Quest Carbon Capture and Storage Project

VOLUME 1: PROJECT DESCRIPTION

Prepared for:
Shell Canada Limited
Calgary, Alberta

Prepared by:
Stantec Consulting Inc.
Calgary, Alberta

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Executive Summary

Introduction and Project Description

Shell Canada Limited (Shell), on behalf of the Athabasca Oil Sands Project (AOSP), which is a joint venture between Shell Canada Energy, Chevron Canada Limited, and Marathon Oil Canada Corporation, is applying to construct, operate and reclaim the Quest Carbon Capture and Storage (CCS) Project (the Project). The goal of the Project is to capture, transport and permanently store carbon dioxide (CO_2), thereby reducing greenhouse gas emissions from the existing Scotford Upgrader. The Scotford Upgrader is located about 5 km northeast of Fort Saskatchewan, Alberta, within Alberta's Industrial Heartland, which is zoned for heavy industrial development.

The three components of the Quest CCS Project are:

- CO_2 capture infrastructure, which involves a process modification to the existing Scotford Upgrader. The method of capture is based on a licensed Shell activated amine technology called ADIP-X.
- a CO_2 pipeline, which will transport the CO_2 from the Scotford Upgrader to the injection wells
- storage of the CO_2 through 3 to 10 injection wells, which will inject the CO_2 into the Basal Cambrian Sands (BCS), a deep saline geological formation, for permanent storage at a depth of about 2 km below ground level

The CO_2 capture infrastructure will be constructed on a previously disturbed area, approximately 150 m by 150 m, adjacent to three existing hydrogen manufacturing units (HMUs) at the Scotford Upgrader. The Project will reduce the CO_2 emissions from the Scotford Upgrader by up to 35%, capturing and storing up to 1.2 million tonnes of CO_2 per year. The capture infrastructure will use amine absorbers to capture approximately 80% of the CO_2 from the process gas stream produced by the HMUs. The captured CO_2 will be dehydrated and compressed prior to entering the pipeline.

The CO_2 from the Scotford Upgrader will be transported to the storage area using a single high-vapour-pressure pipeline, approximately 84 km long and with an outside diameter of 323.9 mm. The pipeline will cross several waterbodies, the largest being the North Saskatchewan River, and will parallel about 28 km of existing pipeline rights-of-way.

The 3 to 10 wells required for injecting the CO_2 into the BCS for storage will be located within the area of interest of the Project. The wells will be connected to the main pipeline by laterals, all assumed to be less than 15 km long. The BCS is overlain by a number of formations which provide containment for the CO_2.

Construction of the CO_2 capture infrastructure is expected to start in Q3 2012, and pipeline construction in Q4 2013. The injection wells will be drilled between Q3 2013 and Q3 2014. Commission and start-up of the operation is anticipated to begin in Q1 of 2015. The lifespan of the Project is considered to be for the life of the Scotford Upgrader (greater than 25 years).

Regulatory Approvals

Shell is seeking partial funding for the Project from the Government of Canada Clean Energy Fund – a program created as part of the federal Economic Action Plan and administered by Natural Resources Canada (NRCan). As such, the Project is subject to a federal environment assessment under the *Canadian Environmental Assessment Act (CEAA)*. NRCan is a Responsible Authority, and has determined that a screening-level environmental assessment (EA) is required under *CEAA*.

Shell will also prepare an Environmental Impact Assessment (EIA), under the Alberta *Environmental Protection and Enhancement Act* (*EPEA*), and associated regulations for the CO_2 storage component of the Project.

Alberta Environment, Alberta Sustainable Resources Development, and the Energy Resources Conservation Board (ERCB) are responsible for a number of approvals required for the individual Project components.

Environmental Setting

The Project is within the municipal boundaries of Strathcona County, Lamont County, Sturgeon County and Thorhild County. The Project occurs entirely on privately held lands, except for several named watercourse crossings (bed and banks) administered by the Crown. Land use across most of the Project area is agricultural. The CO_2 capture infrastructure and the southern portion of the pipeline route are on industrial lands, within Alberta's Industrial Heartland (AIH). Land uses in AIH are industrial, agricultural, subsurface and other resource extraction (i.e., quarries, logging).

Environmental Assessment

The EA considers all three Project components: capture infrastructure, pipeline, and injection wells and storage. The EA conservatively assesses the potential environmental effects of all 10 well pads, access roads, borrow pit areas and pipeline laterals. This includes:

- the five candidate well locations and their access roads, for which field surveys were conducted, and conceptual routes for their lateral pipelines
- consideration of conceptual locations of the remaining five wells (and their access roads and lateral pipelines) to reflect a maximum build-out

To focus the environmental and socio-economic assessment, issues related to the Project are identified from a variety of sources, including:

- regulatory requirements as outlined in the *CEAA* and the Terms of Reference for the Quest CCS Project
- discussions with technical experts from various provincial and federal government agencies
- input from the consultation program (with regulators, landowners, Aboriginal communities and groups, and scientists)
- existing regional information and documentation regarding environmental and socio-economic components in the Project area (e.g., Species at Risk)
- documentation relating to other projects and activities in the Project area
- field studies in the areas where potential environmental effects due to the Project are likely to occur
- professional judgement of the assessment practitioners, based on experience with similar projects elsewhere and other projects and activities in the same region
- experience of Shell

A list of potential valued environmental components (VECs) was developed and is used in the assessment. One or more VECs are identified for each of the disciplines in the environmental effects assessment to reflect the relevant issues. For each VEC, potential Project interactions and potential environmental and socio-economic effects are evaluated. The components considered were:

- air quality
- sound quality
- geology and groundwater
- aquatic resources
- soils and terrain
- vegetation and wetlands
- wildlife and wildlife habitat
- historical resources
- land use
- public health and safety
- socio-economics

Findings and Significance

The Project will not have a significant adverse effect on any biophysical or socio-economic resource provided the mitigation measures identified in the EA are implemented.

Accidents, Malfunctions and Unplanned Events

This assessment considers potential accidents, malfunctions and unplanned events that could occur during any Project phase and result in adverse environmental effects. The significance of residual effects on each potentially affected VEC is evaluated. This evaluation considers the extensive preventative measures committed to by Shell and the low likelihood of these events occurring. The assessment concludes that no significant environmental effects are predicted to occur for each assessed event.

Conservation and Reclamation Plan and Environmental Protection Plan

Detailed conservation and reclamation (C&R) plans for the pipeline and the five candidate injection well pads are provided in appendices to Volume 1. The pipeline C&R Plan summarizes the biophysical and cultural resource conditions identified through field assessments along the route. The C&R plan for the well pads also includes a pre-disturbance assessment that considers baseline terrestrial and historical resources conditions. An environmental protection plan (EPP) is also provided as an appendix to Volume 1. It includes mitigation for environmental effects of pipeline construction on biophysical and cultural resources. The EPP identifies measures to be implemented during all phases of construction and reclamation

Follow-up and Monitoring

Shell will implement follow-up and monitoring programs, including:

- *Measurement, Monitoring and Verification Plan* – Shell is committed to implementing a measurement, monitoring and verification (MMV) plan for the Project. The two primary purposes of MMV activities are to verify storage performance (conformance) and verify containment of CO_2 in the BCS storage complex. A conceptual level MMV plan is included in Volume 1, Appendix A.
- *Additional Field Surveys for Pipeline Reroutes* – Shell will undertake field surveys along areas of the pipeline route where additional field data is required, due to pipeline reroutes.

- *Follow-up Work to Support Site Selection for Well Pads and Associated Infrastructure* – Shell will undertake a site and route selection process for the five remaining well pads and pipeline laterals, access roads and borrow areas. As part of the site selection process, Shell will undertake constraint mapping, and pre-disturbance assessments, which will include field surveys where necessary. Detailed conservation and reclamation plans will also be developed for each Project feature.
- *Pipeline and Well Pad Reclamation and Post-Reclamation Monitoring* – Shell will monitor the pipeline ROW for re-vegetation success for three growing seasons following construction, or until vegetation establishment is complete. In addition, Shell will reclaim the well pads and associated infrastructure to an equivalent land capability after Project decommissioning.
- *Follow-up and Monitoring for VECs* – There are a number of specific follow-up and monitoring activities Shell will implement, as outlined in the EA.

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Acronyms and Abbreviations

ACCS .... Alberta Culture and Community Spirit
ADIP-X .... Shell's activated amine process
AIHA .... Alberta's Industrial Heartland Association
AOI .... Area of Interest
AOSP .... Athabasca Oil Sands Project
ARC .... Alberta Research Council
ASRD .... Alberta Sustainable Resource Development
BCS .... Basal Cambrian Sands
BGWP .... Base of Groundwater Protection
C&R Plan .... Conservation and Reclamation Plan
CAPP .... Canadian Association of Petroleum Producers
CCS .... carbon capture and storage
CEA Agency .... Canadian Environmental Assessment Agency
CEAA .... *Canadian Environmental Assessment Act*
CO_2 .... carbon dioxide
COSEWIC .... Committee on the Status of Endangered Wildlife in Canada
DFO .... Fisheries and Oceans Canada
EIA .... Environmental Impact Assessment
EOR .... enhanced oil recovery
EPEA .... *Environmental Protection and Enhancement Act*
EPP .... Environmental Protection Plan
EPZ .... emergency planning zone
ERCB .... Energy Resources Conservation Board
ERP .... Emergency Response Plan
ESA .... environmentally significant area
FAP .... Fort Air Partnership
GHG .... greenhouse gas
H_2S .... hydrogen sulphide
HARP .... Heartland Area Redwater Project
HDD .... horizontal directional drilling
HMU .... hydrogen manufacturing unit
HSSE & SP .... health, safety, security, environment and social performance
IEA .... International Energy Agency
IPAC-CO2 .... International Performance Assessment Centre for the Geologic Storage of CO_2
IPCC .... Intergovernmental Panel on Climate Change
LMS .... Lower Marine Sand
LNG .... liquefied natural gas
mASL .... metres above sea level
mBSL .... metres below sea level
MCS .... Middle Cambrian Shale
mD .... millidarcy
MD .... measured depth
MDEA .... methyl-diethanolamine
MDT .... Modular Dynamic Tester
MMV .... measurement, monitoring and verification
MPMO .... Major Project Management Office

Mt/a .... million tonnes per year
mTVD........ metres at true vertical depth
NGO .... non-governmental organization
NMR........ nuclear magnetic resonance
NO_X .... oxides of nitrogen
NRCan .... Natural Resources Canada
OSCA .... *Oil Sands Conservation Act*
PSA........ pressure swing adsorber
R&D .... research and development
RA .... Responsible Authority
ROW........ right-of-way
SARA........ *Species at Risk Act*
SCADA .... supervisory control and data acquisition
Shell........ Shell Canada Limited
TEG .... triethylene glycol
the Project........ Quest Carbon Capture and Storage Project
TWS .... temporary workspace
UK .... United Kingdom
UMS .... Upper Marine Siltstone
US........ United States
UWI........ unique well identifier
VEC........ valued environmental component
XRD .... x-ray diffraction
WCSB........ Western Canada Sedimentary Basin
Well 3-4........ Shell Redwater 3-4-57-20W4 well
Well 8-19........ Shell Radway 08-19-059-20W4 well
Well 11-32........ Shell Redwater 11-32-55-21W4 well

1 Introduction

1.1 Purpose of Environmental Assessment

Shell Canada Limited (Shell, the Proponent) proposes to construct, operate and decommission the Quest Carbon Capture and Storage (CCS) Project (the Project), northeast of the City of Edmonton. Shell is seeking partial funding for the Project through the Government of Canada Clean Energy Fund, a program created as part of the federal Economic Action Plan and administered by Natural Resources Canada (NRCan). Government of Canada funding of the Project triggers the need for an environmental assessment under the *Canadian Environmental Assessment Act* (*CEAA*) (Section 5(1)(b)).

Shell will also prepare an Environmental Impact Assessment (EIA), under the Alberta *Environmental Protection and Enhancement Act* (*EPEA*), and associated regulations for the carbon dioxide (CO_2) storage component of the Project. The EIA report will be submitted to the Government of Alberta concurrently with Shell's application to the Energy Resources Conservation Board (ERCB).

An environmental assessment is being submitted consistent with the Canada–Alberta Agreement for Environmental Assessment Cooperation, in which Alberta Environment is the Lead Party. Shell has prepared a single EIA report, which satisfies the requirements under *CEAA* and the *EPEA*.

1.2 Project Overview

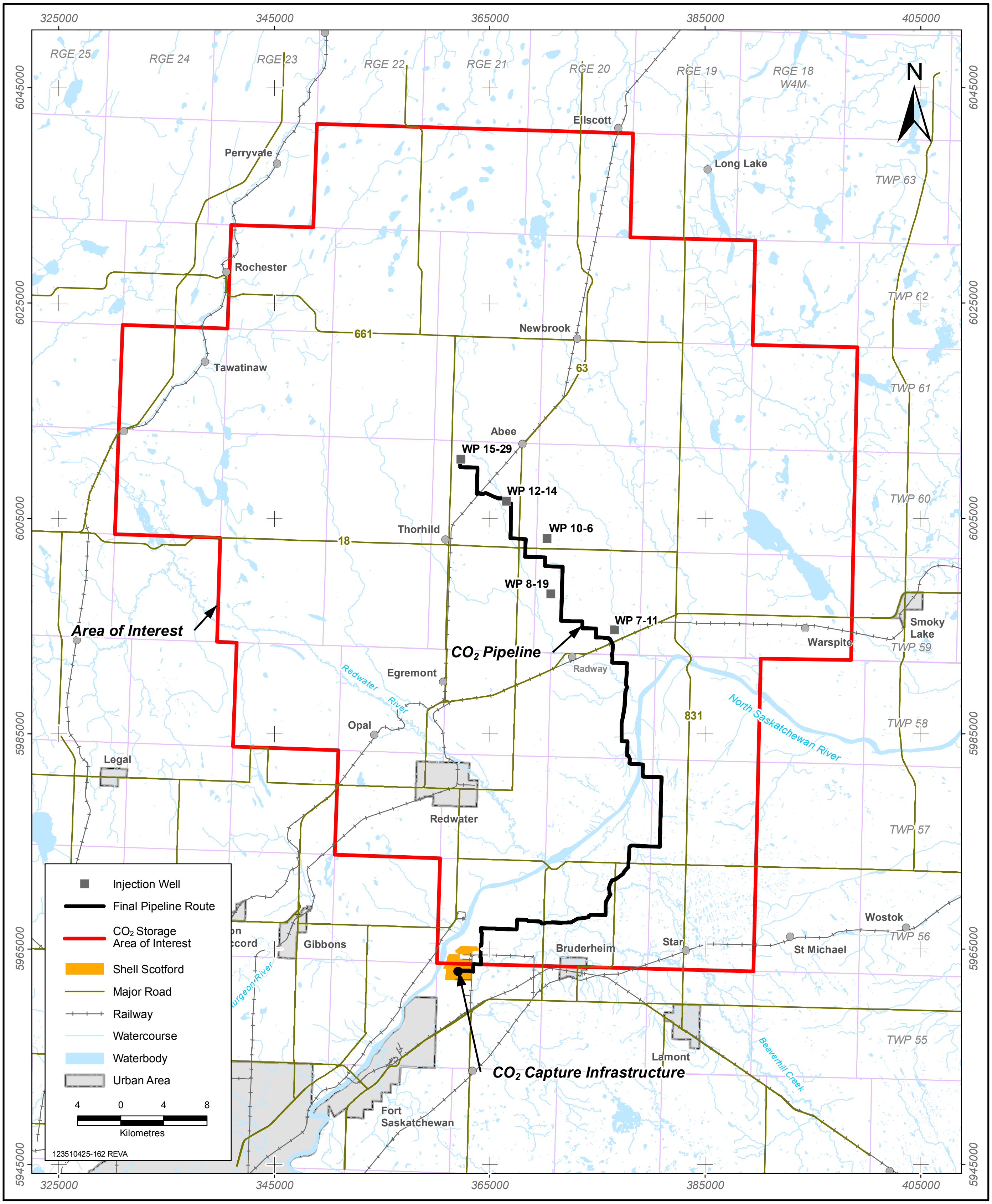
The purpose of the Quest CCS Project is to capture and store up to 1.2 million tonnes per year (Mt/a) of carbon dioxide (CO_2) from the Scotford Upgrader using CCS technology. As a large industrial emitter of greenhouse gases in Alberta, Shell is required under the Specified Gas Emitters Regulation to reduce emissions intensity. The Quest CCS Project is a key component of the greenhouse gas abatement strategy for Shell Canada Limited.

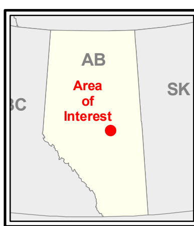
The life of the Project is expected to be tied to the life of the Scotford Upgrader, which is greater than 25 years.

1.2.1 Quest CCS Project Description

The three components of the Quest CCS Project (see Figure 1-1) are:

- CO_2 capture infrastructure, which involves a process modification to the existing Scotford Upgrader
- a CO_2 pipeline to transport CO_2 to storage infrastructure located north of Shell Scotford
- injection well storage infrastructure for permanent storage of CO_2 in a deep saline geological formation





QUEST CARBON CAPTURE AND STORAGE PROJECT

Quest CCS Project Components and Area of Interest

Acknowledgements: Original Drawing by Stantec
Pipeline: Sunstone Engineering October 15, 2010, Wells: Shell August 26, 2010, Basedata: National Road Network, Canvec, Altalis

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Stantec

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FIGURE NO.
1-1

Last Modified: Nov 18, 2010 By: jpetho

1.2.1.1 CO_2 Capture Infrastructure

Up to 1.2 Mt/a of CO_2 will be captured from three existing hydrogen manufacturing units (HMUs). The HMUs manufacture hydrogen to upgrade oil sands bitumen at the Scotford Upgrader. The method of CO_2 capture will be based on a commercially proven activated amine technology called Shell ADIP-X. The CO_2 capture and compression facility also includes multi-stage compression of the captured CO_2 into a dense-phase ready for transportation. The purity of the dense-phase gas will be higher than 95 vol% of CO_2.

The Project capacity is based on the design of the CO_2 capture infrastructure, which will have:

- a stream day (or nameplate) capacity of up to 1.2 Mt/a of CO_2
- a calendar day capacity of 1.08 Mt/a of CO_2 (assuming an on-stream factor of 90%)

1.2.1.2 CO_2 Pipeline

Transportation of the captured CO_2 will be via pipeline, from the Scotford Upgrader to a storage area north of the Scotford Upgrader (see Figure 1-1). The CO_2 pipeline is approximately 84 km in length. Approximately 28 km of this pipeline will be parallel to existing pipeline rights-of-way.

1.2.1.3 CO_2 Storage

Wells will be designed for injection of CO_2 into the Basal Cambrian Sands (BCS) formation, at a depth of approximately 2 km below the surface. A measurement, monitoring and verification (MMV) program will be implemented.

The cumulative stored volume could exceed 27 Mt of CO_2 over the expected Project life (greater than 25 years).

1.2.2 Location

The CO_2 capture infrastructure will involve a process modification to the existing Scotford Upgrader, on lands within the developed area of the Scotford Upgrader. The CO_2 pipeline will extend a distance of 84 km from the Scotford Upgrader, north across the North Saskatchewan River and will terminate north of the village of Thorhild. The 3 to 10 injection wells will be situated in the CO_2 storage area of interest (AOI), occupying about 40 townships in area, ranging from Townships 56 to 63 and Ranges 18 to 24, all west of the Fourth Meridian. For the location of the proposed CO_2 capture infrastructure, the CO_2 pipeline and the proposed location of the first five injection wells, see Figure 1-1.

The CO_2 would then be stored permanently about 2 km below surface in the BCS. The Project storage area is defined by the Pore Space Request AOI (see Figure 1-1), as submitted by Shell to the Alberta Department of Energy in December 2009. The extent of the AOI has been determined as the amount of pore space required in the BCS to inject and store the CO_2 for the expected life of the Project.

1.2.3 CO_2 Capture Infrastructure

The Project comprises new process units including three amine absorber towers, an amine regeneration unit, a multi-stage CO_2 compressor with coolers and separators, and a triethylene glycol (TEG) dehydration unit. It also includes supporting utilities including water, steam, air and nitrogen and electrical power. The Project requires modifications to three existing HMUs.

Capturing the CO_2 will reduce CO_2 emissions from the Scotford Upgrader by up to 35%. The method of CO_2 capture includes absorption and recovery of CO_2 from an intermediate process stream called synthetic gas.

The CO_2 capture infrastructure consists of the following main process blocks (see Section 2):

- CO_2 capture, which includes amine absorbers and associated equipment. One set of each will be located within the plot space of the three HMUs.
- an amine regeneration unit, which includes associated amine storage and a CO_2 vent stack
- CO_2 compression, which includes a multi-stage centrifugal compressor with an electrical motor driver, interstage coolers and knockout drums
- CO_2 dehydration, which includes a TEG absorber and regeneration unit

The amine absorbers will use a methyl diethanolamine-type (MDEA) solvent to capture the CO_2 from the synthetic gas of the HMUs. The custom MDEA-based solvent mixture is a licensed Shell amine system called ADIP-X that is selective for CO_2. The CO_2 will be separated from the amine in a common amine regeneration process to produce CO_2 that is more than 95% pure, at slightly above atmospheric pressure. The remaining gas will consist of hydrogen, methane and trace levels of hydrogen sulphide (H_2S). This trace level H_2S content will be at concentrations below consumer quality natural gas. The combined compressor and TEG dehydration unit will pressurize and dry the CO_2 gas to about 14,500 kPa(g) in a dense-phase (called supercritical) fluid for transportation.

1.2.4 CO_2 Pipeline

Compressed CO_2 will be transported via a new pipeline from the CO_2 capture infrastructure, which will involve a process modification to the existing Scotford Upgrader, to a storage area located north of the CO_2 capture infrastructure. The CO_2 pipeline will be about 84 km long and 323.9 mm (12 inches) in diameter, and will be used to transport the dense-phase CO_2 from the CO_2 capture infrastructure to the storage area. Block valves will be spaced at maximum distances of 15 km along the route and near selected locations, such as watercourse crossings.

The CO_2 pipeline will require an 18 m right-of-way (ROW) and an additional 7 m of temporary workspace during construction. Most of the CO_2 pipeline route will be within agricultural land. The CO_2 pipeline will cross a number of permanent and ephemeral water bodies, the largest being the North Saskatchewan River. The preferred construction method for the North Saskatchewan River crossing is by horizontal directional drilling (HDD). The CO_2 pipeline will also cross several small wetlands.

The CO_2 pipeline will follow existing pipeline rights-of-way for much of the route. Approximately 28 km of the CO_2 pipeline will be adjacent to existing pipeline rights-of-way.

The routing for the proposed CO_2 pipeline in the Quest CCS Project's application, *Directive 56: Application for a CO_2 Pipeline Licence*, under *Directive 056: Energy Development Applications and Schedules* (Directive 56), differs slightly from the route assessed in this environmental assessment. In order to facilitate and complete field studies for the environmental assessment during the 2010 field season, it was necessary to freeze the route in August 2010. Shell, however, continued the consultation with landowners and residents along the CO_2 pipeline route, and additional re-routes have been made in response to consultation and stakeholder feedback. The Directive 56 CO_2 pipeline licence application has, therefore, been submitted with a slightly different route that includes those alterations that were made in consultation with landowners and residents along the right-of-ways. The route in the Directive 56 CO_2 pipeline licence application reflects a freeze date of November 10, 2010. Additional environmental field studies will be conducted in 2011 along those portions of the route that are new and were not surveyed during the 2010 field season.

1.2.5 CO_2 Storage

The cumulative stored volume could exceed 27 Mt of CO_2 over the life of the Quest CCS Project (greater than 25 years).

Wells will be designed for injection of CO_2 into the BCS, at a depth of approximately 2 km below surface. An exploration appraisal well program is underway that will provide necessary information for determining the final locations of the injection wells for permanent CO_2 storage. A measurement, monitoring and verification (MMV) program will be implemented.

Shell completed drilling of three exploration appraisal wells, and gathered and assessed geophysical data to confirm the technical aspects of the site. Characterization of the petrophysical properties in the AOI were primarily based on the results of these three Project appraisal wells, with additional input from offset legacy wells.

Based on the current results, it is expected that approximately 3 to 10 injection wells will be drilled for injecting the CO_2 into the BCS. To date, the locations of five of the injection wells have been determined (see Figure 1-1). Of these, the Shell Radway 08-19-059-20W4 well (Well 8-19) was developed as an appraisal well in 2010. Locations for an additional four wells were identified in 2010. For the locations of these first five injection wells, see Table 1-1, and Figure 1-1.

Although five candidate wells have been included in the application, the proposed storage scheme carries a range of three to ten injection wells, all of which are located within the AOI assumed to be within 15 km of the CO_2 pipeline. The final well number, locations of wells and routing of lateral pipelines to connect the wells to the main CO_2 pipeline will be determined in 2011. If required as per the final injection scheme, some of the wells identified in this environmental assessment may be removed or replaced with updated locations. In addition, a total of up to ten injection wells may be developed as part of the storage component of the Project. The environmental assessment conservatively assesses the potential environmental effects of all ten well pads, access roads, laterals and any associated borrow pits that may be developed as part of the CO2 storage component through consideration of conceptual locations of the remaining five unknown wells.

Table 1-1 Well Locations Included in the CO_2 Storage Scheme Application

Well Name	Potential Injection well	NAD 27 UTM Zone 12 North	NAD 27 UTM Zone 12 East
08-19-059-20W4	1	5997747.399	370705.482
07-11-059-20W4	2	5994416.66	376674.14
10-06-060-20W4	3	6002873.82	370401.14
12-14-060-21W4	4	6006367.36	366539.42
15-29-060-21W4	5	6010249.00	362408.94

1.2.5.1 Measurement, Monitoring and Verification

To verify storage performance(conformance) of CO_2 within the BCS, a MMV program will be implemented (see Appendix A). In addition to the injection wells, monitoring wells will also be drilled as part of the MMV program. Shell will use established and proven MMV technologies and systems so that the storage area performs as expected. This will require data collection and analysis during CO_2 injection and before and after injection start-up for adaptive management.

1.3 Project Proponent

Shell Canada Limited (Shell), on behalf of the Athabasca Oil Sands Project (AOSP), is applying to be the licensee for the Quest CCS Project.

Shell Canada Limited, which will hold all necessary regulatory approvals in respect of the Project, is the managing partner of Shell Canada Energy. Shell Canada Energy will operate the Project on behalf of the AOSP, which is a joint venture between Shell Canada Energy (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%).

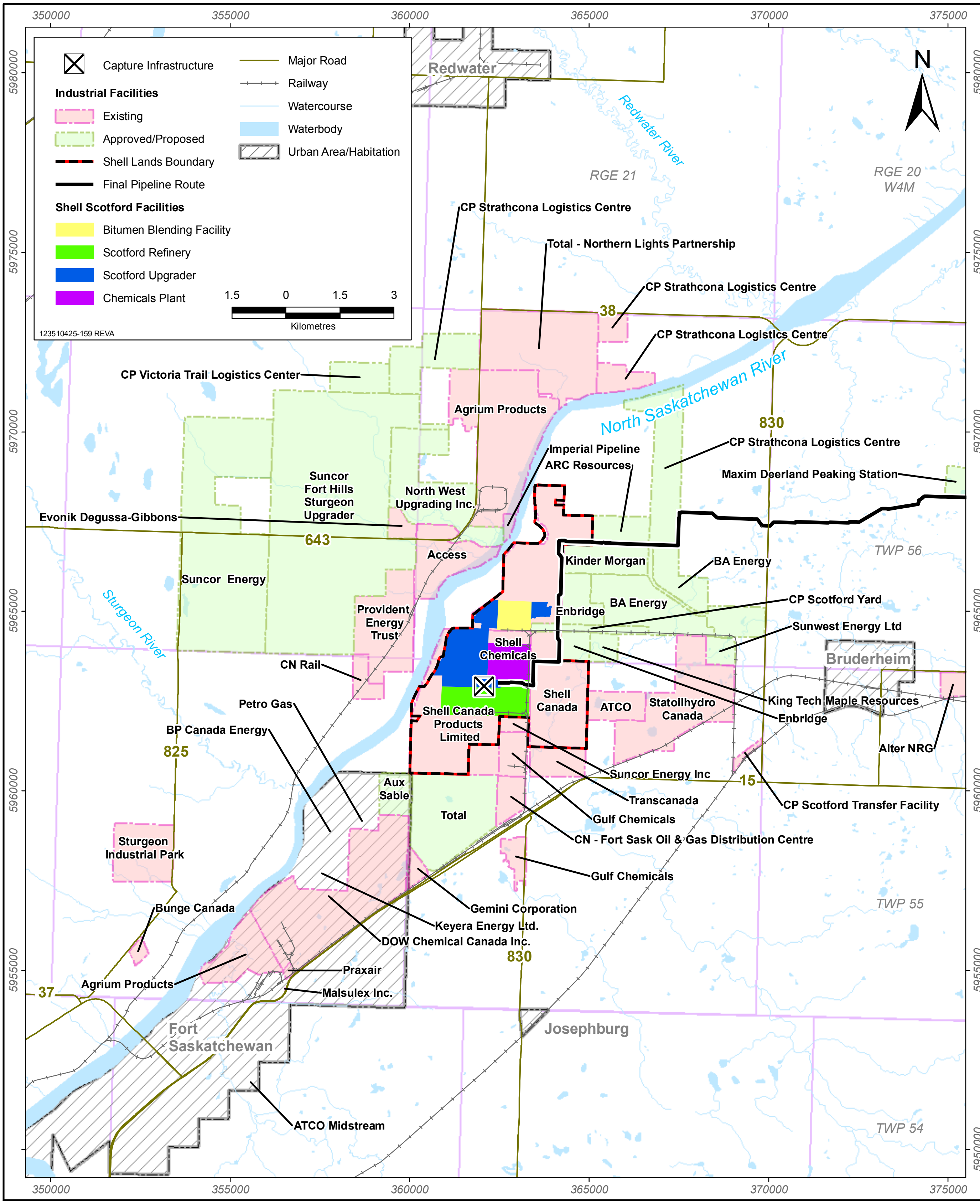
1.3.1 Current Operations

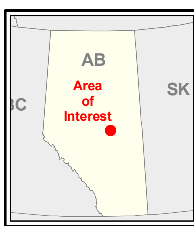
Shell has broad experience in the areas required to implement an integrated CCS project of this scale. The following sections identify operational experience that will contribute to the successful execution of the Project.

1.3.1.1 Shell Scotford

Located 40 km northeast of Edmonton, Alberta, Shell Scotford consists of the AOSP Scotford Upgrader (also referred to as the Scotford Upgrader), Shell Scotford Refinery, Shell Chemicals plant and a future planned AOSP Bitumen Blending Facility (see Figure 1-2).

The proposed CO_2 capture infrastructure, if approved, will be constructed inside the plant boundaries of the Scotford Upgrader and will be connected to the upgrader.





QUEST CARBON CAPTURE AND STORAGE PROJECT

Land Ownership and Urban Areas in the Vicinity of Shell Scotford

Acknowledgements: Original Drawing by Stantec
Pipeline: Sunstone Engineering October 15, 2010, Wells: Shell August 26, 2010, Basedata: National Road Network, Canvec, Altalis, Land Ownership: Alberta's Industrial Heartland Association February 9, 2009

PREPARED BY Stantec

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FIGURE NO. 1-2

Last Modified: Nov. 18, 2010 By: jpetho

The existing Scotford Upgrader has been upgrading bitumen since 2003 and was initially designed with two residue hydro-conversion trains and two HMUs for a total of 1,027 m^3/h (155,000 bbl/cd) of bitumen processing capacity. On a stream-day basis, this capacity is equivalent to about 1,105 m^3/h (167,000 bbl/sd) of bitumen feed, using a 93% on-stream factor. This on-stream factor accounts for both planned and unplanned outages. In 2006, Shell received regulatory approval for the Scotford Upgrader Expansion 1 project, which will bring the total Scotford Upgrader capacity to 290,000 bbl/cd or 311,800 bbl/sd by adding a third hydro-conversion and HMU train along with necessary ancillary process units and equipment, as well as debottlenecking the existing Scotford Upgrader. The Scotford Upgrader Expansion 1 project is currently undergoing start-up, and it is expected that it will be operational in early 2011. The Quest CCS Project, if approved and constructed, will recover CO_2 from all three HMUs.

1.3.1.2 Capture Processes

Shell's portfolio of technologies covers selective removal of gas contaminants, such as CO_2 and H_2S for natural gas, and refining and industrial process gases. Since the 1950s, Shell has built or licensed around 1,200 acid gas treatment plants throughout the global oil and gas industry.

Recent examples of Shell's CO_2 capture technology being used include:

- Australian North West Shelf Venture's fifth liquefied natural gas (LNG) train, commissioned in August 2008, which uses Shell's ADIP-X accelerated MDEA technology for removing CO_2 from feed gas
- Sakhalin Energy's LNG plant Sulfinol-D acid gas removal unit, commissioned in February 2009, which captures CO_2 from LNG plant feed gas
- CO_2 capture from HMU synthesis gas streams using Shell's ADIP-X technology in:
    - New Zealand Refining Company's HMU since 2006
    - Shell's Martinez Refinery since 2005
    - Shell's Singapore Refinery since 2004

1.3.1.3 Compression Processes

Shell's sour gas and CO_2 experience covers dry and wet gas compression, including:

- refinery and chemical plant applications in most of the 50 Shell refineries
- produced gas-sweetening plants, such as Al Noor (Oman)
- CO_2 gathering and injection systems in the United States (US) at the Yellowhammer, Denver, Unit and Thomasville, and recent support to Miller CO_2 in the United Kingdom (UK)
- Shell gas gathering and injection plants in Canada at Caroline, Burnt Timber, Limestone, Waterton and Jumping Pound (H_2S up to 35%, CO_2 up to 9% with more than 50 compressors)
- Emmen and Rossum Weerselo central raw gas gathering (Netherlands)
- Birba (Oman) high-pressure sour gas injection

- Harweel (Oman) ultra-high-pressure sour gas injection project
- Kashagan (Kazakhstan) ultra-high-pressure sour gas injection project

1.3.1.4 Pipelines

Since the 1970s, Shell and other AOSP joint venture partners have operated almost 1,700 km out of the 4,200 km of major CO_2 pipeline infrastructure in the US. This experience includes the Shell-built and operated Cortez pipeline (from Texas to Colorado through New Mexico), the longest and largest CO_2 capacity pipeline in the world. Shell has been building and operating pipelines in Alberta for over 40 years to transport sour gas, sweet gas and heavy oil. The combined joint venture partners CO_2 pipeline expertise is used in the proposed Quest CCS Project.

