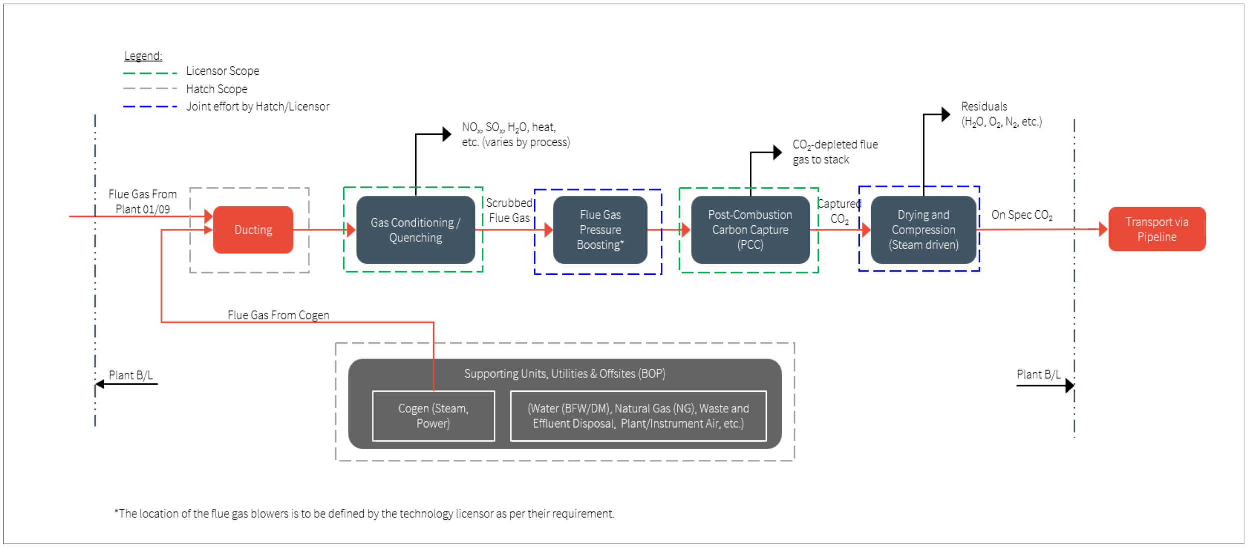

Figure 1 Feasibility B Scope

4.2 Design Criteria

4.2.1 Design Capacity

It is expected that a minimum CO_2 recovery of 90% will be achieved while the project desires to achieve close to 95%. The PCC facility is designed to capture 95% of the CO_2 from the Plant 1 and Plant 9 SMR flue gases, as well as the flue gases from the cogen plant.

The PCC facility will be designed to capture approx. 2,798 tpd (3,084 short tons per day) of CO_2 including CO_2 captured from the Plant 01 and 09 SMR's and flue gas generated from the cogen plant to be located within the PCC facility. The total flue gas and CO_2 content from the cogen will be confirmed and refined in this phase of the project, the design basis is the results from the combined heat and power study completed following Feasibility A.

4.2.2 Turndown and Availability

The previous phase of study (Feasibility A) considered a turndown of 30% based on feeding only flue gas from Plant 01 and reduced flue gas from the boiler, which represented approximately 30% of the total combined flue gas when both Plant 01 and Plant 09, is operating.

For Feasibility B, the flue gas from steam generation increased substantially since the boiler was replaced by a cogen unit which also supplies power and steam to the existing facility, culminating in an increased diluting effect of the combined flue gas streams versus Feasibility A. The PCC unit turndown requirement has subsequently been adjusted for 40% plant turndown. This is to ensure operation of the PCC unit when the feed from Plant 09 is down i.e. when the flue gas from Plant 01 and the cogen flue gas (which combined comprises approx. 53% of the design capacity), are the only feeds to the PCC unit. The 40% turndown selection (as opposed to 53%) is to allow for further turndown operation flexibility at Plant 01 and the co-gen units when only these units are operating.

4.2.3 Flue Gas Conditions

Table 9 Redwater Nitrogen Operations Flue Gas, Plant 01, 09 and Cogeneration Combined

Property	Units	Combined flue gas	
		Winter	Summer
Temperature	°F	378	381
Pressure	psig	0	0
Nominal flowrate	lb/hr (tpd)	2,405,271 (26,184)	2,396,356 (26,087)
CO_2 in flue gas	lb/hr (tpd)	265,439 (2,890)	270,493 (2,945)
N_2	mol%	71.21	70.08
O_2	mol%	4.92	4.92
H_2O	mol%	15.95	16.94
CO_2	mol%	6.98	7.12
Argon	mol%	0.94	0.94

4.2.4 CO_2 Product Specifications

Table 10 CO_2 Specification

Item	Unit	Value
Pressure		
At PCC B/L for CO_2 pipeline transport	psig	2,600
At carbon capture unit outlet	psig	note 1
Temperature		
At PCC B/L for CO_2 pipeline transport	°F	<140
At carbon capture unit outlet	°F	104 (note 2)
Composition of Captured CO_2		
Minimum CO_2	mol%	95 (note 3)
Maximum Hydrocarbons	mol%	2.0
Maximum Hydrocarbon Dewpoint	°F	-27.4
Maximum Glycols, Amines Ammonia	lbs/MMscf	3
Maximum H_2O Content	lbs/MMscf	10 (note 3)
Maximum H_2S Content	ppmv	4
Maximum N_2 Content	mol%	1
Maximum H_2 Content	mol%	1
Maximum CO Content	mol%	1
Maximum CH_4 Content	mol%	1
Maximum Ar Content	mol%	1
Maximum total inert content	mol%	4
Maximum O_2	mol%	0.1
Maximum SO_2	ppmv	100
Maximum NO_x	ppmv	100
Maximum Hg (vol)	ppbv	100
Other substances	Commercially free from sand, dust, gums, oils, impurities, and other objectionable substances	

Notes:

1. To be provided by the Technology licensor based on regenerator operation.
2. A temperature of 104°F or lower is preferred to reduce the CO_2 compressor discharge temperature. Technology licensor to confirm the actual temperature based on the Amine regenerator overhead condenser operation.

3. 95 mol% CO_2 excluding H_2O content. Dehydration unit downstream of carbon capture unit is employed to meet the H_2O content in the recovered CO_2 the PCC B/L.

4.3 Risk Analysis

4.3.1 Risk Management Plan

A risk management plan was drafted early in the project that was adhered to for activities including risk identification, risk register, HAZOP and QRA. If required, the risk management plan will be updated in future phases to accommodate project needs specific to each phase and possible new requirements.

4.3.2 Risk Identification Workshop

A risk identification workshop was held including attendees from Hatch and Nutrien. Identification was done first by open breakout groups followed by a detailed work breakdown structure. Individuals wrote down their own risks on pre-made cards, self-evaluated for probability and impact using pre-defined tables and then posted them on a large risk matrix on the wall.

This meeting was exclusively focused on risk identification with individuals privately evaluating their own identified risks. Excluded from this session:

1. Assignment of Risk Owners
2. Formal evaluation of probability and impact
3. Development of response plans.

These activities were completed offline. The key risks were regularly reviewed with the risk owners and shared with the project leadership bi-weekly. During the project, both a Process Hazard Analysis and Quantitative Risk Analysis (QRA) was completed for all process, execution and business risks.

4.3.2.1 QRA Results

The top discrete risks identified, quantified, and mitigated during the QRA session were:

- Fabrication shop availability, due to low number of facilities with the capability to fabricate vessels the size of the absorber towers.
- Fully constrained natural gas supply pipeline to Redwater facility.
- Large crane availability for installation of absorber towers; only two cranes of appropriate size are available in North America.
- Anticipated labour shortage due to increased activity in the Alberta Industrial Heartland.
- Potential for unknown undergrounds in the selected Plant 19 site.