Some examples of recent pipeline projects managed by Shell are:

- Ormen Lange, Norwegian Sea – the world's longest subsea tieback (about 130 km) from wells at a depth of 850 to 1,100 mBSL
- Sakhalin II Phase 2 liquefied natural gas (LNG) and Oil Project, Russia – two onshore pipelines (122 cm [48 in.] diameter gas and 61 cm [24 in.] diameter oil) over 800 km (as well as 300 km of offshore oil and gas pipelines) as part of the world's largest integrated oil and gas project. The pipelines were laid with limited construction windows in a seismically active area with a diversity of onshore and offshore wildlife.

1.3.1.5 Storage

Shell, Chevron and Marathon bring first-hand subsurface knowledge and key learnings from their CCS portfolio projects such as Barendrecht (Netherlands), CO_2Sink (Germany) and ZeroGen and Gorgon (Australia) to the Quest CCS Project. The joint venture partners' experience from CO_2 enhanced oil recovery (EOR) operations for over 40 years, and underground gas storage for more than 20 years, will be used in characterizing the subsurface aspects of the Quest CCS Project.

The joint venture partners have participated in developing the first and the largest CO_2 EOR floods in the world and have taken lead roles in developing the CO_2 infrastructure that currently exists in the Permian Basin and elsewhere.

1.4 Need for the Project

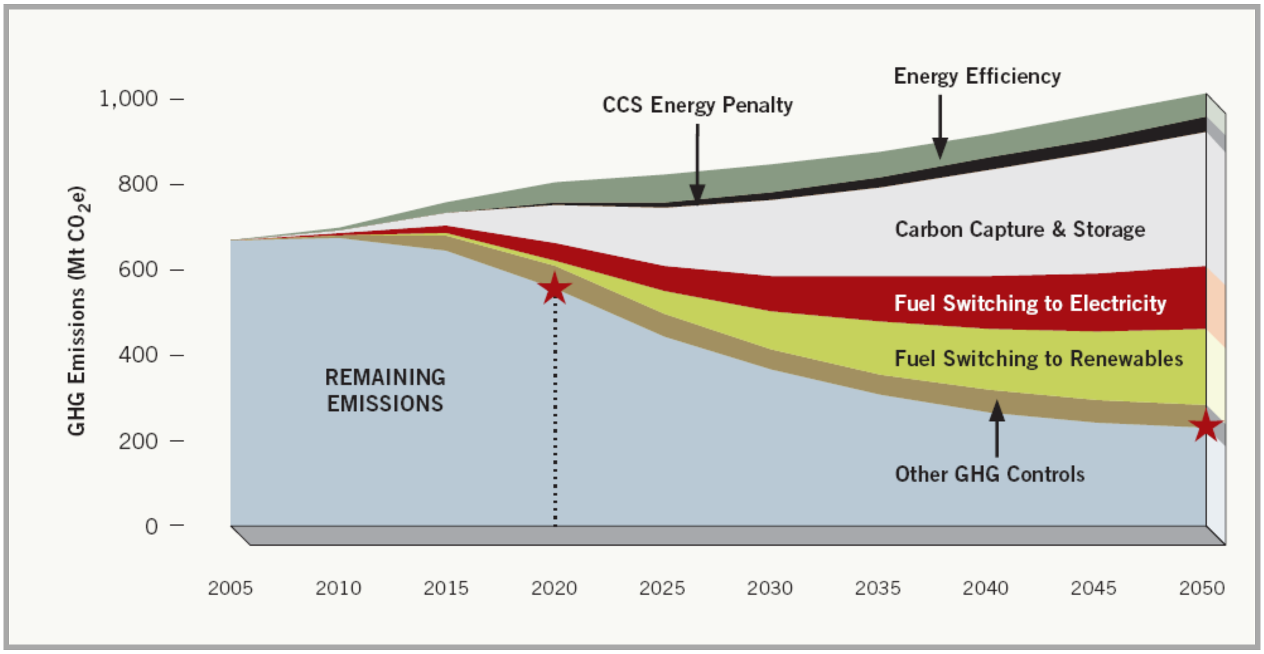
The goal of the Quest CCS Project is to reduce greenhouse gas (GHG) emissions from the Scotford Upgrader through an integrated CCS project. There are no other large-scale commercial alternatives to direct GHG reduction as that offered by the Quest CCS Project. Shell's GHG mitigation strategy has several approaches (see Section 7.4), of which the Quest CCS Project is just one. In the absence of the Quest CCS Project as an offset, Shell would advancing compliance options under the Alberta *Specified Gas Emitters Regulations*, including:

- additional improvements to energy efficiency
- using lower GHG-emitting energy supplies
- purchasing Alberta-sourced offsets
- contributing to the Climate Change and Emissions Management Fund

1.4.1 Canada and Alberta Climate Change Objectives

At the United Nations Climate Change Conference in Copenhagen in 2009, Canada announced its goal to cut CO_2 emissions by 20% below 2006 levels by 2020, and 60% below 2006 levels by 2050 (NRTEE 2009). Subsequently, this target has been updated to a 17% reduction in GHG emissions from 2005 levels by 2020, to align with the US target (Government of Canada 2010a, Internet site). According to the International Energy Agency (IEA), CCS is the only technology available to mitigate CO_2 emissions from large-scale fossil fuel use. The Intergovernmental Panel on Climate Change (IPCC) indicates that CCS technology has the potential to address climate-changing CO_2 emissions quickly.

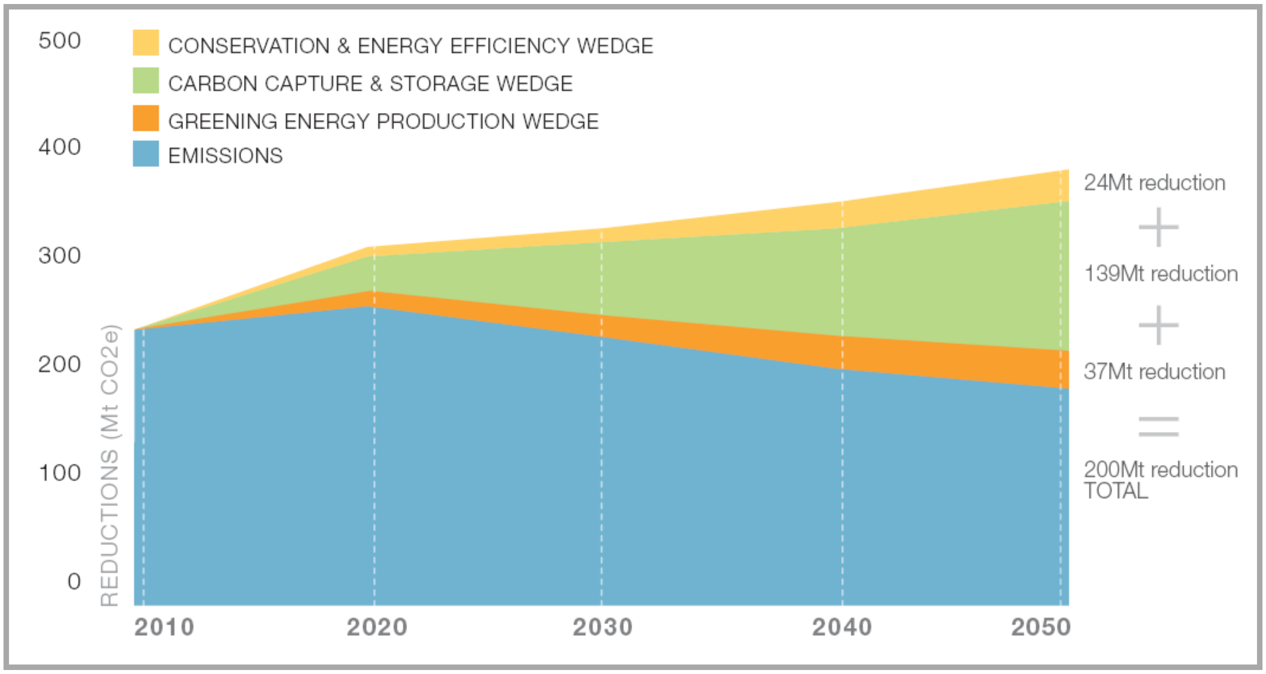
Through the Clean Energy Fund, the Government of Canada intends "to support and promote clean energy by providing funding for research into clean energy technologies such as CCS" (Government of Canada 2010b, Internet site), and to date has provided up to $466 million in support to three CCS projects in Alberta, including the Quest CCS Project. The Government of Canada policy would see CCS technology used to reduce CO_2 emissions by 325 Mt by 2050 (see Figure 1-3; NRTEE 2009).



SOURCE: NRTEE (2008)

Figure 1-3 CCS Technology in the Reduction of CO_2 Emissions in Canada

CCS technology is an important component of the Government of Alberta's Climate Change Strategy (GOA 2008). An action item identified as part of this strategy was to support research and demonstration projects on CCS. Through the use of CCS technology, the Government of Alberta intends to reduce CO_2 emissions by 139 Mt by 2050. This, combined with increased energy conservation and efficiency, and other green energy technologies would contribute to an overall reduction in CO_2 emissions of 200 Mt by 2050 (see Figure 1-4).



SOURCE: GOA (2008)

Figure 1-4 CCS Technology in the Reduction of CO_2 Emissions in Alberta

1.4.2 Shell's CO_2 Emission Abatement Strategy

The Quest CCS Project will capture, transport, and store up to 1.2 Mt/a of CO_2 from the Scotford Upgrader.

As a large industrial emitter of greenhouse gases in Alberta, Shell is required under the *Specified Gas Emitters Regulation* to reduce emission intensity. The Quest CCS Project is needed as a key component of the greenhouse gas abatement strategy for Shell Canada Limited. Shell contributed $5 million toward founding the International Performance Assessment Centre for the Geologic Storage of CO_2 (IPAC-CO2) at the University of Regina. The IPAC-CO2 will focus on key elements of the geological storage of CO_2, including:

- Networking internationally to share and build on the findings of the other research organizations
- Interacting with key stakeholders to identify emerging issues and ensure effective and acceptable risk assessment techniques are developed, applied and communicated

- Creating communications to educate the public and build broad acceptance of CCS technology
- Developing a pool of qualified personnel in the areas of performance and risk assessment (U of R n.d., Internet site)

Further, the Quest CCS Project will support Alberta and Canada's drive to address climate change as part of a global effort. The Quest CCS Project received global recognition and validation in October 2010, when it was endorsed by the Carbon Sequestration Leadership Forum (CSLF) as one of five new CO_2 capture projects to be added to its existing research and development portfolio. The CSLF is a global voluntary climate initiative of developed and developing nations that account for 75% of all anthropogenic CO_2 emissions. The members engage in cooperative technology development aimed at enabling the early reduction and steady elimination of CO_2 emissions (CSLF 2010a, Internet site; CSLF 2010b, Internet site).

The Quest CCS Project will provide several ancillary benefits for both Alberta and Canada. These ancillary benefits and synergies include:

- reductions of up to 1.2 Mt/a of CO_2 from 2015 onward – a material contribution to sustaining a key driver of the economic prosperity in Alberta
- demonstrating and unlocking CO_2 storage capacity in a deep saline formation, which is essential for Alberta to meet its climate change strategy goals of 50 Mt/a of CO_2 storage by 2020 and 139 Mt/a storage by 2050
- promoting innovation for Alberta through the development and deployment of CO_2 capture and geological storage expertise. This can be applied across a variety of new and existing industrial sectors including upgrading, refining and petrochemicals.
- creating value for Alberta by opening a new sector and developing technology, expertise, services and resources that could be marketed in North America and worldwide
- facilitating CCS projects in Alberta's Industrial Heartland – an industrial area with the potential for up to 4 Mt/a CO_2 capture between 2015 and 2020.

1.5 Regulatory Approvals

A screening-level environmental assessment of the Project is required under *CEAA*. Additionally, Shell will prepare an EIA in accordance with *EPEA* for the CO_2 storage component of the Project.

In addition to the environmental assessment, various federal and provincial applications and approvals are required for the individual Project components (see Table 1-2). These are described in the following sections. ERCB Bulletin 2010-22 (ERCB 2010) identifies the existing processes in place to process applications for development and operation of CCS Projects in Alberta.

Shell is also applying to the ERCB for the flexibility to receive third-party CO_2, or to produce and export CO_2 to third parties from the capture infrastructure.

Table 1-2 Regulatory Approvals by Project Component

Responsible Agency	Approval and Applicable Legislation
Project	
Natural Resources Canada	• Section 20 decision regarding the environmental assessment • *Canadian Environmental Assessment Act*
Alberta Environment	• Environmental Impact Assessment determination of completeness • *Environmental Protection and Enhancement Act*
CO_2 Capture Infrastructure	
Alberta Environment	• Amending Approval 49587-01-00 (as amended) for Scotford Upgrader • Approval to construct, operate and reclaim a facility through AENV's Guide to Content of Industrial Approval Applications • *Environmental Protection and Enhancement Act*
Energy Resources Conservation Board	• Amending Approval 8522 (as amended) for Scotford Upgrader • Approval to construct and operate a facility via ERCB *Directive 023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project* (Directive 23) • *Oil Sands Conservation Act*
CO_2 Pipeline	
Energy Resources Conservation Board	• Pipeline licence application in accordance with ERCB Directive 56 • Emergency Response Plan approval in accordance with ERCB *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry* (Directive 71) • *Oil and Gas Conservation Act* • *Oil and Gas Conservation Regulations* • *Pipeline Act* • *Pipeline Regulation*
Alberta Environment	• Conservation and Reclamation Plan approval • *Conservation and Reclamation Regulation* • *Environmental Protection and Enhancement Act*
Canadian Transportation Agency	• Railway crossing agreement authorization • *Canada Transportation Act*
CO_2 Injection Wells	
Energy Resources Conservation Board	• Well licence application in accordance with ERCB Directive 56 • and ERCB *Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements* (Directive 51) • and ERCB *Directive 020: Well Abandonment* (Directive 20) • *Oil and Gas Conservation Act* • *Oil and Gas Conservation Regulations*
CO_2 Storage Component	
Energy Resources Conservation Board	• Approval in accordance with ERCB *Directive 065: Resources Application for Oil and Gas Reservoirs* (Directive 65) – Unit 4.2 Acid Gas Disposal • *Oil and Gas Conservation Act* • *Oil and Gas Conservation Regulations*

1.5.1 *Canadian Environmental Assessment Act*

Shell is seeking partial funding for the Project, which is a project as defined in *CEAA*, through the Government of Canada Clean Energy Fund—a program created as part of the federal Economic Action Plan and administered by NRCan. Because part of the Project cost will be funded through the Clean Energy Fund, the Project is subject to a federal environmental assessment. NRCan is a Responsible Authority (RA) under *CEAA* (Section 5(1)(b) of *CEAA*), and as the Project is not listed under the *Comprehensive Study List Regulations*, nor is it in the *Exclusion List Regulations* under *CEAA*, the RA has determined that a screening-level environmental assessment is required under *CEAA* (Section 18(1) of *CEAA*).

The Major Project Management Office (MPMO) will provide overarching project management support to the RAs for this Project, pursuant to the Cabinet Directive on Improving the Performance of the Regulatory System for Major Resource Projects and the associated Memorandum of Understanding.

1.5.2 Alberta Environmental Impact Assessment and Approvals

1.5.2.1 Environmental Impact Assessment

While neither the Project nor any of its components are considered to be mandatory activities, as defined in the *Environmental Assessment (Mandatory and Exempted Activities) Regulation*, Shell will prepare and submit an EIA report under *EPEA*, and associated regulations for the CO_2 storage component of the Project.

A single environmental impact assessment report will be prepared that meets Alberta Environment's Terms of Reference (TOR) for the Quest Carbon Capture and Storage Project, developed by provincial and federal regulators, and the environmental information requirements prescribed under the Alberta *EPEA* and associated regulations (see Appendix B, Final Terms of Reference and Concordance Table).

1.5.2.2 CO_2 Capture Infrastructure Applications

Modifications to the Scotford Upgrader to install the CO_2 capture infrastructure require amendments to previous approvals issued by Alberta Environment under *EPEA*, and the ERCB under the *Oil Sands Conservation Act* (*OSCA*).

The CO_2 capture infrastructure approvals include (see the Quest CCS Project application entitled *Amendment to OSCA and EPEA Approvals for the Carbon Capture Infrastructure*):

- amendment to the Scotford Upgrader Alberta Energy Resources Conservation Board (ERCB) Approval No. 8522 (as amended) pursuant to Section 13 of the *Oil Sands Conservation Act* for approval to construct and operate the CO_2 capture facility via ERCB's Directive 23
- amendment to the Scotford Upgrader Alberta Environment (AENV) Approval No. 49587-01-00 (as amended) pursuant to Division 2, Part 2 of *EPEA* for approval to construct, operate and reclaim the CO_2 capture facility through AENV's A Guide to Content of Industrial Approval Applications (1999)

For a list of the *EPEA* approvals for the Scotford Upgrader, see Appendix C. For a list of the *OSCA* approvals for the Scotford Upgrader, see Appendix D.

1.5.2.3 Pipeline Applications

Provincial agencies, including Alberta Environment and the ERCB, will be responsible for approving activities associated with the CO_2 pipeline construction, operation and reclamation.

The ERCB will be responsible for issuing a licence for the CO_2 pipeline application, under Directive 56, and the Emergency Response Plan (ERP) under Directive 71 (see the Quest CCS Project's application, *Directive 56: Application for a CO_2 Pipeline Licence)*.

Alberta Environment will be responsible for approval of the Conservation and Reclamation Plan (C&R Plan) for the pipeline, pursuant to *EPEA*. See Appendix E for the C&R Plan for the CO_2 pipeline.

Additionally, Alberta Environment will review watercourse crossings under the *Code of Practice for Pipelines and Telecommunication Lines Crossing Water Bodies*, which is enabled by the Alberta *Water Act*.

1.5.2.4 Injection Well Applications

Each well will be permitted under ERCB Directives 51 and 56. Use of surface lands for access roads, wells sites, and borrow pits which may be required would be permitted as an Application for Surface Disposition under the Alberta *Public Lands Act* to Alberta Sustainable Resource Development (ASRD). Alberta Environment will be responsible for issuing a reclamation certificate for the well pads, pursuant to EPEA. A Conservation and Reclamation Plan (C&R Plan) for the well pads has been prepared in support of that requirement. See Appendix F for the C&R Plan for the well pads.

1.5.2.5 Storage Applications

The Quest CCS Project's application for an acid gas storage scheme (*Directive 65: Application for a CO_2 Acid Gas Storage Scheme*) will be filed with the ERCB in accordance with Directive 65 (Section 4.2), Section 15.070 of the *Oil and Gas Conservation Regulations* and Section 39(1)(d) of the *Oil and Gas Conservation Act*. Shell will also apply to the Alberta Department of Energy for exploration storage tenure pursuant to appropriate legislation governing pore space tenure, which Shell understands is currently in legislative process.

1.6 Other CCS Projects – Summary

Five fully-integrated, large-scale CCS projects are in commercial operation today. Four projects – Sleipner, In Salah, Snøhvit and Rangely – inject CO_2 captured from natural gas production facilities, where CO_2 is separated from the natural gas that is sent to market. In the first three cases, the CO_2 is injected into saline aquifers, whereas in the fourth case, it is used for EOR. A fifth project captures CO_2 at the Great Plains Synfuels Plant (which converts coal to synthetic natural gas) located in North Dakota and transports the CO_2 via pipeline to the Weyburn–Midale project for EOR. All five are contributing to the knowledge base needed for widespread commercial CCS use. The following summary of these projects was extracted from the International Energy Agency (IEA 2010).

1.6.1 Sleipner

The Sleipner project began in 1996 when Norway's Statoil began injecting more than 1 Mt/a of CO_2 under the North Sea. This CO_2 was extracted with natural gas from the offshore Sleipner gas field. Statoil built a special offshore platform to separate CO_2 from other gases. The CO_2 is re-injected about 1,000 m below the sea floor into the Utsira saline formation located near the natural gas field. The formation is estimated to have a capacity of about 600 billion tonnes of CO_2, and is expected to continue receiving CO_2 long after natural gas extraction at Sleipner has ended.

1.6.2 In Salah

In August 2004, Sonatrach, the Algerian national oil and gas company, with partners BP and Statoil, began injecting about 1 Mt/a of CO_2 into the Krechba Formation near their natural gas extraction site in the Sahara Desert. The saline Krechba Formation is 1,800 m below ground and is expected to receive 17 Mt of CO_2 over the life of the project.

1.6.3 Snøhvit

Europe's first LNG plant also captures CO_2 for injection and storage. Statoil extracts natural gas and CO_2 from the offshore Snøhvit gas field in the Barents Sea. It pipes the mixture 160 km to shore for processing at its LNG plant near Hammerfest, Europe's northernmost town. Separating the CO_2 is necessary to produce LNG, and the Snøhvit project captures about 700,000 t/a of CO_2. The captured CO_2 is piped back to the offshore platform and injected in the Tubåsen sandstone formation 2,600 m under the seabed and below the geological formation from which natural gas is produced. The injection of CO_2 started in 2008.

1.6.4 Rangely

The Rangely CO_2 Project has been using CO_2 for EOR since 1986. The Rangely Weber Sand Unit is the largest oilfield in the Rocky Mountain region. Gas is separated and re-injected with CO_2 from the LaBarge field in Wyoming. Since 1986, approximately 23 to 25 Mt of CO_2 have been injected into the reservoir. Computer modelling suggests nearly all of it is dissolved in the formation water as aqueous CO_2 and bicarbonate. Although Rangely uses CO_2 for EOR, it is considered a CCS project insofar as it follows a MMV plan that satisfactorily assesses the viability of the long-term storage of the CO_2.

1.6.5 Weyburn-Midale

About 2.8 Mt/a of CO_2 are captured at the Great Plains Synfuels Plant in the US State of North Dakota, a coal gasification plant that produces synthetic natural gas and various chemicals. The CO_2 is transported by pipeline 320 km across the international border into Saskatchewan, and injected into depleting oil fields where it is used for EOR. The IEA Greenhouse Gas Research and Development (R&D) Programme's Weyburn–Midale CO_2 Monitoring and Storage Project was the first project to scientifically study and monitor the underground behaviour of CO_2. Canada's Petroleum Technologies Research Centre manages the monitoring effort. This effort is now in the second and final phase (2007-2011), of building the necessary framework to encourage global implementation of CO_2 geological storage. The project will produce a best-practices manual for carbon injection and storage.

1.6.6 Lessons Learned from other CCS Projects

The CO2QUALSTORE Joint Industry Partnership led by Det Norske Veritas (DNV) recently compiled a workbook of examples for underground storage of CO_2 including MMV plans (DNV 2010). The Joint Industry Partnership includes the following partners from a number of sectors; oil and gas companies (BP, BG Group, Petrobras, Shell and Statoil); energy companies (DONG Energy, RWE Dea and Vattenfall); technical consultancy and service providers (Schlumberger and Arup); the IEA Greenhouse Gas R&D Programme; and two Norwegian public enterprises (Gassnova/Climit and Gassco). The workbook provides guidance on how site-specific performance targets can be defined and includes practical examples of how to follow the guidance and its various steps. The workbook represents the most recent collection of shared experience and good practices applicable to MMV. This guidance and the good practices illustrated through the examples are central to the approach taken by Shell to all current CCS development projects, including the Quest CCS Project.

Shell has active involvement in a worldwide portfolio of CCS projects and has conducted extensive site characterization, risk assessment and site selection on a number of these projects. The Business Managers for these projects (including the Quest CCS Project Manager) meet monthly to share learnings. The technical study reports from these projects are readily available to the Quest CCS Project team members. Examples of projects from this portfolio are:

- the Prelude and ZEROGEN projects in Australia.
- the Northern California CO_2 reduction project. This project was carried out in collaboration with the Department of Energy's regional organization, WESTCARB, and Lawrence Berkley National Laboratory.
- the Barendrecht project in Holland.
- the Shell GOLDENEYE CCS project in the UK

Shell also has access to technical information and lessons learned from joint venture partnerships. For example, Shell is a joint venture partner on the GORGON CCS project in Australia with Chevron.

The Quest CCS Project team also has access to a number of CCS learning networks. Shell has an internal CCS knowledge sharing network where CCS technical staff can post questions or best practices on CCS projects worldwide. Shell is also one of the founders and sits on the Board of Directors for IPAC-CO2. Through the collaboration, the Quest CCS Project team has access to the IPAC-CO2 knowledge sharing network. Shell also hosts monthly internal webcasts covering both technical and non-technical lessons from the portfolio of CCS projects.

Shell has a CCS centre of excellence based in Rijswijk in Holland that evolved from Shell's expertise on sour gas injection. This team:

- provides guidance on risk management, MMV and coordinates CCS research activities
- is developing the TESLA software, which the Quest CCS Project team is using for risk and uncertainty management

- has developed generic risk registers and decision roadmaps for CCS projects, which have been accessible to the Quest CCS Project team
- provides technical assurance expertise for the Quest CCS Project and other CCS projects

1.6.6.1 Sharing of Quest Lessons Learned

A key consideration in the two major funding agreements with the Governments of Alberta and Canada is the dissemination of knowledge gained from the design, construction and operation of CCS projects. These agreements call for a knowledge-sharing program whereby this information can be used by future CCS project developers to attain carbon storage through CCS technology in the most effective manner possible. Within the Quest CCS Project, the cumulative lessons learned, both from other related projects and the Project, will be shared with the governments as part of the knowledge-sharing program. The program extends through to the operational phase of the Project. Lessons learned from all phases of the Project will be included through regular updates.

2 Project Description

2.1 CO_2 Capture Infrastructure

The CO_2 capture infrastructure consists of the following main process blocks (see Figure 2-1):

- CO_2 capture, which includes amine absorbers and associated equipment. One set of each will be located within the plot space of the three HMUs.
- an amine regeneration unit, which includes associated amine storage and a CO2 vent stack
- CO_2 compression, which includes a multi-stage centrifugal compressor with an electrical motor driver, interstage coolers and knockout drums
- CO_2 dehydration, which includes a TEG absorber and regeneration unit

The amine absorbers will use a methyl diethanolamine-type (MDEA) solvent to capture the CO_2 from the synthetic gas of the HMUs. The custom MDEA-based solvent mixture is a licensed Shell amine system called ADIP-X that is selective for CO_2. The CO_2 will be separated from the amine in a common amine regeneration process to produce CO_2 that is more than 95% pure, at slightly above atmospheric pressure. The combined compressor and TEG dehydration unit will pressurize and dry the CO_2 gas to about 14,500 kPa(g). This will prepare the gas for transportation by pipeline.

The main process units are:

- CO_2 capture, which includes the following components, one of each of which will be located within the plot space of the three HMUs:
  - an amine absorber
  - treated gas wash and cooling system
- amine regeneration, which includes:
  - the stripper column and associated reboiler, pumps and heat exchangers
  - amine filtration
  - amine storage
  - the CO_2 vent stack
- CO_2 compression, which includes a multi-stage centrifugal compressor with an electrical motor driver, interstage coolers and knockout drums
- CO_2 dehydration, which includes:
  - a TEG absorber
  - a packaged TEG regeneration unit

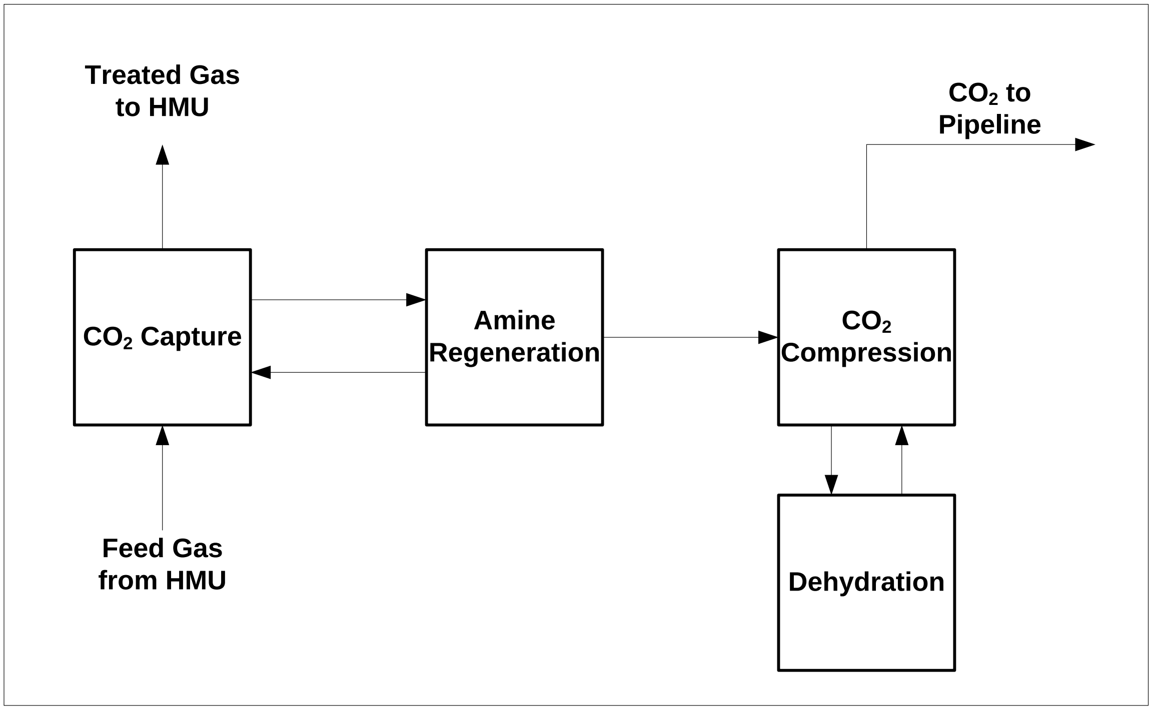


Figure 2-1 CO_2 Capture Infrastructure Simplified Process Blocks

2.1.1 Construction

The construction phase of the CO_2 capture infrastructure will occur entirely within previously disturbed lands within the Scotford Upgrader (see Figure 2-2). Construction of CO_2 capture infrastructure at the Scotford Upgrader will leverage the use of off-site modular construction, pre-fabrication and pre-assembly to reduce the amount of fabrication required directly on the construction sites and to split the scope of work into manageable components. This also increases the amount of fabrication that can be done in Canada. The intent of the Project schedule is to begin construction as part of a previously planned shutdown at the Scotford Upgrader (see Section 5).

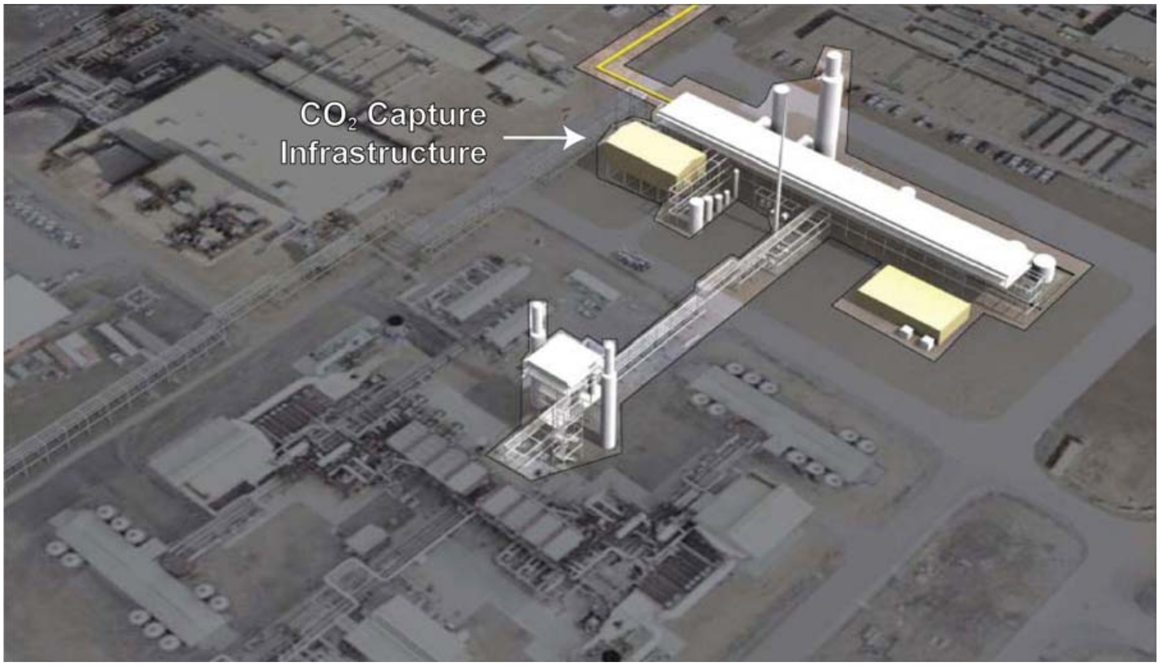


Figure 2-2 Artist's Representation of the Proposed CO_2 Capture Infrastructure

2.1.2 Operation Phase

2.1.2.1 Main Process Units

The main process units are:

- CO_2 capture, which includes the following components, one of each of which will be located within the plot space of the three HMUs:
  - an amine absorber
  - treated gas wash and cooling system
- common amine regeneration, which includes:
  - the stripper column and associated reboiler, pumps and heat exchangers
  - amine filtration
  - amine storage
  - the CO_2 vent stack
- CO_2 compression, which includes a multi-stage centrifugal compressor with an electrical motor driver, interstage coolers and knockout drums
- CO_2 dehydration, which includes:
  - a TEG absorber
  - a packaged TEG regeneration unit

2.1.2.2 CO_2 Capture

An amine absorber and a treated gas wash and cooling system will be installed in each HMU plot area. The raw hydrogen gas from the HMU flows through the amine absorber where it contacts with lean amine. In the absorber, about 80% of the CO_2 in the raw hydrogen gas stream is absorbed into the amine stream to form a rich amine. The rich amine exits the absorber and flows to the amine regeneration area.

The treated gas exiting the top of the amine absorber is cooled by a circulating water wash and cooling system. The treated gas is then routed to the HMU PSA unit that produces the purified hydrogen stream.

2.1.2.3 Amine Regeneration Unit

The rich amine from the three HMUs is combined into a common line and heated with hot lean amine to conserve energy. Preheated rich amine is then routed to the stripper column to remove the CO_2.

Carbon dioxide removal in the stripper column is driven by steam reboilers to produce a purified CO_2 stream and a lean amine stream. The CO_2 stream is sent to the compression unit and the lean amine is cooled and sent to the amine absorbers in HMU 1, 2 and 3 for reuse.

2.1.2.4 CO_2 Compression Unit

The wet CO_2 product from the top of the amine stripper is routed to the CO_2 compression unit, where the CO_2 pressure is increased to about 14,500 kPa(g), using a multi-stage centrifugal compressor. Water condensed between stages is removed using interstage knockout drums. Final CO_2 drying is achieved using the CO_2 triethylene glycol (TEG) dehydration unit.

2.1.2.5 CO_2 Dehydration Facility

To limit the risk of hydrate formation and associated corrosion, a CO_2 dehydration facility is required to remove liquid-phase water from the CO_2 stream.

The CO_2 dehydration facility is a TEG unit that processes gas from one of the compressor's interstage coolers. A lean TEG stream contacts the wet CO_2 stream in an absorption column and absorbs water from the gas to form a rich TEG stream. The dried CO_2 gas is routed back to the interstage compressor for final compression up to pipeline pressure.

The rich TEG stream is regenerated by heating at lower pressure. Liberated CO_2 is recycled back to the CO_2 compressor first-stage suction. Regenerated lean TEG is cooled and sent back to the absorption column for reuse.

2.1.2.6 Utilities and Offsites

The CO_2 capture infrastructure will also include:

- supporting utilities, including:
  - water
  - steam

  - air and nitrogen
  - electrical power

- supporting infrastructure (offsite), including:

  - a CO_2 vent stack
  - tie-ins to the existing flare system
  - amine and chemical storage
  - CO_2 metering
  - interconnecting pipe racks
  - tie-ins and modifications to the existing process control system

Vent Stack and Flare System

The CO_2 capture infrastructure will include a CO_2 vent stack, which safely vents the wet CO_2 stream from the amine regeneration area during a CO_2 compressor trip or temporary outage. Preliminary dispersion modelling has been completed to estimate the diameter and height of the stack required, so that ground-level CO_2 emissions remain within safe limits for personnel. In addition, the stack will be equipped with a drainage system and connections to remove any condensed water or rain water that might collect in the vent system. The vent stack will be metered; this is an integral component of verifying the CO2 balance.

The absorber, treated gas wash and cooling system in the three HMU units will be provided with pressure relief valves that will be tied to the existing HMU flare headers. Further design development and HAZOPs will be done during detailed design and engineering, to confirm the design of these relief valves and their relief loads. There are no additional stacks to be added to the flare system.

2.1.3 Decommissioning and Abandonment

The CO_2 capture infrastructure is intended to be decommissioned at the end of the life of the Project (greater than 25 years).

2.2 CO_2 Pipeline

The CO_2 pipeline consists of a single high-vapour-pressure pipeline approximately 84 km long with an outside diameter of 323.9 mm (12 inches) that will transport dehydrated, compressed, dense-phase CO_2 from the Scotford Upgrader to the injection wells located in the storage area. The north end of the CO_2 pipeline will be located at the last injection well at 15-29-60-21 W4M (see Figure 1-1). The CO_2 will be distributed to other injection well sites along the CO_2 pipeline, using smaller lateral pipelines, assumed to be less than 15 km long.

The CO_2 pipeline will consist of steel pipe with a wall thickness of 12.1 mm. Joints will be welded, and the pipeline will be externally coated. Line block valves will be situated at a maximum of 15 km apart along the CO_2 pipeline, and at watercourse crossings and other notable crossings (i.e., wetlands, road or railway crossings) where appropriate. Other than the block valves and monitoring equipment, no other facilities are associated with the CO_2 pipeline (i.e., compressor stations).

2.2.1 Construction

The construction of the CO_2 pipeline includes crossing several named and unnamed water bodies (including the North Saskatchewan River), roads, highways, third-party pipelines and rail lines. The permanent ROW for the pipeline installation will be 18 m with an additional 7 m of temporary workspace (TWS), resulting in a 25 m combined width. Additional TWS will be required at all crossing locations and substantive deflections (i.e., greater than 120°). The land required for installation of the pipeline is subject to disturbance and constitutes part of the area of physical disturbance as a result of the Project. Pipeline construction is planned to occur in the winter to minimize effects to wildlife and aquatic resources.

2.2.1.1 Soil Handling

Topsoil grading and salvage depths have been determined to ensure that appropriate material handling procedures are implemented. Additional soil survey work is required for areas where data have not been collected, and in sections of the ROW where disturbance might have occurred within the past two years, such as in the TWS of parallel pipeline projects and traversing industrial lands. For soil handling procedures, see Appendix E.

2.2.1.2 Pipeline Installation

For additional details on the construction of the CO_2 pipeline see Appendix E.

Stringing

Periodic gaps will be left in strung pipe, spoil piles and the trench to allow for wildlife, livestock and farm equipment to cross the ROW. Gaps will also be maintained at obvious crossings for farm equipment and at trails used by wildlife and livestock. Gaps will align with gaps in windrows.

Trenching

To limit interference with wildlife, livestock or farm machinery movement, the amount of open trench at any one time will be limited. The amount of trench left open will take into consideration the stability of the trench, the prevailing weather conditions, safety of crews and equipment, and environmental concerns.

Horizontal Directional Drilling (HDD)

Trenchless crossings (HDD or bore) are considered acceptable crossing methods for any watercourse crossing at any time of year, if determined to be geotechnically feasible. Refer to the Drilling Fluid Release Contingency Plan (see Appendix E) for more information regarding HDD.

Backfilling

Topsoil and subsoil will not be mixed during trench backfilling. Backfilling activities will be confined to the construction ROW and will proceed immediately after lowering the pipe in, to limit hazards to livestock and wildlife. Salvaged soil materials will be replaced in the reverse order of excavation, or lower subsoil returned first and upper subsoil second.

2.2.1.3 Crossings

The CO_2 pipeline will cross four fish-bearing watercourses: Beaverhill Creek, the North Saskatchewan River, Namepi Creek (which is crossed twice) and Astotin Creek. Shell is evaluating the technical feasibility for each of these crossings; however, the preferred crossing method for the North Saskatchewan River is by HDD. The other watercourse crossings, which are considerably smaller in channel width, will be crossed following DFO operational statements. Temporary vehicle crossings of the same watercourses may be required.

General measures have been developed for watercourse crossings. Watercourse crossings will be constructed in a way that limits stream bank and bed disturbances, sedimentation, alteration of stream substrates, interruption of stream flow and blockage of fish movements.

Of the 18 watercourse crossings along the CO_2 pipeline, 13 are poorly defined drainage swales with no fish habitat potential. These will be crossed using fords for vehicles and machinery, and open cut or isolated trench for the pipeline installation. Open cut is the preferred crossing method where the channel is dry or frozen to (and including) bed substrate, whereas isolated trenched crossings are to be employed if water flow is present within the channel. For the preferred watercourse crossing methods for both vehicles and pipeline installation on the fish-bearing watercourses, see Table 2-1. Crossing methods will comply with the *Alberta Code of Practice for Pipelines and Telecommunication Lines Crossing a Waterbody*.

Table 2-1 CO_2 Pipeline Fish-Bearing Watercourse Crossings

Watercourse Name	Channel Width (m)	Quarter Section	COP Class[1]	Restricted Activity Period	Proposed Vehicle Crossing Method	Pipeline Crossing Method
Astotin Creek	7.5	NE-13-056-21	C	April 16 to June 30	Ford when dry or frozen. Temporary bridge if flowing water	Open cut when dry or frozen as per the Operational Statement. Trenchless technique if flowing.
Beaverhill Creek	12	NW-20-056-20	C	April 16 to June 30	Ford when dry or frozen. Temporary bridge if flowing water	Open cut when dry or frozen as per the Operational Statement. Trenchless technique if flowing, as a contingency.
North Saskatchewan River	300+	NW-36-57-20	C	April 16 to July 31	No vehicle crossing permitted	Primary method is HDD. Contingency method is a two-stage coffer dam constructed in the fall.

Table 2-1 CO_2 Pipeline Fish-Bearing Watercourse Crossings (cont'd)

Watercourse Name	Channel Width (m)	Quarter Section	COP Class[1]	Restricted Activity Period	Proposed Vehicle Crossing Method	Pipeline Crossing Method
Lower Namepi Creek[1]	16	SW-26-058-20	C	April 16 to June 30	Ford when dry or frozen. Temporary bridge if flowing water	Open cut when dry or frozen as per the Operational Statement. Trenchless technique if flowing.
Upper Namepi Creek[1]	12.5	NE-15-060-21	C	April 16 to July 31	Ford when dry or frozen. Temporary bridge if flowing water	Open cut when dry or frozen as per the Operational Statement. Trenchless technique if flowing.

NOTES:
1 Source: ASRD (2006a), ASRD (2006b).

2.2.1.4 Pipeline Hydrostatic Testing

Hydrostatic testing is required to check the CO_2 pipeline integrity as per existing design codes. For general measures for pipeline testing, see Appendix E. The test medium will likely be water.

2.2.1.5 Conservation and Reclamation

Conservation and reclamation measures are intended to return construction sites to conditions that are similar to preconstruction conditions in accordance with applicable regulatory requirements. These measures may be modified in the field in accordance with site-specific conditions, or if more suitable techniques are developed by experts working in similar environments.

Areas that are not required as hardened surfaces during the operation phase will be reclaimed as soon as practical after construction. The CO_2 pipeline ROW, all temporary workspaces and construction access areas will be reclaimed to an equivalent land capability according to applicable regulatory requirements.

For more details on these measures, see Appendix E.

2.2.2 Operation Phase

The CO_2 stream in the pipeline will be maintained in a dense phase during normal operation. The CO_2 will be compressed and cooled so that it will be in a state known as a super critical fluid, or dense-phase fluid. Under these conditions, CO_2 exhibits properties of both a gas and a liquid. However, the fluid is present in only one phase.

The following criteria will be incorporated into the design of the pipeline:

- the pipeline will transport dense phase CO_2 containing trace amounts of hydrogen sulphide (H_2S) (less than 0.004% or 4 ppm as based upon specifications for commercial fuel gas used by the upgrading process)
- the pipeline will be sized to accommodate a CO_2 flow rate of 3,300 tonnes per calendar day in all cases, based upon the expected range of reservoir characteristics
- minimum delivery pressure at injection point of 9,000 kPa(g) to maintain a dense phase
- maximum allowable operating pressure of pipeline will be 14,500 kPa(g)
- minimum design operating temperature of -45°C
- maximum design operating temperature of 60°C
- the pipeline will be designed and installed to allow passage of electronic internal inspection tools
- aboveground piping and valves will be suitable for low temperature service to -45°C

The CO_2 capture infrastructure will contain a metering skid and launching traps. CO_2 delivery to the injection wells will consist of a receiving scraper trap for catching pipeline pigs and a skid for metering the CO_2 out of the system. This meter will be used as an integral part of the leak detection on the CO_2 pipeline system. Quality sampling of the CO_2 stream will take place to verify that it meets minimum pipeline specifications.

A supervisory control and data acquisition (SCADA) system will collect and transmit data from the CO_2 pipeline back to the Scotford Upgrader control room and will centrally control and monitor the line break valves.

Metering facilities will comprise a pressure-regulating valve and flow meters. Product measurement will be done using mass flow or inferential orifice flow measurement for leak detection.

Proposed surface facilities associated with the Project are a series of aboveground emergency shutdown block valve riser sites, spaced along the ROW to support the safe operation and maintenance of the CO_2 pipeline system. Each riser site and line break valve station will be within the boundaries of the proposed ROW and have been sited to be readily accessible from existing roads. No new access will be required.

2.2.2.1 Reclamation Monitoring

Shell will monitor the CO_2 pipeline ROW for reclamation and re-vegetation success following construction until vegetation establishment is complete. Remedial reclamation measures will be promptly implemented where required. If required, soil amendments may be placed on the slopes to enhance vegetation establishment. Any remedial reclamation required on private lands will be discussed and approved by the landowner. Any remedial reclamation required on Crown land will be discussed with, and approved by, the regional Lands Division Officer at ASRD. See Appendix E for details on reclamation monitoring measures.

2.2.3 Decommissioning and Abandonment

The CO_2 pipeline is expected to be operational for the life of the Project (greater than 25 years). As part of decommissioning and abandonment, the CO_2 pipeline will be depressurized, and abandoned in place. Line break valves will be removed, including connecting pipeline to just below grade. The area of disturbance will be reclaimed and revegetated.

2.3 CO_2 Injection and Storage

The storage component of the Quest CCS Project involves injecting the pressurized CO_2 into the BCS via injection wells drilled into the formation. The BCS storage complex is at the base of the central portion of the Western Canada Sedimentary Basin (WCSB) directly on top of the Precambrian basement. The BCS storage complex is defined herein as the series of intervals and associated formations from the top of the Precambrian basement to the top of the Upper Lotsberg Salt (see Figure 2-3).

This section describes the following:

- extent of AOI
- regional geological setting
- depths below Base of Groundwater Protection
- distance to hydrocarbons
- geological setting of the storage area
- geology of the target storage zone (the BCS)
- bounding formation geology
- geochemistry of the storage zone, including the receiving fluids
- interactions between the injected CO_2 and the storage zone
- CO_2 storage mechanisms
- predicted radius of influence of injected CO_2
- distance to other BCS penetrations
- injection well design
- well decommissioning

In October 2010, Shell sought third party review of this aspect of the Project. The independent project review was managed and facilitated by Det Norske Veritas (DNV), and performed by an expert panel contracted by DNV. The executive summary of the report can be found in Appendix G.

2.3.1 Extent of the Area of Interest

Shell is currently requesting the exclusive right to drill through and store within the BCS storage complex (below the top of the Upper Lotsberg Salt to the Precambrian basement) over the full extent of the 40 townships that define the AOI (see Table 2-2, Figure 1-1) for the life of the Project (greater than 25 years). The pore space request was submitted to the Alberta Department of Energy in December 2009.

Table 2-2 Townships Included Within the AOI

Township	Ranges (W of 4th Meridian)
63	22, 21, 20
62	23, 22, 21, 20, 19
61	24, 23, 22, 21, 20, 19, 18
60	24, 23, 22, 21, 20, 19, 18
59	23, 22, 21, 20, 19, 18
58	23, 22, 21, 20, 19
57	22, 21, 20, 19
56	21, 20, 19

2.3.1.1 Area of Interest – Methodology

The AOI extent represents the current understanding of the CO_2 plume and area of elevated pore pressure taking into account the range of subsurface uncertainties. The approach is to create a series of subsurface models that adequately cover these uncertainties, to generate range of CO_2 plume and pressure front size scenarios.

With the signing of the Letter of Intent between Shell, the Government of Alberta and the Government of Canada, several key Project constraints were accepted between the signatories, including:

- a sustained injection rate of 1.08 Mt/a for a minimum of 10 years
- the Quest CCS Project reaching a sustained injection rate by the end of 2015

To meet the Government of Alberta’s 2015 milestone, the Quest CCS Project team has to:

- design the Project against the low case subsurface scenario model (low capacity/injectivity) so that the required volume and rate of CO_2 can be accommodated within the requested AOI
- select the AOI to cover the region of elevated pressures and prevent pressure interference between potential future CCS projects within the BCS, which may affect injection rates and volumes
- safeguard the containment within the BCS storage complex over the entire life of the Project by having adequate offset distances between the injection wells and any third-party wells that penetrate the BCS

2.3.1.2 Area of Interest – Technical Reasoning

The extent of the AOI is guided by the amount of pore space required to inject 1.08 Mt/a of CO_2 for 25 years so that it is contained within the BCS storage complex for the entire lifecycle of the Project. The extent was determined using the full range of uncertainty on both the reservoir properties and the number of injection wells required (i.e., 3 to 10 wells). Volumetric calculations were carried out to validate dynamic models of CO_2 plume migration under various reservoir and development scenarios to assess the maximum CO_2 plume size that can be expected. The same process was undertaken for the area of elevated pressure in the highly saline brines ahead of the CO_2 plume. In each case, a conservative approach was taken to reflect that CO_2–brine displacement in the reservoir will not be homogeneous.

Modelling the CO_2 plume as well as the area of elevated pressure, to determine the extent of the AOI, is important for two fundamental reasons:

1. There must be sufficient injectivity and capacity to meet the Project objectives, assuming one or more potential CCS schemes in the BCS storage complex. Competing CCS projects have the potential to affect one another, in terms of injectivity, monitoring and liability, through overlapping areas of elevated pressure. Overlapping pressure fronts may result in each offsetting project reaching the ERCB imposed limit for bottomhole pressure (90% of the fracture pressure) prematurely. This would result in additional wells being required to redistribute pressure, or in the scheme being closed prematurely.
2. Containment must be maintained through early warning of potential CO_2–brine migration outside the BCS storage complex, with particular emphasis on safeguarding aquifers above the base of groundwater protection (BGWP). Considerations for this include the following:
    - Adequate offset must exist between CO_2 injection wells and vintage wells and wells of future schemes that penetrate the BCS. Therefore, the proposed scheme maximizes the offset to existing legacy wells. The closest BCS penetration by a legacy well (Imp. Egremont 6-36-58-23W4) occurs 21 km west-southwest of Well 8-19. The closest up-dip legacy well (Imp. Darling No.1 16-19-62-19W4) is 31 km north-northeast of Well 8-19.
    - The CO_2 plume size is small compared with the AOI, reaching a maximum plume size of 3 km away from the wellbore, and will not reach the legacy wells.
    - The legacy wells will encounter pressurized saline brine. Given the BCS reservoir pressure and in situ fluid gradient, a minimum incremental pressure of 3.3 to 4.5 MPa in the BCS would be required to lift 11.7 kPa/m BCS brine into the BGWP zone through an open hole at hydrostatic conditions (see Table 2-3). Current dynamic models indicate that the pressure increases at distances equivalent to the distance to the legacy wells (i.e., 20 to 30 km) would be about half of those required to lift BCS brine into the BGWP or to the surface (modelled above to be 3.3. to 4.5 MPa).

Table 2-3 Pressure Increase Required to Lift BCS Brine above the BGWP

Well Name	Surface elevation (mBSL)	BGWP depth (mBSL)	Delta P (kPa)
Imperial Eastgate No. 1-34	-641.3	-401	3,452
Imperial Egremont W 6-36	-627.9	-408	3,334
Imperial Clyde No. 1	-629.4	-397	3,327
Imperial Darling No. 1	-704.4	-469	4,201
NOTE: mBSL – metres below sea level			

The AOI is within a tectonically quiet area; no faults crosscutting the regional seals were identified in 2D or 3D seismic data.

2.3.2 Regional Geological Setting

The descriptions of the geology of the BCS and other formations are taken from the Geological Atlas of the Western Canada Sedimentary Basin (Mossop and Shetsen 1994, Internet site).

For a regional stratigraphic column showing generalized stratigraphy beneath the AOI, and a regional cross-section from southwest to northeast through the AOI, see Volume 2, Appendix 7A. A brief description of the stratigraphy from the crystalline Precambrian basement rock to the unconsolidated Quaternary deposits follows (see Figure 2-3).

The Precambrian basement rock consists of granite and forms a regional aquiclude beneath the area. The BCS is the target injection and storage zone for the Project, and lies above the unconformity that separates it from the underlying Precambrian igneous rock. The BCS is a saline aquifer composed of sandstone with upper fine to upper coarse, round to subrounded (with some angular and broken) grains. The sand unit is approximately 30 to 60 m thick in the region. Above the BCS lies a sequence of Middle and Upper Cambrian deposits consisting of the Lower Marine Sands (LMS), Middle Cambrian Shale (MCS) and Upper Marine Siltstone (UMS), which, together, form the Cambrian aquitard system.

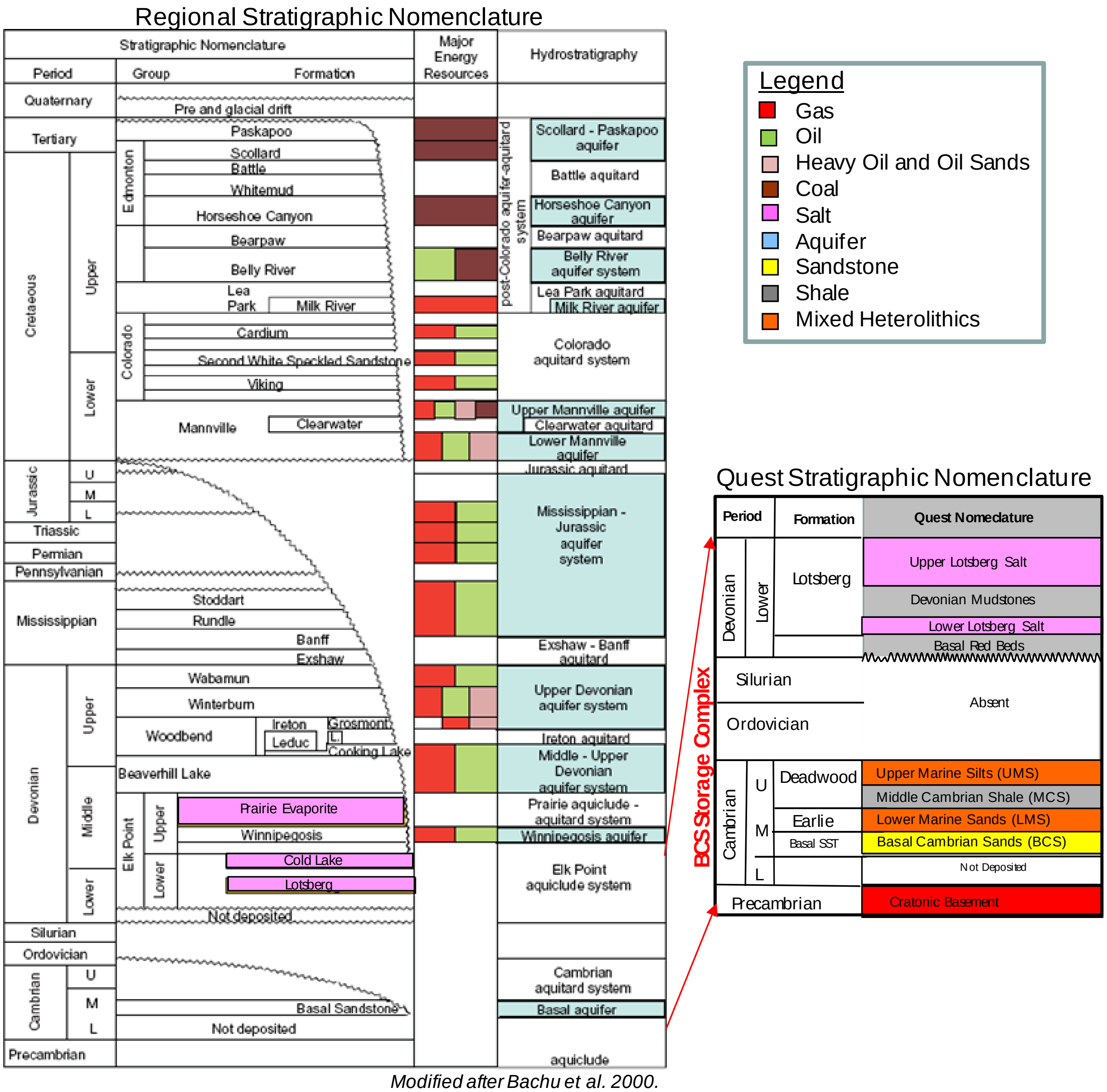
An unconformity exists between the Cambrian deposits and the overlying Devonian Elk Point Group, reflecting the absence of Silurian and Ordovician deposits in the stratigraphic record. The base of the Elk Point Group is marked by the Basal Red Beds, consisting of reddish to orange-brown shale with minor siltstone deposits. Above the Red Beds are the Lower and Upper Lotsberg Formations separated by shale or mudstone. The two Lotsberg formations consist of salts with minor shale, anhydrite and dolomite, forming continuous impermeable seals or aquitards above the Cambrian formations.

The first major porous unit above the target BCS is the Winnipegosis Formation (Keg River Equivalent) within the Elk Point Group. The Prairie Evaporites (Muskeg Formation) form an aquiclude overlying the porous carbonates of the Winnipegosis Formation. This aquiclude consists of dolomite, shale, salt and marlstone. Shales of the Watt Mountain Formation form the uppermost deposits within the Elk Point Group beneath the AOI.

The Beaverhill Lake Group, deposited during the Middle Devonian, consists of a number of formations, primarily made up of limestone, shale and marlstone. Some porosity and permeability has been noted in the Calumet and Moberly Formations, which could be considered aquifers.

Above the Beaverhill Lake Group lie the thick carbonate sequences of the Upper Devonian Leduc and Wabamun Groups. The two groups are separated by an unconformity, where deposits of the Winterburn Group are absent. The lowermost formation in the Leduc Group is the Cooking Lake Formation, consisting of porous and permeable limestone with minor shale stringers. The Ireton Formation forms a thick aquitard within the Leduc Group and is composed of shale and marlstone.

Above the unconformity separating the Wabamun Group from the Leduc, are the Nisku and Calmar Formations of the Leduc Group. Some porosity and permeability have been observed in these formations, which are composed of siltstone, shale and dolomite.



SOURCE: Modified after Bachu et al. (2000).

Figure 2-3 Stratigraphy and Hydrostratigraphy of Southern and Central Alberta Basin

All of the deposits between the Upper Devonian and Lower Cretaceous are absent. Above this major unconformity, the Mannville Group consists of the Ellerslie Formation Sandstone, overlain by the shale Ostracod Zone, which forms a regional aquitard. Above the Ostracod Zone are sandstone units of the Glauconitic Formation and Upper Mannville Formation.

Above the Mannville Group, the Colorado Group forms a thick sequence of deposits predominantly made up of low permeability shale and siltstone. The exception to the low permeability units is the sandstone of the Viking Formation, near the base of the Colorado Group. The Viking Formation is considered an aquifer based on its porosity and permeability. The overlying shales of the Base of Fish Scales, Second White Speckled Shales and the Colorado (or Cardium) Formation form a thick regionally extensive aquitard.

Above the Colorado Group, the Upper Cretaceous Lea Park Formation is composed of marine shales and siltstones with minor sandstone stringers. The Lea Park Formation also forms a regionally extensive aquitard with a thickness of over 100 m across the AOI.

The Belly River Group forms the uppermost bedrock in the region, and hosts aquifers above the BGWP. The Foremost Formation is made up of marine and continental shales, with sandstone members forming regionally extensive aquifers. Distinct coal-bearing zones are also present in the Foremost Formation, the most prominent being the McKay and Taber coal zones. The Foremost Formation subcrops beneath portions of the northeast and central areas of the AOI.

The Oldman Formation of the Belly River Group overlies the Foremost Formation and subcrops beneath the remainder of the AOI. The Oldman Formation is made up of continental deposits of interbedded sandstone, siltstone, shale and coal.

Quaternary deposits above the bedrock surface include preglacial channel fill deposits, glacial drift and other glacially derived deposits. The thickness of the Quaternary deposits varies between 0 and 100 m across the AOI.

2.3.2.1 Base of Groundwater Protection

The base of groundwater protection (BGWP) was defined for all wells using the Alberta Environment Groundwater database (ERCB *Bulletin 2007-10: Alberta's Base of Groundwater Protection (BGWP) Information* [April 2007] and ERCB *General Bulletin 2000-8: Process Changes to Disposal Well Applications* [March 2000]). Within the AOI, the base of the Belly River Formation or Wapiti Group is considered the BGWP. The marine shales of the Lea Park Formation define the approximate lower boundary of the BGWP.

For the depth to BGWP for the first five injection wells, see Table 2-4.

For a further discussion on the BGWP and its variability across the AOI, see Volume 2, Appendix 7A.

Table 2-4 Depth to Base of Groundwater Protection

Injection Well	Well UWI	Depth BGWP (mASL)	Depth BGWP (mTVD)
1	08-19-059-20W4	+435.2	211.56
2	07-11-059-20W4	+434.79	205.88
3	10-06-060-20W4	+459.67	192.54
4	12-14-060-21W4	+453.59	194.76
5	15-29-060-21W4	+447.54	209.71

NOTES:
mASL – metres above sea level
mTVD – metres true vertical depth

2.3.2.2 Distance to Hydrocarbon Pool or Accumulation

There are no known hydrocarbons or hydrocarbon pools in the BCS within the AOI. No hydrocarbon-bearing zones were encountered in Well 8-19. No hydrocarbons below the Upper Lotsberg salts are expected in any of the proposed future injection wells.

The vertical distance to the Leduc Formation, which holds the deepest known hydrocarbons in the AOI, is greater than 1 km. However, there is an additional lateral offset to hydrocarbons as the edge of the Leduc reef is located more than 10 km downdip to the southwest of any of the potential injection wells.

2.3.3 Geology of the Storage Complex

The BCS storage complex includes, in ascending stratigraphic order:

1. Precambrian granite basement unconformably underlying the BCS.
2. BCS of the Basal Sandstone Formation – the target CO_2 injection and storage zone.
3. Lower Marine Sand (LMS) of the Earlie Formation – a transitional heterogeneous clastic interval between the BCS and overlying Middle Cambrian Shale (MCS).
4. Middle Cambrian Shale of the Deadwood Formation – thick shale representing the first main regional seal above the BCS.
5. Upper Marine Siltstone, likely Upper Deadwood Formation – progradational package of siliciclastic material made up of predominantly green shale with minor silts and sands.
6. Devonian Red Beds – fine-grained siliciclastics predominantly composed of shale.
7. Lotsberg Salts – Lower and Upper salts which respectively represent the second and third (ultimate) seals and aquiclude to the BCS storage complex. These salt packages are predominantly composed of 100% halite with some minor shale laminae in the AOI. They are separated from each other by a 50 m undifferentiated Devonian mudstone.

The rocks that compose the BCS storage complex in the AOI were deposited during the Middle Cambrian to Early Devonian directly atop the Precambrian basement. Erosion of the Precambrian surface during this interval likely resulted in a relatively smooth and gently southwest-dipping (<1 degree) top Precambrian surface. Regionally, the Cambrian clastic packages pinch out towards the northeast, and the Devonian salt seals thicken towards the northeast (see Figure 2-4).

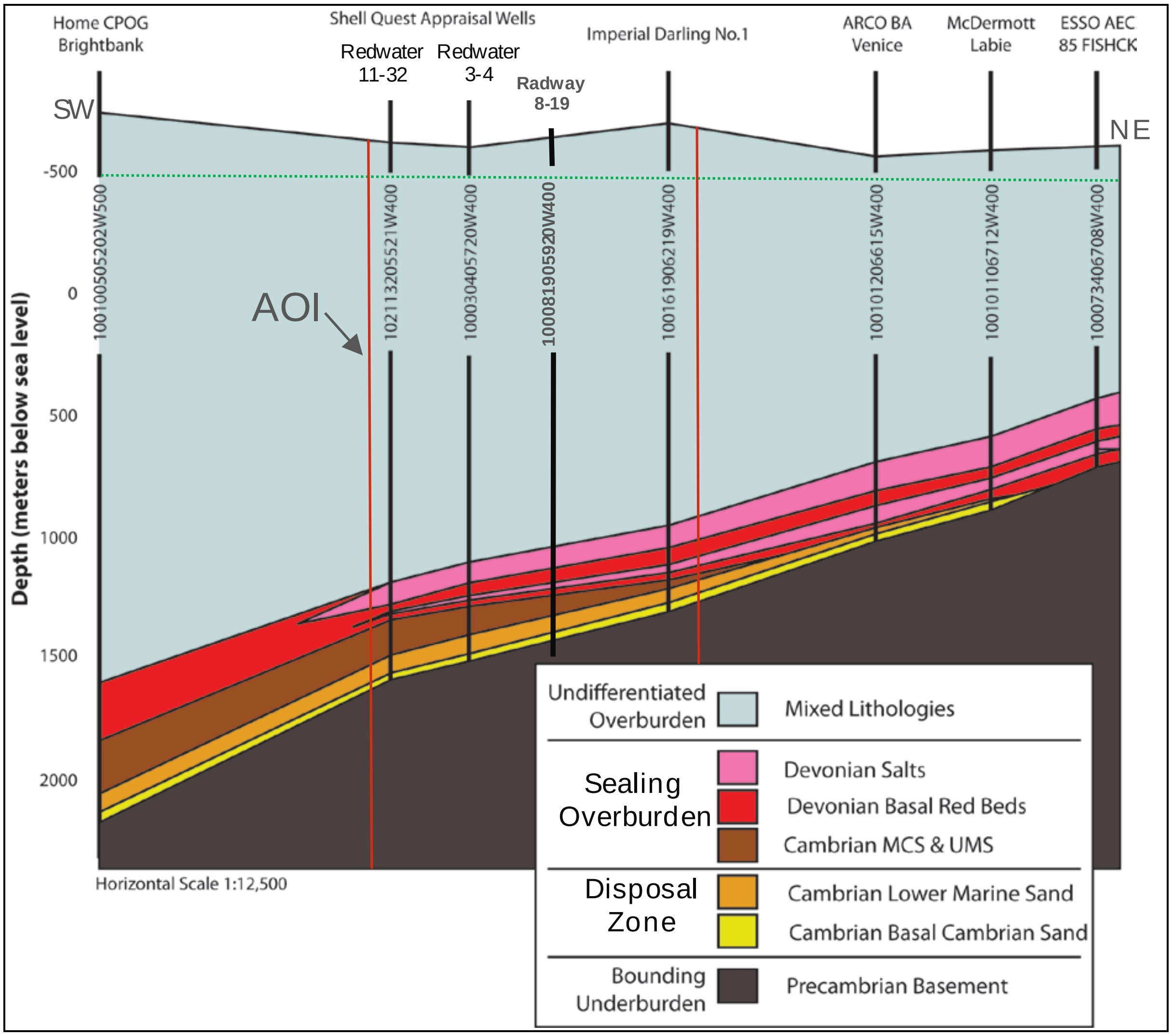


Figure 2-4 WCSB Cross-Section

2.3.3.1 Geology of the Target Storage Zone

The BCS is the target injection and storage zone and is composed mainly of fine to coarse-grained sandstone with minor shaley intercalations, lying unconformably on a variably rugged topography of Precambrian age crystalline basement. This BCS is widespread throughout much of the Alberta Plains, and is absent only locally where isolated Precambrian highs precluded deposition.