Key mitigations identified during the risk assessment to decrease the likelihood and impact of schedule slippage and decrease contingency are:

- Start FEED no later than 76 months prior to planned project completion.
- Commit to fabrication shop space and include upfront payment no later than 70 months prior to planned project completion.
- Engage early with construction contractors during FEED to mitigate labour cost uncertainties and availability.
- Secure availability of large cranes for absorber tower installation no later than 24 months before the start of construction.

- Establish agreement with natural gas supplier and ensure capacity and availability prior to the start of construction.

In addition to these key mitigations, the following key assumptions were made for the risk analysis, and schedule and cost development:

- Large vessels (absorber towers) will be delivered to site in the winter, 24 months before commissioning to ensure no delays to the construction schedule. Due to the size of the vessels, they must only be transported in the winter once the ground is frozen and there are permissible road conditions.
- QRA results are based on the base CapEx and schedule.
- The final estimated contingency for both cost and schedule will be P80 – post-mitigated.

4.4 Project Achievements

4.4.1 Project Objectives

The project objectives remained unchanged between Feasibility A and B.

1. Develop a point of view for the technology and process options available for carbon capture at Redwater.
2. Develop the business case to justify the responsible deployment of capital, by:
    a. Concept screening study, and preliminary technology investigation of three CCUS options.
    b. Quantifying technology requirements and site limitations for the deployment of carbon capture technologies.
    c. Confirm process options and advance the preliminary concept to a point that Nutrien can justify proceeding to subsequent phases of the project.
3. Develop collaborations and partnerships, with:
    a. Industry, to complete the sequestration value chain (transmission and permanent sequestration)
    b. Government and academia, for knowledge development of pre- and post-combustion capture technologies to further the overall status of carbon capture in Alberta.

Below is a list of project achievements related to the stated project objectives.

1. Complete options analysis for three decarbonization opportunities at Redwater Nitrogen Operations through feasibility A.
2. Complete Class 4 estimate for a post-combustion carbon capture facility, with estimated 10-15% engineering development.
3. Optimization of PCC project through inclusion of combined heat and power.
4. Technical packages for two different proprietary carbon capture technologies for comparison,
5. Participation in knowledge sharing activities, including collaboration with internal Nutrien project resources, government stakeholders, and industry peers.

4.5 Analysis of Results

4.5.1 CapEx Estimate

The cost estimate in

Table 11 used a hybrid estimating methodology, combining a deterministic detailed estimate (time and material) method with a stochastic factored estimate method. For this estimate the contingency used was 20% of the Total Base Cost, based on the QRA results. The estimate accuracy range is -20% /+30%.

The ISBL sized mechanical equipment list was provided by the technology licensor, together with information on equipment capacity and specifications. Hatch provided pricing for all items (both ISBL and OSBL) on the mechanical equipment list, based on vendor quotes for about 92% of the equipment cost, and using Hatch's in-house database for the smaller remainder items.

MTOs were provided by all engineering disciplines; a detailed estimating method was used where MTOs were provided, such as for Mechanical, Piping, Structural Steel, Concrete, Steel Piles, Electrical, and partially for the Civil and Instrumentation MTOs. The factored estimating method was used for the instances when extraction of full MTOs was not possible, due to the lack of engineering deliverables, which is consistent with the overall engineering development at this stage. As the provided MTOs were based on preliminary assumptions, factors have been used to account for the missing information and costs.

Table 11 Feasibility B Capital Cost Estimate Summary

CapEx Summary	
Total Direct Cost	$ 531,732,791
Indirect Costs	$ 277,405,686
Total Base Cost	$ 809,138,478
Contingency, Escalation and Owner's Cost	$ 330,749,768
Total Installed Cost	**$ 1,139,888,246**

4.5.2 OpEx Estimate

Operating costs are classified into one of two categories; (1) variable and (2) fixed.

Variable costs include costs associated with:

- Raw Materials
- Chemicals, Catalysts, and Operating Consumables,
- Utilities
- Waste Disposal

Fixed costs considered within the scope of this estimate include costs associated with:

- Staffing
- Maintenance
- Insurance

The numbers generated and reported in this section are reflective of those at an AACE Class IV level of CapEx certainty.

In addition to the total operating cost of the cogen plant and PCC unit, the levelized cost of steam and power production in the cogen plant was estimated. As a portion of the steam and power produced is exported to the Redwater site, the cost for the exported portion was deducted from the total annual operating cost to determine the net OpEx of the carbon capture facility only. In this case, the steam and power are assumed to be exported ("sold") to the Redwater facility at the levelized cost. The levelized cost of electricity using above method is 9.38¢/kWh including capital recovery. The levelized cost for steam is $14.60 CAD per tonne (6.53 CAD/GJ of steam) including capital recovery.

A summary of the total operating cost estimate associated with the proposed cogen Plant and carbon capture facility is outlined in Table 12. A total annual operating cost of $82.3 MMCAD was estimated, representing an average cost per unit of CAD $85/tonne of CO_2 captured (not including transportation and sequestration costs).

The annual OpEx net of operations utility imports for the carbon capture facility (i.e. excluding the portion of steam and power exported to the Redwater site and transportation and sequestration costs) is estimated as $52.5 MMCAD, representing an average cost per unit of CAD $54/tonne of CO_2 captured.

Table 12 OpEx Summary Results

Description	Annual Cost (CAD)	Average Cost per Unit (CAD/tonne CO_2 Recovered)	% Contribution of Total OpEx	Notes
Variable Costs	$ 46,632,192	$ 48.02	56.6%	1, 2
Direct Fixed Costs	$ 24,237,758	$ 24.98	29.5%	
Allocated Fixed Costs	$ 11,398,882	$ 11.74	13.9%	
Total OpEx	**82,268,832**	**$ 84.73**	**100%**	
Cost for Steam Export to Redwater Site	($ 7,439,564)	($ 7.66)	-	3
Cost for Power Export to Redwater Site	($ 22,334,549)	($ 23.01)	-	3
Total Net OpEx	**$52,494,719**	**$ 54.08**	**-**	**4**

Notes:

1. Included total natural gas import required for cogen Plant. Note the cogen Plant is replacing a portion of the steam produced from the existing utilities boilers; therefore, a portion of this total natural gas can be attributed to replacing the steam production from the utility boilers.
2. The new cogen Plant will produce the steam and power requirements for the operation of the proposed carbon capture unit; the excess power and steam will be sent to the existing Redwater facility. No power import from the grid is required for the proposed carbon capture facility.
3. Cost for steam and power export to Redwater site are estimated based on levelized cost including capital recovery.
4. Total net operating cost of the carbon capture facility only. This net operating cost does not include the cost for producing the steam and power in the cogen Plant for export to the existing Redwater site.