This formation was created from sand, originally deposited by rivers, that was reworked into tidal dunes many times over during a rise in sea level. Within the AOI, this process ultimately yielded a very clean, high net/gross (0.75–0.97), 35 to 46 m thick sheet sandstone that presently acts as a basin-scale saline aquifer with no known hydrocarbon accumulations (see Figure 2-5).

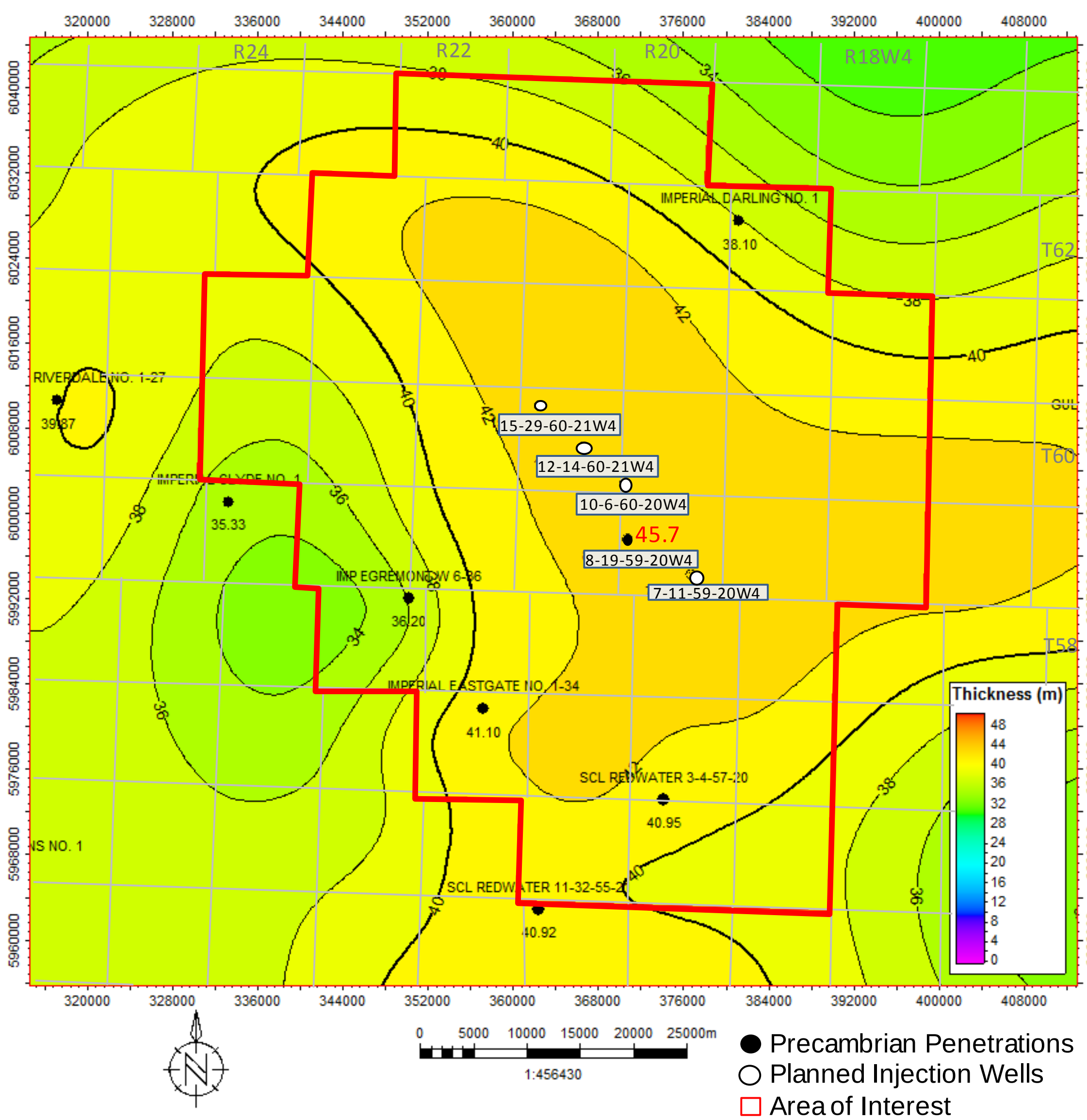


Figure 2-5 Basal Cambrian Sands Gross Sand Thickness

Characterization of the petrophysical properties of the BCS in the AOI were primarily based on the results of the Quest CCS Project appraisal wells, Shell Redwater 11-32-55-21W4 (Well 11-32) and Shell Redwater 3-4-57-20W4 (Well 3-4) with additional input from offset legacy wells. Some porosity data was also available from well logs drilled previously in the BCS. As part of its appraisal well program to confirm the geological aspects of the AOI, Shell has also drilled and completed the first proposed injection well for the Quest CCS Project, Shell Radway 8-19-56-20W4 (Well 8-19).

Porosity and Permeability of the Target Storage Zone

For the actual log porosity and permeability values of the BCS in Well 8-19 and the expected range of values for injection Wells 2 to 10, see Table 2-5.

Table 2-5 BCS Calculated Porosity and Permeability Values of CO_2 Injection Wells

Parameter	Well 8-19	Injection Wells 2 to 10	
	Actual	Minimum	Maximum
Average porosity BCS (v/v)	0.16	0.11	0.19
Average permeability BCS (mD)	150	20	500

Fluid Type in the Target Storage Zone

The fluid type in the BCS is highly saline water. The current reservoir fluid description is based on sample analysis from the Well 11-32. In December 2008, six Modular Dynamic Tester (MDT) samples from two depths within the BCS reservoir were obtained in Well 11-32. Four sample chambers captured formation fluids from 2,198.0 m measured depth (MD) and two more samples were collected from a depth of 2,191.6 m MD. The high quality samples showed minimal contamination. The samples were analyzed for water density.

The value for total dissolved solids in formation water from Well 11-32 was approximately 269,000 mg/l, which corresponds to a water density at ambient conditions of 1,176 kg/m^3. An average pH of 5.9 was measured from six pressurized samples immediately after they were flashed in the laboratory. The gas water ratio measured from the gas volume flashed from these samples averaged 0.25 m^3/m^3 with a composition of 25.2 mol% of CO_2, 72.2 mol% of N_2 and 2.4 mol% of C_1. The formation water viscosity was 1.18 cP at reservoir conditions.

2.3.3.2 Geology of the Bounding Formations

The basal bounding formation of the BCS storage complex is the Precambrian basement. Above the BCS are the three major seals considered the most important for containment of CO_2. Deposited between the three major seals are additional intervals that act as secondary baffles that will contribute to the effective containment of the CO_2. In ascending stratigraphic order, the three main seals and three baffles in relation to the BCS are:

1. LMS – baffle
2. MCS – first major seal
3. UMS – baffle
4. Devonian Red Beds – baffle

5. Lower Lotsberg Salt –second major seal
6. Upper Lotsberg Salt –ultimate seal

Basal Seal – Precambrian Basement

The BCS in the Cambrian sequence lies directly above the Precambrian basement. Seismic surveys and appraisal well Formation Micro Imager (FMI) logs indicate the presence of fractures on the Precambrian basement surface that likely were driven by accretion of Archean Province and Palaeo-Proterozoic terranes over 1.5 billion years before Cambrian deposition. Erosion of the Precambrian surface during this interval likely resulted in a relatively smooth and gently dipping (<1 degree) top Precambrian surface with small localized dip variations. However, the limited Precambrian topography that did exist allowed for known but rare areas of non-deposition during the Cambrian that appear to be both localized and concentrated along Precambrian basement block terrain boundaries. The AOI has been located to avoid these areas of non-deposition. Despite the presence of fractures in the basement, no substantial porosity or permeability is expected in the Precambrian interval.

Baffle – Lower Marine Sands of the Earlie Formation

The LMS records a gradual deepening in the environment of deposition relative to the BCS as the transgression of the Middle Cambrian sea continued landward (east to northeast). Core descriptions of the LMS illustrate a fining upwards grain size distribution. Sedimentological description indicates a position in the subtidal environment, basinward of the marginal marine environment in which BCS deposition occurred. The upper LMS consists predominantly of sediments deposited in a distal environment, above storm wave base, with intermittent sand deposition likely delivered via episodic storm-driven flows. Within Shell Wells 11-32, 3-4 and 8-19, the LMS net-to-gross ratio ranges from approximately 0.35 to 0.57. Across the AOI, the LMS varies in thickness from approximately 50 to 75 m. The average total porosity calculated for the recent Shell Wells 11-32, 3-4 and 8-19 is 10 to 12% and the effective porosity is 6%. The average permeability is 4 millidarcies (mD).

CO_2 will not be injected into the LMS. Although the LMS shows some porosity and minor permeability, the vertical permeability is negligible making the LMS a baffle to vertical CO_2 migration.

First Seal – Middle Cambrian Shales of the Deadwood Formation

The Middle to Upper Cambrian MCS records the first major seal above the BCS. Descriptions of core suggest that the MCS was likely deposited on the distal portion of the interior cratonic platform between the up-dip siliciclastic deposits characteristic of the BCS and the down-dip outer margin carbonate platform deposits that manifest in Middle to Upper Cambrian Rocky Mountain outcrops to the west and southwest (e.g., the Pika, Waterfowl and Lynx Formations). Core descriptions show a transition from principally massive thick-bedded shales at the base to progressively more thin-bedded shales with interbedded but rare limestones and coarse-grained siltstones and fine-grained sandstones up-section.

Within the AOI, the MCS is the oldest formation affected by the Devonian unconformity. This yields a section that decreases from approximately 55 m in thickness in the southwest, where it is conformably overlain by the UMS and not subject to the unconformity-associated erosion, to approximately 20 m in the northeast, where it is in direct contact with Devonian strata (see Figure 2-6). The MCS is believed to be a competent seal even at the minimum thickness interpreted within the AOI. The MCS clays consist predominantly of varying amounts of illite and kaolinite, with minor amounts (<15%) of smectite and chlorite, confirmed through x-ray diffraction (XRD) from core analysis and natural gamma-ray spectroscopy from logs and geochemistry. The MCS records the lowest estimated net-to-gross ratio within the Cambrian succession and acts as the first major stratigraphic seal. Horizontal permeability levels within occasional sands in the MCS are in the nano to microdarcy range, as interpreted from the shale and clay content described in these sands. However, the vertical permeability is interpreted to be in the nanodarcy range due to the presence of laminated bedding. No core measurements were achieved in these sand streaks.

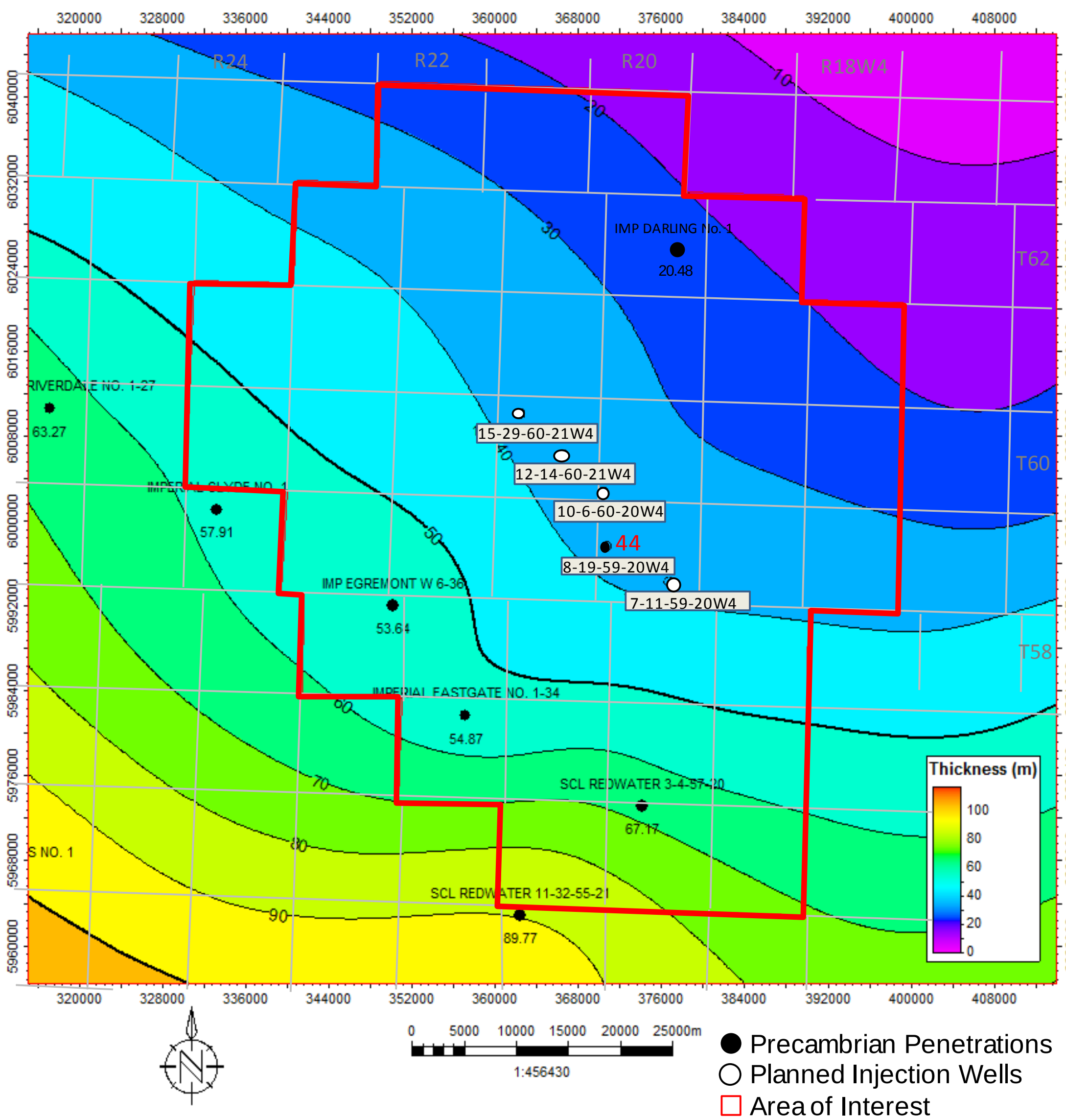


Figure 2-6 Thickness and Extent of Middle Cambrian Shale Over the AOI

Baffle – Upper Marine Sands of the Upper Deadwood Formation

The UMS lies above the MCS shale, which is the first major seal to the BCS storage complex.

The Upper Cambrian UMS is only evident in the southwest portion of the AOI primarily due to erosion associated with the Devonian unconformity. In the UMS, sediments similar to the transitional LMS have been recorded and likely represent a progradational package of siliciclastic material that was deposited in response to either an increase in sediment supply or to a relative fall in sea level. The UMS thins from a maximum thickness of approximately 60 m in the southwest to a northwest–southeast oriented erosional truncation in the northeast corner of the AOI. The UMS consists of predominantly greenish shales with minor silty and sandy interludes. Total porosities in the UMS can be up to 12% with less than 1 to 2% effective porosity, as observed from Well 11-32 intermediate hole section NMR log. Permeability levels of less than 1 mD were consistently estimated in this section from NMR logs with virtually no vertical connectivity interpreted consistent with the poor horizontal properties observed from logs.

Baffle – Devonian Red Beds

Directly overlying the Cambrian UMS are Devonian Elk Point Group fine-grained siliciclastics and evaporites. The Devonian unconformity, that separates the Cambrian and Devonian sequences, represents approximately 100 million years. The Cambrian sedimentary sequence was typified by a passive continental margin transgression, whereas the Devonian Elk Point Group succession was controlled by a more complex palaeotopographic environment. The Basal Devonian Red Beds represent the first deposition on the Cambrian strata. The red beds consist of fine-grained siliciclastic sediments eroded from adjacent highlands (e.g., the Peace River Arch to the northwest, the Western Alberta Ridge to the west, and the cratonic high to the northeast).

The Basal Red Beds are composed of green and red shales with silty stringers. These have been described as lagoon or bay deposits consisting of thick-bedded, mottled gray to red, silty mudstone with common halite-filled vugs and concretions. In the core from Well 3-4, most of the sequence consisted of shales grading to dolomitic siltstone with traces of salt and anhydrite. In Wells 3-4 and 11-32, total porosity values as high as 10% were recorded but typical porosity values were below 5%, with permeability values ranging from 0.001 to 1 mD, as confirmed from NMR readings in Well 11-32.

Second Seal and Ultimate Seal – Lotsberg Formation Devonian Salts

Overlying the Devonian Red Beds is the Devonian Lotsberg Formation. The Lotsberg Formation salts are true aquicludes as a result of their large lateral extent, thickness, impermeability, plastic-like quality, and ability to anneal via plastic deformation.

The Lotsberg Formation consists of two mappable salt units, named the Lower and Upper Lotsberg salts, separated by an additional layer of fine-grained siliciclastics, deposited during periods of relative basin isolation and subsequent evaporite formation. The Lower and Upper Lotsberg salts are predominantly composed of 100% halite with some minor shale laminae. The Lower and Upper Lotsberg Salts represent the second and (ultimate) seals for the BCS storage complex respectively.

The Upper Lotsberg salt is the ultimate seal because it is the thickest, most regionally extensive seal and represents the top of the BCS storage complex. Both the Lower and Upper Lotsberg salts thicken towards the Central Alberta sub-basin northeast of the CO_2 storage AOI to a maximum thickness of 60 m and 150 m, respectively (Grobe 2000). The Lower Lotsberg is thin (~10 m) in the Western portion of the AOI but thickens to 35 m in the northeast (see Figure 2-7). The Upper Lotsberg is a true aquiclude present over the entire AOI and varies in thickness from approximately 55 m in the west to 90 m in the northeast of the AOI (see Figure 2-8).

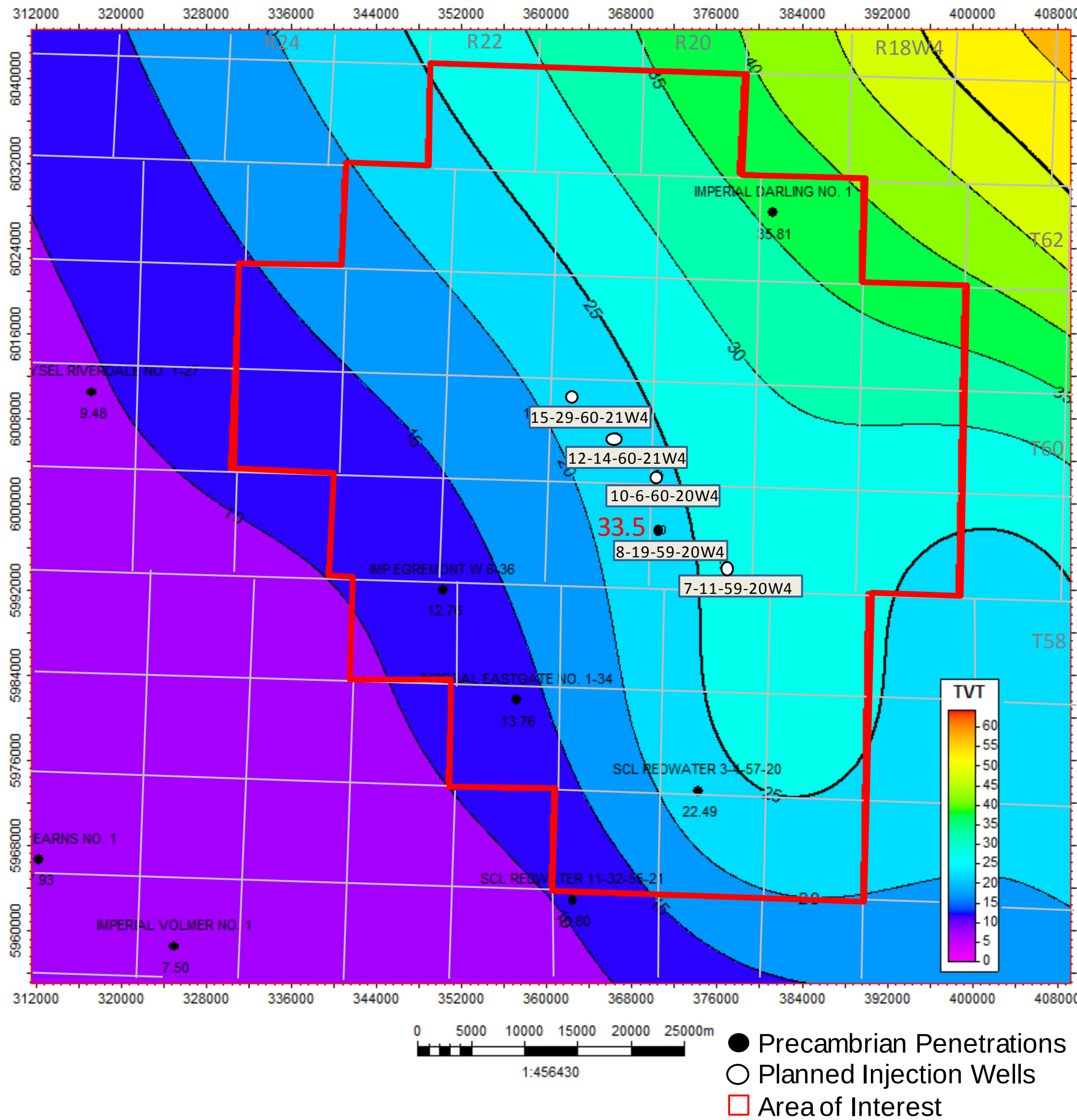


Figure 2-7 Extent and Thickness of the Lower Lotsberg Salt in the AOI

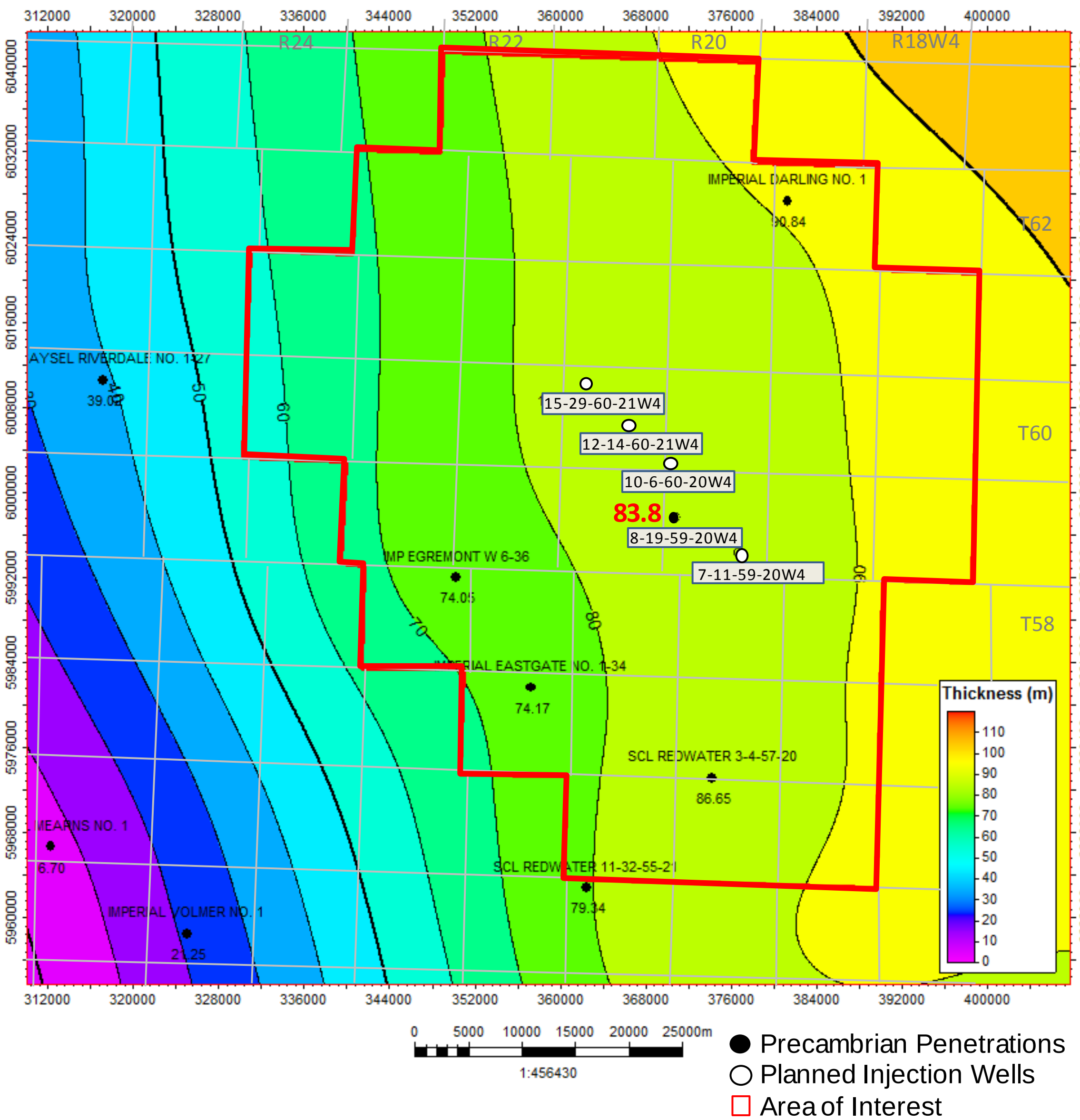


Figure 2-8 Extent and Thickness of the Upper Lotsberg Salt in the AOI

2.3.4 CO_2 Storage in the BCS Storage Complex

2.3.4.1 Effect of CO_2 on BCS Brine

When dry super-dense CO_2 initially contacts BCS formation water, some of the CO_2 will dissolve in the brine, and some water will evaporate into the super-dense CO_2. The wet CO_2 will then displace brine near the wellbore, leaving residual brine behind the displacement front. The trailing, dry CO_2 will continue to cause water in the residual brine to evaporate, resulting in salt concentrating in the brine and eventually precipitating from it. At the same time, CO_2 dissolved in the brine will acidify the brine because of carbonic acid being generated and separating to produce bicarbonate ions and protons. Acidification drives all of the geochemical processes during CO_2 injection, migration and trapping in the reservoir by dissolving/precipitating minerals and gases and adsorbing/desorbing/exchanging ions.

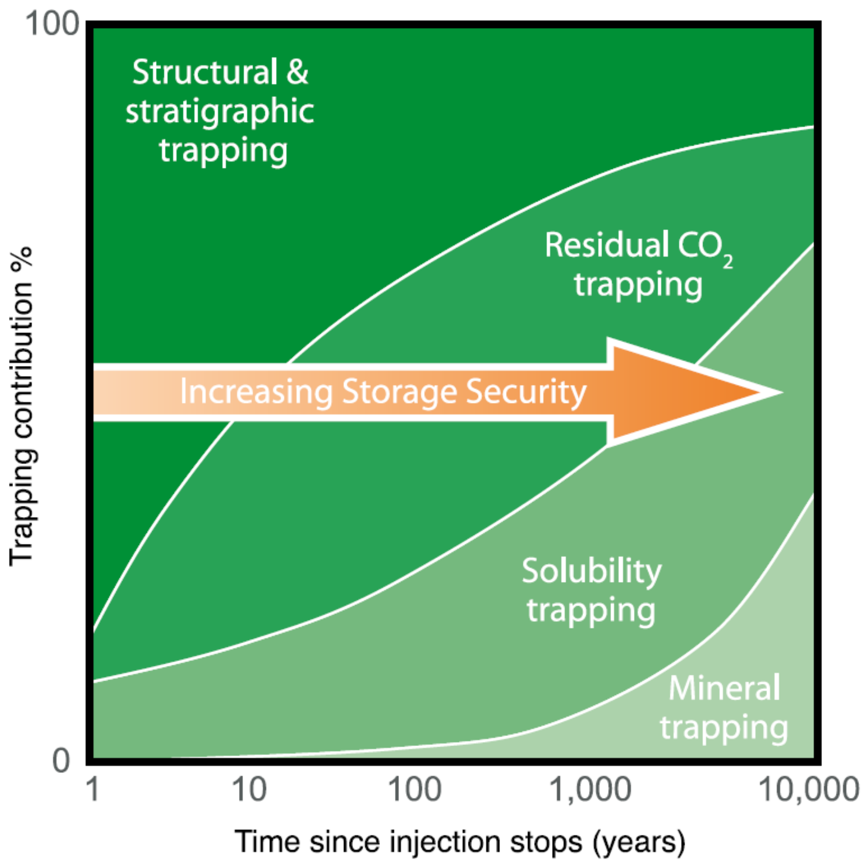
2.3.4.2 Mechanisms for Trapping CO_2

For a summary of CO_2 storage mechanisms, see Figure 2-9. Storage security depends on a combination of physical and geochemical trapping. Injected CO_2 partially displaces brine in the reservoir and partially dissolves in the brine. A portion of injected CO_2 is permanently trapped in place due to residual trapping, solubility trapping and mineral trapping mechanisms.

The free-phase CO_2 is the remaining CO_2 trapped by structural and stratigraphic traps in the BCS storage complex. Over time, the physical process of residual CO_2 trapping and geochemical processes of solubility trapping and mineral trapping increase. This results in more CO_2 becoming permanently trapped, and less free-phase CO_2 existing.

The average mineralogy of the BCS, defined through petrology, was used as input to geochemical modelling of rock and fluid interaction of injected CO_2 and formation brine. Primary minerals included in the reactive transport modelling in TOUGHREACT are quartz (75 vol%), K-feldspar (5 vol%), dolomite/ankerite (1 vol%), anhydrite (1 vol%), illite (1 vol%) and kaolinite (1 vol%). Halite and calcite are classified as secondary minerals that form during CO_2 injection. The key conclusions of the laboratory-calibrated, reactive transport modelling study are that at the end of injection:

- the main geochemical mechanism for trapping CO_2 is associated with dissolution in formation brine. At the end of injection, approximately 4% of the total injected CO_2 volume is dissolved in the brine. The remaining CO_2 is physically trapped via capillary forces at irreducible saturation with some portion of the CO_2 remaining in a mobile phase at the end of the injection period. After 50 years, (i.e. 25 yrs post end injection, these percentages go to 60% mobile, 25% residual and 15% dissolved CO_2 at 25 years plus post injection.
- dolomite and K-feldspar continue to dissolve in the low pH flushed zone of the BCS. Hence, the net amount of geochemical CO_2 trapping in the matrix is negative, meaning additional CO_2 is released in the low pH zone while dissolving the carbonate impurities of the BCS.



SOURCE: Benson and Cook (2005)

Figure 2-9 Summary of CO_2 Storage Mechanisms

2.3.4.3 Halite Precipitation

Injecting dry CO_2 over a prolonged time into the BCS will create a dry-out zone around each of the injection wells due to brine evaporation, resulting also in halite precipitation.

Geochemical modelling, using TOUGHREACT, estimated that at the end of 25 years of injection such dry-out zones may extend several tens of metres away from the wellbore into the formation. Core flooding experiments to study the effect of halite precipitation on CO_2 injection in the BCS have been conducted in Shell's Research Laboratory in Rijswijk and at MetaRock, Houston.

The first set of experiments showed a slight reduction in effective permeability during dry-out, potentially associated with end-cap effects. The second set of laboratory tests showed a slight increase in effective permeability, believed to be the result of increasing effective porosity due to the drying out of irreducible water.

In the unlikely event that permeability reduction due to halite precipitation occurs in the field, mitigation to restore well injectivity will involve flushing the region near the wellbore with fresh brine, and dissolving the halite.

2.3.4.4 Interaction between the Target Zone and First Seal

Any possible geochemical alteration of the first reservoir seal, the MCS, was studied during reactive transport modelling based on the available XRD data. The mineralogy package of the MCS predominantly consists of quartz (20 vol%), illite/smectite/mica (30 vol%), kaolinite (30 vol%), K-feldspar (7 vol%), dolomite/ankerite (1 vol%) and chlorite (4 vol%). Model results determined that:

- in the shale, CO_2 exposure reduces the pH from 5.5 to 4.0, leading to dissolution of dolomite and feldspar in the reactive zone within the shale
- the formation of clay minerals due to the dissolution of the feldspar appears to reduce the shale permeability further, hence potentially enhancing the sealing properties of the MCS

2.3.4.5 Radius of Influence of Stored CO_2

An analytical CO_2 plume size can be calculated by assuming homogeneous displacement of brine by the injected CO_2 in a cylindrical shape around the 8-19 wellbore. This is a simplified method that would indicate the minimum radius of influence. The presence of reservoir heterogeneities and non-uniform displacement around the wellbore will cause non-uniform displacement, including:

- in high permeability layers, or towards the top of the reservoir, the CO_2 will migrate outside this assumed cylinder
- in lower permeability layers or deeper intervals, the CO_2 front may not quite reach this assumed cylindrical CO_2 plume radius

The reservoir parameters that are used to make this analytical calculation for cylindrical migration are from the Well 8-19 results, and the property range is taken from regional data used to create the Well 8-19 predictions (see Table 2-6). The results in the table suggest that the radius of the CO_2 plume size after 25 years of injection could extend to between 0.5 to 3 km away from the wellbores, depending on (in order of priority):

- the number of wells
- the sweep efficiency
- maximum CO_2 saturation
- porosity
- BCS reservoir thickness
- other reservoir parameters of minor impact

The analytical results were used to check the quality of dynamic simulation results for various subsurface realizations. Figure 2-10 illustrates simulation results from a subsurface realization that incorporates reservoir heterogeneity and low case reservoir property values. The CO_2 saturation is displayed for a layer at the top of the BCS after 25 years of injection. The CO_2 plume of each individual well is not circular as it is influenced by the modelled northeast–southwest directionality of the expected reservoir permeability distribution. Heterogeneity and low reservoir properties result in a plume radius larger than in the analytical base case calculations, with the plume dimensions along their largest cross-sections approximately double the analytically calculated base case plume size (see Table 2-6). The simulated CO_2 plume sizes vary slightly with location depending on the permeability distribution and local thickness and topography variations.