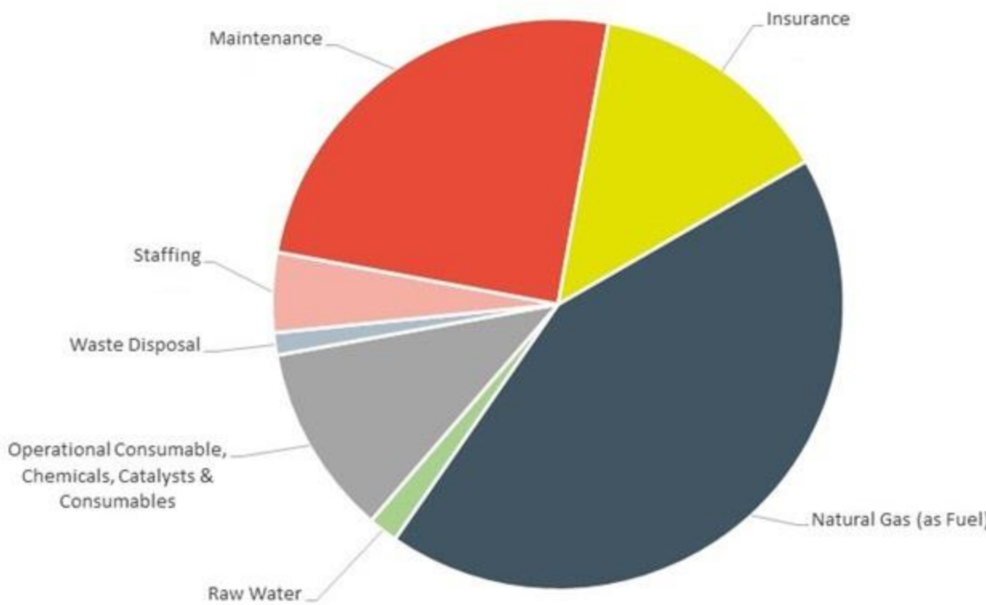

Figure 2 Distribution of Operating Costs

4.5.2.1 Transportation and Sequestration Costs

Redwater Nitrogen Operations does not have onsite capability for CO_2 sequestration. Therefore, to complete the CCS value chain a third-party transportation and sequestration partner must be engaged. A ranged cost per tonne CO_2 was used to estimated cost for transportation and sequestration services. This cost was added on top of the variable operating costs indicated in 4.5.2 OpEx Estimate when developing the project financial model.

4.5.3 Project Schedule

A Level 2 Schedule for the overall project execution was developed as part of the Feasibility B Study. The total post-mitigated schedule including FEED and EPCM is 330 weeks, or over 6 years. This execution schedule does not show completion of construction and commissioning by 2030.

The base schedule, as show in Figure 3, has construction completion at the end of 2030 with commissioning and start-up in 2031. Targeting construction completion before the end of 2030 maximizes the federal CCUS ITC eligibility, takes advantage of the current planned maintenance and reliability schedule for Redwater, and ensures adequate project execution planning time.

See 4.3.2.1 QRA Results for key mitigations included in the final schedule as a result of the Quantitative Risk Analysis.

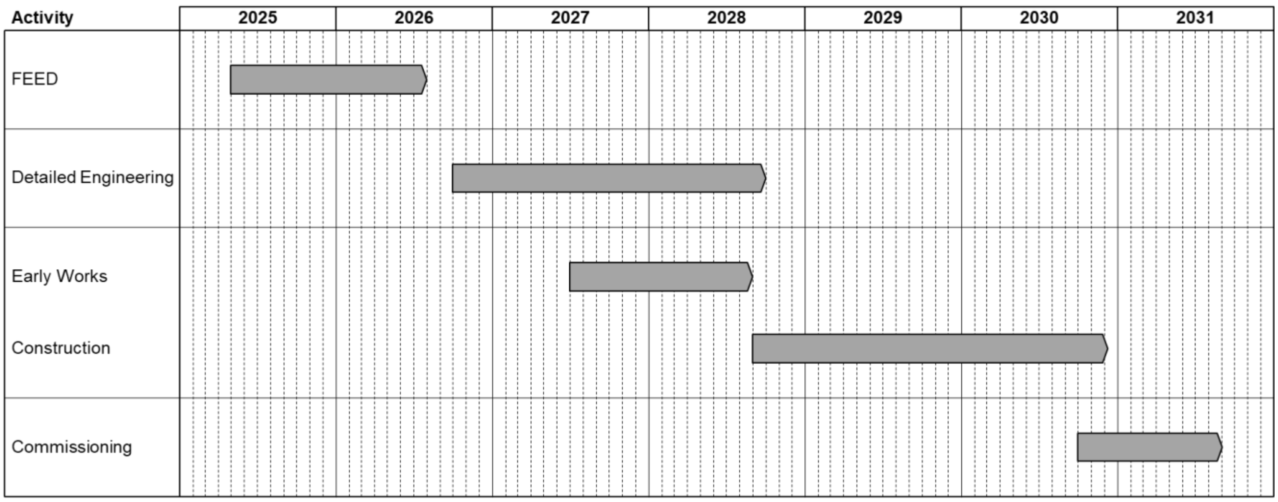

Figure 3 Project Milestone Schedule

4.5.4 Economic Summary

Table 13 Feasibility B Economic Summary

Parameter	Units	
Technical and Performance		
CO_2 captured for sequestration	tpd	2,798
CO_2 recovery	%	95%
Net CO_2 capture	tpd	2,124
Economics		
Capital Expense	Millions CAD (P50-P100)	$1,102 to 1,268
Operating Expense[1]	CAD/tonne CO_2	$85 $57 (Net of Cogen Synergies)

<u>Notes</u>

1. In 2023 Canadian Dollars.

4.6 Feasibility B Conclusion and Recommendations

At this stage of engineering, development of a Class 4 capital and operating expense estimate has been determined with -20% / +30% accuracy for a 2,798 tpd CO_2 post-combustion capture (PCC) plant. The design has the capacity to process flue gases from both the Plant 01 and 09 steam methane reformers and a new 50MW cogeneration plant that will supply steam and power to the PCC and the existing site. The project team has gone through detailed value engineering exercises to develop a design that is tailored and optimized to Redwater. Risk analysis and mitigation exercises have been completed at multiple points in the engineering development process to accurately estimate project schedule and contingency.

The results of the economic analysis of the project does not support the responsible deployment of capital to further develop this project. The current market environment does not support incremental demand or premium product pricing for low-carbon ammonia, fertilizers, and industrial products produced from low-carbon ammonia. This lack of market driven revenue is a fundamental barrier to project economics and the business case. Uncertainty in the value and liquidity of carbon credits further imposes risk in the economic model. Nutrien does not believe that the operating, transportation, and sequestration costs would be offset sufficiently by the value of TIER carbon credits.

5 Lessons Learned

5.1 Background

Throughout the feasibility study, Nutrien tracked key lessons learned from this project that could support similar facilities and similar evaluations. Similar facilities and corporate approaches to decarbonization projects, particularly for post-combustion carbon capture, will inherently be different and not translate directly. However, the lessons learned from the project provide insightful high-level findings for decarbonization projects, particularly at ammonia-producing facilities including two of Nutrien's ammonia-producing facilities in Alberta (the Fort Saskatchewan Nitrogen Operations and the Carseland Nitrogen Operations).

Due to the volume of lessons learned and recorded during the project, the lessons learned in this report focus on categories noted by the project team as medium and high impact – important or critical to the success of the project, respectively. The team also noted 'nice to haves', and lessons for future stages not immediately relevant to the project. The categories of lessons learned during the feasibility study have been categorized as:

1) High-value activities during feasibility
2) Design considerations
3) Flue gas testing
4) Knowledge sharing
5) Regulatory
6) Site assessment
7) Project management
8) Technology selection

Additionally, lessons learned from government support and the economic impact of the project were also explored.

5.2 Lessons Learned During Feasibility Study Activities

5.2.1 High-Value Activities

Several high-value activities were conducted during the feasibility study that tackle project challenges and maximize the value of the feasibility study for the potential next phases of the project. Descriptions of such high-value activities are listed below:

- Constructability Analysis: Communicating and exchanging knowledge with teams involved in similar projects enables shared learning for better project execution.

- Decision Quality Workshop: A workshop helped outline project goals and the best approaches to achieve them, aligning the project and client teams towards a common objective.
- Value Engineering Workshop: A systematic approach to evaluate options in a team environment and identify, document, and rank the most effective approaches for cost savings.
- Risk Assessment and Workshop: Obtaining risk registers from other projects helped ensure potential risks were identified and addressed, improving the accuracy of project scope, budget, and schedule. Conducting risk analysis workshops early and throughout the project helped identify and address potential risks and mitigation measures promptly. Regular reviews of the risk register ensured that any new risks were identified and addressed quickly. Quantitative risk analysis, using data and facts, helped determine contingency and objectively assess risk severity and cost impact.
- External Project Review: Input from individuals not directly involved in the project offers a different perspective and validates project parameters, such as schedule, budget, contingency, and risks.
- Knowledge Sharing: Sharing new methodologies and lessons learned, both internally and externally, benefits the company and the industry by promoting successful carbon capture project implementation.
- Knowledge Centre Workshop: Workshops conducted by organizations like The International CCS Knowledge Centre provide valuable opportunities to learn from others' experiences, share findings, and identify potential gaps in project scope.
- Lessons Learned Tracking: Maintaining lessons learned tracking list, including both positive and negative experiences from other projects, helps ensure valuable insights are captured and implemented.

5.2.2 Design Considerations

As noted in previous sections, preliminary work by Nutrien prior to the project identified three potential carbon capture options to decarbonize the hardest to abate, and largest remaining, emissions sources for nitrogen operations. The first phase of the Feasibility Project was used to identify the decarbonization option to be carried forward for the remainder of the study, through Front End Engineering Design (FEED), and ultimately FID. Option 1, post-combustion carbon capture was viewed as the most feasible pathway to decarbonize RNO and is the main focus of the lessons learned perspective. A major challenge for the project is the high capital costs associated with post-combustion carbon capture projects, therefore specific actions were taken to identify the lowest cost options and opportunities for cost reduction in the construction and operation of the potential project stemming from key design considerations.

To accomplish that goal, the project team conducted decision quality, value engineering and lessons learned from existing workshops, to identify key design options that could be altered from a base case to reduce costs. The options were then evaluated to determine the lowest cost options to move the project forward. Some key highlights are explored below:

5.2.2.1 Air vs Water Cooling Study

A study was conducted to compare the effectiveness and cost of air cooling versus water cooling systems for carbon capture in the Nutrien Redwater Fertilizer Operations. The study was conducted by comparing two potential cooling systems: Case 1, which used an air cooler design used in Feasibility A (based on a dry bulb temperature of 80 degrees Fahrenheit), and Case 2, which utilized a cooling water system. The study found that because it requires a smaller plot area and represents a slight savings in CapEx and

OpEx a water system should be used in Feasibility B. However, a significant amount of additional freshwater intake to supply make-up water to the cooling tower is required.

5.2.2.2 Cylindrical Train Trade-off Study

This trade-off study investigated and recommended a two-train cylindrical quencher/absorber configuration powered by a cogeneration unit for carbon capture at RFO. This configuration was chosen because it offers the most significant savings in annual OpEx due to carbon tax/emission advantages, despite higher initial costs. This conclusion stems from an analysis comparing rectangular and cylindrical column designs, one- and two-train configurations, and the use of a cogeneration unit versus a steam boiler. The study ultimately found cylindrical columns to be more feasible for onsite installation and transportation. Additionally, a cogeneration unit with HRSG was preferred due to its capacity to generate low-carbon power and sufficient steam for both the carbon capture unit and the Redwater site.

5.2.2.3 Regenerator Pressure Trade-off Study

This study compared the costs and benefits of using a higher stripping pressure in the regenerator unit for carbon capture. The results showed that the increased operating costs from higher solvent loss at the higher pressure are offset by the decreased natural gas costs associated with reduced reboiler steam consumption. Additionally, capital cost savings can be realized by operating the regenerator at a higher pressure due to a smaller regenerator diameter, lower reboiler duty, and reduced CO_2 compression requirements. Ultimately, the study recommended using a higher operating pressure for regenerator operation based on the overall capital and operating cost impacts.

5.2.2.4 Utility Integration

Options to incorporate existing utility systems were evaluated including their capacities and how they could reduce the project's CapEx. By integrating existing steam, condensate, boiler feed water, plant air, instrument air, and nitrogen systems, it was found that the CCS facility could leverage existing infrastructure, leading to a reduction in the size of utility units and a corresponding decrease in CapEx. This included reaching out to third parties to understand the potential impacts on their systems and associated timelines to be included in the project schedule. The study highlights the importance of defining utility integration strategies early in the project to optimize the design and reduce project costs.

5.2.2.5 Turbine Configurations Study

This exercise examined multiple gas turbine configurations to meet the power and steam demands of the existing facility and additional demands from existing pre-combustion capture (PCC) equipment. The study found that all evaluated options would result in similar CO_2 emission reductions. The study recommends obtaining more detailed information from vendors during Feasibility B, particularly regarding the flue gas temperature, rate, and composition from heat recovery steam generator vendors. The study results recommended that a vendor-provided configuration should be used as a basis for developing specifications for the cogeneration equipment and advised considering the potential future use of hydrogen in the fuel blend and ensuring the equipment is designed to handle the anticipated hydrogen blend.

5.2.2.6 Hydrogen Fuel Switching Viability Study

A study was conducted to explore the technical feasibility of switching to hydrogen as an alternative fuel source. The study found that converting existing equipment to operate on 100% hydrogen fuel appeared technically feasible, with a significantly lower CapEx than post-combustion carbon capture. However, this approach presents considerable risks, including process performance risks for heaters and reformers, uncertainty about the impact of hydrogen conversion on equipment lifespan, and limited successful implementation examples. Despite the potential of hydrogen fuel switching, the study recommends a detailed cost and risk analysis in collaboration with burner and heater vendors to assess its competitiveness against carbon capture. The high price of hydrogen fuel and the limited availability of blue hydrogen are also cited as potential challenges.

5.2.2.7 Modularization

Efforts were made during the feasibility study to assess and implement modularization strategies. A key action was the completion of a desktop modularization study during Feasibility B, which aimed to identify components suitable for off-site construction. This study was complemented by a trade-off study focusing on the large carbon capture columns, specifically the quencher and absorber. This analysis considered transportation limitations and determined that using two trains of cylindrical columns, rather than a single larger column, would be more feasible due to size constraints.

A primary takeaway was the potential for modularization to significantly reduce project costs by moving a large portion of construction off-site. This shift to a controlled factory environment would minimize on-site labour needs, crane usage, and weather-related delays. Another key finding was the importance of considering modularization early in the project lifecycle. The evaluations recommended prioritizing off-site fabrication for the potential project for large columns, such as the quencher, absorber, and regenerator, and conducting thorough transportation studies to ensure that module designs align with load size and weight restrictions.

5.2.3 Flue Gas Testing

Initial flue gas testing was conducted to support and evaluate the crucial role of flue gas composition in the design and operation of the potential carbon capture system. Routine environmental testing and initial testing in Feasibility A did not encompass all the necessary components that could influence the design as provided by the technology provider. A second series of testing was completed during Feasibility B which tested for additional species required by the technology licensors. A key learning from the project was the importance of flue gas being viewed as a process input as opposed to a waste product. Flue gas composition and impurities will have material impacts on process design and solvent efficiency.

Additional flue gas testing was noted to be of continued importance for the next phase of the project for the following reasons:

- Variability in operating conditions: additional data points will improve understanding of the variability in flue gas composition
- Impact of Flue Gas Impurities on System Performance: Impurities in the flue gas, particularly NO_x and SO_x, can lead to increased oxidative degradation of the amine solution used in the carbon capture process. This degradation can result in the buildup of heat-stable salts, hindering system efficiency and increasing solvent consumption and makeup, ultimately driving up costs.