Table 2-6 Notional CO_2 Plume Radius Based on Reservoir Parameters for Well 8-19

Parameter	Base Case	Promoting Maximum Plume	Promoting Minimum Plume
BCS reservoir height (m)	46	28	43
BCS net-to-gross ratio	0.90	0.80	1.00
BCS porosity	0.16	0.11	0.19
BCS net pore height (m)	6.62	2.46	8.17
Maximum CO_2 saturation	0.60	0.40	0.75
CO_2/brine sweep efficiency	0.80	0.50	0.95
Effective CO_2 saturation	0.48	0.20	0.71
Formation temperature	60.0	64.0	55.0
Formation pressure	20.45	20.2	20.7
CO_2 density at Pi, Ti	731	711	761
Injected CO_2 after 25 years (Mt)	27	27	27
Number of wells	5	3	10
Notional CO_2 plume radius (m)	**860**	**2,860**	**440**

NOTE:
Based on reservoir parameters for Well 8-19.

The pressure front associated with the CO_2 injection will extend beyond the area of the CO_2 plume. The radius of influence for pressure will depend mainly on the total injected volume, the maximum allowable bottomhole pressure and the formation compressibility. The minimum connected volume requirement would extend about 8 to 12 times further into the reservoir than the CO_2 plume, according to simplified material balance calculation. Therefore, for a CO_2 plume size of between 500 m and 3 km, the minimum connected volume radius would need to be between 4 km and 30 km.

Figure 2-11 illustrates the pressure increase after 25 years of injection from dynamic modelling of the same heterogeneous, low reservoir property subsurface realization as shown previously (see Figure 2-10). The pressure response in the BCS is seen to extend some 20 to 40 km away from the injection wells. In other subsurface realizations where reservoir porosity and permeability are higher, the extent of the pressure increase is somewhat smaller. Analytical aquifer boundary conditions are applied to the dynamic model built in the Computer Modelling Group's Generalized Equation-of-State Model compositional reservoir simulator that assume some of the pressure increase will be dissipated by the reservoir outside the model area.

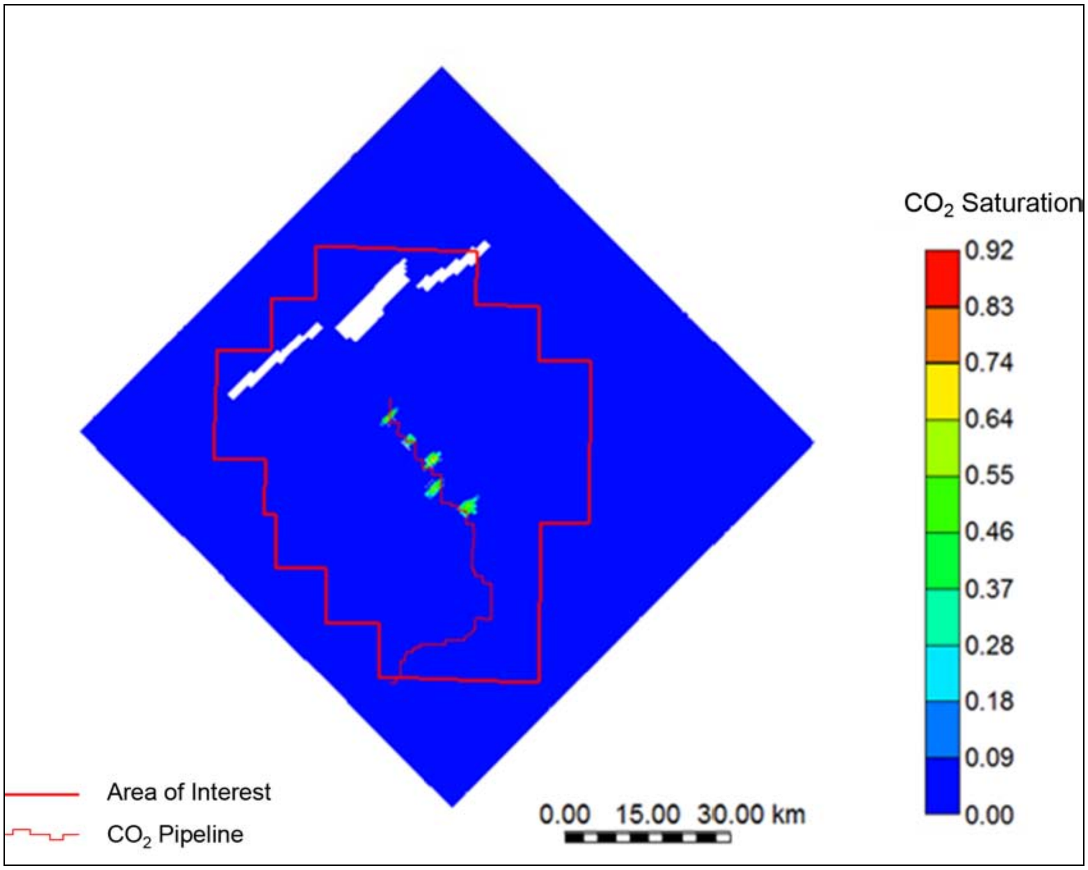


Figure 2-10 CO_2 Saturation after 25 years of Injection for a Heterogeneous, Low Reservoir Property Realization

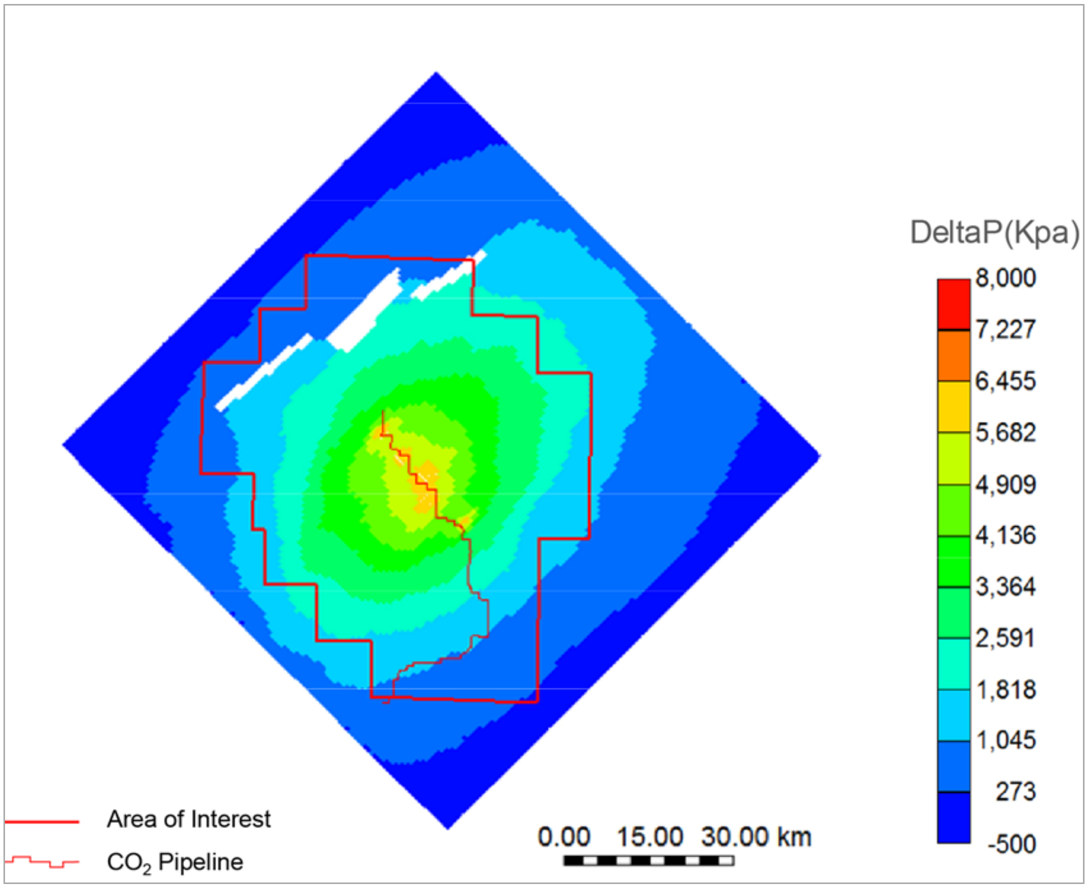


Figure 2-11 Pressure Increase after 25 Years of Injection for a Heterogeneous, Low Reservoir Property Realization

2.3.4.6 Distance to Closest Injection Site

There are currently no active, commercial CO_2 injection projects in the BCS storage complex within the AOI.

The nearest proposed CO_2 injection project is the Heartland Area Redwater Project (HARP) by Alberta Research Council (ARC) and ARC Energy Trust of Calgary. Their primary injection target is the Redwater Leduc Reef complex, located in part within the AOI but more than 10 km southwest of any of the potential Quest CCS Project injection wells. Current information indicates that the HARP project does not plan to penetrate the Upper Lotsberg Salt.

The closest injection well considering the entire stratigraphic section (above Upper Lotsberg Salt) is 11-06-60-19W4/2 located 10 km northeast of Well 8-19. This well disposes water into the Wabamun Formation.

The closest injection well to penetrate the BCS storage complex is a water injection well, Canadian Natural Resources Limited (CNRL) 03/10-21-063-08W4/0. With this well, water is injected into the undefined Cambrian sandstone at a depth of approximately 1,400 mTVD and approximately 90 km northeast of the AOI.

2.3.5 Injection Wells

2.3.5.1 Construction

One of the Project wells, Well 8-19, was permitted under ERCB Directive 56 and has been drilled, completed and tested. Of the potential remaining wells, the locations of four have been identified (see Figure 1-1).

Wells will be licensed under ERCB Directive 56. Once the new unique well identifiers (UWIs) are known, the Directive 65 application will be amended to include those UWIs. Following this, an ERCB Directive 51 application will be submitted for the wells.

Generally, well construction will involve clearing the well pad and access road. Drilling equipment will be transported to site and set up. This generally includes a drill rig, trailers, power generators, light towers and supporting vehicles.

The wells will be drilled, and casing installed and cemented. The conceptual design of the wells will follow the design basis of the recently drilled Well 8-19 (see Figure 2-12). Key aspects include using:

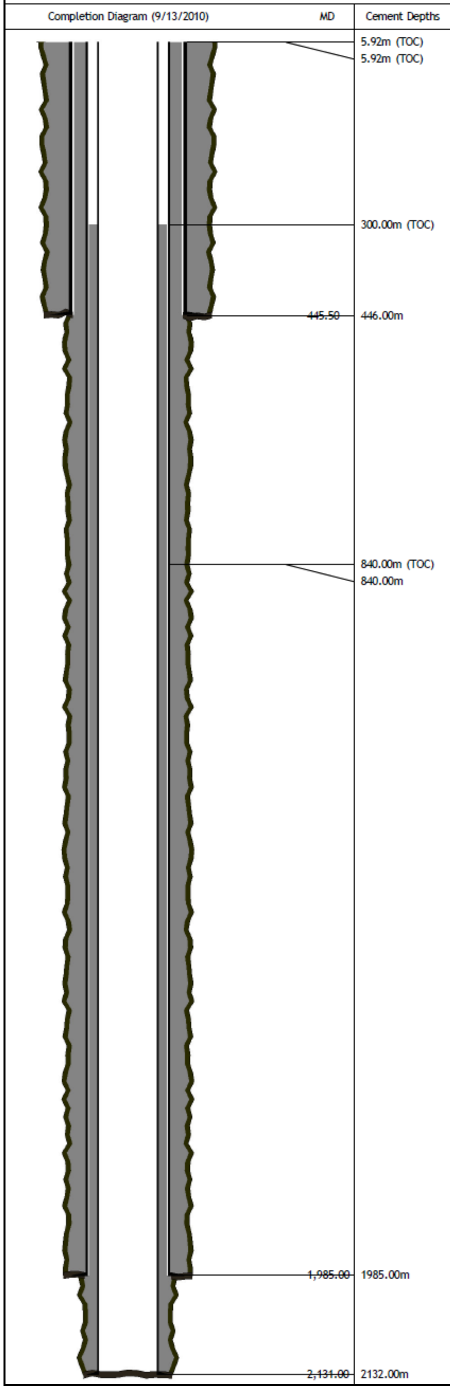
- a shale inhibitive drilling fluid system suitable for maintaining wellbore integrity, supporting data acquisition and minimizing formation damage. Current design is an oil-based-mud system although other compatible mud systems may still be used in future wells.
- three casing strings, each cemented to surface to maximize borehole stability. Surface hole casing will be set below the BGWP zone. Intermediate casing setting depth will be located below the first seal (MCS) inside the LMS layer. This will effectively isolate all the three main seals behind intermediate casing before the main hole is drilled and cased. Main hole casing will be set below the top of the Precambrian basement.
- 22Cr chrome casing will be run from target depth to inside the MCS layer, for the production casing string to mitigate potential corrosion effects of the CO_2 brine. The packer will be set inside the 22Cr casing, for completion with mechanical integrity. Based on the predicted downhole conditions, injection schedule, estimated workover and well intervention requirements for the duration of well life time, TN-80S_S will be used above the 22Cr casing up to the surface.

Horizontal and highly deviated well designs, as well as an option to decrease the number of casings strings to two, are currently under review. If chosen for future injection wells, Shell will amend the Directive 65 application and the wells will be required to attain Directive 51 approval before injection.

Once the wells have been tested, and the pipeline laterals constructed and completed, the wells will be connected to the laterals. The drilling equipment will be disassembled and removed from the site and the well pads will be reclaimed.

RADWAY 100/08-19-059-20W4 (08-19-059-20W4)

Well Status Diagram



UWI: 100081905920W400
Water Depth: 640.10m
Longitude: -112.978
MAASP A:
Datum: DFE @ 646.02m (NABORS 78)(default)
TD:
Northing: 5,997,747.39m
RKB: 646.02m
Latitude: 54.114
Easting: 370,705.48m

Hole	Top MD (m)	Base MD (m)
445mm hole section	5.85	446.00
311mm hole section	446.00	1,985.00
222mm hole section	1,985.00	2,132.00

Surface Casing Size: 339.70 MD Top: 5.85m
MD Landed: 445.50m Min ID: 313.60mm

Item Description	#Jts	Length (m)
CASING JOINT(S)	35	425.81
CASING FLOAT COLLAR	1	0.48
CASING JOINT(S)	1	12.81
CASING FLOAT SHOE	1	0.55

Intermediate Casing Size: 244.50 MD Top: 5.92m
MD Landed: 1,985.00m Min ID: 225.00mm

Item Description	#Jts	Length (m)
Casing TN80SS, LT&C	57	787.11
ECP/Stage Tool	1	6.58
Casing TN80SS, LT&C	60	836.37
Casing TN80SS, LT&C	17	234.45
Casing TN80SS, LT&C	7	98.73
Casing Float Collar	1	0.62
Casing TN80SS, LT&C	1	14.68
Casing Float Shoe	1	0.54

Item Description # Jts Length (m) Top MD (m)

Production Casing Size: 177.80 MD Top: 5.92m
MD Landed: 2,131.00m Min ID: 156.23mm

Item Description	#Jts	Length (m)
Steel Casing	163	1,958.78
Chrome casing	14	153.95
Guide Shoe	1	0.52
Steel Shoe Track Joint	1	11.23
Float Shoe	1	0.60

Figure 2-12 As-drilled Well Diagram for Well 8-19

2.3.5.2 Operation Phase

Once the wells are operational, activity at the site will be limited to maintenance and safety checks. CO_2 will flow from the CO_2 pipeline to the laterals and wells, and will be injected downhole into the BCS.

Bottomhole Injection Pressure

Based on the available offset data from the appraisal wells, and validated by log derived minimum horizontal stress estimates for Well 8-19, the bottomhole injection pressures for the commercial well design will be limited to 90% of the lowest observed fracture extension pressure in the LMS at 17.4 kPa/m. For a top BCS reservoir depth in Well 8-19 at 2,041.3 m MD this would correspond to a bottomhole pressure constraint of 31,967 kPa (90% safety factor already applied). This value:

- is well below fracture initiation and extension pressures observed in the BCS of 20.7kPa/m in the 11-32 well
- is lower than the log-derived minimum horizontal stress interpreted for the first seal (the MCS) of 18.1kPa/m in the 11-32 well.

Pressure constraints will be implemented on a well-by-well basis, rather than for the entire development, as fracture pressures are depth dependant.

The bottomhole injection pressures are in alignment with surface design, assuming a 12-inch pipeline and 7 km well spacing. The current facility design is expected to deliver the injectant to the well heads at a pressure of between 12 and 14 MPa and a temperature of between 0 and 18°C. At these conditions, the maximum achievable bottomhole pressure would vary between 31 and 32 MPa, depending on the density of the CO_2. Surface monitoring and control will be implemented to avoid the bottomhole pressure exceeding the fracture pressure limit.

Fracture Extension and Cap Rock Threshold Pressures

Maintaining bottomhole injection pressures below the fracture propagation pressure within the BCS is expected to prevent pressure-induced fractures occurring that would potentially threaten the containment of the injected CO_2 and displaced brine within the BCS. If pressures in the reservoir and around the wellbore remain below this value, new fractures are not likely to be induced, and any existing open natural fractures are not likely to propagate.

Although fracturing of the BCS is undesirable for CO_2 plume development and might cause loss of conformance (e.g., CO_2 fingering), it does not threaten containment unless these fractures propagate upwards and remain open through all the seals within the BCS storage complex. Although fractures tend to propagate upwards within homogeneous formations, many different mechanisms exist for effectively arresting vertical fracture extension within the heterogeneous and layered formations in the BCS storage complex above the BCS. The following are some of the main barriers for arresting vertical fracture extension:

- The minimum horizontal stress contrast, calculated as the ratio of the Young's Modulus between two layers located at the reservoir–seal interface, is typically sufficient to arrest vertical fracture extension if it exceeds 1.1. Log analysis on Well 8-19 indicates a stress contrast between the MCS and the BCS of 1.5, which makes a very effective barrier to vertical fracture extension. Similar values for the stress ratio were calculated for Wells 11-32 and 3-4, while ratios at the LMS–BCS and MCS–LMS interface also exceed 1.1.

- Weak interfaces – slippage along weak interfaces induced by the approach of a propagating fracture will frequently arrest vertical fracture extension. The LMS contains a highly laminated sequence of many sand–shale interfaces. Many of these interfaces will likely be sufficiently weak to arrest vertical fracture growth. The presence of many such interfaces further increases the likelihood of fracture arrest.

In summary, the minimum horizontal stress contrast and the presence of many weak interfaces within the LMS are expected to constitute effective barriers to fractures extension above the first seal (MCS). A further barrier is to avoid the propagation of fractures within the injection zone (BCS), as intended by the bottomhole pressure constraint.

2.3.5.3 Decommissioning and Abandonment

The lifespan of the storage component of the Project is considered to be at least 25 years.

The wells will be abandoned after post-injection monitoring is complete.

For abandoning wells, ERCB Directive 20 requirements will be adhered to, as a minimum. The wells will be considered as Level A, cased and completed wells, and will be abandoned as follows:

- The wells will be initially displaced with noncorrosive, inhibited fluid, before multiple cement plugs are placed.
- Multiple cement plugs along with bridge plugs will be placed inside the wells.
- Cement will cover all nonsaline groundwater zones.

Gas migration and surface casing vent flow tests will be done before downhole abandonment begins, to avoid having to re-enter the well to correct a wellbore problem.

The surface abandonment will be completed only after the subsurface has been abandoned to the satisfaction of the ERCB.

Shell will adhere to the ERCB guidelines for surface abandonment, including:

- Surface, intermediate and production casing strings will be capped at surface with a steel plate that is fastened and installed in a manner as to prevent any potential for pressure to build up within the casings while restricting access to the casing strings at surface.
- cutting off the casing string(s) a minimum of 1 m below the final contour elevation, with the following exceptions:
    - If the well is in an area with special farming practices, such as deep tillage, drainage works, or peat lands, or is within 15 km of an urban development, the casing string(s) must be cut off a minimum of 2 m below final contour elevation.

2.4 Project Support Requirements

2.4.1 Personnel

The Project construction is estimated to generate 4,420 person-years of direct, indirect and induced employment. The breakdown of the direct labour force requirement for the Project is as follows:

- an average of 590 persons and a peak of 950 persons during the construction of the CO_2 capture infrastructure
- an average of 120 persons, working in two crews of approximately 60 persons each, along the CO_2 pipeline ROW for the construction of the pipeline over a 9-month period
- an average of 15 people onsite in the County of Thorhild for a period of six months for the drilling of injection wells and the associated surface infrastructure for CO_2 storage

Additional construction-related employment will be created in offsite manufacturing facilities and engineering firms.

The Project will create nine full-time and one part-time permanent operation and maintenance positions in the Project area. It will also create three full-time and two part-time positions involved in remote monitoring support in Calgary.

2.4.2 Water

As part of the construction phase of the Project, water is expected to be required for pipeline hydrostatic testing. Water withdrawals for hydrostatic testing will be done in accordance with the Alberta Environment *Code of Practice for the Temporary Diversion of Water for Hydrostatic Testing of Pipelines* and the *Code of Practice for the Release of Hydrostatic Water from Hydrostatic Testing of Petroleum Liquid and Gas Pipelines*.

As part of the Project operation phase, water for the CO_2 capture infrastructure will be supplied through the existing Scotford Upgrader water supply system, under the current Alberta Environment water licence (No. 00070013-01-00), which allows for a maximum calendar year withdrawal of 8,146,800 m^3. Water at the CO_2 capture infrastructure is required for utility water (about 4 m^3 per stream hour [m^3/sh]), potable water (maximum intermittent flow of 4 m^3/sh) and process water (about about 16 m^3/sh).

Process water will be required to make up for water losses in the absorption and regeneration areas of the CO_2 capture infrastructure. Process water at the CO_2 capture infrastructure will be recycled within the absorption, regeneration and compression areas, where possible.

Drilling of the injection wells will require water for the drilling operation and possibly for testing the drill casings or injectivity of the well. Water will be sourced locally, either from private landowners near the well sites (i.e., from dugouts) or through a temporary diversion licence from Alberta Environment under the Alberta *Water Act*. Water that is returned to surface will be tested and treated before discharging.

3 Emissions, Discharges and Waste

3.1 Atmospheric Emissions

During the construction phase of the Project, atmospheric emissions are expected to result primarily from construction equipment and machinery required for all three Project components. These emissions are expected to disperse quickly, thereby negligbly affecting air quality within the Project area.

During the Project operation phase, the CO_2 capture infrastructure will result in up to 1.2 Mt/a of CO_2 being captured from the Scotford Upgrader, thereby reducing CO_2 emissions by up to 35%.

The fuel gas currently used in the HMU reaction furnace is a combination of HMU PSA tail gas and upgrader fuel gas. The PSA tail gas typically contains more than 45% by volume CO_2 that acts as a diluent to reduce the burner flame temperature, thus resulting in reduced production of NO_X.

When the CO_2 capture infrastructure is in operation, the CO_2 in the tail gas will be captured for storage, resulting in a high hydrogen/methane content gas. The new PSA tail gas will burn at a substantially hotter flame temperature in the HMU reaction furnace and will require additional combustion air to maintain the furnace within acceptable operating conditions. The higher flame temperature will double the NO_X production from the HMU. As a result, the Project will install low NO_X burners and will investigate solutions to further reduce NO_X emissions from the HMU.

Fugitive CO_2emissions are expected to be associated with the CO_2 pipeline transport and storage component of the Project during operation. Negligible atmospheric emissions are expected during the decommissioning and abandonment phase of the Project.

3.2 Discharges

As part of the construction phase of the Project, discharges are expected only in association with pipeline hydrostatic testing and dewatering of the pipeline trench. Water from the pipeline trench will be discharged to a vegetated area away from surface water bodies. Management of discharges associated with hydrostatic testing will follow the Alberta Environment *Code of Practice for the Release of Hydrostatic Test Water from Hydrostatic Testing of Petroleum Liquid and Gas Pipelines*. This will include obtaining and analyzing a water sample before and after testing to determine the suitability of the release of the test water to land or water. Hydrostatic testing will likely be performed on 30 km-long sections of pipeline at a time. After each section of pipeline is tested, the hydrostatic test water will be reused for the next section until the testing is completed (approximately three uses). The approximate volume of hydrostatic test water is expected to be 2,500 m^3.

Process water at the CO_2 capture infrastructure will be recycled within the absorption, regeneration and compression areas, where possible. A portion of recycled process water will be purged to the existing waste water treatment facilities at the Scotford Upgrader to avoid buildup of contaminants. Normally, about 16 m^3/sh of waste water will be produced and sent to the existing waste water treatment facilities. There is sufficient capacity within the Scotford Upgrader wastewater treatment system to handle discharges from the CO_2 capture infrastructure.

Waste water produced from the CO_2 capture infrastructure will be higher for brief periods during intermittent maintenance activities. Once treated, water will be released to the North Saskatchewan River, in accordance with the Scotford Upgrader *EPEA* Approval and the federal *Fisheries Act*.

No discharges have been identified with other components in the operation phase. No discharges are anticipated as part of decommissioning and abandonment.

3.3 Waste Management Plan

Shell will implement a waste prevention program to limit the amount of waste being generated and requiring disposal. Shell Scotford has an existing waste management plan in place, which will be amended to include waste from the CO_2 capture infrastructure. A separate waste management plan will be developed for the CO_2 pipeline and injection wells.

Non-process-related waste is generated primarily from construction and maintenance activities. Most of the waste generated during the Project will be during the construction phase. Process-related solid waste that might be produced in the CO_2 capture infrastructure includes amine filter particulates and spent activated carbon from the carbon filter. Process-related waste is not expected to be generated as part of the CO_2 pipeline or CO_2 storage components.

All liquid waste streams (e.g., process wastewater) at the CO_2 capture infrastructure will be collected and recycled, where feasible. Net process wastewater will be sent to the Scotford Upgrader waste water treatment facility for treatment and disposal. Other liquid waste streams (e.g., lube oils) will be handled and disposed of according to Shell Scotford procedures for the capture infrastructure, or according to the waste management plan developed for the CO_2 pipeline or CO_2 storage components. Wastewater volumes at the CO_2 capture infrastructure are expected to be about 16 m^3/sh.

3.3.1 Strategy

The aim of the waste prevention program is to limit the amount of waste being generated that requires disposal.

Waste prevention can be achieved through procurement practices that result in minimal packaging, reusable packaging (e.g., pallets and containers) and construction practices and procedures developed with waste prevention in mind.

Waste will be limited through reduction, reuse, recycle and recover practices. This will be followed by reduction in the amount of waste and the overall volume of waste before final disposal. Shell will identify and specify at the end of the Front End Engineering and Design phase all solid waste generated by the process, and the required handling systems to move, store, treat, recycle and dispose of solid waste.

Materials such as lead, mercury and asbestos will not be used. Workplace Hazardous Materials Information System (WHMIS)-controlled material that is introduced into the capture infrastructure or CO_2 pipeline or storage components (e.g., treated wood in cooling towers, insulation or paints) and that will remain after construction will:

- be approved by Shell Scotford Industrial Hygiene
- have material safety data sheets provided

3.3.2 Waste Disposal

Waste produced at the CO_2 capture infrastructure will be handled and disposed of according to the following Scotford Upgrader handling and disposal procedures as explained below. Except for the new type of amine, no new waste streams are expected at the Scotford Upgrader as a result of the CO_2 capture infrastructure. Waste generate as part of the CO_2 pipeline or storage components will be handled and disposed of according to the waste management plan for those components.

3.3.2.1 Hazardous Waste

Hazardous waste will be disposed of as follows:

- Project chemical, oily and medical waste will be managed consistent with the existing Shell waste management program.
- Batteries will be collected and stored in separate (dedicated) containers and recycled.
- Lubrication and motor oils will be returned to a recycling plant or refinery.
- Chemicals and solvents will be returned to the supplier for recycling, or to a suitable waste disposal facility.

3.3.2.2 Non-Hazardous Waste

Non-hazardous waste will be disposed of as follows:

- For construction dedicated facilities or containers (or both) are required for the different types of waste.
- For operations, containers must have a protected (covered) area and facilities for surface drainage. Chemical containers and drums will be reused. Recycling in the domestic circuit will be avoided.

3.3.2.3 Industrial and Domestic Waste

Industrial and domestic waste will be disposed of as follows:

- Scrap metal and paper will be recycled using third-party companies.
- Other industrial and domestic waste will be transported to an approved landfill site

3.3.2.4 Drilling Waste

Drilling waste will be generated during drilling of the injection wells for the CO_2 storage component of the Project. A number of options are available for handling and disposing of drilling waste, dependent on the drilling fluid used and the results of the analysis of the drilling waste.

Drilling waste will be managed according to ERCB *Directive 050: Drilling Waste Management*, including submission of appropriate notification, sampling, and toxicity assessment (if required).

For the drilling of Well 8-19, about 1,000 t of drill cuttings where generated. These were removed from the site daily and transported to a landfill for disposal. No onsite storage was required for drilling waste. It is estimated that about 500 m^3 of liquid drilling waste and about 1,000 t of solid drilling waste (cuttings) will be generated during drilling and completion of each injection well. This number could vary between 10 and 30%, depending on drilling techniques. It is expected that drilling waste will be managed similarly for the other planned injection wells.

4 Alternatives

4.1 Alternatives to the Project

The goal of the Project is to reduce greenhouse gas emissions (GHG) from the Scotford Upgrader through an integrated CCS project. In the absence of the Quest CCS Project, Shell would continue advancing compliance options under Alberta's *Specified Gas Emitters Regulation* to fill the gap, including:

- improving energy efficiency
- using lower GHG-emitting energy supplies
- purchasing Alberta-sourced offsets
- contributing to the Climate Change and Emissions Management Fund

An EOR alternative could potentially exist, if and when a market for CO_2 develops.

4.1.1 Enhanced Oil Recovery Alternative

If and when an EOR market for CO_2 develops, captured CO_2 from the Project could be offered for sale under terms of a specific CO_2 contract.

The Project is well-positioned, close to hydrocarbon-producing formations, which are suitable for enhanced oil recovery. The Redwater Reef is the closest hydrocarbon-producing formation.

EOR would be a secondary outlet for CO_2 storage and an alternative revenue stream. The Redwater EOR Project (operated by ARC Energy Trust) and Swan Hills EOR Project (operated by PennWest Energy) are the closest EOR market outlets.

4.2 Alternative Means for the Project

Evaluation of alternative means for carrying out the Project considers alterations in the three Project components: capture, transport and storage. This section considers alternative technologies for capture of the CO_2 at the Scotford Upgrader, routing and design alternatives for the CO_2 pipeline, and an overview of the CO_2 storage area selection process.

4.2.1 CO_2 Capture Infrastructure

Shell carried out a number of studies to evaluate alternative CO_2 capture technology. The selection of the preferred technology for the CO_2 capture infrastructure was based on:

- defining the technology selection criteria
- defining the most suitable CO_2 removal locations
- reviewing and assessing the alternative technologies for CO_2 recovery suitable for the removal location and selection criteria

4.2.1.1 Technology Selection Criteria

The following criteria were applied in order of priority, for selecting the point source and the process technology to recover CO_2 in the Scotford Upgrader:

1. Captures large-scale amounts of $CO_{2.}$
2. Uses commercially proven technology, preferably applied to HMUs.
3. Maximizes the net CO_2 captured.
4. Minimizes waste and emissions generated by the CO_2 capture infrastructure
5. Uses a simplified design for operational reliability and lower capital and operating costs.
6. Maximizes Scotford Upgrader facility interfaces.
7. Minimizes construction requirements.

4.2.1.2 CO_2 Removal Location

The technology selection criteria narrowed the source for CO_2 down to the HMU. Other locations at the Scotford Upgrader (primarily fired heaters and process furnace stacks) have CO_2 concentrations in the 4 to 12% range at low pressure, and require more expansive facilities for removing CO_2 on the scale contemplated for the Quest CCS Project.

A team of technical staff from Shell and the HMU licensor evaluated the CO_2 stream access within the HMU. The team determined that the two most feasible locations were the:

- feed gas to the PSA (i.e., before the PSA)
- tail gas from the PSA (i.e., after the PSA)

The quantity and quality of the gas at either of these two possible locations are ideal for capturing CO_2 using well-known and mature technologies. The main difference between the feed gas and the tail gas streams from the PSA is the pressure and CO_2 concentration of these streams.

The team concluded that the quantity and quality of gas at either of these two locations is favourable for capturing CO_2 using well-known, mature technologies. The main difference between the two options is the higher pressure and CO_2 partial pressure in the feed gas stream before the PSA.

4.2.1.3 Alternative Technology Evaluation

Using these two removal locations around the PSA, the Project team made the selection on the basis of best-fit with the technology selection criteria. The alternative technologies that were examined included:

- monoethanolamine or MDEA absorbers downstream of the PSAs
- activated MDEA (aMDEA) absorbers upstream of the PSAs
- refrigeration and liquid separation (cryogenic and methanol) downstream of the PSAs
- physical solvents downstream of the PSAs
- Linde PSA adsorbent process downstream of the PSAs
- membrane separation technology

Based on the results of the studies, the Quest CCS Project team selected the absorption process upstream of the PSA using aMDEA. Shell has developed its own aMDEA technology called ADIP-X. The ADIP-X technology is commercially proven and applied on a large industrial scale. Shell has installed the ADIP-X technology in several facilities over the past five years, including LNG plants and the following, which are in HMU-retrofit CO_2 removal service:

- Bukom Refinery, Singapore
- Martinez Refinery, US
- Petit Couronne Refinery, France
- NZ Refining Company, New Zealand

4.2.2 Pipeline Routing and Design Considerations

4.2.2.1 Routing Selection

Shell engaged in a detailed route selection process that considered the following criteria:

- location of the CO_2 storage area
- paralleling existing pipeline rights-of-way and other linear disturbances, where possible
- avoiding environmentally sensitive areas and wetlands, and limiting the number of watercourse crossings
- routing the CO_2 pipeline to maximize the viability of HDD across the North Saskatchewan River
- accommodating landowner and government concerns to the extent possible and practical
- shortening the length of the CO_2 pipeline to reduce total area of disturbance

Also considered were proximity to reserves, towns and country residential developments. For details on the route selection process, see Appendix H.

Shell will endeavor to use existing rights-of-way for temporary workspace and reduce the amount of new ROW clearing where possible and practical. Shell has approached industry and discussed using existing rights-of-way as part of its construction planning process. Approximately 28 km of the CO_2 pipeline will be parallel to existing rights-of-way.