5.2.4 Knowledge Sharing

To support the final outcomes report and the overall success of this project and future projects, Nutrien both accessed lessons learned from previous projects and actively tracked lessons learned. This included participating in a multi-day lessons learned workshop led by the International CCS Knowledge Centre. This activity also helped to identify missing scope in the work originally outlined for the Feasibility A phase. The monthly updated lessons learned tracking list included both positive and negative lessons. The tracking tool has been useful in meeting reporting requirements and will be a useful tool for similar projects conducted by Nutrien in the future.

5.2.5 Project Management

The project team highlighted the importance of proactive project management in CCS projects. Some key actions and the lessons learned include:

- Early engagement of a construction contractor or expert is crucial to assess constructability and understand potential impacts on project cost and schedule. Budgeting for sufficient time for non-disclosure agreement execution for similar projects should be considered.
- Developing a comprehensive schedule at the earliest opportunity provides insights into timelines and identifies critical decision points. This should be baselined with regular reporting to track slippages as well as well-defined decision logs and action lists in alignment with any invoicing cycles.
- Regular cost tracking ensures adherence to the budget and allows for early identification of potential cost savings.
- Early identification of equipment cost accuracy for major items helps determine appropriate contingency levels and increases the overall accuracy of the cost estimate.
- Effective document management is vital. Training on document-sharing platforms and maintaining a comprehensive list of documents with clear descriptions facilitate easy access and retrieval.

5.2.6 Regulatory

The feasibility study found success in proactive and early engagement with regulatory bodies. A key recommendation is to initiate early government consultations to gain a clear understanding of the regulatory application process and integrate it into the project schedule. This early interaction also allows for introducing the project to the relevant government agencies, for Nutrien both federal and provincial, and understanding their specific requirements, which helps prevent potential delays during the approval process.

Additionally, the project team found value in close collaboration between the engineering team, and regulatory specialists. This collaborative approach ensured that regulatory considerations were effectively integrated into the project design and execution, allowing for early identification and mitigation of potential regulatory challenges. For example, the project team learned that by re-using existing disturbed areas on the facility site, environmental impacts can be minimized. This highlights how proactive planning and coordination with regulatory experts can streamline the approval process and reduce potential environmental impacts.

5.2.7 Site Assessment

Site assessments using a variety of methods to gather comprehensive information were noted as a key feasibility activity. A key action taken was the use of drones for mapping and creating 3D renderings. Drone mapping provided valuable data on site access routes, identifying potential challenges such as turns, elevations, and necessary road widening, which could then be incorporated into a transportation study to determine load limitations. The 3D rendering videos, showcasing the integration of the CCS unit with existing facilities, proved useful for visualizing the project scope and communicating it to stakeholders and government agencies. Another critical action was conducting site visits and walkarounds with the project team and third parties. These visits allowed for a firsthand understanding of the site's constraints, existing operations, and potential challenges, leading to a more accurate cost estimate and informed decision-making.

The site assessments yielded valuable insights and informed recommendations for future projects. Observations made during site visits highlighted the potential for integrating existing utilities into the CCS facility design. For example, identifying excess capacity in existing systems allowed for the utilization of existing steam, condensate, and boiler feedwater systems, resulting in cost savings by reducing the need for new utility units. The site assessments also emphasized the importance of having a dedicated site representative on the project team. This individual can provide valuable input on site-specific considerations, contributing to a more accurate project scope, a more refined cost estimate, and greater buy-in from site personnel. Site assessments were noted as critical for understanding the unique characteristics of a project site and informing key project decisions related to design, construction, and cost estimation.

5.2.8 Technology Selection

The project team employed a comprehensive approach to technology selection, recognizing the need to evaluate multiple options to mitigate the risk of committing to a suboptimal solution. While the initial Feasibility A assessment centred on one single proprietary carbon capture technology, Feasibility B expanded the scope to include other commercially viable amine-based technologies. This broader evaluation aimed to identify the technology best suited to the project's specific requirements and avoid potential cost overruns associated with an inadequate initial choice. To ensure a thorough comparison, the team conducted a detailed knowledge transfer and analysis between two different technologies, considering factors such as cost, efficiency, and operational parameters. This in-depth assessment informed the final technology selection, paving the way for subsequent engineering phases.

Recognizing the value of diverse expertise, the project team strategically adjusted the scope of work assigned to the technology licensors and a third-party engineering firm. Certain tasks, such as cost estimation, were shifted from the licensors to the engineering firm to leverage their local experience and vendor relationships, potentially leading to more accurate cost assessments. This collaborative approach allowed the licensors to focus on core deliverables while capitalizing on the engineering firm's specialized knowledge.

Furthermore, the project team actively engaged with both technology licensors, requesting insights into potential design optimizations based on their experience with other commercial CCS facilities. Both licensors provided valuable input, leading to the identification of several optimization opportunities, some of which were incorporated into the Feasibility B design. This proactive approach to optimization highlights the importance of leveraging the knowledge and experience of technology providers to refine the chosen technology's application and enhance project efficiency.

5.3 Lessons Learned on Government Support

As noted in 2.5 Feasibility A Conclusion and Recommendations the study found that post-combustion carbon capture would return a negative NPV for the investment and solutions to reduce CapEx were explored.

Support for post-combustion CCS projects is part of both Canada and Alberta's emission reduction plans, communications and policies. Government policies and incentives create both financial reasoning and potential sources of revenue for operating capture facilities and government programs play a major role in incentivizing capital investments in CCUS projects. The study explored all relevant programs and policies as part of the evaluation of project economics.

Table 14 summarizes the key policy and regulatory requirements that are designed to incentivize the adoption of technology to reduce emissions in the fertilizer industry:

Table 14 Key Policy and Regulatory Requirements

Policy / Legislation	Description
Government of Canada	
Investment Tax Credits (ITC) *Income Tax Act*	Budgets 2021 to 2023 announced a variety of ITCs for investments in eligible property. Relevant for the ammonia industry are ITCs for Clean Hydrogen, Clean Electricity, and Carbon Capture Utilization and Storage (CCUS). Additional Capital Cost Allowance classes relevant to new projects have been added to the Income Tax Act.
Federal Output-Based Pricing System (OBPS) *Greenhouse Gas Pollution Pricing Act (GGPPA)*	The GGPPA has two parts: a regulatory charge on retail fossil fuels like gasoline and natural gas, known as the federal fuel charge, and a performance-based large emitter system for industries, known as the OBPS. The federal OBPS is a benchmark for GHG emissions regulations from provinces and indicates a rapidly rising price for carbon emissions reaching $170 in 2030.
Clean Electricity Regulation *Draft Clean Energy Regulation*	This draft legislation places requirements on electricity production taking effect for new projects in 2025. A key consideration for the ammonia industry relates to any combined heat and power units utilized at production facilities.
Government of Alberta	
Alberta Emission Offset System *Technology Innovation and Emission Reduction Regulation*	In Alberta, the Technology Innovation and Emissions Reduction (TIER) Regulation, supplants the federal Output-Based Pricing System (OBPS) system. Emission Offset credits under TIER result from voluntary reductions of greenhouse gas emissions that comply with Alberta Emission Offset Quantification Protocols. The sequestration of CO_2 via EOR or in a saline formation generates an Emission Offset credit for the facility that performs the sequestration activity. This is often different from the party that captures the CO_2. Credits can be shared with the capturing facility via contractual arrangements. Emission Offsets can be banked, traded/sold or used in TIER. Sequestration facility owners may also convert Emission Offsets to Sequestration Credits at the request of the TIER facility that captured the CO_2. These credits can then be used against the facility's TIER compliance obligation or further transformed into Capture Recognition Tonnes and deducted from the Total Reportable Emissions for the capturing facility in the year of capture. These credits represent an opportunity for the capturing facility to recoup emission costs and improve the value of emission reduction projects. Funds collected by TIER are used to support various emission reduction projects throughout the province and are often reinvested into emission reduction projects.

Policy / Legislation	Description
Carbon Capture Incentive Program (ACCIP)	ACCIP is a program that is expected to provide completed CCUS projects with a grant equivalent to 12% of eligible capital costs. The final details are expected to be finalized in late 2024.

6 Environmental Impacts

6.1 Emissions Reduction Impact

In the existing "Do Nothing" case, the major in-scope combustion flue gases are emitted from the Plant 01 and Plant 09 SMR flue gas, and the existing utility boilers. There are also equivalent CO_2 emissions associated to the power imported from the grid. The existing "Do Nothing" case emits approximately 2,534 tpd of CO_2.

In the new proposed PCC facility for Feasibility B, the cogen plant will produce 1,168 tpd of additional CO_2 from the combustion of natural gas to produce steam and power. However, 95% of the CO_2 contained in cogen flue gas is captured. The existing utility Boiler will operate at minimum firing rate to produce 9 MTPH with a small amount of associated, unabated emissions. Although the new cogen plant will produce power for the carbon capture facility and export the excess power of 28.6 MW to the rest of the Redwater site, it does not meet all the current Redwater power demand. There is approximately 226 tpd of indirect CO_2 emissions due to power import from the grid of 25.4 MW, based on the TIER 2022 High Performance Benchmark for electricity.

Emissions with the installation of the proposed PCC facility and cogen plant will include the 5% of cogen emissions not captured in the new PCC facility, the CO_2 from the existing Boiler flue gas, and the CO_2 associated with the residual power import from the grid; in total, 410 tpd of CO_2 emissions is expected, which represents an 84% reduction in overall CO_2 emissions compared to the existing arrangement with vented flue gas emissions from Plant 01 and Plant 09 SMRs, the utility boilers and indirect emissions from imported electricity.

A summary comparison of the select sources of existing CO_2 emissions at the Redwater site vs. the CO_2 emissions with the proposed PCC and Cogen Plant is included in Table 15. The CO_2 emissions profile in the "Do Nothing" case is based on the worst-case design conditions.

Table 15 CO_2 Emissions Summary

Parameter	Units	Redwater Site (Do Nothing)	Feasibility A	Feasibility B	Notes
Total Combustion CO_2 (in project scope)	**tpd (lb/hr)**	**2,054 (188,679)**	**2,392 (223,412)**	**2,982 (273,924)**	**5**
CO_2 Captured in PCC facility					
PCC CO_2 Capture Recovered	**tpd (lb/hr)**	**-**	**2,047 (188,036)**	**2,798 (256,999)**	**3, 5**
CO_2e Emissions from Power Import from Grid					
Power Generation from cogen	MW	-	-	44.9	
Power Consumption	MW	54	61.5	70.3	

Parameter	Units	Redwater Site (Do Nothing)	Feasibility A	Feasibility B	Notes
PCC facility	*MW*	-	*7.5*	*16.3*	
Existing Redwater Site	*MW*	*54*			*4*
Balance of Power (Import from Grid)	**MW**	**-54**	**-61.5**	**-25.4**	**1**
CO_2e Emissions Rate	MT CO_2/MWh	0.37			2
CO_2e Emissions from Power Import from Grid	**tpd (lb/hr)**	**480 (44,092)**	**546 (50,155)**	**226 (20,760)**	
Summary of CO_2 Emissions					
Combustion CO_2 (in project scope, not captured in PCC facility)	tpd (lb/hr)	2,054 (188,679)	385 (35,366)	184 (16,939)	
CO_2e Emissions due to Power Import from Grid	tpd (lb/hr)	480 (44,092)	546 (50,155)	226 (20,760)	
Total CO_2 Emissions	**tpd (lb/hr)**	**2,534 (232,771)**	**931 (85,521)**	**410 (37,662)**	
% Reduction in CO_2 Emissions compared to "Do Nothing"	*%*	-	*63%*	*84%*	

Notes:

1. Negative (-) number indicates power import from grid.
2. Assuming 0.37 tonnes CO_2 emissions/MWh, as per TIER High Performance Benchmark for Electricity (2022). Note that the electrical emission profile should be updated with the long-term TIER benchmark outlook for electricity in the next phase.
3. Assuming 95% CO_2 recovery in PCC facility.
4. Current power consumption by the existing Redwater site.
5. In scope combustion emissions include combustion emissions from Plant 01 SMR, Plant 09 SMR, existing auxiliary boiler, and future cogen with HRSG. Only post-combustion carbon capture from the Plant 01 and Plant 09 SMR flue gas stacks is considered in this CO_2 balance.

6.2 Other Environmental Impacts

Few carbon capture facilities or projects have been permitted in the Province of Alberta due to the relatively recent interest in the development and operation of these facilities at scale. To date, no provincial legislation or regulations have been produced that are specific to carbon capture approvals, licenses, or permits. Hatch has identified four required permits/approvals aligned with potential environmental and safety impact: an Environmental Protection and Enhancement Act approval, a Design Review and Registration with the Alberta Boilers Safety Association, a Power Plant Alteration Approval with the Alberta Utilities Commission, and an Agreement with the Alberta Electric System Operator. In addition to the required permits and approvals, additional approvals may be required depending on the final project description. These include potential Water Act, Fisheries Act, and various Transportation Act approvals.

6.2.1 Potential Environmental Effects

The construction and operation of the PCC has the potential to result in environmental effects on the surrounding landscape and communities. At this stage of the development, a detailed quantitative analysis of project effects is not possible, this would be completed as part of the FEED study to support the permits, licenses, and approvals submissions. A high-level qualitative identification of the potential environmental effects has been completed at this stage to help facilitate the next stage of development.

A review of the current project description, layout, emissions, and waste streams was completed based on the information presented in this report. The potential changes to the current facility that may result in environmental effects include:

- A change in the emissions profile for the facility due to the overall reduction in CO_2 emissions and increase in volatile organic compound (VOC) emissions from the amine system.
- A change in the noise profile for the facility due to the addition of noise generating equipment associated with the PCC.
- An increase in the disturbance footprint due to the addition of the PCC infrastructure.
- An increase in the waste streams (i.e., wastewater and solid waste) due to the additional water treatment required and the amine reclamation waste generation.

The potential effects associated with these changes to the Nutrien Redwater facility are as follows:

- Construction related potential effects
  - Indirect effects of dust on surrounding vegetation.
  - Increase in particulate matter due to dust.
  - Vehicle/wildlife interactions.
  - Spills.
- Operations related potential effects
  - Indirect effects of air emissions on surrounding ecosystems, site workers, and communities.
  - Indirect effects of noise on surrounding communities.
  - Decrease in power import resulting in reduced grid power production requirements.
  - Indirect loss of habitat due to dust and noise.
  - Direct habitat loss due to site clearing and grading.
  - Increase potential for spills from new facility.
  - Increase in waste generation, solid and liquid.
  - Increase in hazardous material generation and handling requirements.

These potential effects and potential mitigation measures for these potential effects will be analyzed and developed in detail during the next phase of engineering. It is likely that additional effects will be identified during that process as the project description is further defined.