4.2.2.2 Routing Changes Resulting from Consultation

During initial public consultation with Project stakeholders, several route changes were made to accommodate landowner, local authority and regulator concerns. Most of the rerouting was required to address the complexity of establishing exit routing from Shell Scotford, east through Strathcona Country, Lamont County and north to the North Saskatchewan River crossing.

Before the original proposed route was presented to the public, preliminary routing reviews considered a possible CO_2 pipeline route that went west of Shell Scotford instead of east. This route alternative proceeded west from Shell Scotford, across the North

Saskatchewan River, and then north through Alberta's Industrial Heartland and the Redwater Reef area. This route was not chosen because of the:

- poorer alignment with the CO_2 storage area for the injection wells
- complexity of routing though the industrialized area
- density of existing pipelines and poor soil conditions in the Redwater Reef area
- potential geotechnical challenges with the North Saskatchewan River at the proposed crossing location

The re-routes out of Shell Scotford were a result of routing concerns expressed by some industrial landowners and some area landowners. The first re-route investigated an alignment exiting Shell Scotford to the north, then east bordering Bruderheim Natural Area, and then joining the pipeline corridor to the north. This route option was abandoned because of concern from Alberta Tourism, Parks and Recreation. The subsequent proposed routing that is applied for in this application is aligned next to the recent Inter-Pipeline Fund pipeline ROW.

The CO_2 pipeline was also re-routed from the original routing presented at the open house at the North Saskatchewan River crossing. This re-route moved the crossing to a site where the geology allows the most probable success of using HDD for the watercourse crossing.

For additional details on route selection, see Appendix H.

4.2.2.3 CO_2 Storage

Shell used a number of parameters to evaluate subsurface areas for CO_2 storage, including:

- reservoir capacity
- injectivity and lifecycle containment criteria
- compatibility of CO_2 source composition with the reservoir and seals
- location choice for aboveground installations and pipelines

The Quest CCS Project ranked favourably when screened against the emerging selection criteria for safety and security of CO_2 storage (see Table 4-1).

Structured exploration appraisal programs were used to acquire data required to construct volumetric and dynamic 3D earth models that address these evaluation criteria.

Several types of rock formations are suitable for CO_2 storage, including saline aquifers, which are deep, porous rock formations containing naturally occurring salt water. To obtain the highest levels of CO_2 storage containment and capacity, the most suitable formations are usually selected at depths of 800 m or more, where pressures and temperatures of the rock keep the injected CO_2 fluid in a dense phase. The identification, assessment and development of a suitable storage formation on the basis of rock characteristics of capacity, injectivity, containment and monitoring involves proven technologies and practices used by the petroleum industry over many decades. Shell has used this experience to conduct appraisal and study activity over a region around Scotford and has identified the BCS and the multiple overlying layers of continuous impermeable seals as the preferred storage complex in the area.

Table 4-1 Assessment of the BCS for Safety and Security of CO_2 Storage

Criterion Level	No	Criterion	Unfavourable	Preferred or Favourable	BCS Storage Complex
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)	Three major seals (MCS, Lower Lotsberg and Upper Lotsberg Salts) continuous over entire CO_2 storage AOI. Salt aquicludes thicken updip to the NE.
	2	Pressure regime	Overpressured pressure gradients >14 kPa/m	Pressure gradients less than 12 kPa/m	Normally pressured <12 kPa/m
	3	Monitoring potential	Absent	Present	Present
	4	Affecting protected groundwater quality	Yes	No	No
Essential	5	Seismicity	High	<=Moderate	Low
	6	Faulting and fracturing intensity	Extensive	Limited to moderate	Limited. No faults penetrating major seal observed on 2D (two-dimensional) or 3D (three-dimensional) seismic.
	7	Hydrogeology	Short flow systems, or compaction flow, Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow	Intermediate and regional-scale flow-saline aquifer not in communication with groundwater
Desirable	8	Depth	<750–800 m	>800 m	>2,000 m
	9	Located within fold belts	Yes	No	No
	10	Adverse diagenesis	Significant	Low	Low
	11	Geothermal regime	Gradients ≥35°C/km and low surface temperature	Gradients <35°C/km and low surface temperature	Gradients <35°C/km and low surface temperature
	12	Temperature	<35°C	≥35°C	60°C
	13	Pressure	<7.5 MPa	≥7.5 MPa	20.45 MPa
	14	Thickness	<20 m	≥20 m	>35 m
	15	Porosity	<10%	≥10%	16%
	16	Permeability	<20 mD	≥20 mD	Average over CO_2 storage AOI 20-500 mD
	17	Cap rock thickness	<10 m	≥10 m	Three cap rocks MCS 20-55 m L. Lotsberg Salt 10–35 m U. Lotsberg Salt 55–90 m
	18	Well density	High	Low to moderate	Low

SOURCE: *CCS Site Selection and Characterization Criteria – Review and Synthesis*. Alberta Research Council, Draft submission to IEA GHG R&D Program, June 2009.

Several geological storage projects have successfully stored millions of tonnes of CO_2 for many years, without detectable leaks. Three large-scale CCS projects have been in operation for over five years or more and many new projects are planned for start-up in the coming years. One project has been operating in the Weyburn oilfield in Saskatchewan since 2000. This project uses a pipeline to transport CO_2 captured near Beulah, North Dakota and then injects it into the Weyburn field for enhanced oil recovery. The In Salah project in Algeria extracts CO_2 from produced gas and injects it back into a depleted gas formation, and the Sleipner CCS project in the Norwegian North Sea injects CO_2 for storage in a saline aquifer.

4.2.3 Environmental Effects of Alternative Means of Carrying out the Project

Shell assessed the environmental effects of alternative means of carrying out the Project as part of the selection process for the three main components of the Project. A summary of how environmental effects were assessed in the selection process for the capture infrastructure, pipeline and storage components of the Project is provided.

The selection process for the CO_2 capture infrastructure technology strived to limit the effects to the environment through:

- maximizing the CO_2 captured
- limiting emissions and generation of hazardous wastes
- minimizing interaction and effects on the Scotford Upgrader (i.e., water use, power requirements)
- minimizing construction requirements.

Shell developed technology selection criteria that incorporated these environmental considerations.

For the pipeline routing and design, Shell considered the potential environmental effects of the alternatives by incorporating environmental considerations into the pipeline routing and design criteria. Pipeline construction and operation have the potential to affect the terrestrial and aquatic environment, and therefore, Shell developed pipeline routing and design criteria that favoured limiting the footprint of the pipeline (e.g., paralleling existing pipeline rights-of-way, limiting the length of the pipeline), avoiding environmentally sensitive areas and limiting potential effects on aquatic environment by using HDD to cross the North Saskatchewan River.

Shell also developed assessment criteria for the selection of the CO_2 storage area, where the fundamental consideration is the ability of the complex to store CO_2 in perpetuity, and thus reduce the potential for CO_2 and brine to interact with groundwater, aquatic and terrestrial environment.

5 Project Schedule and Execution Plan

The timing for the construction start-up and operation of the Quest CCS Project is anticipated as follows:

- Construction of the CO_2 capture infrastructure will begin in the third quarter of 2012 and continue to Q4 of 2014.
- Construction of the CO_2 pipeline will begin in Q4 2013 and end in Q2 2014.
- Drilling of the injection wells will take place between Q4 2013 and the end of Q1 2014.

Final Investment Decision on the Quest CCS Project is anticipated in Q1 of 2012.

The integrated Quest CCS Project will become operational in conjunction with the commissioning and start-up of the CO_2 capture infrastructure. Commissioning and start of operations ramp-up of the full Quest CCS Project is anticipated to begin in the first quarter of 2015. Full sustained operation will be achieved by the fourth quarter of 2015. The Quest CCS Project is expected to operate for the life of the Scotford Upgrader (greater than 25 years).

These timelines are subject to change, pending regulatory approval, market conditions and internal and joint venture Project approvals.

For the schedule of the full integrated Quest CCS Project, see Figure 5-1.

5.1 CO_2 Capture Infrastructure

The CO_2 capture infrastructure will be executed in manageable work phases to reduce the effects of this Project on the existing Scotford Upgrader operation. The current plan is to tie in the CO_2 capture infrastructure to the Scotford Upgrader during the planned 2013 and 2014 turnarounds. The current anticipated schedule for key CO_2 capture infrastructure work and milestones is as follows:

- Q4 2010 – finalization of design premises
- Q1 2011 to Q1 2012 – basic engineering and design
- Q1 2012 – final investment decision for the CO_2 capture infrastructure
- Q2 2012 to Q3 2013 – detailed engineering and design
- Q3 2012 to Q4 2014 – construction of the CO_2 capture infrastructure
- Q1 2015 to Q3 2015 – commissioning and start-up of the CO_2 capture infrastructure
- Q4 2015 – full sustained operation

Decommissioning and abandonment of the Project could commence after 25 years and would require disassembly of the CO_2 capture infrastructure.

These timelines are subject to change, pending regulatory approval, market conditions and internal and joint venture Project approvals.

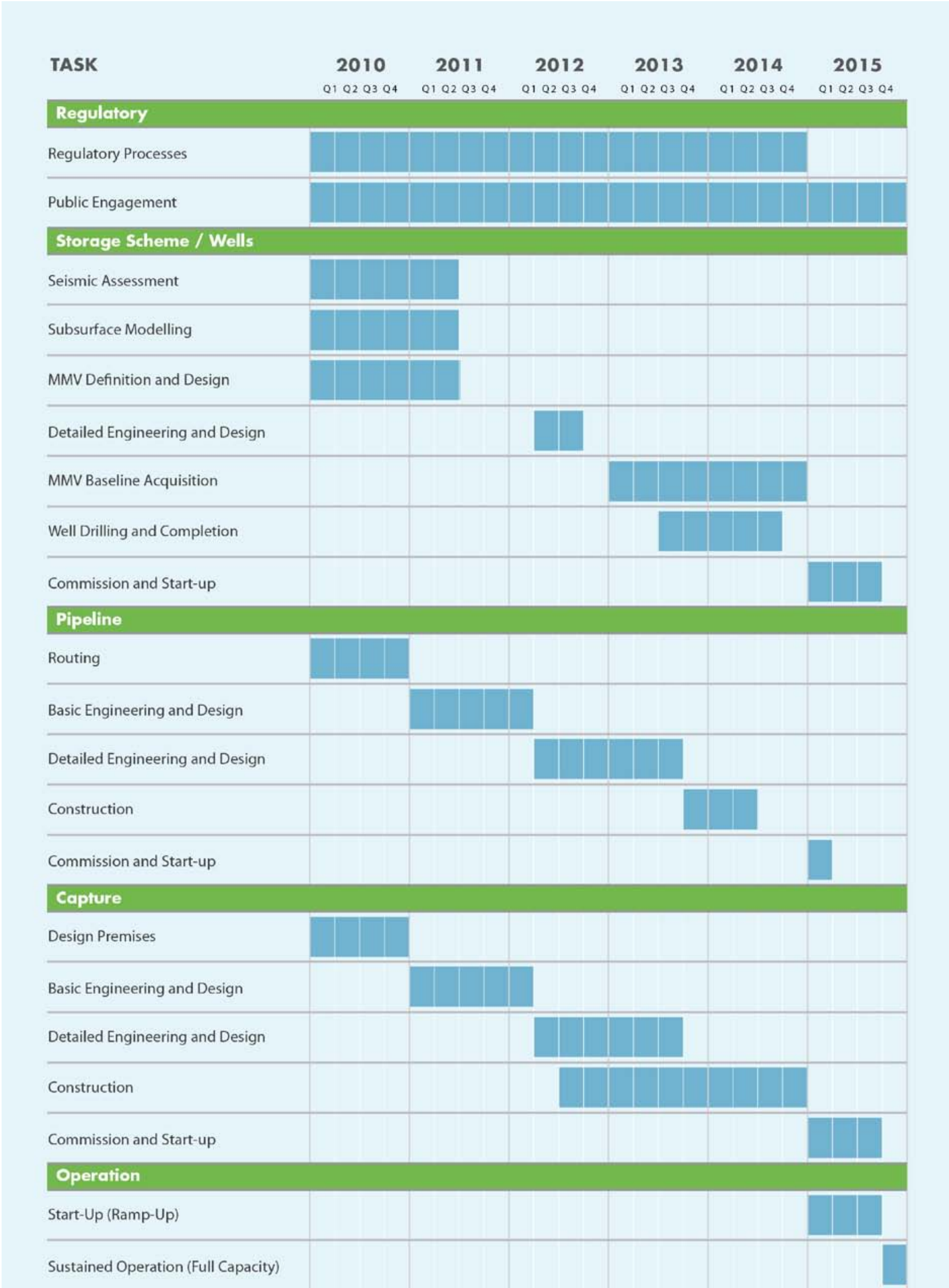


Figure 5-1 Quest CCS Project Schedule

5.2 CO_2 Pipeline

The current anticipated schedule for CO_2 pipeline construction and operation milestones is as follows:

- Q4 2010 – finalization of pipeline routing
- Q1 2011 to Q1 2012 – basic engineering and design
- Q1 2012 – final investment decision for the pipeline component
- Q2 2012 to Q3 2013 – detailed engineering and design
- Q4 2013 to Q2 2014 – construction of the pipeline
- Q1 2015 – commissioning and start-up of the pipeline
- Q4 2015 – full-capacity sustained operation

Decommissioning and abandonment will occur once the CO_2 capture infrastructure has been shut down. The CO_2 pipeline will be depressurized and abandoned in place.

5.3 CO_2 Injection and Storage

Drilling of Well 8-19 was completed in August 2010.

The current anticipated schedule for injection well and storage component milestones is as follows:

- 2010 and 2011 – continuation of seismic assessment, subsurface modelling, and definition of the specifics of the MMV program
- Q1 2012 – final investment decision for the storage component
- Q2 2012 to Q3 2012 – detailed engineering and design
- Q1 2013 to Q4 2014 – acquisition of baseline MMV information
- Q3 2013 to Q3 2014 – drilling and completion of the injection wells
- Q1 2015 to Q3 2015 – commissioning and start-up of the Project
- Q4 2015 – full-capacity sustained operation

The injection wells would be decommissioned at the same time as the CO_2 capture infrastructure. Once CO_2 had stopped flowing to the wells, they would be abandoned through capping at the surface following the processes described previously (see Section 2).

6 Stakeholder Engagement and Aboriginal Consultation

6.1 Introduction

6.1.1 Commitment

Shell supports, and is committed to working with, regulatory agencies and regional stakeholders to facilitate responsible development. Shell's development is focused on designing and executing a robust project, conserving resources, protecting the environment and enhancing the Project's regional socio-economic opportunities.

6.1.2 Consultation Goals

Shell's public consultation goals are to:

- establish an organized process for obtaining public input and addressing it in the Project's development, mitigation efforts and monitoring
- identify stakeholders who might be affected by the Project, or who might have questions or concerns about it
- provide stakeholders with clear, timely information about the technology, environmental performance, potential environmental effects and opportunities associated with the Project
- inform stakeholders of Shell's development plans for the Scotford area, and deliver this information in an integrated way that conveys both the short- and long-term effects of the plans
- obtain input from stakeholders about their concerns with, and objections to, Shell's plans, and identify ways to address or reduce them
- identify opportunities to maximize benefits to stakeholders
- establish new relationships, or build on existing ones
- implement appropriate mitigation measures

Through this process, Shell strives to:

- search actively for win–win results and ways to add value for all parties
- build long-term ownership of, and commitment to, mutually agreed outcomes

6.1.3 Consultation Process

Stakeholder consultation is part of the ongoing, long-term business activities associated with the existing Scotford Upgrader operation. Project staff will continue to work closely with neighbours and participate in regional multi-stakeholder groups and initiatives to address environmental and socio-economic issues and concerns related to current and planned future activities.

For a full list of Quest CCS Project consultation activities, see Appendix J.

6.2 Stakeholders

6.2.1 Identified Stakeholders

Shell has identified the stakeholders for the Project (see Table 6-1). The interested parties identified include:

- individuals and groups that might be affected by the Project
- all landowners, occupants and residents within a 5 km emergency planning zone (EPZ) of Shell Scotford
- all landowners, residents and occupants within 500 m of either side of the proposed CO_2 pipeline (pipeline EPZ)

Table 6-1 Quest CCS Project Stakeholders

Stakeholder Group	Stakeholder Subgroups
First Nations and Métis organizations	• Alexander First Nation • Beaver Lake Cree Nation • Saddle Lake Cree Nation • Métis Nation of Alberta, Region 2 and 4
Local communities and organizations	• Grazing rights holders • Landowners, occupants and residents within 5 km of the Scotford site • Landowners, occupants and residents within the EPZ of the proposed CO_2 pipeline route • Leaseholders and lease allotment holders
Government agencies	• Alberta Environment • Alberta Energy • Alberta Health and Wellness • Alberta Infrastructure and Transportation • Alberta Sustainable Resource Development • Alberta Tourism, Parks and Recreation • Canadian Environmental Assessment Agency • Environment Canada • Energy Resources Conservation Board • Fisheries and Oceans Canada (DFO) • International and Intergovernmental Relations • Natural Resources Canada • Transport Canada – Navigable Waters

Table 6-1 Quest CCS Project Stakeholders (cont'd)

Stakeholder Group	Stakeholder Subgroups
Regional and municipal governments	• City of Edmonton • City of Fort Saskatchewan • County of Lamont • County of Strathcona • County of Sturgeon • Thorhild County • Town of Bruderheim • Town of Redwater • Hamlet of Radway • Hamlet of Thorhild
Special interest groups	• Alberta Snowmobile Association • Citizens for Responsible Development • Ducks Unlimited • Environmental Resource Centre • Fort Air Partnership (FAP) • Friends of Lamont County • Northeast Regional Community Awareness Response
Industry and Industry Associations	Agrium Inc. Air Liquide CN Rail CP Rail Dow Chemical Gulf Chemical and Metallurgical Corp. North West Upgrading Inc. StatOil Suncor Total E&P Canada Alberta Chamber of Resources Alberta Industrial Heartland Association (AIHA) Canadian Association of Petroleum Producers (CAPP) Integrated CO_2 Network Northeast Capital Industrial Association

6.2.2 Stakeholder Consultation

6.2.2.1 Consultation Focus

Consultation with stakeholders focused on:

- providing an overview of the scope of the proposed Quest CCS Project
- discussing the potential environmental and socio-economic effects of the Quest CCS Project, and the opportunities to limit and mitigate them
- identifying a process and method of consultation preferred by the various stakeholders
- identifying stakeholder key areas of interest and concerns
- establishing feedback mechanisms for stakeholders to provide input into the Project design

6.2.2.2 Landowner, Occupant and Resident Consultation

In January 2010, Shell issued a public information package that included information on the proposed Project. This package was distributed to landowners, occupants and residents, local or urban authorities and Crown disposition holders.

Shell initiated direct consultation with landowners, occupants and residents along the CO_2 pipeline in January 2010. The public information package was sent out to all landowners, residents and occupants of properties within 1,200 m of the pipeline (initial calculations for a 41 cm (16 in.) diameter pipeline had indicated an EPZ of 800 m with an additional 400 m emergency awareness zone on each side of the pipeline). Face-to-face meetings were held with landowners and occupants. The purpose of the meetings was to provide information about the Project, the proposed activities, obtain access to their properties for environmental data collection and obtain their nonobjection to the pipeline application. Through the process, there were many re-routes of the pipeline ROW in order to address landowner concerns.

As the engineering progressed, and Shell confirmed a 323.9 mm (12 in.) diameter pipeline, the EPZ was reduced to 450 m. Landowners were contacted and advised that they were no longer in the EPZ.

Shell has continued its contact with these pipeline EPZ landowners and occupants through to the time of submission of the regulatory applications as part of its consultation and ROW acquisition strategies.

Landowners and residents within the 5 km EPZ of Shell Scotford were also provided with the project information package.

In advance of its winter 2010 3D seismic program, Shell met face-to-face with over 300 landowners and occupants in the area of the survey. The purpose of the meetings was to provide information about the surveys and to discuss any concerns they might have with the surveys. The issues of clubroot disease and night-time operations were raised. Shell issued its clubroot mitigation policy in a fact sheet format, and provided it to the landowners. Water well testing was offered and conducted both before and after the seismic program for any landowner or occupant that wanted it. Similar consultation is occurring during the fall of 2010 for the continuation of the 3D seismic data collection survey, which was interrupted prior to completion due to early spring weather.

Consultation with the landowners for each of the identified well locations has been through face-to-face meetings, and by providing information about the wells and the Project.

6.2.3 Aboriginal Consultation

The goal of Shell's Aboriginal consultation is to ensure that Shell, and the appropriate Crown agencies and decision makers, are aware of, and have information on, the potential for Project effects on the exercise of Aboriginal and Treaty rights, and to the extent possible, to limit or mitigate those effects.

Shell's Aboriginal consultation has included the following:

- notification of open houses
- distribution of information packages for self-identified interested parties, including Saddle Lake Cree Nation, Alexander First Nation and Métis Nation of Alberta Regions 2 and 4
- offer to present a Quest CCS Project overview to the Métis Nation of Alberta Regions 2 and 4

6.2.3.1 Non-Governmental Organization Engagement

Shell has established a series of oil sands dialogue events with key non-governmental organizations (NGOs) to understand their perspectives on the oil sands and identify opportunities for common ground. A number of sessions have already been held. Upcoming sessions taking place in Vancouver, Toronto, Montreal and London, United Kingdom, will also introduce CCS and the Quest CCS Project into the discussion. The Quest CCS Project has also contracted the International Institute for Sustainable Development to identify CCS outreach best practices and lessons learned.

6.2.4 Communication Methods

6.2.5 Methods Used

Consultation for the Project has built upon a 30-year history of consultation and communication methods. For this Project the consultation methods include:

- issuing a Project information package
- mailing the Project information package and hosting face-to-face meetings with landowners, occupants and residents within the pipeline EPZ
- mailing the Project information package to landowners, occupants and residents within the 5 km EPZ of Shell Scotford
- issuing local community newsletters to stakeholders, landowners and occupants within the 5 km EPZ of Shell Scotford
- posting information on Shell's website (www.shell.ca/Quest)

- advertising a Quest CCS Project e-mail address and toll-free telephone line (quest-info@shell.com and 1-800-250-4355, press 3)
- hosting open houses, regularly scheduled community meetings and individual and group meetings
- distributing comment cards at Shell-sponsored events
- obtaining evaluations through annual community surveys
- providing Project update presentations to municipal governments

6.2.6 Environmental Assessment Terms of Reference

AENV the Canadian Environmental Assessment Agency (CEA Agency) required Shell to prepare a TOR for the EA. A draft was released for public comment in August 2010, and finalized and issued to Shell in November 2010.

Advertisements were placed in local and Aboriginal newspapers to notify the community about where copies of the proposed TOR for the Quest CCS Project could be obtained. Announcements were placed in daily and weekly newspapers (see Table 6-2), beginning on August 16, 2010.

Table 6-2 Terms of Reference Published Announcements

Daily Papers	Dates
Edmonton Journal	August 19 and 21, 2010
Edmonton Sun	August 19, 2010
Sherwood Park News	August 17, 2010
Calgary Herald	August 19 and 21, 2010
Weekly Papers	**Dates**
Fort Saskatchewan Record	August 19, 2010
Lamont Farm n' Friends	August 20, 2010
Lamont Leader	August 17, 2010
Redwater Review	August 17, 2010
Westlock News	August 16, 2010
Saint Albert Gazette	August 18, 2010
Saint Albert City News	August 20, 2010
Alberta Sweetgrass (Aboriginal publication)	August 23, 2010

Copies of the Project summary tables and the proposed TOR for the Quest CCS Project were made available for viewing at the following locations:

- Shell's website
- the offices of Alberta Environment in Edmonton
- City of Fort Saskatchewan City Hall
- Sturgeon County Centre
- Thorhild County Office Planning Department
- Strathcona County Heartland Hall
- Lamont County Administration Building

Notification of the TOR for the Quest CCS Project was provided by mail to Alexander First Nation, Metis Nation of Alberta and Metis Region 4. However, no party requested a copy of the TOR. Copies of the TOR were provided to Alexander First Nation, Saddle Lake First Nation and Metis Region 4 by the CEA Agency. Letters were sent in August 2010 to all landowners and occupants within 5 km of the Scotford Upgrader, and within 500 m of the pipeline, advising them that the TOR was available for public comment.

6.2.7 Project-Specific Open Houses

Open house attendees had the opportunity to review information describing the Quest CCS Project components along with information on the regulatory process. Display materials presented information on the technology proposed for the Project, the case for CCS and information about how potential environmental and socio-economic effects of the Project would be identified through the EA process.

Comment and feedback forms were catalogued and filed.

6.2.7.1 Dates and Locations

On October 16, 2008, an open house was held in Fort Saskatchewan at the Dow Centennial Centre to communicate initial information about the proposed Project. Shell staff and consultants, as well as third party experts, attended the open house to respond to attendees' questions. Third-party experts from the University of Alberta and IPAC-CO2 at the University of Regina were in attendance.

A second round of open houses was held March 1-4, 2010 in Bruderheim, Fort Saskatchewan, Radway and Thorhild. The focus of these open houses was on the CO_2 capture infrastructure, the CO_2 pipeline and the CO_2 storage facilities.

A third round of open houses was held November 1-4, 2010 in Bruderheim, Fort Saskatchewan, Radway and Thorhild. The focus of these open houses was to explain the regulatory process and opportunities for public input, as well as CCS as a proven technology and questions regarding safety and containment. Third-party experts from IPAC-CO2 at the University of Regina were in attendance to discuss the technology.

6.2.7.2 Attendance at October 16, 2008 Fort Saskatchewan Open House

Stakeholders were informed of the open house through advertisements in local newspapers. Invitations were also sent to stakeholders within the 5 km EPZ of Shell Scotford. Representatives of the University of Alberta and IPAC-CO2 at the University of Regina attended.

The attendance log was signed by 69 people.

Feedback received at the October 16, 2008 open house centered around issues and concerns on containment of the CO_2 and the cost of the Project.

6.2.7.3 Attendance at March 1-4, 2010 Fort Saskatchewan, Bruderheim, Radway and Thorhild Open Houses

Stakeholders were informed of the open houses during consultation visits and through advertisements in local newspapers. Invitations were also mailed out to stakeholders within the 5 km EPZ of Shell Scotford and to landowners and residents along the proposed CO_2 pipeline. Key stakeholders including local county council members were also invited to attend.

The attendance log was signed by 260 people.

Feedback received at the March 1–4, 2010 open houses centred on issues and concerns on public safety and the perception that the technology used for the Quest CCS Project is unproven.

6.2.7.4 Attendance at November 1–4, 2010 Fort Saskatchewan, Bruderheim, Radway and Thorhild Open Houses

Stakeholders were informed of the open houses during consultation visits and through advertisements in local newspapers. Invitations were also mailed out to stakeholders within the 5 km EPZ of Shell Scotford and to landowners and residents along the proposed CO_2 pipeline. Key stakeholders including local county council members were also invited to attend.

The attendance log was signed by 160 people.

Feedback received at the November 1–4, 2010 open houses centred on issues and concerns about the pipeline and air.

6.2.8 Local Community Newsletter

A quarterly community newsletter issued to all stakeholders within the 5 km EPZ of Shell Scotford regularly contains updates on the proposed Project.

6.2.9 Shell's Website

Information about the proposed Quest CCS Project was posted on Shell's external website, www.shell.ca/Quest. This information included:

- Quest CCS Project Overview – January 2010
- Quest 3D Seismic Backgrounder – January 2010
- Quest Pipeline Construction and Operation – January 2010
- Proposed TOR for the Quest CCS Project – August 2010
- Proposed Quest Pipeline Route Map – August 6, 2010
- Summary Tables for the Capture Project, the Pipeline Project and the Storage Project – August 2010
- Commonly asked questions about CCS – September 2010

6.3 Issues Management Approach

Issues management is based on stakeholder engagement and public consultation programs. Through these programs, issues regarding the Project and its potential cumulative environmental effects are identified, documented and addressed by the Project team. Within the Project team, key individuals are identified for each issue, to foster better management strategies and to provide stakeholders with better access to information on issues.

Where appropriate, potential mitigation strategies are developed mutually with communities and groups.

Key environmental and socio-economic issues have been identified and efforts are underway to identify potential mitigation actions. In some cases, additional information is being gathered for a better understanding of specific concerns.

6.3.1 Stakeholder Input

6.3.1.1 Areas of Stakeholder Concern

During the public consultation process, stakeholders identified the following issues related to the Quest CCS Project:

- containment and potential leakage or rupture from storage sites
- perception that CCS technology is unproven
- groundwater contamination
- pipeline, well or storage failure
- practicality of CCS addressing CO_2 emission issues
- emergency preparedness and the ability to respond
- potential health effects, including increasing cumulative air emissions
- adverse environmental effects related to increased rail and road traffic
- regional land use concerns

6.3.1.2 Containment Concerns Related to the Pipeline, Injection or Storage

See Table 6-3 for a summary of the questions raised about containment, and the concerns over potential leakage or rupture related to the CO_2 pipeline, injection or storage, and Shell's responses and commitments made to address the concerns.

Table 6-3 Summary of Concerns Related to Containment

Question or Concern	Summary of Responses
How will the Quest CCS Project ensure the CO_2 pipeline is safe?	• Canada has more than 100,000 km of oil and natural gas pipelines that have operated safely for decades. The Quest CCS pipeline transporting the CO_2 will be very similar to those used to transport natural gas and oil. There are 4,200 km of CO_2 pipeline operating in the US. • Shell will design, construct, operate and maintain the Project facilities using best practices to meet the highest safety standards. The pipeline will be constantly monitored. In the unlikely event of a leak, valves will automatically close to isolate the section of the pipeline to limit the release of CO_2 and the ERP will be activated.

Table 6-3 Summary of Concerns Related to Containment (cont'd)

Question or Concern	Summary of Responses
What happens when a CO_2 pipeline ruptures?	• CO_2 is 1.5 times heavier than air. In the unusual circumstance that a large pocket of CO_2 was to be abruptly released from the pipeline, the greatest risk would be posed to low lying areas if there were little to no wind at the time. CO_2 tends to form a cloud that hugs the ground surface. How quickly the cloud dissipates would depend on the geography and weather at the time of the event. • The pipeline is constantly monitored by a leak detection system. If a potential leak were to be detected, the system would be shut down and the event investigated. This is the case for all operating oil and gas pipelines. The volume of CO_2 in the pipeline between valves (located at a maximum of 15 km apart) at any instant would limit the size of the CO_2 cloud. • To ensure public safety the ERP would be activated. • The ERP is planned around an EPZ of 450 m.
How will Shell be sure that the CO_2 stays underground?	• Shell will use CCS best practices to ensure that the selection, design and operation of the CO_2 storage formation meet all the requirements for safe and permanent storage of CO_2. At a properly designed and well-managed CO_2 storage site, the chance of CO_2 leakage is extremely low. • It is crucial that an appropriate reservoir is chosen for CO_2 underground storage. The trapping mechanisms involved in the deep geological formations are the same ones that have stored oil and gas for millions of years as well as natural accumulations of CO_2. • Alberta has some of the most promising geology for CO_2 storage in Canada. The geological formation that the Quest CCS Project will use to store CO_2 is the BCS. The CO_2 will be trapped within the tiny pore spaces between the grains of the sandstone rock formation (not open underground caverns). At this depth, rock pressures and temperature would keep the injected CO_2 in its dense-phase form. • Because the CO_2 is stored 2 km underground, there are multiple impermeable seal rocks that provide numerous barriers to prevent any leakage from occurring to the surface. The MMV plan, including deep monitoring wells, will monitor CO_2 movement in the unlikely event CO_2 leaks from the storage reservoir into one of the zones above the BCS. The MMV plan outlines the response to any leak that is detected.
What is the composition of the substance being buried? What is the risk of this reacting with existing substances underground?	• The injected CO_2 that will be at least 95% by volume of pure $C0_2$. All the chemical components that will be injected exist naturally in the atmosphere and underground. • Shell's primary concern is to safely and securely store the CO_2 (either in free gas form or dissolved in water form) in the storage reservoir. The CO_2 will be kept underground by a succession of overlying seals, in much the same kind of trapping mechanisms that have kept oil and gas underground for millions of years. As a precaution, underground monitoring will be conducted to ensure that CO_2 stays in the BCS storage complex. Because the CO_2 will be trapped in the tiny pore spaces of rocks, any leakage to the geological layers immediately above the storage zone would be extremely slow and in the unlikely event this did occur there would be plenty of time to detect and deal with any leaks. The MMV plan will be designed to do this.
At what pressure will the CO_2 be injected? Will that fracture the reservoir?	• The pipeline will be a 900# class pipeline, which is similar in pressure to the sour gas lines that are in service all over Alberta today. The pressure will be a maximum of 14,500 kPa(g).

6.3.1.3 Environmental Concerns

Table 6-4 summarizes the questions raised and Shell's responses and commitments to address:

Groundwater

Stakeholders expressed concern about potential effects from the Quest CCS Project on the local groundwater. Stakeholders requested information on volumes required and processes to protect surface water, groundwater and aquifers.

Air

Stakeholders had questions on emissions and asked what processes would be in place to monitor the air quality. Stakeholders also requested information on measures in place to mitigate the increased levels of NO_X from the CO_2 capture infrastructure.

Table 6-4 Summary of Environmental Concerns

Question or Concern	Summary of Responses
Groundwater	
Will the Quest CCS Project affect the local groundwater? Is there a risk that CO_2 will contaminate my well water/drinking water? Is there a risk that CO_2 will contaminate my drinking water? Is there a risk that the displaced brackish water will contaminate groundwater, i.e., drinking water? Will it increase the risk of arsenic contaminating my well? Will this affect my water well? What if it does?	• Site selection is the first mitigation measure for protecting groundwater; only sites with a high level of integrity are selected for CO_2 storage. The storage reservoir that will be used for the Quest CCS Project will be much deeper than usable sources of groundwater (more than 1800 m deeper) and the CO_2 will be contained by multiple layers of impermeable rock layers above the storage. • Up to three barriers of borehole steel casing, each cemented in place to surface, will ensure that the injected CO_2 safely reaches the deep storage formation and that shallow groundwater is protected. The MMV plan will be designed to detect and provide early warnings of any potential leaks. • Injection pressures will conform to regulatory requirements and be maintained at levels that ensure the injection formation and overlying seals maintain their mechanical integrity. When injection stops, a closure period of continued monitoring will take place and then the injection wells will be plugged and abandoned to ensure the long-term containment of the stored CO_2. • An extensive study of the regional groundwater was undertaken for the EA.
Will the development cause poor surface water quality and quantity?	• The Project will be designed to prevent surface water contamination. • Construction activities will meet regulatory guidelines to protect surface water. Sediment and erosion plans will be implemented to protect surface water systems during construction. Setback distances from waterbodies will be used to reduce the Project's effects on surface water.