7 Economic and Social Impacts

In 2020, The International CCS Knowledge Centre and RSM conducted a study that estimated the economic impacts of developing CCUS projects. The estimation, which excluded environmental and other benefits, provides the order of magnitude of construction impacts of developing three CCUS projects. Updated to 2023 figures (Table 16), three full-scale CCS projects would directly generate nearly $1.2B in GDP; roughly $3.1B when taking into consideration indirect and induced effects over the construction horizon; and a total of 6,100 jobs across Canada (though primarily in regions adjacent to the project) over four years (International CCS Knowledge Centre and RSM, 2020).

Table 16 Economic Impact of Three Full-Scale CCS Projects in Millions of $CAD (2023)

	Output	GDP	Labour Income	Employment (Jobs)
Direct	3,045	1,214	814	2,343
Indirect	2,250	1,154	692	2,171
Induced	1,273	731	348	1,607
Total	**6,568**	**3,099**	**1,854**	**6,121**

The 2020 study used an input-output model which simulates the economic impacts of an expenditure on a given basket of goods and services or the output of one or several industries. Input-output models provide a reasonable basis but ignore non-market impacts, assume that labour and capital are fully available to complete the projects, and do not include any repercussions associated with the transfer of labour from one economic sector to another.

Using StatsCanada's input-output multipliers and simple application of the above study and applying it to the CapEx estimate, it is possible to estimate at a high level the gross economic impacts of such a facility Assuming a total CapEx of CAD $1.14 billion (2024) the economic impact of the construction is shown in Table 17.

Table 17 Estimated Economic Impact of Construction in Millions of $CAD (2024)

	Output	GDP	Labour Income
Direct	1,140	471	318
Indirect	798	420	263
Induced	440	287	119
Total	**2,378**	**1,179**	**700**

Considering the impact from a job and local business perspective, the Boundary Dam CCS project used over 60 contracted companies and more than 5 million person-hours of labour over four years requiring the equivalent of 735 full-time employees (FTE) jobs per year during construction. The input-output model used to produce Table 17 would produce a similar estimate of 685 jobs per year over a five-year construction period.

If the construction of the proposed capture facility were to access the CCUS-ITC, the project would have to make best efforts to adhere to labour requirements to avoid financial penalties. These labour requirements are included in Table 18.

Table 18 Federal CCUS ITC Labour Requirements

Prevailing Wage Requirements	Apprenticeship Requirements
Compensation: Covered workers must be paid (excluding overtime but including benefits) equivalent to a relevant eligible collective agreement. **Collective Bargaining Equivalency**: Based on the most recent collective bargaining agreements or project labour agreements with a building trade union **Communication**: The prevailing wage requirements must be communicated to employees.	**Work Hours**: Recipients must make reasonable efforts to ensure apprentices work at least 10% of total hours. **Reasonable Efforts**: Every four months, a project must: • Advertise for apprentices to fulfill the required hours. • Communicate with at least one trade union and one educational facility for hiring apprentices. • Confirm with a trade union that as many apprentices as possible have been provided. Unions have 5 business days to respond.

Prevailing Wage Requirements	Apprenticeship Requirements
	Exceptions: Reasonable efforts are not required if laws or collective agreements limit the proportion of apprentices.

In addition to the economic impact and jobs created during construction, if completed the project would support high-quality long-term jobs in operating the capture facility. Though the full complement of staff required for operations is not fully committed, using existing post-combustion carbon capture sites as an analog could be beneficial for understanding the roles and approximate number of jobs that could be utilized if the project is completed.

Below is a description of the staff roles at Boundary Dam CCS facility as an example of the positions required to operate a capture facility.

- Operators – Operate the carbon capture facility. This includes six shifts with five individuals per shift, comprising a Shift Supervisor, two Process Operators, and two Facility Operators.
- Maintenance Resources – Maintenance personnel are being shared with the power station; however, extra resources were assigned to meet the facility's maintenance needs.
- Chemistry Capacity – SaskPower has expanded its chemistry capacity at multiple locations to manage these operations effectively.
- Process Engineers – The team includes on-site process engineers responsible for day-to-day operations support, along with support from remote engineers who work on plant optimization and other capital projects.
- On-Site Management Staff – Management staff members for the facility are on-site, including a Production Manager and a Production Support Manager.

The number of positions required to operate a capture facility is highly specific to the industrial process, the composition of flue gas to be captured, the size of the facility, the CCS technology used, and the level of integration between the industrial and capture facilities. A representative estimate for full time positions was included in the projects fixed operating expense estimate.

8 Overall Conclusions

Preliminary work by Nutrien identified three potential carbon capture options for the facility. This study first undertook a trade-off assessment to identify the option to be carried forward for the remainder of the study. This was the work completed under Milestone 1 of the study, called Feasibility A. The options included: (1) post-combustion carbon capture from the flue gas from the reformer stack(s), (2) installation of an auto-thermal reformer (ATR) to replace the existing steam-methane reformer (SMR) with capture of the CO_2-rich process gas stream, and (3) installation of auto-thermal reforming with CO_2 capture to generate hydrogen fuel to replace methane as a heat source. Option 1 would involve the installation of an amine-based post-combustion carbon capture system. For Option 2, the current SMR process would be replaced by ATR technology to produce a higher concentration CO_2-rich stream for capture, thus greatly reducing the volume of flue gas. Option 3 would install ATR technology upstream of the existing SMR process, the resulting hydrogen would replace methane as a heating fuel source for the plant.

The results from these studies came to the determination that post-combustion flue gas capture is the most technically feasible solution of the three proposed options. An evaluation for the post-combustion carbon capture of flue gas from the existing Plant 01 and Plant 09 SMRs as well as additional flue gas from a proposed cogen plant was conducted in Feasibility B to reduce the carbon footprint at Nutrien's Redwater Nitrogen Operations (RNO) site.

The Feasibility B design was developed based on processing 100% of the flue gases from Plant 1 SMR, Plant 9 SMR, and the cogen plant in a two-train cylindrical quencher and absorber configuration. The targeted CO_2 capture efficiency is 95% for a total CO_2 captured of 2,798 tpd. An estimated 410 tpd of residual in scope CO_2 emissions from the Redwater site is expected, an 84% reduction in the overall CO_2 emissions with respect to the current "Do Nothing" case.

A plant layout was developed based on technology licensor PFDs, and preliminary equipment sizes for the major equipment, including the BOP utility equipment and cogen plant. Process functionality of the equipment, potential risk to operators and the public, optimized use of plot space, constructability, and accessibility to equipment for maintenance were considered.

The Redwater Post Combustion Carbon Capture Facility including Cogen Plant CapEx cost is estimated to be CAD $1.14 billion, inclusive of a 20% contingency applied to the total direct, indirect, and owner's costs. The estimate accuracy is anticipated to be -20% /+30%. A total annual operating cost of $82.3 MMCAD was estimated for the PCC facility development representing an average per unit cost of CAD $85/tonne of CO_2 captured. However, as a portion of the steam and power produced in the Co-Gen Plant is exported to the Redwater facility, it is assumed to be "sold" to the existing Redwater facility. The levelized cost of producing the steam and power was calculated as $14.6 CAD/tonne steam and 9.38¢/kWh power, and the portion exported to the Redwater facility was deducted from the annual OpEx to estimate the net operating cost of the carbon capture portion of the facility. The net OpEx was estimated to be $52.5MMCAD annually or CAD $54/tonne of CO_2 captured.

The results of the economic analysis of the project does not support the responsible deployment of capital to further develop this project. The current market environment does not support incremental demand or premium product pricing for low-carbon ammonia, fertilizers, and industrial products produced from low-carbon ammonia. Additionally, ammonia production is unable to participate in the Low Carbon Fuel Standard for biofuels. This lack of market driven revenue is a fundamental barrier to project economics and the business case.

Despite federal and provincial tax incentive programs, the project is not economically viable and prior to the commencement of FEED or any next steps, project economic viability would need to be illustrated. For this reason, no further development work will be completed on this project. The knowledge sharing activities outlined in Section 10 below and in the Knowledge Transfer Plan will be completed to disseminate lessons learned throughout the industry and to other key stakeholders.

9 Next Steps

If development of the project were to continue, on top of any further engineering development, the following activities are also recommended to further define the project parameters:

- Update the Design Basis based on flue gas analysis results from July 2024. Iterations between flue gas flow to the PCC and steam requirement from the cogen plant are required to define the flue gas flow and composition as basis for the technology licensor design.
- Confirm SCR unit requirements based on regulatory requirements and review NO_x removal package technical specification.
- Further air dispersion modelling is required to size the CO_2 vent stack based on the flue gas contaminants and the required regulatory emissions thresholds. This model will evaluate the impact of gas exposure on people and surroundings from vent/stack releases as well as optimize the layout design during FEED.
- CO_2 transportation to the offsite reservoir is not part of the Project scope. However, the battery limit, tie-in point to CO_2 pipeline and the custody transfer of the recovered CO_2 must be further defined.
- Further evaluate process optimizations identified as part of the modularization study, such as reboiler design, potential to increase the number of plate and frame heat exchangers in the combined train to optimize modularization and heat integration work to recover heat from the flue gases. In addition to further develop utilities integration with the existing Nutrien site.
- In total, the proposed carbon capture facility requires a maximum total raw water makeup of 1,840 USGPM The following options can be investigated during the next phase of engineering to reduce raw water import to the PCC facility:
    - Blowdown from the Co-Gen Plant can be sent to the cooling tower as makeup to reduce the raw water import.
    - Consider a hybrid cooling system in which air cooling is utilized to cool the cooling water return. This hybrid system could reduce the overall cooling water make-up (thus also reducing the raw water import to the PCC facility) and the cooling tower blowdown to the settling ponds. However, the hybrid cooling system requires more plot area than a conventional cooling tower and may be more costly.
    - Treatment of overhead condensate from the existing ammonia plant for re-use as cooling tower make-up.
- The following items need to be defined during the next engineering phase for the fire water system:
    - Fire protection philosophy.
    - Fire water requirement for the PCC facility considering specific requirement for the carbon capture process and BOP.
    - Fire water distribution header and distribution system sizing.
    - Integration with existing fire water system at the Redwater facility.

- Detailed Reliability, Availability, and Maintainability (RAM) analysis to be conducted in the next phase of the project to verify plant availability.
- The availability of additional natural gas to the cogen plant as well as the requirement of an additional metering station needs to be investigated during the next engineering phase. The pipeline that currently feeds into Redwater is now fully constrained and fully contracted. Additional service will need to be requested by Nutrien to a corresponding third-party entity accordingly with the project schedule which is targeting PCC facility operation by the end of 2030.
- Feasibility B assumed the TIER 2022 High Performance Benchmark for electricity to estimate the additional indirect CO_2 emissions due to power import from the grid. The electrical emission profile should be updated with the long-term TIER benchmark outlook for electricity in the next phase.
- Tie-in to Plant 01 building – the Plant 01 building structure is aged and may not be able to handle additional loads required to support the flue gas ducting. Additionally, the area around Plant 01 is congested with little space available for duct supports external to the existing building structure. Investigate if the existing building can be used for supporting the Plant 01 ducting from stack to ground and identify the preferred support option to be engineered.
- Tie-ins to existing Redwater facility – identify tie-in locations to the existing Redwater facility and tie-in routings for Instrument and Utility Air, Potable Water, Service Water, Raw Water, Clarified Water from Plant 35, Fire Water System, Nitrogen, Natural Gas, MP Steam, Electrical and Chemical Sewer. Assess capacity of existing pipe rack system to support the tie-in runs

10 Communications Plan

The communications plan for the Emissions Reduction Alberta (ERA) Final Outcomes Report is designed to effectively disseminate the outcomes of the ERA-funded project to key stakeholders, including government agencies, industry partners, and the public. This plan outlines a strategic approach to sharing the project's achievements in technological advancements, and economic impacts. By utilizing a mix of communication channels—such as social media, web content and industry conferences—the plan aims to raise awareness, engage stakeholders, and inspire further innovation in the pursuit of a low-carbon future. Through targeted messaging and impactful content, this communications plan will ensure that the project's successes are widely recognized, and that the knowledge gained is shared for the benefit of ongoing and future initiatives.

10.1 Objectives

- Ensure Awareness: Raise awareness about the project's outcomes, emphasizing its impact on emissions reduction and environmental benefits.
- Engage Stakeholders: Build strong engagement with key stakeholders, including government bodies, industry partners, academic institutions, and the public, to foster collaboration and support.
- Share Knowledge: Disseminate knowledge and insights gained from the project to inspire further research and innovation.
- Highlight Achievements: Showcase the project's achievements and advancements in technology readiness levels and Canada’s CCS potential.

10.2 Key Activities

Carbon Capture Kickstart Knowledge Sharing Session (May 2024)

- The purpose of this session was to convene key technical project contacts from all Carbon Capture Kickstart proponents to exchange non-confidential lessons learned.
- The session was co-facilitated by Emissions Reduction Alberta (ERA) and the International CCS Knowledge Center with all *Carbon Capture Kickstart Lessons (*CCK) program participants in attendance.

Conference Pre-launch: CCK Lessons Learned Report and Presentations (October/November 2024)

- Key Messaging: Key messaging will be prepared by Nutrien and shared with the International CCS Knowledge Centre and ERA prior to launching the full report to be used for promotional materials on an ongoing basis.
- Presentation & Shared Lessons-Learned Report from Carbon Capture Kickstart: The International CCS Knowledge Centre is developing a Lessons Learned Report and an accompanying presentation slides detailing activities from the CCK program's funded projects. The presentation will cover a summary of the projects funded by the program including project objectives, methodologies, results, and impacts. Such a summary will not share lessons learned or identifying data of individual projects, but rather a summation of the project lessons learned, of which Nutrien's Final Outcome Report is one deliverable. The presentation will be delivered by Shannon Timmons, Manager of Project Development & Technical Services at GHGT and in workshops and presentations. A Lessons Learned report will be published and available to the public on ERA's website, shared with Nutrien and available for use at Nutrien's discretion on an ongoing basis.

Social Media Posts (On-going)

- Key Messaging: Nutrien will develop and share any key messaging to both the ERA and the International CCS Knowledge Centre for their promotional campaigns for the CCK projects, as needed.
- Nutrien will engage with relevant posts from the ERA and International CCS Knowledge Centre upon posting.

Public Information Sharing Events Post-Project (On-going)

- Information Sharing Sessions: The final report will be represented and promoted at information sessions attended and co-hosted by Nutrien using the slides curated and shared with ERA.
- Handouts/Online Dissemination: Summarized reports will be distributed in both hardcopy and digital formats, with contact information for further inquiries following the launch.

10.3 Evaluation

The ERA and International CCS Knowledge Centre will track and review engagement of CCK project results.

Metrics

- Monitor website traffic and report downloads.
- Track social media engagement (likes, shares, comments).
- Evaluate workshop attendance and participant feedback.
- Gather feedback from stakeholders and address inquiries.

Review

- Assess the overall effectiveness of communication activities.
- Collect and analyze feedback from stakeholders.
- Identify areas for improvement and adjust the communications plan accordingly.

11 References

Environment Canada, Health Canada. (2001). *Priority Substances List Assessment Report: N-Nitrosodimethylamine.* Minister of Public Works and Government Services.

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