Table 6-4 Summary of Environmental Concerns (cont'd)

Question or Concern	Summary of Responses
Groundwater	
How will Shell protect the supply and quality of aquifers and water wells during the operation of the Project?	To prevent contamination of potable water and shallower aquifers, the following project design features are being considered to prevent the upward migration of saline water up the wells from the BCS: • multiple casing strings to protect the shallow hydrocarbon and potable water zones • appropriate casing material selection to protect casing against degradation in the presence of high saline water and CO_2 • casing type and grade appropriate for well operating envelope • CO_2 resistant cement design • good drilling practices to ensure effective cement placement to protect shallow horizons • completing the well with down hole instrumentation and implementing an effective MMV plan to monitor well integrity • multiple casing design and effective cement design and its placement will ensure all geologic seals are effectively covered above the injection zone to prevent upward migration of saline water. • adherence to local regulations and directives, Shell and industry best practices and incorporating lessons from other CO_2 capture and storage projects shall ensure a competent and safe well. During drilling, the following Project design features will be considered: • using water-based drilling muds to the BGWP • designing well drilling programs to minimize drilling fluid losses to the formation • using surface casing beyond the depth of fresh water aquifers to provide isolation from the CO_2 injection wells • including groundwater monitoring in the MMV plan
How will the pipeline construction affect rivers and streams?	• Pipeline construction is designed to limit disturbance to rivers and streams. The pipeline will cross four fish-bearing waterbodies: North Saskatchewan River, Namepi Creek, Astotin Creek, Beaverhill Creek • Horizontal directional drilling is proposed to limit construction disturbance at the North Saskatchewan River crossing. The pipeline route accommodates this.
Air	
How will facility emissions be managed?	• Air emissions have been modelled to ensure that the Project's design will meet the Alberta Ambient Air Quality Objectives and Guidelines. • Mitigation measures (low NO_X burners) for NO_X emissions will be implemented at the CO_2 capture infrastructure. • Shell will monitor and report on emissions and air quality data will be available from the FAP. • Shell is committed to working with local communities to address any air or odour concerns.
What about Shell's commitment to reduce greenhouse gas emissions?	• The Quest CCS Project is a greenhouse gas reduction project • Shell is committed to meeting the regulatory requirements for greenhouse gas emissions management. • The Quest CCS Project aims to reduce CO_2 (a greenhouse gas) emissions by capturing up to 1.2 Mt/a of CO_2 each year from the HMUs at the Scotford Upgrader.

6.3.1.4 Employment and Business Opportunities

Stakeholders and business providers in the local area expressed interest in the economic benefits that the Project could provide to local businesses and individuals. Information was requested on employment and contracting opportunities, and on how these businesses and individuals would be able to participate. Stakeholders also enquired about how work opportunities could be made sustainable beyond the peak of project activity. Table 6-5 summarizes issues and concerns presented related to employment and business opportunities.

Table 6-5 Summary of Employment and Business Concerns

Question or Concern	Summary of Responses
How will the local communities benefit from the Quest CCS Project?	Local communities in the area of the Quest CCS Project would benefit from: • employment opportunities, including approximately 500 construction jobs per year (2012–2014) • full-time operating and maintenance positions at the Scotford Updgrader; • local contracting and procurement opportunities • leadership in green technology for Alberta's Industrial Heartland • increased sustainable energy for Alberta

6.3.1.5 Emergency Preparedness

Stakeholders in the local area had questions about how Shell would respond to a pipeline rupture.

Table 6-6 summarizes the questions raised about emergency preparedness and the ability to respond in case of a CO_2 pipeline rupture.

Table 6-6 Summary of Concerns Related to Emergency Preparedness

Question or Concern	Summary of Responses
Why do you need an ERP?	Shell facilities are designed with safety as a high priority. The many safeguards in place make the possibility of an emergency extremely remote; nevertheless, as an additional precaution, ERPs will be developed. Additionally, an ERP is a regulatory requirement.
What is an ERP?	The ERP outlines the responsibilities and duties that Shell and government agencies will perform to protect public safety in the unlikely event of an emergency situation.
What ERP will you do for the Project?	Development of these ERPs will involve modifying the existing ERP for the Scotford Upgrader and drafting an ERP for the CO_2 pipeline and injection wells.
How does an ERP work?	In the unlikely event of a pipeline rupture, Shell would implement the ERP. Shell would take immediate measures to notify, and take steps to protect the public. The event (e.g., a leak) would be isolated as quickly as possible and Shell would work closely with the regulator and other emergency response personnel.

7 Environmental and Socio-Economic Management

Shell is committed to protecting the environment and actively managing its environmental performance. This is reflected in Shell's Business Principles and Health, Safety, Security, Environment and Social Performance (HSSE & SP) framework. Design features and mitigation measures have been incorporated into the Project to prevent or reduce potential environmental effects. Effective environmental management includes an understanding of:

- baseline environmental conditions
- comprehensive environmental assessments
- effective Project design
- environmental performance monitoring during construction and operation
- maintenance requirements and operational limits and constraints of facilities
- approval and other regulatory requirements as well as commitments to stakeholders

To understand the potential environmental effects of future industrial developments on the surrounding areas, Shell participates in the following multi-stakeholder groups in the region:

- Northeast Capital Industry Association
- Fort Air Partnership
- North Saskatchewan Watershed Alliance, Watershed Planning and Advisory Council

7.1 Health, Safety, Security, Environment and Social Performance

The control framework for Shell's HSSE & SP (see Figure 7-1) defines and communicates HSSE & SP requirements at Shell-operated facilities. It includes mandatory standards, manuals, specifications and glossary terms, and non-mandatory assurance protocols and guides.

Of the manuals included in Shell's HSSE SP control framework, this section describes the most important aspects of the following:

- HSSE & SP Management System Manual
- environment
- social performance

The other manuals contain detailed processes that support the HSSE & SP management system manual.

HSSE requirements outlined in this section will be integrated into the Scotford Upgrader's health, security, safety and environment (HSSE) management system, which complies with ISO 14001. The system will be continuously monitored and improved.

Figure 7-1 HSSE & SP Control Framework

7.1.1 HSSE & SP Management System Manual

Shell is committed to:

- implementing an HSSE management system that includes continuous improvement
- implementing an environmental management system that complies with ISO 14001
- standardizing HSSE requirements on Shell operations by applying self-imposed HSSE standards and guidelines
- communicating with stakeholders to understand and respond to their interests and concerns
- conducting research to improve Project efficiency and HSSE performance
- continuing to integrate HSSE management and sustainable development principles into business decision-making processes

7.1.1.1 Policy and Objectives

HSSE management is integral to business excellence and project development. This requires commitment, leadership and effective communication. It also requires that the necessary plans and resources are in place to achieve HSSE objectives. All Shell employees and contractors must understand the HSSE objectives and their individual responsibility to help achieve them.

For Royal Dutch Shell's HSSE & SP policy, see Figure 7-2.

7.1.1.2 Compliance with HSSE & SP

Shell will have on-site resources for monitoring site compliance with Shell's HSSE control framework and identifying who is responsible for:

- monitoring HSSE & SP performance
- leading HSSE & SP continuous improvement plans
- managing the HSSE & SP skill pool

7.1.1.3 Competency

Defining HSSE-critical competency requirements for each work position and identifying training needs are key components of HSSE management.

The goals of the individual competency program at the Scotford Upgrader, and which will be used for the Project, are to:

- ensure all employees and contractors do their jobs in a way that complies with Shell's HSSE policy and commitment to sustainable development
- develop competency profiles for each position on the Project, starting with those positions that are considered HSSE critical
- support training requirements by continuously assessing competency
- track training and competency levels for workers

Competency will be maintained by:

- assessing the skills required for each work position
- selecting candidates who meet, or exceed, the minimum skill set required
- orienting new or transferred personnel into the individual competency program
- evaluating HSSE-critical skills and competencies continuously, and providing refresher courses or advanced training, where required

Line managers will identify, monitor and support staff training.

ROYAL DUTCH SHELL COMMITMENT AND POLICY ON HEALTH, SECURITY, SAFETY, THE ENVIRONMENT AND SOCIAL PERFORMANCE

COMMITMENT

In Shell we are all committed to:

- Pursue the goal of no harm to people;
- Protect the environment;
- Use material and energy efficiently to provide our products and services;
- Respect our neighbours and contribute to the societies in which we operate;
- Develop energy resources, products and services consistent with these aims;
- Publicly report on our performance;
- Play a leading role in promoting best practice in our industries;
- Manage HSSE & SP matters as any other critical business activity; and
- Promote a culture in which all Shell employees share this commitment.

In this way we aim to have an HSSE & SP performance we can be proud of, to earn the confidence of customers, shareholders and society at large, to be a good neighbour and to contribute to sustainable development.

POLICY

Every Shell Company:

- Has a systematic approach to HSSE & SP management designed to ensure compliance with the law and to achieve continuous performance improvement;
- Sets targets for improvement and measures, appraises and reports performance;
- Requires contractors to manage HSSE & SP in line with this policy;
- Requires joint ventures under its operational control to apply this policy, and uses its influence to promote it in its other ventures;
- Engages effectively with neighbours and impacted communities; and
- Includes HSSE & SP performance in the appraisal of staff and rewards accordingly.

Peter Voser
Chief Executive Officer

Lorraine Mitchelmore
President and Canada Country Chair

Originally published in March 1997 and updated by the Executive Committee December 2009.

Figure 7-2 Royal Dutch Shell's HSSE & SP Policy

Field Construction and Operating Team – HSSE Training

Team members will receive training relevant to their work positions and at a level necessary to implement HSSE plans. Training will include:

- using Shell's hazards and effects management process, which includes direction on how to complete hazard and risk assessments
- using incident management procedures and processes for responding to incidents and to reduce the probability of future incidents
- conducting regular emergency response drills
- applying the incident command system
- following a proactive management process to identify new risks and ensuring that they are managed

7.1.1.4 Risk Management

Shell applies its hazards and effects management process during design, construction and operation.

As part of this process, an HSSE case will be developed to demonstrate that all hazards and their associated risks are properly identified, assessed and managed, including:

- controls to prevent the release of a hazard
- recovery preparedness measures to reduce the effects of a hazard

7.1.1.5 Planning

Planning includes developing:

- procedures to identify existing and emerging HSSE risks and aspects that must be controlled and influenced
- procedures to identify and assess legal and other requirements that apply to HSSE
- procedures to establish and maintain documented HSSE goals and targets
- management programs that designate responsibility for achieving HSSE management system goals and targets
- management plans that are approved and actively supported by senior management

7.1.1.6 Emergency Preparedness and Response

As part of the operation of the Quest CCS Project, it is possible that an accident, malfunction or unplanned event could occur. Shell will have in place ERPs to address accidents, malfunctions, incidents or emergencies that might occur during operation of any of the components of the Project.

The CO_2 capture infrastructure component will involve a process modification to the existing Scotford Upgrader, which currently has an ERP in place. In keeping with Alberta ERCB Directive 71, Shell will amend its existing Scotford ERP to address CO_2 capture accidents, malfunctions, incidents or emergencies.

Shell will also prepare a stand-alone site-specific ERP for the CO_2 pipeline and injection wells. This ERP will include all pipeline segments downstream of the emergency shutdown valve exiting Shell Scotford, as well as the CO_2 injection wells and the monitoring wells developed for the MMV program. In keeping with ERCB Directive 71, Shell will submit the CO_2 pipeline and injection well ERP to the ERCB for review and approval before the start of operation. Shell Scotford personnel will be the primary Shell responders responsible for implementing the ERP, which will provide the structure, process, and action plans that will enable Shell to effectively respond to any emergency along the pipeline route, at the injection wells, or at the monitoring wells (see figure in the back pocket of this binder).

The primary goal of both ERPs is to provide an effective, comprehensive response to prevent injury or damage to site personnel, the public, the CO_2 capture infrastructure, the CO_2 pipeline, the injection wells and the environment in the event of an emergency. Although the existing Shell Scotford ERP and the new Shell CO_2 pipeline and injection well ERP will be separate documents, Shell Scotford personnel will be responsible for implementing both ERPs. Both ERPs will use the same interrelationship between Shell Scotford and Shell Calgary. Through Shell's Oil Sands Crisis Management Team in Calgary and the Country Crisis Management Team, also in Calgary, Shell Scotford personnel can call upon company-wide advice and support during any operational emergency. This is referred to as the Shell Emergency Response Management System.

In addition to this advice and support, Shell Scotford personnel are also able to obtain additional personnel, equipment and resources to assist with emergency response activities. This is accomplished through the Shell Scotford Manufacturing Incident Command Team, the Shell Canada National Response Team and various mutual aid sources.

Through this integrated emergency response process, Shell is able to meet the intent of both ERPs, which is to put in place effective measures to:

- notify and protect the workers and the public
- minimize environmental effects
- minimize asset property loss
- regain steady-state operations
- minimize emergency response time
- maximize response effectiveness
- co-ordinate with involved regulatory agencies or industry
- minimize effects on business and company reputation

Through both ERPs the following will be addressed:

- process accidents, malfunctions, incidents or emergencies with the CO_2 capture infrastructure
- CO_2 pipeline rupture or release response
- CO_2 release from an injection well
- leakage of CO_2 from the BCS to ground surface
- spills
- fires or explosions and fire control
- serious injuries or fatalities

- encroaching grassland or bush fires
- severe weather and natural disasters
- bomb threats
- evacuation and rescue
- *Canadian Environmental Protection Act* requirements

7.1.2 Implementation, Monitoring and Reporting

Shell will implement, monitor and report on its HSSE systems by:

- including HSSE planning and assessment components in each stage of Project development
- developing and implementing plans to ensure that work is done in an orderly way that meets all of Shell's expectations, regulatory requirements, stakeholder and permit commitments, and values
- providing:
  - the required resources, including the organization, capital equipment and systems to ensure that HSSE plans are carried out
  - leadership, stewardship and accountability at all levels
- managing all hazards and effects, including identifying substantial risks and developing plans to limit and manage those risks
- implementing procedures and practices to control potentially hazardous tasks
- conducting training and competency assessments so that workers are capable of performing their work safely and efficiently
- monitoring and measuring performance and success against HSSE targets and performance standards
- taking preventive and corrective action by applying lessons learned and seeking continuous improvement opportunities
- communicating with stakeholders to identify and understand their concerns, and to foster their involvement and participation

Performance Checks

HSSE performance will be checked against plans and will include:

- developing procedures for:
  - regularly monitoring, measuring and recording key characteristics of operations and activities
  - defining responsibilities and authorities for handling and investigating incidents and carrying out corrective and preventive actions
  - handling and maintaining records (e.g., for training) and the results of audits and reviews
- following a program and procedures for conducting periodic audits

Corrective Action

Corrective action will include:

- following the site management-of-change process
- assigning accountability to individuals for follow up and compliance
- providing procedures and the training required for corrective action
- documenting corrective action activities

7.1.2.1 Reporting Spills and Emissions

Shell will design, construct, operate and maintain the Project components to prevent or limit the release of substances that might adversely affect health, safety or the environment. Shell will develop a pipeline and well ERP that will include hazardous material spills. The ERP for the Scotford Upgrader will be revised to include amine spills as an event. Response to any spill will be in accordance to the ERPs. If spills or emissions occur, they will be reported according to regulatory requirements and corporate standards.

For incidents that have, or are likely to have, an off-site effect, notification will be given to key community, government and industrial contacts. Notification decisions will be based on potential effects and available information.

Key contacts include:

- local residents
- Alberta Environment
- Energy Resources Conservation Board
- Counties within area affected by the spill
- Fisheries and Oceans Canada
- Environment Canada
- the Royal Canadian Mounted Police
- Shell's crisis management team
- other facility operators at Shell Scotford, including, as examples, the Scotford Refinery, Shell Chemicals and Air Liquide
- third-party facility owners, such as:
  - Inter Pipeline Fund
  - ATCO Power
  - ATCO Pipelines
  - ATCO Electric

Note that the order in which notifications will be made is not implied in this list. Notifications and the order in which they will be made depend on the event.

Notification

Notifications regarding spills and emissions will:

- describe the incident, based on the facts available
- identify potential environmental effects
- provide the status of containment and cleanup
- identify the incident command team member responsible for providing further updates
- include other information that may be necessary to meet applicable regulatory requirements

7.1.2.2 Assurance

To provide assurance that the HSSE & SP control framework requirements are implemented and effective at the Project site, Shell will:

- establish and maintain a risk-based HSSE & SP assurance plan
- define competence requirements and accreditation for leaders of independent and internal Shell HSSE & SP audits
- monitor the follow-up of actions from group and business HSSE & SP assurance until they are implemented and closed out

The HSSE management system will be reviewed at least annually to ensure its continuing suitability, adequacy and effectiveness.

7.1.3 Social Performance

Shell is committed to social performance (SP), as set out in its HSSE & SP policy.

Shell’s commitment to social performance is an overarching corporate goal, alongside growth and profitability. Each of these goals is essential for delivering long-term value to Shell’s shareholders, for earning acceptance in the communities in which Shell operates, and providing the foundation for the company’s development projects and business activities.

Economic, environmental and social considerations are integrated in decision-making in all of Shell’s business activities. Shell requires social performance plans, that address some of the non-technical risks of a project for all large-scale opportunities, and all opportunities involving unusual risk.

Through social investment, Shell invests over $3M annually towards the communities affected by the Project. Key investment areas include:

1. Civic/ community development
2. Education/ leadership
3. Employees
4. Aboriginal
5. Environment

Shell will continue to comply with legislation and exercise environmental due diligence, consistent with the requirements of the International Organization for Standardization (ISO) 14001 standard. Shell will also continuously improve the overall environmental performance of its operations and products, while ensuring short and long-term commercial success. Shell will strive to mitigate the Project's environmental effects and enhance the benefits in communities that are affected by its projects. This includes setting goals and reporting progress regularly.

7.2 Environmental Management Initiatives

Shell will incorporate key mitigation measures as described below to limit the environmental effects of the Project. Further information on environmental management initiatives is provided in the Environmental Assessment Summary (see Section 8) of this document.

7.2.1 Capture Infrastructure

7.2.1.1 Greenhouse Gas Emissions

The Project will capture up to 1.2 Mt/a of CO_2 and permanently store the CO_2 in a deep saline aquifer.

7.2.1.2 Air Quality Management

As a result of the Project, NO_X emissions will more than double the current emissions from the HMUs at the Scotford Upgrader. The Project will replace the existing HMU burners with technologically proven low NO_X burners that will aid in limiting the projected NO_X emission increase. The environmental review modelled the mitigated increased NO_X emissions and predicted environmental effects that are within the Alberta Ambient Air Quality Objectives. The selection of this technology reduces the NO_X emissions increase to about 3 t/d, which will not result in a significant adverse environmental effect.

In addition, Shell will invest in maturing flue gas recycling for potential installation on the Quest CCS Project, and continue tracking the suitability of ultra-low NO_X burners for steam methane reformers.

7.2.1.3 Water Management

The Project will be constructed by modifying the HMUs of the existing Shell Scotford Upgrader. The existing water infrastructure will be used for water management. Although the Project will increase the overall water demand, water withdrawal from the North Saskatchewan River will remain within the licensed volumes already in place for the Scotford Upgrader.

7.2.2 Pipeline

Shell has prepared an Environmental Protection Plan (EPP) that describes measures to be implemented during CO_2 pipeline construction and reclamation to limit and mitigate potential environmental effects. It is an integral part of the construction contract and will be used during construction and reclamation of the Project and its associated facilities. See Appendix I for the Pipeline EPP.

7.2.3 Storage

The Project design incorporates both natural and Project-specific mitigation measures to limit potential environmental effects on groundwater. Many of these mitigation measures are passive and are associated with the natural features of the storage area. The site selection process for the Project deliberately included areas with natural mitigation features, such as the bounding geological units above the BCS, including the Upper and Lower Lotsberg and Prairie Evaporite salt seals. The integrity of the confining salt seals was maximized by selecting a Project storage area where the fewest historical penetrations of those seals occur.

The proposed injection well design also provides multiple casing strings to protect nonsaline groundwater resources. Active mitigation measures are also proposed as part of the MMV plan for the Project. For details of these passive and active mitigation controls, see Section 10.

Shell has also prepared pre-disturbance assessments and C&R plans for the five of the potential three to ten well pads and associated infrastructure that describe measures to be implemented during construction and reclamation to limit and mitigate potential environmental effects. Pre-disturbance assessments and C&R plans will be developed for any additional well pads, as required.

7.3 Sustainable Development

Shell is committed to sustainable development. Shell's aim to balance short- and long-term interests, and integrate economic, environmental and social considerations into its standards, processes, controls and governance has been a continual part of Shell's Business Principles since 1997.

Shell's approach to sustainable development involves meeting the world's growing need for energy in economically, socially and environmentally responsible ways through the careful selection of which projects it invests in, developing more energy-efficient products, and striving to improve the way it runs its operations.

Shell has been working to improve the efficiency of its operations by developing new and cleaner technologies related to reducing CO_2 emissions. Shell considers CCS an essential technology that will, in the long-term, reduce operational costs, avoid current and future costs of emissions and even create new income streams, such as through carbon credits or EOR.

According to the International Energy Agency (IEA), CCS is the only technology available to mitigate CO_2 emissions from large-scale fossil fuel use. The Intergovernmental Panel on Climate Change (IPCC) indicates that CCS technology has the potential to address climate-changing CO_2 emissions quickly. CCS involves capturing CO_2 emissions and disposing of them safely underground in depleted oil and gas reservoirs or saline formations where impermeable rock once held natural gas for millions of years. It is believed that CCS could account for nearly 19% of the total CO_2 reductions needed by 2050 and for more than 50% by 2100. The IEA believes that the economic cost of stabilizing CO_2 emissions by developing other technologies and energy sources would be considerably higher.

Shell has been investing in CCS research, as well as funding a number of demonstration projects, including the world's largest, most technologically advanced CCS demonstration project in Mongstad, Norway.

7.4 Greenhouse Gas Management

7.4.1 Climate Change Policy

Shell shares the global concern about climate change. Because climate change is a long-term issue requiring long-term solutions, Shell is taking action now to reduce GHG emissions and is committed to reporting its progress voluntarily.

In addition to the Quest CCS Project, Shell:

- seeks to improve the efficiency of its current operations proactively through GHG and energy management plans
- continues to research and develop technologies that increase efficiency and reduce emissions in hydrocarbon production
- is aggressively developing low-CO_2 sources of energy, including natural gas and low-CO_2 fuel options
- is helping to manage energy demand by growing the market for products and services to help customers use less energy and emit less CO_2
- is working with governments and advocating the need for more effective CO_2 regulation
- includes the cost of CO_2 in evaluating potential projects
- maintains open and transparent communication with key stakeholders
- encourages employees to develop an understanding of, and take action to address, climate change

7.4.2 Greenhouse Gas and Energy Management Plan

Abatement opportunities have been incorporated into the CO_2 capture design, where economically viable, to reduce energy consumption and associated GHG emissions. As per Shell standards, the CO_2 capture infrastructure will include unit-level metering and instrumentation to allow for integration into the GHG reporting system of Shell Scotford.

Quest will play an integral role in Shell Scotford's GHG and Energy Management Plan by generating offsets that could be used to meet current and future GHG regulations. Greenhouse gas emissions for Shell Scotford are reported to external stakeholders and regulators annually.

A full life-cycle analysis of GHG emissions for the Quest CCS Project has been completed and included in as part of this environmental assessment (Appendix K). The analysis shows that although direct and indirect emissions will result from the Quest CCS Project, those emissions are substantially smaller in magnitude compared to the quantity of CO_2 that is captured and stored by the Project.

8 Environmental Review

8.1 Air Quality

The Project has the potential to interact with air quality primarily through emissions from the capture infrastructure. Even with mitigation, operation of the capture infrastructure will lead to an increase in thermal generation of nitrogen oxides (NO_X), which will affect ambient NO_2 concentrations and is also a precursor for $PM_{2.5}$ formation, potential acid input (PAI) deposition, nitrogen deposition, ozone formation and regional haze. The environmental assessment also considers greenhouse gas emissions.

Effects are assessed for Base Case, Application Case and Planned Development Case.

Construction related air emissions are also considered in the assessment, but these are expected to be localized and of short duration, and therefore were not assessed further.

Several spatial boundaries are used for the assessment, all centered on Shell Scotford. A CALMET domain area of 125 by 125 km defined meteorological characteristics for the assessment, and a CALPUFF domain of 100 by 100 km defined the major emission sources for the assessment. A 50 by 50 km local assessment area (LAA) is used to describe ambient air quality concentration patterns and includes the Cities of Edmonton and Fort Saskatchewan, the communities of Lamont, Redwater, Bruderheim, Gibbons and Bon Accord, and natural areas such as the nearby Astotin natural areas, as well as the northern portion of Elk Island National Park. An 80 by 80 km regional assessment area (RAA) is used to predict PAI and nitrogen deposition. The RAA encompasses the area where there is potential for environmental effects from the Project to interact with similar environmental effects from other projects or human activities, and includes all of Elk Island National Park and Beaver Hills-Cooking Lake Moraine.

Air dispersion modelling considered emissions from both the Project and other existing and planned air emission sources within the air quality RAA in order to predict the ground level concentrations at receptor locations. Results are compared with relevant ambient air quality guidelines, with none of the assessed parameters (NO_X, SO_2 and $PM_{2.5}$) expected to exceed the ambient air quality guidelines. There are no exceedances of the Alberta Ambient Air Quality Objectives (AAAQO) as a result of the Project. A summary of the assessment results is provided below.

- The Project is predicted to increase the maximum 1-hour, 24-hour and annual NO_2 concentrations by up to 20, 9.6 and 0.5 $\mu g/m^3$, respectively, a 5 to 7% increase relative to Base Case. The highest changes due to the Project are predicted at or near the shell Scotford fenceline.
- The Project is predicted to increase the maximum 1-hour, 24-hour and annual $PM_{2.5}$ concentrations by up to 1.7, 0.3 and 0.01 $\mu g/m^3$, respectively, or a maximum increase relative to Base Case of between 0.1% and 1.4%. The largest changes as a result of the Project are predicted to occur at or near the Shell Scotford fenceline.
- The Project is predicted to increase the PAI deposition by up to 0.003 keq H+/ha/a. The spatial RAA average for PAI deposition is predicted to increase by less than 1%.

- Nitrogen deposition is predicted to increase by up to 0.03 kg N/ha/a. The spatial average across the RAA is predicted to increase by less than 1%.
- The Project is predicted to increase the ozone precursor, NO_X deposition by 1.7%, while precursor VOC emissions are not expected to increase as a result of the Project.
- NO_X emissions due to the Project can form ammonium nitrate in the atmosphere, a particle associated with decreased visibility. It is estimated that the Project should not contribute to a perceptible increase in haze or associated decrease in visibility.
- The Project is designed to capture and store up to 1.2 Mt/a of CO_2, the direct CO_2 capture is expected to be 1,024 kt CO_2e/a based on an uptime of about 90%. Relative to the Scotford Upgrader, this value represents an 18% reduction.

There are a number of existing monitoring and reporting programs that Shell participates in relative to air emissions from the Scotford Upgrader. Shell plans to continue participating in these programs. In addition, the Scotford Upgrader has a monitoring program in place that includes both source and ambient monitoring. The continuation of this program with the addition of a NO_X analyzer at the Scotford 2 ambient monitoring site will help assess the influence of the emission changes associated with the Project.

8.2 Sound Environment

The assessment focuses on noise sources associated with the capture infrastructure, as no continuous operational noise sources will be present along the pipeline or injection wells. In the province of Alberta, the Energy Resources Conservation Board (ERCB) regulates sound levels generated by energy facilities and their operation. The applicable regulatory noise control requirements are defined in ERCB Directive 38. The assessment was done used noise modelling software and methodology consistent with Northeast Capital Industrial Association (NCIA) requirements. Noise propagation methods used in this assessment are those prescribed by the International Organization for Standardization (ISO) Standard 9613. The ERCB has accepted the ISO 9613 standard for noise assessments under Directive 38. Sound propagation is calculated using the latest version of Cadna A, which incorporates ISO 9613 sound propagation algorithms.

Effects of the Project are assessed within a LAA, which encompasses the project development area (PDA), which includes Shell Scotford, and a surrounding 3 km distance. Noise from normal operation is not expected to carry beyond the 3 km distance. Predictions of noise levels at receptors within 3 km of the Scotford Upgrader are made and compared with the relevant Directive 38 permissible sound levels (PSLs). Predicted sound levels are well below the nighttime PSL at each of the residences. At all receptor locations, the predicted sound levels are in compliance with the PSLs.

Cumulative Sound Levels (CSL) from concurrent operation of the CO_2 capture infrastructure together with other existing facilities, approved projects, and planned developments in the LAA are expected to be less than or equal to the PSLs at all the residences. Therefore, the environmental effects of CO_2 capture infrastructure on the sound environment would be not significant.

Requirements for residential noise monitoring according to Directive 38 are complaint driven. No follow-up post-construction monitoring is required at the residences, unless a complaint is received. Any monitoring that might be necessary will be addressed at that time.

8.3 Geology and Groundwater Resources

The Project, through injection and storage of CO_2 in the Basal Cambrian Sands (BCS) has the potential to interact with nonsaline groundwater. The BCS, a deep saline aquifer system, is overlain by a succession of low permeability seals that act as barriers between the BCS and nonsaline groundwater system. The area over which potential interactions between the Project and groundwater resources are likely to occur is vertically bound by the ground surface as the uppermost surface and the base of groundwater protection (BGP) as the lowermost surface. The lateral extent of the groundwater resources assessment area is based on the Area of Interest (AOI), which extends over about 40 townships.

Construction activities may interact with groundwater resources, primarily if dewatering is required to manage any locally high water tables. However, dewatering would occur only once during construction and would be at a local scale, of short duration and low magnitude.

Based on the Project design and site selection, leakage of CO_2 or BCS brine is not expected to occur. The Project design incorporates both natural and Project-specific mitigation controls to limit the environmental effects on nonsaline groundwater. Many of these mitigation controls are passive and are associated with the geology of the storage area. The site selection for the storage area included areas with natural mitigation features, such as the bounding geological units above the BCS storage complex. The proposed injection well design also provides multiple casing strings to protect nonsaline groundwater resources. Active mitigation controls are proposed as part of the measurement, monitoring and verification (MMV) plan for the Project. Shell’s exploration tenure will restrict future penetrations of the BCS storage complex across the groundwater assessment area.

The injection of CO_2 into the storage area might cause subsurface vertical strain (heave) due to increased pressures within the BCS. However, based on the predicted change in groundwater levels resulting from surface heave, the potential environmental effects on groundwater quantity will be low. As a result, environmental effects of the Project on groundwater resources will be not significant.

Project activities will not contribute to the cumulative environmental effects on groundwater. Project-specific residual environmental effects as a result of surface heave are not expected to be measurable and therefore are not expected to contribute to cumulative environmental effects. Additionally, Shell’s exploration tenure will also restrict penetrations of the BCS storage complex. As a result, no further cumulative environmental effects assessment is required.

8.3.1 Aquatic Resources

Project activities that are likely to interact with aquatic resources will be limited to the construction phase of the pipeline. The LAA encompasses the PDA plus 200 m upstream and 300 m downstream for all watercourses except the North Saskatchewan River. The LAA for the North Saskatchewan River is the PDA plus 2 km upstream and 3 km downstream. The LAAs are defined to encompass an area where 90% of sediment generated during construction would be expected to be deposited. To capture potential discrete and non-point effects, the RAA is 15 km from each watercourse crossing with flowing water.

A survey of aquatic baseline conditions at all watercourse crossings along the pipeline was completed. Of the 18 watercourse crossings along the pipeline route, five occur on four fish-bearing watercourses: Astotin, Beaverhill, Lower Namepi Creeks (crossed twice), and the North Saskatchewan River. Three crossings (Astotin, Beaverhill and upper Namepi Creek) had habitat suitable for forage fish but were ranked as marginal habitat. The lower Namepi Creek crossing contained suitable habitat for some spring spawning species, but not sport fish. The creek has limited habitat at other times of the year due to low water levels. Then North Saskatchewan River supports fish habitat, but no unique or critical habitat components for any species occurs in the area of the planned crossing.

The North Saskatchewan River is planned to be crossed using horizontal directional drilling (HDD) and, hence, there will be no direct interaction with fish and fish habitat. All remaining watercourses will be crossed using the methods outlined in the appropriate DFO Operational Statement and will not be considered a harmful alteration, disruption or destruction (HADD) of fish habitat. If any crossing causes a HADD that requires DFO authorization, Shell will provide fish habitat compensation according to DFO’s No Net Loss Policy so that no residual environmental effects on fish habitat would occur. The Project will not result in any net loss of fish habitat, discharge of deleterious substance to fish habitat or affect critical habitat of species listed on Schedule 1 of SARA.

Since the North Saskatchewan River will be crossed using HDD methods, there is no pathway for sediment release during normal construction activities. Astotin, Namepi and Beaverhill Creeks have marginal habitat with little to no flowing water, except in spring. All are likely to be dry or frozen to the bottom during fall and winter and will be crossed using methods outlined in a DFO Operation Statement and the application of appropriate mitigation measures will avoid a HADD at these locations. Residual environmental effects on fish or fish habitat are expected to be not significant. The Project will result in short-term increases in total suspended solids (TSS) concentrations during construction of the watercourse crossings. However, as the temporary increases in the TSS concentrations would be at levels below the CCME guidelines for the protection for aquatic life, any adverse environmental effects on the aquatic environment is expected to be not significant.

The watercourses that will require isolation have a fish community composed of primarily small forage fish. Rescue of these fish can be difficult because of the small size of the species and their tendency to associate with vegetation, amongst other complications. It is probable that some fish will remain inside the isolated area during construction, which might result in the death of some fish. The overall environmental effect on the fish population is expected to be low in magnitude because of the large numbers of forage fish, their rapid breeding cycles, tolerance to high turbidity and the small area of the actual disturbance. Environmental effects will be confined to the isolated area within the ROW and will be alleviated immediately following construction. With planned mitigation, the isolation may still result in some fish mortality or stress. Fish stranded within the isolated area can be removed as the dewatering process takes place, which concentrates the fish in a small area and increases the number able to be captured and the likelihood of the loss of a large number of individuals is low.

Therefore, in consideration of planned mitigation and compensation, the Project will result in not significant adverse environmental effects on the aquatic environment.

No other planned projects or changes to land use have been identified that have a direct overlap with the LAA during the proposed construction period. Once construction is complete, the aquatic habitat will be restored and the Project will no longer interact with aquatic resources. With the appropriate mitigation measures, no residual environmental effects on aquatic resources are expected, so cumulative environmental effects are not further assessed.

8.4 Soils and Terrain

Project interactions with soils and terrain are expected to occur during construction and decommissioning and abandonment of the pipeline and well pads. During construction of the pipeline and injection wells, activities such as topsoil stripping, grading, trenching and backfilling may cause an adverse environmental effect on soil capability and terrain stability through alteration of the morphological and physical properties of terrain and soils

Soils analysis, including fieldwork, was done for the entire PDA, which includes the pipeline ROW and temporary workspace as well as injection wells, associated access roads, and borrow pits. Terrain analysis is provided for five areas within the PDA, which are identified as areas most likely to be affected by the Project, due to the presence of steep slopes or unique terrain features: North Saskatchewan River, Namepi, Astotin and Beaverhill Creeks, and the Beaver Hills-Sand Hills area. The RAA includes the PDA plus a 15-km surrounding distance.

The terrain of the PDA is relatively flat, except for minor areas of steeper land adjacent to rivers and creeks. Slope failure due to natural riverbank erosion was observed at Namepi Creek, and minor mass wasting evidence and steep slopes were identified at the North Saskatchewan River. Sand dunes of the Beaver Hills-Sand Hills area are at the southern end of the ROW. All dunes are closely spaced and fully vegetated, indicating the dunes are unmoving.

Guidelines and principles of environmental protection for pipeline construction have a long history of successful application in the province. With the implementation of mitigation measures, the magnitude of the residual environmental effect of soil loss is expected to be low.

Soil handling management techniques, such as using three-lift handling or a wider stripped area, have been developed to reduce the potential for admixing, compaction and rutting. These management techniques will reduce environmental effects from Project construction on soil quality. With the implementation of mitigation measures, the magnitude of the residual environmental effect of a change in soil quality is expected to be low.

Mitigation (using rip-rap to prevent slope toe erosion) will actually improve the natural stability of the slopes by providing better drainage and by protecting naturally eroding river banks. With these improvements, the likelihood of failure at all the crossings is considered low.

Environmental effects will be medium term in duration, and frequency will be once, when dunes are removed for pipeline installation. Dune loss and damage are considered not significant because mitigation measures, which include reclamation and stabilization, will keep loss and damage from occurring, thus preserving important habitat.

In general, by applying industry standard mitigation measures for controlling soil erosion, admixing (soil loss or degradation by handling), compaction and rutting and salinity redistribution, the magnitude of the residual environmental effects on soils will be low.

Project-specific residual environmental effects will not act in a cumulative fashion with the environmental effects of other past, present or future projects and activities. The Project will not contribute to the cumulative environmental effects on soils. As a result, cumulative environmental effects are not further assessed.

8.5 Vegetation and Wetlands

Potential environmental effects of the Project include: fragmentation and direct loss of vegetation; effects on wetlands and rare plants through pipeline and well pad construction; introduction of non-native and invasive species; alteration to vegetation communities resulting from control of undesirable species (i.e., weeds and woody vegetation); and the spread of agricultural pests, such as clubroot.

Project effects on vegetation and wetlands have been assessed within the LAA, which includes the PDA plus 500 m on each side of the pipeline. The RAA includes the LAA plus 15-km on each side of the pipeline.

One rare vascular plant, *Botrychium multifidum* var. *intermedium* was found during field surveys in the LAA. Six Environmentally Significant Areas (ESAs) are present in the RAA; one of the ESAs, the North Saskatchewan River Valley, is bisected by the LAA. All species identified in the LAA are common and are well represented elsewhere in the region (i.e., they are not considered provincially rare species), except for one rare vascular plant: leather grape fern. This rare plant occurrence was identified within the ROW. Mitigation for this occurrence of leather grape fern will be to transplant it to a site adjacent to the ROW where it will not be disturbed by construction or operation of the pipeline. It will be monitored for transplantation success.

Native vegetation in the RAA is fragmented, and non-native and invasive species are found typically within the interior of small patches of native vegetation. To mitigate environmental effects from fragmentation, much of the ROW parallels or intersects existing pipeline rights-of-way, and therefore, will not contribute to fragmentation in those areas and lessen fragmentation effects overall. Although the ROW bisects one ESA at the North Saskatchewan River, further fragmentation will not occur due to routing along existing pipelines and the use of a horizontal directional drill crossing under the North Saskatchewan River.

The assessment shows that although diversity may be reduced in the RAA landscape, community and species diversity will remain. Environmental effects on changes to landscape diversity, community diversity and species diversity are predicted to be not significant. Cumulative effects are determined to be not significant.

8.6 Wildlife and Wildlife Habitat

Potential environmental effects on wildlife and wildlife habitat include habitat reduction from vegetation clearing and increased sensory disturbance due to construction-related activities; habitat fragmentation; increase in direct wildlife mortality through collisions with vehicles; and increased predator access through an increase in linear infrastructure.

Project effects on wildlife and wildlife habitat have been assessed for the LAA, which includes the PDA plus 500 m on each side of the pipeline. The RAA has been considered to provide a regional context for interpreting the wildlife observations within the LAA.

The Project passes through three wildlife management areas (WMAs), including the Edmonton, Vermillion and St. Paul WMAs. The Project also passes through ESA 690, which consists of the North Saskatchewan River valley and some forested tributaries. This river valley contains diverse riparian and valley habitats, functions as a wildlife corridor and is a key wintering area for ungulates and other wildlife. However, the majority of Project activities is located in a highly fragmented landscape dominated by cultivated fields. The general environmental context for the region is disturbed lands with low biodiversity.

Close to 230 ha of land cover is expected to be disturbed along the 84-km long pipeline route, and approximately 78% (179 ha) of the PDA is on agricultural or previously disturbed lands. Cultivated fields make up 70% (160 ha) of the PDA. Therefore, most of the land cover in the PDA is considered to be of low quality or of no value to species at risk or most other wildlife. Habitat that is more likely to be suitable to most wildlife species is limited to approximately 25% (55 ha) of the PDA and exists in a highly fragmented state. Upland forest or shrub habitat is restricted to 10% of the PDA (22.7 ha), and 5.5% of the land cover is classified as wetlands, including marshes, fens and bogs.

Of the 11 Species at Risk chosen for the assessment, only western toad and Olive-sided Flycatcher were detected during baseline surveys and only the flycatcher was detected within the LAA. In addition, the only other assessment species that has been documented in other data sources in the RAA is the Common Nighthawk.

Of the potential 55 species of management concern known to occur in the region, less than half were detected in the LAA during the 2010 baseline surveys and only three are noted in the FWMIS within the RAA. Of the 20 species of management concern detected in the LAA, 15 were game species.

Availability of high suitability habitat for the assessed species is limited in the LAA. The landscape in which the construction of the Project is proposed is fragmented and disturbed. As a result, the magnitude of the environmental effect of construction activities on habitat availability for the assessed species is low. The predicted environmental effect is not significant.

Construction-related change in mortality rates of wildlife species will likely be constrained to areas where the PDA is within key habitat types. Given the limited geographic extent of key habitat in the LAA, few mortality events are predicted and will not affect wildlife populations or diversity at the local scale. Therefore, the magnitude of the effect of construction activities on wildlife mortality is considered low and is predicted to be not significant.

Since the landscape within the LAA is already fragmented and disturbed, and the construction phase of the pipeline will be short in duration, environmental effects of the Project construction on habitat connectivity are considered low in magnitude and not significant.

The environmental effects of the Project at the local scale are predicted to be low in magnitude and short in duration, Project environmental effects are predicted to not contribute measurably to environmental effects on regional populations. Therefore, cumulative environmental effects is not further assessed.

8.7 Historical Resources

The Project has the potential to affect historical resources during construction because activities such as well pad clearing and preparation, pipeline trenching, access upgrades and facility construction may disturb historical resources sites. Increased vehicle traffic during construction can result in damage or loss to historical sites, while increased access into the area construction activities may have secondary effects such as illegal artefact collection.

A baseline field survey was conducted and targeted areas with high potential for historical, archaeological or paleontological features. Eight precontact archaeological sites and two historic sites were discovered within the footprint of the Project; however, all have low heritage value, and no further study is recommended for the sites. Localities containing palaeontological resources (such as dinosaur fossil localities) were identified at four locations near the Project.

With respect to historical resources, Projects are regulated by Alberta Culture and Community Spirit (ACCS) under the *Historical Resources Act*. ACCS independently assesses the scientific value of historical resource sites and determines the need for, and scope of, mitigation measures. Consequently, project-specific effects on historical resources are mitigated to the standards established by ACCS.

In this context, after implementation of the required mitigation measures issued by ACCS, there is no residual effect from the Project on historical resources. All recommendations of the provincial heritage resource authorities will be implemented.

At the east side of the North Saskatchewan River crossing, a deep testing program for archaeological resources is recommended before Project construction. Palaeontological construction monitoring is recommended at the North Saskatchewan River (east valley slope) and Namepi Creek.

Shell will conduct historical resources surveys for any new areas of the PDA that have not yet been identified, such as pipeline laterals, new well pads, access roads and borrow pits. As there are no residual effects on historical resources, further assessment of potential cumulative environmental effects is not required.

8.8 Land Use

Land use in the area is primarily agricultural with some industrial and transportation corridors and small areas of natural vegetation. The potential environmental effects on land use are direct loss of agricultural land, disruption to agricultural and transportation activities, disruption to industrial activities, and consistency/non-consistency with intent of land use policies.

The Project has the potential to affect land use in the areas that will be physically disturbed by construction of the Project. Project effects on land use have been assessed for the LAA, which includes the PDA plus 500 m on each side of the pipeline, and the RAA, which includes the LAA plus 15 km on either side.

Construction of the pipeline and well pads will temporarily remove lands from agricultural use during construction. However, this direct loss of land from the agriculture land base will be reversed during operation. There will be a small gain of agricultural land in the assessment area after reclamation is complete due to conversion of some upland areas and cleared/burned areas to agricultural land. Following construction, temporarily disturbed areas (including the pipeline ROW) will be reclaimed to an agricultural or native seed mix, resulting in a low disturbance to the agriculture land base in the LAA.

The movement and storage of construction equipment and vehicles during construction of the Project may interfere with access to some agricultural lands and industrial facilities. Shell will consult with landowners and industrial operators in the LAA to identify any such interactions, and then act to avoid conflicts where feasible. To mitigate potential effects of the Project on railway traffic, Shell will establish railway crossing agreements with CN and CP. With implementation of mitigation measures, the Project will result in a low magnitude disruption to the agricultural activities, industrial activities, and rail traffic in the LAA.

Shell will be consistent with the intent of the existing land use policies in the LAA. However, the construction and operation of the pipeline and the injection wells takes place in areas that are not all currently designated for industrial use. While some of these areas may have to be re-zoned to industrial, Shell’s design of the pipeline and well pads has located the facilities in a manner to minimize disturbance to the environment and land use and with concern for public safety, so that the Project will be consistent with the intent of land use policies. Therefore, the Project is expected to be consistent with the intent of land use policies and effects are predicted to be not significant.

Project-related traffic during construction will act cumulatively with existing traffic in the RAA, but the effect is short-term, and is negligible in magnitude. In addition, the Project will not limit the availability of agricultural land in the RAA. The Project’s contribution to cumulative effects on land use is predicted to be not significant.

8.9 Public Health and Safety

The Project has the potential to contribute to effects on public health and safety, through the effects of air emissions on human receptors. In particular, health effects are evaluated through a human health risk assessment (HHRA), which is a quantitative, chemical-specific evaluation of potential health effects related to the Project and other emission sources in the region.

Effects are assessed for Base Case, Application Case and Planned Development Case.

The LAA is 50 by 50 km and includes the Cities of Edmonton and Fort Saskatchewan; the communities of Lamont, Redwater, Bruderheim, Gibbons, and Bon Accord. The RAA is 80 by 80 km, and includes the communities of Thorhild and Radway, as well as Elk Island National Park and Beaver Hills-Cooking Lake Moraine. The HHRA focuses on discrete receptor locations within a nominal 8 to 10 km distance of the Shell Scotford fenceline for evaluating locations where people are known to live or frequent.

The increased NO_X emissions associated with operation of the capture infrastructure may also result in an increase production of secondary particulate matter ($PM_{2.5}$). As no operational releases to water or soils are expected, the HHRA focuses on the inhalation of ambient emissions only. Uptake of the emitted chemicals into other environmental media (soil, vegetation, country foods, etc.) is not anticipated to occur.

The key findings of the HHRA are as follows:

- Minor exceedances of health-based acute inhalation exposure limits are predicted for NO_2 at two industrial receptor locations. In all cases, existing sources contribute the most to predicted exposures with minimal incremental change being attributable to the Project. Examination of these exceedances suggests that their occurrence would be intermittent and infrequent in nature.
- The maximum predicted concentrations of hourly NO_2 are below levels at which adverse health effects have been observed in exposed individuals.
- Concentrations of $PM_{2.5}$ are expected to remain below guidelines set for both short-term (i.e., 24-hour) and long-term (i.e., annual) averaging times.

The results of the HHRA indicate that the predicted concentrations of NO_2 and $PM_{2.5}$ are not expected to result in adverse health effects.

There are several existing monitoring and reporting programs that Shell participates in relative to air emissions from the Scotford Upgrader which are relevant to the HHRA.

8.10 Socio-Economics

Interaction between the Project and the socio-economic environment will occur primarily during construction. Key issues include housing effects, population effects, health provider effects, traffic effects and effects on emergency services and social services. Effects are assessed for both an Application Case and a Planned Development Case (PDC). Several potential effects are assessed at a local level, including the effects of construction traffic, the potential effects on accommodation and service providers and the potential effects on drilling locations.

The regional assessment area (RAA) is defined as the Edmonton Census Metropolitan Area and the urban municipalities within its boundaries, and the Counties of Thorhild, Lamont, Smoky Lake, Athabasca and Westlock and the urban municipalities within their boundaries.

The Project is expected to create 475 person-years of onsite full-time operation employment over the life of the Project. The projects included in the PDC are estimated to hire 1,635 positions between 2010 and 2020. The Quest CCS Project's workforce requirement represents less than 1% of this cumulative operation hiring.

Construction expenditures for the Project are estimated to be between $900 million to $1.2 billion. Construction expenditures will provide a stimulus to the provincial economy through wages and salaries paid to workers and direct purchase of goods and services, including equipment modules and structural steel elements as well as professional engineering and environmental services. Portions of these expenditures will circulate through the provincial economy, multiplying the economic benefits of the Project. Once the Project is fully operational, expenditures are expected to be $34 million annually. Annual expenditures may reach $42 million in years which involve maintenance turnarounds or seismic programs.

The Project is a collaboration between the Government of Alberta, the Government of Canada, Shell, and the AOSP Joint Venture partners. The funding agreement between the provincial government and Shell has not been finalized and therefore the treatment of the Project with respect to taxation is uncertain. Changes in the prices of key inputs into bitumen upgrading, such as natural gas or the light-heavy differential, have a greater effect on tax revenue than the costs associated with building and operating the Project.

The Application Case is not expected to have a measurable effect on changes in permanent population rate. The PDC is expected to have a permanent population effect in the RAA. The total PDC population effect is estimated at 2,600 persons or 0.2% of the expected population of the RAA at the end of hiring in 2020.

The Project-related housing effects will be limited to temporary accommodation requirements for non-resident workers. This demand is expected to be met by hotels, motels, campgrounds and short-term house and apartment rentals in the RAA. Cumulative operation hiring will drive housing demand in the RAA, particularly in Fort Saskatchewan, Strathcona County, Sturgeon County and Edmonton between 2010 and 2020 as various projects begin operation.

The road infrastructure close to Shell Scotford has been upgraded as part of the Scotford Upgrader and SE1. The current road infrastructure is sufficient to accommodate the CO_2 capture infrastructure workforce commuting traffic. The Project may generate some additional rail traffic for delivery of amine to the CO_2 capture infrastructure. The additional effect however on the existing rail volume within AIH will be minimal. Traffic effects associated with the CO_2 pipeline and storage components of the Project are expected to be localized and temporary in nature. Ongoing work will be required so that the infrastructure development plans are appropriate to the long-term investment activities of industry and community growth. Decisions to undertake development projects on primary and secondary highways lie with the provincial government, in consultation with municipalities and industry.

The Application case will have a limited effect on local health providers. Discussions with local health officials suggest that Shell's approach to safety and delivery of onsite health services were successful in mitigating the number of patients referred to the Fort Saskatchewan Health Centre during construction of SE1. The capacity of the RAA health system is sufficient to accommodate expected demands created by Project pipeline and drilling activities. Construction and operation-related activities associated with the PDC will have an effect on the health system in the RAA but capacity is expected to be sufficient to accommodate the additional demands represented by PDC activity.

The effects on emergency services will be much smaller than that experienced during the construction of SE1 because the Project's CO_2 capture infrastructure peak workforce is roughly 10% of the SE1 construction workforce peak. Fire and ambulance effects related to the Project are expected to be low. Onsite first medical response will be available, and Shell will coordinate response protocols with the Strathcona Emergency Services department. The construction workforce is expected to have substantially lower effect on police forces in the region as compared to SE1. Shell will incorporate observations from onsite security and traffic issues during SE1 into its policies and practices with a view to effects of the much smaller Project construction workforce. In the PDC, emergency response capacity in the RAA will need to increase, particularly in Sturgeon County and Lamont County as more industrial development occurs there. As development plans become certain and construction begins on proposed projects, municipalities and industry can finalize mutual aid agreements, funding and staffing requests, equipment purchases and infrastructure development. It is expected that these steps will be undertaken as projects included in the PDC commence, and therefore sufficient capacity will be in place to manage future effects.

Application Case effects on social services in the RAA are expected to be low because most construction workers are already resident in the RAA and the operation workforce is small. Discussions with Fort Saskatchewan Family and Community Services (FCSS) indicate that they did not experience increased effects on social services due to SE1, beyond issues related to traffic issues in the city. For the PDC, cumulative industrial activities are key drivers of population growth in the RAA. As communities grow, social service capacities will need to increase correspondingly in the RAA.

9 Conservation and Reclamation Plan Summary

The Pipeline Conservation and Reclamation (C&R) Plan addresses the CO_2 pipeline component of the Project. However, it does not consider the pipeline laterals because the locations of these have not yet been finalized; however the construction of the laterals will follow similar methods identified in the pipeline C&R. The C&R Plan for the CO_2 pipeline (see Appendix E) is a requirement under the *Environmental Protection and Enhancement Act* and the TOR for the Quest CCS Project.

Several CO_2 pipeline routes have been reviewed and considered for selection. Routing has involved careful review and consideration of regulatory requirements, landowner input and Project costs to determine the preferred and optional routes. The CO_2 pipeline has six anchor points, including the Scotford Upgrader and five injection wells. The final configuration could include four to 11 anchor points, depending on the number of wells developed. The pipeline also has a routing control point, where engineering, construction and environmental considerations have limited the options for a watercourse crossing on the North Saskatchewan River.

To characterize the environmental setting of the proposed CO_2 pipeline route, biophysical information that had been previously compiled and filed publicly was reviewed in conjunction with data collected during field investigations conducted between May 18 and September 3, 2010.

The CO_2 pipeline route lies entirely within the White Area. It is within Thorhild Plains, Redwater Plain and the North Saskatchewan Valley Districts of the Eastern Alberta Plains Physiographic Region.

The CO_2 pipeline route is underlain by bedrock from the Upper Cretaceous nonmarine Belly River Group. The surficial geology includes Pleistocene and Holocene deposits. North of the North Saskatchewan River is dominated by glacial till composed of an unsorted mixture of clay, silt, sand and gravel with minor amounts of water-sorted material. Glaciolacustrine and glaciofluvial stream sediments, as well as a few small deltaic deposits, are adjacent to the North Saskatchewan River. Aeolian deposits occur in the area near the southern end of the CO_2 pipeline route.

The soils underlying most of the CO_2 pipeline route are dominated by Black Chernozemic soils, but have appreciable extents of less-productive Dark Gray Chernozemic soils and Brunisolic soils. The northern part of the route has a high proportion of Luvisolic soils, reflecting the climatic transition between parkland to the south and boreal forest to the north.

The proposed CO_2 pipeline ROW crosses 18 watercourses, ranging from ephemeral field drainages to the North Saskatchewan River. All watercourses are part of the North Saskatchewan River drainage basin, and all of the small watercourses crossed by the ROW are direct tributaries of the North Saskatchewan River. Most water bodies surveyed along the proposed CO_2 pipeline route are considered ephemeral.

Of the 18 crossings identified, only five crossings have fish habitat potential. These five crossings occur on four watercourses: the Astotin, Beaverhill and Namepi Creeks and the North Saskatchewan River. The North Saskatchewan River crossing contained fish habitat that has some potential for use by lake sturgeon as spawning habitat and spawning by other coarse substrate spawners like walleye, sauger, and suckers. Lower Namepi Creek contains suitable habitat for spring spawning sucker species. Other crossings have habitat suitable only for forage fish and are ranked as marginal habitats. All watercourses will be crossed using methods outlined within one of DFO's Operational Statements and will not result in the harmful alteration, disruption or destruction of fish habitat.

As construction is occurring in the winter, the preferred crossing method for most of the watercourses is open cut, assuming the creeks are dry or frozen to the bottom. A trenchless method is the contingency plan for these crossings if flowing water is present at the time of construction, provided they meet the DFO Operational Statement criteria for open cut crossings. The North Saskatchewan River will be crossed using HDD, with open cut as the contingency

The CO_2 pipeline route crosses two Natural Regions and Subregions: the Central Parkland Natural Subregion of the Parkland Natural Region and the Dry Mixedwood Natural Subregion of the Boreal Forest Natural Region (Natural Regions Committee 2006). The Central Parkland Natural Subregion consists of groves of aspen intermixed with grasslands, with marshes typically found in depressions. The native vegetation of the Dry Mixedwood Subregion includes upland forests dominated by aspen along with stands of birch and balsam poplar. Coniferous forests can also be present. Fens are the typical wetland type here and can be wooded or support a canopy of shrubs or sedges. Large parts of the Central Parkland and southern part of the Dry Mixed Subregions have been converted to agricultural, residential and industrial use. Although no rare ecological communities were identified; one rare vascular plant, leather grape fern, was found during field surveys. Mitigation measures identified are expected to address potential effects to this species. The point where the CO_2 pipeline route crosses the North Saskatchewan River is considered an environmentally significant area (ESA) by the Province of Alberta, although the construction is not expected to affect this ESA. Several noxious and introduced weed species were identified during vegetation field surveys. In addition, clubroot, a soil-borne disease, has been identified as occurring in areas along the CO_2 pipeline ROW.

The wildlife community along the CO_2 pipeline route was evaluated using existing information on wildlife known to occur along the CO_2 pipeline route, as well as acoustic amphibian surveys, and yellow rail and breeding bird surveys. From the information collected, the species at risk with the highest regulatory and management concern anticipated to occur in the area were chosen to represent the broader suite of wildlife species found along the ROW. The potential species at risk selected included the Western toad, the Yellow Rail and nine other bird species. Each of the species selected is listed under Schedules 1, 2 and 3 of the *Species at Risk Act* (*SARA*), Committee on the Status of Endangered Wildlife in Canada (COSEWIC), or under the Alberta *Wildlife Act* as Endangered or Threatened. Western toads occur at the northern end of the ROW, but no closer than 8.3 km from the CO_2 pipeline route. No yellow rails were detected during field studies.

The CO_2 pipeline route spans the municipal boundaries of four municipalities: Strathcona County, Lamont County, Sturgeon County, and the County of Thorhild No. 7. The five potential CO_2 injection well pads and laterals, however, are all located within the County of Thorhild No. 7. Land use types along the CO_2 pipeline route can be grouped into natural landscapes, agricultural lands and industrial lands. The proposed CO_2 pipeline route crosses privately owned agricultural land and includes mixed cultivation and pasture land. The route will not cross First Nations reserve lands or traditional territories.

During field studies, 18 pre-contact archaeological sites and eight historic sites were identified along the CO_2 pipeline route. Of these sites, ten are currently located within the ROW, nine have low heritage value, and the tenth site (a structure) is of moderate heritage value. Three areas of paleontological interest also occur along the CO_2 pipeline route.

Although the proposed route and construction methods have been selected to limit the effects of the Project on the environment and existing land users, there is the potential for Project activities to produce environmental effects. For an overview of the potential environmental affects anticipated and the mitigation measures selected to reduce these environmental effects, see Table 9-1.

Table 9-1 Potential Environmental Effects and Proposed Mitigation

Potential Environmental Effect	Mitigation
Soils and Terrain	
Terrain instability on steep slopes at watercourse crossings as a result of CO_2 pipeline installation	• Use the geotechnical evaluations for the NSR crossing, which have been completed to determine the feasibility of the proposed HDD crossing method. • Complete trenchless crossing of Beaverhill Creek, if an open cut method is not viable under DFO's Operational Statement. • Develop erosion control and terrain stability plans for watercourses where trenched crossings are proposed.
Disruption of natural surface drainage	• Compact and recontour replaced materials appropriately, to restore the elevations that existed before construction.
Soil contamination due to soil admixing	• Conduct topsoil stripping activities according to the prescribed soil handling procedures in the EPP (see Appendix I) and on the environmental alignment sheets (see Attachment B of Appendix I). • Use suitable equipment and soil handling and storage procedures. • Back slope trench walls, if sloughing is encountered on the walls, and acquire any additional TWS before further stripping or soil storage.
Soil contamination due to mixing upper soil layers with deeper soil layers	• Excavate, store and replace the distinct soil layers to avoid any mixing.
Soil contamination due to introduction of hazardous materials or wastes	• Inspect and maintain all construction equipment and vehicles routinely, to prevent leakage of fuels, coolants or lubricants from contacting the ground. Store hazardous materials securely. Dispose of garbage and construction waste appropriately. • Establish proper training, equipment and materials and monitor them to ensure appropriate preparation for a spill or release event.
Soil contamination due to introduction of soil borne diseases and pests	• Limit or eliminate the movement of contaminated soil materials between parcels of land. • Disinfect any construction-related object based on the identified risk of diseases being present. • Develop specialized plans for managing disease and pests. Update plans before and after construction.
Soil compaction	• Limit travel in locations where fine or moderately fine-textured soil materials occur and during wet soil conditions. • Place restrictions on the timing of traffic and weight of equipment. • Strip and salvage the soil layers that may be degraded, and replace them when vehicle and equipment passage is no longer required. • Consider the installation of snow ramping, matting or geotextiles.

Table 9-1 Potential Environmental Effects and Proposed Mitigation (cont'd)

Potential Environmental Effect	Mitigation
Soils and Terrain (cont'd)	
Erosion	• Limit soil disturbance, especially on soil types susceptible to erosion. • Employ ways of reducing or containing the movement of disturbed soils.
Increase in surface stoniness	• Remove stones from the surface of the backfilled subsoil and topsoil.
Surface Water and Aquatics	
Water quality and quantity	• Conduct watercourse and wetland crossing and hydrostatic testing according to the appropriate *Water Act Codes of Practice*, *EPEA Code of Practice* and conditions or advice provided by the regulatory agencies consulted. • Schedule construction activities to avoid restricted activity periods and take advantage of seasonal low flows. • Develop appropriate pollution prevention and spill contingency plans.
Fish or aquatic species rescue	• Have fish rescue completed by qualified personnel. • Salvage and restore excavated bed and bank material. • Screen all water withdrawal intakes according to the *Water Act* and DFO (1995) requirements.
Loss or alteration of habitat	• Verify that all activities comply with the *Water Act*, DFO Operational Statements and the *Pipeline Associated Watercourse Crossing* guideline (CAPP 2005). • Verify that crossing locations meet the Operational Statement criteria for the proposed crossing method and that they have a valid contingency method.
Vegetation	
Rare plant and communities	• Mark rare plant locations on the environmental alignment sheets and provide appropriate mitigation measures in the EPP. • Construct the pipeline route to follow existing linear disturbances as much as possible. • Revegetate areas of native vegetation with an appropriate seed mix.
Wetlands	• Consult with AENV for mitigation, approval and possibly compensation for directly affected wetlands. • Maintain existing drainage patterns through surface drainage planning and installation of silt fencing for wetlands immediately next to the Project area.
Introduction and spread of weeds	• Limit the extent of disturbance. • Limit the potential for weed seeds to be transferred, and use a weed control program to respond quickly to infestations.
Wildlife and Wildlife Habitat	
Wildlife mortality	• Schedule construction activities during the winter, to avoid the presence of many wildlife species, where appropriate. • Mark locations of wildlife species on the environmental alignment sheets, and provide site-specific mitigation measures in the EPP. • Prohibit recreational all-terrain vehicles, pets and firearms from the Project area. Restrict work-related travel to avoid low-light conditions, and adhere to posted speed limits. • Store hazardous materials securely. Dispose of garbage and construction waste appropriately.

Table 9-1 Potential Environmental Effects and Proposed Mitigation (cont'd)

Potential Environmental Effect	Mitigation
Wildlife and Wildlife Habitat (cont'd)	
Loss or alteration of habitat	• Reduce areas to be cleared and ensure adequate definition of work area boundaries. • Complete supplemental surveys before construction to identify any habitat for wildlife species at risk or of management concern and include additional mitigation in the EPP. • Reclaim areas of native vegetation using native seed mix, planting willow stakes, salvaging native vegetation and using encroachment of small shrubs and trees.
Fragmentation of habitat	• Create periodic breaks in strung and welded pipe and salvaged soil piles, along with corresponding bridges in the excavated trench at intervals, to allow wildlife movement.
Sensory disturbance	• Avoid sensitive timing of wildlife lifecycles. • Maintain appropriated setback distances form important habitat features wherever possible.
Land Use	
Disruption of residents	• Maintain effective communication with residents regarding all relevant Project information (location, timing, safety), and any updates, throughout the duration of Project activities.
Disruption of recreation	• Provide appropriate notification of watercourse crossing activities to the local population and post signage to inform recreational users of construction activities and timing. • Notify outfitting companies of construction schedule, and avoid areas and timeframes used for hunting and fishing where feasible.
Disturbance of agriculture	• Communicate directly with agricultural operators so that Project activities, and how these might interact with agricultural operations, are fully understood. Monitor and update information. • Negotiate compensation for disruptions in agricultural operations as soon as reasonable.
Disturbance of industry	• Conduct active and ongoing consultation with other industrial land owners in the Project area, including owners of road, rail, and other pipeline installations. • Conduct extensive planning, adhering to required agreement conditions and occupational health and safety guidance on ground disturbance practices, to avoid potential land use conflicts.
Historical and Paleontological Resources	
Historical resources	• Conduct a deep testing program, as recommended for the east side of the North Saskatchewan River.
Palaeontological resources	• No mitigation measures are outlined in the C&R Plan.

For the alignments sheets for the CO_2 pipeline route, see Attachment B of Appendix I. The alignment sheets show the entire CO_2 pipeline route at a scale of 1:5,000 and illustrate relevant environmental and socio-cultural features near the ROW. They also include location-specific mitigation measures, such as wildlife habitat setbacks and soil handling procedures.

Conservation and reclamation plans were also developed for each of the five injection wells (see Appendix F). These site-specific pre-disturbance assessments and C&R plans present baseline conditions at the locations of the well pads and associated facilities, and provide relevant construction, conservation and reclamation details.

The Pipeline EPP accompanies the Pipeline C&R Plan. The Pipeline EPP describes measures to be implemented during CO_2 pipeline construction and reclamation to limit and mitigate potential adverse environmental effects. It is an integral part of the construction contract and should be used during construction and reclamation of the CO_2 pipeline and its associated facilities.

The Pipeline EPP addresses construction with standard construction practices and equipment during frozen ground conditions in the late fall through winter, when CO_2 pipeline construction is scheduled to occur. The Pipeline EPP also includes typical construction drawings, environmental alignment sheets, contingency plans and Operational Statements from DFO.

If construction timing is rescheduled outside the projected time, the Pipeline EPP will need to be revised and updated accordingly. The Pipeline EPP will be reviewed before construction so that any changes to the CO_2 pipeline ROW, detailed design and any applicable approval conditions are reflected.

10 Measurement, Monitoring and Verification Plan Summary

The Quest CCS Project is located within the Alberta Basin and the geology of the selected storage site offers multiple layers of protection to minimize the potential for any CO_2 or brine to result in environmental effects to the protected groundwater zone, the ecosystem, or the atmosphere. Each geological seal on its own is likely to be sufficient to ensure long-term containment of injected CO_2 and the displaced brine. However, no matter how detailed and extensive the appraisal program to characterize these geological seals, some small uncertainty and risk will remain. The MMV plan aims to verify the storage performance and the absence of any significant environmental effects due to CO_2 storage. If necessary, MMV activities shall create additional safeguards by triggering control measures that prevent or correct any loss of containment before significant environmental effects could occur.

As part of the MMV plan, a risk-based workflow has been applied. This relies on a systematic assessment of the whole suite of containment risks, followed by a review of the effectiveness of safeguards provided by geology, engineering and a recognition of MMV performance targets. The proposed conceptual MMV plan is designed to have the sensitivity, speed and scale necessary to provide early warning of any breach of containment. This would trigger appropriate responses, thereby reducing the remaining risk, and ensuring that the remaining risk is insignificant compared to everyday risks broadly accepted by society.

Transfer of long-term liability will depend on the actual storage performance verified through MMV activities. The MMV plan will be designed to demonstrate that actual storage performance conforms to model-based forecasts and that these forecasts are consistent with permanent secure storage at an acceptable risk.

For the full MMV plan, see Appendix A.

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